Global Power Best Practice Series

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Effective Mechanisms to Increase the Use of Demand-Side Resources

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Worldwide, the electricity sector is undergoing a fundamental transformation. Policymakers recognize that fossil fuels, the largest fuel source for the electricity sector, contribute to greenhouse gas emissions and other forms of man-made environmental contamination. Through technology gains, improved public policy, and market reforms, the electricity sector is becoming cleaner and more affordable. However, significant opportunities for improvement remain and the experiences in different regions of the world can form a knowledge base and provide guidance for others interested in driving this transformation.

This Global Power Best Practice Series is designed to provide power-sector regulators and policymakers with useful information and regulatory experiences about key topics, including effective rate design, innovative business models, financing mechanisms, and successful policy interventions. The Series focuses on four distinct nations/regions covering China, India, Europe, and the United States (U.S.). However, policymakers in other regions will find that the Series identifies best — or at least valued — practices and regulatory structures that can be adapted to a variety of situations and goals.

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11. Integrating Renewable Resources into Power Markets

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Foreword

It's hard to say why change comes slowly to some areas of human endeavor and quickly to others. The occurrence of that curious confluence of technology, economics, and societal readiness is as unpredictable as the flight of a honeybee. A revolution in communications brought about by the internet, cell phones, and the nano-transistor might have tickled imaginations fifty years ago, but its imminence, had that been foretold, would surely have amazed the very faculties of those mid-century eyes and ears.

So too would have the lethargy of certain elements of the energy sector. The uses to which we put electricity have, for reasons marveled at a moment ago, expanded greatly; but our relationship to the thing itself—how we produce it, how we sell it, how we think about it—hasn't really changed in the eleven decades since Thomas Edison's inspired idea to sell lighting—that is, end-use services—rather than kilowatt-hours was undone by a proliferation of competitors and, perversely enough, end uses. Electricity became commoditized, distributed and paid for according to usage, delivered by wires, and available on demand at the flick of a switch. That's still pretty much the story today. For all that roils in this industry—and the last half century has been nothing if not turbulent—its essential methods do not.

Or, at least, not much—and certainly not enough. Forty years ago began the great effort to apply, with real rigor, the principles of economics to investment and operations in the power sector. Approaches around the world varied—in China the focus was on modernizing the generating fleet; in England, on privatization and competition; in America, on a better allocation of risk between consumers and suppliers—but the common, overarching goal has been to improve efficiency, spur innovation, and drive down the cost to society of this essential good. And, to varying degrees, the enterprise has been successful. Thermal efficiencies have risen, renewable technologies abound, and elasticities of demand are revealing themselves. But these advances have been rather more evolutionary than revolutionary, and crucial progress along several dimensions—in particular, the integration of environmental damage costs into planning and dispatch and the means by which comprehensive investment in the truly lowest cost resources, among them end-use energy efficiency, can be secured—is still dreadfully lagging.

It is the latter need that this paper addresses. Nearly four decades of experience has demonstrated that key policy reforms are necessary to ensure that the demand side is fully exploited. Identified here is a suite of fourteen—some aimed at still-regulated vertically integrated power sectors, some at liberalized market systems, and some at both—that have proven particularly effective in breaking down the economic and institutional barriers to investment in clean energy resources on the customer's side of the meter. To policymakers for whom the demand side is an intriguing cipher, this paper offers a detailed look at the important first tools that they might consider adapting to their particular needs. Other policymakers, those who are already working in this arena, should find value here too—a new approach to a recurring problem, perhaps, or a different idea altogether whose time has come. We might hope for some kind of swift, revolutionary change in the power sector, but we cannot wait for it. At the very least, we can pick up the pace a little bit. Inside these pages are some very good ideas for doing so.

Frederick Weston
Principal
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Executive Summary

Measures using demand-side resources comprise actions taken on the customer's side of the meter to change the amount and/or timing of electricity use in ways that will provide benefits to the electricity supply system.

Decades of experience around the world make it clear that demand-side resources provide the fastest, lowest cost, and cleanest way to meet energy service needs. More recently, new approaches provide exciting and low cost demand-side options to improve electricity system reliability and allow for reliable integration of renewable resources. However, the electricity sector has long been dominated by a primary focus on the supply side. So it is not surprising that regulatory rules, market reforms, and power sector planning have been designed with electricity generation, transmission, and distribution in mind, without considering the use of demand-side resources where these are cost-effective and appropriate.

This paper describes a relatively small number (14) of the most effective mechanisms for increasing the use of demand-side resources in the electricity sector. Some of these mechanisms aim at integrating demand-side resources into electricity markets. Others aim at increasing the role of demand-side resources in system operations and planning processes.

Mechanisms for Increasing the Use of Demand-Side Resources

The following mechanisms are included in this paper.

Regulatory Mechanisms

- Imposing an Obligation to Carry Out Integrated Resource Planning
- Decoupling Electricity Provider Revenue from Sales Volume
- Requiring Published Information on Opportunities for Demand-Side Resources
- Mandating Implementation of Cost-Effective Demand-Side Measures
- Imposing Energy Efficiency Obligations
- Mandating Implementation of Time-Varying Electricity Pricing

Policy Mechanism

- Establishing an Energy Saving Fund

Market-Based Mechanisms

- Enabling Demand-Side Bidding into Electricity Markets
- Enabling Bidding of Demand-Side Measures to Relieve Network Constraints
- Providing Network Support Payments for Demand-Side Measures

Load-Targeting Mechanisms

- Using Load Control to Address System Needs and Integrate Renewables
- Implementing Load Scheduling to Time-Target Changes in End-User Loads
- Operating Energy Storage to Time-Target Changes in System Load
- Implementing Geographic Targeting of Demand-Side Measures

Summaries of the Mechanisms

Imposing an Obligation to Carry Out Integrated Resource Planning

This mechanism places a regulatory obligation on electricity providers to implement a planning process that examines the forecasted growth in future demand for electricity and evaluates alternative methods of meeting the resulting load on the system, including using demand-side resources. The goal is to identify the least-cost resource mix for electricity providers and their end-use customers.

This planning process is known as "integrated resource planning" (IRP).

Decoupling Electricity Provider Revenue from Sales Volume

Decoupling is a regulatory mechanism that breaks the link between the amount of electricity sold and the actual (allowed) revenue collected by an electricity provider. The purpose is to reduce the incentive that electricity providers have to increase profits by increasing electricity sales. Consequently, the corresponding disincentive to avoid reductions in sales, such as by investing in energy efficiency programs or other activities that may reduce load, is also reduced. This enables decision-making by the electricity provider to be refocused on making least-cost investments to deliver reliable energy services to customers even when such investments reduce the volume of electricity sales.

Requiring Published Information on Opportunities for Demand-Side Resources

This mechanism requires electricity providers to publish information about opportunities for using demand-side resources to reduce loads in ways that can:

- defer or eliminate the need to build additional electricity generation capacity; and/or
- defer or eliminate the need to augment and/or expand the electricity network by building poles and wires.

The purpose of publishing the information is to enable proponents of demand-side resource projects to propose options to an electricity provider that can achieve the objectives of the electricity provider in relation to expanding generation or network capacity at a lower cost than supply-side options.

Mandating Implementation of Cost-Effective Demand-Side Measures

This mechanism requires electricity providers to include all available cost-effective demand side measures when they are acquiring resources for use in meeting customer demand for electricity. The mechanism applies a policy or regulatory condition on the usual resource acquisition procedure adopted by electricity providers. This condition requires electricity providers to investigate, assess, and select cost-effective demand-side measures in preference to supply-side resources. The condition may specify the methodology to be used when assessing cost effectiveness and may also stipulate the relative priorities to be assigned to different demand-side measures.

Imposing Energy Efficiency Obligations

This mechanism requires obligated parties to meet quantitative energy savings targets through implementing cost-effective demand-side measures, particularly end-use energy efficiency. Typically, this mechanism sets annual energy savings targets for a long-term period, requiring obligated parties to achieve specified reductions in energy use through energy efficiency measures.

Mandating Implementation of Time-Varying Electricity Pricing

This mechanism requires electricity providers to implement time-varying electricity prices for some or all of their end-use customers. The purpose is:

- to increase economic efficiency by better matching prices to the time-varying costs of supplying electricity;
- to provide pricing signals encouraging customers to modify the way they use electricity, particularly by reducing load at peak times; and
- to delay investment in new electricity generation and network infrastructure.

The mechanism can result in increased use of demand-side resources in the electricity sector through incentivising the use of demand response measures.

Establishing an Energy Saving Fund

This mechanism involves the establishment of a financial facility dedicated primarily to funding projects that acquire energy savings through installing energy efficiency measures. The range of financial products such a fund may offer to proponents of energy efficiency projects is potentially very wide and may include grants, senior and junior loans, loan guarantees, and equity participation.

Enabling Demand-Side Bidding into Electricity Markets

Demand-side bidding enables the demand side of an electricity market to participate in market trading. Demand-side bids are typically made over timescales ranging from a year to a few seconds ahead of the time of delivery. There are two basic types of offer in demand-side bidding: offers involving a bid for total demand, and offers involving a bid for a change in demand.

Enabling Bidding of Demand-Side Measures to Relieve Network Constraints

This mechanism establishes a process that enables parties to bid demand-side measures to relieve constraints on electricity networks. Demand-side measures are bid as alternatives to building network infrastructure ("poles and wires") to augment or expand the existing network.

Providing Network Support Payments for Demand-Side Measures

This mechanism establishes rules within an electricity market for:

- valuing the network benefits and services available from the implementation of demand-side measures; and
- providing a commensurate financial return to parties implementing demand-side measures that deliver defined network benefits and services.

This is a separate mechanism to bidding of demand-side measures to relieve network constraints. In the bidding mechanism, payments for implementing demand-side measures are determined by the bidding process. In contrast, network support payments are determined through a process of valuing the benefits and services delivered.

Using Load Control to Address System Needs and Integrate Renewables

This mechanism uses load control technology to enable changes in the levels of end-use customer loads:

- in response to particular events such as periods of high electricity prices or problems on the electricity network; or
- to integrate intermittent generation such as wind or photovoltaics into the system.

Implementing Load Scheduling to Time-Target Changes in End-User Loads

This mechanism establishes contractual arrangements that enable system operators to request specified changes in end-user load levels at times when doing so delivers benefits or services to the system. This is a type of short-term demand response; typically system operators request changes in end-user load levels for periods lasting from one to several hours.

The effect of this mechanism is very similar to some types of demand-side bidding into electricity markets, but the method of implementation is quite different. In demand-side bidding, scheduling of demand-side measures is determined by the bidding process. In contrast, in load scheduling the system operator directly requests the owners or aggregators of the loads involved to implement changes in load levels.

Operating Energy Storage to Time-Target Changes in System Load

This mechanism uses energy storage technology to convert grid-connected electricity into another form of energy, hold it for later use, and when required at a future time, release the stored energy as electricity or as another useful form of energy. Just as transmission and distribution systems move electricity over distances to end-users, energy storage systems can move electricity through time, providing it when and where it is needed. Energy storage systems can help balance variable renewable generation and, properly deployed and integrated, can help increase the reliability of the electricity network.

Implementing Geographic Targeting of Demand-Side Measures

This mechanism establishes processes for targeting the implementation of demand-side measures to particular geographic areas or localities where they will be most effective in relieving network constraints. This mechanism is similar to bidding of demand-side measures to relieve network constraints except that this mechanism is focused on delivering the results of implementing demand-side measures to targeted geographic localities.

Effectiveness of Mechanisms

The effectiveness of these mechanisms in any particular region or country will depend on the structure of the electricity sector, and the regulatory regime and system planning processes in place. It is therefore important to take these factors into account when planning the use of any of the mechanisms described in this paper.

Abbreviations and Acronyms

ADEME Agence de l'Environnement et de la Maîtrise de l'Énergie (the French Government's environmental and energy management agency)

ARRA American Recovery and Reinvestment Act of 2009

AUD Australian Dollar

BEC Business Energy Coalition (California)

CAISO California Independent System Operator

CERT Carbon Emissions Reduction Target (United Kingdom)

CFL Compact Fluorescent Lamp

CPUC California Public Utilities Commission (United States)

DC Direct Current

DEUS Department of Energy, Utilities and Sustainability (New South Wales)

DM Demand (-Side) Management

DPS Vermont Department of Public Service

DSB Demand-Side Bidding

DSM Demand-Side Management

EDF Électricité de France

EEC Energy Efficiency Commitment (United Kingdom)

EEO Energy Efficiency Obligation

EERS Energy Efficiency Resource Standard

EESoP Energy Efficiency Standards of Performance (United Kingdom)

EU European Union

FERC Federal Energy Regulatory Commission (United States)

GBP British Pound

GW Gigawatt

GWh Gigawatt-hour

IRP Integrated Resource Planning

ISO Independent System Operator

km Kilometer

kV Kilovolt

kVA Kilovolt-Ampere

kW Kilowatt

LCP Least-Cost Planning

LIPA Long Island Power Authority (United States)

MVA Megavolt-Ampere

MW Megawatt

MWh Megawatt-hour

PACA Provence-Alpes-Côte d'Azur (region of France)

PG&E Pacific Gas and Electric Company (United States)

PPA Power Purchase Agreement

PSB Public Service Board

PUC Public Utility Commission (United States)

RDM Revenue Decoupling Mechanism

USD US Dollar

VEIC Vermont Energy Investment Corporation

WMECO Western Massachusetts Electric Company (United States)

1. Introduction

Measures using demand-side resources comprise actions taken on the customer's side of the meter to change the amount and/or timing of electricity use in ways that will provide benefits to the electricity supply system.

Decades of experience around the world make it clear that demand-side resources provide the fastest, lowest cost, and cleanest way to meet energy service needs. More recently, new approaches provide exciting and low cost demand-side options to improve electricity system reliability and allow for reliable integration of renewable resources. However, the electricity sector has long been dominated by a primary focus on the supply side. So it is not surprising that regulatory rules, market reforms, and power sector planning have been designed with electricity generation, transmission, and distribution in mind, without considering the use of demand-side resources where these are cost-effective and appropriate.

This paper describes a relatively small number (14) of the most effective mechanisms for increasing the use of demand-side resources in the electricity sector. Some of these mechanisms aim at integrating demand-side resources into electricity markets. Others aim at increasing the role of demand-side resources in system operations and planning processes.

The relative effectiveness of these mechanisms in any particular state or country will depend on the structure of the electricity sector, and the regulatory regime and system planning processes in place.

A. What Are Demand-Side Resources?

Demand-side resources can be used to change the load on an electricity network in three ways:

- by increasing energy efficiency;
- by implementing load management; and/or
- by installing distributed generation.

Energy efficiency develops and deploys technologies and design practices that reduce energy use while delivering the same level of energy service (e.g., well-lit rooms at a comfortable temperature). Energy efficiency measures are essentially non-dispatchable and always involve a load reduction.

Load management involves changes in end-use electricity consumption, particularly during times of high demand and/or high electricity prices. Load management includes direct load control, demand response, interruptible loads, load shifting, power factor correction, and fuel substitution. Until recently, load management measures have not been dispatchable, have generally been deployed in a "broad-brush" fashion, and have usually required some involvement by the end-use customer. In the future, load management will become a much more fine-grained and controllable tool deployed in the course of everyday operations than has traditionally been the case. Load management will increasingly be dispatchable under the control of a utility, system operator, or demand-side aggregator, and in many cases, will be carried out automatically without any intervention by the customer. Load management will also have to be able to deliver both reductions and increases in load to enable cost-effective integration of renewables into the generation mix.

Distributed generation comprises usually small-scale generation units that may or may not be connected to and synchronised with the main electricity network. Distributed generators may be operated in several different ways. They may be dispatched to meet system needs, dispatched to meet local needs of the grid, operated by the customer to control utility bills, or operated by the customer in the event of a lack of service from the system.

Changes in load achieved through deploying demand-side resources may reduce the need for additional generation and/or network capacity. In addition, demand-side resources can play a crucial role in creating efficient regional power markets, integrating renewables, lowering price volatility and generator market power, disciplining power costs, and improving reliability.

B. Mechanisms for Increasing the Use of Demand-Side Resources

There are four main types of mechanisms for increasing the use of demand-side resources in the electricity sector:

- regulatory mechanisms;
- policy mechanisms;
- market-based mechanisms; and
- load-targeting mechanisms.

Fourteen individual mechanisms classified into the four main types are listed in Table 1.

The mechanisms included in Table 1 have been selected on the basis that they act directly on the electricity sector to increase the use of demand-side resources. Other mechanisms, such as codes and standards, act more broadly and may also influence increased use of demand-side resources. However, because such mechanisms are not focussed directly on the electricity sector, they are not considered in this paper.

In addition, many of the mechanisms identified in Table 1 overlap and interact with each other in the same way that, in the real world, a suite of actions will overlap and interact in a fairly jumbled and muddled way. Consequently, this paper is not intended to provide a neat and mutually exclusive classification of mechanisms. Rather, it is intended to stimulate policy makers to think about policy actions that they could develop and implement in their own jurisdictions.

Table 1

Mechanisms for Increasing the Use of Demand-Side Resources

		Vertically Integrated Electricity Utilities with Regulated Markets	Markets with Unbundled Electricity Providers	Competitive Wholesale Electricity Generation Markets with Regulated Electricity Retailers	Fully Competitive Electricity Generation and Retail Markets
Regulatory Mechanisms					
R1	Imposing an obligation to carry out integrated resource planning	E	Y*	Y*	
R2	Decoupling electricity provider revenue from sales volume	E	E+	Y+	Y+
R3	Requiring published information on opportunities for demand-side resources	Y	Y	Y	Y
R4	Mandating implementation of cost-effective demand-side measures	Y	Y	Y	Y
R5	Imposing energy efficiency obligations	E	E	E	E
R6	Mandating implementation of time-varying electricity pricing	Y	Y	Y	
Policy Mechanism					
P1	Establishing an energy saving fund	E	E	E	E
Market-Based Mechanisms					
M1	Enabling demand-side bidding into electricity markets			E	E
M2	Enabling bidding of demand-side measures to relieve network constraints	Y	Y	Y	Y
M3	Providing network support payments for demand-side measures	Y	Y	Y	Y
Load-Targeting Mechanisms					
T1	Using load control to address system needs and integrate renewables	Y	Y	Y	Y
T2	Implementing load scheduling to time-target changes in end-user loads	Y	Y	Y	Y
T3	Operating energy storage to time-target changes in system load	Y	Y	Y	Y
T4	Implementing geographic targeting of demand-side measures	Y	Y	Y	Y

Y: Mechanism can be applied in this market structure
E: Mechanism is particularly effective in this market structure
**: Electricity retailers only*
+: Electricity transmission and distribution service providers only

Table created by David Crossley, 2012.

2. Application and Effectiveness of Mechanisms

Mechanisms for increasing the use of demand-side resources vary in their applicability to, and effectiveness in, the four main types of electricity markets:

- vertically integrated electricity utilities with regulated markets;
- markets with unbundled electricity providers;
- competitive wholesale electricity generation markets with regulated electricity retailers; and
- fully competitive electricity generation and retail markets.

In Table 1 (page 11), "Y" indicates that a mechanism can be applied to a particular type of market. The Table shows that, although some mechanisms (particularly load targeting mechanisms and mechanisms related to providers of electricity transmission and distribution services) can be applied across all the four types of markets, other mechanisms can be applied only to some types of markets. Each market type has a group of mechanisms that are particularly effective in that market structure (shown as "E" in Table 1).

A. Vertically Integrated Electricity Utilities with Regulated Markets

By definition, vertically integrated utilities own facilities along the whole electricity supply chain from generation plant, through transmission and distribution networks, to the retail sale of electricity to end-users. Although neighbouring utilities often trade bulk quantities of electricity, the lack of competition means most jurisdictions regulate all aspects of vertically integrated utilities.

Because these utilities are vertically integrated they are able to take full advantage of the range of generation-, transmission-, and distribution-related benefits demand-side resources provide. Nevertheless, the benefits of even very low cost demand-side resources are outweighed by regulatory practices, especially rules that allow utilities to pass through changes in generation cost directly to consumers. Typical regulatory practices mean increased electricity sales are profitable and demand-side resources that reduce sales, reduce profits.

There are several regulatory, policy, and load targeting mechanisms that:

- encourage the integration of demand-side resources into a vertically-integrated electricity supply chain;
- encourage utilities to invest in these resources;
- impose demand-side resource obligations on utilities; or
- limit the utility role to collecting funds needed to support demand-side investment.

Relevant mechanisms discussed in this paper include:

- imposing an obligation to carry out integrated resource planning during system planning;
- decoupling the revenue of electricity providers from the volume of electricity sales;
- imposing energy efficiency obligations on electricity providers; and
- establishing an energy saving fund with financial contributions from electricity providers and/or emissions trading schemes.

B. Markets with Unbundled Electricity Providers

In some regions, vertically integrated utilities have been unbundled into separate electricity generation, transmission, and combined distribution/retail supply providers.[1] In some cases, unbundling is taken one step further to create stand-alone electricity retailers that sell electricity without owning and operating the distribution

1 There are also numerous examples, particularly in the United States, of competitive wholesale generation markets being introduced without unbundling vertically integrated utilities.

systems that enable delivery to end-users. Although unbundling can be carried out without establishing a formal competitive wholesale electricity market,[2] unbundling necessitates some form of trading of bulk quantities of electricity between the individual generation providers and the providers responsible for selling electricity to end-users.

