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ENERGY CONSULTING

Report on international experience with smart meters (energy)

Prepared for:
The Parliamentary Commissioner for the Environment

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Preface

Strata Energy Limited specialises in providing services relating to the energy industry and energy utilisation. The company was established in 2003. Strata Energy provides advice to clients through its own resources and through a network of associate organisations. Strata Energy's consulting division, Strata Energy Consulting, has completed work on a wide range of topics for clients in the energy sector in both New Zealand and overseas.

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Executive summary

1. For more than a century the measurement of electricity consumption for the vast majority of consumers has been accurately recorded using meters that are read manually by a meter reader visiting the consumer's premises. However, economic, environmental and technological drivers are now combining to provide a worldwide impetus for the introduction of smart electricity metering. In jurisdictions around the world, smart metering is being seen as an enabler of a number of applications and processes that can address some of the issues relating to:
   a) electricity costs;
   b) efficient electricity price signalling;
   c) choice of services and information for electricity consumers;
   d) electricity outage management and system monitoring for electricity distributors;
   e) efficient energy usage; and
   f) a reduction in greenhouse gas emissions.
2. For the purposes of this report, smart metering is defined as an electronic meter with functionality that (at a minimum) allows for:
   a) two-way communication between the metering point and data collector or energy supplier;
   b) manual or automated response to load control and/or pricing signals; and
   c) secure and robust management of data between relevant parties.
3. The potential benefits to be realised from implementing smart metering are driving ever-increasing functionality requirements. Both the benefits of smart metering and the associated functionality are discussed in this report.
4. Internationally, the status of smart metering implementation programmes ranges from conceptualisation, through cost-benefit analyses and trials, to completed implementation. An international overview of smart metering is provided in this report, along with three international case studies that demonstrate a range of activities associated with investigating and implementing smart metering.
5. In New Zealand, the implementation of smart metering is in its formative stages. Currently, smart metering is installed in 3 percent of New Zealand's electricity metering installations. However, despite the small number of smart electricity meters currently installed in New Zealand, there appears to be an intention amongst the majority of electricity market participants to move towards smart metering over the next five years.
6. Hence, the opportunity exists for New Zealand to learn from overseas experience before undertaking any substantial rollout(s) of smart metering. Despite the differences between New Zealand and virtually all of the overseas jurisdictions currently progressing smart metering initiatives, there are several key insights that New Zealand can glean from overseas experience. Some of the key matters for consideration by New Zealand from the application of international approaches and learning include:

a) the importance of enunciating policy objectives upfront, so that key AMI design decisions can be made;

b) ensuring that some of the trials of smart metering are public trials, to enable the sharing of information across stakeholders; and

c) clearly defining the roles and responsibilities of stakeholders in the event that smart metering is implemented.

7. Should New Zealand proceed with the widespread introduction of smart metering, a number of implementation challenges are likely to arise, particularly in respect of ensuring that the design of the smart metering arrangements enable the achievement of the public policy objectives. Government can play a key role, not only in defining public good aspects of energy policy, but also in effecting legislation and/or regulation required to address market and regulatory imperfections surrounding the introduction and ongoing use of smart metering.

8. This report posits that the primary environmental benefits of smart metering are a reduction in greenhouse gas emissions and a reduction or deferral in new infrastructure investments (generation and transmission / distribution). These environmental benefits are delivered through consumers either forgoing or conserving electricity use or moving their usage to off-peak times, especially during the night.

9. It should be noted however that environmental benefits generically similar to those listed against smart metering may also be achieved through the use of alternatives, such as ripple control systems coupled with multi-rate basic meters.

10. The report concludes with the following set of recommendations, which outline the key steps required in seeking to achieve New Zealand's energy and environmental policy outcomes via the use of demand response initiatives such as smart metering:

a) as a starting point, a robust inventory of New Zealand's metering and ripple control assets should be undertaken. This should also include confirmation from electricity industry participants of the number of smart meters that they intend to roll out over the next 5-10 years and the timeframe within which this will occur. The purpose of this survey is to establish the extent to which the New Zealand electricity industry is committed to rolling out smart metering;

b) New Zealand's energy and environmental policies should be clearly defined, and followed by implementation of rules and regulations catering (in a non-discriminatory manner) for the range of alternative demand response technologies that can be used to effect these policies (e.g. smart metering, multi-rate metering, ripple relay technology and in-home displays);

c) public trials and pilot schemes should be undertaken to assess the extent to which demand response can be achieved through active means (i.e. via price signals) and passive means (e.g. via ripple control);

d) if the New Zealand electricity industry does not demonstrate sufficient commitment to achieving the country's energy and environmental policy outcomes via the use of demand response initiatives such as smart metering, a public cost-benefit analysis should be undertaken to determine the extent of additional regulation required to achieve those outcomes. The results from the public trials and pilot schemes would feed into this; and

e) finally, it should be remembered that the drivers for electricity industry participants to roll out smart metering are not necessarily aligned with national energy policy and environmental objectives. Should smart metering become widespread in New Zealand, there will still remain a need to ensure that these policy objectives are met.

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Introduction and purpose

11. The development and convergence of metering and communication technologies is making the installation of advanced metering infrastructure (AMI) on electricity supply networks more cost-effective.

12. The increasing cost of energy in both economic and environmental terms is leading governments, electricity utilities and consumers to seek better solutions to the ways in which energy can be conserved and used most efficiently.

13. In jurisdictions around the world, advanced metering (also known as smart metering) is being seen as an enabler of a number of applications and processes that can address some of the issues relating to:

    a) electricity costs;
    b) efficient electricity price signalling;
    c) choice of services and information for electricity consumers;
    d) electricity outage management and system monitoring for electricity distributors;
    e) efficient energy usage; and
    f) a reduction in greenhouse gas emissions.

14. Internationally, continued growth in energy consumption, along with ageing generation[1], transmission and distribution assets and a growing resistance to infrastructure expansion, are combining to present economies with challenges on how best to utilise existing energy assets before investing in expansion or replacement.

15. A key benefit of smart metering is that it provides a means by which consumers can manage their use of electricity better, thus allowing them to reduce their electricity consumption or shift the time at which they use electricity. This in turn enables the deferral of investment in electricity generation, transmission and distribution assets and may result in significant reductions in greenhouse gas emissions.

16. Smart metering also offers a number of other benefits, ranging from automated remote meter readings and a more efficient customer switching process, to more efficient management of electricity networks.

17. Smart metering is being investigated and implemented around the world. A number of cost-benefit analyses are being performed, numerous pilot schemes have been launched, and a number of rollouts are either in progress or have been completed.

18. The purpose of this report is to define how smart metering works, how it can be used to benefit consumers, suppliers and the community, and what New Zealand can learn from other jurisdictions that are addressing their electricity supply issues using smart metering.

1 New Zealand's generation assets are relatively young by international standards.

Background

19. The Parliamentary Commissioner for the Environment (PCE) has developed a new strategic plan, which consists of a number of work streams, including energy. With Government and industry investigating the application of smart meters in New Zealand, the PCE believes it important that the environmental benefits of this technology are explicitly recognised and understood before it is introduced in New Zealand.

20. The PCE has provided a clear description of its requirements in the Request for Proposals (RFP) document. Strata Energy understands that the PCE's primary requirement for this consultancy assignment is the preparation of a report which provides key recommendations based on the terms of reference below:

    a) provide an overview of international development and implementation of smart meters;

    b) use case studies to illustrate a range of smart meter rollouts and uses, including quantification of the reduction of peak power or electricity consumption, and the costs of smart meters;

    c) address smart meter implementation challenges and measures needed to maximise environmental benefits by identifying:

        i) barriers to implementation, and how these barriers have been addressed;

        ii) key design features needed, and how these can be provided; and

        iii) the role of government for facilitating implementation;

    d) discuss the application of international approaches and learnings to New Zealand. Include discussion of how to ensure the easy and cheap transfer of meter ownership when a customer changes suppliers, and what minimum technical standards are needed to ensure maximum environmental benefit to New Zealand.

21. Strata Energy understands that the PCE is particularly interested in the degree to which smart meters have delivered benefits to consumers while reducing the electricity sector's environmental footprint. Specifically the PCE would like to know if a consumer, provided with additional information about his or her electricity use coupled with price signals, will reduce peak use and whether emissions will reduce as a result. Also, do smart meters result in load shifting?

22. Lastly, Strata Energy understands that the PCE would like to learn about both the degree of uptake, and also the state of play with regulation such as emerging international standards, along with the most effective implementation options for smart meter technology (policy, technical, operational or otherwise).

Introduction to smart metering

Background and definition

23. For more than a century the measurement of electricity consumption has been accurately recorded using electro-mechanical Ferraris disc meters that are read manually by a meter reader visiting the consumer's premises. These meters can record consumption as a single number (a single register meter), or have multiple registers that separately record consumption at different times of the day (time-of-use (TOU) consumption recording). Switching between the registers can be done using time clocks or ripple control signals.

24. In the latter part of the twentieth century electronic meters with no moving parts began to be installed, replacing the Ferraris disc meters. Sophisticated meter reading devices began to replace the pen and paper formerly used by meter readers. In some instances, the installation of communications to the meter provided an opportunity for the meter to be read remotely. This functionality is known as automated meter reading (AMR) and entails the meter communicating consumption totals for a defined period of time (e.g. daily or monthly) to a central data collection point.

25. However, for the vast majority of meters in New Zealand a physical visit to the premises continued to be required in order to record the electricity consumption so that consumers could be invoiced.

26. It was thought initially that the advent of competition in the retailing of electricity during the 1990s would lead to significant advances in metering, to enable opportunities for retailers to develop innovative products and consumers to be able to respond to electricity market price signals. It was envisaged meters that recorded electricity on an interval basis (e.g. half-hourly) would become more prevalent, thereby enabling retailers to pass on wholesale electricity market price signals to consumers.

27. However, the development of deemed and dynamic load profiles[2] to estimate half-hour volumes from non-interval metered electricity consumption slowed the advances in interval metering. The cost of profiling was significantly lower than the cost of installing an interval meter. It is only in recent years, with further technological advances, that the option of installing interval meters for mass market consumers has become sufficiently cost-effective to be considered an economically-viable alternative to using profiling.

28. It is important to note that interval meters do not in themselves provide electricity consumers with real-time price (RTP) information. Rather, they enable consumers to see the price of electricity on a half-hour basis at the time of receiving their next electricity invoice. In order to provide consumers with real-time[3] price information, it is necessary to install communications to the customer's premises enabling this information to be conveyed from a remote data source (e.g. the retailer's offices).

29. Combining the provision of RTP information and AMR requires two-way communications with the meter. With this functionality, the meter becomes an advanced meter, or smart meter. The smart meter and the associated

2 Deemed profiles are static profiles of consumption whereas dynamic profiles are non-static profiles of consumption.

3 For the purposes of this report "real time" is taken to mean within approximately an hour either before or after consumption occurs.

communications to and from it are commonly known as advanced metering infrastructure (AMI).

30. Advanced metering, smart metering and AMI are commonly used interchangeably. For the purposes of this report, smart metering is used primarily, consistent with the language in the Request for Proposal, and is defined as:

a) an electronic meter with functionality that (at a minimum) allows for:

i) two-way communication between the metering point and data collector or energy supplier;

ii) manual or automated response to load control and/or pricing signals; and

iii) secure and robust management of data between relevant parties.

Smart metering communications

31. As noted above, the meter is just one component of the smart metering infrastructure. Meters are smart because of the underlying technology associated with AMI. In addition to the meter, there is also the communications infrastructure and the data collection and management systems and processes. There has been some debate as to where the "smartness" should reside – in the meter or in the metering data management (MDM) systems located in the back office of the data collector? Industry consensus internationally appears to be coming down on the side of centralised intelligence in order to accommodate the IT applications for interval data and related communications systems[4].

32. As noted above AMI requires the use of two-way communications. This contrasts with the use of one-way communications for AMR and for direct load control at consumers' premises. Smart metering utilises wired and wireless communications technologies, which include:

a) wired networks using frequencies above the power frequency:

i) Power Line Carrier (PLC), where data is transferred over the medium and low voltage power lines;

ii) Distribution Line Carrier (DLC), where data is transferred over the low voltage power lines;

iii) Broadband over Power Line (BPL), where data is transferred over the medium and low voltage power lines at higher rates than under the PLC and DLC communications options.

b) wireless networks:

i) General Packet Radio Service (GPRS), which transmits and receives data in packets over a Global System for Mobile communications (GSM) network, rather than establishing a continuous channel from a portable terminal for the transmission and reception of data;

ii) 3rd Generation cellular (3G), which operates on wide area cellular telephone networks and offers high-speed internet access and video telephony, with speeds upwards of 2Mbps;

4 Smart Metering for Electric and Gas Utilities – an Oracle White Paper, November 2007, p.9

iii) Worldwide Interoperability for Microwave Access (WiMAX), which enables the high speed wireless transmission of data over longer distances (commonly in the range of 10-20 km) using a microwave radio system;

iv) mesh radio, where data is transferred between smart meter modems until they reach a data concentrator, from which the data is then transferred to the data collector's MDM system;

33. Most of these systems exist or are seriously being considered for use in New Zealand.

34. Smart meters can also have the capability to communicate with appliances within a consumer's premises via a home area network (HAN). A HAN will use technologies such as Zigbee or Bluetooth to connect digital devices within a premises (e.g. computers, home security systems and 'smart' appliances, such as air conditioners, heat pumps, washing machines and dryers, that have the ability to be remotely controlled). Zigbee can also be used to communicate with concentrators in a mesh radio solution as described above.

Smart metering functionality

35. The potential benefits to be realised from implementing smart metering are driving ever-increasing functionality requirements. The list below represents a compilation of typical specifications listed by a number of United States energy utilities in their recent AMI RFPs[5], and the current draft minimum Australian specification for smart meters[6], and New Zealand's smart metering functionality requirements, as set out by the Electricity Commission[7]:

a) ability to measure, record and provide time-stamped TOU data for each customer, often hourly, but also for as short an interval as 15 or 30 minutes[8];

b) ability to remotely read meters on demand;

c) ability to detect tampering;

d) memory to store a specified minimum number of days of readings on the meter (minimum of 15 days (New Zealand), 35 days (Australia) and anywhere from 7 to 45 days depending on the utility (USA));

e) daily reading of meter registers, often between midnight and 6am of the day following the measurement and recording of consumption;

f) ability to record active energy flows both into and out of the electricity network in instances where a customer has installed local generation (e.g. photovoltaic cells);

g) option of remote disconnection/connection;

h) ability to limit power to individual customers (e.g. in recovery from a blackout to manage stability, or in order to provide a capacity-based tariff

5 Assessment of Demand Response & Advanced Metering 2007, Federal Energy Regulatory Commission, 2007, p.25

6 MCE Decision Paper, A National Minimum Functionality for Smart Meters, 13 December 2007

7 Advanced Metering Policy, Electricity Commission, April 2008

8 The Electricity Commission has not stated that smart meters must be 60/30/15 minute interval meters. Instead the Commission considers that, as a minimum, a smart meter should contain at least six general accumulation registers which may start and stop their accumulation at programmable times to at least 30 minute resolution and coincident with the half hour meter data logging boundaries.

option, or as a "soft" means of dealing with non-payment by providing a minimal capacity to the premises as an alternative to disconnection);

i) ability to change meter settings (e.g. load management, supply capacity control) remotely;

j) ability to remotely upgrade meter firmware[9];

k) ability to send load control messages to equipment in or around customer home (e.g. hot water cylinders) to support demand response;

l) positive notification of outage and restoration;

m) enable the recording and remote reading of information in relation to quality of supply and other events (e.g. outage);

n) voltage flagging capability if voltage is outside of the range configurable by the local utility;

o) voltage interval reading capability at same interval as meter readings;

p) measurement, recording and remote reading of reactive interval energy measurement and recording on three phase meters;

q) support for some form of prepay metering (since disconnection and reconnection are easily managed);

r) inclusion of data warehousing systems – seen as increasingly necessary to store large volumes of data gleaned from AMI and MDM systems;

s) tight integration with MDM into overall operations management systems – with links to accounting, billing, reporting, outage management, and other operations systems; and

t) ability to extend AMI and smart grids to multiple in-home appliances, including an in-home display, connected together as part of a HAN;

u) enable meters to be activated and registered on the system remotely once installed, rather than manually;

v) remote synchronisation of the meter time clock;

w) ability for the meter to be read visually (using the meter display) and/or using a hand-held device;

x) ensure appropriate communications and data security (e.g. use of commonly used protocols (such as XML[10]); secure storage, transportation and processing of data; a time-stamped event log capturing critical smart metering parameter or state changes).

36. The table below summarises the smart metering functionality described above across New Zealand (confirmed national minimum functionality), Australia (draft national minimum functionality) and the United States (a compilation of typical specifications listed by a number of energy utilities):

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9 Computer programming instructions that are stored in a read-only memory unit rather than being implemented through software.

10 Extensible Markup Language

Functionality	New Zealand	Australia	USA
Measurement and recording of time-stamped consumption data to at least 30 minute intervals	✓	✓	✓
Tamper detection	✓	✓	✓
Remote disconnect/connect	✓	✓	✓
Quality of supply monitoring	✓	✓	✓
Notification of outages	✓	✓	✓
Provision for a HAN	✓	✓	✓
Remote upgrade of meter software	✓	✓	✓
Minimum meter reading storage	15 days	35 days	7-45 days
Support prepay metering	✓	✓[11]	✓
Communications and data security	✓	✓	
Remote reading on demand	✓		✓
Daily reading		✓	✓
Local reading using visual display	✓	✓	
Export/import reading	✓	✓	
Remote load management	✓	✓	
Limit power to consumers	✓	✓	
Provision for an interface to an in-home display	✓	✓	

11 While support for prepay metering is not explicitly listed in the draft minimum national Australian functionality, the remote connect/disconnect functionality included in the national specification is considered to support prepay metering through back-office systems and the like – i.e. system disconnects, reconnects or supply limits based on product and credit status.

Functionality	New Zealand	Australia	USA
Remote changing of meter settings (e.g. supply capacity control)	✓	✓	
Remote time clock synchronisation	✓	✓	
Use of common protocols	✓		
Reactive energy measurement (for three phase meters)		✓	
Remote registration and activation of new meters		✓	
Voltage interval reading			✓

Table : Smart Metering Functionality

Benefits and costs of smart metering

Benefits

37. Depending on what functionality is included, smart metering can offer a range of benefits to consumers, distributors, retailers, the economy and the environment. A number of these benefits are listed below, grouped into general categories that identify the party to whom the primary benefit flows. A benefit to one party may represent a cost to another party (e.g. retailers and generators may earn less revenue as consumers reduce their consumption as a consequence of TOU pricing / critical peak pricing (CPP)).

38. Major identified benefits of smart metering include[12]:

a) Consumers:

i) providing increased and relevant information to electricity users to assist in promoting the efficient use of electricity and reduced power bills. Consumers viewing their consumption and the associated cost of that consumption in small (up to 15 minute) intervals, rather than large (e.g. monthly) intervals, are able to make more informed consumption decisions. If consumers have in-home displays, then pricing information can be provided close to real time, enabling further improvements in their decision making;

ii) providing an opportunity for smart appliances to be installed at a consumer's premises, which can be programmed to respond to electricity price or other signals relayed via the smart meter;

iii) improving customer service through improved billing accuracy and enabling retailers to provide more innovative products to consumers;

iv) providing the opportunity to offer load reduction to distribution and transmission network owners and to retailers, either directly or via a demand aggregator;

v) providing the opportunity to offer interruptible load into the market for electricity ancillary services (e.g. reserves and voltage support), either directly or via a demand aggregator;

vi) reducing the amount of unserved energy at a consumer's premises, due to improvements in outage restoration times enabled by premises-level outage information;

vii) potentially reducing energy costs, both by managing energy use better within the premises, and also through the potential for lower per-unit supply tariffs enabled through better utilisation of the transmission and distribution networks and by aggregate load shifting towards lower-cost generation times;

12 Advanced Metering Policy, Electricity Commission, April 2008

Cost Benefit Analysis of Smart Metering and Direct Load Control. Stream 2: Network Benefits and Recurrent Costs. Phase 2 – Consultation Report, CRA International, February 2008

Cost Benefit Analysis of Smart Metering and Direct Load Control. Workstream 3: Retailer Impacts – Phase 2 Consultation Report Ministerial Council on Energy, KPMG, March 2008

Cost Benefit Analysis of Smart Metering and Direct Load Control. Workstream 4: Consumer Impacts Phase 2 Consultation Report, NERA, February 2008

b) Retailers:

i) allowing retailers to offer a range of new products/services, including new tariff products, load management services, home automation and information services;

ii) allowing retailers to more accurately sculpt tariff products to customer groups' loads and to determine cost of supply at the resolution of an individual customer by time period;

iii) avoiding the cost of profiling and reducing the cost of load research;

iv) providing more timely and accurate consumption information to retailers so that the duration (and cost) of time spent on customer billing enquiries falls;

v) reducing fraud/theft and bad debts and the costs associated with revenue protection and bad debts;

vi) reducing working capital costs for retailers as a consequence of quicker meter reads and therefore quicker invoicing of customers;

vii) providing increased accuracy in the settlement process as a consequence of lower non-technical losses caused by meter tampering and profiling;

viii) allowing retailers to reduce their data validation costs and to optimise their contracted positions against consumer load and reduce hedging costs;

c) Meter readers:

i) avoiding the need (and cost) to visit a consumer's premises to undertake routine/special meter reads[13];

ii) avoiding the cost of portable data entry units;

iii) avoiding the cost of meter reading route management;

iv) reducing the cost of managing keys to access consumers' premises for meter reading purposes; and

v) improving the quality of meter readings, for less cost;

d) Distribution and transmission network operators:

i) receiving the benefits of deferring network augmentation planned to meet peak demand;

ii) offering tariffs that incentivise consumers to alter consumption behaviour, leading to better management of the network and reduced operational and capital expenditure on it;

iii) avoid the cost of investigating consumer complaints about loss of supply which prove to not be a loss of supply from the network;

iv) largely avoiding the need to visit a consumer's premises for disconnection of supply and reconnection of supply;

v) reducing network non-technical losses by decreasing the incidence of theft or fraud and consumption at vacant premises;

13 The likelihood of needing to visit a consumer's premises for meter reading purposes is extremely low, and therefore has been discounted from the analysis.

vi) via remote service checking being able to inform customers more quickly of whether a fault is distribution-related so that the customer can take action to get a non-distribution fault rectified more quickly;

vii) avoiding the cost of maintaining and upgrading/replacing ripple control systems and time switch-based systems;

viii) checking that remote load control signals have been received;

ix) reducing network losses by more effectively identifying and managing them (e.g. reducing network technical losses by providing the ability to reduce peak load on parts of the distribution network);

x) improving electricity network reliability by identifying points of failure on a network, reducing unserved energy, reducing customer faults calls and improving outage management including the cost-effectiveness and speed of recovery from supply outages/shortages;

xi) improving the detail and cost-effectiveness of quality of supply recording and reporting, assisting distributors with network planning, reliability and more effective operations, and avoiding costs associated with investigating customer complaints about apparent voltage issues;

xii) checking voltage limits (high and low) on a low voltage feeder to ensure the voltage is within compliance limits;

xiii) improving power factor via the use of apparent power (kVA) tariffs;

xiv) reducing the cost to distributors of meeting regulated service standards and enabling improvements in such standards through the provision of improved distributor services information to regulators;

e) The economy:

i) delaying investment in generation, transmission and distribution assets and reducing generation operating costs to meet peak electricity demand by signalling the cost of energy usage at specific times of the day (i.e. TOU pricing / CPP);

ii) improving the efficiency of investment in reserve generation capacity (e.g. to accommodate 'dry year risk' in a predominantly hydro generation-based electricity sector such as New Zealand);

iii) avoiding the cost of multiple meters for multi-tariff consumers / consumers with import and export electricity flows;

f) The environment:

i) reducing carbon emissions by reducing thermal electricity generation via energy conservation and demand response to TOU price signals;

ii) reducing or deferring expansion of the transmission and distribution networks and the consequential effects on landscape and habitats;

iii) carbon emission reduction through the reduced need for vehicle use for meter reading, disconnection/reconnection of premises, fault investigation and outage management; and

iv) promoting the efficient use of resources at the point of electricity consumption may encourage wider environmentally responsible behaviour.

