Enabling Demand Response:
Overcoming Barriers to Time of Use Rates

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List of Terms and Acronyms	
AMI	Advanced metering infrastructure: The full measurement and collection system, including customer meters, communication networks, and data management systems" that enable utilities to measure customer energy consumption for TOU rates
AMR	Advanced/automated meter reading
DR	Demand response: Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized
kW	A unit used to measure rate of energy use or production. Equal to 1,000 watts.
kWh	A unit used to measure amount of energy used or produced. Equal to 1,000 watt-hours
LDC	Load duration curve
MW	A unit used to measure rate of energy use or production. Equal to 1,000,000 watts.
MWH	A unit used to measure amount of energy used or produced. Equal to 1,000,000 watt-hours
NPCC	Northwest Power and Conservation Council
OPUC	Oregon Public Utilities Commission
PGE	Portland General Electric
PNW	Pacific Northwest
PSE	Puget Sound Energy
TOU	Time of use rate schedule
WUTC	Washington Utilities and Transportation Commission

Executive Summary

This study examines the barriers to the use of "smart grid" technologies and the demand response (DR) programs they enable. It analyzes the DR programs of three utilities: Puget Sound Energy, Portland General Electric and PacifiCorp. The research question is as follows: What state policy, regulatory and utility action will cost-effectively increase the penetration of advanced metering infrastructure (AMI) and time of use (TOU) rates among residential customers of investor-owned utilities in the Pacific Northwest (PNW)?

The PNW is the focus of this study because of its history as a leader in energy efficiency policy, energy technology development and its rapidly changing resource environment. Regulatory and utility leadership and innovation in AMI and TOU would be expected in the PNW given these conditions. However, it is clear that this is not the case.

The thesis of this study is that utilities and regulators should actively encourage the implementation of AMI among investor owned utilities in the PNW to capture operational benefits. Second, utilities and regulators should eliminate the service charge that is charged to TOU rate participants in order to reduce the cost of participating and therefore increase customer participation.

An in-depth case study methodology is employed. It integrates analysis of qualitative and quantitative facts about the chosen cases and the PNW and US electric systems. This study investigates the utilities as individual cases and also makes comparisons across them.

Chapter 1
Barriers to the “Smart Grid”

This study examines the barriers to utility implementation of “smart grid” technologies and the demand response (DR) programs they enable them to carry out. It seeks to identify actions by regulators, policy makers and utilities that will increase the viability of DR programs enabled by specific smart grid technologies. A case study analysis of three such programs results in conceptual policy recommendations and makes a theoretical contribution to existing literature on this topic.

Smart grid technologies are broadly defined as the set of products that utilize information technology to improve the cost efficiency of the generation, transmission, distribution and end use of electricity. They have applications from monitoring, controlling and connecting small scale distributed resources to the electric grid to the digital optimization of transmission, distribution and the end use of electricity. Smart grid technologies can be applied across the entire electric infrastructure to optimize asset use and create new opportunities for energy efficiency and conservation. These innovative solutions have the potential to defer the construction of costly transmission lines and environmentally detrimental fossil fuel generation (DOE 2003: ; GEF 2005: ; Reilly 2003).

1.1 The research question

The research question is as follows: What state policy, regulatory and utility action will cost-effectively increase the penetration of AMI and TOU rates among residential customers of investor-owned utilities in the Pacific Northwest (PNW)? Answering this question for the region speaks to the broader issue of how utilities and regulators can work together to increase the penetration of AMI, TOU rates and ultimately the next generation of technologies and rate structures among all customers in the US. It provides a valuable analysis for a variety of constituencies in the PNW and across the nation.

In order to answer this question, this study will establish the following. It will identify the most significant barriers to AMI and TOU rates among investor-owned utilities in the PNW. It will analyze the causes of these barriers. Ways in which utilities in the region have overcome these barriers will also be analyzed. This will result in recommendations about how these barriers can and should be overcome through legislative and regulatory action as well as utility business choices.

1.2 Statement of the problem

AMI and the DR programs they enable, such as (TOU) rates, can reduce these detrimental effects and reduce the environmental impact of electricity consumption (Kannberg et al 2003: ; NETL 2007b). One of the key benefits of DR, which is explained in greater depth in Chapter 2, is its capability to reduce the amount of generation, transmission and distribution that must be built to serve electricity demand (Kannberg et al 2003: ; NETL 2007b). Reducing peak electricity demands can improve the environmental profile of the electric system because utilities and other electricity producers rely on different types of generation resources to provide different levels of output (Kempton & Tomic 2005a: ; Masters 2004).

Often, those resources that are highest-emitting of sulfur dioxides, carbon dioxide and nitrogen oxides are used to meet peak demand, and those that are used to meet base loads are the newest and most efficient resources (Holland & Mansur 2004: ; Ottinger et al 1990). This is not always the case, however, as different types of resources are used to meet peak loads in different parts of the US (Holland & Mansur 2004). The benefits of shifting peak loads will vary with the type of resource used to meet them, but in most cases, often reducing peak loads will reduce emissions.

AMI is the "enabling technology of the smart grid," which will eventually provide a gateway for a variety of new products and services (Loeff 2007a: par 6). In addition to reducing emissions via demand response programs, AMI can enable utilities to more easily integrate renewable resources into the electric system (Kempton & Tomic 2005a: ; 2005b). It can also help utilities to predict, prevent and solve a number of electric system problems (Loeff 2007b: ; Reilly 2003).