In markets with unbundled electricity providers, the entity that bears the generation cost is the key to increasing the use of demand-side resources in the electricity sector.

Where generation costs do not pass through to end-use consumers, the electricity retailer (which may also be the operator of the distribution network) will see the generation cost savings. When marginal generation costs exceed marginal revenue from kWh sales, demand-side resources will produce a net benefit to the retailer. This however is the rare case.

More often, unbundling of vertically integrated utilities results in generation costs being passed directly through to end-users. In this case, only the customer bears the generation cost. None of the entities that comprise the power sector are positioned to benefit from the generation cost-related savings that may be achieved by implementing demand-side measures.

In this case, only the wires businesses (operators of transmission and distribution networks) are positioned to see any benefits from implementing demand-side measures. However, they only see the benefits that relate to cost savings in transmission and distribution networks. For the wires businesses, achieving load reductions in specific locations and/or at specific times of the day may be more cost-effective in relieving network congestion than expanding or augmenting the network through building poles and wires. However the benefits from implementing demand-side measures can be significantly reduced if (as is often the case) the profits of wires businesses are mainly determined by the volume of electricity transported through the network, or their earnings growth is primarily driven by an allowed rate of return on capital invested in building poles and wires.

In contrast, generators and stand-alone electricity retailers rely entirely on the volume of electricity sales ("throughput") to generate revenue and profits. Any reduction in electricity sales from deploying demand-side resources reduces both their revenue and their profits.

There are several regulatory, policy, and load targeting mechanisms that:

- reform regulatory practices to encourage wires businesses to invest in demand-side resources;
- impose demand-side resource obligations on particular electricity providers; or
- limit the electricity provider role to collecting funds needed to support demand-side investment.

Relevant mechanisms discussed in this paper include:

- decoupling the revenue of wires businesses from the volume of electricity sales;
- imposing energy efficiency obligations on electricity providers;
- establishing an energy saving fund with financial contributions from electricity providers and/or emissions trading schemes.

C. Competitive Wholesale Electricity Generation Markets with Regulated Electricity Retailers

Competitive wholesale electricity generation markets can function effectively with both vertically integrated utilities, as in many parts of the United States, and with unbundled electricity providers, as in Europe, Australia, New Zealand, and several other countries. The first stage in introducing competition is usually to make the wholesale electricity generation market competitive while retaining franchises for the retail sale of electricity to end-users. Retail franchises are typically established on a geographic basis with all end-users located within a geographic area being served by the same vertically integrated utility or stand-alone electricity retailer and retail prices being controlled by a regulator.

The introduction of competition at the wholesale level may provide an opportunity for demand-side resources to compete with supply-side resources through directly bidding load reductions into wholesale energy markets and

2 For example, in China electricity generators have been unbundled into stand-alone generators and the grid companies (combined transmission, distribution, and retail supply providers). The grid companies purchase bulk electricity from the generators at fixed prices rather than at prices determined by a competitive market. However, this is an unusual arrangement, and unbundling of generation is more usually accompanied by the establishment of some form of competitive wholesale electricity market.

bidding to provide ancillary services and forward capacity where markets for such services exist.

There are several regulatory, policy, and load targeting mechanisms that:

- impose demand-side resource obligations on particular electricity providers;
- enable electricity providers to bid load reductions into markets; and
- limit the utility role to collecting funds needed to support demand-side investment.

Relevant mechanisms discussed in this paper include:

- imposing energy efficiency obligations on electricity providers;
- enabling demand-side bidding into electricity markets; and
- establishing an energy saving fund with financial contributions from electricity providers and/or emissions trading schemes.

D. Fully Competitive Electricity Generation and Retail Markets

Fully competitive electricity generation and retail markets often include completely unbundled energy providers.[3] The addition of retail competition to electricity markets in theory provides electricity retailers with a commercial rationale to provide energy efficiency and demand response services to their customers as a way of differentiating themselves from competitors. In practice, however, few electricity retailers in competitive markets have changed their business models to incorporate energy efficiency and demand response products.

The most effective mechanisms to achieve increased use of demand-side resources in competitive wholesale and retail electricity markets are the same as those for wholesale-only markets. However, the effectiveness of these mechanisms will depend on how well competitive electricity retailers are able to respond to customer and system needs. This will in turn depend on the retail pricing and market design.

Relevant mechanisms discussed in this paper include:

- imposing energy efficiency obligations on electricity providers;
- enabling demand-side bidding into electricity markets; and
- establishing an energy saving fund with financial contributions from electricity providers and/or emissions trading schemes.

3 In some fully competitive markets, such as the Australian National Electricity Market, some previously unbundled electricity generators and retailers are recombining to form so-called "gentailers." The advantage of this arrangement is that the combined entity can use its generation assets as a physical hedge to shield the electricity retailing business from exposure to high prices in the wholesale electricity market.

3. Regulatory Mechanisms

Economic regulation is the explicit public or governmental intervention into a market to achieve public benefits that the market fails to achieve on its own.[4,5] In the case of increasing the use of demand-side resources in the electricity sector, the purpose of regulation is to achieve this increase where the level of demand-side resources participating in the electricity market is below an economically optimal level.

A. Imposing an Obligation to Carry Out Integrated Resource Planning

i. Description

This mechanism places a regulatory obligation on electricity providers to implement a planning process that examines the forecasted growth in future demand for electricity and evaluates alternative methods of meeting the resulting load on the system, including using demand-side resources. The goal is to identify the least-cost resource mix for electricity providers and their end-use customers. This planning process is known as "integrated resource planning" (IRP). Figure 1 (page 16) presents an outline of the IRP process.

Traditional electricity sector planning, as carried out worldwide, begins with a forecast of electricity demand. It then considers the capital and operating cost of different generating options and finds the least-cost generation mix that meets demand. IRP expands the process to consider a broader range of options, especially demand-side resources. When done well, IRP essentially identifies the size, location, cost, and value of demand-side resources to the electricity sector and the least-cost mix of generation and demand-side resources needed to meet customer energy service needs.[6]

Ideally, the IRP process should look at a wide range of options to meet future needs and include consideration of all social and environmental costs when evaluating the options. Supply-side options for evaluation should include continued operation of existing power plants, building new power plants, buying power from other generators, and encouraging customer-owned distributed generation. Demand-side options should include non-generation alternatives, such as investing in DSM programs, promoting energy efficient new construction, reducing transmission and distribution system line losses, and any other available, reliable, and cost-effective means of meeting future demand for electricity.[7]

The IRP process may also consider future requirements for local and regional transmission and distribution network infrastructure and establish a plan for future upgrades to existing lines, and/or construction of new lines, and/or the deployment of demand-side resources to relieve network constraints.

Such a broad-ranging planning process provides an opportunity for demand-side resources to be evaluated on their merits (particularly their cost-effectiveness) as methods for meeting forecasted future electricity demand and future requirements for network infrastructure.

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4 Lazar, 2011a.

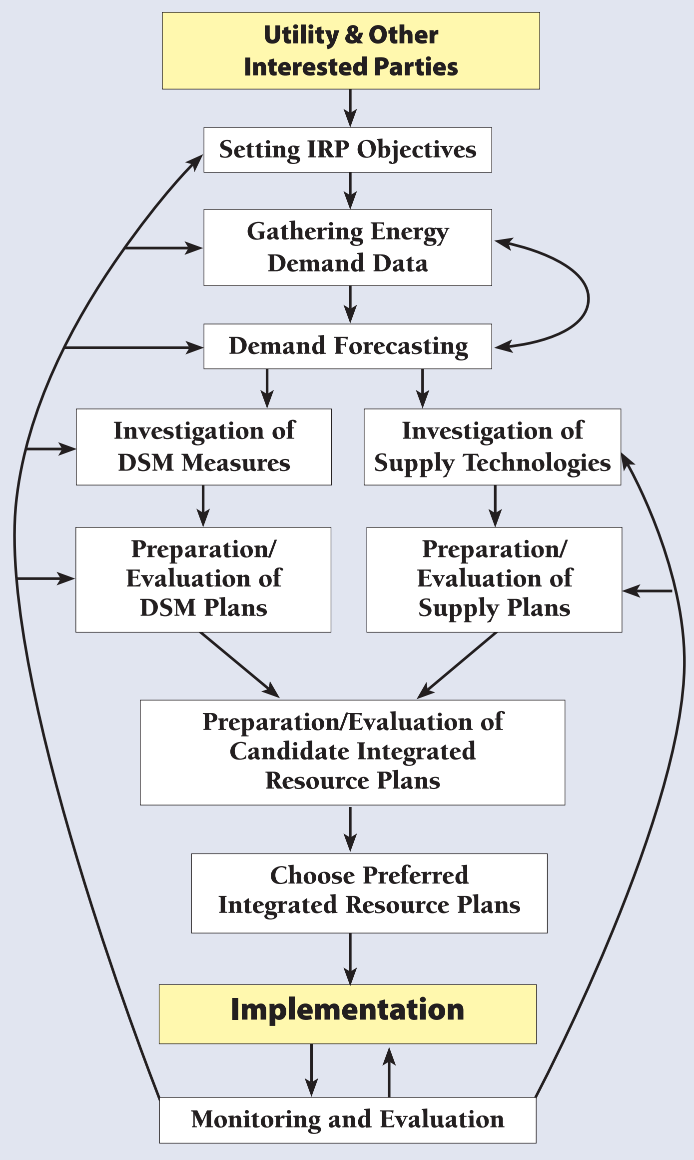
5 See the list of references (page 60) for information on how to access documents referenced in this paper.

6 IRP is included in this paper as a regulatory mechanism that can be imposed on one or more parts of the electricity sector depending on the structure of the sector. However, it is also a vital tool that should be used more generally by regulators and policymakers, because it is at the core of all electricity sector-related decision making and policy, regardless of the structure of the sector. Where the electricity sector is vertically integrated and regulated, IRP informs utilities and regulators whether investments and operating practices are prudent and least-cost. Where the sector is unbundled and competitive, IRP informs policymakers on whether the market is delivering what is needed, and if not, the changes in market design and rules that may be required. Simply stated, IRP tells you what you need. Markets can then be designed to deliver what you need in an efficient manner.

7 Lazar, 2011a.

Figure 1

The Integrated Resource Planning Process[8]



ii. Implementation

As a regulatory mechanism, IRP can be made an obligation on vertically integrated utilities to implement a planning process that examines the forecasted growth in future demand for electricity and evaluates alternative methods of meeting the demand, including demand-side resources. Where the power sector has been unbundled, IRP can be made an obligation on transmission and distribution system operators ("wires businesses") to consider demand-side resources and other non-wire alternatives to meet future requirements for local and regional transmission and distribution network infrastructure and to establish a plan for future upgrades to existing lines and/or construction of new lines.

The purpose of IRP is to identify the least-cost option. Least-cost in this case means lowest total cost over the planning horizon, given the risks faced. The best resource mix is typically the one that remains cost-effective across a wide range of futures and sensitivity cases, while meeting established resource security and reliability standards.[9]

Many aspects of the implementation of IRP are technical and straightforward, and follow established electricity planning methodologies. Others aspects of IRP add new methodologies and slightly more complexity to the analysis. For example, most demand-side resources are very different from supply-side resources. Demand-side resources are usually smaller in scale, and may be intermittent or otherwise not as predictable or as "firm" as supply-side resources. These perceived disadvantages may be reduced by technology that enables targeting of some demand-side measures to particular time periods and/or geographic locations. Such targeting enables these measures to be used effectively to provide demand response during peak periods or at times of high prices in wholesale electricity markets. In particular, an evaluation methodology that takes into account the particular characteristics of demand-side resources can enable their deployment in system planning to defer investment in grid infrastructure (i.e., "poles and wires").

Finally, many aspects of IRP require the application of judgment and policy. This is why IRP is often described as an iterative and public process that involves many stakeholders and interested parties. These complexities are a strength, not a weakness of IRP. In particular, developing a robust methodology for estimating the relative cost-effectiveness of different demand-side and supply-side options can be challenging. Determining how to value social and environmental costs is a particularly difficult methodological issue that requires both judgement and the development of policy positions.

8 The Tellus Institute (undated).

9 Lazar, 2011a.

iii. Application

This regulatory mechanism was first implemented during the 1980s and early 1990s when regulators in several US states placed IRP obligations on large vertically-integrated investor-owned monopoly utilities. The boundary within which the planning process applied was primarily the utility's geographic service territory. All resources owned by the utility, wherever located, were included. Resources not owned by the utility and located outside the service territory could be included if they were likely to be cost-effective and compliant with resource security and reliability standards.

Although IRP was originally applied to individual monopoly utilities, this planning process can, and has been, applied in other situations.

- Denmark's 1994 Electricity Act included an effective IRP obligation. Combined electricity distribution/retail supply companies were required to prepare DSM plans. Generation and transmission companies and the independent system operator (ISO) drew up scenarios for generation and transmission. The Danish Energy Agency developed guidelines and coordinated an overall 20-year plan for the whole country.[10]
- Since 2008, the two investor-owned utilities in Connecticut have been required by state legislation to submit an annual IRP for the state as a whole, while also participating in the competitive forward capacity market operated by ISO-New England. The Connecticut statute stipulates that resource needs should first be met through all available energy efficiency and demand reduction resources that are cost-effective, reliable, and feasible. In addition, the projected customer cost impact of any demand-side resources considered must be reviewed on an equitable basis with other resources.[11]
- The current round of electricity market reform in the United Kingdom is driven by IRP-type studies that show what mix of generation and demand-side resources is needed to meet long-term climate goals. Similar activities are underway in other regions.

iv. Market Impact

A regulatory obligation requiring electricity providers to implement IRP can increase the use of demand-side resources where these are more cost-effective than supply-side resources. The requirement to procure cost-effective demand-side resources:

- establishes a market for demand-side resources where such a market does not already exist; and
- increases the quantity of demand-side resources bid into competitive wholesale electricity markets where the market rules enable demand-side bidding.

For example, in May 2009, the results of the second auction in the ISO-New England forward capacity market showed that energy efficiency measures bid by the two Connecticut utilities accounted for 25 percent of the total capacity and 50 percent of the total energy efficiency resource purchased.[12]

v. Effectiveness

Where this regulatory mechanism has been implemented, obligated electricity providers are legally required to implement IRP. The effectiveness of the mechanism is therefore determined by how successfully IRP operates within an existing regulatory regime and market structure.

Following the restructuring of electricity markets in the United States, questions have arisen about the effectiveness of IRP where competitive electricity markets have been implemented, perhaps because IRP was traditionally seen as a centralised planning approach, while deregulation was supposed to allow individual decision-making by electricity providers.[13] Among the states that restructured, some suspended the IRP obligation, while in other cases the Public Utilities Commissions (PUCs) shifted from mandatory to optional IRP, or have imposed obligations on electricity providers to implement resource portfolios with defined levels of investment in DSM and/or renewables.

However, IRP can still have a role in jurisdictions with restructured electricity markets. As the case of Connecticut demonstrates, it is possible to maintain an IRP obligation while the obligated electricity providers participate in a competitive electricity market. An IRP obligation can also be imposed on electricity providers that own and operate transmission and distribution networks; the obligation will require them to implement an IRP process when they are considering augmenting and/or expanding their networks.

10 D'Sa, 2005.

11 Betkowski, 2009.

12 Betkowski, 2009.

13 D'Sa, 2005.

vi. Case Study

The following case study briefly describes the IRP process carried out by the vertically integrated utility PacifiCorp in the United States. PacifiCorp serves more than 1.7 million customers across 136,000 square miles in six states. The company comprises three business units: Pacific Power serves customers in Oregon, Washington, and California; Rocky Mountain Power serves customers in Utah, Wyoming, and Idaho; and PacifiCorp Energy operates a broad portfolio of power-generating assets.

PacifiCorp prepares its integrated resource plan on a biennial schedule, filing its plan with state utility commissions during each odd numbered year. For five of its six state jurisdictions, the Company receives a formal notification as to whether the IRP meets the commissions' IRP standards and guidelines, referred to as IRP acknowledgement. For even-numbered years, the Company updates its preferred resource portfolio and action plan by considering the most recent resource cost, load forecast, regulatory, and market information.[14]

PacifiCorp's IRP process uses system modelling tools as part of its analytical framework to determine the long-run economic and operational performance of alternative resource portfolios. These models simulate the integration of new resource alternatives with the companies' existing assets, thereby informing the selection of a preferred portfolio judged to be the most cost-effective resource mix after considering risk, supply reliability, uncertainty, and government energy resource policies.

PacifiCorp filed its 11th Integrated Resource Plan[15] with state regulatory commissions on March 31, 2011. The filing initiated the state processes for acknowledgment in Idaho, Oregon, Utah, Washington, and Wyoming.

The 2011 Plan is a comprehensive decision support tool and road map for meeting the company's objective of providing reliable and least-cost electric service to all of its customers while addressing the substantial risks and uncertainties inherent in the electric utility business. The Plan was developed with considerable public involvement from state utility commission staff, state agencies, customer and industry advocacy groups, project developers, and other stakeholders.

The key elements of the 2011 Plan included:

- the resource portfolio modelling process and assumptions;
- a finding of resource need, focusing on the first 10 years of a 20-year planning period;
- the preferred portfolio of supply-side and demand-side resources to meet this need; and
- an action plan that identified the steps to be taken during the next two to four years to implement the plan.

The preferred portfolio in the 2011 Plan reflected a significant increase in energy efficiency relative to prior IRPs.

For PacifiCorp, the 2011 Plan is part of an evolving process that incorporates current information and reflects continuous improvements in system modelling capability required to address new issues and an expanding analytical scope. PacifiCorp's preferred portfolio and action plans are not seen as static products reflecting resource acquisition commitments, but rather represent a flexible framework for considering resource acquisition paths that may vary as market and regulatory conditions change.[16] The preferred portfolio and action plans are augmented by a resource acquisition path analysis informed by extensive portfolio scenario modelling. Specific resource acquisition decisions stem from PacifiCorp's procurement process as supported by the IRP and business planning processes, as well as compliance with then-current laws and regulatory rules and orders.

B. Decoupling Electricity Provider Revenue from Sales Volume

i. Description

Decoupling is a regulatory mechanism that breaks the link between the amount of electricity sold and the actual (allowed) revenue collected by an electricity provider.[17] The purpose is to reduce the incentive that electricity providers have to increase profits by increasing electricity sales.[18]

14 PacifiCorp, 2011a.

15 PacifiCorp, 2011b.

16 PacifiCorp, 2011b.

17 Lazar, Weston, & Shirley, 2011b.

18 In theory, under traditional regulation, marginal revenue is equal to marginal costs, so increased sales do not lead to increased profits. The adoption of deferred accounting practices and pass-through mechanisms has produced perverse incentives in which practically all increases in sales lead to increased profits and vice versa.

Figure 2

Equations for Setting Electricity Prices With and Without Decoupling[22]

Traditional Ratemaking Equation	Ratemaking Equation with Current Period Decoupling
$\text{Unit Price} = \dfrac{\text{Allowed Revenue Requirement}}{\text{Expected Units of Consumption}}$	$\text{Allowed Revenue} = \text{Last Rate Case Revenue Requirement}$
$\text{Actual Revenue} = \text{Unit Price} \times \text{Actual Units of Consumption}$	$\text{Unit Price} = \dfrac{\text{Allowed Revenue}}{\text{Actual Units of Consumption}}$

Consequently, the corresponding disincentive to avoid reductions in sales, such as by investing in energy efficiency programs or other activities that may reduce load, is also reduced. This enables decision-making by the electricity provider to be refocused on making least-cost investments to deliver reliable *energy services* to customers even when such investments reduce the volume of *electricity sales*.

There is a variety of different approaches to decoupling, all of which share a common goal of ensuring the recovery of a defined amount of revenue, independent of changes in sales volume during the period under consideration.[19]

Decoupling mechanisms are usually implemented within a regulatory framework referred to as "revenue regulation" or "revenue cap regulation." Under revenue regulation, a portion of the total revenue of an electricity provider is set each year by the regulator at a particular monetary value ("cap") calculated according to an established formula. The structure and levels of retail prices are then set to ensure that the regulated portion of revenue remains within the cap determined by the regulator. Any over- or under-collection of revenue during one time period is corrected in determining the revenue cap for the following time period.

To achieve full decoupling, the portion of total revenue subject to a cap must be set at 100 percent; a lower value will achieve only partial decoupling. Full decoupling insulates the revenue collected by an electricity provider from any deviation of actual sales from expected sales. The cause of the deviation (e.g., increased investment in energy efficiency, weather variations, changes in economic activity) does not matter. Any and all deviations will result in an adjustment ("true-up") of collected revenue with allowed revenue.[20]

ii. Implementation

In implementing decoupling for an electricity provider, the regulator first determines the revenue requirement for the provider. The revenue requirement is the aggregate of all approved costs incurred by the provider, comprising: operating expenses; the cost of invested capital including both interest on debt and a "fair" return to equity investors; and a depreciation allowance. The next step involves selecting the method whereby the allowed revenue (the revenue "cap") will be set so as to deliver the revenue requirement; a common method is to set the cap on a revenue-per-customer basis. The final step is to set the structure and levels of retail prices.