39. The relative values to New Zealand of many of the benefits listed above has recently been estimated by the Electricity Commission[14]:

Application	**Benefit**	Can be **shed** for up to **10** hours per year	Can be **shed** for up to **100** hours per year	Can be **shifted** for up to **100** hours per year	Can be **shifted** for up to **500** hours per year	**Comment**
Reserve market	Providing FIR* – North Island	Approximately $40,000/MW	Approximately $40,000/MW	Approximately $40,000/MW	Approximately $40,000/MW	Prices would drop if more IL*** was offered. Only some IL providers can meet compliance standards, and compliance costs should be set against benefits. AUFLS****-armed load cannot be offered.
	Providing SIR** – North Island	Approximately $27,000/MW	Approximately $27,000/MW	Approximately $27,000/MW	Approximately $27,000/MW	
	Providing FIR or SIR – South Island	Approximately $2,000/MW	Approximately $2,000/MW	Approximately $2,000/MW	Approximately $2,000/MW	(South Island reserve prices are typically much lower than North Island)
Wholesale market	Reducing load during high price periods, avoiding energy costs	Potentially $6,000/MW	Potentially $20,000/MW	Potentially $3,000/MW	At least $7,500/MW	The value depends on location - e.g. North Island would be more than South Island. The value should not rise above the cost of providing new peaking generation (see 'Generation alternatives' row below).
Generation alternatives	Defer construction of thermal peaking generators	Up to $56,000/MW	Up to $56,000/MW	Probably not adequate for this application	Probably not adequate for this application	This situation could arise in future if and when additional peaking capacity was required for winter security.
Greenhouse reductions	Displace thermal stations, resulting in lower net emissions	About $120/MW at a carbon price of $15/t	About $1200/MW at a carbon price of $15/t	Probably nil	Probably nil	These benefits, while small, would be fully cumulative with other uses of interruptible load.

* Fast Instantaneous Reserve
** Sustained Instantaneous Reserve
*** Interruptible Load
**** Automatic Under-frequency Load Shedding

14 Load Management Value and Pricing Report, Electricity Commission, August 2007

Application	Benefit	Can be **shed** for up to **10** hours per year	Can be **shed** for up to **100** hours per year	Can be **shifted** for up to **100** hours per year	Can be **shifted** for up to **500** hours per year	Comment
Transmission alternatives	Using managed load as a non-transmission alternative to achieve deferral of specific transmission projects	Some fraction of $50,000/MW to $500,000/MW deferral benefit. Might be 100% of this value in years when <10 hrs of capacity required	Deferral benefit ranging from $50,000/MW up to $500,000/MW, depending on site	As per load shedding entries to left, but value considerably reduced due to recovery effect	As per load shedding entries to left, but value considerably reduced due to recovery effect	Only applies in constrained regions as part of the GUP process. Requires site specific analysis. Needs to be sufficient managed load available to achieve a significant deferral - Auckland upgrade would have needed 100 MW for even a 1-year deferral. Load in excess of that needed to achieve of a deferral has no additional value.
	Reducing load during high price periods caused by transmission constraints - see 'Wholesale market' section below (since this would bring benefit by reducing wholesale market energy costs)					
	Using managed load to reduce interconnection charges - see 'Distribution alternatives' section below (since interconnection charges are bundled with distribution charges)					
Distribution alternatives	Using managed load to control peak demand, defer distribution investment and reduce interconnection charges	Probably not adequate for this application	Approximately $90,000/MW to $150,000/MW for decreases in peak demand, depending on network	Approximately $90,000/MW to $150,000/MW for decreases in peak demand, depending on network	Approximately $90,000/MW to $150,000/MW for decreases in peak demand, depending on network	This is currently the predominant use of interruptible load.
	ALTERNATIVE APPROACH - Using managed load as a non-network alternative to achieve deferral of specific distribution projects	Some fraction of deferral benefit,, which could potentially ranges from near nil to over $500,000/MW. Might be 100% of this value in years when <10 hrs of capacity required	Deferral benefit ranging from near nil to over $500,000/MW, depending on site	As per load shedding entries to left, but value considerably reduced due to recovery effect	As per load shedding entries to left, but value considerably reduced due to recovery effect	An alternative representation of, rather than additional to, the distribution investment deferral benefits included in the row above. Only applies in specific locations and at specific times where distribution investment would otherwise be required. Requires site specific analysis. Needs to be sufficient managed load available to achieve a significant deferral – and load in excess of that needed to achieve of a deferral has no additional value.

Table : Relative Monetary Value of Smart Metering Benefits

40. As can be seen, significant benefits can be achieved in deferring network augmentation and generation capacity.

Costs

41. As with the benefits of smart metering, the costs will vary depending on the functionality. Listed below are a range of major identified costs[15] associated with smart metering, grouped into general categories[16]:

a) Capital costs:

i) smart meters;

ii) communications network infrastructure;

iii) installation of smart meters and communications infrastructure;

iv) communications network management systems;

v) meter data management (MDM) systems;

vi) alterations to customer information and billing systems;

vii) alterations to distribution network management systems;

viii) such alterations to other IT systems and business processes as are justified to make use of the 'smart' functionalities in the meter;

ix) project management;

x) IT network infrastructure and systems integration;

xi) development of rules, regulations and laws;

xii) smart metering trials;

xiii) customer liaison and compensation during the rollout;

b) Operational costs:

i) smart meter maintenance/replacements;

ii) communications network management and maintenance;

iii) communications network usage charges;

iv) meter data management;

v) IT system operation;

vi) indirect overheads;

c) Stranded asset costs:

i) replacing metering and load control systems before the end of their economic life could classify them as 'stranded' assets, as there is unlikely to be a market for second-hand "non-smart" meters. This is not an economic cost per se, but recovery of stranded asset accounting write-offs is usually allowed for in regulatory determinations.

15 Strictly speaking these costs are net of the costs that would be incurred if existing basic metering arrangements are retained.

16 Advanced Metering Policy, Electricity Commission, April 2008

Cost Benefit Analysis of Smart Metering and Direct Load Control. Stream 2: Network Benefits and Recurrent Costs. Phase 2 – Consultation Report, CRA International, February 2008

Cost Benefit Analysis of Smart Metering and Direct Load Control. Workstream 3: Retailer Impacts – Phase 2 Consultation Report Ministerial Council on Energy, KPMG, March 2008

Cost Benefit Analysis of Smart Metering and Direct Load Control. Workstream 4: Consumer Impacts Phase 2 Consultation Report, NERA Economic Consulting, February 2008

International overview of smart metering

42. The implementation of smart metering around the world first began to gather momentum around 2000. Prior to this time, AMR was the primary form of new metering technology being rolled out internationally – largely in the United States.

43. The impetus for smart metering has not been uniform[17]. For some jurisdictions (e.g. the states of Victoria in Australia and California in the USA), the primary driver for the rollout of smart metering is demand reduction during summer peak demand periods, driven by increasing use of air conditioning. In other jurisdictions (e.g. Sweden), an important driver has been improved billing accuracy. This was also a key driver behind the initial smart meter rollout in Italy, along with revenue protection and a reduction in visits to premises.

44. This section of the report provides a summary of many of the major smart metering initiatives internationally. Three specific case studies are then used to elaborate on key themes associated with these initiatives, including the reasons for implementing smart metering, the anticipated or actual costs and benefits, and key implementation issues.

Australia

Victoria

45. The Australian state of Victoria has been investigating the costs and benefits associated with smart metering since 2002, when the Victorian energy regulator[18] undertook a cost-benefit analysis for the rollout of interval meters in the state, which included consideration of the possible addition of two-way communications. The main quantitative focus of the cost-benefit analysis was on the efficiency gains resulting from customers responding to price signals provided by an interval meter.

46. As a consequence of substantial benefits from demand response, the cost-benefit analysis indicated that there was a net benefit to Victoria's electricity consumers from a rollout of interval meters without communications attached to them to approximately half of small consumers[19]. Hence, in 2004 the regulator mandated such a rollout.

47. In 2005 the Victorian Government and Victoria's electricity distribution businesses co-funded a cost-benefit study that looked at whether the interval meter rollout should be augmented into a rollout of meters with remote communications ("Advanced Interval Meters"). This study recommended that such a rollout should proceed over a four year period, commencing in 2008, and that it should encompass all small customers. In early 2006, the Victorian Government formally endorsed the deployment of advanced metering to all Victorian consumers. Subsequently, the minimum functionality of such meters has been defined to include a wide range of "smart" functionalities.

17 Smart Metering with a Focus on Electricity Regulation, ERGEG, October 2007

18 The Essential Services Commission (ESC)

19 With consumption less than 100 MWh per annum.

National

48. In 2007 the Council of Australian Governments endorsed a staged approach to the rollout of smart meters to areas across Australia where benefits outweighed costs. A national cost-benefit analysis was initiated, which developed a standardised smart meter functionality for Australia, and then estimated the net benefits of a national rollout of smart metering with this functionality.

49. The national cost-benefit analysis estimates a range for net benefits in each state and territory. The findings of the study are that there is a net benefit of rolling out smart meters for the overall Australian economy, although in some jurisdictions the indicated net benefits range from negative to positive, because of the range of assumptions. Importantly, the estimates in this analysis have much lower demand response benefits than were found in the Victorian analyses, but this is more than offset by the considerable operational benefits, including those associated with the "smart" functionalities such as remote connect/disconnect and the ability to limit supply capacity. The national cost-benefit analysis is currently with stakeholders for consultation and, within the next few months, the states and territories will assess the extent (if any) of smart metering rollouts within each of their jurisdictions[20].

Canada

Ontario

50. Ontario has been developing its smart metering programme since 2003, when the Ontario Government set energy conservation targets extending out to 2025, with smart metering considered critical to achieving these. In July 2004 the Minister of Energy asked the Ontario Energy Board to provide a plan for installing smart meters in every electricity customer's premises by the end of 2010. At the time, 95 percent of meter installations in Ontario had electromechanical electricity meters.

51. The purpose of the Ontario rollout is to enable consumer demand response. In the shorter term, the province wanted to see reductions of 1.35 GW and 2.7 GW in peak demand by the years 2007 and 2010 respectively. In the longer term, Ontario is targeting a peak energy demand reduction of 6.3 GW by the year 2025[21]. The province appears to be well on its way to meeting at least the shorter term goals. Latest indications are that the province met its 2007 target of a 1.35 GW (5 percent) reduction in peak demand.[22]

52. In January 2005 the Ontario Energy Board produced a report to the Minister of Energy, which provided an implementation plan for the Ontario smart metering rollout. This plan provided for 800,000 smart meters to be installed by 31 December, 2007 and for all 4.3 million of Ontario's electricity customers to have smart metering installed by 31 December, 2010. By the end of 2007, some 1.1 million smart meters had been installed,[23] placing the province's rollout ahead of schedule.

20 Except for Victoria, which maintains its commitment to a rollout.

21 Ontario Ministry of Energy website, last updated March 2008

22 Annual Report 2007, Ontario Chief Energy Conservation Officer, 2007

23 Ontario Ministry of Energy website, last updated March 2008

Quebec

53. In 2006 the Quebec Government proposed that all consumers would have smart meters installed by 2009, to encourage people to use energy more efficiently. The Government viewed smart metering as a means to cut peak period electricity consumption in Quebec.

54. However, in December 2007 Hydro Quebec, the state-owned vertically integrated incumbent electricity utility announced that it would not undertake such a rollout, as it considered that the costs outweighed the benefits to consumers.[24]

France

55. In June 2007 the French energy regulator[25] announced that smart meters would be rolled out to all 34 million low voltage electricity sites[26] in France[27]. This policy statement followed a cost-benefit study undertaken in late 2006, coupled with stakeholder consultation in early 2007. No date was set for when the rollout is to be completed, although the cost-benefit study demonstrated that the positive net benefit from a rollout would be higher under a five year as opposed to 10 year timeframe[28].

56. In its policy outline, the regulator noted that a smart meter rollout was justified on the basis of improvements in the following three areas:

    a) consumer information;

    b) operation of the electricity market; and

    c) distribution network operators' costs.

57. Interestingly, Electricité de France, the largest energy supplier in France, announced in August 2006 that its distribution arm would be undertaking a pilot project, involving 300,000 meters, intended to establish a large-scale smart metering system[29]. As a consequence, CRE considered it "essential to begin immediately to outline the policy to be followed for electricity metering at installations connected to low voltage public distribution grids for a power level of 36 kVA or less"[30].

24 Hydro Quebec shelves smart meters, CBC News, December 2007

25 Commission de Regulation de l'Energie (CRE)

26 Sites with a subscribed power level of 36 kVA or less.

27 Communication by the Commission de regulation de l'energie of 6 June 2007 concerning changes to low-power low-voltage electricity metering (≤ 36 kVA), Commission de Regulation de l'Energie, June 2007

28 Comparatif international des systemes de tele-relevu ou de telegestion et etude technico-economique visant a evaluer les conditions d-une migration du parc actuel de compteurs, Capgemini Consulting, March 2007

29 Smart Metering with a Focus on Electricity Regulation, ERGEG, October 2007

30 Communication by the Commission de regulation de l'energie of 6 June 2007 concerning changes to low-power low-voltage electricity metering (≤ 36 kVA), Commission de Regulation de l'Energie, June 2007

Ireland

58. In March 2007 the Irish energy regulator[31] released a consultation paper on smart metering, stating that the regulator was in favour of introducing smart metering and TOU tariffs for all 1.7 million electricity customers in Ireland[32]. The key benefits identified by the regulator were:

a) reduced power bills for electricity consumers;

b) reduced peak demand enabling deferral of investment in electricity networks and generation; and

c) reduced greenhouse gas emissions from generators.

59. The regulator subsequently decided, in November 2007, to work with stakeholders "in structuring and implementing the role out (sic) of an optimally designed universal smart metering programme that will embrace all aspects of smart metering relevant to the Irish electricity market"[33].

60. A working group, operating under the direction of a newly formed Steering Group, was established at the end of 2007 to investigate smart metering applications. The intention was for the working group to report its initial views by the beginning of March 2008, with ESB Networks (the vertically integrated incumbent electricity utility in Ireland) envisaging that the first smart meters would be installed in April 2008.

61. The energy regulator's position is consistent with the Irish Government's policy in respect of smart metering, which envisages a rollout of smart meters across Ireland by the end of 2012[34].

Italy

62. In December 2006, Italy's energy regulator[35] mandated the rollout of smart meters to all low voltage consumers over the period 2008 to 2011[36]. This rollout was pre-empted by ENEL, Italy's largest power company, which undertook the world's first large-scale AMI rollout. From 2001 to 2006 ENEL installed some 27 million smart meters across Italy (by 2008 this figure had risen by another 3 million[37]).

63. ENEL's business case was predicated on expected savings or revenues in the areas of:

a) revenue protection (reduction in fraud/theft);

b) reduction in bad debts;

c) purchasing and logistics;

d) field operations (reducing the number of visits to premises – often to manually change supply-limiting circuit breakers); and

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31 The Commission for Energy Regulation (CER)

32 Demand side management and smart metering. Consultation paper, CER, March 2007

33 Smart Metering. The next step in implementation, CER, November 2007, p.5

34 An Agreed Programme for Government. A Blueprint for Ireland's Future 2007-2012, Fianna Fáil and the Progressive Democrats, June 2007

35 Italian Regulatory Authority for Electricity and Gas (AEEG)

36 Smart Metering with a Focus on Electricity Regulation, ERGEG, October 2007

37 Enel Press Release, January 2008

e) customer services (especially improved billing accuracy)[38].

64. With savings of 500 million Euros per annum, ENEL anticipated recovering the (minimum) 2.1 billion Euro investment within 4-5 years.

65. The Italian energy regulator is also currently investigating whether or not to mandate a smart meter rollout for gas consumers.

Norway

66. Currently in Norway, connection points are hourly metered if they have average annual consumption greater than 100,000 kWh. In 2007 the Norwegian Water Resources and Energy Directorate (NVE) conducted a survey on costs and benefits associated with a rollout of smart metering to all connection points. The study concluded that the benefits of such a rollout would "most likely outweigh the costs"[39]. Specifically, the study concluded that, although the rollout of smart metering imposed a net cost on society when considering measurable costs and benefits, there would most likely be a net benefit to society taking into account qualitative benefits.

67. NVE has therefore recommended to the Norwegian Ministry of Energy and Petroleum that a full rollout of smart metering occurs in Norway, with 2013 being a possible deadline for implementation.

Spain

68. Since 1 July 2007, Spain has required the installation of smart meters on a new and replacement basis (i.e. at new installations and when the meters at existing installations are replaced)[40]. Then in December 2007, the Spanish Government announced[41] the following timetable for installing smart meters in premises with contracted power less than 15 kW:

a) 1 January 2008 to 31 December 2010: 30 percent of total meters;

b) 1 January 2011 to 31 December 2012: an additional 20 percent of total meters;

c) 1 January 2013 to 31 December 2015: an additional 20 percent of total meters;

d) 1 January 2016 to 31 December 2018: the remaining 30 percent of total meters.

Current policy is that no additional costs are to be imposed on consumers as a consequence of the rollout[42].

69. In Spain, as in Italy, industry has taken the lead rolling out smart meters. In October 2006 Endesa, Spain's largest electricity company, announced the rollout of approximately 11 million smart meters across its network. This represented almost half of Spain's approximately 24 million premises.

38 Smart Metering; van Gerwan, R., Jaarsma, S., Wilhite, R., KEMA, June 2006

39 Policy recommendations on smart metering to the Ministry of Petroleum and Energy, NVE, 2007

40 Annual Report 2006, Comision Nacional de Energia, 2007

41 Ministerial Order ITC/3860/2007

42 Smart Metering with a Focus on Electricity Regulation, ERGEG, October 2007

Sweden

70. In March 2003 Sweden announced the requirement that, by 1 July 2009, all electricity meters (over 5 million users) would be read monthly. (Prior to 2003 meters were only read more than once a year if their annual consumption was greater than 100,000 kWh.) At the time of announcing the new requirement, it was estimated that the more frequent readings would benefit the Swedish economy by 600 million Swedish kroner (SEK) per year. The cost of the reform was estimated at SEK 10 billion.

71. Winter weather conditions in Sweden make it almost impossible to fulfil this requirement without the use of AMR, at a minimum. Initially, the monthly meter reading requirement stimulated investment in AMR. However, that has now been superseded by investment in smart metering to take advantage of the additional benefits that smart meters and two-way communications offer over AMR and one-way communications[43].

The Netherlands

72. The Netherlands liberalised its domestic energy market in 2005. Since then, the costs and benefits of smart metering have been investigated. In 2007 the Ministry of Economic Affairs announced a proposed smart meter rollout over 6 years to approximately 7-7.5 million connection points, commencing in August 2008. The cost of the rollout is estimated to be EUR 1.1 – EUR 1.5 billion, with a net benefit of EUR 0.8 – EUR 1.2 billion. It is expected that project costs will be recovered over a 10-12 period, and will be funded from the current meter tariff[44].

73. The major benefits identified as a result of a rollout included:

    a) a price decrease due to competition, resulting from easier switching;

    b) fewer complaints to call centres as a result of energy businesses having more efficient operating processes;

    c) energy conservation by households[45].

74. The distribution network operators (DNOs) will have responsibility for the rollout of the smart meters, and will own, operate and maintain them. Meanwhile electricity suppliers will have responsibility for collection and management of the metering data[46]. A key feature of the proposed rollout is that there should be interoperability and compatibility between systems.

United Kingdom

75. In 2006 Ofgem[47], the energy regulator in Great Britain, undertook a consultation process in which it provided a cost-benefit analysis for smart

43 Domestic Metering Innovation, OFGEM, February 2006, p.42

44 Smart Metering in the Netherlands – A Blueprint for Europe?, Spencer Jones, J., 2007

45 Recommendation: Implementing smart metering infrastructure at small-scale customers, SenterNovem, October 2005

46 Smart Metering with a Focus on Electricity Regulation, ERGEG, October 2007

47 Office of Gas and Electricity Markets

metering in the United Kingdom and outlined a range of policy options that might realise the potential benefits of smart metering. Ofgem considered five main benefits:

a) avoided manual meter read costs;

b) reduced customer service costs by eliminating estimated invoices;

c) reduced theft from more sophisticated tamper detection mechanisms;

d) avoided peak load investment as a consequence of peak demand reduction – primarily through the shifting of load to off-peak periods; and

e) reduced energy use from consumers receiving more accurate and real-time consumption and pricing information[48].

76. However, in contrast to many other jurisdictions, based on its analysis and responses to its consultation, Ofgem concluded that "competition rather than a regulated "one size fits all" approach is the best way to deliver smarter metering"[49].

77. However, Ofgem recognised that some barriers could prevent a competitive metering market operating effectively and identified where it had a role in removing various barriers to innovation (e.g. facilitating common standards to provide for interoperability of smart meters; removing the requirement for two-yearly visual inspections of meters).

78. In its May 2007 Energy White Paper, the British Government set out its expectation that, by 2017, all domestic energy customers would have smart meters with visual displays of real-time information[50]. In July 2007 four smart metering trials commenced in Great Britain that were jointly funded by the British Government and electricity suppliers. These involve approximately 40,000 households and are being undertaken over a two-year period.