Despite these benefits, the fact that a "smart grid" requires the addition of new technology to the electric infrastructure as well as changes to ratemaking and billing procedures presents serious challenges for electric utilities and their regulators. If utilities cannot recover the costs of their investments in new technologies, these technologies will not be the optimal choice (GEF 2005: ; Reilly 2003). Other barriers include the aversion of electric utilities to adopt new technologies (GEF 2005: ; Reilly 2003). Utilities may charge participants in voluntary demand side management programs to participate, instead of spreading program costs across all customers, which reduces participation, the cost-effectiveness of the programs and the benefits they create for the electric system (Faruqui & George 2006). Additionally, there is no accountability for social and environmental impacts of the electricity grid (Pullins 2006: par 7). Such barriers to the use of smart grid technologies are acknowledged by environmental NGOs (Mazza 2005), research organizations (Faruqui & George 2006: ; Faruqui & Wood 2007: ; GEF 2005: ; Reilly 2003), federal power agencies (BPA 2006), and law firms (Gish 2005).

1.3 Significance of the research

This study has conceptual significance because it seeks to identify economically viable measures that utilities and regulators can implement to facilitate the internalization and reduction of the social and environmental costs of electricity consumption. It builds on existing knowledge of the barriers facing both utility implementation of new technologies and radical change in utility business operations. This study provides conceptual recommendations to regulators about how they can guide programs to optimize economic and environmental benefit in an industry where demand is growing rapidly and resource options are becoming increasingly constrained.

This study is empirically significant because it gathers and analyzes primary data from interviews with utility executives about their TOU programs and compares and analyzes costs across these different programs. The information gathered here will inform other utilities and regulators who seek to implement TOU programs and roll out AMI systems. One of the programs analyzed in this study, which was implemented by

Puget Sound Energy (PSE) in 2000-2001, is often cited in the literature as one of the earliest large-scale utility implementations of a TOU rate schedule in the US (FERC 2006). An original analysis of this program will contribute to existing investigations by revealing data from regulatory filings and information known only by utility executives. A comparison of this utility's program with those of utilities in its same region is also highly useful for future TOU policy decisions in the region and across the country.

This study is of interest to many audiences, including regulators and policymakers across the country and at various levels of government. It will be valuable to regulators and utilities in the Pacific Northwest, especially Oregon and Washington, who are and will continue to be confronted with decisions about AMI and TOU. It will also be valuable for state and local policymakers whose policies affect public utilities and electricity customers in the region. The findings of this study will be of interest in other parts of the US in which AMI as well as other smart grid technologies face similar barriers to implementation.

Energy technology entrepreneurs in the PNW, and the researchers who serve them, may find the results of this study useful to inform the design, pricing and marketing of products. It will also help them understand the utility regulatory landscape and its relationship with AMI and TOU rate schedules. This is important because the PNW has recently emerged as a leader in the development and commercialization of smart energy technologies (Mazza 2005: ; Reilly 2003). Cost information on utility programs may serve as marketing tools and benchmarks for pricing analyses for these companies. Analysts who cover this smart energy sector, especially in the PNW, continue to call for the creation of markets for these technologies in the region (Anderson 2005: ; Pernick

2007). However, they often fail to identify specific actions utilities and regulators should take. This study will provide this industry with policy actions that it can support.

1.4 The argument

This research finds that a low or negative financial benefit for utilities implementing residential TOU rate programs is the most significant barrier to investment in these programs in the PNW. This poor performance is the result of two factors. First, the implementation of advanced meters and communications infrastructure solely for carrying out TOU rate programs has resulted in high costs to utilities. Second, low participation rates among utility customers have also created high costs and resulted in low levels of financial benefit for the implementing utilities. Financial benefits and participation rates are measured as "high" or "low" in comparison to each other. A high benefit can justify high costs and low costs can justify a low benefit. In these particular cases, the level of benefit has not justified the level of cost incurred. Analysis of the causes of this issue is a major component of this study.

The thesis of this paper is that utilities and regulators should carry out the two following actions to increase the cost-effectiveness and value of TOU rate programs as capacity resources in the PNW. First, public utility commissions should actively encourage the implementation of advanced metering infrastructure among investor owned utilities in the region to capture operational benefits. Second, utilities and regulators should eliminate the service charge that is charged to TOU rate participants in order to reduce the cost of participating and therefore increase customer participation.

1.5 Research design

This study employs an in-depth case study methodology to answer the research question and sub-questions presented in this chapter. It integrates analysis of qualitative and quantitative facts about the chosen cases and the PNW and US electric systems. This study investigates the utilities as individual cases and also makes comparisons across them.

The PNW is the focus of this study because of its history as a leader in energy efficiency policy and utility implementation, its leadership in energy technology development and its rapidly changing resource situation. Regulatory and utility leadership and innovation in AMI and TOU rates would be expected in the PNW given the region's highly successful energy efficiency programs and policies (NPCC 2005c: ; 2007a). It might also be expected as a result of the high concentration of energy technology firms in the region, many of which are prevalent in the digital metering and smart grid industry (Itron 2005: ; Mazza 2005: ; Reilly 2003). Additionally, utilities in the region are facing growing peak power demands, which they have not faced in the past (Corson 2007: ; PSE 2007: ; Storrow 2007). Despite these conditions, it is quite clear that innovation with respect to AMI and TOU rates has not been as prevalent or aggressive as it has been with energy efficiency.