Decoupling differs most from traditional regulation when setting retail prices (see Figure 2). While traditional regulation sets prices, then lets revenues float up or down with consumption, decoupling sets the allowed revenue, then lets prices float down or up with consumption. This price recalculation is done repeatedly – either with each billing cycle or on some other periodic basis (e.g., annually).[21] The focus here is on delivering the level of revenue needed to match the revenue requirement.

iii. Application

Revenue regulation and decoupling were first developed during the late 1980s and early 1990s and applied by regulators in several US states to large vertically integrated, investor-owned monopoly utilities. Revenue regulation and decoupling have since been implemented in several other countries, including Northern Ireland and Australia.

Decoupling can only be applied to electricity providers that are subject to regulatory price controls. It cannot

19 Lazar et al, 2011b.

20 Id.

21 Id.

22 National Renewable Energy Laboratory, 2009.

be applied to providers that are free to set their prices and thereby determine their own revenue, such as in jurisdictions where the retail electricity market is fully competitive.

In jurisdictions where electricity providers have been unbundled, decoupling can be applied to regulated monopoly providers, particularly the providers that own and/or operate electricity transmission and distribution networks. In Australia, revenue regulation is the standard form of regulation applied to all transmission service providers and to distribution service providers in some states. Consequently, the revenue of these providers is independent of the volume of energy transported through their networks. This removes a disincentive for the providers to utilise demand-side resources to reduce loads as an alternative to augmenting or expanding their networks.

iv. Market Impact

As a mechanism that applies only to electricity providers that are subject to regulatory price controls, decoupling does not affect electricity markets directly. To the extent that removing the disincentive to reducing sales increases the use of demand-side resources by electricity providers, decoupling may contribute to:

- establishing a market for demand-side resources where such a market does not already exist; and
- increasing the quantity of demand-side resources bid into competitive wholesale electricity markets where the market rules enable demand-side bidding.

v. Effectiveness

Decoupling diminishes a bias against reducing sales but it does not provide any incentive for electricity providers to use demand-side measures to reduce load. Consequently, the effectiveness of decoupling (e.g., as a mechanism to increase the implementation of energy efficiency measures by electricity providers) has been questioned. However, decoupling is not intended to be the main driver for increased energy efficiency and/or increased utilisation of demand-side resources. Achieving these objectives may require the implementation of other mechanisms in addition to decoupling.

vi. Case Study

The following case study briefly describes a decoupling mechanism applied to the electricity distributor Western Massachusetts Electric Company (WMECO) in the United States.

The State of Massachusetts has adopted decoupling measures to provide distribution companies with better financial incentives to pursue an aggressive expansion of investment in energy efficiency and demand-side resources.

In July 2008, the Massachusetts Department of Public Utilities stated in its Order in D.P.U. 07 50 A:[23]

> *Distribution companies must have the proper regulatory and financial incentives to fully pursue the economic, price, reliability, and environmental benefits that are available from (1) improving the efficiency of energy production, delivery, and consumption; (2) building a strong and effective price-responsive demand; (3) fostering the rapid development of renewable energy and distributed generation within Massachusetts; and (4) supporting the evolution towards a more efficient distribution infrastructure.*

The Order in D.P.U 07-50-A also directed each gas and electric utility to include a decoupling proposal in its next rate case.

On 31 January 2011, the Department issued an Order[24] in D.P.U. 10-70 (the WMECO rate case) that applied a mechanism for the annual reconciliation of WMECO's distribution revenue and adjustment of the company's distribution rates in accordance with a revenue decoupling mechanism (RDM).

As stated in WMECO's testimony to the rate case hearing,[25] the purpose of the RDM was to adjust base rates on an annual basis to account for the impact of changes in the company's actual base revenues relative to the Target Revenues (i.e., revenue caps) by rate class established in the company's rate case. The differences between Actual Revenues and Target Revenues were primarily the result of the company's energy demand-side resource initiatives and the energy efficiency efforts of its customers, as well as the continued economic decline in the company's service area, particularly among commercial and industrial customers.

For many years, WMECO has offered its customers support to implement energy efficiency measures to help

23 Massachusetts Department of Public Utilities, 2008.

24 Massachusetts Department of Public Utilities, 2011.

25 Massachusetts Department of Public Utilities, 2010.

them reduce electrical usage. These programs include the residential "MassSAVE" program that provides home energy audits and incentives to implement measures such as insulation and air sealing. They also include programs that cover the entire cost of implementing energy saving measures for the company's low-income customers. WMECO offers programs for all businesses in its territory – from small commercial to large industrial – that help to fund both retrofit and new construction measures. Following approval of its Three Year Energy Efficiency Plan for 2010 through 2012, the company began to implement a significant increase in the size of its investment in energy efficiency from USD 12 million in 2009 to USD 35 million by 2012.

WMECO proposed a total revenue decoupling mechanism that annually reconciled the difference between the company's actual distribution revenues and Target Revenues for that year. The Company's proposed mechanism was designed to provide for annual filings that were straightforward to audit and review.

The Order implementing the RDM was generally based on WMECO's proposal. The Order required an annual adjustment to be made to Base Rates in a given Rate Year to reconcile Target Revenue with Actual Revenue received during the immediately preceding Rate Year. The Order specified that the annual RDM Adjustment should be calculated in accordance with the following formula, and applied in the upcoming Rate Year:[26]

$$\mathbf{RDMAF_i = (TR_{i-1} - AR_{i-1} + PPA_i) / FkWh_i}$$

Where,

$RDMAF_i$ means the RDM Adjustment factor applicable during year i,

TR_{i-1} equals the total Target Revenue specified in the Order,

AR_{i-1} means the Actual Revenue reported during year i-1,

PPA_i means the reconciliation in the upcoming Rate Year of estimated actual revenue included in prior period calculations of RDMA, and the recovery of any deferred amounts, and

$FkWh_i$ = the forecast of total kWh sales applicable in the upcoming Rate Year, defined as the forecasted amount of electricity to be distributed to the Distribution Company's distribution customers.

The effect of this formula is that the annual RDM Adjustment Factor is calculated by dividing (1) the difference between Target Revenues and Actual Revenues for the most recently completed annual period by (2) projected kWh deliveries for the next recovery period. This method of determining the RDM Adjustment Factor on a total revenue basis is consistent with the approach authorised by the Massachusetts Department of Public Utilities in previous rate cases for other electricity distributors.

WMECO will calculate class Target Revenues for each rate class. The initial Target Revenues will be equal to base revenues by class at the base rates that were provided in section 3 of the Order implementing the RDM. Actual Revenues, by class, will be determined directly from the actual booked base distribution revenues on a calendar month basis accumulated for the 12- to 23-month period. The difference between Actual Revenues and Target Revenues for that year by class will be summed and then divided by the projected total annual WMECO sales for the period over which the adjustment is to be recovered.

The Order implementing the RDM also required that as part of its annual filing, WMECO must submit the following information for its residential, commercial, industrial, and street lighting customers: (1) monthly customer counts; (2) monthly kWh sales; (3) weather-normalised kWh sales; (4) lost base revenue from energy efficiency programs for the most recent calendar year available; and (5) forecasted sales for the next two years.

C. Requiring Published Information on Opportunities for Demand-Side Resources

i. Description

This mechanism requires electricity providers to publish information about opportunities for using demand-side resources to reduce loads in ways that can:

- defer or eliminate the need to build additional electricity generation capacity; and/or
- defer or eliminate the need to augment and/or expand the electricity network by building poles and wires.

The purpose of publishing the information is to enable proponents of demand-side resource projects to propose

26 Massachusetts Department of Public Utilities, 2011.

options to an electricity provider that can achieve the objectives of the electricity provider at a lower cost than supply-side options such as building new generation capacity or poles and wires. In its simplest form the mechanism simply requires energy providers to publish the specified information without necessarily acquiring demand-side resources. However, the mechanism can be linked to a mandate that requires energy providers to implement cost-effective demand-side measures (see section 3.D, page 24).

Information that an electricity provider is required to publish under this mechanism may include:

- detailed information regarding the forecast need for additional capacity in a way that enables interested parties to identify the likely nature, size, timing, and geographic locations of future capacity expansions;
- information that makes transparent the underlying assumptions and decision-making process relating to investments that expand its generation and/or network capacity; and
- details of the process that will be followed by the electricity provider in soliciting, evaluating, and procuring both demand-side and supply-side resources to address future requirements for additional capacity.

ii. Implementation

The information required by this mechanism is typically published either by an individual electricity provider or by a market operator as a regular public report on the adequacy of the existing generation and/or network capacity to maintain an acceptable level of supply reliability. This public report is often referred to as a "Statement of Opportunities" or a "Regional System Plan." For example, in the United States, the 2011 Regional System Plan published by the independent system operator ISO-New England[27] outlines the region's electricity needs for the next 10 years and explores the generation, demand-side resources, and transmission improvements that can meet those needs. In Australia, the 2011 Electricity Statement of Opportunities[28] published by the Australian Energy Market Operator provides a broad analysis of opportunities for generation and demand-side investment in the Australian National Electricity Market (NEM).

The following levels of information are typically included in such public reports:

- a low level of detail across the whole system to provide an indication of where additional capacity is, and is not, likely to be required in the foreseeable future;
- a medium level of detail for parts of the system where additional capacity is forecast to be required within a defined period (e.g., five years) to allow customers and third parties to consider whether they may be able to assist in addressing any capacity shortfalls; and
- when action is being taken to acquire additional capacity, a higher level of detail on the nature, size, timing, and geographic location of the forecast capacity shortfall, including illustrative system support options developed by the electricity provider.

The reports may also include:

- information about consultation with customers and other interested parties in relation to specific forecast capacity shortfalls; and
- details of the resource procurement process to be implemented by the electricity provider.

iii. Application

This is a relatively new mechanism that has not yet been widely used. It can be implemented under any electricity sector structure, although it is currently used in regions with restructured electricity markets.

The unbundling of electricity providers has driven requirements for increased public disclosure about operational issues. Individual providers carrying out only one of the electricity industry functions require information about the activities of the separate providers carrying out the other functions so that they can plan their own activities. Regulators have assisted by mandating the public disclosure of this information.

The increased availability of information has allowed third parties, including providers of demand-side resources, to identify opportunities to contribute to the activities of electricity providers, particularly by providing load reductions as alternatives to expanding generation and network capacity. Regulators have used mandatory information disclosure to encourage the use of demand-side

27 ISO New England, 2011.

28 Australian Energy Market Operator, 2011.

resources where such resources are cost-effective compared with supply-side resources.

iv. Market Impact

Mandatory disclosure of information about opportunities for using demand-side resources to address capacity shortfalls creates markets for such resources. These range from highly structured markets, as in the forward capacity markets that have been established in some regions of the United States, to less structured markets, as when individual electricity providers include demand-side resources in their resource acquisition processes.

v. Effectiveness

Mandatory disclosure of information is a necessary but not sufficient condition to achieve increased use of demand-side resources in the electricity sector. Information disclosure will enable providers of demand-side resources to propose options to an electricity provider, but does not guarantee that these options will be taken up by the electricity provider. In the early years of operation of the information disclosure Code of Practice described in the following case study, some providers of demand-side resources complained that they were spending considerable funds in developing demand-side options, but these options were not being taken up. Additional supportive mechanisms and policies may be required to ensure uptake of all cost-effective demand-side resources identified through an information disclosure process. Some of these additional mechanisms and policies are highlighted in the following case study.

vi. Case Study

Expansion and augmentation of electricity networks is an area in which information disclosure can be effective in encouraging increased use of cost-effective demand-side resources. Many jurisdictions with unbundled electricity providers are now requiring mandatory disclosure about forecast network constraints.

The following case study briefly describes the mandatory Code of Practice[29, 30] in the state of New South Wales in Australia that requires electricity distributors to publish information about network constraints in their systems and evaluate alternative options for addressing these constraints.

The current third edition of the Code has been formally issued in accordance with Clause 6 of the *Electricity Supply (Safety and Network Management) Regulation 2002*. This requires electricity distributors in the state of New South Wales to take the Code into account in the development and implementation of their network management plans. In particular, the network management plan must specify where it or its implementation departs from the provisions of the Code and, if so, what arrangements are in place to ensure an equal or better outcome.

The Code requires electricity distributors in New South Wales to:

- publish information that makes transparent the underlying assumptions and decision-making process relating to investments that expand their distribution networks;
- publish detailed information regarding the need for network expansion in a way that enables interested parties to identify likely locations of forthcoming network constraints;
- use a formal process to determine whether demand management[31] (DM) investigations are warranted for identified emerging network constraints, and publish the results;
- carry out DM investigations that provide opportunities for market participation;
- analyse DM and network expansion options on an equal basis according to the published methodology and assumptions and publish the result of those determinations;
- implement DM options where they are determined to be cost effective; and
- prepare and publish reports on these activities annually.

The Code's objectives are for transparency in information provision and equal treatment in processes and evaluation in "circumstances in which it would be reasonable to expect that it would be cost-effective to avoid or postpone

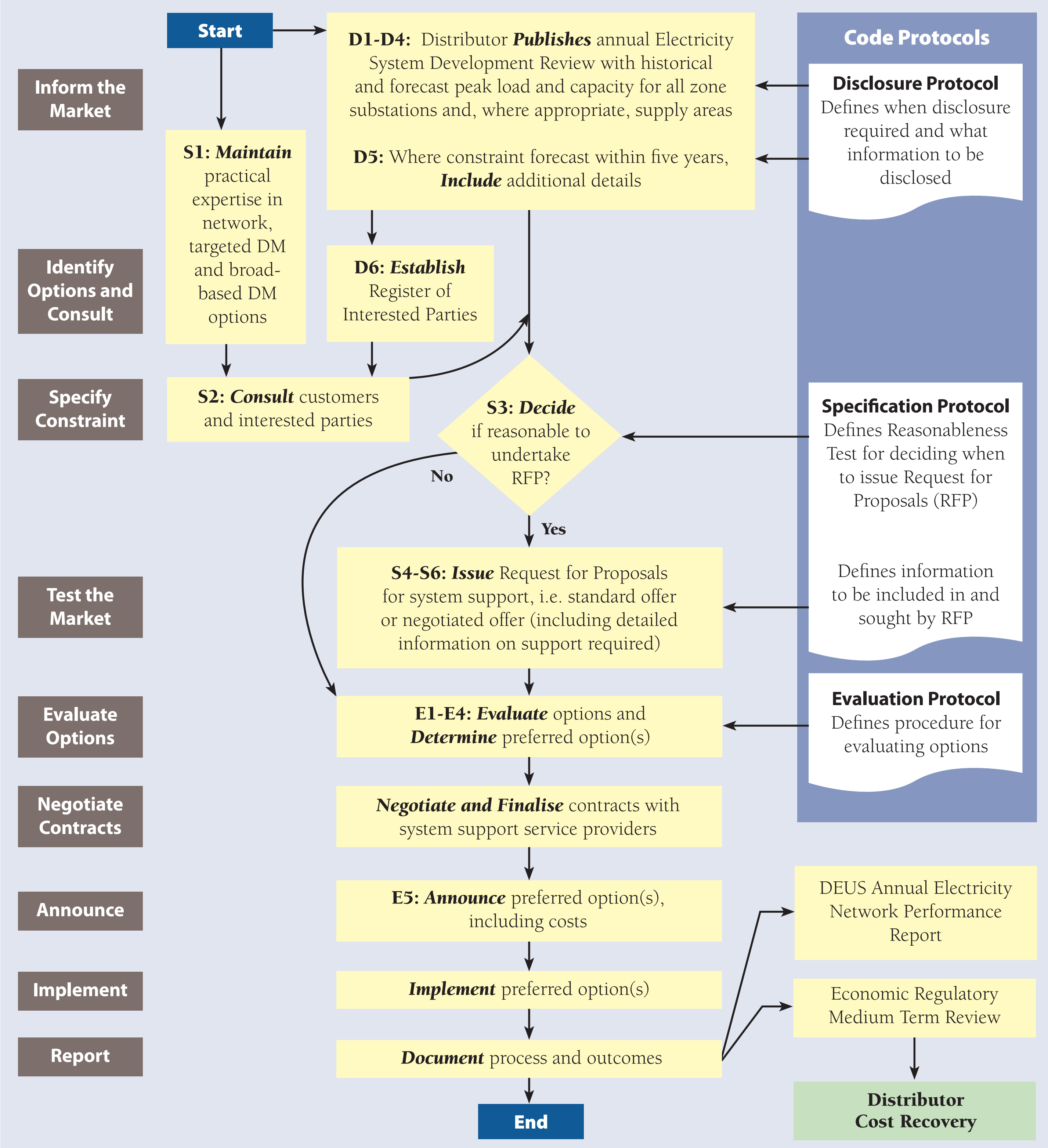
29 Department of Energy, Utilities and Sustainability, 2004.

30 A Code of Practice provides detailed practical guidance in relation to meeting legislative obligations. Codes of practice are often applied to occupational health and safety issues but can also be applied to any situation in which legislative obligations exist.

31 "Demand management" is the term used in Australia for demand-side management.

Figure 3

Electricity System Development Procedure for Distributors in New South Wales[32]



32 Department of Energy, Utilities and Sustainability, 2004.

the expansion of the network by the implementation of [demand management] strategies."

The Code recognises that the focus should not just be on the network, but rather on the delivery of end-user energy services by means of the electricity system as a whole. Constraints that arise within the distribution network can be addressed by changes in customer behaviour, by changes in equipment used by customers, or by installation of small-scale generation at a local level, as well as by enhancement of the distribution network.

These options could be devised and implemented by customers or by electricity distributors. The market-based procedure in the Code is intended to ensure that all supply- and demand-side options developed by customers or third parties and by the distributor itself can be developed and evaluated at the same time and in the same manner as network augmentation, including the use of a competitive process.

The procedure described in the Code is illustrated in Figure 3 (page 24). The procedure requires:

- a process for informing the market by disclosing appropriate information about the current and future state of the electricity supply system – the Disclosure Protocol;
- a process for fully and consistently specifying the constraint in the electricity supply system – the Specification Protocol; and
- a process for fairly and consistently evaluating proposals to overcome this constraint – the Evaluation Protocol.

The **Disclosure Protocol** ensures that distributors provide regular public reports on the status of their networks that include all necessary information in a clear and consistent form, without wasting effort in providing unnecessary information.

The **Specification Protocol** ensures that system constraints are fully and accurately specified. The Protocol requires distributors to consult with customers and interested parties in relation to each of the constraints and options to address them. The Protocol also describes the process through which alternative options for addressing constraints can be invited and proposed in a manner that allows direct comparison with each other and with options developed by the distributor. The Specification Protocol defines a Reasonableness Test, which the distributor should apply in deciding whether to issue a formal Request for Proposals in relation to each constraint.

The **Evaluation Protocol** ensures that disparate network enhancement and other system support options are given fair consideration and are equitably evaluated including all relevant costs and benefits. The Protocol requires that all conforming options should be evaluated and ranked on the basis of total annualised cost of providing the system support adjusted to account for the relative risk profile of options. The Protocol also requires distributors to publicly announce the recommended options resulting from the evaluation and the annualised cost to the distributor of the recommended options.

D. Mandating Implementation of Cost-Effective Demand-Side Measures

i. Description

This mechanism requires electricity providers to include all available cost-effective demand-side measures when they are acquiring resources for use in meeting customer demand for electricity.

The mechanism applies a policy or regulatory condition on the usual resource acquisition procedure adopted by electricity providers. This condition requires electricity providers to investigate, assess, and select cost-effective demand-side measures in preference to supply-side resources. The condition may specify the methodology to be used when assessing cost effectiveness and may also stipulate the relative priorities to be assigned to different demand-side measures.

This mechanism does not set quantitative targets but instead relies on measures of cost-effectiveness to determine the amount of demand-side measures to be acquired. This distinguishes mandating implementation of cost-effective demand-side measures from imposing energy efficiency obligations on electricity providers (see section 3.E, page 27).

In some cases, targets may be set in which a policy decision has been made to preferentially acquire certain types of demand-side resources. For example, if there is a policy to acquire renewable energy, then a specific renewable energy target may be set with a different set of cost effectiveness criteria to that of other demand side resources.