79. The British energy industry is calling for the British Government to mandate a smart meter rollout. However, at present, there is no legal framework or timetable for such a rollout. The Department for Business, Enterprise and Regulatory Reform (DBERR) is currently undertaking a cost-benefit analysis in respect of such a rollout. While the British Energy Retailers Association is putting the cost of a 10 year rollout at approximately GBP 5 billion[51], DBERR figures are suggesting the cost could be over GBP 15 billion[52].

80. In April 2008, the British Government stated that all larger business customers will be required to have smart metering installed by 2012. This policy will affect approximately 170,000 electricity sites. The Government has delayed a decision on a smart meter rollout to all business and domestic customers until further impact assessment work is undertaken and feedback from the smart metering trials is received in November 2008[53].

48 Domestic Metering Innovation, Ofgem, February 2006

49 Domestic Metering Innovation – Next Steps, Ofgem, June 2006

50 Meeting the Energy Challenge. A White Paper on Energy, Department of Trade and Industry, May 2007

51 Smart meters: the clock is ticking,, Fortson, D., March 2008

52 Impact Assessment of Smart Metering Roll Out for Domestic Consumers and for Small Businesses, Department for Business Enterprise and Regulatory Reform, April 2008

53 Energy Billing and Metering: Changing Customer behaviour; Government response to a consultation; April 2008, Department for Business Enterprise and Regulatory Reform, April 2008

United States of America

81. In the year to September 2007, US utilities announced new deployments of more than 40 million smart meters between 2007 and 2010[54]. A 2007 paper[55] identifies five key drivers for AMI in the USA:

a) operations – utilities are being pushed by ratepayers, shareholders, and regulators to contain costs while providing higher levels of customer service. Automating energy management through AMI could help to reduce costs and improve service and profitability;

b) regulation – while the US Federal Energy Regulatory Commission (FERC) has regulatory responsibility for the wholesale electricity transmission system, in general the US Federal Government has left regulation of the electricity distribution system to individual states. Consequently, many state regulations are driving smart metering uptake, as is demonstrated below in the California case study. However, two recent federal Acts do place certain smart metering obligations on individual states:

i) the Energy Policy Act of 2005 has required states to consider deploying smart meters for residential and small commercial customers; and

ii) the Energy Independence and Security Act of 2007 contains provisions on 'smart grid' technologies to address some of the regulatory and technological barriers to widespread installation of smart meters.

Regulatory reliability standards, especially those tied to performance-based rates, also drive utilities to improve their delivery of energy;

c) conservation – the possibility of fuel expenses increasing is providing an incentive to better measure and manage energy. Furthermore, energy consumption is linked to degradation of the environment through climate change and resource depletion. This provides an incentive to use energy more wisely. Many electricity utility CEOs foresee regulatory caps on carbon emissions in the near future;

d) technology – computing and telecommunications technology continues along Moore's Law (computing power doubling approximately every two years) and Metcalfe's Law (a network's power equals the square of the number of nodes), making them more affordable and powerful to deploy in electricity utilities' operations;

e) grid operations – the North American transmission and distribution grid is strained and constrained. Increasing efficiency in energy consumption lowers stress on the system. At the same time, smart metering contributes to the ability to model grid operations, a step towards building a 'smart' distribution grid[56].

54 Assessment of Demand Response and Advanced Metering, Federal Energy Regulatory Commission, 2007

55 The Critical Role of Advanced Metering Infrastructure in a World Demanding More Energy, Eric Miller, 2007

56 A 'smart' grid or distribution system would allow for flow of information from a customer's meter in two directions: both inside the house to thermostats, appliances, and other devices, and from the house back to the utility.

Case studies

82. In this study the following jurisdictions have been selected for review:
    a) Victoria (Australia);
    b) California (USA); and
    c) Ontario (Canada).

83. Strata Energy Consulting is aware of similar work being performed by other consultants and has reached an agreement with Concept Consulting to concentrate on these countries while Concept Consulting provides material on Australia, Italy, the Netherlands and the United Kingdom.

84. The ordering of the three case studies considered in this report is intentional. Strata Energy Consulting believes that it reflects the desirable sequence of activities associated with investigating and, if appropriate, implementing smart metering.

85. The Australian study focuses on the cost-benefit analyses that have been undertaken in the state of Victoria and more recently at a national level. We then turn to a look at the various legislative and regulatory requirements enabling smart metering in the US, both at a federal level and then at a state level, with the case study focused on the state of California. Lastly, the Canadian province of Ontario is selected as an example of the actual physical implementation of smart metering.

Australia – Victoria

86. With the introduction of full retail competition (FRC) in Victoria in January 2002, the Victorian energy regulator, the Essential Services Commission (ESC), indicated that it was prepared to consider mandating interval meters across all customer classes in Victoria if the benefits outweighed the costs. In November 2002 the ESC released a position paper[57], which presented a cost-benefit analysis for the rollout of interval meters in the state, which included consideration of the possible addition of two-way communications.

87. This cost-benefit analysis indicated that there was a net benefit to Victoria's electricity consumers from a rollout of interval meters without communications attached to them. The position paper proposed that interval meters be installed for Victorian electricity customers according to the following timetable:
    a) interval meters to be installed within two years for large customers with consumption greater than 160 MWh;
    b) interval meters to be installed within five years for small business and residential customers (consumption less than 160 MWh) with off-peak metering or three phase metering; and
    c) the installation of interval meters on a new and replacement basis, unless grounds to justify an accelerated rollout were received, for small business and residential customers with single-phase non-off-peak metering.

57 Installing Interval Meters for Electricity Customers – Costs and Benefits, Position Paper; Essential Services Commission, November 2002

88. As Victoria's electricity demand exhibits weather-driven needle peaks, the main quantitative focus of the ESC's position paper was on valuing demand reduction benefits resulting from customers responding to price signals provided by an interval meter. The net benefit would result from the value of the avoided capacity cost (generation, transmission and distribution) exceeding the incremental cost associated with the interval metering.

89. The ESC's position paper estimated that overall demand reduction at peak times for the Victorian residential sector could be as high as 20 percent, using a price elasticity of -0.1 and a 3:1 CPP ratio (i.e. the peak period tariff is three times more expensive than a single flat tariff). Hence, if the coincident peak demand[58] for the typical Victorian household was initially 0.66kW in the base year, then the reduction in peak demand could be approximately 0.13kW. Valuing the benefit of a change in peak demand at a marginal capacity cost of $130/kW year, the study estimated that the avoided capacity cost associated with the reduction in this household's coincident peak demand of 0.66kW was approximately $17 per annum.

90. The ESC's position paper estimated that the Victorian business sector might achieve demand reductions in the order of 5 percent, using a price elasticity of -0.025 under TOU pricing. Because of the higher consumption level of these customers, the study concluded that a larger reduction in usage, in absolute terms, could be achieved through the introduction of interval metering for business customers.

91. Importantly, all customers were assumed to face time-varying prices. This contrasts with the MCE cost-benefit study described later in this section, which did not assume 100 percent uptake of TOU tariffs by customers.

92. In July 2004, the ESC issued a final decision[59] on the rollout of interval electricity meters in Victoria, which mandated the following rollout:

a) interval meters to be installed by 2008 for all large customers (those consuming greater than 160 MWh per year), with new and replacement installation commencing in 2006;

b) interval meters to be installed by 2011 for all small business and large residential customers (those consuming less than 160 MWh per year but more than 20 MWh per year) with off-peak metering or three phase metering, with new and replacement installation commencing in 2006;

c) interval meters to be installed by 2013 for all small business and residential customers (those consuming less than 20 MWh per year) with off-peak metering or three phase metering, with new and replacement installation commencing in 2006;

d) interval meters to be installed on a new and replacement basis for all small business and residential customers with single phase, non-off-peak metering, with installation commencing in 2008.

93. The ESC's 2004 final decision estimated net benefits of approximately AUD 275 million from the two year and five year rollouts combined, while the new and replacement rollout policy had a net benefit of approximately AUD -2 million.

94. Following the mandating of the interval meter rollout (IMRO) programme by the ESC, the Victorian Government and Victoria's electricity distribution

58 Coincident peak demand is the energy demand by a group of consumers during periods of peak system demand.

59 Mandatory Rollout of Interval Meters for Electricity Customers – Final decision; Essential Services Commission, July 2004

businesses co-funded a cost-benefit study in 2005, which investigated whether an advanced metering infrastructure (AMI) rollout should proceed in Victoria. This 2005 cost-benefit study[60] concluded that there was a net benefit to Victoria from accelerating the IMRO programme so that it was undertaken in four years, commencing in 2008, and from mandating advanced communications functionalities, provided the communications technologies used were all or some of mesh radio, distribution line carrier (DLC) and power line carrier (PLC). The use of wireless communications technologies was found to impose a significant net cost on Victoria.

95. Specifically, the 2005 study found that under an accelerated advanced interval metering rollout (AIMRO) of four years, the estimated net benefits shown in Table could be realised relative to the IMRO study, over an 18 year period:

Communications	NPV
Wireless	AUD -529 million
DLC	AUD 79 million
Mesh radio	AUD 26 million
PLC	AUD 61 million

Table : AIMRO Cost-Benefit Study Results

96. By far the largest benefit described under the AIMRO study was the avoided cost of manual meter readings – routine readings and special readings (including energisations / de-energisations).

97. The study estimated an average reduction in peak-period energy use of approximately 10 percent for those customers receiving AMI meters (i.e. excluding the loads of large customers that were already required to have interval metering). As with the IMRO study, the AIMRO study assumed 100 percent of customers receiving meters faced time-varying prices.

98. In early 2006 the Victorian Government formally endorsed the deployment of smart metering to all Victorian electricity consumers, with the rollout to be implemented according to the following timetable:

a) 2009 – smart meters installed for 5 percent of premises;

b) 2010 – smart meters installed for 20 percent of premises;

c) 2011 – smart meters installed for 35 percent of premises;

d) 2012 – smart meters installed for 40 percent of premises.

99. As a consequence of Phase 1 of the Ministerial Council on Energy (MCE) national cost-benefit study, Victoria has broadly aligned the functionality of the smart meters in its rollout with the functionality agreed by the MCE.

A national rollout in Australia?

100. In April 2007, the Council of Australian Governments (COAG) endorsed a staged approach to the rollout of electricity smart meters to those areas

60 Advanced Interval Meter Communications Study – Draft Report; CRA International, 23 December 2005

across Australia where benefits outweighed costs, as indicated by the results of a cost-benefit analysis.

101. Responsibility for undertaking the cost-benefit analysis was placed with the Ministerial Council on Energy (MCE). In mid-2007 MCE engaged four consultancies to undertake the cost-benefit analysis across two phases. The first phase looked at the business cases for each of a range of potential functionalities that were considered to be non-core (i.e. voluntary), while the second phase produced a national cost-benefit analysis based on the functionalities selected in Phase 1, broken down across Australia's states and territories.

102. As a consequence of Phase 1 of the cost-benefit analysis, the MCE agreed that a consistent national minimum functionality was necessary to maximise the benefits from introducing smart metering. The initial functionality included:

a) remotely read interval metering, with the meter capable of daily reads;

b) quality of supply and outage detection to improve consumer supply services;

c) import and export metering to support distributed generation such as solar photovoltaic (PV);

d) ability to control connection and disconnection remotely and to apply capacity limits on supply;

e) ability to manage load through a dedicated circuit to support existing off-peak arrangements; and

f) supporting management functions such as data security, tamper detections, remote configuration, remote upgrade and remote registration and activation of new meters.

103. The MCE is considering further requirements around the smart meter being able to interface with an in-home display (IHD) or other in-home device (e.g. appliance) via a home area network (HAN).

104. Phase 2 of the cost-benefit analysis is currently in progress, with a series of reports with stakeholders for consultation.

105. In summary, the analysis estimates that smart metering will deliver net benefits to the Australian economy of between AUD 179 million and AUD 3.9 billion in net present value (NPV) terms over a 20 year period, compared with a counterfactual of continuing to use accumulation meters.

106. The most beneficial of the rollout options considered is for each distributor to be given the responsibility for owning and installing meters and undertaking the associated metering data management services within its area of operations, as a monopoly service provider.

107. The net benefits of a smart metering rollout are not unequivocally positive across all of the Australian states and territories, as shown by the following figures[61]. Figure provides the results for a smart metering rollout against the counterfactual of a continuation of each jurisdiction's current metering policy, while Figure provides the results for a smart metering rollout against the counterfactual of accumulation metering.

61 Cost Benefit Analysis of Smart Metering and Direct Load Control. Overview Report for Consultation. Report for the Ministerial Council on Energy Smart Meter Working Group, NERA Economic Consulting, 29 February 2008

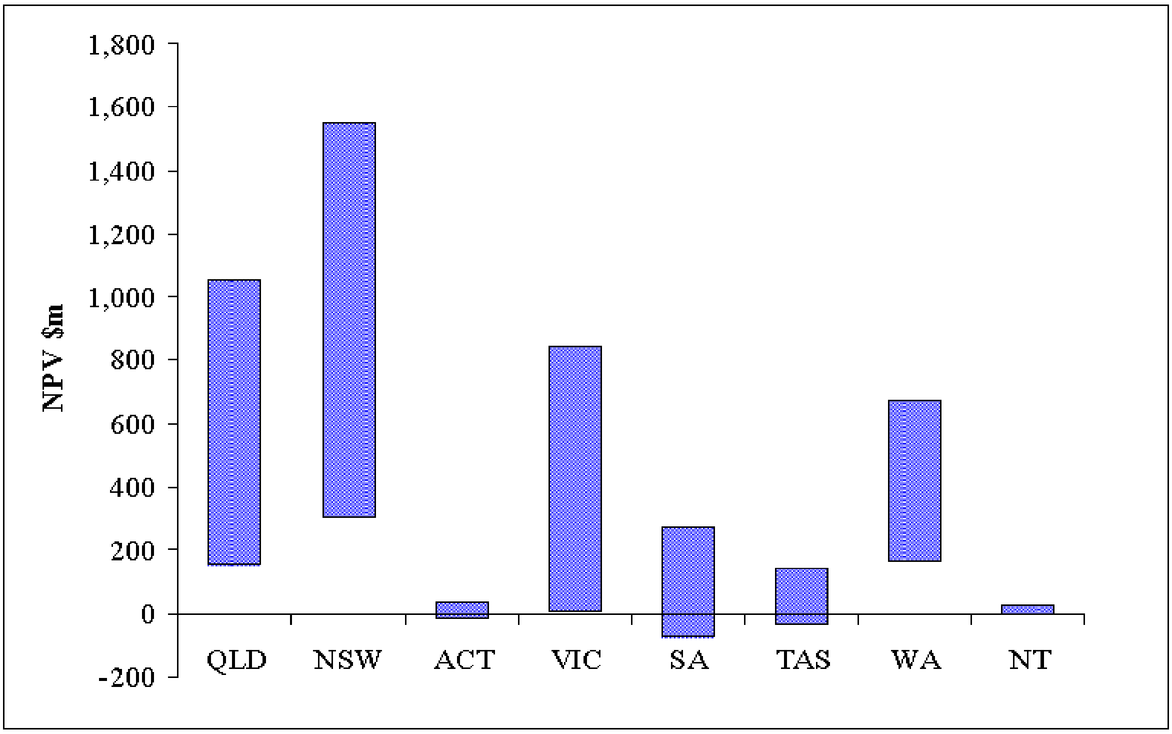


Figure : Summary of results by jurisdiction – Net Benefit (NPV, AUD million), Scenario 1 (Excluding HAN, Current Metering Policy Counterfactual)

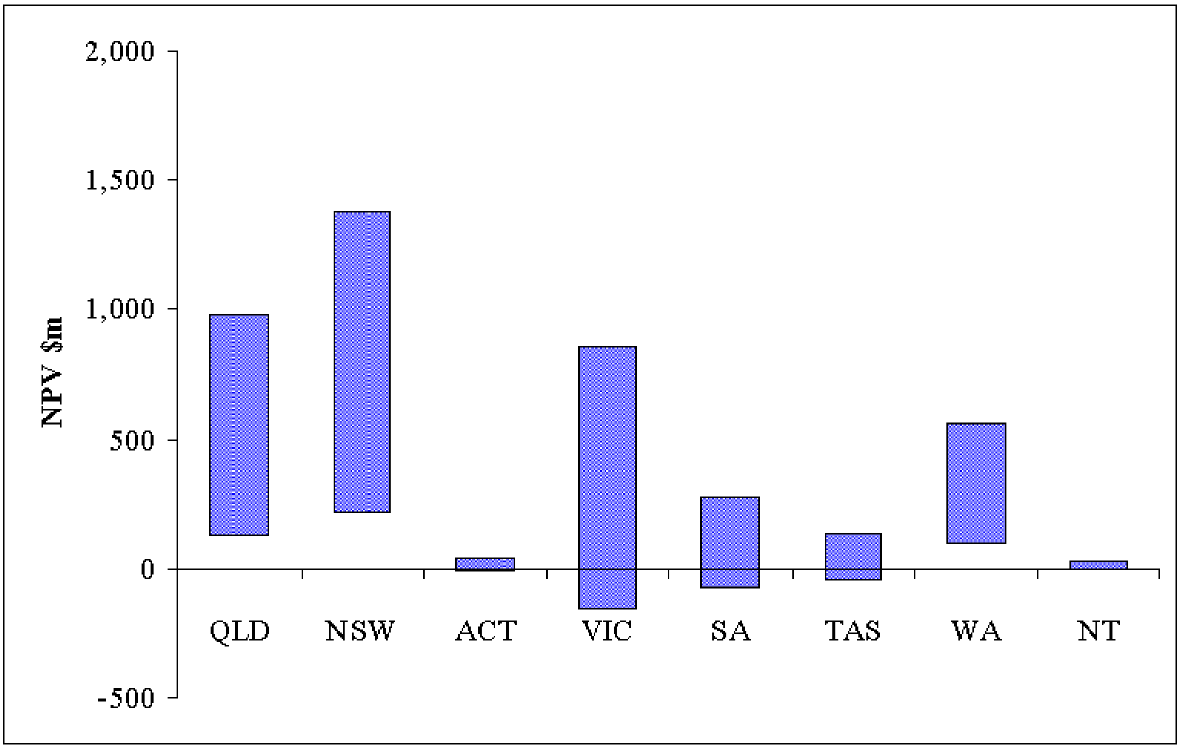


Figure : Summary of results by jurisdiction – Net Benefit (NPV, AUD million), Scenario 1 (Excluding HAN, Accumulation Counterfactual)

108. The MCE national cost-benefit analysis has found the majority of the estimated AUD 4.5 – AUD 6.7 billion of benefits from a distributor-led smart metering rollout arise from avoided meter costs (not having to replace the existing meter stock) and business efficiency benefits for distributors[62] (estimated to be approximately 39-44 percent and 41-55 percent of total benefits, respectively).

109. Demand response benefits represent 6-12 percent of total estimated benefits[63] (between AUD250 and AUD738 million in NPV terms over the 20 year period of the national cost-benefit analysis). For those customers assumed to take up CPP tariffs, the study estimates reductions in peak demand across the Australian jurisdictions of up to 21.5 percent[64], while customers assumed to take up TOU tariffs are estimated to reduce their consumption by up to 5.8 percent[65] in peak periods.

110. However, these reductions do not apply to all customers – i.e. some customers are assumed to have CPP and/or TOU pricing in their tariffs, while most were assumed not to have any form of TOU pricing, in spite of the capability of the meters. This contrasts with the key underlying assumption in the Victorian cost-benefit studies whereby 100 percent of customers were assumed to have CPP / TOU pricing in their tariffs, thereby leading to a greater demand response effect with the introduction of smart metering. Further, the Victorian studies assumed for the TOU and CPP tariffs a much greater ratio of peak to average prices.

111. The difference between studies in respect of this key underlying assumption has had a significant impact on the estimated benefit from demand response achievable under a national smart metering rollout in Australia. Specifically, the benefit from demand response estimated under the national cost-benefit study is significantly less per meter than is estimated under the Victorian IMRO and AIMRO studies.

112. The cost of a national rollout of smart metering in Australia under a distributor-led rollout is estimated to be between AUD 2.7 billion and AUD 4.3 billion in NPV terms over a 20 year period. The two largest costs are metering hardware and its installation, which together account for approximately 70 – 80 percent of the total cost.

113. The MCE is due to consider a national smart meter rollout at its next meeting, which is expected to be in June 2008.

62 NB: The majority of "business efficiency" benefits are savings in meter reading costs for smaller customers, which are almost all undertaken by distributors.

63 NB: This excludes the potential demand response benefits associated with including an interface between the smart meter and the home area network.

64 In Western Australia.

65 Also in Western Australia.

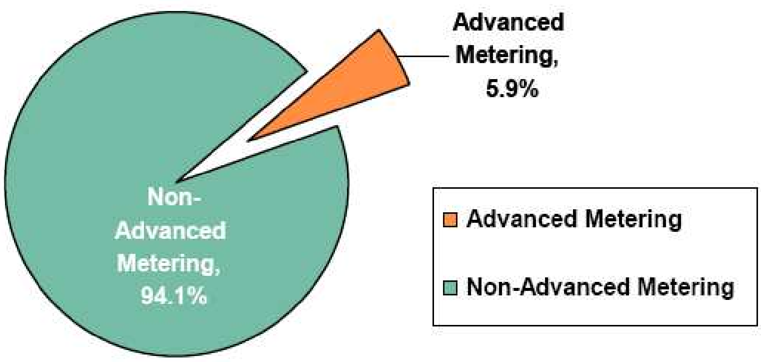
United States of America – California

Introduction

114. All of the US electricity industry operates as an integrated system of generation, transmission, and distribution facilities. Approximately 150 control centres manage the flow of electricity through the system under normal operating conditions[66].

115. Per capita electricity consumption in the US has increased by nearly 50 percent over the past 30 years; with annual growth rates of 4.2 percent, 2.6 percent, and 2.3 percent in the 1970s, 1980s, and 1990s, respectively. Electricity consumption is projected to grow by a further 30 percent between 2006 and 2030, at an average annual rate of 1.1 percent per annum.[67]

116. In the year to September 2007, US utilities announced new deployments of more than 40 million smart meters between 2007 and 2010[68.] The level of advanced metering as reported by FERC in 2006 is illustrated in Figure .



Source: FERC 2006 survey

Figure : Uptake of Smart Metering in the United States

Energy Policy Act 2005

117. Section 1252 (Smart Metering) of the Energy Policy Act 2005 sets out the following federal standard for smart metering: *"each electric utility shall offer [...] a time-based rate schedule [that enables] the electric consumer to manage energy use and cost through advanced metering and communications technology".* This standard, and the process mandated for considering it, was set out via amendment to the Public Utility Regulatory Policies Act of 1978[69].