This is at least partially due to the fact that peak electricity demands in the region are still of a relatively low magnitude (see Chapter 3). This study agrees with the statement that "DR programs that decrease demand at costs that exceed the willingness of consumers to pay for supply won't be cost-effective and should not be pursued" (Earle & Faruqui 2006: 24). However, this study holds that the cost-ineffectiveness of TOU programs in the PNW is due to many factors in addition to low peak electricity demands in the region. In fact, there are a number of very important factors affecting the success of utility TOU programs over which utilities and regulators have control, and which require exploration. Analyzing these factors is the purpose of this study. To do this, the effect of the low magnitude of peak power demands is held constant in order to determine the effects of these other factors. This results in recommendations based on these findings that will become increasingly relevant as the region's electricity industry becomes more demand-focused.

The three utilities and programs chosen for this study were selected from a population of five investor-owned utilities in Washington and Oregon (Beyer et al 2006: ; WUTC 2007c). Of these five, Avista and Puget Sound Energy (PSE) provide electric service in Washington, Portland General Electric (PGE) and Idaho Power provide service in Oregon, and PacifiCorp provides service in each state (Beyer et al 2006: ; WUTC 2007c). PSE, PGE and PacifiCorp were chosen for this study.

These three were selected for two reasons. First, these utilities serve the most customers in each state and so their actions have the greatest effect on consumers, policy and the environment. PacifiCorp and PGE together serve over 98% of customers who purchase electricity from investor owned utilities in Oregon (Beyer et al 2006: 9; WUTC 2007c). PSE serves over 70% in Washington (WUTC 2007c).

Second, these utilities were selected because they differ across a number of relevant variables, which enables a robust and useful comparison. These variables include size of service territory, size of business, resource mix and customer demographics. PSE and PGE each have electricity operations in one state, and largely serve urban customers in relatively population-dense service territories (PGE 2007b: ; PSE 2001a). By contrast, PacifiCorp has operations in seven states and mostly serves rural customers across a less population-dense service territory (PacifiCorp 2006a). During the time of its program, PSE had the greatest exposure to the market price of electricity of the three utilities (PSE 2001a). PacifiCorp, owning the majority of its own generation resources, faces much lower exposure while PGE faces a level of exposure somewhere in between the two (PacifiCorp 2006a: ; PGE 2007b). Another difference among the utilities that is useful for this analysis is the existence or non-existence of an advanced metering infrastructure at the initiation of their programs. PSE had an advanced metering system in place when its TOU program began (Englert 2007a). PGE and PacifiCorp did not (Carpenter 2007b: ; Marx 2007b). PacifiCorp has no plans to roll out an AMI system, while PGE has decided to roll out an AMI system over the next few years (Carpenter & Tooman 2007a: ; Marx 2007b).

Table 1.1: Summary of utility size and operations

	Service territory (sq mi)	No of residential customers	Annual revenue	Electricity from short-term purchases	Electricity from own generation
PSE	6,000	925,000	$1.4 Billion	25%	34%
PGE	4,000	697,840	$1.3 Billion	10%	31%
PacifiCorp	136,000*	460,000**	$2.9 Billion***	17%	76%

*All states
**Oregon Only
***All operations

Evidence was gathered directly from the utilities studied, their regulatory bodies and from the analyses of other researchers. The main form of evidence used in this study is in-depth interviews with executives at each utility, a policy analyst at the WUTC and resource economists at the Northwest Power and Conservation Council (see Table 1.2). These interviews provide information about the costs incurred under the TOU rate programs, the causes of the low participation rates, expert opinions on the future of the regional electricity system, and historical facts about regulatory decisions. Data from regulatory filings and reports provided by the OPUC and WUTC is also used as evidence. These filings and reports provide factual information about the timing of events, the details of utility TOU programs, and the rationale behind various regulatory decisions. They also provide quantitative data on participation rates, participant satisfaction and the economic and energy impacts of these programs.

Table 1.2: Interview subjects

Interview Subject	Organization	Organization Type	Position at Organization
Jesse Berst	Global Smart Energy	Smart energy technology market research firm	Managing editor
Stan Price	Northwest Energy Efficiency Council	Energy-efficiency NGO	Executive director
Ken Corum	Northwest Power and Conservation Council	Regional energy planning organization	Senior economist
Maury Galbraith	Northwest Power and Conservation Council	Regional energy planning organization	Resource analyst
Charlie Grist	Northwest Power and Conservation Council	Regional energy planning organization	Senior analyst
Jeff Bumgarner	PacifiCorp	Utility	Director of demand-side management
Bruce Carpenter	Portland General Electric	Utility	Manager of revenue operations
Conrad Eustis	Portland General Electric	Utility	Director of retail technology development
Laura Rooke	Portland General Electric	Utility	Manager of demand-side management
John McClaine	Puget Sound Energy	Utility	Manager of energy information infrastructure
Eric Englert	Puget Sound Energy	Utility	Manager, Regulatory Initiatives & Tariffs
Dick Byers	Washington Utilities and Transportation Commission	Public utility commission	Senior policy analyst
Douglas Marx	PacifiCorp	Utility	Director of Metering Assets

1.6 Chapter summary

Chapter 2 introduces relevant details about the US electric industry. It explains energy efficiency, DR programs and the technologies that enable DR programs. It then reviews the literature on the financial, cultural, technical and regulatory barriers to smart grid technologies, energy efficiency programs, DR programs and general theory about radical technological change in the electricity industry. It determines the barriers shared by energy efficiency and DR and provides a theoretical framework for analyzing demand side management programs in investor owned electric power utilities. Chapter 3 provides background on the PNW electric industry and describes the cases that are the focus of this study. Chapter 4 analyzes primary data on the barriers to the implementation of AMI and TOU rate programs among the cases. Chapter 5 uses the results of this analysis to relate this study to the literature. It summarizes the findings and makes recommendations for PNW regulators and utilities based on these findings. It concludes by contextualizing the cases studied among national AMI and TOU implementations. It argues that PNW regulators and policymakers should encourage the implementation of AMI and TOU in order to spur the growth of the smart energy technology sector in the PNW.