The cost-effectiveness of demand response resources may also be assessed differently from other demand-side resources because demand response is often acquired specifically to deal with peak load problems or to assist with the integration of renewable energy into the resource mix, rather than to contribute to meeting overall demand.

ii. Implementation

There are two main ways in which this mechanism can be implemented. One way is to implement a "loading order," which requires electricity demand to be met first by cost-effective demand-side measures. The second way is to simply mandate electricity providers to acquire all or a proportion of demand-side measures that are cost-effective, reliable, and feasible.

iii. Application

This mechanism has been implemented mainly in the United States. The states of California, Washington, and Massachusetts have adopted mandates requiring their electricity providers to identify and pursue all achievable cost-effective energy efficiency before considering investment in new generation options. The California mandate applies to investor-owned utilities, and the Washington mandate applies to both investor-owned and public utilities with more than 25,000 customers.[33]

iv. Market Impact

By increasing the quantity of demand-side resources acquired by electricity providers, this mechanism:

- establishes a market for cost-effective demand-side resources where such a market does not already exist; and
- significantly changes the dynamics of wholesale electricity markets by lowering the clearing price and therefore changing the merit order of generators that are less cost-effective than demand-side measures.

v. Effectiveness

Mandating implementation of cost-effective demand-side measures should be very effective in achieving increased use of demand-side resources in the electricity sector. However, in practice, the effectiveness of this mechanism will be largely determined by the methodology used to assess the cost-effectiveness of demand-side measures. For this reason, jurisdictions adopting this approach generally specify a methodology to be used in evaluating demand-side measures to avoid a situation in which only small quantities of demand-side resources are being acquired by electricity providers. In addition, applying rewards and penalties based on the performance of electricity providers in acquiring cost-effective demand-side resources will increase the effectiveness of this mechanism.

vi. Case Study

The following case study briefly describes the loading order[34] policy for electricity resources implemented in the state of California in the United States.

In 2003, California's principal energy agencies – the California Energy Commission, the California Public Utilities Commission (CPUC), and the California Consumer Power and Conservation Financing Authority – established an energy resource loading order policy to guide their energy decisions. The purpose of the loading order is:[35]

- to reduce electricity demand by increasing energy efficiency and demand response; and
- to meet new generation needs first with renewable and distributed generation resources, and second with clean fossil-fuelled generation.

The loading order was adopted in the 2003 Energy Action Plan prepared by the California energy agencies. The California Energy Commission's 2003 Integrated Energy Policy Report also used the loading order as the foundation for its recommended energy policies and decisions.

The loading order policy was codified by statute in 2005.[36] The statute requires the procurement plans developed by each of California's three investor-owned utilities to first meet the utility's unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible. The loading order puts energy efficiency first because it is believed to be the lowest-cost, environmentally preferred resource.[37]

33 Hopper et al, 2009.

34 Although the term "loading order" is often used to describe the dynamic process used by system operators to meet demand on a short-term basis, in California the term is applied to the process whereby energy providers acquire resources over the long term.

35 California Energy Commission, 2005.

36 California, 2005.

37 Hopper et al, 2009.

38 California Public Utilities Commission, 2004.

To implement the loading order policy, the CPUC adopted long-term energy efficiency goals for the state's investor-owned utilities, drawing in part from the results of a study that estimated the achievable cost-effective energy efficiency potential in the three utilities' service territories.[38] The loading order policy had a direct impact on the amount of energy efficiency proposed in the utilities' resource plans, and their proposals closely match the CPUC goals. Although several additional supporting policies and factors are in place to encourage and eliminate barriers to California's investor-owned utilities pursuing energy efficiency, it was the annual energy savings goals specified by the CPUC, and the underlying statutory mandate for utilities to acquire all achievable cost-effective energy efficiency, that drove the specific levels of energy efficiency proposed in these utilities' resource plans.[39]

E. Imposing Energy Efficiency Obligations

i. Description

This mechanism requires obligated parties to meet quantitative energy savings targets through implementing cost-effective demand-side measures, particularly end-use energy efficiency. Typically, this mechanism sets annual energy savings targets for a long-term period, requiring obligated parties to achieve specified reductions in energy use through energy efficiency measures.

Different jurisdictions have used a variety of terms to describe this mechanism, including "energy efficiency obligation" (EEO), "energy efficiency resource standard" (EERS), "energy efficiency portfolio standard," and "energy efficiency commitment."

Energy efficiency obligations may be placed on vertically integrated electricity utilities or on one or more types of unbundled electricity providers. Because the targets usually specify percentage reductions in electricity sales to end-use customers, the obligation is often placed on electricity retailers. The obligation may also be placed on distribution network operators, particularly where these businesses are also electricity retailers.

In some jurisdictions, EEOs are placed on providers of other fuels such as gas and heating oil, or even on end-users. Energy efficiency projects in the electricity sector may be included as eligible activities for meeting the obligations of these other obligated parties. Such projects will increase the contribution of demand-side resources in meeting the demand for electricity.

ii. Implementation

In implementing an EEO, a government or regulator determines:

- the level of the energy savings target to be achieved;
- the type and level of any penalties applicable for noncompliance with the obligation;
- who the obligated parties will be and how the overall energy savings target will be allocated to individual obligated parties;
- the sectoral overage of the EEO, that is, both the energy types covered and the end-use sectors in which energy savings measures may be implemented to achieve the EEO target;
- the eligible energy efficiency measures that may be implemented to achieve energy savings that contribute to the EEO target;
- which parties may be accredited to carry out eligible energy efficiency projects and how this accreditation is carried out;
- how energy savings are to be measured, reported, and verified, including any deemed energy saving values[40] for specified energy efficiency measures; and
- where required, how activities undertaken by obligated parties to meet their obligations will be funded.

Obligated parties generally achieve their EEO targets by assisting end-use customers to save energy through energy efficiency programs, including the use of rebates and other

38 California Public Utilities Commission, 2004.

39 Hopper et al, 2009.

40 A deemed energy saving is an estimate of the energy saving achieved by installing a single unit of an energy efficiency measure, such as replacing an incandescent light bulb with a compact fluorescent one. The estimate is usually developed from data sources and analytical methods that are widely considered acceptable for the specified measure and purpose. The estimate may be applied to situations other than that for which it was developed. Then the estimate is "deemed" to be acceptable as the quantity of energy saving claimable for installing a particular energy efficiency measure. Using deemed energy savings significantly reduces the cost of measuring and verifying energy savings.

incentives. The obligated parties may themselves carry out energy efficiency projects in customers' premises, or may commission specialists such as energy service companies to carry out the projects. Some EEOs allow savings from building codes, appliance efficiency standards, combined heat and power facilities, and distribution system efficiency improvements to count toward meeting the target.

If the jurisdiction adopts a cumulative savings objective – say, 15 percent electricity savings by 2020 – annual targets will typically increase over time to reflect the continued impacts of measures installed each year. With a cumulative target, the lifetime savings associated with installation of energy efficiency measures are counted. Thus program administrators are fully credited for installing long-lived and well maintained measures. Yearly savings targets provide short-term goals and a yardstick for monitoring progress.

An EEO may allow obligated parties to make a compliance payment in lieu of meeting the target, with the money directed to a state agency charged with achieving the intended savings. A penalty may be imposed if an obligated party fails to meet their target.

An EEO may also be placed across a whole jurisdiction and incentive payments provided to third parties who install eligible energy efficiency measures in residences, businesses, or industrial facilities. The incentives are typically based on engineering estimates of the savings achieved by eligible measures. In this model, the obligated party has no role in delivering energy efficiency – it simply pays for the resource delivered.

Some EEOs are accompanied by energy efficiency certificate[41] trading schemes. Energy efficiency certificates are legal instruments that certify that a particular quantity of verified energy savings has been achieved. At the end of each accounting period, the obligated parties surrender sufficient certificates to meet their energy savings targets for that period.

Energy efficiency certificate trading schemes accredit either or both obligated parties and non-obligated parties[42] to carry out eligible energy efficiency projects and to create certificates for the total amount of verified energy savings they achieve through each project. When non-obligated parties are enabled to carry out eligible energy efficiency projects and to create certificates, this can provide a powerful stimulus to the development of an energy services industry. Certificates created by non-obligated parties are sold to obligated electricity providers and this provides a funding stream for energy efficiency projects.

Jurisdictions vary in the arrangements established to fund the costs incurred by obligated parties in undertaking activities to meet their obligations. In many jurisdictions, particularly in Europe and Australia, the costs incurred by the obligated parties are treated as costs of doing business and are funded entirely by the obligated parties. Obligated parties who are energy providers may then seek to recover these costs through increasing the prices they charge end-users. In other jurisdictions, a more formal process may be established to determine the reasonable costs involved in meeting the obligations and then include these costs into a pricing determination or rate case.

iii. Application

Energy efficiency obligations have been implemented widely in many countries throughout the world. The United Kingdom regulator first imposed an EEO on electricity retailers in 1994. More recently, obligations have been placed on electricity retailers in Belgium (Flanders), Denmark, France, and Italy.[43] In the United States between 2007 and 2010, 26 states adopted energy efficiency resources standards for electricity so that now more than half of all states have an EERS in place.[44] Three Australian states have imposed EEOs on electricity retailers.[45] In South America, an EEO has been implemented in Brazil.[46] In India, an EEO on end-users is being planned and will be implemented in 2012.[47]

iv. Market Impact

An EEO establishes a new market or expands an existing market for installing energy efficiency measures. An EEO accompanied by an energy certificate trading scheme

41 Energy efficiency certificates are also known as "white certificates" or "white tags."

42 Such non-obligated parties may include specialised energy service companies or even individual end-use customers.

43 Bertoldi et al, 2009.

44 Nowak et al, 2011.

45 Crossley, 2009.

46 Lees, 2010.

47 Bureau of Energy Efficiency, 2011.

establishes a new market for certificates and also provides a source of funding for energy efficiency projects.

v. Effectiveness

EEOs are generally very effective in establishing new markets for energy efficiency as a demand-side resource. Typically, electricity providers and other obligated parties that fail to achieve their EEO targets must pay a penalty. Experience with EEOs has shown that providers generally strive to meet the targets and avoid paying the penalty. In the United States, some states are implementing EEOs requiring as much as 1.5 to 2 percent savings per year after a period of ramp-up.[48]

One problem that has emerged with EEOs is that they tend to encourage the implementation of low cost, easy to install energy efficiency measures ("low hanging fruit"), such as the replacement of incandescent with compact fluorescent light globes. This occurs particularly where energy savings values are deemed for such measures and may lead to situations in which not all the cost-effective energy savings available at a site are acquired ("cream skimming"). The additional cost involved in returning to the same site at a later date may make acquiring the remaining energy savings not cost-effective. This problem may be overcome by establishing provisions that require a minimum proportion of an obligated party's energy savings target to be achieved by implementing comprehensive packages of energy savings measures that acquire all the cost-effective energy savings available at a site.

vi. Case Study

The following case study briefly describes the long-running energy efficiency obligation imposed on electricity retailers in the United Kingdom.

The first EEO implemented in the United Kingdom, and in Europe, commenced in 1994 when the then electricity regulator for England and Wales commenced an initiative known as the Energy Efficiency Standards of Performance (EESoP).[49] Under this initiative, the regulator required electricity suppliers (i.e., electricity retailers) with more than 15,000 customers to spend GBP 1.00 per residential customer on household energy savings measures. The regulator also set energy savings targets to be achieved by the suppliers. The program was extended to electricity suppliers in Scotland in 1995 and in Northern Ireland in 1997. In 2000, the EESoP program was extended by the regulator to all electricity and gas suppliers in the United Kingdom with at least 50,000 customers. The suppliers were required to spend GBP 1.20 per customer on household energy savings measures.

The EESoP ran from 1994 until 2002 and became the dominant vehicle through which energy efficiency measures were delivered to residential customers in the United Kingdom. Suppliers met their energy saving targets by setting up in excess of 800 schemes to deliver energy efficiency measures.

EESoP had both social goals and environmental benefits. The majority of customers assisted under EESoP 1 (1994 to 1998) were disadvantaged.[50] In EESoP 2 (1998 to 2000) and EESoP 3 (2000 to 2002) energy suppliers were required to focus approximately two thirds of their expenditure on this customer group. To reach disadvantaged households, suppliers integrated some of their schemes with social housing providers. In this way energy suppliers could target a large number of low-income consumers and offer them the benefits of energy efficiency at little and no cost by leveraging funds from social housing providers. Energy suppliers also provided energy efficiency solutions to their own consumers who were in need. Some suppliers ran schemes that were targeted at their consumers who were in debt. Other suppliers ran schemes with their prepayment meter customers.

The EESoP program demonstrated that energy suppliers were capable of meeting, and exceeding, the energy efficiency targets set. Over the eight years of the program, suppliers developed in-house expertise through managing and delivering energy efficiency schemes.[51]

Under the *Utilities Act 2000*, a new program called the Energy Efficiency Commitment (EEC) was established that built on the success of the EESoP. Under this program, the United Kingdom government took over the role of the regulator in setting energy savings targets for energy suppliers, commencing in 2002. EEC was the UK government's key energy efficiency policy for existing households.

48 Nowak et al, 2011.

49 Energy Saving Trust, 2001.

50 Ofgem and the Energy Saving Trust, 2003.

51 Ofgem and the Energy Saving Trust, 2003.

The EEC program was implemented in two phases, EEC1 (2002 to 2005) and EEC2 (2005 to 2008). EEC1 required electricity and gas suppliers to achieve an energy savings target of 62 TWh in domestic households in Great Britain between 1 April 2002 and 31 March 2005.[52] At least 50 percent of the target had to be met in relation to a Priority Group of consumers, defined as those in receipt of certain income-related benefits and tax credits.

Energy suppliers promoted their schemes through numerous routes and partnered with different organisations to deliver measures to consumers. The main routes for suppliers to promote measures to consumers involved them:

- offering measures direct to consumers;
- partnering with other organisations such as social housing providers and charities;
- partnering with appliance retailers and manufacturers; and
- linking in with other government programs.

In early 2008, the United Kingdom government announced that, following the completion of EEC2, the EEC would be renamed the Carbon Emissions Reduction Target (CERT). CERT has become the government's main policy instrument for reducing carbon emissions from existing households. CERT requires certain gas and electricity suppliers to meet a carbon emissions reduction obligation (carbon obligation).[53] At least 40 percent of this target must be achieved by targeting certain low-income domestic consumers or those over 70 years old – the "Priority Group."

The target is divided between the obligated suppliers according to the number of domestic customers to whom they supply electricity and gas. Energy efficiency measures can be provided to any domestic household in Great Britain that is heated by gas, electricity, coal, oil, or liquefied petroleum gas (LPG). The funding for the installation or distribution of measures comes from the obligated suppliers. However, they are not required to spend a fixed amount of money per household.

Energy suppliers are not limited to offering measures to their own consumers and can partner with other organisations for the distribution of measures or to encourage the uptake of measures. For each scheme, suppliers must demonstrate that their activity has led to additional energy efficiency measures being installed.

Suppliers can meet up to five percent of their obligation through the Priority Group flexibility mechanism. This aims to target low-income, hard-to-treat homes. Priority Group flexibility recipients must be in receipt of relevant benefits or tax credits and not in social housing.

An uplift of 50 percent additional energy savings is available on market transformation activities, which include microgeneration. Suppliers can also meet a proportion of their obligation through carrying out demonstration projects, to trial new types of measures or customer reactions to information or measures. Market transformation activities and demonstration activities combined are capped at six percent of a supplier's obligations.

F. Mandating Implementation of Time-Varying Electricity Pricing

i. Description

This mechanism requires electricity providers to implement time-varying electricity prices for some or all of their end-use customers. The purpose is:

- to increase economic efficiency by better matching prices to the time-varying costs of supplying electricity;
- to provide pricing signals encouraging customers to modify the way they use electricity, particularly by reducing load at peak times; and
- to delay investment in new electricity generation and network infrastructure.

The mechanism can result in increased use of demand-side resources in the electricity sector through incentivising the use of demand response measures.

ii. Implementation

Electricity providers generally implement time-varying pricing by requiring customers who have particular end-use applications or high-volume electricity use to go on to time-of-use or critical peak pricing.

Historically, time-varying pricing was implemented by installing time clocks that energised particular circuits in customer's premises only during set time periods of the day.

52 Ofgem, 2005.

53 Ofgem, 2007.

This technology was introduced for storage appliances such as storage water heaters and space heating, which were supplied with low-price electricity during off-peak periods.

Implementing more sophisticated time-varying electricity pricing requires the installation of interval electricity meters that are capable of recording the quantities of energy consumed over set, frequent time intervals. When such meters include one-way or two-way communications between the electricity provider and the meter, they are generally known as "smart meters."

iii. Application

In some jurisdictions, electricity providers have implemented voluntary schemes of time-varying prices in which customers could choose to go on to time-of-use tariffs. The largest and longest-running of these types of scheme is in France (see the case study on page 32).

No jurisdiction has successfully implemented mandatory time-varying electricity prices for all general supply customers over the long term. Governments in several jurisdictions have mandated universal rollouts of smart meters to particular customer classes and have also attempted to mandate time-of-use pricing for all customers with smart meters. However, following complaints from customers, most jurisdictions have replaced mandatory time-of-use pricing with voluntary schemes. For example, the government in the Australian state of Victoria suspended mandatory time-of-use pricing associated with a smart meter rollout after an investigation found that time-of-use pricing would negatively impact many Victorians, increasing household energy costs by approximately AUD 100 a year.[54]

Pilot programs of time-varying pricing have been carried out in many jurisdictions and these have provided some indication of the benefits available from altering the timing of electricity use through time-of-use and critical peak pricing, particularly where the introduction of time-varying pricing was accompanied by the installation of devices that enabled the energy provider to directly control customer loads.

iv. Market Impact

Time-varying pricing coupled with direct load control of customer loads can give electricity providers considerable flexibility to manage loads during different time periods throughout the day, and also throughout the year. This flexibility can provide significant benefits to electricity markets, system operations, and planning processes. Consequently, the mechanism may indirectly contribute to increasing the use of demand-side resources in the electricity sector.

v. Effectiveness

The effectiveness of time-varying pricing depends on end-use customers modifying the way they use electricity, particularly by reducing load at peak times. Trials and full-scale implementations of time-varying pricing have generally shown that customers' responses are variable. A particular problem is that customers' responses tend not to persist over time. Customers will change their behaviour for a period after they go on to time-varying prices but often revert to their previous usage patterns, particularly if reductions in electricity bills are not large, or if bills actually increase with time-varying pricing.

A tentative conclusion from the results of critical peak pricing trials carried out in several countries is that a price differential of about ten times between the critical peak price and the off-peak price is required to achieve significant and firm peak load reductions.[55] A more robust conclusion is that linking time-of-use pricing with load control technology that directly reduces peak loads on the electricity network by remotely switching appliances and equipment at customers' premises is the most effective mechanism for reducing peak loads, because remote switching requires only one "set and forget"decision by end-use customers.[56]

In jurisdictions with full retail competition it is not possible to mandate any particular price structure, because the actual price structure implemented is determined by the electricity retailers. Retailers will still have an incentive to implement time-varying pricing, maybe in conjunction with load control technology, to reduce customers' loads during times of high prices in the wholesale electricity market.

54 Energy Matters, 2010.

55 Crossley, 2008a.

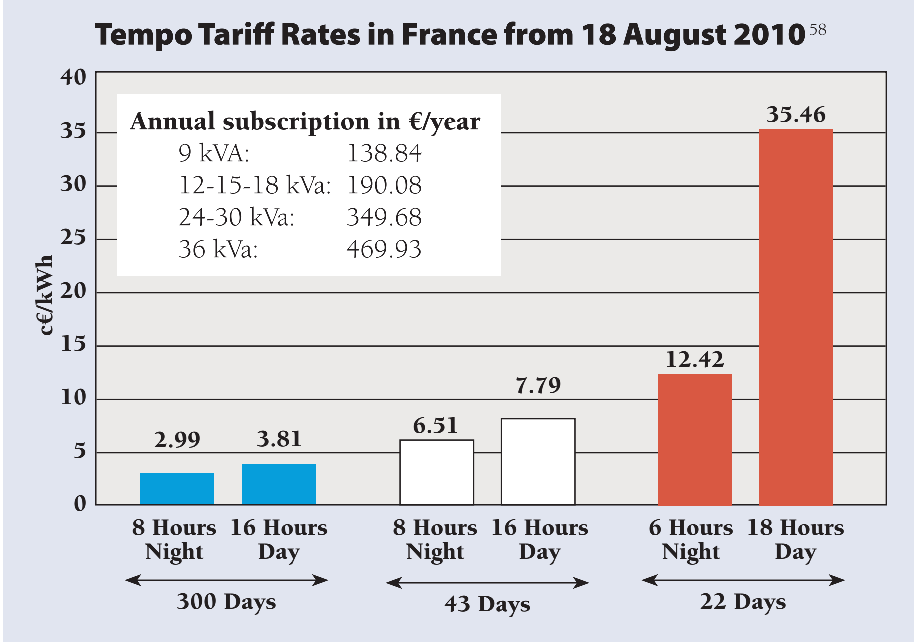
56 Crossley, 2008a.

vi. Case Study[57]

The following case study briefly describes time-of-use electricity pricing in France.

In France, electricity bills for residential and small business customers include a standing charge determined by the level of maximum demand (in kVA) nominated by the customer (*puissance souscrite*), and an energy usage charge based on the type of tariff chosen by the customer (*type d'abonnement*). There are three types of electricity contract from which residential and small business customers can choose.

Figure 4



Option Base

Option Base is suitable for lower usage, smaller homes and holiday homes with only occasional usage. This is the simplest of the three contract types with the lowest standing charge and a flat rate for electricity usage all the time throughout the day and year.