118. This standard requires the provision of:

a) time-of-use (TOU) pricing – differentiated tariffs covering a specific time period are to be offered to consumers in advance of their consumption, and typically are not to change more than twice a year;

b) critical peak pricing (CPP) – on certain peak days, prices can reflect discounts for reducing peak period energy consumption. This overrides the TOU pricing described above;

66 Smart Grid Provisions in H.R. 6, 110th Congress, Congressional Research Service, 2007

67 Annual Energy Outlook 2008, Department of Energy, 2008

68 Assessment of Demand Response and Advanced Metering, Federal Energy Regulatory Commission, 2007

69 The PURPA Act is a US federal law enacted in 1978 which was intended to encourage more energy-efficient and environmentally friendly commercial energy production.

c) real-time pricing (RTP) – with tariffs changing as often as hourly;

d) credits for consumers with large loads who enter into peak load reduction agreements that reduce a utility's planned capacity obligations.

119. State Commissions and unregulated electricity utilities were required to *consider* the standard but were not required to *adopt* it if they did not think it appropriate. Specifically, they were obliged by law to:

a) undertake an investigation into whether provision and installation of time-based meters and communications devices by electric utilities was appropriate in their jurisdictions[70];

b) make this consideration only after holding public hearings; and

c) advise Congress by August 2007 as to whether or not they would adopt the standard.

120. If the standard was accepted, then time-based rate schedules had to be offered to customers by August 2007, and suitable time-based meters provided to any customer who elected to take up a time-based tariff. If the federal standard was declined, parties had to make the reasoning behind this decision publicly available[71].

121. By July 2007, only two states had decided to adopt the standard, with another 11 deciding not to require it, and 4 more deferring their decision until a later date[72]. A large number of states had made no decision at that point. Reasons given for declining or deferring the standard included:

a) waiting for results from state demand-response pilot programmes;

b) adopting similar standards; and

c) already have similar state policy or processes in place.

FERC annual assessments

122. The Energy Policy Act 2005 also placed an obligation on FERC to provide annual regional assessments of demand response resources, the penetration of smart metering and other technologies, and identification of any barriers to the adoption of these.

123. To date, FERC has published annual regional assessments on demand response and smart metering technologies in 2006 and 2007. Amongst other things, FERC's 2006 report[73] sought to quantify the costs of AMI, as follows:

a) in 2005/2006 the average hardware cost of advanced meters had decreased to USD 76 per meter, down from USD 99 in the late 1990s;

b) the capital costs of installing AMI have stayed relatively constant over the period 2002-2006, generally bound by USD 125 per meter on the lower end and USD 150 on the upper end;

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70 If parties had already considered, approved or implemented time-based rate schedules and smart metering standards within the previous three years, then they were exempt from the requirement to undertake another investigation, and could simply adopt or decline the federal standard.

71 PURPA section 111(a)

72 Assessment of Demand Response and Advanced Metering, Federal Energy Regulatory Commission, 2006 and 2007

73 Assessment of Demand Response and Advanced Metering, Federal Energy Regulatory Commission, 2006

c) for the AMI deployments where both the hardware costs per meter and the total AMI capital cost per meter were available, the hardware costs per meter were as low as 50 percent and as high as 70 percent of the total AMI capital costs.

124. Among the more interesting developments contained in the 2007 report were:

a) in the year to September 2007, utilities announced new deployments of more than 40 million smart meters between 2007 and 2010 – although not all announced plans will necessarily go into effect;

b) in 2007, AMR meters[74] were still out-shipping smart meters, but a number of utilities had recently announced plans to deploy smart meters to replace previously installed AMR meters. It was thought that smart meter sales may outpace AMR meter sales within three to five years;

c) smart metering near-term growth potential may be capped by existing and near-term available manufacturing capability limitations[75].

125. The 2007 report also identified three important issues and challenges facing the uptake of smart metering:

a) *technological obsolescence concerns* – issues of uncertain meter life-expectancy and risk of post-installation technological obsolescence remain, which would result in having to replace the smart meters before original costs are recovered[76].

a) *deployment decisions* **–** pilots or test-phase deployments continue to be used extensively to assess costs and benefits and to allow both utilities and their customers to test and "try out" various smart metering products, configurations and features.

b) *interoperability and open standards* **–** while some utilities have expressed an interest in open standards, it has not been a major factor in recent smart metering selections. However, this is likely to change.

Energy Independence and Security Act 2007

126. This federal Act contained provisions under Title XIII (Smart Grid) to encourage the deployment of 'smart' technologies[77] for metering, communications concerning grid operations and status, and distribution automation. The Act directs the integration of 'smart' appliances and consumer devices.

127. The Act requires the Department of Energy to report on smart grid technologies, progress, regulatory or government barriers, and opportunities. It directs the Department of Energy to work closely with FERC and the National Institute of Standards and Technology to ensure co-ordination and integration of activities among the federal energy agencies.

74 AMR stands for Automated Meter Readings. Like AMI-capable meters, AMR meters can be read remotely, but readings are taken relatively infrequently (e.g. monthly). Whereas AMI-capable meters provide customer consumption much more frequently (e.g. hourly or more frequently).

75 Together AMR and AMI meter sales have been experiencing approximately 20 percent compounded growth yearly over the past several years, with this growth forecasted to continue for the next 5 to 6 years.

76 FERC reported that a number of recent Requests for Proposals (RFPs) have, as a result, included requirements for warranties of advanced metering equipment and have required that the firmware be remotely upgradeable, in order to mitigate these risks.

77 i.e. real-time, automated, interactive technologies that optimise the physical operation of appliances and consumer devices.

128. The Department of Energy must also work with appropriate agencies, electricity utilities, the states, and other stakeholders to develop advanced measurement techniques to monitor peak load reductions and energy efficiency savings from smart metering and demand response.

129. The Act authorises a smart grid research and development programme (including USD 100 million per year in 2008-2012 for demonstration projects) to be run by the Department of Energy, as well as funds for a Department of Energy matching grant programme for one-fifth of smart grid investment costs. At the state government level, the Act requires state regulators to consider requiring and funding smart grid investments.

130. The Act also directs the National Institute of Standards and Technology to develop a framework for the connection of smart grid devices and systems, and directs FERC to adopt such standards and protocols.

State legislative and regulatory activity

131. Several states and individual utilities took actions to introduce greater demand response and price-responsiveness into retail markets in recent years, with a growing number of them directing the implementation of time-based rates. Some noteworthy cases include[78]:

a) California: The California Public Utilities Commission continued its support of demand response, directing changes to 2007 electricity utility demand response programmes, and initiating rule-making on measurement and verification and cost-effectiveness. More detail on California can be found below.

b) New York: In April 2006, the New York Public Service Commission directed electricity utilities to place their largest customers on day-ahead real-time pricing as their default tariff[79].

c) Illinois: In 2006, Illinois enacted legislation requiring electricity utilities to consider and evaluate the use of dynamic pricing to enable customer demand response, and directing the Illinois Commerce Commission to evaluate whether such pricing and smart metering would produce net benefits (for customers).

d) Connecticut: Connecticut enacted comprehensive energy legislation with features promoting energy efficiency, demand response, smart metering and renewable energy. The legislation removes key barriers to electricity utility promotion of demand reduction, requires implementation of TOU rates by January 2008[80], and instructs all electricity utilities to submit AMI deployment plans for deployment by January 2009 as a prelude to TOU rates. The legislation also directs the Department of Public Utility Control to "develop a real-time energy report for daily use by television and other media".

132. A comprehensive state-by-state breakdown of actions can be found in *2007 Assessment of Demand Response and Advanced Metering*, FERC, 2007.

78 2007 Assessment of Demand Response and Advanced Metering, FERC, 2007

79 Most NY utilities' real-time tariffs apply to customers with demands greater than 1 or 2 MW, but utilities will lower these size thresholds over the next few years.

80 Comprising mandatory TOU rates for larger customers whose demand is 350 kW or more, and voluntary critical peak pricing or real-time pricing for all customer classes.

California

Background to smart metering

133. In May 2000, California entered a sustained period of extraordinarily high and volatile electricity prices and power system instability. By January 2001, these shortages had become so severe that it was necessary to institute rolling blackouts to avoid larger and less controllable cascading blackouts[81].

134. California's electricity crisis lasted until June 2001 and imposed huge costs on the state's residents and businesses. Since then, the state has become increasingly concerned about the need to meet its growing population's demand for electricity, and in 2002 started to develop demand response and smart metering policies.

135. In June 2002, the California Energy Commission and the California Public Utilities Commission initiated joint rulemaking proceedings on demand response, smart metering, and dynamic pricing. Their goal was to develop demand response as a resource to enhance electricity system reliability, reduce power purchase and individual consumer costs, and protect the environment. The desired outcome of this effort was that a broad spectrum of demand response programmes and tariff options would be available to customers who made their demand-responsive resources available to the electricity system.

136. Resulting from this, the California Energy Commission initiated a proceeding to develop state policies on dynamic pricing and beyond-the-meter demand-response technology standards, such as smart thermostats[82].

137. In parallel, the California Public Utilities Commission ordered that electricity utilities consider programmes and tools that offer customers improved options to reduce their electricity usage during high-demand situations. California's investor-owned electricity utilities were directed to explore smart metering technologies and conduct a two-year state-wide pilot programme to gauge customer interest in dynamic pricing options[83].

California smart metering policy drivers

138. The Californian Energy Commission estimates that by 2010 the majority of consumers in California will have meters that can measure electricity at least every hour[84]. According to the California Public Utilities Commission, there are three key policy drivers behind this[85]:

    a) in 2003, the California Public Utilities Commission and the California Energy Commission established a loading order for California of preferred energy resources. Demand response is second in the loading order after energy efficiency. Thus, demand response is a very high priority resource in California;

81 California's Electricity Market: A Post-Crisis Progress Report, Carl Pechman, printed in Public Policy Institute of California, Volume 3, Number 1, January 2007

82 Order Instituting Informational and Rulemaking Proceeding, Docket # 02-DemandResponse-01, California Energy Commission, July 17, 2002

83 Order Instituting Rulemaking, Docket # 02-06-001, California Public Utilities Commission, June 6, 2002

84 California 2008 Energy Action Plan Update, p.10

85 Talking Points for Edison Electric Institute's 2007 Fall Legal Conference; CPUC Commissioner Timothy Simon, October 5, 2007

b) the California Energy Commission has set demand response goals that direct utilities to achieve 5 percent reduction of system peak from demand response; and

c) the 2005 California Energy Action Plan articulated the need to transform California's investor-owned electricity utility distribution network into an intelligent, integrated network enabled by modern information and control system technologies.

139. The California Energy Action Plan requires that dynamic pricing tariffs be made available to all customers, and reconfirms a target of 5 percent of system peak demand being met by demand response.

140. A 5 percent reduction in California's peak demand of approximately 61,008 MW amounts to 3,050 MW. The amount of peaking capacity necessary to meet this peak demand can be computed by allowing for a reserve margin of 15 percent and line losses of 8 percent. This amounts to 3,789 MW. A conservative value of the avoided cost of generation capacity is USD 52 per kilowatt year. Thus, the total value of avoided generation capacity costs would be roughly USD 200 million per year. Over a 20-year time horizon, the present value of this could reach USD 3 billion[86].

141. As at 2007, the actual demand response reduction in California was estimated at 2.2 percent. However, the inclusion of demand reduction from interruptible demand response programmes would increase the estimated total reduction to 5.7 percent of the system peak, although interruptible demand response is not counted towards the 5 percent target[87]. A recent report suggests that this 5 percent goal is realistic, and represents the *likely* deployment of cost-effective technologies[88].

142. The California Energy Commission has also opened a proceeding to examine how its legislative authority to adopt load management standards for the state can be used to accelerate California's pace of demand response. These standards would be applicable to publicly owned electricity utilities. The Energy Commission is expressly authorised to consider the following load management techniques, although its authority is not limited to these three:

a) adjustments in rate structure to encourage use of electrical energy at off-peak hours or to encourage control of daily electrical load;

a) end-use storage systems that store energy during off-peak periods for use during peak periods, such as thermal storage, pumped storage, and other storage systems;

b) mechanical and automatic devices and systems for the control of daily and seasonal peak loads.

143. Load management, combined with dynamic pricing, could substantially increase the effect of demand response measures on peak demand in California. The following list sets out the progressive impact of these measures:

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86 2007 Integrated Energy Policy report, California Energy Commission, 2007, p.96

87 The state of Demand Response in California, Brattle Group, April 2007

88 Mandating demand response: California's load-management experience argues for formal DR standards, Pfannenstiel and Faruqui, Public Utilities Fortnightly, 1 January 2008. The report also identified Technical potential of 25 percent reduction (representing the most that can be achieved with maximum deployment of the best available technologies) and Economic potential of 12 percent (representing the maximum deployment of cost-effective technologies) .

a) without load management standards, optional dynamic pricing alone might bring about a drop of about three percent in peak demand[89];

b) if dynamic pricing becomes the *default* tariff as a result of a new load management standard, the impact on peak demand could be up to 10 percent;

c) if dynamic pricing is deployed along with programmable communicating thermostats (activated through load management standards), peak demand could be reduced by 18 percent;

d) if automatic demand response software is installed in all medium and large commercial and industrial facilities, an additional reduction in peak demand of over 2 percent might be obtained (making for a 20 percent total reduction).

The need for demand response in California

144. According to the Californian Energy Commission, there were 14 million electricity customers in California in 2005 (88 percent of them residential), consuming around 230,000,000 MWh of electricity[90].

145. California uses less electricity per person than any other state in the US. While per capita electricity consumption in the United States increased by nearly 50 percent over the past 30 years, California's per capita electricity use remained almost flat, due in large part to cost-effective building and appliance efficiency standards and other energy efficiency programmes[91].

146. Despite this, electricity use in California is projected to grow at 1.25 percent annually, while peak demand is growing at a rate of 1.35 percent (850 MW) per year. This peak increase is largely the result of high population growth in hotter inland areas of the state[92], prompting ever-higher demand during summer temperature peaks and heat storms.

147. This growing demand cannot be met by conventional non-renewable generation, as there are strong legislative drivers to increase the amount of renewables, and to limit investment in new generation with excessive CO_2 emissions:

a) Senate Bill 1078, passed in 2002, established a renewable portfolio standard and set a goal of renewable generation for 20 percent of the state’s requirements by 2020. The 2003 Energy Action Plan accelerated Senate Bill 1078’s renewable portfolio standards goal, moving the 20 percent goal up to 2010[93], and established a ‘loading order’ that prioritised energy efficiency and demand response as the state’s new preferences for capacity acquisition[94];

89 That is, consumers could opt to have pricing that changes dynamically in response to critical peak days.

90 See http://www.energy.ca.gov/maps/maps-pdf/ELECTRICITY_MARKET.PDF

91 2007 Integrated Energy Policy Report, California Energy Commission, 2007, p.2

92 By 2040, nearly 40 percent of the state’s population, or more than 20 million people, will reside inland.

93 SB 107, signed into law in September 2006, formally adopts this accelerated goal.

94 The loading order prioritises the acquisition of different types of energy resources. The first priority is to rely on energy conservation to minimise increases in electricity and natural gas demand. The second priority is to fill new generation needs with a combination of renewable energy resources and distributed generation. The third preferred resource is clean fossil fuel-based generation, such as natural gas. The loading order requires that this third priority be used only if conservation, renewable sources, and distributed power are insufficient to meet forecast needs.

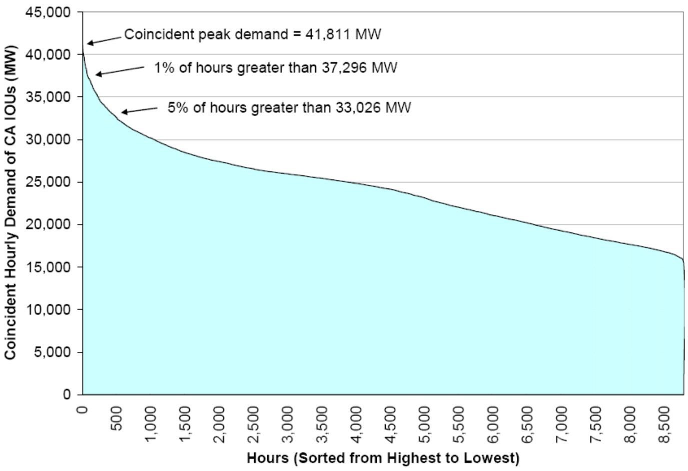
b) the Global Warming Solutions Act of 2006 (also known as AB 32), sets the goal of achieving 1990 greenhouse gas emission levels by 2020;

c) Senate Bill 1368 (Global Warming Emissions Standards for Electricity Generation), passed in 2006, prevents long-term investment in power plants with greenhouse gas emissions in excess of a combined cycle natural gas plant, and prohibits an electricity provider from entering into long term power purchase agreements unless the base load generation complies with greenhouse gas emission performance standards[95]; and

d) the Public Utilities Commission and the Energy Commission cap CO_2 emissions for electricity generation at 1,100 lbs / MWh – roughly equivalent to the per MWh CO_2 emissions from a new combined-cycle natural gas turbine.

148. Given that 89 percent of electricity consumed in California comes from non-renewable generation[96] and accounts for 28 percent of the state's CO_2 emissions, the legislative drivers above clearly require the consideration of more demand response options to help meet California's goals. The 2008 update to California's Energy Action Plan noted that meeting both the growing peak demand and the AB32 mandate would require unprecedented levels of energy efficiency investment, and listed demand response as a top-priority resource for tackling these issues.

149. As the Energy Action Plan indicates, there is significant potential for demand response in California. For example, as shown in Figure , the coincident peak demand[97] of the three California investor-owned electricity utilities[98] exceeded 37,296 MW during only one percent of the hours in 2004, with a peak of 41,811 MW. If these utilities could reduce peak demand by about 10%, California could defer construction of over 4,500 MW of new generation.



Source: The State of Demand Response in California

Figure : 2004 Load Duration Curve for California Investor-owned Electricity Utilities

95 This statute does not extend to short term power purchases or spot market purchases. These purchases can still be made from coal fired power plants that do not meet the newly mandated standard. However, new coal fired power plants being built to provide baseload power to California utilities will have to comply with stringent greenhouse gas limits.

96 California 2008 Energy Action Plan Update, figure 5, p.12

97 That is, the maximum combined demand of all three utilities at any one time.

98 Pacific Gas and Electric, San Diego Gas and Electric, Southern California Edison.

150. Historically, to achieve peak demand reductions, California has relied on reliability-triggered programmes, such as direct load control of central air conditioners through receiver switches and curtailable and interruptible rates. However, given recent advances in smart metering technology, much of the focus of demand response policy is now on the price-responsive and signal-responsive programmes that this technology facilitates.

151. Consequently, as well as facilitating the deployment of AMI, energy policy is now focusing heavily on dynamic pricing tariffs to incentivise consumers to change their energy consumption patterns, and on beyond-the-meter demand-response technology standards, to help get the most out of the state's investment in smart metering.

California state-wide pricing pilot[99]

152. Between July 2003 to December 2004, California's three investor-owned electricity utilities conducted a USD 20 million state-wide pricing pilot programme, to test a variety of dynamic pricing designs. The programme involved some 2,500 residential, small commercial and industrial customers. The experimental process involved a working group that was facilitated by the state's two regulatory commissions and involved dozens of interested parties and stakeholders, some opposed to dynamic pricing and some supporting it.

153. The experiment provided time-varying prices and smart meters to all participants. In addition, some of the participants also received enabling technologies such as smart thermostats and always-on gateway systems. Smart thermostats automatically raise the temperature setting on the thermostat by two or four degrees when the price becomes critical. Always-on gateway systems adjust the usage of multiple appliances in a similar fashion and represent state-of-the-art technology and practices[100].

154. The experiment showed that the average Californian customer reduced demand during the top 60 summer hours by 13 percent in response to dynamic pricing signals that were five times higher than their standard tariff[101]. Customers who responded to these pricing signals and who also had a smart thermostat[102] reduced their load by 27 percent. Those customers who had an always-on gateway system reduced their load by 43 percent[103].

155. The experiment also showed that customers did not respond equally to the price signals. Some responded a lot and some did not respond at all. In fact, about 80 percent of the collective demand response came from just 30 percent of the customers.

156. Based on a review of collective reports from the study, the California Energy Commission[104] concluded that:

99 The power of five percent, the Brattle group, 2007

100 Such systems are tipped to enter the market on a commercial basis in 2008. Commercial prices are not available yet.

101 The 13 percent drop occurred during the six months of the summer season from May to September. Responses during the inner summer months of June-August were a percentage point higher. The 14 percent number might be more applicable during critical-peak conditions.

102 The use of a module in the customer's home that enables the customer or the energy utility to programme air conditioning usage based on network conditions.

103 Ahmad Faruqui, "Pricing Programs: Time-of-Use and Real Time," in Encyclopedia of Energy Engineering, 2007

104 California Statewide Pricing Pilot (SPP) Overview and Results, Mike Messenger, California Energy Commission, March 2006. Available from www.energetics.com/madri/toolbox/pdfs/pricing/pricing_pilot.pdf

a) residential CPP rates could, within five years of deployment, reduce California's peak load at least 1,500 MW and up to over 3,000 MW;

b) dynamic rates encourage greater conservation and peak demand impacts than conventional inverted tier[105] or TOU rates;

c) residential and small to medium commercial and industrial customers understand and overwhelmingly prefer dynamic rates to existing inverted tier rates[106].

Current Californian smart metering proposals

157. In 2004, on the basis of the State-wide Pricing Project findings, the California Energy Commission established three minimum regulatory requirements for approval of the smart metering project proposals:

a) smart metering systems must meet six minimum functional requirements criteria;

b) smart metering project proposals must be cost-effective;

c) investor-owned electricity utilities must provide a comprehensive plan for implementing their smart metering projects, including smart metering deployment and system integration.

158. The six functional requirements of a smart metering system were:

a) capable of supporting various price responsive tariffs;

b) capable of collecting energy usage data at a level that supports customer understanding of hourly usage patterns and their relation to energy costs;

c) capable of allowing access to personal energy usage data such that customer access frequency did not result in additional smart metering system hardware costs;

d) compatible with applications that provide customer education and energy management information, customised billing, and complaint resolution[107];

e) compatible with utility system applications that promote and enhance system operating efficiency and improve service reliability;

f) capable of interfacing with load control communication technology.

159. The three largest investor-owned electricity utilities subsequently filed smart metering proposals with the California Public Utilities Commission:

a) *Pacific Gas and Electric (PG&E)* – a USD 1.74 billion smart metering project to deploy, by 2011, 5.1 million smart electricity meters using PLC and to deploy 4.2 million smart gas meters using fixed radio frequency networks[108]. PG&E estimates that 89 percent of the rollout cost can be

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105 Under an inverted tier rate system, consumers are charged more if we use electricity above a minimum amount.