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Chapter 2
A Review of the Literature on Smart Grid Technology, Energy Efficiency and Utility Business Models

The literature finds that advanced metering infrastructure (AMI) and time of use (TOU) rates face barriers to their use by investor owned electric utilities. These may include revenue loss, inefficient allocation of costs and benefits across participating customers, the inability of utilities to gain cost recovery on investments, differing regulations across state boundaries, uncertainty with regard to technical risks, electric utilities' buying practices, and their aversion to radical change. Some of these barriers are unique to the advent and commercialization of AMI and dynamic rate schedules. Some have a history of hindering energy efficiency programs. A review of the literature shows that some of those barriers faced by both may be a product of the investor-owned utility business models and regulatory environment in most of the US. It also shows that AMI and TOU rates face their own set of challenges, which may require innovative new solutions that have not been used to overcome those faced by energy efficiency.

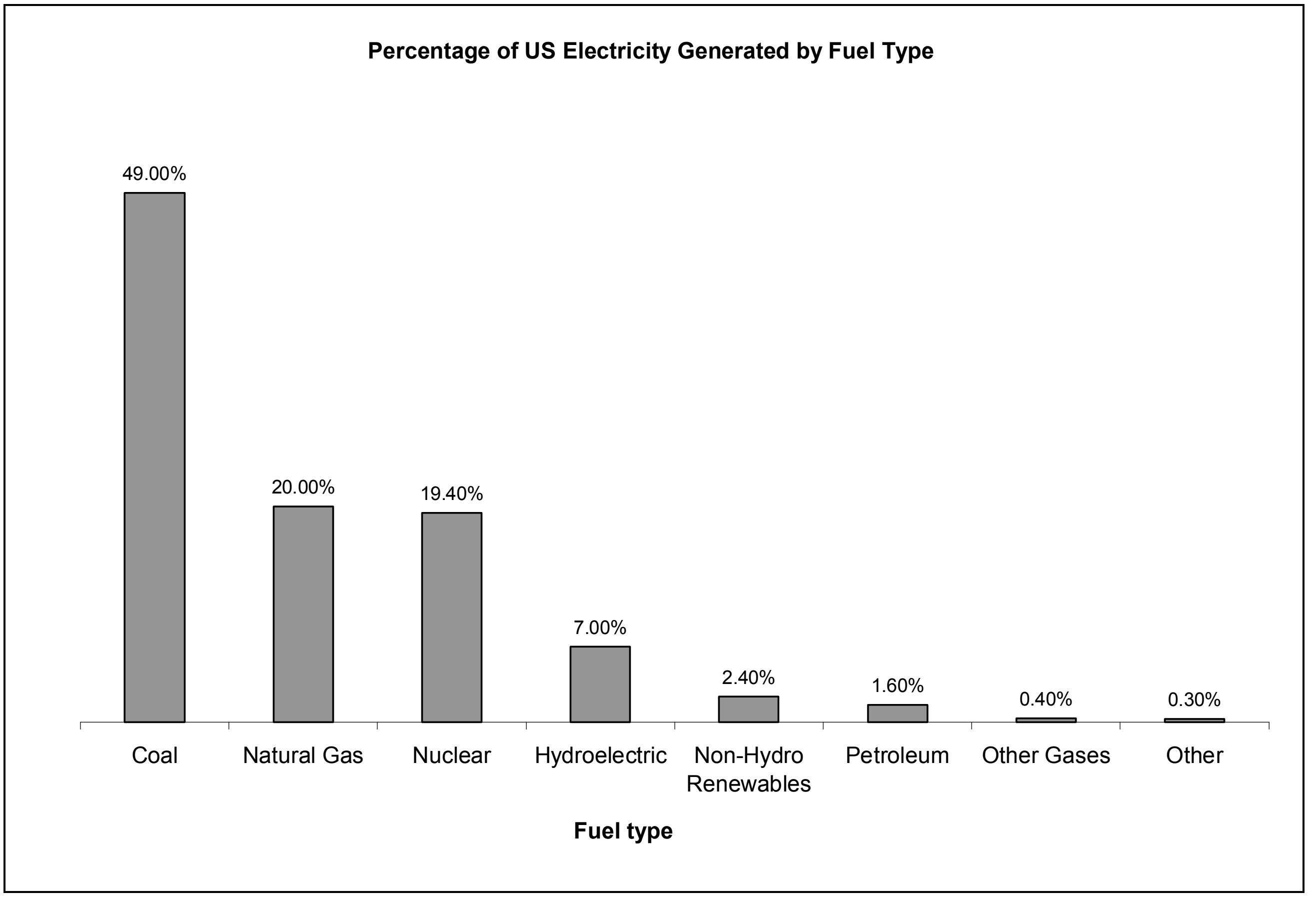
This review presents the findings to which this study can be compared. In the following chapters evidence is presented to support, critique and add to the results shown here with analysis from a specific region, regulatory environment and specific utilities. This implies that other research can be applied to solve problems in this region. Most importantly, it enables this study to add to the body of knowledge on electric utility implementation of AMI and TOU rate programs.