Option Heures Creuses (Option HC)

Option HC suits the majority of houses occupied full-time where heating is non-electric.

This is a two-part time-of-use tariff with normal (*heures pleines*) and off-peak (*heures creuses*) rates. The standing charge is slightly higher than that of Option Base, but this is offset against a lower off-peak rate for part of the day. The off-peak period is from 10 pm until 6 am each night and, in some regions, also at midday. Option HC is usually used in conjunction with a water heater operated by ripple control so that the heating element is switched on only during off-peak periods.

Option Tempo

Option Tempo is for high-use households, such as very large houses, and those with electric heating and full-time occupation, and for small business customers.

This is a quite complicated charging system with six rates of electricity pricing based upon the actual weather on particular days and on hours of use. Under Option Tempo, each day of the year is colour coded. There are three colours, blue (*jours bleus*), white (*jours blancs*), and red (*jours rouges*), which correspond to low, medium, and high electricity prices.

The colour of each day is determined mostly by the electricity provider Électricité de France (EDF) based on the forecast of electricity demand for that day – the level of demand is mainly influenced by the weather. The French transmission network operator also has the ability to determine the day colour if there is significant congestion on the electricity network.

In addition to a colour, each day also has normal and off-peak periods based on Option HC outlined above, with 10 pm until 6 am being the off-peak period.

The rules for the Option Tempo are as follows:

- the Tempo year starts on 1st September;
- the Tempo day starts at 6 am;
- the number of days per year of each colour is fixed - there are 300 blue days, 43 white days, and 22 red days;
- Sunday is always a blue day; and
- red days cannot fall on a holiday or a weekend or on

57 This case study is based on Giraud, 2004 and Kärkkäinen, 2004.

58 Giraud, 2004, plus updated price information from the Électricité de France website at: http://bleuciel.edf.com/abonnement-et-contrat/les-prix/les-prix-de-l-electricite/tarif-bleu-47798.html#acc52410

more than five weekdays in a row.

On blue days, the electricity price is by far the lowest – during the off-peak period on a blue day the price is extremely low (see Figure 4, page 32). On white days, the price is higher than under Option Base or Option HC. On red days, the price is very high to encourage lower electricity usage – the normal rate on red days is nine times that of the off-peak rate on blue days. Red days are usually the coldest days in winter.

There are four different versions of Option Tempo, depending on the metering, communications, and load control equipment installed at the customer's premises:

- **standard Tempo** (the customer has only an electronic interval meter);
- **dual energy Tempo** (the customer's space-heating boiler can be switched from one energy source to another);
- **thermostat tempo** (the customer has load control equipment that is able to adjust space heating and water heating loads according to the electricity price); and
- **comfort Tempo** (the customer has a sophisticated energy controller).

Customers who choose Option Tempo are informed each night about the colour for the next day. At 8 pm a signal is sent down power lines using a ripple control system. Most Tempo customers have a display unit that plugs into any power socket and picks up the signal. The display unit shows the day colour with lights, both for the current day and (from 8 pm) for the next day. An (optional) beep informs the consumer if the following day will be a red day. The display unit also shows whether or not the current electricity price is at the off-peak rate. For older systems without a display unit the information is available over the telephone or via the internet.

Customers can adjust their electricity consumption manually by switching off appliances, adjusting thermostat settings, and so on. Some customers who have the necessary communications and load control equipment are able to select load control programs that enable automatic connection and disconnection of separate water-heating and space-heating circuits.

Compared with blue days, the Tempo tariff has led to a reduction in electricity consumption of 15 percent on white days and 45 percent on red days, on average 1 kW per customer. Tempo customers have saved 10 percent on average on their electricity bill, and 90 percent of the customers are satisfied with the tariff. However, customers do not appreciate red days occurring consecutively.

Although the Tempo tariff has been successful, less than 20 percent of electricity customers in France have chosen Option Tempo. Tempo customers have very particular customer profiles and are interested in managing their energy use. They are prepared to constrain their lifestyles to make comparatively small financial savings relative to their incomes.

The Tempo tariff was designed specifically for the situation in which EDF is a monopolistic generator and retailer of electricity. Specifically, much of the impetus for implementing the Tempo tariff and the associated load control systems came from the fact that EDF needs responsive load in order to operate a system with 80 percent of electricity produced by baseload nuclear plants.

However, the Tempo tariff is not adapted to the competitive electricity market, which is being introduced in France. In this market:

- the network use of system charge does not vary between seasons; and
- the value of peak load reduction is not reflected in spot prices for energy, which are less volatile than the marginal costs of supply.

When EDF needs to manage its global load curve in a competitive electricity market, it will have to develop other types of dynamic pricing for mass market customers. In July 2009, EDF discontinued the Tempo tariff for new customers and for customers who are on the tariff at their current residence and then move house.

4. Policy Mechanism

A. Establishing an Energy Saving Fund

i. Description

This mechanism involves the establishment of a financial facility dedicated primarily to funding projects that acquire energy savings through installing energy efficiency measures. The range of financial products such a fund may offer to proponents of energy efficiency projects is potentially very wide and may include grants, senior and junior loans, loan guarantees, and equity participation.

In addition to providing funding for energy efficiency projects, energy saving funds can be used to:

- address technical, regulatory, and market barriers preventing the uptake of all cost-effective energy efficiency;
- stimulate the development of an energy services industry with the capability to deliver energy efficient solutions; and
- improve consumers' awareness of energy efficiency opportunities.

ii. Implementation

Energy saving funds are most commonly developed and implemented by governments, although other entities such as business associations and philanthropic foundations may also be involved.

The implementation of an energy saving fund involves a number of steps, including:

- establishing the purpose and goal of the energy saving fund;
- deciding how the fund will be capitalised, the sources of capital, and the level of capitalisation;
- establishing a new organisation, or nominating an existing organisation, that will be responsible for the administration of the fund;
- determining the allowed uses for funding as well as prohibited uses;
- setting the eligibility criteria for parties applying for funding;
- establishing a process for reviewing applications for funding;
- setting criteria for selecting successful applications;
- determining the conditions applicable to various types of disbursements from the fund (e.g., grants, loans, investments, and the like);
- providing technical and other assistance to successful applicants for funding; and
- tracking and monitoring the results of successful applications.

In general, there are three basic models that can be used to allocate funding from an energy saving fund:

- the **investment model** uses loans and equity participation to directly invest in energy efficiency projects and companies implementing such projects;
- the **project development model** promotes the implementation of energy efficiency projects by providing grants to fund part of the cost of implementing projects and/or by paying incentives for energy savings achieved; and
- the **industry development model** uses business development grants, marketing support programs, research and development grants, resource assessments, technical assistance, consumer education, and demonstration projects to facilitate market transformation toward increased energy efficiency.

Around the world, a wide variety of different types of organisations are responsible for the administration of energy saving funds, including:

- government agencies;
- regulatory agencies;
- quasi-autonomous non-governmental organisations ("qangos");
- non-profit organisations; and
- energy providers.

iii. Application

Since the mid-1970s, many energy saving funds have been established by various levels of government and other parties all around the world.

In the most recent wave of activity in this area, capital sourced from government economic stimulus packages implemented in response to the Global Financial Crisis has been used to establish energy saving funds in many countries. For example, in the United States, the *American Recovery and Reinvestment Act of 2009* (ARRA) provides funding totalling USD 3.1 billion for state energy programs. One of the program areas that the ARRA legislation encourages is the creation of long-term funding mechanisms to extend the impact of the ARRA funds. Many states have applied for ARRA funding to set up revolving loan funds for energy efficiency and/or renewable energy.[59]

Another new source of capital for energy saving funds is the revenue obtained from selling permits and allowances in emissions trading schemes. For example, over the initial two years of the Regional Greenhouse Gas Initiative emissions trading scheme in the northeast of the United States, 86 percent of permits were auctioned. Of the two-year revenue of USD 789 million, 52 percent was allocated to state and utility programs to improve energy efficiency.[60]

iv. Market Impact

Energy saving funds increase the level of energy efficiency in a jurisdiction and may indirectly expand the participation of demand-side resources in electricity markets. Where electricity providers are mandated to make financial contributions to an energy saving fund,[61] the connection with, and impact on, the local electricity market is more direct. In particular, a proportion of the demand that would otherwise be served by the energy provider supplying electricity will now be served by the implementation of energy efficiency measures funded by the energy provider.

v. Effectiveness

Energy saving funds can be very effective in increasing the level of energy efficiency in a jurisdiction, although as noted in the previous section, their impact on increasing the use of demand-side resources in the electricity sector is mostly indirect.

vi. Case Study[62]

The following case study of the implementation of an "efficiency utility" in the US state of Vermont is an example of an energy saving fund that has had a significantly direct impact on integrating energy efficiency into a retail electricity market.

Throughout the 1980s and 1990s Vermont's electricity distribution utilities were responsible for implementing energy efficiency programs. In late 1999 the state's regulator, the Vermont Public Service Board (PSB), decided to transfer that responsibility to an independent "efficiency utility." This body was to be funded by a small system benefits charge on electricity prices, effectively creating an energy saving fund.

The PSB issued a Request for Proposal to engage an organisation to serve as the efficiency utility under a three-year contract with an option for renewal for a second three years. The Vermont Energy Investment Corporation (VEIC), a local non-profit organisation, was selected from among five bidders to play that role. It subsequently created the Efficiency Vermont brand under which all statewide electric efficiency programs for residential, commercial, and industrial customers have been marketed.

In 2005, VEIC rebid (this time against one competitor) and won the right to continue serving as the efficiency utility for the period 2006 through 2008 and potentially through 2011 (i.e., the same three-year contract with an option for a three-year renewal). Beginning in 2012, the state will treat the efficiency utility – with VEIC continuing to play that role – as more of a regulated "franchise" with a longer-term commitment, rather than rebidding the contract every six years. The objectives of this change include allowing Efficiency Vermont to take a longer-term view on energy efficiency planning and investments and to interact more in policy arenas and with the states' distribution utilities than it had in the past. However, it will still operate with three-year performance goals.

59 Booth, 2009.

60 Regional Greenhouse Gas Initiative, Inc., 2011.

61 For example, by adding a small fee (known in the United States as a "system benefits charge") to the electricity prices paid by customers, with the revenue from the fee being allocated to an energy saving fund.

62 This case study is taken from Wasserman & Neme, 2011.

Responsibility for evaluating Efficiency Vermont's programs is vested with the Vermont Department of Public Service (DPS), using a portion (roughly USD 3 million over three years) of the funds collected through the system benefit charge. Efficiency Vermont developed the country's first Technical Reference Manual in which deemed savings values or formulas were developed and documented for a wide range of prescriptive measures (which typically account for about half of Efficiency Vermont's savings). Those values are periodically updated through collaborative discussions with the DPS when evaluation work in Vermont (or elsewhere) provides a basis for changes.

Efficiency Vermont issues an annual report on its previous year's energy savings based on both deemed savings values and site-specific calculations for custom commercial and industrial projects (which typically account for the other half of the savings). The DPS reviews the savings estimates and makes recommendations for modifications. The review is typically conducted by a third-party consultant with expertise in energy efficiency program evaluation and involves, among other things, a detailed review of a statistically representative sample of custom projects. Efficiency Vermont and the DPS then attempt to resolve any differences of opinion on technical matters and ultimately file recommended adjustments to the regulator for final approval or – if there are outstanding disagreements – resolution of disputes.

The Efficiency Vermont contract includes a "hold-back" of roughly 3 percent. That 3 percent is allocated across several different performance metrics, including total first-year MWh savings actually delivered, coincident peak demand (MW) savings delivered, and the net present value of the economic benefits of the energy efficiency programs. As the operator of Efficiency Vermont, VEIC eventually receives the held back payments, or portions of the payments, based on its performance relative to the metrics.

The impact of Vermont's policies has been significant. From 2009 through 2011 Efficiency Vermont programs are expected to achieve verified annual electricity savings of nearly 300 GWh. That is less than the goal of 360 GWh due largely to the impacts of a downturn in the economy making sales of energy efficiency measures and services more difficult than expected when the goals were established. However, it still represents incremental annual savings of 5.5 percent of electricity sales (an average reduction of about 1.8 percent per year). Electricity savings have been delivered at a levelised cost of approximately USD 0.04/kWh.

5. Market-Based Mechanisms

A. Enabling Demand-Side Bidding into Electricity Markets

i. Description

Demand-side bidding (DSB) enables the demand side of an electricity market to participate in market trading. Demand-side bids are typically made over timescales ranging from a year to a few seconds ahead of the time of delivery.

There are two basic types of offer in DSB:[63]

- offers involving a bid for total demand; and
- offers involving a bid for a change in demand.

Bids for total demand are typically made in day-ahead electricity markets and consist of a series of downward sloping demand curves in which less electricity is purchased as the price increases. A typical scheme for DSB in a day-ahead energy market would be for buyers of electricity to submit their demand curves by noon the day before the operating day with different demand curves for each operating hour and delivery location. Each demand curve would typically consist of a sequence of price-quantity pairs that would represent the buyers' willingness to pay a certain amount for the quantity indicated. For instance, if a buyer was willing to pay $100/MWh for 1,000 MW, but would only want 800 MW if the price rose to $120/MWh, the buyer would submit the price-quantity pairs: ($120/MWh, 800 MWh) and ($100/MWh, 1,000 MW). The demand curves submitted to the market operator would then be cleared with the supply curves submitted by electricity generators. This would give the buyer a position that would be delivered the next day.[64]

Bids for a change in demand comprise an offer to reduce or increase demand at a given time. The bid may be made by an individual large customer, or bids from a group of smaller customers may be combined by an aggregator. Bids for changes in demand may be made in several different types of electricity markets:

- in *real-time spot markets* where the bidder is essentially a price taker and receives the marginal clearing price when the price for the demand-side offer is below or at the margin;
- in *day-ahead markets* where demand-side bids are based on the bidder's expectations of what the real-time price on the next day will be;
- in *longer-term forward capacity markets* where the bidder has a reasonable expectation that they will be able to reduce or increase load at a specified time in the future;
- in *emergency and reserve trader*[65] *markets*, where the bidder is confident that they will be able to reduce or increase load when an emergency or unforecasted event occurs; and
- in *ancillary services markets*, where the bidder is confident that they will be able to reduce or increase load within the notice period specified by the type of ancillary service required.

A demand-side bidder may receive one or more of several payments for their bid, including

- a payment for the *quantity of energy consumption* reduced or increased over the time period that the change in demand occurred;
- a payment for the *change in the load level* (reduction or increase) achieved – this can be based on the maximum or average change in load; and
- an *availability payment* for the contracted change in demand – this type of payment is usually not available in real-time spot markets or day-ahead markets.

63 Roberts, 2002.

64 Earle & Faruqui, 2008.

65 The purpose of a reserve trader market is to allow the market operator to contract for reserve generation capacity to be deployed when a shortfall of reserve capacity is projected.

ii. Implementation

Implementation of DSB requires the operator of an electricity market to establish specific market rules that allow consumers to make bids for total demand and/or bids for changes in demand into the market and define the conditions under which DSB can occur. Specific issues addressed by the DSB rules will vary depending on the type of bid and the type of electricity market to which the rules apply. In general, issues that should be addressed by the rules include:

- a protocol for making a demand-side bid into the market (which may be different from the protocol for bidding generation output because of the different characteristics of demand-side resources);
- protocols for defining the size of a change in load (reduction or increase), the shape of the load profile, and the duration of the change in load;
- the minimum size of changes in load that may be offered into the market;
- the minimum and maximum number of occasions that a demand-side bidder can change their load over a specified time period;
- the different notice periods required for changes in load depending on the type of service a demand-side bid is intended to provide;
- the method whereby a demand-side bidder will be informed whether a bid has been accepted;
- methods for measuring, reporting, and verifying the change in load actually achieved; and
- the payments that demand-side bidders will receive for different types and durations of changes in load.

There is some debate about whether demand-side bidders who submit bids for changes in demand in day-ahead or real-time markets should receive a payment in addition to the marginal clearing price. In the PJM market in the United States, bids to curtail load in the day-ahead or real-time energy markets receive a payment to reduce load. These payments to demand-side bidders are funded through a charge levied on energy providers who sell electricity directly to end-users. The reasoning is that the payment to demand-side bidders corrects a market imperfection and that the charge is justified because the energy providers benefit from the reduction in load, which results in a lowering of the wholesale market price. This approach is supported by a 2011 Order[66] from the United States Federal Energy Regulatory Commission (FERC) requiring that a cost-effective demand response resource must be compensated for the service it provides to the energy market at the market price for energy. FERC reasons that this approach for compensating demand response resources helps to ensure the competitiveness of organised wholesale energy markets and to remove barriers to the participation of demand response resources, thus ensuring just and reasonable wholesale rates.

In other markets, payments to demand-side bidders are treated no differently from other payments for bids into the market and affect the financial positions of all market participants, (i.e., generators as well as energy providers). This is the case in the England and Wales market.[67]

iii. Application

Currently, DSB is practiced in several electricity markets in North America and Europe.

In the United States, there are six regional wholesale electricity markets with significant DSB programs. These programs range from direct participation in energy markets (both day-ahead and real-time), participation in parts of ancillary services markets, as well as specialised demand response programs centred around responding to system emergencies.[68]

In the England and Wales wholesale electricity market, DSB occurs in the Balancing Mechanism, which was specifically designed from the outset to allow this to occur. Demand-side bidders have to provide information on their intended level of consumption during the settlement period and the price and extent to which they are prepared to move away from this level. If their offer is accepted (i.e., they are requested to reduce their demand), they are paid their offer price for the energy they do not consume.[69]

iv. Market Impact

DSB is a mechanism that directly increases the integration of demand-side resources into electricity markets. DSB can improve the efficiency of the

66 United States Federal Energy Regulatory Commission, 2011a.

67 Earle & Faruqui, 2008.

68 Ibid.

69 Ibid.

electricity supply chain by increasing competition in the wholesale energy market and by acting as an alternative to conventional generation. For example, DSB can be used to balance electricity supply and demand and also maintain the quality and security of supply. In addition, a very important effect of DSB is that it often lowers the clearing price in wholesale electricity markets because most demand-side options are usually available at lower bid prices than many generation options.

v. Effectiveness

The effectiveness of this mechanism is dependent on the level of DSB actually achieved. In US markets, there appears to be less DSB than potential estimates indicate is possible. This is probably also the case in other countries. Reasons for the low level of DSB in the United States include:[70]

- the disconnect between wholesale prices that are set by the market and retail prices that are approved by regulators;
- wholesale prices that have price caps so that the ability to capture high prices through demand response is limited; and
- barriers to DSB in the particular business rules in the wholesale market.

It should also be noted that DSB is mainly concerned with demand reductions rather than energy efficiency. Although some demand reductions bid into markets are achieved through energy efficiency, the majority are achieved through short-term demand response. While demand response is a demand-side resource, it does not necessarily lead to reductions in energy use over the long term.

vi. Case Study[71]

The following case study briefly describes DSB in the Nord Pool wholesale electricity market that operates across the Nordic region (Norway, Sweden, Denmark, and Finland).

In the Nord Pool day-ahead market (Elspot), participation is optional. After taking account of any obligations under their physical bilateral contracts, Elspot market participants submit generation offers and demand-side bids in the form of a price/volume curve for each hour of the following day. Nord Pool sets hourly ex ante prices at the intersection of the aggregate supply and demand curves. By 1:30 p.m. on the day ahead, Nord Pool informs each participant of its generation or purchase commitments in the spot market and allows participants 30 minutes to check that their net trading position is in accordance with their bids and offers. Once confirmed, accepted bid and offer quantities become firm contracts for physical delivery. Participants have no opportunity to revise their bids and/or offers. Because market participants provide demand curves as well as supply curves, provision is made for price-responsive demand to participate in the market. Over 20 percent of Norwegian demand is considered to be potentially price-responsive.

Because of the ready availability of balancing services from hydropower plants, the opportunities for DSB in the Nord Pool real-time ancillary services markets are limited. Opportunities for the demand side to provide fast reserve and constraint management have been developed, and in the future it is anticipated that opportunities to provide frequency response may also be developed.

A separate reserve options market has been in existence in Norway since winter 2000, and demand-side bidders are able to participate in this market. The purpose of the reserve options market is to ensure that an adequate level of regulating reserve offers are submitted during the winter months when there is most need for reserve.

Over 2,000 MW of option contracts are required to supplement the regulating reserve that is normally available. Weekly auctions are held for the option contracts and successful bidders receive an option fee, in return for which they are obliged to offer reserve in the regulating reserve market although they are free to choose the price at which they do so. When Statnett, the transmission system operator, schedules reserve, the marginal price is paid for all reserve provided (i.e., the price of the most expensive accepted offer for upward regulation and the price of the cheapest accepted bid for downward regulation).

Option contracts may be offered for a minimum of 25 MW of reserve capacity. Reserve must be made available between 6 a.m. and 10 p.m. on business days with the potential for delivery within 15 minutes for a period of not less than one hour (and at least 10 hours of reserve delivery per week must be possible). The obligation to

70 Ibid.

71 This case study is taken from Earle & Faruqui, 2008.

offer reserve placed on demand-side participants with option contracts is reduced (or removed) if they reduce their consumption in the Elspot market in response to high prices. In these circumstances, however, their option fees are correspondingly reduced.