106 This preference may be because under an inverted tier rate structure, customers with little control over the amount of electricity they use are penalised by higher rates, regardless of whether usage coincides with higher prices or not. Whereas under dynamic rates, consumers are rewarded for shifting load away from critical peak times, regardless of how much electricity they consume overall.

107 That is, meters must be able to integrate with 3rd party energy management, billing, and complaint systems.

108 This was authorised by CPUG in 2006. As of November 2007, PG&E had installed approximately 243,000 meters (gas and electric), mostly in Bakersfield and Sacramento. In December 2007, PG&E filed a proposal for an additional $624 million to upgrade its AMI system.

recovered through operational benefits[109]. Approximately half of these operational benefits come from implementing an automated remote meter reading process.

b) *San Diego Gas and Electric (SDG&E)* – a USD 572 million smart metering project to install 1.4 million smart electricity meters and 900,000 smart gas meter modules between 2008 and 2011[110]. SDG&E estimates that approximately half of the rollout cost can be recovered through operational benefits.

c) *Southern California Edison (SCE)* – a USD 1.7 billion smart metering project to install 5.3 million meters in households and businesses with usage under 200 kilowatts between 2009 and 2014[111]. SCE estimates that approximately half of the rollout cost can be recovered through operational benefits

160. Between them, these utilities account for some 77 percent of California's electricity consumers.

109 Final Opinion Authorizing Pacific Gas and Electric Company to Deploy Advanced Metering Infrastructure, California Public Utilities Commission, July 20, 2006, Decision No. 05-06-028

110 This was authorised by CPUC in 2007. SDG&E is currently finalising contracts with meter and infrastructure vendors.

111 A CPUC decision on SCE's AMI proposal is scheduled for August 2008, with a proposed AMI deployment schedule of 2009 to 2012.

Canada – Ontario

161. The following case study illustrates how the Canadian province of Ontario has set about implementing a decision to roll out smart meters. There are aspects of the work undertaken in Ontario that would be useful to both the New Zealand Government and the Electricity Commission – particularly in relation to operational costs, requirements, regulations and technical standards associated with smart metering.

Background

162. Ontario must build an almost entirely new electricity system by 2025. Estimates show that over the next 20 years, Ontario will need to refurbish, rebuild, replace or conserve 25,000 MW of generating capacity – more than 80 percent of Ontario's current electricity generating capacity – at an estimated cost of CAD 70 billion[112].

163. Ontario has been developing its smart metering programme since 2003, when the Ontario Government set energy conservation targets extending out to 2025, with smart metering considered critical to achieving these. It appears that the major power outage on the northeast coast of North America in August 2003 and the concurrent wholesale price volatility were key factors[113] influencing the Ontario Government's decision to undertake a smart meter rollout as part of a more general energy efficiency policy[114].

164. In July 2004 the Minister of Energy asked the Ontario Energy Board (OEB) to provide a plan for installing 800,000 smart electricity meters by 31 December 2007, with remaining Ontario electricity customers each receiving an installed smart meter by 31 December 2010. At this time most residential and small commercial customers in Ontario had electromechanical meters that recorded cumulative energy consumption only. These customers represented more than 95 percent of meter installations in the province.

165. In January 2005, the OEB produced a report to the Minister of Energy entitled "Smart Meter Implementation Plan", which estimated implementation costs for a smart metering rollout of approximately CAD 1 billion [115]. In April 2005, a study[116] investigating the benefits of a smart meter rollout for Ontario estimated the present value of benefits to be between CAD 1.1 billion and CAD 2 billion, depending on consumers' elasticity of demand in response to TOU and CPP tariffs. The study estimated a reduction in system peak capacity requirements of approximately 4-9 percent. Generation capacity avoidance was the largest contributor to the overall benefits of the rollout.

166. The OEB implementation plan is now obsolete as many of its recommendations have been implemented or modified in some way. However, it is insightful to look at the plan, as it sets out the main issues that have to be dealt with when establishing a framework for a smart metering rollout. Therefore, Strata Energy Consulting has used the content in either summarised or verbatim

112 The Power of Smart Metering, CapGemini Canada, 2007

113 The Power of Smart Metering, CapGemini Canada, 2007

114 Smart Metering with a Focus on Electricity Regulation, ERCEG, October 2007

115 Ontario Energy Board, Smart Meter Implementation Plan – Report to the Minister, January 2005

116 Discussion Draft: Benefits of Smart Metering for Ontario, Navigant Consulting, April 2005

form to highlight key rollout issues and how they were addressed in Ontario. Where relevant we have indicated subsequent developments.

167. It is clear that consumer demand response was the main driver behind introducing smart metering. The intention was to encourage the coupling of smart metering with TOU and CPP price plans, so as to enable consumers to have both the incentive from price signalling and the means to respond to price signals.

168. The OEB envisaged that residential electricity consumers would be able to control their consumption by moving energy use to off-peak periods (e.g. operating the dishwasher at night), or by lowering use during peak periods (e.g. setting the air conditioner a few degrees warmer in the afternoon), either manually or with automatic devices set to react to price or demand levels. Similarly, commercial and industrial consumers, who were previously invoiced based on load profiling, would now receive invoices based on 15 minute or hourly metering data and consequently would be able to make more informed consumption decisions.

Implementation planning

169. The OEB's 2005 implementation plan:

a) identified the mandatory technical requirements for smart metering, along with the support systems that distributors would require;

b) set priorities for implementation in order to meet the Ontario Government's targets;

c) identified regulatory mechanisms for the recovery of costs; and

d) identified how barriers to the introduction of smart metering could be mitigated (e.g. addressing stranded asset costs).

170. In addition, the implementation plan addressed competitiveness in the provision and support of smart metering, and the need for and effectiveness of TOU rates.

171. The main features of the implementation plan included:

a) all existing and new customers of licensed distributors in Ontario, including all residential and small commercial customers, having some type of smart meter by 31 December 2010;

b) smart meters capable of recording hourly interval data for every consumer with peak demand under 200kW and 15 minute interval data for consumers with peak demand over 200kW;

c) installing a two-way communication system for transferring data (e.g. remote meter reads) between the meter and the distributor. Smart meters recording consumption every 15 minutes (interval meters) would use dedicated phone lines, while smart meters with hourly recording would use a range of public and private wide area network (WAN) infrastructure communication media including wireless radio frequency, PLC and shared telephone transmission;

d) consumers would be able to access consumption data by telephone or internet the day after consumption occurred;

e) a two stage implementation:

i) to meet an interim target of 800,000 consumers with smart meters by the end of 2007, initial installation would focus on large consumers (greater than 200kW peak demand[117]) and residential and commercial consumers in large urban areas; then

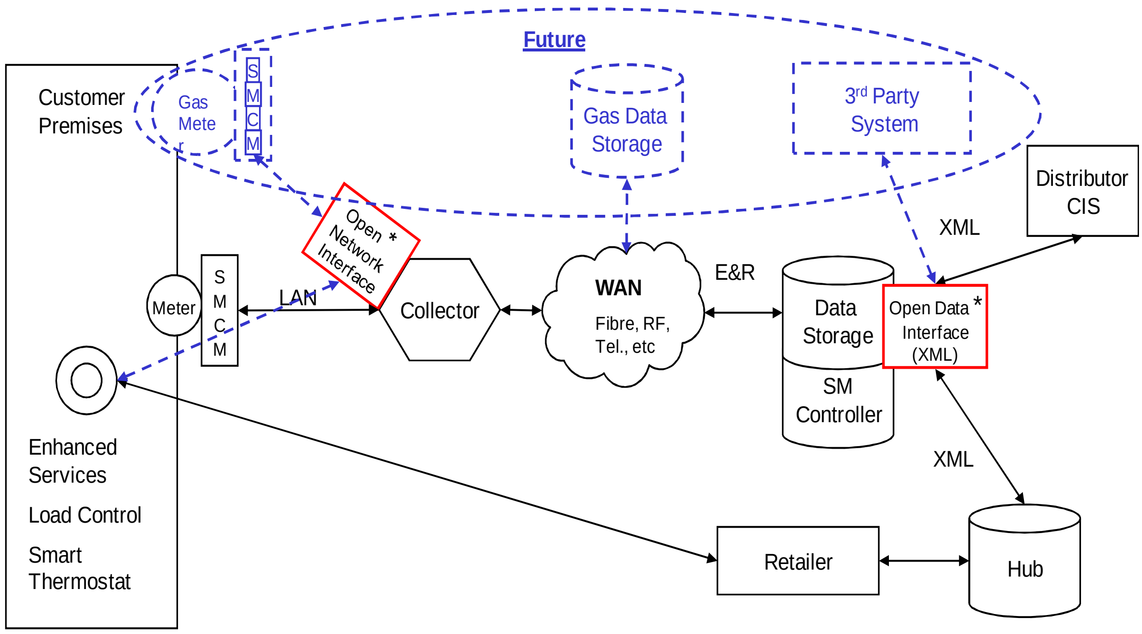
ii) the rollout to the remainder of the province would commence in 2008, thereby enabling smaller distributors to learn from the experiences of the larger distributors[118];

f) a programme co-ordinator would monitor progress and co-ordinate the activities of distributors;

g) consumers might be able to choose enhanced services, such as remotely controlled energy consumption or in-home customer display, from a distributor or retailer for an additional charge;

h) distributors would continue to be responsible for the maintenance and installation of smart meter systems.

172. Figure illustrates the type of AMI envisaged in Ontario.



Source: Ontario Energy Board
SMCM = smart meter communication module
CIS = consumer information system

Figure : Provision for Future Multi-utility Application: Two-way System with Open Access

173. The OEB encouraged distributors to carry out an initial set of pilot programmes using dedicated conservation and demand management funds during 2005. The intent was to gain useful information about the installation and operation of smart meter systems before making final decisions on a particular system.

117 The mandatory level for interval meters was 500kW at the time.

118 The Ontario system had approximately 90 distributors on it at the start of the process, with the largest being One Hydro, which supplied approximately 1.3 million of the 4.5 million customers in Ontario.

Responsibility for implementation

174. Several parties were identified as having key roles in the Ontario smart metering implementation process. The OEB proposed the following breakdown of responsibilities for each of these:

a) Ministry of Energy – responsibility for policy decisions over the life of the project;

b) Ontario Energy Board – responsibility for establishing a regulatory framework for smart metering;

c) Distributors – responsibility for selecting a smart metering system that best suits their regional conditions and customer mix, with ongoing responsibility for the installation, servicing and reading of the meters;

d) Programme Co-ordinator – the OEB proposed hiring a Programme Coordinator[119] to oversee the implementation – monitoring progress and co-ordinating the activities of distributors over several years. This Programme Co-ordinator would operate under the direction and authority of the OEB and report to the OEB;

e) Independent Electricity System Operator (IESO) – responsibility for identifying constrained areas for priority installation of smart metering and monitoring the power system and initiating formal critical peak calls on a provincial basis as required from time to time; and

f) Vendors – responsibility for obtaining necessary approvals for meters and radio frequency licences, and for making any product adjustments to enable an open interface for system interoperability.

Cost breakdown

175. Three types of costs have been considered under the Ontario smart metering rollout:

a) capital costs for meters, communications, installation and distributor system changes (e.g. to accommodate increased data volumes);

b) ongoing operating costs for meter reading, metering services and meter re-verification; and

c) stranded costs – costs pertaining to old meters and other distributor assets made obsolete by the introduction of smart metering.

176. The implementation plan proposed that, as soon as a distributor began installing smart metering, the capital and operating costs of the smart metering rollout be included in a distributor's delivery charges, regardless of whether or not customers had a smart meter. In addition, the plan proposed that stranded costs continue to be included in distribution charges. These proposals have been enacted via regulation.

177. The total capital cost through to 2010 for the smart metering rollout (meters, communications, installation and distributor system changes) was estimated at CAD 1 billion. The net increase in annual operating cost for the province, when all meters are installed, was estimated to be CAD 50 million.

119 Subsequently, the Ministry of Energy entered into an arrangement with the Independent Electricity System Operator (IESO) whereby the IESO supports the Government's smart metering initiative by co-ordinating and project managing implementation activities.

178. Smart metering costs for the new single phase residential meter and communication system were expected to average CAD 250 for each meter installed. This includes the cost of modifying existing systems and providing new data storage facilities and data handling software. This represents CAD 2.47 on the average monthly residential bill.

179. Additional ongoing costs associated with data handling, presentation and communication were expected to add a further CAD 1.42 to the average residential customer's monthly bill.

180. Distributor operating savings from smart metering were estimated to total about CAD 0.39 per residential customer per month, due mainly to savings in meter reading costs.

181. Hence, upon completion of the rollout, an additional monthly charge of CAD 3 – CAD 4 may be required to cover capital and operating costs.

182. Based on survey data, stranded costs associated with meter hardware made obsolete by the rollout were estimated at CAD 473 million, excluding the cost of removing and handling the old meters. Adjusted for depreciation over the period 2005-2010, the stranded cost reduced to approximately CAD 407 million.

Total new capital cost / month	CAD 2.47*
Total operating cost / month	CAD 1.42
Total operating savings / month	CAD -0.39**
Net cost per month residential	**CAD 3.50**

**based on amortizing the capital cost of $250 for a smart meter*
***primarily due to $0.30 savings in meter reading costs. Excludes any benefits relating to demand response*

Table : Ontario Smart Metering Consumer Cost Impact

183. In evaluating cost recovery options, the OEB considered four principles:

a) cost recovery mechanisms should be reasonable and timely;

b) the allocation of costs should be fair;

c) cost recovery should promote economic efficiency and be related to benefits, where possible; and

d) cost recovery should be consistent among distributors.

184. The Board considered three ways to recover the incremental costs. These were:

a) A general tax: Despite the general benefits to society and the electricity system of the program, the Board rejected the idea of a general tax as not apportioning costs and benefits equitably.

b) Capital contribution from customers: The Board also rejected the concept of recovery through a capital contribution (upfront payment from customers) for most customers. It would create complexity around the treatment of common capital costs such as system changes and shared infrastructure. A customer could also end up paying for capital contributions more than once due to moving between distributor areas. Finally, it inhibits affordability (rate shock) by spreading costs over a short period rather than the used and useful life of the smart meter which may have a depreciation period of 15 years.

c) Distribution rates: Recovering costs through distribution rates means that the capital and operating costs of shared services are borne by the class of customers which gains the benefit of the program.

185. The only option meeting the four principles was recovery of costs through distribution rates.

Pilot projects

186. The OEB encouraged distributors to conduct pilots of a variety of vendor technologies and approved a number of these as part of distributor conservation and demand management initiatives. Experience from these pilots was to be incorporated into the planning of the large urban distributors for the initial deployment of 800,000 smart meters.

187. The OEB sought to determine the impact of various pricing plans on the behaviour of consumers, approving a number of pilot schemes covering the full range of consumers in both urban and rural communities across Ontario. An example is the Ontario Energy Smart Price pilot, run by the OEB in co-operation with Hydro Ottawa between June 2006 and February 2007. The pilot tested consumer response to TOU, CPR (critical price rebate) and CPP rates using smart meters and consumer communication. It resulted in 93 percent of participating consumers seeing a reduction in their invoices, with an average reduction in energy usage of 6 percent.

Ownership of meters

188. The OEB analysed a number of alternatives for smart metering service provision. One option was full customer choice in metering provision and services (contestable supply). The OEB did not recommend this approach, as it could not find sufficient quantitative evidence that opening metering to competition would provide enough benefits to justify removing it from monopoly control. It was felt that the experience in the USA suggested that competitive metering did not realise significant benefits to consumers. There was also a concern that this approach might slow down the rate of smart metering deployment during the transition period.

Meter data management

189. One of the major components of Ontario’s smart metering arrangements is the meter data collection IT system. This IT system is also the central control point for registering new smart meters and accepting the data retrieved from the meter. In addition, it routes the metering data to certain key distributor systems (e.g. the meter data repository and customer information system).

190. During the course of the smart metering rollout, the Ministry of Energy decided on the need for a central metering data management and repository system (MDM/R) for smart metering. Legislation to establish this was introduced in 2006, after extensive consultation, to provide potential for system-wide planning and customer based efficiency gains. The MDM/R is currently being developed by the IESO and will be operated by the IESO through a new regulated organisation known as the Smart Metering Entity.

191. The MDM/R functions include collecting and storing metering data, processing it for TOU and CPP billing, and making it accessible to consumers and to distributors to match their billing cycles. This data will also be made available to retailers, energy-service companies and other interested parties in a manner that fully protects the privacy of consumers. Centralisation of the MDM/R functions is intended to standardise the verification and billing processes for electricity across Ontario.

192. Regulations specify that the Smart Metering Entity will perform the following meter data functions[120]:

a) collect and manage (including facilitation of the same) and store information and data on the consumption or use of electricity in Ontario;

b) provide and promote non-discriminatory access to data and information related to the consumption of electricity, including its communication and technologies; and

c) establish, own or lease, and operate one or more databases to facilitate collecting, managing, storing and retrieving smart metering data.

Open access

193. The OEB concluded that open standards would be essential to the success of any industry-wide technology initiative that involves multiple participants and requires disparate systems to communicate with each other. Open standard interfaces are the foundation for interoperability among different vendor products.

194. At the opposite end of the spectrum are proprietary standards, which are vendor-specific and whose details are not in the public domain. In addition, these standards are only used and accepted by a specific vendor.

195. In between these two alternatives are open protocols whereby a manufacturer makes available, with or without a licensing fee, the information necessary for another manufacturer to communicate with a device.

196. Without open access, customers are locked into vendor-specific solutions. So open access is the key to interoperability among different vendor products. The OEB envisages that the smart meter system could be the basis of a province-wide communication system for the electricity industry in Ontario. It is hoped that in the near future other services, in addition to electricity meter reading, could be offered using the smart meter network infrastructure.

120 Ontario Regulation 393/07, August 2007

New Zealand metering and demand response arrangements

Metering arrangements

197. There are approximately 1.9 million electricity metering installations in New Zealand at present, with this number growing by approximately 30,000 per annum[121]. An electricity meter located at one of these installations falls into one of six technical classifications (termed categories).

198. Figure below shows the distribution of metering installations across New Zealand by category as at the beginning of 2008.

Region	Metering Category[2]							
	0	1	2	3	4	5	6	Total
Auckland	2,033	512,288	4,691	949	264	14	15	520,254
Bay of Plenty	349	127,746	871	177	38	1	6	129,188
Canterbury	2,215	226,493	3,916	479	63	2	4	233,172
Gisborne	473	46,655	534	33	12	2	2	47,711
Hawkes Bay	494	120,727	1,011	138	39	1	6	122,416
Manawatu	87	47,270	512	84	10	1	2	47,966
Marlborough	71	23,141	262	49	16	1	0	23,540
Nelson & Bays	265	42,996	573	70	22	0	1	43,927
Northland	500	92,889	651	65	10	1	8	94,124
Otago	169	26,095	385	41	10	1	3	26,704
Other	191	31,956	897	107	32	2	6	33,191
Southland	542	127,514	1,447	188	42	7	8	129,748
Taranaki	219	58,309	467	67	16	2	5	59,085
Waikato	559	132,232	1,139	206	48	5	8	134,197
Wairarapa	289	40,303	841	30	7	1	3	41,474
Wanganui	219	51,781	359	81	15	1	3	52,459
Wellington	578	173,324	1,870	227	57	2	1	176,059
West Coast	72	16,367	229	24	4	0	5	16,701
North Island	*5,800*	*1,403,524*	*12,946*	*2,057*	*516*	*31*	*59*	*1,424,933*
South Island	*3,334*	*462,606*	*6,812*	*851*	*157*	*11*	*21*	*473,792*
Total	*9,325*	*1,898,086*	*20,655*	*3,015*	*705*	*44*	*86*	*1,931,916*

Note:
(1) Active metering installations as recorded on the electricity registry.
(2) Metering categories defined in code of practice D1 of schedule D1 of part D of the Electricity Governance Rules, 2003.

Source: Electricity Commission

Figure : Active Metering Installations1 by Region and Category as at February 2008

199. The categories of metering in New Zealand are as follows:

a) category 0 installations are unmetered and usually consist of small loads that are easily estimated, such as individual street lamps and traffic lights. For these installations the cost of installing a meter is not justified;

b) category 1 meters measure consumption in domestic and very small commercial premises for loads up to 100 amps or approximately 70 kW;

c) category 2 meters are usually installed in premises where the load does not exceed 500 amps or 340 kW;

d) category 3 meters are for medium-sized commercial and industrial premises up to 1200 amps or 1.9 MW; and

e) meters falling within categories 4, 5 and 6 are for large industries.

121 Electricity Commission

200. Category 1 and Category 2 meters are read monthly or bi-monthly. The consumption is generally accumulated over the period, but may be allocated into separate TOU quantities (night and day) depending on the nature of the installation, the number of registers on the meter(s) and whether measurement of consumption can be switched between the registers.

201. For consumption between 340 kW and 1.9 MW the New Zealand electricity market rules require a Category 3 meter, which measures the consumption in half hour intervals. As the reading is stored in the meter, it is possible to read the meter manually on a monthly basis, or the meter can be read more often using a remote reading system.

202. A survey of a large sample of meters conducted in 1998 indicated that the average age of meters installed at that time was 24 years[122]. As there has been no widespread replacement of meters in New Zealand since then, it can be assumed that the average age is above that now. This raises the question of how long a meter should be left in situ.

203. There is some concern among New Zealand electricity market participants over the electricity market rules requirement that Category 1 and Category 2 installations be recertified by 2015 and 2010 respectively. Although the market rules allow for statistical sampling of meters for certification purposes, given that approximately two million meters need to be recertified by 2015, a considerable number of meters will still have to be removed to enable recertification of the population using representative samples. The following submission from one market participant summarises a key sentiment within the New Zealand electricity industry.

    a) "TrustPower firmly believes that some strong direction is required from the Electricity Commission ("the Commission") regarding the compliance of existing Category 1 and 2 metering installations. TrustPower does not consider the present "do nothing" approach appropriate given the considerable timeframes required to certify New Zealand's existing metering asset. If the Commission's position regarding Cat 1 and Cat 2 compliance is made clear we feel this will either drive compliance or possibly encourage the introduction of Advanced Metering. On the other hand if the Commission's position is not made clear we are concerned that come 2010 and 2015 a number of meter owners will have no option but to cease supplying metering services."