This review begins with a brief background on the US electric system. It then describes the set of technologies that have been labeled "smart grid" technologies. TOU rates, which are a form of price-based DR, and AMI, which is necessary to implement these schedules and other DR programs, are explained. The similarities and differences between DR and energy efficiency programs are explained. Relevant aspects of the electric utility business model are introduced and their implications for utility decision-making processes with respect to investments in efficiency and DR are discussed. The relevant barriers to utility implementation of TOU rates and energy efficiency that have been identified in the literature are then summarized and compared. Finally, the contribution of this work is explained in light of the existing literature and knowledge of AMI and TOU rates.

2.1 The US electric system

The US electric system relies on large, centralized generation resources (EIA 2006: ; Faruqui 2007a: 48; NETL 2007a: 5). Energy from distributed generation makes up only 3% of the total electricity supply (NETL 2007a: 5). The majority is supplied by electric utilities and independent electricity producers (EIA 2006). Annual sales in the US electric industry are over $320 billion dollars (EIA 2007c). Of this, 43% are sales of electricity to residential customers, 37% to commercial, and 19% to industrial customers (EIA 2007b). Note that most electricity is provided by fossil fuel generating plants (see Figure 2.1) (EIA 2006). It is proven that the carbon dioxide, sulfur dioxide and nitrogen oxide emissions that result from electricity generated by fossil-fuel fired power plants are tremendous (Hester & Harrison 1999: ; Sims et al 2003).

Figure 2.1: Percentage of US electricity generated by fuel type



There are over 3,000 electric utilities in the US (EIA 2001). As of 2001, 240 were investor-owned utilities (EIA 2001). Over 2,000 were publicly-owned by non-federal governments and the remainder were federally and cooperatively owned utilities (EIA 2001). Although they only make up 7% of the total number of utilities in the US, investor-owned utilities serve the majority of customers, sell the majority of the electricity and own the majority of the assets (EIA 2001: ; GEF 2005).

The US electric system for the most part does not utilize customer demand shifts or distributed generation as energy or capacity resources (Faruqui 2007a: 48). Among US investor-owned electricity customers, only 5.7% have the enabling technology installed at their residences or facilities (FERC 2006: 26). Among utilities that have the technology in place, only 15% use it for price-responsive DR programs (FERC 2006: 31). This means a very small portion of investor-owned utilities in the US have price-responsive DR programs (FERC 2006: 31).

2.2 Low utilization, high costs

The US electric system as a whole is overbuilt and underutilized. Some generation, transmission and distribution resources constructed are used for only a small percentage of the total hours in a year (Berst 2007b: ; Masters 2004: 141; Mazza 2003). This is a product of the fact that the system must accommodate daily and seasonal demand flux. Also, the system must be built with a "capacity margin" above the peak of this flux to accommodate generation and transmission outages and other extreme events (Kannberg et al 2003: 4; Masters 2004). [1]

Underutilization results in the construction of power plants solely to meet peak demand, which are more costly than those used to meet base load demand (Kannberg et al 2003: ; Masters 2004: ; Oren et al 1985). "Baseload" power plants (most often coal or nuclear in the US) operate non-stop, and have high capital costs and low operating costs (Kempton & Tomic 2005a: ; Masters 2004). "Peaking" plants (generally gas turbines) are run to meet peak demand and have low capital costs and high operating costs (Kempton & Tomic 2005a: ; Masters 2004). A plant's costs are recouped by revenues from its operations, so it is optimal to build high capital cost plants to serve consistent demand and low capital cost plants to serve intermittent demand (Kempton & Tomic

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[1] The capacity margin, reserve margin or reserve capacity is defined as follows: "A measure of available capacity over and above the capacity needed to meet normal peak demand levels" (EnergyVortex 2007b).

2005a: ; Masters 2004). Peaking plants must be built, but are used for only a small percentage of the year (Faruqui et al 2007: 2; Kempton & Tomic 2005a). As a result, one utility executive noted, “that peak can cost millions” (Carpenter 2007b).

Annual *load duration curves* (LDCs) for the US electric system demonstrate that the system’s capacity is underutilized (Kannberg et al 2003: 5; Masters 2004: 141). LDCs show the duration in hours of a particular level of demand on an electric system, which is measured in kilowatts (kWs). LDCs are created by lining up the hours of the year in chronological order, and creating a data point at the amount of power demanded at each hour of the year. These hours are then reordered from highest to lowest kW demand (see Figure 2.2). The result shows how many hours per year the demand is equal to or above a particular level (Masters 2004: 141). The total area under the curve is equal to the total amount of electricity used in the system over a year (Masters 2004: 141). A simulated average LDC for a US electric system appears in Figure 2.3. It demonstrates how some power plants and transmission infrastructure are operated at highest capacity for a relatively small percentage of the hours out of the year compared with the number of hours they are operated at less than peak capacity. Distribution assets are also underutilized and their LDCs have shapes similar to those of generation assets (Kannberg et al 2003: 5).