The reserve options market has proved popular with consumers, with up to 1,200 MW of the contracts signed with demand-side participants. At times, this has represented almost 70 percent of the contracts signed (although a much smaller proportion of the total available reserve of about 8 TWh). Participation has mostly been from large industrial facilities (metals and paper production). However, Statnett has also been working to encourage medium-sized consumers (electric boilers and back-up generation) to participate in the reserve options market and, indeed, in the day-ahead market.

Some studies have also been carried out to explore the extent to which smaller loads (including domestic customers) could also participate in the broad Nord Pool market. This would require the introduction of smart metering (to allow consumers to respond to price signals) and automatic load shedding controls. Although these studies showed that there was a potential for greater demand-side involvement, they also highlighted the technologic and cost-related challenges that would need to be overcome to encourage participation.

B. Enabling Bidding of Demand-Side Measures to Relieve Network Constraints

i. Description

This mechanism establishes a process that enables parties to bid demand-side measures to relieve constraints on electricity networks. Demand-side measures are bid as alternatives to building network infrastructure ("poles and wires") to augment or expand the existing network.

To be effective in relieving network constraints, demand-side measures must be capable of addressing the particular characteristics of these constraints. Network constraints have both timing and spatial dimensions.[72]

In relation to timing, network constraints may be:

- narrow peak related – occurring strongly at the time of the system peak and lasting seconds, minutes, or a couple of hours; or
- broad peak related – less strongly related to the absolute system peak, occurring generally across the electrical load curve and lasting several hours, days, months, years, or indefinitely (e.g., where the network is close to capacity).

In relation to the spatial dimension, network constraints can:

- occur generally across the network in a particular geographic area; or
- be associated with one or more specific network elements such as certain lines or substations.

Demand-side measures that may be used to relieve network constraints include:

- direct load control;
- distributed generation, including standby generation and cogeneration;
- demand response;
- energy efficiency;
- fuel substitution;
- interruptible loads;
- load shifting; and
- power factor correction.

ii. Implementation

The bidding process is typically established by the operator of an electricity distribution or transmission network and consists of six stages:

- identification and characterisation of the network constraint;
- identification of a supply-side solution for relieving the constraint and determination of the cost of implementing this solution;
- identification of possible demand-side options for relieving the constraint;
- publication of a Request for Proposals to implement demand-side measures that will address the identified network constraint;
- comparison of the costs of demand-side options with the costs avoided by deferring or avoiding the supply-side solution; and
- selection of demand-side or supply-side solutions for implementation.

72 Crossley, 2008c.

iii. Application

This mechanism is routinely used in the state of New South Wales in Australia to implement cost-effective demand-side measures to relieve location-specific, small-scale network constraints typically involving one network element (e.g., a substation or a particular line).

iv. Market Impact

This mechanism establishes a market for cost-effective demand-side resources to contribute to relieving network constraints. It therefore contributes directly to increasing the integration of demand-side resources into electricity markets.

v. Effectiveness

The effectiveness of the mechanism depends on:

- the availability of demand-side resources that can deliver firm load reductions with appropriate timing and in specific locations to address identified network constraints; and
- the robustness of the analysis of the costs of implementing demand-side measures as compared with the avoided costs of deferring or avoiding supply-side solutions.

vi. Case Study[73]

The following case study briefly describes a project using bidding of demand-side measures to relieve a network constraint undertaken by EnergyAustralia, a distribution network operator in the state of New South Wales, Australia.

EnergyAustralia's objective for the project was to implement demand-side measures that would maintain network performance at the required level at a lower cost than investing AUD 4 million for an additional transformer at the zone substation for the suburb of Drummoyne in Sydney.

The capacity limits of the Drummoyne zone substation were 66.6 MVA in summer and 72 MVA in winter. Peak demand in the Drummoyne area had grown steadily. Loads were growing more rapidly in summer than in winter, but off a lower base. Peak demand was forecast to exceed the capacity limit by 0.5 MVA in the winter of 2008 unless action was taken to increase capacity or reduce demand. The winter peak demand usually occurred on weekday evenings between 6:00 and 9:30 pm. The forecast summer peak demand indicated no overload issue during the summer in the foreseeable future.

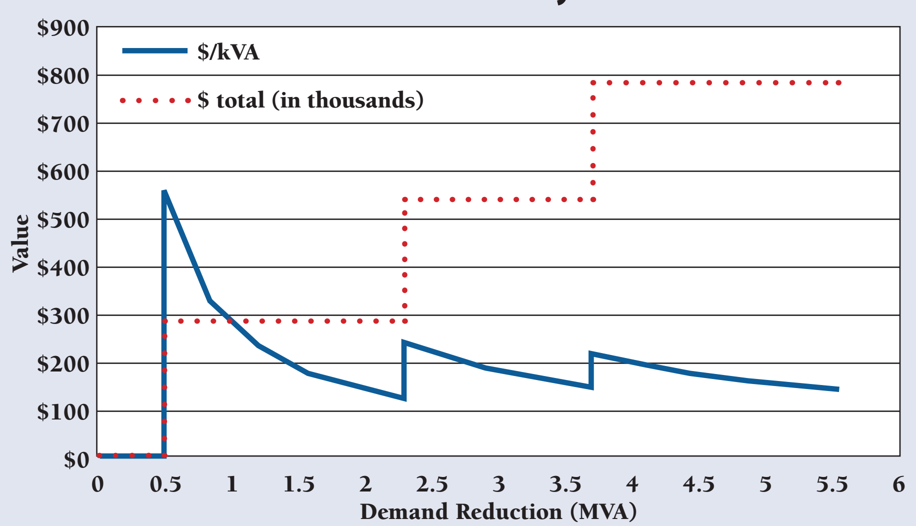
Based on the load profiles, the key drivers for load growth appeared to be a mix of residential loads and a sizeable proportion of retail or commercial load. The area had experienced steady load growth in the years prior to 2005 that might be attributable to new residential development and multiunit residential construction.

The preferred supply-side solution was to install a third transformer in the Drummoyne zone substation and extend the 11kV switchboard at an estimated cost of AUD 4 million. A decision to proceed would need to be made before the end of 2006 to enable the installation to be completed before winter 2008.

To defer the supply-side investment by one year (that is, until 2009), EnergyAustralia would need to implement demand reductions totalling 500 kVA prior to winter 2008. Because a decision had to be made by late 2006, EnergyAustralia would need to be confident before then that the demand reductions were going to be delivered in

Figure 5

Value of Avoided Distribution Costs for Various Levels of Demand Reduction at the Drummoyne Zone Substation[74]



73 This case study is taken from Crossley, 2008b.

74 EnergyAustralia, 2006

time and that they would be effective on winter evenings. Deferring the supply-side investment for periods longer than one year would require a 2.3 MVA reduction in peak demand before winter 2009 and a 3.7 MVA reduction before winter 2010.

In assessing the cost effectiveness of options, the cost to EnergyAustralia of the demand-side options was compared to the value of the avoided costs from the change in timing of expenditure on the supply-side solution. This provided a broad indication of the level of funding that might be available for a portfolio of demand-side measures. However, the determination of cost effectiveness is complex and the value EnergyAustralia assigned to individual projects might be higher or lower than this figure.

The value of avoided costs at various levels of demand reduction is shown in Figure 5 (page 41). A 0.5 MVA reduction would enable a one-year deferral and have a value of about AUD 280,000 or AUD 550/kVA (2005 values). For a two-year deferral, the value rose to about AUD 540,000, but significantly larger demand reductions would be required and the relative value reduced to approximately AUD 220/kVA. To be considered cost-effective, the overall cost to EnergyAustralia of a portfolio of demand-side measures had to be below these amounts.

EnergyAustralia's investigation identified potentially cost-effective demand-side options, analysed each of the options and their potential impact and cost, and then shortlisted the options that might form feasible demand-side projects. The most cost-effective demand-side options were then developed further and compared with the supply-side solution.

EnergyAustralia prepared a Demand Management Options Consultation Paper seeking proposals for demand-side measures capable of contributing to deferring the construction of a new transformer at Drummoyne zone substation. The consultation paper was advertised in July 2005 in newspapers and on EnergyAustralia's website. Notifications were also sent to parties in the EnergyAustralia register of organisations interested in DSM. Nine submissions were received.

In addition, EnergyAustralia identified 20 major customers in the Drummoyne area, based on their peak demands, and visited their sites and collected information about their usage of energy and possible demand-side options.

Using these various sources and information from experience in other areas, EnergyAustralia assembled a list of demand-side options for analysis. Each of the options was assessed in relation to the likely size of demand reduction that would result at the time of network peak at the Drummoyne zone substation. The cost to EnergyAustralia of establishing and utilising each option at this level for varying periods of availability from one to three years was also estimated. Based on these estimates, EnergyAustralia ranked the options and compared them to the value of deferring the proposed supply-side investment.

Eight possible demand-side options were identified:

- Contracting with customers who had standby diesel generators to enable the use of the generators to provide short period demand reduction when required.
- Installation of power factor correction equipment at customers' premises.
- Installation of fixed dimming systems for commercial lighting.
- Upgrading of commercial lighting systems using retrofitted efficient lighting kits.
- Peak load control by advanced control system.
- Peak demand reduction by using advanced residential metering and control devices.
- Residential compact fluorescent lamp (CFL) direct distribution program.
- Installation of thermal storage systems.

Table 2 (Page 43) summarises the estimated size and cost of each identified DSM option.

Figure 6 (Page 43) compares the cost and demand reduction impact of the identified demand-side options with the value of avoided distribution costs. Stacking the options from lowest relative cost to highest showed that sufficient demand reduction to achieve a one-year deferral could be identified at a lower cost than the value of the avoided costs. However, a two-year deferral would be unlikely to be cost effective.

Figure 6 suggests that all demand reductions would be cumulative. However, because several of the identified demand-side options targeted the same opportunities, some demand reductions would not be cumulative. Therefore, achieving sufficient demand reductions for a two-year deferral would be more difficult and more expensive than Figure 6 indicates.

On the basis of this analysis, the power factor correction project and the first of the CFL proposals appeared likely

Table 2

Demand-Side Options Identified in the Drummoyne DSM Project[75]

DSM Options	Winter Peak Load Reduction	Total Cost to EnergyAustralia ($NPV)	Cost to EnergyAustralia ($/kVA)	Number of Customers Involved	Time for Implementation
Ice storage system	40 kVA	–	–	1	1 to 2 years
Power factor correction	66 kVA	AUD 9,400	AUD 142	5	1 to 2 years
Residential CFL program Proposal 1	1,052 kVA	AUD 180,000	AUD 171	10,000	1 to 2 years
Residential CFL program Proposal 2	1,165 kVA	AUD 295,000	AUD 253	12,500	1 to 2 years
Peak load control by advanced control system	234 kVA	AUD 44,000 to AUD 89,000	AUD 187 to AUD 380	3	1 to 2 years
Standby diesel generator	170 kVA	AUD 67,000	AUD 394	1	1 to 2 years
Combined demand reduction projects	600 kVA	AUD 238,000	AUD 398	2,226	1 to 2 years
Fixed dimming for lighting system	175 kVA	AUD 87,500	AUD 500	17	1 to 2 years
Installation of Cent-a-Meter energy monitoring device	712 kVA	AUD 706,000	AUD 992	9,410	1 to 2 years
Upgrade of lighting system	106 kVA	AUD 123,700	AUD 1,166	11	1 to 2 years

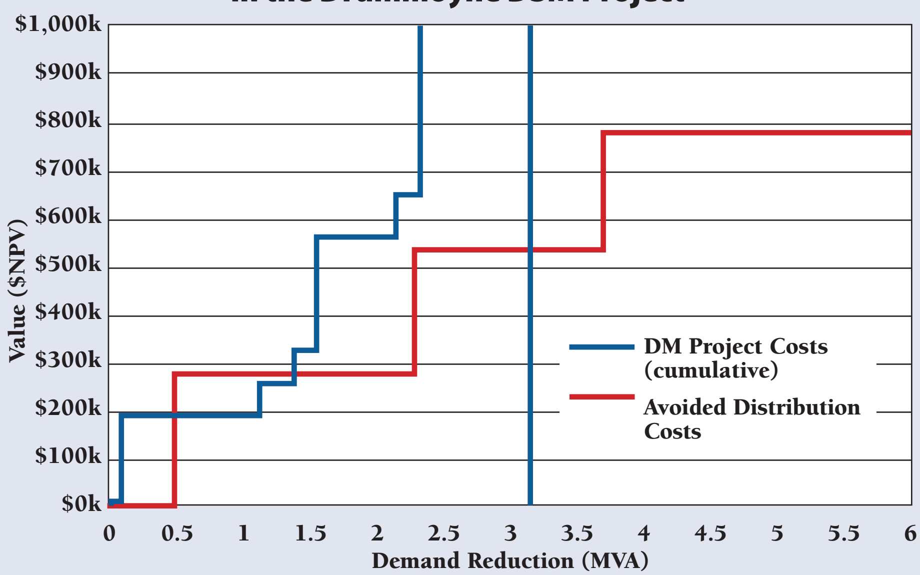
to be cost effective. The CFL project was selected for implementation.

Mass distributions of CFLs to households had become common in the state of New South Wales as a way of creating tradeable emission abatement certificates under a state-wide emissions trading scheme. However, in the Drummoyne project, the distribution of CFLs was much more closely targeted and monitored to ensure that the lamps were actually installed. The project was initiated by EnergyAustralia's network business rather than by its retailer arm, even though the abatement certificates generated were used by the retail business to help meet its obligations under the New South Wales emissions trading scheme.

The CFL installations were carried out by a third-party contractor who had proposed the measure in response to EnergyAustralia's Demand Management Options Consultation

Figure 6

Cost and Demand Reduction Impact of Demand-Side Options Compared with the Value of Avoided Distribution Costs in the Drummoyne DSM Project[76]



75 EnergyAustralia, 2006

76 Ibid.

Paper. The CFL project commenced with an advertising campaign in the target area that involved local municipal councils. Marketing activities were employed to promote the program, including posters sent to local businesses, letterbox drops, calling cards, outdoor banners, press advertisements, and targeted media relations.

High power factor, 15 watt CFLs were packaged in boxes of five for distribution to households in the target area. Each household was given one box of five CFLs free of charge. Door-to-door delivery and installation were carried out during specific times and days to maximise the number of people at home. For each box of CFLs delivered, delivery staff completed forms that included the householders' names, addresses, and signatures, plus answers to a short survey. The signed forms provided verification of the number of boxes of CFLs distributed. For households where no one was home, a flyer containing project information and a mail order form was left at the house. A follow-up phone survey was conducted during the delivery period to assess how many CFLs were actually installed.

C. Providing Network Support Payments for Demand-Side Measures

i. Description

This mechanism establishes rules within an electricity market for:

- valuing the network benefits and services available from the implementation of demand-side measures; and
- providing a commensurate financial return to parties implementing demand-side measures that deliver defined network benefits and services.

This is a separate mechanism to bidding of demand-side measures to relieve network constraints (see section 5.B, page 41). In the bidding mechanism, payments for implementing demand-side measures are determined by the bidding process. In contrast, network support payments are determined through a process of valuing the benefits and services delivered.

ii. Implementation

There are three main types of benefits and services that demand-side measures may provide to electricity networks:

- reducing energy losses resulting from the transmission and distribution of electricity;
- deferring or avoiding augmentation or expansion of electricity networks;
- delivering various ancillary services, including:
  - voltage regulation;
  - load following;
  - active/reactive power balancing;
  - frequency response;
  - supplemental reserve; and
  - spinning reserve.

The value of each of these benefits or services to the network operator depends on the particular circumstances in which they are delivered. Consequently, determining values on which to base network support payments to parties implementing demand-side measures is complex. Market rules that implement network support payments should therefore specify the methodologies to be used for determining the values of the network benefits and services delivered by demand-side measures and for setting the levels of the network support payments based on these values.

The market rules should also specify the parties responsible for funding the payments. Because the operators of transmission and distribution networks will be the main beneficiaries from the implementation of demand-side measures, they should bear the main burden of making network support payments. Depending on the circumstances, a particular electricity generator, or even a large end-user, may also be a beneficiary. Where this is the case, the particular generator or end-user should also contribute a portion of the network support payments.

Finally, the market rules implementing network support payments should also specify how network operators may recover the cost of these payments. Typically this is done through a pass-through mechanism that allows the network operator to include the cost of network support payments in its regulated return on assets, or in its next price determination or rate case.

iii. Application

In the Australian National Electricity Market, network support payments are available to distributed generators to reflect the benefits they provide to the electricity network (see the case study on page 45).

iv. Market Impact

Market rules that provide for network support payments to be made to parties that implement demand-side measures may contribute to increasing the integration of demand-side resources into electricity markets. However, this mechanism is not sufficient by itself to increase the use of demand-side resources.

v. Effectiveness

The effectiveness of this mechanism depends on the value ascribed to the network benefits and services provided by demand-side measures and the proportion of this value allocated to network support payments. To be effective, the level of the payments made will have to be sufficiently higher than the costs of implementing demand-side measures to provide a reasonable profit to the implementing parties.

vi. Case Study

The following case study briefly describes the rules governing network support payments for embedded generators in the Australian National Electricity Market.

In Australia, the National Electricity Market currently operates under a detailed set of rules called the *National Electricity Rules*.[77] The Rules authorise network support agreements between an operator of a transmission or distribution network and a market participant or any other persons providing network support services to improve network capability by providing a non-network alternative to a network augmentation.

Generators that are connected to distribution networks (embedded generators) have the potential to reduce the long-term need for investment in transmission infrastructure. This is because such embedded generators may be able to reduce the distribution network's need to be supplied from the transmission network. When a network support agreement is established between a network operator and an embedded generator, the agreement may include payments to the generator in recognition of the network support being provided by the generator.

There are currently two payments that embedded generators can receive:

- a network support payment directly from a transmission network operator for a specific service provided by the embedded generator to defer investment in the transmission network; and
- a payment from the distribution network operator that recognises that the embedded generator has enabled the distributor to avoid transmission use of system charges levied by the transmission network operator. This is paid where the embedded generator has reduced the demand taken by the distributor from the transmission system at times of peak demand. The *National Electricity Rules* require this benefit to be passed on to the embedded generator.

In December 2011, a change was made to the *National Electricity Rules* to place an obligation on transmission system operators, when negotiating a network support payment with an embedded generator, to take into account the services being provided by the generator, and the extent to which the generator will be compensated for those services by avoided transmission use of system payments.[78] This clarifies that embedded generators can receive both payments, but should only be compensated once for each distinguishable benefit they provide.

77 Australian Energy Market Commission, 2011a.

78 Australian Energy Market Commission, 2011b.

6. Load-Targeting Mechanisms

A. Using Load Control to Address System Needs and Integrate Renewables

i. Description

This mechanism uses load control technology to enable changes in the levels of end-use customer loads:

- in response to particular events such as periods of high electricity prices or problems on the electricity network; or
- to integrate intermittent generation such as wind or photovoltaics into the system.

ii. Implementation

A complete load control system consists of three basic elements as shown in Figure 7:

- technology located at the program operator's premises;
- communications technology; and
- technology located at the customer's site.

There are a variety of ways in which load control systems can be implemented:[80]

- **the program operator for the load control system may be:**
  - an electricity retailer or distributor;
  - a market or system operator; or
  - a demand response service provider.

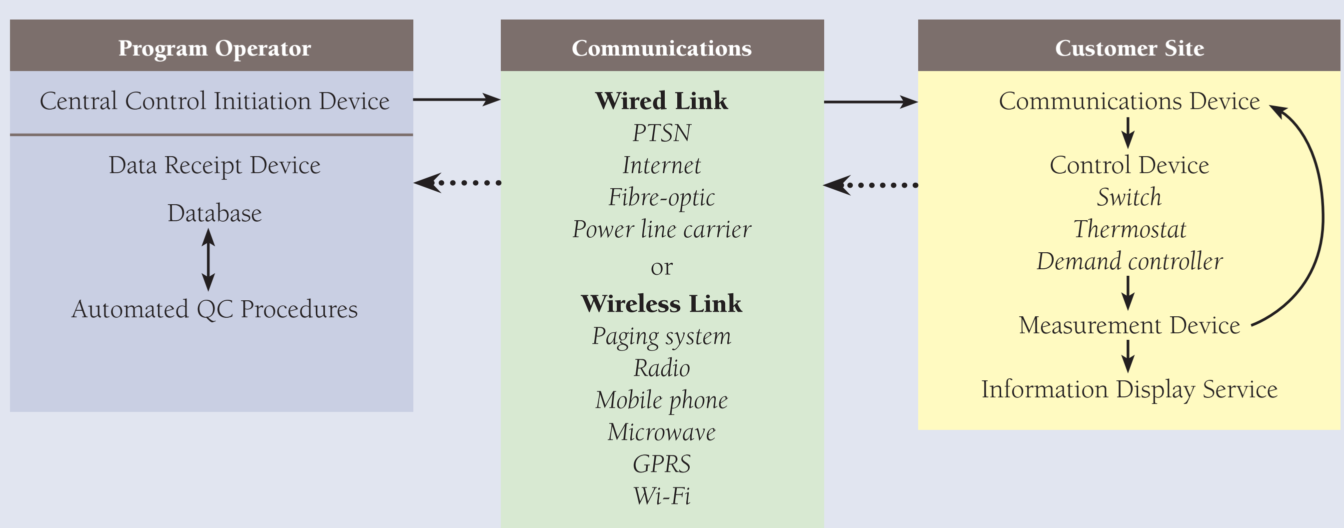
- **switching of end-use customer loads may be:**
  - carried out *manually* by the customer turning down or switching off appliances and equipment in response to a request from the program operator;
  - carried out *automatically* according to thresholds (e.g., time of day or electricity prices) pre-set by the customer following guidelines provided by the program operator; or

79 Modified from Lockheed Martin Aspen, 2006.

80 Crossley, 2008a.

Figure 7

Load Control System Components[79]



- initiated *remotely* by a signal sent from the program operator[81] through direct communication links to the customers' electrical equipment; a second signal is sent to restore normal operation at the conclusion of a program event.