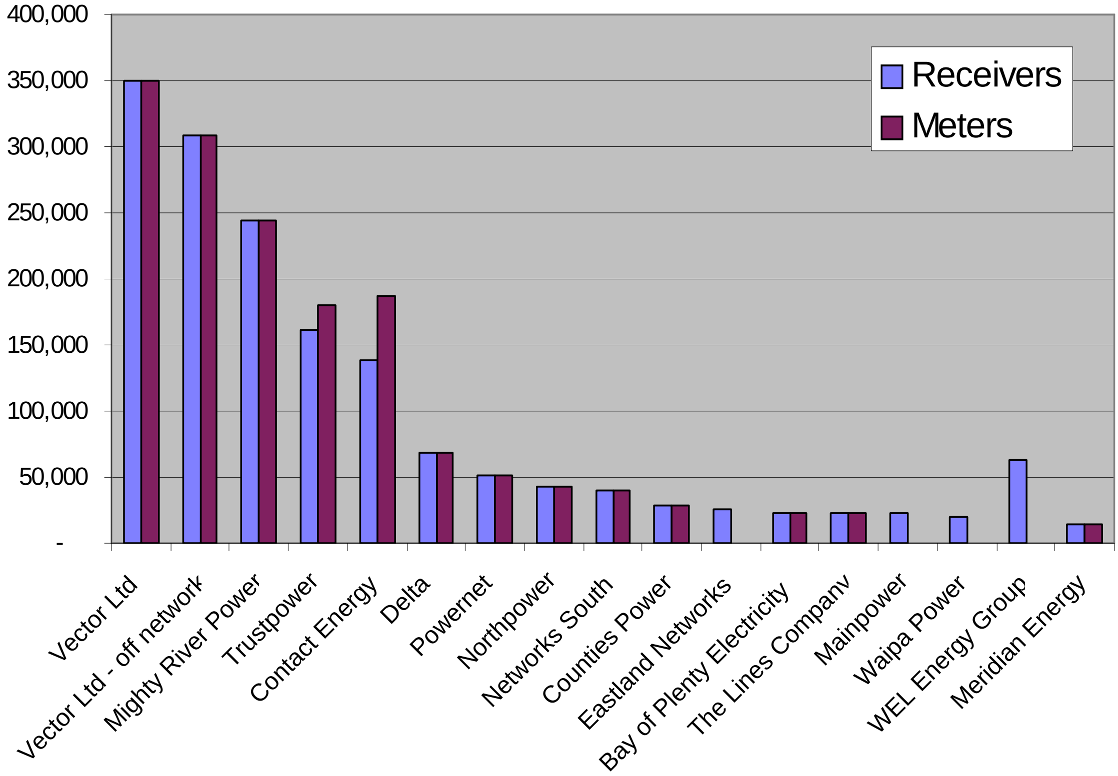
204. As pointed out in this submission, the Electricity Commission has not made any new announcements about recertification or replacement of elderly meters. Therefore, it is possible that an opportunity exists for a concerted effort to move towards new metering technologies rather than continuing with the status quo in New Zealand.

Meter ownership

205. The separation of lines and energy businesses in New Zealand, which occurred in 1999, led to the fragmentation of meter ownership. Whereas before 1999 all the meters were owned by the incumbent power company on each network, the sale of assets resulted in meters being owned by a range of participants including retailers, distributors and third party metering providers:

122 An Overview of Metering and Related Technology in New Zealand, Electricity Commission, November 2004

206. Figure below illustrates the approximate spread of metering (and ripple control receiver) ownership as at 2006. It must be noted that the number of meters and ripple control receivers owned by the various parties is approximate, but provides an illustration of the diversity of ownership.



Source: Enermet

Figure : New Zealand Meter Ownership

207. As far as Strata Energy Consulting can ascertain, the meters owned by retailers are at either Category 1 or Category 2 installations. Interval meters (Category 3 or above) are owned by other parties.

Demand response arrangements

208. Demand response is defined as the planning, implementation, and monitoring of activities designed to encourage customers to modify patterns of electricity usage, including the timing and level of electricity demand. It includes strategic conservation, time-based rates, peak load reduction, as well as customer management of energy bills.

209. Traditionally, the main issue with the provision of demand response as a product has been demonstrating the reliability of the level of response over a given period and measuring it. Smart metering offers a solution to this problem by providing accurate recording of quantities and events, thereby enabling contractual commitments put in place around demand response to be verified.

210. Demand response can be achieved in two ways, either by consumer response to pricing signals provided by suppliers (defined here as active demand

response), or by direct control of a consumer's load (direct load control or DLC), (defined here as passive demand response).

Direct load control

211. A key project within the Electricity Commission is the development, in consultation with interested parties, of an optimised approach to the use of load management and the facilitation of technology to achieve the benefits of load management for consumers and other stakeholders.

212. The Electricity Commission is seeking to determine the optimal load management infrastructure for New Zealand, by identifying the benefits of load management, and identifying any barriers to load management and the steps required to remove or minimise these barriers. The Electricity Commission's work programme has been split into three phases:

a) Phase 1: Appraisal of existing load management capabilities in New Zealand;

b) Phase 2: Quantifying in monetary terms the value of load management in New Zealand; and

c) Phase 3: Optimising load management capability in New Zealand and removing any barriers to the further development of load management technology[123].

213. The main focus of the load management programme is the direct control of consumers' load (i.e. passive demand response). Direct load control involves a third party physically managing the level of the consumer's load. This is most commonly done in New Zealand by distributors using the power lines to transmit signals to switching devices (receivers) at consumers' premises. The technology employed is known as ripple control and the communication system is power line carrier (PLC).

214. In 2006, the Electricity Commission's Existing Capability Working Panel (ECWP) undertook Phase 1 of the load management programme. The ECWP surveyed the owners of load control transmitters and receivers, publishing the following findings.[124]

a) approximately 70-85 percent of installations have a load control receiver (i.e. 1.3-1.6 million[125]);

b) responses indicate that approximately 880 MW of load is controlled in New Zealand, however more research is required to refine this;

c) the main uses for ripple control are:

   i) control of hot water cylinders;

   ii) switching meter registers for tariff purposes;

   iii) night storage heater control;

d) Other potential uses identified are:

   iv) irrigation;

123 Technology Facilitation Project plan v0.3, Electricity Commission, December 2007

124 Electricity Commission – Load Management, Final Report of the ECWP, RMAG papers, September 2006

125 Correspondence with Enermet in April 2008 indicates that there are 1.4 million receivers installed.

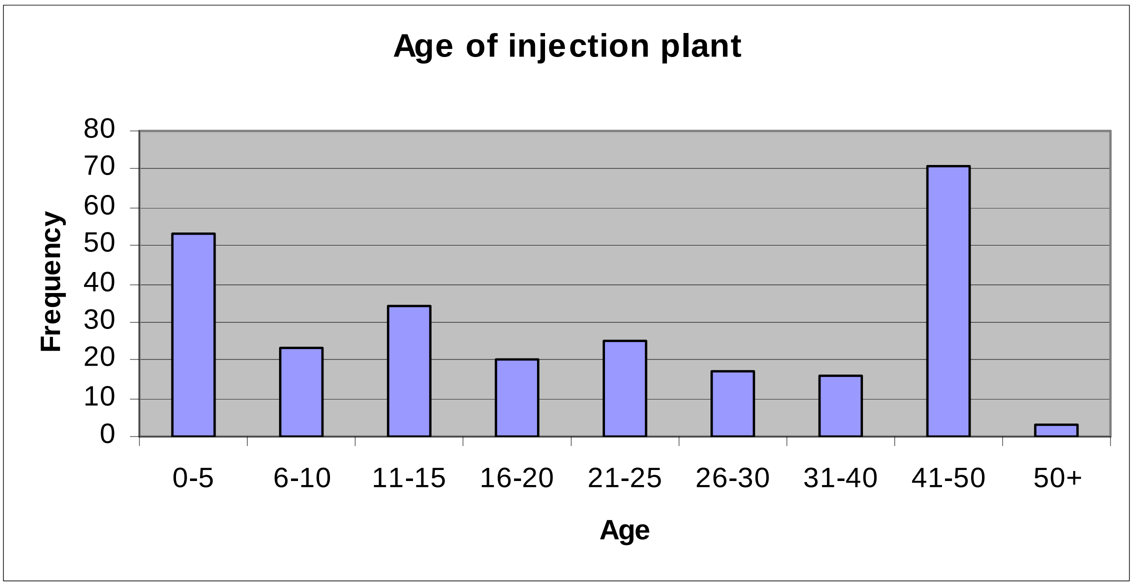
v) air-conditioning;

vi) domestic appliances;

vii) start/stop signalling for stand-by generators;

viii) demand side management of industrial/commercial plant.

e) a significant proportion of transmitters are over 30 years old and have reliability issues, particularly pilot wire systems;



Source: Enermet 2004

Figure : Age of Injection Plant in New Zealand

f) the capability of load management systems is being eroded by gas water heating, apartment living, lack of promotion of load control tariffs by retailers and attenuation of signals due to load growth;

g) transmitter owners do not know the level of stranded receivers on their networks;

h) urban areas have more reliable systems than rural areas due to signal overlap;

i) owners are committed to maintaining and upgrading plant but there are issues relating to optimised deprival valuation (ODV) and ownership, which impede investment in some systems;

j) the cost of receivers represents about 90 percent of the cost of a ripple control system;

k) there is virtually no checking of receiver operation;

l) for some owners of receivers, maintenance is reactive – it depends on consumer complaints;

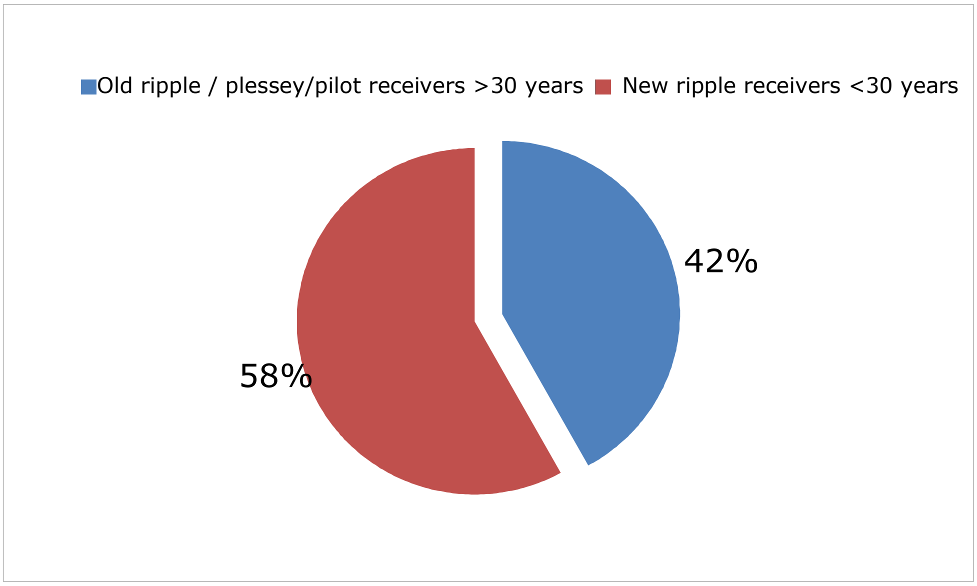
m) most transmitters operate at high frequencies (>350Hz), which are problematic due to interference and signal absorption;

n) at that time only five distributors (4.3 percent of installations) required load control at every hot water installation[126].

126 This is now six, as Orion has amended its connection conditions to require a load control receiver to be installed for hot water cylinders.

215. Interestingly, there are no rules or regulations defining the performance of load control systems in New Zealand. This is despite the fact that direct load control makes a significant contribution to the management of load on the electricity power system, influences the level of investment in networks and generation, and provides opportunities for adjusting the tariff rate for consumers' consumption (via the switching of consumption measurement between meter registers).

216. Moreover, approximately 0.5 million of the 1.4 million ripple control receivers in New Zealand are more than 30 years old, and many of these are associated with obsolete technology and unreliable performance.



Source: Enermet 2008

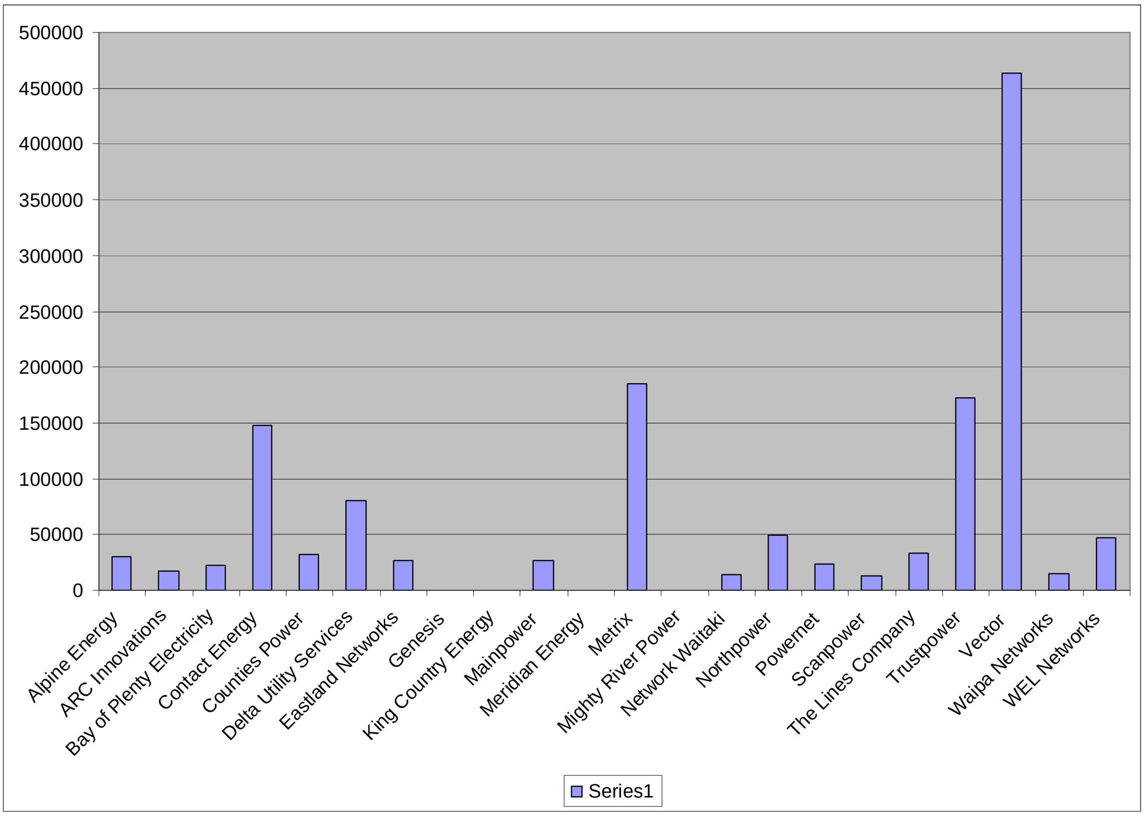
Figure : New Zealand Meter Ownership

217. In practically every one of New Zealand's 28 electricity distribution networks the transmitters of ripple control signals are owned by the distributor, but the ripple control receivers can be owned by the distributor, a retailer or a third party. Table below illustrates the changes in ownership of receivers from 1998 (when power companies split into lines and energy businesses) to 2006 (when Vector acquired a large number of ripple control receivers from NGC).

	1998	**2005**	**2006**
Incumbent network	100%	24%	45%
Retailers	0	36%	36%
Third Party	0	40%	19%

Table : Changes in the Ownership of Receivers

218. Figure below shows a more recent distribution of the ownership of ripple control receivers:



Source: Enermet – 2008

Figure : New Zealand Ownership of Ripple Control Receivers

Consumer response

219. Consumer demand response requires a pricing signal that the consumer can detect and act upon. For the majority of consumers in New Zealand, the only pricing signal they see is the electricity bill, which may be an estimate and which provides information that is out-of-date and will probably not reflect the actual resource (or economic) cost of their consumption over the billing period.

220. The prices that consumers are charged depend on the pricing plans that are offered by retailers. The structure of these pricing plans in turn depends on the metering arrangements at the consumers' premises as well as the line charges imposed by distributors. However, retailers may repackage prices and socialise price signals across consumers.

221. Overseas studies have shown that consumers will respond to pricing signals when they have the means to do so (as illustrated elsewhere in this report). The level of response depends on the incentive provided and the timeframe within which to respond. Studies have found that automatic response provides the most effective and lasting result[127].

222. It is probably reasonable to assume that New Zealand's electricity consumers will behave in ways similar to those of consumers in overseas jurisdictions, in that they will reduce or increase demand and consumption in response to an increase or decrease (respectively) in prices. The extent of the consumer

127 E.g. Response of residential customers to critical peak pricing and time-of-use rates during the summer of 2003, California Energy Commission, 2004

demand response will depend on the price level at the time and the mechanism available to respond (manual or automatic).

223. In New Zealand, a large proportion of domestic load can be switched by using ripple signals to control hot water cylinders. This is analogous to the Californian demand response, which is achieved through the automatic switching of air-conditioning load using programmable thermostats.

224. The availability of appliances that have the capability to be operated remotely or automatically in response to pricing signals will determine the extent to which further gains from consumer demand response will be achieved.

Policy and regulatory arrangements

225. Relevant Government policy is contained in the New Zealand Energy Strategy (NZES) (2007), the New Zealand Energy Efficiency and Conservation Strategy (NZEECS) (2007) and the Government Policy Statement (GPS) on electricity governance (2006).

226. The NZES notes that smart metering is expected to enhance New Zealand's existing load management capability, however to be fully effective smart metering requires TOU electricity pricing. The NZES states that the Electricity Commission, when developing smart metering guidelines under the NZEECS, will take account of this as well as concerns over whether current New Zealand meter ownership arrangements are inconsistent with the deployment of smart metering[128].

227. The NZEECS places an action on the Electricity Commission to publish voluntary technical guidelines on smart metering by the end of 2007, and to investigate and decide by the end of 2009 as to whether regulation is required in order to roll out smart metering in New Zealand[129].

228. The GPS states that the Electricity Commission "should develop, in consultation with interested parties, principles or model approaches to distribution pricing and monitor their uptake. The Commission should recommend regulations if required to ensure compliance. The March 2008 draft GPS, which currently is under consideration after submissions, adds "*As part of this work the (Electricity) Commission should investigate barriers to demand side participation*"[130].

229. The GPS also requires that the Electricity Commission should promote the efficient use of electricity. It should seek this objective in multiple and mutually-reinforcing ways:

a) "by promoting and facilitating the efficient use of electricity by end-users, including providing financial incentives for investment in electricity efficiency where it is cost-effective to do so and in response to market failures and barriers;

b) by promoting cost-reflective pricing by seeking innovative ways to enable residential and other consumers without time-of-use meters to respond to pricing incentives to use electricity more efficiently;

128 New Zealand Energy Strategy to 2050; Powering Our Future, Ministry of Economic Development, October 2007

129 New Zealand Energy Efficiency and Conservation Strategy, Making It Happen: Action plan to maximise energy efficiency and renewable energy. Energy Efficiency and Conservation Authority. October 2007

130 Government Policy Statement on Electricity Governance, October 2006

c) by keeping under review, and making recommendations to the Government as appropriate, on whether there is a strong case for requiring the progressive introduction of smarter meters for consumers (which is amended in the March 2008 draft GPS to '*by making recommendations to the Government as appropriate on the development of guidelines and/or potential rule changes to facilitate the progressive introduction of advanced/smarter meters for consumers*');

d) by encouraging and facilitating demand-side participation in the wholesale and retail markets; and

e) by promoting the efficient use of ripple control (which is amended in the March 2008 draft GPS to '*by promoting the efficient use of load management*')."

230. The main regulatory provisions relating to the obligations of New Zealand electricity market participants in respect of meters reside in part D of the market rules (known as the Electricity Governance Rules). Meanwhile general requirements relating to accuracy and safety are contained in the Electricity Regulations 1997. The latter cover all low voltage supply meters used for revenue purposes.

231. Regulation of electricity lines businesses' pricing is covered by Part 4A of the Commerce Act, which is administered by the Commerce Commission. Retail pricing is considered to be competitive and therefore is not subject to external regulation.

232. As can be seen, it is clear that the Electricity Commission has the pivotal government agency role in facilitating the introduction of smart metering and distribution pricing methods in New Zealand, with the Commerce Commission having certain responsibilities for distributors' prices.

233. It should be noted that there is no regulatory requirement for retailers to adopt a distributor's pricing methodology or for distributors or retailers to provide pricing that would encourage demand response conducive to reducing consumption, inefficient investment or carbon emissions. There are arguments for and against whether risk mitigation by retailers is likely to lead to them mimicking network price profiles in retail prices, to some extent for most retail products.

234. However, it is unclear how the Electricity Commission can ensure that price signalling extends through the supply chain by mandating the provision of various pricing signals to consumers (e.g. TOU / CPP / RTP tariffs). In this regard there appears to be a gap in New Zealand's regulatory arrangements.

Technology developments

235. There are factors relating to the historical development of metering installations in New Zealand that make this country almost unique internationally. Specifically, the majority of domestic metering installations are equipped with at least one meter and a load control receiver.

236. In June 2007, the Electricity Commission issued a discussion paper on smart metering and sought industry feedback on the type of content to be included in potential guidelines for smart metering and also potential rule changes[131].

237. This discussion paper presented an overview of current trends in metering systems, as well as the attributes/functionalities offered by such systems. The paper identified the benefits that should be expected from these new investments and also the preferred enduring functionalities that these systems should provide over time, as existing systems in New Zealand are retired or updated. The paper sought comments from respondents on specific questions relating to:

a) the present and emerging metering environment;

b) smart metering strategies and load management;

c) objectives of smart metering;

d) benefits of smart metering;

e) smart metering functionalities;

f) issues arising with large scale change to smart metering;

g) relevant Electricity Governance Rules (2003); and

h) a minimum functionality list for AMI.

238. Based on the responses received and its analysis of the New Zealand metering environment, the Electricity Commission has developed a policy document[132] and a set of guidelines for smart metering, both of which take into account the submissions received as well as market requirements.

239. The Electricity Commission's smart metering policy can be summarised best in the Commission's own words:

a) "In general, this policy adopts a flexible and hands-off approach. The Commission considers that AMI system designers and operators should be allowed to find the best technical and economic means to deliver the outcomes sought. The policy areas identified, and the associated guidelines that have resulted, are intended to assist platform operators in the task of establishing and operating their advanced meter infrastructure to best support the strategic objectives and hence maximising the likelihood they will give rise to the benefits sought over time."

240. The AMI Policy addresses the following issues:

a) support for the GPS;

b) open operation of smart metering systems;

c) pricing of services;

d) communications and interface protocols;

e) metrology and meter reading;

f) management of load control;

g) data security, access, storage, and transportation;

h) provision of customer displays and a home area network interface;

131 Advanced Metering Infrastructure Discussion Paper, Electricity Commission, June 2007

132 Advanced Metering Policy and Guidelines, Electricity Commission, 2008

i) premises disconnection/reconnection and prepayment; and

j) supply to remote areas.