Figure 2.2: Creating a load duration curve (Masters 2004: 141)

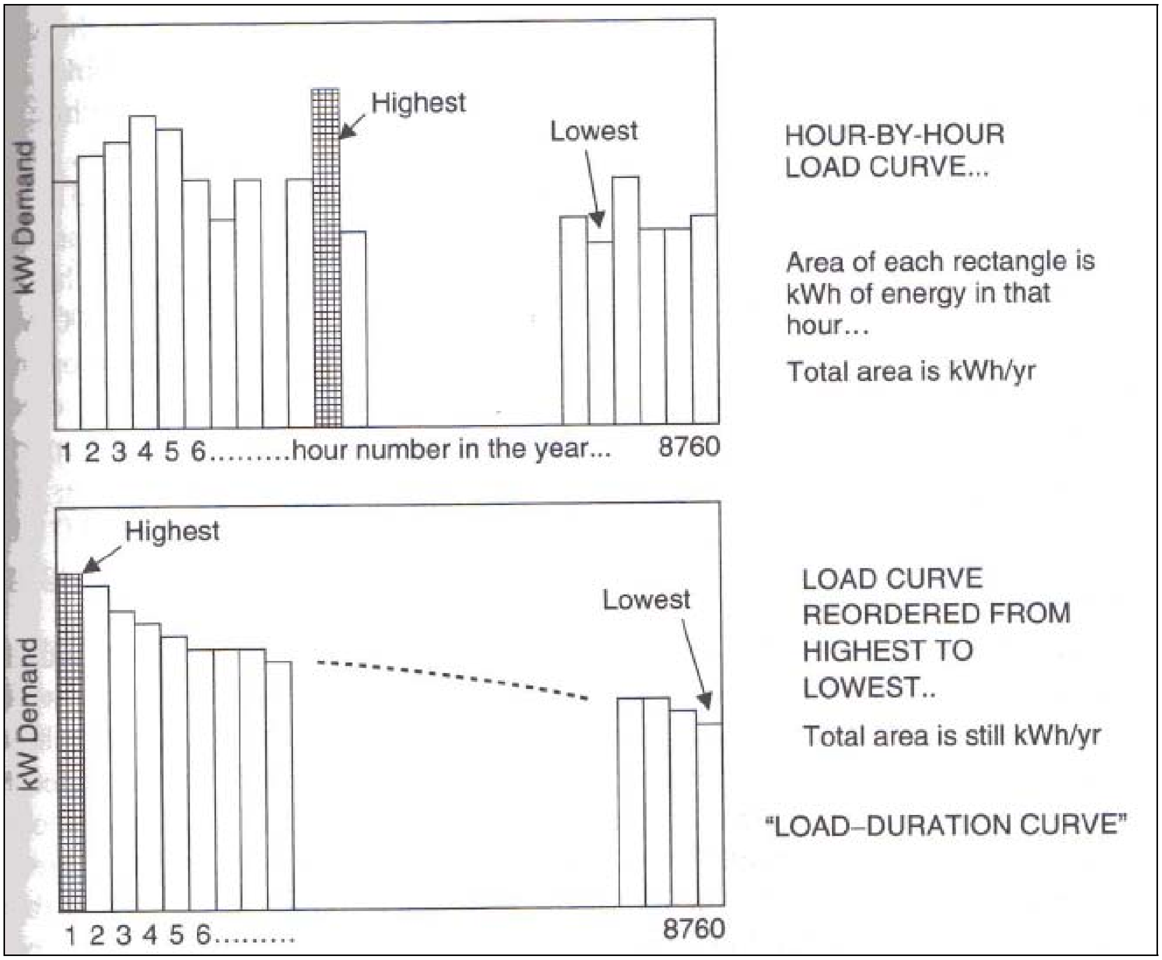
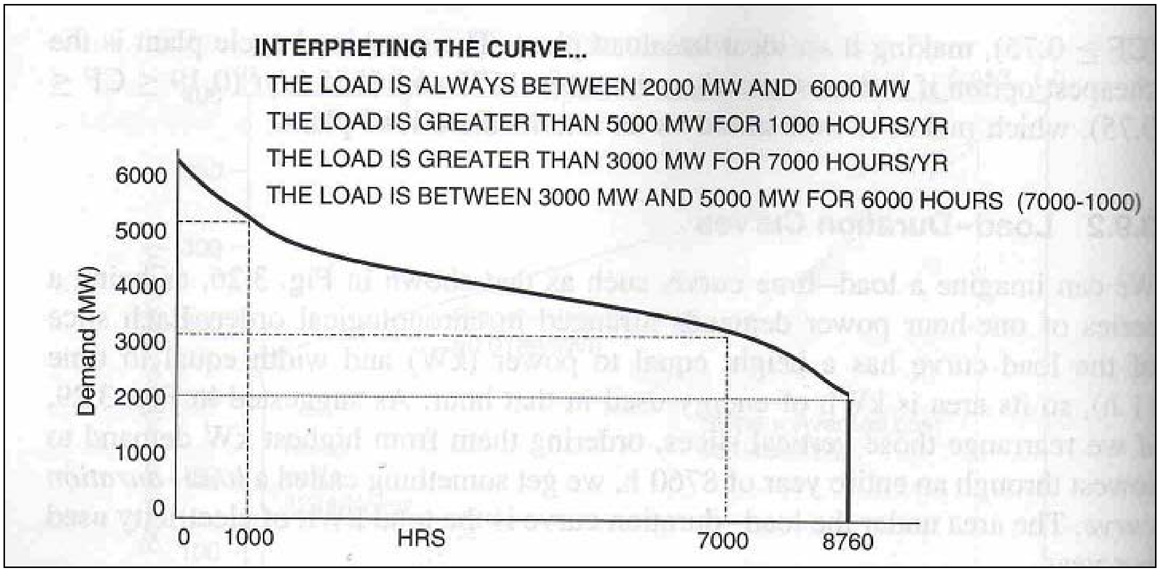


Figure 2.3: Interpreting a load duration curve (Masters 2004: 141)



Reducing the magnitude of peak demand saves utilities (and therefore customers) money partially because it reduces the amount of these resources necessary to meet growing demand (Faruqui et al 2007: 4-5; Kannberg et al 2003: 12; Masters 2004: 141). Investment in programs that shift demand from on peak to off peak times can help utilities to meet growing demand with less generation, transmission and distribution resources (Faruqui et al 2007: ; Kannberg et al 2003: 12).