- **switching of loads may involve:**
  - *cycling* loads on and off according to pre-set timing schedules;
  - *reducing* or increasing loads to pre-set levels; or
  - *switching off* loads completely.

The particular way in which a load control system is implemented and operated will be driven by the objective to be achieved. In general, automated and remote switching of appliances and equipment are the most effective methods of operation, because they require only one "set and forget"decision by end-use customers.[82]

iii. Application

Load control systems are currently being implemented by a range of program operators in many countries around the world.

iv. Market Impact

Load control systems actively enable increased use of demand-side resources in the electricity sectors. It is likely that such systems will increasingly be deployed to address peak load problems on electricity networks and to integrate intermittent generation into the system.

v. Effectiveness

The effectiveness of this mechanism in achieving increased use of demand-side resources depends on the level of take-up of load control systems by end-use customers. Take-up can be increased by targeted marketing and communication to end-use customers by load control program operators.

vi. Case Study[83]

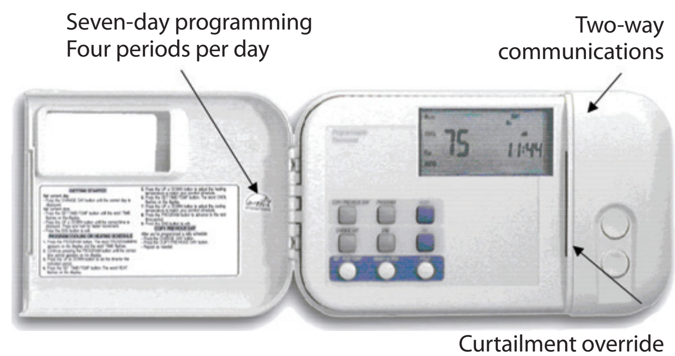
The following case study describes the LIPAedge program developed by Long Island Power Authority (LIPA) in the United States to use central control of residential and small commercial air-conditioning thermostats to achieve peak load reduction.

The LIPAedge program is based on the programmable ComfortChoice thermostat (see Figure 8). The system operator uses an internet-based system to control a demand-side resource comprising approximately 20,000 thermostat-controlled air conditioners. Skytel two-way pagers are used to transmit a curtailment order to the thermostat and to receive acknowledgment and monitoring information. One or more pager signals are generated and transferred to the SkyTel pager network (see Figure 9, page 48).

Commands go via satellite to pager towers, where they are broadcast to the thermostats. The thermostats take immediate action or adjust their schedules for future action, depending on what the system operator ordered. The thermostats log the order and respond via pager, enabling LIPA to monitor the response to the event. The thermostats also collect data every minute on temperature, set point, and power consumption (hourly duty cycle). They retain this information as hourly averages and report it to the utility. The thermostat itself holds seven days of hourly data.

Figure 8

ComfortChoice Thermostat Used in the LIPAedge Program[84]



81 The signal may be sent manually by the program operator or automatically in response to trigger events such as exceedances of pre-set electricity price levels or pre-set load levels on particular network elements, or excursions outside pre-set frequency or voltage parameters.

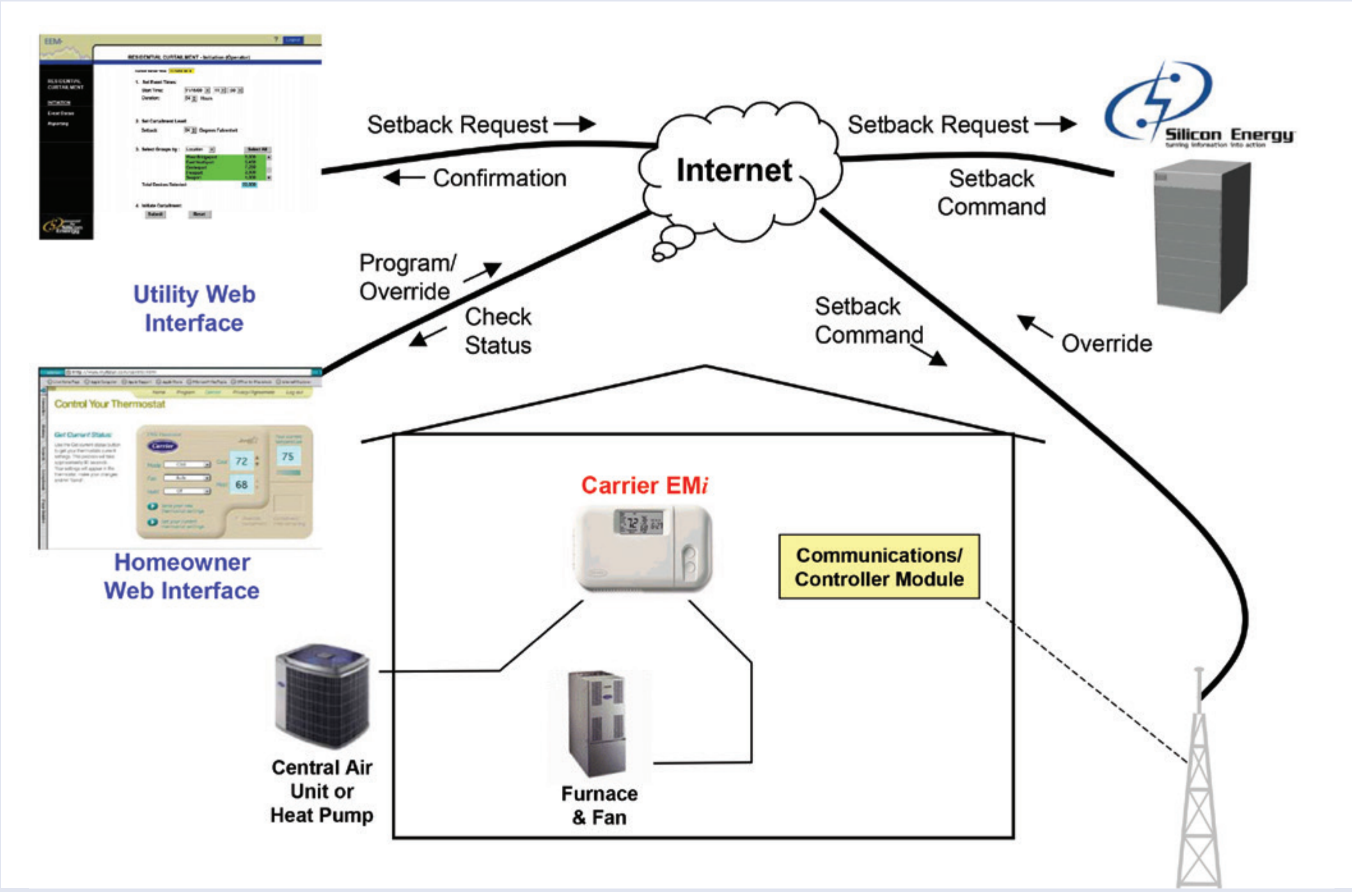
82 Crossley, 2008a.

83 This case study is taken from Crossley, 2008b.

84 Long Island Power Authority, 2002.

Figure 9

The Carrier/Silicon Energy Direct Load Control System for the LIPAedge Program [85]



For a summer load curtailment, the system operator might send a command at 9:00 am directing all thermostats to move their set points up four degrees, starting at 2:00 pm and ending at 6:00 pm. Alternatively, the system operator could send a command directing all thermostats to completely curtail immediately. The command would be received and acted upon by all loads, providing full response within approximately 90 seconds. This is far faster than generator response, which typically requires a 10-minute ramp time.

Thermostats can be addressed individually, in groups, or in total. This important advantage provides both flexibility and speed. System operator commands that are addressed to the entire resource are implemented through a single page that all thermostats receive. Similarly, 15 subgroups can be addressed if response is required in a specific area to alleviate a transmission constraint. Thermostats can be addressed individually as well. This capability is useful for monitoring the performance of the system (each thermostat is checked weekly for a "heartbeat").

The customer also receives benefits. The thermostat is fully programmable and remotely accessible, with all of the associated energy savings and convenience benefits. A web-based remote interface is provided for customer interaction. Customers can also override curtailment events. This feature appears to be important to gain customer acceptance and it probably increases the reliability of the response.

Two-way paging communication enables the utility to monitor load performance both during response events and under normal conditions. Response from the thermostats is staggered over a time period set by the utility to avoid overwhelming the paging system. It typically requires 90 minutes for 20,000 thermostats to respond. Thus the system provides for performance monitoring but not in the

85 Long Island Power Authority, 2002.

2- to 8-second intervals typical for large generators.

The LIPAedge program is available for Residential Central Air Conditioning customers and Small Business customers, although the program is now closed to new participants. Customers who sign up to the LIPAedge program receive a ComfortChoice thermostat and installation free of charge. Customers also receive a one-time bonus payment of USD 25 (residential customers) or USD 50 (small commercial customers).

LIPAedge customers agree to have their central air conditioning system adjusted between the hours of 2 pm and 6 pm for a maximum of seven days throughout the four-month summer season. Customers have access to a dedicated web page for their thermostat and are able to remotely change the set point of their air conditioner whenever they want.

LIPA initiates curtailment events by either increasing the set point on LIPAedge thermostats by 3 to 4 degrees, or by cycling air conditioner compressors off for a portion of each hour.

Customers can override curtailment messages sent to their thermostat, although LIPA encourages its customers not to override during a curtailment event. If the customer decides to override the curtailment, the change is recorded by the thermostat and a wireless message is then sent back to the central server.

LIPA collected name-plate power consumption information on the air-conditioning equipment being controlled when it installed the ComfortChoice thermostats for the LIPAedge program. It also directly measured the power consumption of a subset of those loads to estimate the actual load of the aggregation. LIPA determined that the average capacity of residential air-conditioning units being controlled was 3.84 kW, whereas the average capacity of small commercial units was 6.38 kW. The total 23,400 individual loads had a peak capacity of 97.4 MW if all the units were on at 100 percent duty cycle.

LIPA monitored the performance of 400 units from 1 May 2002 through 29 September 2002. Hourly data were collected from each unit for duty cycle and facility temperature. Those data were used to estimate the performance of all 23,400 responsive loads. LIPA found that each controlled load provided an average of 1.06 kW of demand reduction (1.03 kW per residential air-conditioner and 1.35 kW per small commercial air-conditioner). LIPA expected 24.9 MW of peak reduction response from the full 23,400 controlled air-conditioners.

B. Implementing Load Scheduling to Time-Target End-User Loads

i. Description

This mechanism establishes contractual arrangements that enable system operators to request specified changes in end-user load levels at times when doing so delivers benefits or services to the system.

This is a type of short-term demand response; typically system operators request changes in end-user load levels for periods lasting from one to several hours.

The effect of this mechanism is very similar to some types of demand-side bidding (DSB) into electricity markets (see section 5.A, page 37), but the method of implementation is quite different. In DSB, scheduling of demand-side measures is determined by the bidding process. In contrast, in load scheduling the system operator directly requests the owners or aggregators of the loads involved to implement changes in load levels.

ii. Implementation

Load scheduling is implemented by the system operator establishing contractual arrangements directly with the owners or aggregators of the loads involved. Typically, the terms of the contract include:

- the minimum size of loads that will be accepted under the contractual arrangements;
- technical requirements for switching and monitoring the levels of loads under contract;
- the circumstances in which the system operator may request changes in load levels;
- the minimum and maximum notice periods provided by the system operator before requested load level changes are required to be delivered; and
- the remuneration paid by the system operator to the owners or aggregators of contracted loads.

iii. Application

This mechanism is an updated version of interruptibility contracts that many electricity providers used to have with end-use customers before the introduction of competitive electricity markets. Implementation of this newer form of interruptibility as contractual arrangements between system operators and end-users is not widespread.

iv. Market Impact

This mechanism directly facilitates the integration of demand-side resources, in the form of short-term demand response, into electricity markets.

v. Effectiveness

The effectiveness of this mechanism in achieving increased use of demand-side resources depends on:

- the level of interest among system operators in establishing contractual arrangements directly with end-users and aggregators; and
- the take-up rate of the contractual arrangements by end-use customers.

Given the load switching and load monitoring required, end-users will require technical assistance in evaluating and making a decision about any load scheduling proposals.

vi. Case Study[86]

The following case study describes the load scheduling activities of the Business Energy Coalition (BEC) in California.

The BEC is a project between Pacific Gas and Electric Company (PG&E), major businesses, and civic leaders. Facilitated by The Energy Coalition, the BEC is designed to address the specific business challenges regarding load reductions during critical peak hours. Working closely with its members individually and as a group, the BEC develops and implements effective load curtailment strategies for periods of high demand.

The BEC targets large end-use customers with roughly 1000 kW or more of peak demand who are able to drop 10 to 15 percent of their peak load during curtailment events. Commercial properties that have not historically participated in any demand response program before are targeted, such as Class “A” high-rise office buildings and premier hotels. The BEC works with end-users to develop a set of realistic load curtailment protocols that are based on individual site characteristics. Should one site fail to meet an individual goal on a particular day, other group members stand ready to step-up their own contributions to meet the group goal.

In 2005, the BEC enrolled 32 PG&E customers who agreed to deliver, as a group, 10 MW of electrical load reduction during peak hours. These charter members easily surpassed their group goal. In 2006, the group was expanded to include an additional 30+ new members, who delivered more than 15 MW of peak reduction. By 2008, the BEC had enrolled over 130 members with a group goal of delivering up to 50 MW of demand response electrical reduction capacity.

BEC members receive a comprehensive demand response assessment by leading engineering experts, advanced real-time metering equipment, and a specialised web-based load monitoring software system. Load reduction is achieved through a customised step-by-step curtailment protocol for each facility.

A load curtailment may be requested by PG&E in response to the following Program Triggers:

- the California Independent System Operator (CAISO) declares – or PG&E expects the CAISO to declare – a Stage 1 or higher emergency;
- the CAISO forecasts – or PG&E expects CAISO to forecast – a system load to meet or exceed 43,000 MW; and
- the CAISO or PG&E foresee or declare a localised system emergency, including high temperature forecasts and loss of generation or transmission resources. In this case, PG&E may call an event for a particular BEC participant group, as defined by PG&E’s transmission planning areas.

Curtailment events are limited to five hours per event and five curtailments per month.

BEC members receive incentive payments of up to USD 75/kW of contracted load reduction annually with no non-performance penalties. The actual incentive payment received is based on a member’s hourly performance over the course of the curtailment season.

C. Operating Energy Storage to Time-Target Changes in System Load

i. Description

This mechanism uses energy storage technology to convert grid-connected electricity into another form of energy, hold it for later use, and when required at a future time, release the stored energy as electricity or as another useful form of energy.

86 This case study is taken from The Energy Coalition website at www.energycoalition.org/BEC/

Just as transmission and distribution systems move electricity over distances to end-users, energy storage systems can move electricity through *time*, providing it when and where it is needed.[87] Energy storage systems can help balance variable renewable generation and, properly deployed and integrated, can help increase the reliability of the electricity network.

Storage applications differ from other distributed energy resource options, such as distributed generation or energy efficiency, in three key respects:[88]

- they do not have a typical operating profile or load shape that can be applied prospectively;
- they are "limited energy" resources with a narrow band of dispatch and operation; and
- they can participate in multiple wholesale electricity markets and provide several benefits simultaneously to the wholesale system, electricity distributors, and end-use customers.

ii. Implementation

A range of technologies are available for energy storage, as shown in Figure 10.

Energy storage technology can be used in a number of different ways. Table 3 (page 52) shows ten major applications for energy storage identified in an EPRI study.

Energy storage may be used by both end-use customers and system operators.

Customers can use energy storage as a price hedging mechanism that stores electricity generation output when electricity prices are low and releases useful energy when prices are high. Storage electric water heaters are an example of this use of energy storage technology.

System operators can use energy storage in three main ways:

- to reduce peak loads on the network and particularly to integrate intermittent generation such as wind or photovoltaics into the system;
- to provide a capacity reserve that can be made available at short notice; and
- to provide a variety of ancillary services.

87 Electric Power Research Institute, 2010.

88 Electric Power Research Institute, 2010.

89 Cowart, 2011.

Figure 10

Technology Options for Energy Storage [89]

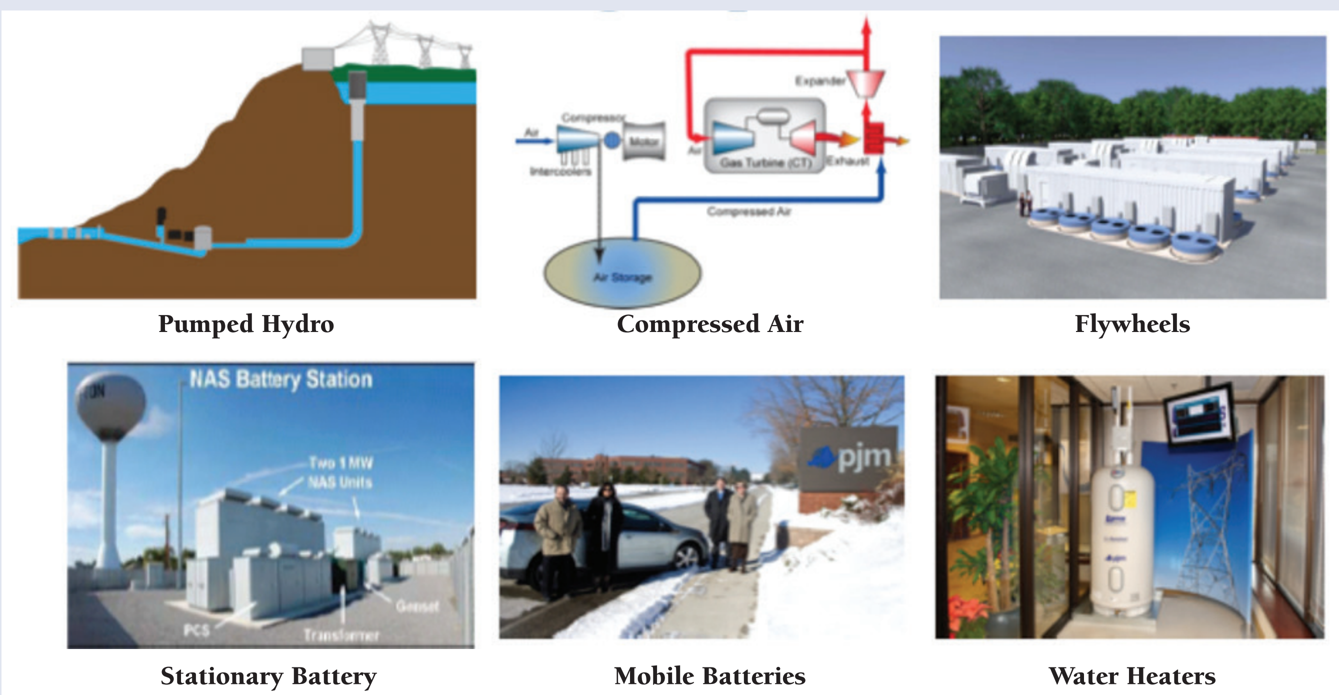


Table 3

Definition of Energy Storage Applications [90]			
Value Chain		**Application**	**Description**
Generation and System-Level Applications	**1**	Wholesale Energy Services	*Utility-scale storage systems for bidding into energy, capacity, and ancillary services markets*
	2	Renewables Integration	*Utility-scale storage providing renewables time shifting, load and ancillary services for grid integration*
T&D System Applications	**3**	Stationary Storage for T&D Support	*Systems for T&D system support, improving T&D system utilisation factor, and T&D capital deferral*
	4	Transportable Storage for T&D Support	*Transportable storage systems for T&D system support and T&D deferral at multiple sites as needed*
	5	Distributed Energy Storage Systems	*Centrally managed modular systems providing increased customer reliability, grid T&D support, and potentially ancillary services*
	6	ESCO Aggregated Systems	*Residential-customer-sited storage aggregated and centrally managed to provide distribution system benefits*
End-User Applications	**7**	C&I Power Quality and Reliability	*Systems to provide power quality and reliability to commercial and industrial customers*
	8	C&I Energy Management	*Systems to reduce TOU energy charges and demand charges for C&I customers*
	9	Home Energy Management	*Systems to shift retail load to reduce TOU energy and demand charges*
	10	Home Backup	*Systems for backup power for home offices with high reliability value*

T&D = Transmission and Distribution; C&I = Commercial and Industrial; ESCO = Energy Services Company; TOU = Time of Use

To use an energy storage facility effectively, system operators must be able to both direct generation output into storage and dispatch the release of electrical energy from storage. This will require the establishment of contractual arrangements between the system operator and energy storage providers.