241. From its smart metering policy, the Electricity Commission has developed a set of smart metering guidelines, which reinforce the underlying reliance on the market to address the issues associated with smart metering. However, these guidelines do indicate that rule changes will have to be made to facilitate smart metering. It should also be noted that the Electricity Commission's smart metering policy is advisory and, in line with the GPS requirement to encourage rather than regulate, recommends only that the policy be followed.

Smart metering developments

242. To date approximately 60,000 smart meters have been installed in New Zealand[133], representing 3 percent of New Zealand's electricity metering installations.

243. However, despite the small number of smart electricity meters currently installed in New Zealand, there appears to be an intention amongst the majority of electricity market participants to move towards smart metering over the next several years. A number of New Zealand's major retailers have publicly indicated that they are preparing to roll out a combined total of more than 1.5 million smart meters within the next five years[134]. This represents over 80 percent of New Zealand's current metering installations.

Rollout completion date	Number of smart meters installed	Retailer
2009	135,000	Meridian Energy
2009	35,000	Contact Energy
2011	340,000	Mercury Energy
2013	465,000	Contact Energy
2013	575,000[135]	Genesis Energy

Table : Major New Zealand Smart Metering Rollouts

133 New Zealand Energy Strategy to 2050; Powering Our Future, Ministry of Economic Development, October 2007
Power retailers get smart, C. McEntee, March 2008
50,000 smart meters in use, Meridian Energy press release, May 2008

134 The market led path to advanced metering, G. Dennehy, April 2008
Power retailers get smart, C. McEntee, March 2008

135 The figure of 575,000 is estimated from Genesis Energy's 2007 Annual Report, which provides the total number of electricity customers supplied by Genesis Energy.

Application of international approaches and learning to New Zealand

Introduction

244. As noted in the previous section, smart metering is being installed in New Zealand, but not yet in substantial quantities. Hence, the opportunity still exists for New Zealand to learn from overseas experience before undertaking any substantial rollout(s) of smart metering.

245. The majority of international jurisdictions progressing smart metering initiatives differ from New Zealand in the extent to which they have disaggregated, liberalised and privatised their electricity sectors. In these jurisdictions there is still significant vertical integration within the electricity sector. The primary implication of this is that the decision on whether or not to invest in smart metering is more easily made in other jurisdictions rather than in New Zealand, as the costs and many of the benefits are concentrated in perhaps one or two entities, rather than being dispersed across multiple parties. In economic terms, the potential for free-riding is reduced – the party paying for the smart metering investment will realise more of the benefits than in a disaggregated sector, and therefore will be more likely to invest.

246. Institutional arrangements in Great Britain and Victoria exhibit the most similarities to those in New Zealand. Both of these jurisdictions have disaggregated and liberalised electricity sectors. However, Victoria does differ to New Zealand in the treatment of meter ownership and metering data collection and management. In Victoria, the provision of interval metering and the associated collection and management of the interval metering data is currently a contestable activity, which retailers can either undertake themselves or outsource. In contrast, non-interval metering is the responsibility of the distributors. Under its smart metering rollout, Victoria is proposing that distributors have responsibility for the rollout and be given exclusive responsibility for smart metering over the period 31 December 2008 – 31 December 2013. This differs to New Zealand and Great Britain, where metering and metering data provision are contestable activities for all types of meters.

247. Despite the various differences between New Zealand and virtually all of the overseas jurisdictions currently progressing smart metering initiatives, there are several key insights that New Zealand can glean from overseas experience. This section highlights key matters for consideration by New Zealand from the application of international approaches and learning. Per the terms of reference, it includes a discussion on how to provide for the easy and cheap transfer of meter ownership when a customer changes suppliers, and what minimum technical standards for smart metering are needed to maximise the environmental benefit to New Zealand.

Clear objectives and design

248. Before introducing smart meters it is highly desirable to agree the objective(s) to be achieved. As has been noted earlier in this report, smart metering provides a range of benefits, the values of which vary considerably between jurisdictions and across different parties. Enabling and fully realising the potential from each benefit can require very different actions, each of which attracts a different cost.

249. Therefore it is important for policy objectives to be enunciated upfront, so that key AMI design decisions can be made in respect of statutory and regulatory enablers, IT and business process change requirements, AMI cost recovery, minimum AMI functionality and technology, the use of open versus proprietary standards[136], implementation approaches, and the like.

250. Setting policy objectives in respect of smart metering should not be confused with enacting smart metering enabling legislation and addressing market and regulatory imperfections surrounding the introduction of smart metering. The former is an upfront task, whereas the latter tasks are undertaken once a decision has been made on whether or not to proceed with smart metering.

251. With smart metering becoming a global technology, small jurisdictions such as New Zealand should take care to not make their smart metering design too jurisdiction-specific, as this will discourage major international metering vendors from entering the market, thereby lessening competition in the most costly area of the rollout. It appears that the Electricity Commission has been mindful of this when developing the minimum smart metering functionality requirements for New Zealand.

252. Ensuring that the design phase of the rollout is not overly lengthy assists in maintaining stakeholder engagement.

Smart metering trials and pilot schemes

253. Smart metering trials and pilot schemes have provided an opportunity for overseas jurisdictions to test smart metering technologies (i.e. metering and communications technologies), to assess consumer response to price signals and to enable both electricity suppliers and customers to experiment with different smart metering functionalities.

254. In Europe alone, the following countries were recently identified as having previous or ongoing smart metering trials:[137]

a) Denmark;

b) Finland;

c) France;

d) Latvia;

e) Norway;

136 For instance, Ontario has opted for open standards as opposed to proprietary standards with open access. In contrast, the Electricity Commission has identified that there are advantages in allowing proprietary standards for smart meter installations, provided that open access is available through the sharing of protocols.

137 European research experience and needs on smart metering; John Parson, European Smart Metering Alliance, October 2007

f) Poland;

g) Portugal;

h) The Netherlands;

i) United Kingdom.

255. Some unpublished trials are also believed to have occurred.

256. Overseas experience suggests that the benefits to be gained from such trials / pilot schemes can be maximised through a few key measures including:

a) clearly stated objectives and careful design of the trial, through input from the various stakeholders with an interest in smart metering;

b) the ability to gather high quality data from the trial (e.g. detailed and accurate data on energy consumption, consumer decision-making variables, optimal smart metering technologies; energy conservation advice provided to consumers; smart meter functionality); and

c) public access to detailed data from the trial – usually through the government or the regulator running the trial.

257. The third point is particularly important. As noted above in the example of European smart meter trials, it is understood that there have been a number of trials undertaken where the results were not published. This limits a trial's value from a public policy / regulatory policy standpoint.

258. Although commercial entities in New Zealand may trial smart metering, the purpose of such trials tends to be the achievement of the organisation's commercial objectives. In order to gauge the extent to which public policy objectives can be met with smart metering it would be desirable for one or more smart metering trials to be undertaken that have public policy objectives. These trials could test consumer demand response to differing technologies and differing pricing mechanisms (i.e. non-TOU, TOU, CPP and RTP) across the spectrum of consumers with non-interval meters (i.e. small/large domestic, small/medium commercial, with differing load patterns).

259. Such demand response studies could be designed to achieve statistically significant results on:

a) the extent to which different pricing structures and price differentials cause electricity consumption to shift from peak to off-peak periods;

b) the extent to which different pricing structures and differentials cause reduction in overall electricity usage;

c) the impact on total electricity bills for the participants;

d) the extent to which specific technology improves the level of response;

e) the attitudes of participants to the information provided;

f) the impact of the level of involvement in achieving changes in usage; and

g) the influence of demographics on the level of response.

260. In addition, consumers could also be studied for their response to environmental information such as carbon "consumption" and propensity to substitute their standard product with a fully renewable resource product at a higher price.

Involvement of government/regulatory agencies

261. The first significant smart meter rollout in the world was that undertaken by ENEL in Italy. The fact that this rollout was driven by a corporate entity was made possible because of ENEL's size and position of incumbency in the Italian electricity industry (supplying all of Italy's residential customers and 85 percent of Italy's distributed energy requirements[138]). However, in New Zealand this level of aggregation does not exist.

262. Australia provides a useful insight into how government and/or regulatory agencies can play a key role in a smart meter rollout decision. In the state of Victoria, the first step towards a smart meter rollout occurred in 2002 when the Victorian energy regulator released a position paper that recommended a rollout of interval meters (without communications capability). A key reason why the regulator prepared this report was the level of disaggregation in the Victorian energy industry, and the fact that the costs and benefits associated with a rollout of interval meters fell across different stakeholder groups.

263. Not only did the Victorian regulator fulfil the role of information aggregator but moreover, because of its regulatory role, it was able to place a binding decision on those parties it considered best placed to implement the rollout (the distributors). The argument can be made that, had the decision been left to 'the market' on whether or not an interval meter rollout should proceed, the rollout would never have proceeded. The parties bearing the costs (the distributors) were not going to realise sufficient benefits to justify it, even though the combined benefits to distributors and consumers did justify it.

264. It is for this reason that the responsibility for deciding whether or not a jurisdiction-wide smart meter rollout should occur has been placed with government and/or regulatory agencies in other jurisdictions around the world. Not only are they able to aggregate the costs and benefits across disparate stakeholders, they have the means to mandate a rollout and assign responsibility for undertaking it.

Cost-benefit studies

265. Overseas jurisdictions have generally invested in undertaking cost-benefit studies to determine whether the rollout of smart metering is desirable. However, in some instances it appears that this has not been the policy. Such an approach runs the risk of the rollout decision being reversed, as appears to have occurred recently in Quebec, Canada.

266. Should New Zealand tend towards a centralised approach to implementing smart metering, then overseas experience suggests that the cost-benefit study should be undertaken by either the government or regulator, because of New Zealand's disaggregated electricity sector. Such an approach provides an opportunity for various disparate stakeholders to input information into a centralised process, which enables the study to aggregate information so as to replicate that which would be gathered under a vertically-integrated industry arrangement.

267. This is particularly important in estimating the benefits of smart meter rollouts. While the costs of a rollout tend to be concentrated (in the entity/entities

138 Domestic Metering Innovation, Ofgem, February 2006

performing the rollout), the benefits tend to be dispersed across various stakeholders. Hence, it is quite probable that a cost-benefit analysis undertaken by the party or parties which would be responsible for a rollout will show a net cost, even if a cost-benefit analysis undertaken by a regulatory agency using equivalent costs will show a net benefit.

268. However, care is required when undertaking a public cost-benefit analysis to minimise the risk of bias. This bias can arise in a number of ways:

a) the public nature of the analysis means that stakeholders will most likely not offer up benefit and cost information that they consider to be commercially sensitive;

b) other stakeholders with a vested interest in seeing the rollout proceed / not proceed may provide information that is overly optimistic / pessimistic; and

c) information provided into the analysis is usually, by necessity, indicative and subject to assumptions, which significantly influence the cost-benefit ratio.

269. These biases are strongly influenced by the regulatory regime – for example, the nature of the regulatory cost recovery compact and the incentives that apply to costs and to benefits accruing to a regulated entity.

270. While these issues can arise in instances where a cost-benefit analysis is undertaken within a corporate entity, the commercial rigour brought to bear on such a large investment decision, which is being funded by the organisation, tends to reduce such biases.

Implementation

271. The Ontario case study provides an example of how to operationalise a smart metering implementation. The main features of the Ontario programme include:

a) the Government has set a specific target of the quantity of meters and a reasonable timeframe for their installation;

b) the Ontario Energy Board has developed a comprehensive plan covering the main activities required to meet the Government's targets;

c) the Ministry of Energy and Ontario Energy Board have:

   i) determined who should own the meters (distributors);

   ii) defined a functional specification for smart metering infrastructure;

   iii) defined the technical standards for smart meters;

   iv) defined a metering and data management system and data repository for use by all market participants;

   v) identified the standards required to ensure inter-operability and open access across the smart metering infrastructure;

   vi) determined that the costs for the roll out (including stranded asset costs) will be recovered through distributors; and

vii) identified the roles to be played by each of the major government and market bodies, i.e. the Ministry of Energy, the OEB itself, the independent system operator, the distributors and vendors.

272. Since the implementation plan was published, the Ontario Government has passed enabling regulations to cover the pricing, data handling and overall management of the smart metering infrastructure.

273. In addition, the Ontario Energy Board is using pilot schemes to test different pricing structures in order to determine consumer demand response. Distributors are also using pilot schemes in conjunction with metering manufacturers to test the different metering and communications technologies.

274. However, care should be taken to ensure that the allocation of resources in a rollout is not directed solely towards achieving the targeted number of meters installed. Doing so may be to the detriment of other aspects of the rollout, such as putting in place the necessary systems and processes for realising the different intended benefits of smart metering.

Smart metering and customer switching

275. The potential for retail competition to be adversely affected by certain smart meter ownership arrangements is a concern shared across overseas jurisdictions. A common approach being adopted internationally is to place ownership of the smart meter with the distributor (e.g. Victoria, Norway, Ireland). In a number of instances the distributor is also being given responsibility for meter data collection and management (e.g. Ontario). However, in some jurisdictions this activity is being kept contestable (e.g. the Netherlands).

276. As noted above, Great Britain and New Zealand each have competitive metering arrangements, and therefore it is useful to look at the approach to smart meter ownership being adopted by the British energy regulator Ofgem. In summary Ofgem does not believe that re-regulating meters is in customers' best interests, as the "track record of the network companies in offering cost-effective, good quality metering services and in choosing reliable metering technologies has been mixed at best"[139].

277. Further, Ofgem does not believe that the risk of an energy supplier having meters stranded because of customers switching away is material. In Ofgem's view, this provides a strong incentive for the supplier to offer competitive prices and good customer service so as to retain the customer. Suppliers also have the option of signing agreements with each other to rent each others' meters. Ofgem also notes that customers have demonstrated a willingness to enter into longer term contracts with suppliers, which offers another risk management tool.[140]

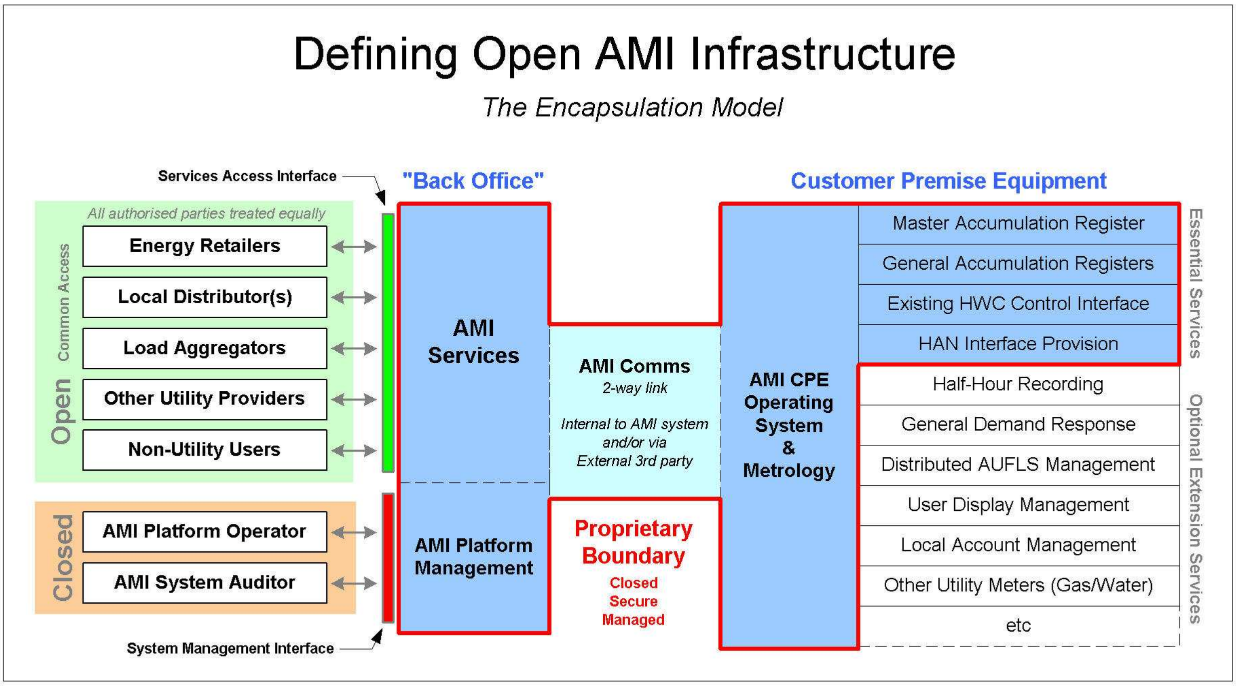
278. Nevertheless, Ofgem notes that interoperability of smart meters is critical to ensuring that customers can switch energy suppliers without having to change their meter. Achieving interoperability via common technical standards is also important to ensuring that energy suppliers do not face technical barriers to using smart meters installed by their competitors. Hence, Ofgem is working

139 Domestic Metering Innovation – Next Steps, Ofgem, 2006, p.1

140 Domestic Metering Innovation – Next Steps, Ofgem, 2006

with the British electricity industry to agree common standards for the interoperability of smart meters. Ofgem notes that its facilitation role is to assist the industry to deliver results more quickly than if the industry were to develop the standards without the regulator acting as independent facilitator. An additional and important incentive on the industry to agree common interoperability standards in a timely manner is Ofgem's ability to regulate if necessary.

279. An alternative to mandating smart meter interoperability is to require open protocols, whereby competitors are able access to each other's proprietary technologies, with or without a license fee. An advantage of this approach is that it avoids a potentially significant investment in time and effort to develop the interoperability protocols. This approach has been adopted by Ontario, and in New Zealand by the Electricity Commission.



Source: Electricity Commission 2008

Figure : Defining Open Advanced Metering Infrastructure

280. Figure illustrates the Electricity Commission's view on how open proprietary smart metering systems could be deployed without creating a barrier to competition. Those parties wishing to offer smart metering-related services or products to electricity customers would contract for access to AMI via the "Services Access Interface". The Commission's position is that all parties using AMI should be treated equally by the AMI providers, although distributors may be given preferred access to load control under special circumstances, such as if network security is threatened.

Technical standards that maximise environmental benefit

281. Technical standards for smart metering do not in themselves maximise environmental benefits from smart meters. Smart metering provides environmental benefits primarily to the extent that it leads to consumers

either forgoing/conserving electricity use or moving their usage to off-peak times, especially during the night. The primary environmental benefits are a reduction in greenhouse gas emissions and a reduction or deferral in new infrastructure investments (generation and transmission / distribution).

282. The load control functionality of smart metering may also prove to be beneficial in supporting renewable energy forms such as wind power, which increase an electrical system's requirements in respect of instantaneous reserves and frequency-keeping reserves. Traditionally, these forms of reserves have been provided by generators, with some ripple controlled hot water heating provided by distributors. Similarly, a requirement for smart metering to be able to meter separately in both import and export directions can facilitate tariffs for distributed generation from renewables, such as from photovoltaics and wind.

283. The amount of the reduction or deferral in new infrastructure investments arising from the introduction of smart metering will depend primarily on the quantum of energy conservation by electricity consumers and on the quantum of electricity that is shifted from peak demand periods to shoulder and off-peak demand times.

284. The amount of the greenhouse gas emission reduction brought about by smart metering will depend primarily on consumers' energy conservation (i.e. electricity consumption foregone rather than shifted), the jurisdiction's mix of generation plant and the scheduling of that plant to generate, and on the carbon emissions of the consumer arising from the consumer's use of electricity[141].

285. In Australia, electricity generation is heavily dependent on fossil fuels, with more than 90% of the country's electricity produced from thermal generation (black coal, brown coal, gas and oil)[142]. The carbon intensity of Australia's electricity generation varies by jurisdiction, ranging from approximately 0.1 tonnes of CO_2-equivalent per MWh in Tasmania, which primarily uses hydro electricity generation, to 1.3 tonnes of CO_2-equivalent per MWh in Victoria, which is largely dependent on coal-fired generation.[143] In other words, conserving 1 MWh in Victoria would reduce greenhouse gas emissions by approximately 1.3 tonnes of CO_2-equivalent, while a 1 MWh demand reduction in Tasmania would yield only approximately 0.1 tonnes of CO_2-equivalent reduction.

286. The current Australian national cost-benefit study[144] has estimated that greenhouse gas emission reductions from a national rollout of smart metering in Australia are largely *negative* initially (i.e. emissions actually increase). This reflects several complex interactions including:

a) demand response primarily shifting electricity consumption to off-peak periods, rather than generating significant energy conservation;

b) most Australian off-peak generation currently being coal;

141 E.g. for a given reduction in energy consumption, the reduction in greenhouse gas emissions from a cement plant will be greater than for a fish processing plant.

142 Energy in Australia 2008, ABARE, February 2008

143 National Greenhouse Accounts (NGA) Factors, Department of Climate Change – Australian Government, January 2008

144 Cost Benefit Analysis of Smart Metering and Direct Load Control; Stream 5: Economic impacts on wholesale electricity market and greenhouse gas emission outcomes; Phase 2 Consultation Report, CRA International, February 2008

c) the low cost of coal in Australia prior to the introduction of a cap-and-trade emissions trading scheme.

287. The national cost-benefit study shows that, as the price of coal increases in future years, emissions reductions become progressively more significant.

288. In New Zealand, approximately one-third of electricity is generated from fossil-fuelled plants[145]. The Ministry for the Environment has estimated that the carbon intensity of New Zealand's electricity generation is currently 0.6 tonnes of CO_2-equivalent per MWh[146]. Emissions from thermal electricity generation have increased substantially over the past decade, from approximately 3.7 million tonnes of CO_2-equivalent in 1996 to 8.3 million tonnes of CO_2-equivalent in 2006[147].

289. The use of demand reduction is a tool to slow this trend and contribute to the government policy target of 90 percent of New Zealand's electricity being generated from renewable sources by 2025. However, Strata Energy is unaware of any study that has estimated the impact on New Zealand's greenhouse gas emissions from a national smart metering rollout.

Active and passive demand response

290. Smart metering is expected to deliver environmental benefits primarily through a combination of active and passive demand response. Active demand response means consumers making a decision to curtail or move consumption. The economic incentive of higher prices is considered to be the primary motivation for active demand response. Passive demand response is where consumers agree that a third party (e.g. the distributor or the energy retailer) may curtail or move consumption on behalf of the customer.

291. The key smart metering functionality that encourages active demand response is the provision of real-time pricing to consumers. However, while this information may be displayed on a smart meter, the meter is often not in a location where the consumer can easily view the display. This is when the ability for a meter to interface with a HAN is important, as the HAN may include an in-home display which provides such information to the consumer in a convenient location, e.g. the kitchen.