2.3 The role of demand response

To directly shift load or induce shifts in customer behavior, utilities invest in demand response (DR) (Schwartz 2003: 5-9). DR is defined by the Federal Energy Regulatory Commission as

> Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized. (FERC 2006: 5)

Many types of programs can be implemented to shift customer demand (Faruqui 2007b: ; Schwartz 2003). Utilities and other organizations can install devices that control the operations of customers' appliances or equipment (El-Amin et al 1999: ; Schwartz 2007: 7-9). They can pay customers to reduce demand during individual events (Herter 2007). They can charge different prices at different times of day or times of year to give customers an incentive to shift energy usage away from a particular time (Schwartz 2007: 5). Customers who participate in demand response programs accept a higher level of risk than those on flat rate schedules by exposing themselves to some of the variance in electricity price throughout the day (Faruqui 2007b: ; Faruqui & Wood 2007). Customers are compensated with the opportunity to save money through load shifting (Faruqui 2007b).

A relatively popular type of DR, and that which is the focus of this study, is time of use (TOU) rates. TOU rates differ from "flat" rates in that the price charged to customers changes throughout the day (Du Bois 2006: ; Faruqui et al 2007). TOU rates are generally highest when total customer consumption is highest (Faruqui et al 2007: ; Schwartz 2003: 5). This gives customers an incentive to reduce consumption during these times, and shift it to periods when total consumption on the system is lower (Faruqui et al 2007: 2). The result is a "flatter" LDC. This means that utilities no longer need to purchase or generate as much peak electricity to serve demand. In pilot programs across the US, TOU rates have successfully reduced customer consumption during demand peaks as well as overall customer consumption (Herter 2007: ; King & Delurey 2005: ; Spees & Lave 2007: 76).

In principle, TOU rates signal customers with the varying cost of power throughout the day (FERC 2006: 11-2, 76). Under flat rate schedules, most customers are charged based on their total consumption over the billing period and their peak demand over a billing period (Cassazza & Delea 2003: 44). TOU rates signal customers with prices that more closely approximate what utilities pay for electricity at different times throughout the day (Cassazza & Delea 2003: 44; Faruqui et al 2007: 3).

2.4 "Smart grid" technologies and the role of advanced metering infrastructure (AMI)

"Smart grid" technologies have been identified over the past few years as a broad set of products and services that utilize information technology to improve the utilization of generation, transmission, distribution and end use of electricity (GEF 2005: ; Mazza 2005: ; Reilly 2003). These technologies have applications from monitoring, controlling and connecting small scale distributed resources to the power grid to the digital optimization of transmission, distribution and end use of electric power (GEF 2005: ; Mazza 2005: ; Reilly 2003). They can be applied across the entire electric infrastructure to reduce costs, create new opportunities for efficiency and conservation, and increase the reliability of the energy system (DOE 2003: ; GEF 2005: ; Reilly 2003). Some of these applications can enable utilities to defer the construction of costly and environmentally detrimental transmission lines and fossil fuel-based generation (DOE 2003: ; GEF 2005: ; Reilly 2003).

This set of technologies may some day transform the electric industry with the introduction of new products and services, which will have several overarching characteristics identified by the Pacific Northwest National Laboratory and the National Energy Technology Lab (GEF 2005: 2; NETL 2007c). A smart grid is and will be "self-healing," and able to rapidly detect, analyze, respond to and restore itself from perturbations (NETL 2007c). It will "empower and incorporate the consumer" to the design, operation, supply and management of electricity and the electric system (NETL 2007c). The smart grid will integrate a wide variety of generation sources, including renewable electricity sources (NETL 2007a). The smart grid can facilitate an increased utilization of generation, transmission and distribution infrastructure (GEF 2005: 2; Kannberg et al 2003: ; NETL 2007c).

AMI falls under the umbrella of smart energy and is the focus of this study because it can enable many types of DR programs (Levy et al 2004). AMI can be used to record consumption levels at intervals throughout the day so customers can be charged different rates at different times of day (Levy et al 2004). Currently, consumption data are collected from the majority of US electric meters only once a month, when the meter reader arrives (FERC 2006: vi). To read customer meters more often requires the installation of new meters with communications capabilities (Levy et al 2004). These are advanced meters (Levy et al 2004). To collect, store and process this data requires new meter reading and data management systems, as well (FERC 2006). This entire system is called AMI. For the purposes of this study, it is formally defined as the "…full measurement and collection system, including customer meters, communication networks, and data management systems" that enable utilities to measure customer electricity consumption for TOU rates (FERC 2006: 17-8).