The terms of an energy storage contract should include:

- technical requirements for accessing and monitoring the energy storage facility under contract;
- the circumstances in which the system operator may direct generation output into storage and dispatch the release of electrical energy from storage; and
- the remuneration paid by the system operator to the energy storage provider.

iii. Application

On a worldwide basis, 125.5 GW of energy storage has been installed, the overwhelming majority being pumped storage technology (see Figure 11, page 53).

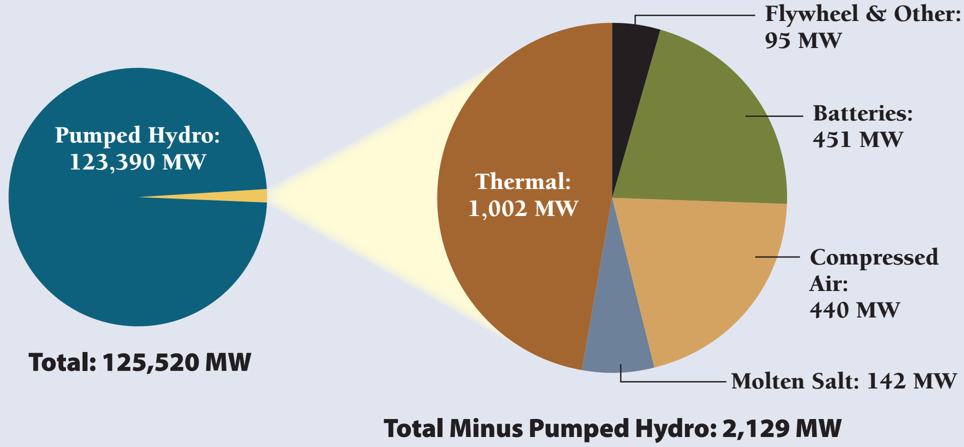
iv. Market Impact

Energy storage provides a technology whereby demand-side resources, particularly distributed generation, can be integrated into electricity markets. Energy storage is typically used by system operators to enable the integration of intermittent distributed generation such as wind and photovoltaics and to provide a range of ancillary services.

90 Electric Power Research Institute, 2010.

Figure 11

Total Worldwide Installed Energy Storage[91]



In 2009, A123 Systems and AES Energy Storage began commercial operation of a 12 MW lithium-ion battery energy storage system installed at AES Gener's Los Andes substation in the Atacama Desert in northern Chile. The system delivers Capacity Release for Power Generators, a service developed by AES Energy Storage to enable a battery-based installation to meet system obligations for spinning reserve, allowing power generators to produce and sell power previously required to be held in reserve. It continuously monitors the condition of the power system, and if a significant frequency deviation occurs (e.g., the loss of a generator or transmission line), the energy storage system can provide up to 12 megawatts of power nearly instantaneously. This output is designed to be maintained for 15 minutes at full power, allowing the system operator to resolve the event or bring other standby units online.[93]

The project helps the system operator manage fluctuations in demand, delivering frequency regulation in a less expensive, more responsive, and more accurate manner than traditional methods. In addition, because the project replaces unpaid reserve from the power plant, AES Gener receives payment for its full output capacity by selling directly to the electric grid.[94]

Performing continuously for more than 18 months as a critical reserve unit for Chile's Northern Grid, the project is the only reserve unit that has responded to all generator-assisted fault restorations since January 2010. During this time it has demonstrated a response speed consistently higher than other units, while continuously overachieving in delivering the committed level of response. In addition to fast and accurate response times benefitting the grid,

v. Effectiveness

Energy storage can be a highly effective mechanism to integrate intermittent distributed generation into the system. In particular, the use of energy storage can mitigate or avoid a requirement to spill intermittent generation when the system is overloaded or there is insufficient demand on the system.

vi. Case Study

This case study describes two projects in northern Chile that use energy storage technology to provide the ancillary services frequency regulation and spinning reserve.

Figure 12

A 12 MW Lithium-ion Battery Frequency Regulation and Spinning Reserve Project in Northern Chile[92]

91 Cowart, 2011.

92 Electric Power Research Institute, 2010.

93 Wesoff, 2012.

94 AES Energy Storage, 2012a.

the project has allowed AES Gener to increase power generation from its Norgener plant by four percent.[95]

In May 2011, AES Gener and AES Energy Storage began construction on another 20 MW project in northern Chile that will deliver the same service. Located near a new thermal power plant, the system will increase AES Gener's storage capacity from 12 MW to 32 MW and allow the plant to more effectively use its generating capability while still providing critical spinning reserve services to the northern grid.

D. Implementing Geographic Targeting of Demand-Side Measures

i. Description

This mechanism establishes processes for targeting the implementation of demand-side measures to particular geographic areas or localities where they will be most effective in relieving network constraints.

This mechanism is similar to bidding of demand-side measures to relieve network constraints (see section 5.B, page 40), except that this mechanism is focussed on delivering the results of implementing demand-side measures to targeted geographic localities.

ii. Implementation

Geographic targeting is typically implemented through a five-stage process:

- the network operator identifies a network constraint in a particular geographic location that may be addressable through demand-side measures;
- the network operator characterises the constraint and carries out a preliminary assessment of the potential for demand-side measures to address the constraint;
- the network operator publishes the information it has assembled on the network constraints and possible demand-side measures and issues a Request for Proposals to potential implementors of demand-side projects;
- project implementors submit proposals to the network operator; and
- the network operator selects cost-effective projects for implementation.

iii. Application

Geographic targeting of demand-side measures is implemented extensively by electricity distributors in the state of New South Wales in Australia where it is routinely used in small-scale demand-side management projects targeted at a particular network element (e.g., a substation or an individual distribution feeder). Geographic targeting has also been used on similar small scales in a few localities in the United Kingdom and the United States. Larger scale geographic targeting was used in the Provence-Alpes-Côte d'Azur (PACA) region of France (see the case study below).

iv. Market Impact

Geographic targeting establishes a market for demand-side resources, although opportunities to implement demand-side measures are limited to areas or locations where network constraints have been identified.

v. Effectiveness

The effectiveness of this mechanism depends on the identification of opportunities to use demand-side measures to relieve network constraints and the willingness of network operators to consider implementing demand-side measures as alternatives to network augmentation or expansion.

vi. Case Study [96]

This case study describes geographic targeting of demand-side measures to address overloading of transmission lines in the Provence-Alpes-Côte d'Azur (PACA) region of France.

The PACA region is supplied from Tavel near Avignon, via two 400 kV transmission lines – a southern line that goes to Broc Carros via Néoules and a northern line that goes as far as Boutre. A 225 kV line completes the ring by connecting Boutre to Broc-Carros (see Figure 13, page 55).

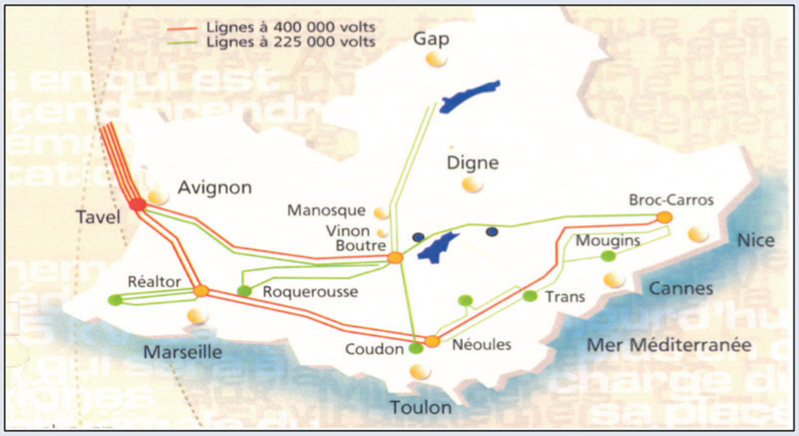
Planning for the upgrading of the Boutre-Carros line to supply increasing load growth in the area commenced in 1983. The initial plan comprised double 400 kV lines on separate easements over 170 km in length. Six route options for the upgraded line were proposed. However, there was strong opposition to this project because the

95 AES Energy Storage, 2012b.

96 This case study is taken from Crossley, 2008b.

Figure 13

High Voltage Transmission Lines in the Eastern Part of the Provence-Alpes-Côte d'Azur Region of France[97]



lines would pass through the classified scenic gorges of the Verdon Regional Park.

In 1994, a petition against all the route options collected 3,000 signatures. In January 1997, a seventh route option was proposed. In July and August, a petition was circulated supported by local governments in the area. The petition requested studies of alternatives to the line and 23,000 signatures were obtained, including 12 percent of tourists in the European Union. In November, the Department of the Environment established a public commission of inquiry into the Boutres-Carros line and the project was suspended.

In 2000, a decision was made on an alternative solution. This comprised:

- replacement of the existing 225 kV line by a single 400 kV line, 100 km in length, on the same easement;
- removal of an existing 150 kV line, which accompanied the 225 kV line; and
- implementation of an ambitious DSM and renewable energy distributed generation program called the "Eco-Energy Plan" to slow down the growth in demand.

In May 2006, the state court, after a complaint from an environmental group, refused planning permission for the upgrading of the Boutre-Carros line. Following the court decision, the Eco Energy Plan program was the only way to secure supply to this region by keeping load growth within the capacity of the existing 250 kV line.

The Eco-Energy Plan comprised a very large integrated DSM project (including distributed generation). At the time, it was the largest DSM project in the European Union and possibly the world. It had three main objectives:

- to increase the efficiency of electricity usage and to create a critical mass of scientific and technological competence in relation to electricity DSM;
- to modify the electricity-using behaviour of consumers, and building owners and managers; and
- to contribute to the development of local renewable energies and to establish a solid basis for future energy choices.

The following description is based on the analysis and program design developed following the initial decision in 2000. Following the refusal of planning permission in 2006, the DSM program was strengthened to meet the new constraints.

Preliminary studies were carried out in 2001:

- to quantify the level of load reduction required, after the scheduled completion of the new 400 kV line in 2005, to avoid network constraints in the period to 2020;
- to understand the evolution and structure of peak demand in the eastern part of the PACA region;
- to quantify the potential load reductions achievable through implementing DSM and distributed generation; and
- to identify a detailed program of DSM and distributed generation measures.

Figure 14 (page 56) shows that, following the scheduled completion of the new 400 kV line in 2005, with a fault level of n-1 (involving the loss of one line or substation) capacity constraints were likely to reappear in the winter of 2018. To avoid a further new line being required before 2020, the Eco-Energy Plan would have to reduce load by 35 MW in winter.

97 Harinck and Combes (2003)

Figure 14

Capacity Constraints in Winter with Fault Level n-1 Following Scheduled Completion of the New 400-kV Line in 2005[98]

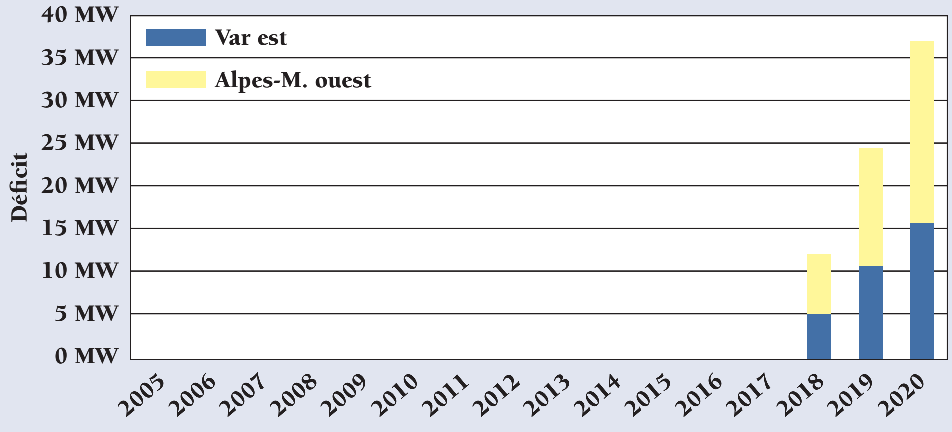


Figure 15

Capacity Constraints in Summer with Fault Level n-2 Following Scheduled Completion of the New 400-kV Line in 2005[99]

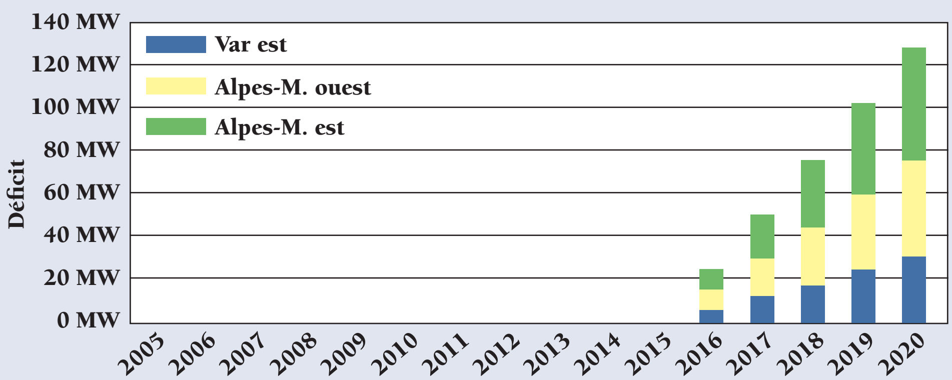


Figure 15 shows that with a fault level of n-2 (involving the loss of two lines or substations), capacity constraints were likely to reappear in the summer of 2016. An n-2 fault level is possible in summer because of the risk of forest fires under the southern double circuit 400 kV line. To avoid a further new line being required before 2020, the Eco-Energy Plan would have to reduce load by 130 MW in summer.

Figure 16 and Figure 17 show the end-use composition of peak demand in the region in winter and summer. In winter, peak demand is dominated by lighting and heating, and in summer, air conditioning is dominant with lighting also an important contributor to the peak.

Figure 18 (page 57) shows forecasts of the potential load reductions achievable through the Eco-Energy Plan by implementing DSM and distributed generation over the period 2005 to 2020.

98 Harinck and Combes, 2003

99 Ibid.

100 Rosenstein, 2004

101 Ibid.

Figure 16

Winter Peak Demand by End-Use in the Eastern Part of the Provence-Alpes-Côte d'Azur Region[100]

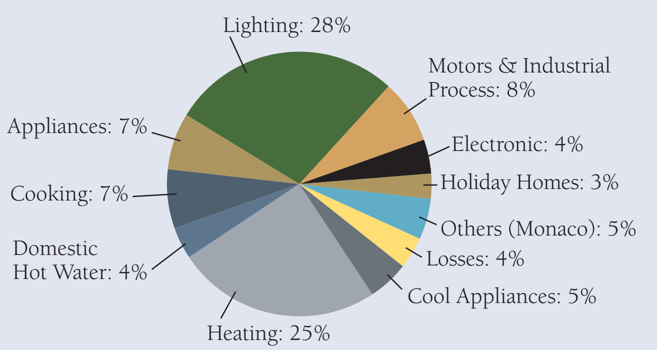


Figure 17

Summer Peak Demand by End-Use in the Eastern Part of the Provence-Alpes-Côte d'Azur Region[101]

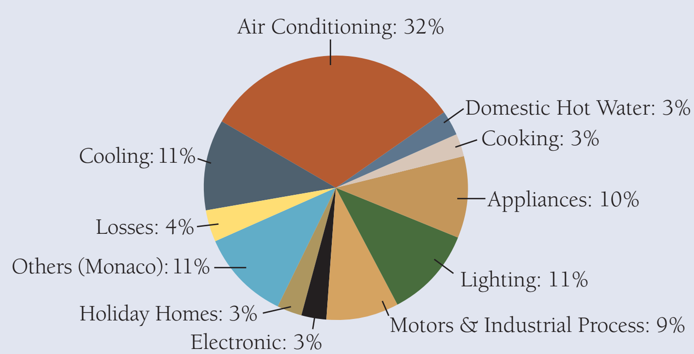


Figure 18

Forecasts of Potential Load Reductions Achievable through the Eco-Energy Plan 2005 to 2020[102]

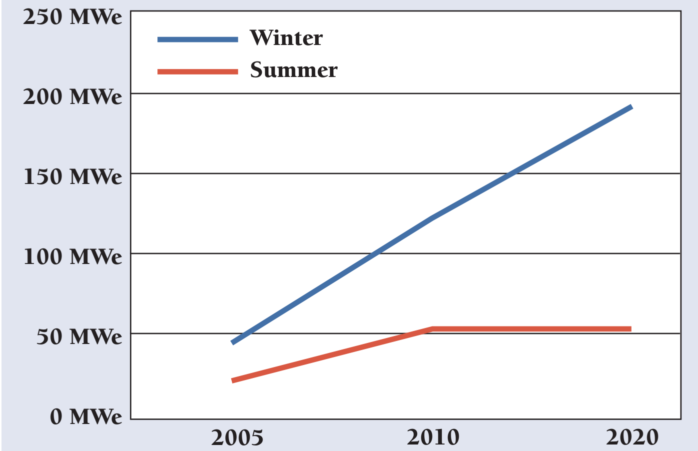


Figure 19

Forecasts of Potential Load Reductions Achievable through the Eco-Energy Plan in Winter 2006[103]

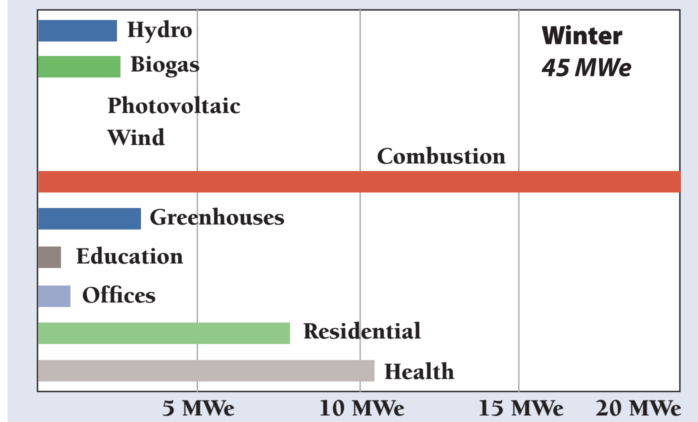


Table 4

Forecast Impacts and Costs of Identified DSM Measures to be Implemented Through the Eco-Energy Plan[104]

	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)	Impact on Consumption (GWh)	Public Funding (M€)
Communication and information campaigns				2.9
Increasing awareness and training of engineering departments and installers				3.6
Demonstration energy management projects in State and local authorities, EDF and ADEME	26	5.5	52.5	4.6
Specific measures for new residential and commercial buildings	1.2	0.1	2.5	7.6
Large-scale dissemination of CFLs in social sector	2.3	0.5	6	2
Promotion of efficient lighting in commercial sector	24	12	72	1.8
Promotion of CFLs and energy efficient white goods	57	8	115	3.6
Energy efficient retrofitting in residential and commercial sectors	41	11.5	125	9.1
Energy efficient retrofitting in tourism sector	3	2.3	9	2.6
Domestic hot water		15	5	3.3
Wood heating	8		7	2.1
Specific measures for large industrial and commercial consumers	16.5	11		2.3
Cogeneration, biogas, hydro installations	45	23		3
Photovoltaic installations	0	0.3		0.9
Evaluation				3
Total	**224**	**89.2**	**394**	**52.4**

Figure 19 (page 57) shows a breakdown of the forecast load reductions achievable in winter 2006. Based on these forecasts, the target load reduction to be achieved through the Eco-Energy Plan in winter 2006 was set at 45 MW.

The Eco-Energy Plan was launched in March 2003. Initially six priority areas were identified:

- communication and information;
- new building construction;
- efficient lighting and domestic electrical appliances;
- large consumers and distributed generation;
- demonstration projects by the Eco-Energy Plan institutional partners; and
- public housing.

In 2004, a further two priority areas were added:

- existing buildings; and
- tourism.

Table 4 (page 57) shows the forecast impacts and costs of the identified DSM measures to be implemented through the Eco-Energy Plan

102 Harinck and Combes, 2003

103 Ibid.

104 Rosenstein, 2004

7. Conclusion

The aim of this paper is to provide information about how to increase the use of demand-side resources in the electricity sector where these resources are cost-effective and appropriate.

The paper has described 14 of the most effective mechanisms for increasing the use of demand-side resources. Some of these mechanisms aim at integrating demand-side resources into electricity markets. Others aim at increasing the role of demand-side resources in system operations and planning processes.

The relative effectiveness of these mechanisms in any particular region or country will depend on the structure of the electricity sector, and the regulatory regime and system planning processes in place. It is therefore important to take these factors into account when planning the use of any of the mechanisms described in the paper.

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