292. The key smart metering functionality that encourages passive demand response is the meter's ability to receive and relay load control messages to equipment in or around a customer's home so as to support demand response. This too is considered best enabled through a HAN interface capability that is built into the meter. Although smart metering is now beginning to incorporate the ability to limit power to individual customers, this functionality relates more to managing network stability as part of the recovery from a blackout.

293. It should be noted that both active and passive demand response can be achieved without installing smart metering. Passive demand response is already widespread internationally through the use of ripple control systems that operate across the power lines. Meanwhile, in France the largest energy supplier, Electricité de France, achieves active demand response by combining TOU / CPP tariffs with a basic form of in-home display and a six register TOU

145 Energy Data File, Ministry of Economic Development, June 2007

146 Carbon abatement effects of electricity demand reductions, Ministry for the Environment, November 2007

147 New Zealand Energy Greenhouse Gas Emissions 1990-2006, Ministry of Economic Development, June 2007

meter. However smart meters, in conjunction with a HAN, can provide much greater flexibility and greater precision in their ability to control loads and to provide energy management information, thus facilitating a far wider range of products and the ability to more easily modify and evolve those products.

Implementation challenges and measures to maximise environmental benefits

Addressing barriers to implementation

Investment return certainty

294. Perhaps the largest barrier to the implementation of smart metering is certainty of the recovery of the investment. In a competitive metering market various risks arise in respect of this certainty of recovery (e.g. customers switching away from the supplier who also owns the meter; lack of interoperability of smart meters).

295. There are two approaches to addressing this fundamental barrier – regulate a guaranteed return on investment or leave the quantum of the return to be determined by the market.

296. The British approach is the latter, whilst other international jurisdictions are favouring the former. These other jurisdictions appear to be taking the view that, if smart metering is estimated to provide a positive net benefit to society, then in order to implement it relatively quickly, they will if necessary protect (maybe fully) the party introducing smart metering from the risk of investing in an asset that could be stranded within the investment period.

297. However, as the British example shows, even under a market return approach, there is still a role for the regulator in reducing uncertainty around the investment return (e.g. by ensuring interoperability of smart meters).

Stranded assets

298. While there is the risk of a stranded smart metering asset, this risk also applies equally to existing metering assets. The long life of the basic Ferraris disc meters and ripple control receivers deployed extensively throughout New Zealand at metering installations raises a potential barrier to investing in smart metering. There will naturally be a reluctance to invest in new technology if a good rate of return can be obtained on existing assets.

299. However, competition in metering assets provides owners of existing assets with an incentive to upgrade or face the prospect of their assets becoming redundant. The recent rollout of a smart metering system in Christchurch provides an excellent illustration of how this can happen.

300. If the government or regulator mandated a smart meter rollout, then the cost of the rollout may need to factor in recovery of stranded asset costs, as has occurred in some overseas jurisdictions.

Free-rider issues

301. A situation where some parties invest and others share or “free ride” on the benefits causes a dilution of the benefits to the investors. Applying this to the smart meter implementation scenario, retailers that provide customers with access to smart metering may reduce the costs of energy and line charges for retailers who continue with basic meters and non-TOU tariff arrangements (e.g. by reducing non-technical losses). Similarly, consumers who opt for a

smart meter and then undertake active or passive demand response can reduce the cost of electricity for those consumers who do not have a smart meter.

302. Under a mandatory smart meter rollout scenario the above situation does not arise. However, were smart meters to be installed in a piecemeal manner, then most likely there is a role for a regulatory or government agency to address (if possible) such free-rider issues.

Key design features

303. As noted above, smart metering provides environmental benefits to the extent that it leads to consumers either forgoing or conserving electricity use or moving their usage to off-peak times, especially during the night. Smart metering is expected to deliver these environmental benefits through a combination of active and passive demand response.

304. In order to achieve active demand response it is critical that sufficiently strong price signals are provided to consumers so as to incentivise them to respond with changes in demand. To this end, consumers should have pricing plans with TOU tariffs and most likely CPP tariffs. Further benefit would be derived from the introduction of real-time pricing, or perhaps better, ex-ante pricing (i.e. price signals are sent to consumers the day before consumption occurs).

305. Passive demand response should also be encouraged through the use of pricing signals (i.e. consumers receive cheaper electricity if they agree to have their hot water heater turned off at certain times by the distributor or retailer).

306. The ways in which consumers respond to different forms of tariffs, and consumer uptake behaviour, are not well understood and are likely to vary considerably by jurisdiction. A well-informed design process is required.

307. It is also important to note that, at least generically, the environmental benefits listed against smart meters may also be achieved through the use of alternatives. The existing load control systems installed in all distribution networks in New Zealand provide a significant reduction in the potential maximum demand that the power system has to meet. Ripple control has the potential to provide signals that will enable the introduction of TOU and CPP tariffs, in conjunction with conventional meters with multiple registers. As noted above, active demand response can be achieved by combining TOU / CPP tariffs with a basic form of in-home display and a multi-register TOU meter (as opposed to an interval meter). However, further research and design is required to assess the quantum of environmental benefits achievable by different means.

308. Finally, it is worth considering the possibility that, if gas and electricity could be measured by the same smart metering arrangements, then the potential for fuel switching and carbon emission optimisation could also be developed. For example, Orion has customers with dual fuel boilers that can switch from electricity to gas when the peak pricing level makes it economic to do so. Orion provides advanced notice of high peak prices to those customers. There may be other applications where fuel switching could be encouraged by price signalling.

The role of government in facilitating implementation

309. As noted above, the Government has a key role to play in bringing together the objectives of various stakeholders and forming a cohesive and succinct set of objectives that could be met using smart metering. Government has a crucial role to play in defining public good aspects of energy policy such as energy efficiency and conservation strategies as well as setting targets for environmental improvements.

310. The Government and/or the energy regulator also have key roles to play in effecting legislation and/or regulation required to address market and regulatory imperfections surrounding the introduction and ongoing use of smart metering. Some of the areas that may warrant this are described below.

Smart metering and customer switching

311. Noting the lessons from Great Britain in respect of meter interoperability, the Electricity Commission could take a similar role to Ofgem and work with the New Zealand electricity industry to agree common standards for the interoperability of smart meters (including common performance levels). As with Ofgem, the Electricity Commission would be in a facilitation role, assisting the electricity industry to deliver results more quickly than if the industry were to develop the standards alone. An additional and important incentive on the industry to agree common interoperability standards in a timely manner would be the Electricity Commission's ability to regulate if necessary.

312. Notwithstanding Great Britain's position in respect of smart metering ownership, in New Zealand there is the potential for smart metering to become a barrier to competition if a retailer, who is also the smart meter owner or operator, does not provide access to the meter when a customer switches to another retailer. While the Electricity Commission's smart metering policy discourages this behaviour, it has no force in law.

313. A recent High Court decision[148] stating that a retailer's refusal to lease meters to other retailers was not anti-competitive may be seen to weaken New Zealand's light-handed regulatory approach to meter ownership. However, the fact that most retailers do lease meters, and that smart metering providers will be looking to achieve a return on their investment may reduce the risk of customers with smart meters effectively being locked into a single retailer.

314. The Government, the Commerce Commission and the Electricity Commission should carefully monitor access arrangements and take appropriate action to prevent customer lock-in (e.g. the Government legislating to ensure open access to smart metering).

Cost-reflective tariffs

315. As noted earlier, active demand response is a key benefit associated with the introduction of smart metering, arguably perhaps the most important individual benefit. In order to achieve this, it is critical that sufficiently strong

148 Commerce Commission v Bay of Plenty Electricity HC WN CIV-2001-485 917 [13 December 2007]

price signals are provided to consumers so as to incentivise them to respond with changes in demand.

316. To this end, there is obvious merit in encouraging distributors and retailers to introduce pricing plans that enable TOU tariffs and most likely CPP tariffs. If insufficient economic incentive exists for these parties to introduce such plans, then regulation could be used as a fallback option.

Distribution price regulation and investment hurdles

317. In 2007, the Electricity Commission's Value and Pricing Working Panel (VPWP) undertook Phase 2 of the Commission's load management programme. In its final report[149] the VPWP identified that distributors believed that the threshold regime administered by the Commerce Commission effectively penalised investment in upgrading existing load control systems.

318. The VPWP report recommended that this situation be reviewed, to ensure that there was no impediment to distributors investing in technology such as smart metering. The VPWG report went on to suggest that the CPI–X+D approach used by the New South Wales energy regulator should be examined as a possible approach for incentivising New Zealand's distributors to invest in demand-side schemes.

319. Strata Energy Consulting suggests that, if such an incentive were to be introduced in New Zealand, it should be carefully examined to ensure that it did not create an uneven playing field for parties wishing to develop demand-side schemes.

Multiple load control operators on a network

320. To assist distributors to ensure security of supply it would appear desirable for distributors to have access to load control systems that operate using smart metering.

321. The Electricity Commission has decided that such arrangements should be left to negotiations between the smart metering owner and the distributor. However, if commercial arrangements cannot be satisfactorily negotiated, or barriers to trade become apparent, or security of supply is endangered, then the Electricity Commission has indicated that it would consider regulation.

Under-investment

322. There may be an economic incentive on some parties to replace a smart meter with a lower level of technology. While such an action may result in a net benefit to the individual economic agent, that action may impose a net cost on society.

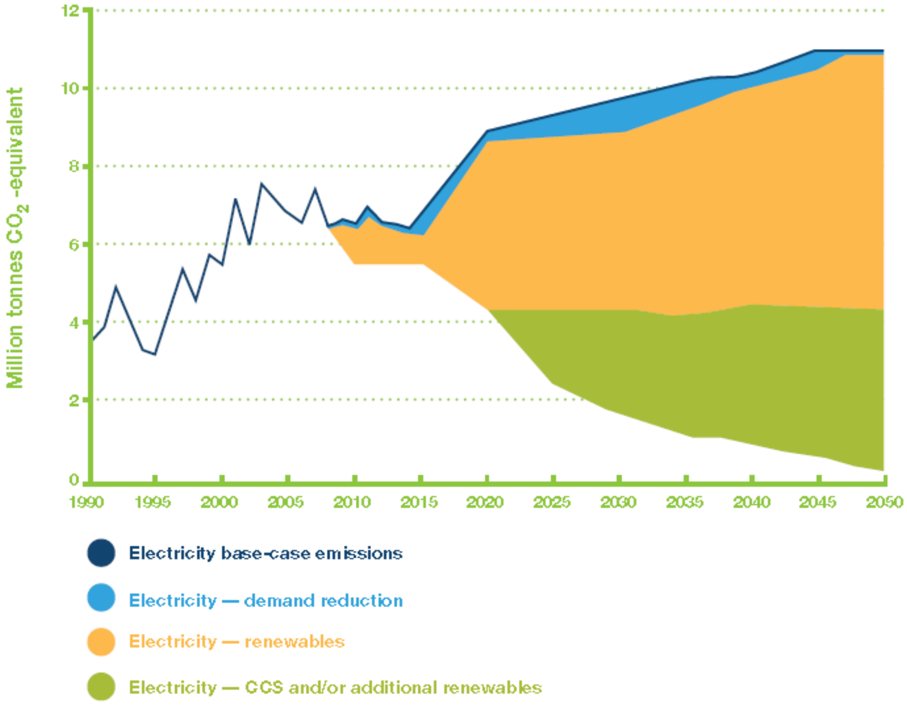
323. The Electricity Commission has considered this under-investment risk, and factored it into the Commission's guidelines on recommended minimum standards for smart metering. This acts as a disincentive to remove installed smart metering and replace it with more basic metering, as the Electricity Commission may consider regulation if its guidelines are not complied with.

149 Final Report of the VPWP, Electricity Commission, August 2007

Summary and conclusion

324. Smart metering achieves environmental benefits primarily to the extent that it leads to consumers either forgoing or conserving electricity use or moving their usage to off-peak times, especially during the night. The primary environmental benefits are a reduction in greenhouse gas emissions and a reduction or deferral in new infrastructure investments (generation and transmission / distribution). Smart metering is expected to deliver these environmental benefits through a combination of active and passive demand response.

325. As smart metering is still in its infancy, it is too soon to be able to provide robust quantitative data on the extent to which smart metering has delivered benefits to consumers while reducing the electricity sector's environmental footprint. However, the 'New Zealand Energy Strategy to 2050' views demand response as having a reasonably small, albeit important, role in reducing electricity sector emissions. The majority of the reduction is driven by aggressively pursuing existing and new renewable-based electricity generation and through the use of carbon capture and storage (CCS) technology from approximately 2020[150].



Source: Ministry of Economic Development

Figure : Emissions reduction opportunities in the New Zealand electricity sector

326. It is important to note however that environmental benefits generically similar to those listed against smart metering may also be achieved through the use of alternatives. Further work would be required to establish the relative environmental impact of smart metering versus the range of alternatives, the extent to which these benefits are additive and the extent to which they are mutually exclusive. The existing load control systems that are installed in all distribution networks in New Zealand provide a significant reduction in the

150 New Zealand Energy Strategy to 2050; Powering Our Future, Ministry of Economic Development, October 2007

potential maximum demand that the power system has to meet. Ripple control has the potential to provide signals that will enable TOU and CPP tariffs to be introduced in conjunction with conventional meters with multiple registers. As noted above, active demand response can be achieved by combining TOU / CPP tariffs with a basic form of in-home display, which bypasses the customer's meter.

327. Having said this, the existing arrangements in New Zealand that enable passive demand response are ageing and therefore it is timely to look at replacement technologies. Smart metering offers many additional features and benefits to a like-for-like replacement of New Zealand's metering and ripple control assets.

328. However, because there are alternative approaches to achieving New Zealand's energy and environmental policy objectives, it is important to first clearly define, in sufficient detail, what these policy objectives are, and then implement rules and regulations that cater for the range of alternative technologies.

329. Finally, it should be remembered that the drivers for electricity industry participants to roll out smart metering are not necessarily aligned with national energy policy and environmental objectives. Should smart metering become widespread in New Zealand, there will still remain a need to ensure that these policy objectives are met.

Key recommendations

330. As a starting point, a robust inventory of New Zealand's metering and ripple control assets should be undertaken. This should also include confirmation from electricity industry participants of the number of smart meters that they intend to roll out over the next 5-10 years and the timeframe within which this will occur. The purpose of this survey is to establish the extent to which the New Zealand electricity industry is committed to rolling out smart metering.

331. New Zealand's energy and environmental policies should be clearly defined, in sufficient detail, and followed by implementation of rules and regulations catering (in a non-discriminatory manner) for the range of alternative demand response technologies that can be used to effect these policies (e.g. smart metering, multi-rate metering, ripple relay technology and in-home displays).

332. Public trials and pilot schemes should be undertaken to assess the extent to which demand response can be achieved through active means (i.e. via price signals) and passive means (e.g. via ripple control).

333. If the New Zealand electricity industry does not demonstrate sufficient commitment to achieving the country's energy and environmental policy outcomes via the use of demand response initiatives such as smart metering, a public cost-benefit analysis should be undertaken to determine the extent of additional regulation required to achieve those outcomes. The results from the public trials and pilot schemes would feed into this.

334. The Electricity Commission, Commerce Commission, Ministry for Economic Development and other government agencies should co-ordinate their activities in relation to smart metering.

Glossary[151]

Advanced Metering Infrastructure (AMI): AMI is defined as the communications hardware and software and associated system and data management software that creates a network between advanced (smart) meters and business systems and which allows collection and distribution of information to customers and other parties such as distributors, demand aggregators and retailers.

Ampere (amp): The electric current through a given cross-section of a conductor may be measured as the quantum of electrical charge moving through that cross-section in one second. One ampere is equal to a flow of 6.28 x 1018 electrons per second, or one coulomb per second152.

Automated Metering Reading (AMR): AMR is defined as a meter with one-way communications hardware and software enabling the meter to transmit meter reading information remotely via radio signals to the metering data collector.

Billing or Revenue Meter: Meters installed at customer locations that meter electric usage and possibly other parameters associated with a customer account and provide information necessary for generating a bill to the customer for the customer account.

Conservation: Conservation includes consumer actions or decisions to use less energy, perhaps by reconsidering priorities and eliminating some energy use. Actions could include turning off extra lights, raising thermostats in summer or lowering them in winter, and taking pre-vacation steps such as turning off power strips or lowering water-heater temperatures. Conservation and energy efficiency (see separate definition) are often used as though they are synonymous, because both reduce kilowatt hours used by consumers.

Critical Peak Pricing (CPP): CPP rates are a hybrid of the TOU and RTP design. The basic rate structure is TOU. However, provision is made for replacing the normal peak price with a much higher CPP event price under specified trigger conditions (e.g., when system reliability is compromised or supply prices are very high).

Demand Aggregator: A company which contracts for demand reductions, or acts an agent on behalf of retail customers, in order to offer directly into the ancillary services or transmission alternative markets. Demand aggregators act as an intermediary for many small retail loads that cannot individually participate in the organised markets because they individually cannot meet a requirement that a demand-response offer be of minimum size.

Demand Response (DR): The planning, implementation, and monitoring of activities designed to encourage customers to modify patterns of electricity usage, including the timing and level of electricity demand. It includes strategic conservation, time-based rates, peak load reduction, as well as customer management of energy bills.

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151 The definitions in this section have been sourced mainly from the Federal Energy Regulatory Commission Survey on Demand Response, Time-Based Rate Programs/Tariffs and Advanced Metering Infrastructure Glossary.

152 The American Heritage Dictionary of the English Language, Fourth Edition

Demand Response Event: A period of time identified by the DR programme sponsor (Transpower as System Operator or Grid Owner) when it is seeking reduced energy consumption and/or load from customers participating in the programme. Depending on the type of programme and event (economic or emergency), customers are expected to respond or decide whether to respond to the call for reduced load and energy usage. The programme sponsor generally will notify the customer of the DR event before the event begins, and when the event ends. Generally each event is a certain number of hours, and the programme sponsors are limited to a maximum number of events per year.

Electricity: A form of energy characterized by the presence and motion of elementary charged particles generated by friction, induction, or chemical change.

Energy: The capacity for doing work as measured by the capability of doing work (potential energy) or the conversion of this capability to motion (kinetic energy). Energy has several forms, some of which are easily convertible and can be changed to another form useful for work. Most of the world's convertible energy comes from fossil fuels that are burned to produce heat that is then used as a transfer medium to mechanical or other means in order to accomplish tasks. Electrical energy is usually measured in kilowatt-hours.

Energy Efficiency: Refers to programmes that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programmes reduce overall electricity consumption (reported in megawatt-hours), often, but not always, without explicit consideration for the timing of programme-induced savings. Such savings are generally achieved by substituting technologically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive) with less electricity. Examples include energy saving appliances and lighting programmes, high-efficiency heating, ventilating and air conditioning (HVAC) systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems.

Kilowatt (kW): One thousand watts.

Kilowatthour (kWh): One thousand watt-hours.

Line Loss: Electric energy lost because of the transmission of electricity. Much of the loss is thermal in nature.

Load (Electric): The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of the consumers.

Load Control: A system or programme that enables load to be altered, in response to certain events (e.g. high loading on the electrical system or high energy prices).

Load Forecasting: The estimation of future load requirements for specified intervals for a period of time. The load forecast may provide an estimate of hourly loads for a group of ultimate customers for the next five years, for example.

Maximum Demand: The greatest amount of all demands of the load that has occurred within a specified period of time.

Megawatt (MW): One million watts of electricity.

Megawatthour (MWh): One thousand kilowatt-hours or 1 million watt-hours.

Outage Management: The response of an electric utility to an outage affecting the ultimate customers of the electric service. The utility may use the AMI network to detect outages, verify outages, map the extent of an outage, or verify the service has been restored after repairs have been made.

Peak Demand: The maximum load during a specified period of time.

Power Quality Monitoring: The ability of the AMI network to discern, record, and transmit to the utility instances where the voltage and/or frequency were not in ranges acceptable for reliability.

Premise Device/Load Control Interface or Capability: The ability of the AMI network to communicate directly with a device located on the premises of the ultimate customer, which may or may not be owned by the utility. These might include a programmable communicating thermostat or a load control switch.

Pre-Pay Metering: A metering and/or software and payment system that allows the ultimate customer to pay for electric service in advance.

Price Responsive Demand Response: All DR programmes that include the use of time-based rates to encourage retail customers to reduce demands when prices are relatively high. These DR programmes may also include the use of automated responses. Customers may or may not have the option of overriding the automatic response to the high prices.

Pricing Event Notification Capability: The ability of the AMI network to convey to utility customers participating in a price responsive DR programme that a DR event is planned, beginning, ongoing, and/or ending.

Provision of Usage Information to Customers: The ability of the AMI network to convey to ultimate customers information on their usage in a timely fashion. Timely in this context would be dependent on the customer class, with larger customers generally receiving the information with less lag time than residential customers.

Real Time Pricing (RTP): A retail rate in which the price for electricity typically fluctuates hourly reflecting changes in the wholesale price of electricity. RTP prices are typically known to customers on a day-ahead or hour-ahead basis.

Reduce Line Losses: The ability to use the AMI network to lower the line losses on the transmission system.

Remotely Change Metering Parameters: The ability to change parameters associated with a particular revenue or billing meter, such as the length of the data interval measured, without a site visit to the meter location.

Remote Connect/Disconnect: The ability to physically turn on or turn off power to a particular billing or revenue meter without a site visit to the meter location.

Smart (advanced) meter: An electronic meter with functionality that (at a minimum) allows for:

- Two-way communication between the metering point and data collector or energy supplier;
- Manual or automated response to load control and/or pricing signals; and
- Secure and robust management of data between relevant parties

Smart Grid: A distribution system that allows for the flow of information from a customer's meter in two directions: both inside the house to thermostats, appliances and other devices, and from the house back to the utility. This could allow appliances to be turned off during periods of high electrical demand and cost, and give customers real-time information on constantly changing electric rates. For example, new technologies such as a programmable communicating thermostat (PCT) could connect with a customer's meter through a HAN, allowing the utility to change the settings on the thermostat based on load or other factors.

Time-of-use (TOU) Rate: A rate with different unit prices for usage during different blocks of time, usually defined for a 24 hour day. TOU rates reflect the average cost of generating and delivering power during those time periods. Daily pricing blocks might include an on-peak, partial-peak, and off-peak price for non-holiday weekdays, with the on-peak price as the highest price, and the off-peak price as the lowest price.

Transformer: A device that operates on magnetic principles to increase (step up) or decrease (step down) voltage.

Transmission: The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

Transmission System: An interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers. In New Zealand the system is owned and operated by Transpower.

Watt (W): The unit of electrical power equal to one ampere under a pressure of one volt. A watt is equal to 1/746 horsepower.

Watt-hour (Wh): The electrical energy unit of measure equal to one watt of power supplied to, or taken from, an electric circuit steadily for one hour.