AMI can use a variety of platforms and can have a variety of capabilities. It can transfer information between customers and utilities via cellular networks, radio frequency, paging systems, power line carriers, or cables (GSE 2006: 23). All AMI systems support full two-way communication to the meter. Some have the capability to automatically disconnect the customer from the grid for non-payment, and others make a variety of measurements (GSE 2006: 23). Others can be used to send control commands to systems within buildings to reduce demand (GSE 2006: 23).

AMI can provide utilities many other benefits in addition to the ability to implement demand response (King 2006). It can enable utilities to pinpoint power outages and the sources of technical problems on their systems (Carpenter 2007b: ; King 2006: 10). It can reduce the cost of meter reading and increase meter reading accuracy (Carpenter 2007b: ; Cummins 2007). Furthermore, expenditures on technology that reads meters are capitalized, while expenditures for traditional meter reading are expensed (Carpenter 2007b). Capital expenditures are long lived investments on which utilities earn a rate of return. Expenses do not earn a rate of return (Corum & Galbraith 2007). Money spent on technology that reads meters automatically earns a rate of return while money spent on salaries for meter readers does not (Carpenter 2007b).

2.5 Energy efficiency

The US federal government and many US states have mandated energy efficiency programs in various forms and various regions for over thirty years (Kushler et al 2006: ; Nadel & Kushler 2000: ; Prindle et al 2003). Early on, programs were initiated in response to the high cost of generation fuel in the 1970s (Prindle et al 2003: iii). In the 1990s, energy efficiency reemerged in response to environmental concerns, electric system reliability problems and energy price spikes (Nadel & Kushler 2000: ; Prindle et al 2003: iii). These programs have consisted of the mandating, marketing and/or funding of the purchase and use of energy-efficient appliances, lighting, or building materials in the commercial, residential and industrial sectors (Gellings et al 2006: 55-6).

2.6 Demand response vs energy efficiency

DR programs, such as TOU rates, differ from energy efficiency programs in important ways. The primary purpose of demand response programs is to “shift” electricity use to “off-peak” times of day, and may also result in reductions in the amount of energy consumed by end users or (King & Delurey 2005: ; Spees & Lave 2007). Energy efficiency programs are intended to reduce the amount of energy consumed (Prindle et al 2003). Both alter end use of electricity in order to defer the construction of traditional generation and transmission resources (Faruqui et al 2007: ; Prindle et al 2003).

Energy efficiency and DR also differ in the level of infrastructure change necessary for their implementation. Energy efficiency does not involve radical changes to the electricity infrastructure owned by the utilities, and for the most part, it does not involve active, real-time management of electricity resources by a utility, transmission organization or customer (Gellings et al 2006: ; Prindle et al 2003: iv). Energy efficiency programs improve the efficiency of end use equipment (Gellings et al 2006). By contrast, DR requires changes to infrastructure owned by utilities and business operations carried out by them (King & Delurey 2005: ; Levy et al 2004). These include the implementation of new meters, data management systems, rate structures, and billing and planning operations (King 2006: ; NETL 2007c).

As a result, one of the most important differences between energy efficiency and DR is that energy efficiency programs can be added to utility operations without changes to billing processes and the electricity infrastructure owned by the utility (Gellings et al 2006: ; York & Kushler 2005). The implementation of AMI and DR requires not only an enormous capital investment, but also change to existing business operations and systems (Kannberg et al 2003: ; King 2006: ; NETL 2007c). These differences limit the comparisons that can be made between barriers to efficiency and smart energy.

2.7 Financial barriers to energy efficiency and demand response

For most electric utilities, profits are tied to sales, and therefore reductions in customer electricity consumption reduce revenues and prevent utilities from recovering forecasted revenue if policies are not in place to mitigate these effects (Kushler et al 2004: ; 2006: ; Vine et al 2003). Recovering the costs of investments is important so utilities focus on ways to reduce costs (Kushler et al 2006: ; Vine et al 2003). There is an incentive to sell as much electricity as possible unless the marginal cost of supplying a kWh is greater than the revenue received from supplying it (Vine et al 2003: 409). As a result, revenue losses from demand side management programs must be recouped via policy mechanisms to help utilities recover these costs (Kushler et al 2002: ; Kushler et al 2004: ; 2006: ; Nadel & Kushler 2000: ; NPCC 2007a). In the absence of well-functioning mechanisms to overcome this barrier, investments in demand side management by US utilities have been low, even when such programs have been the most cost-effective resource for serving demand (Kannberg et al 2003: ; Kushler et al 2004: ; 2006: ; Nadel & Kushler 2000: ; Vine et al 2003).

DR programs do not always result in reductions in energy consumption, so they do not always face this revenue loss barrier (EEE 2006). In some cases, DR programs even result in *increases* in total energy consumption when participating customers increase off-peak consumption (EEE 2006: ; King & Delurey 2005). When there is no reduction in total energy consumption, and when costs and rates are in alignment—the rate charged for on-peak electricity is equal to the cost of supplying it—utilities do not suffer economic losses from customer load shifts (Faruqui & Wood 2007). This is because when a customer shifts a kWh of electricity consumption to an off-peak time of day, the revenue the utility would have received from supplying that kWh theoretically equals the cost of supplying it (Faruqui & Wood 2007).

The "conservation effect" is observed when demand response results in reductions in total electricity consumption (King & Delurey 2005). Although conservation is not the primary objective of DR, a review of over 200 DR programs across the US found that the majority do have some conservation effect, although the magnitude of the effect varies widely across different programs (King & Delurey 2005). When the conservation effect occurs, lost revenues must be recovered in order for a utility to consider DR as economically preferable to other resources (Faruqui & Wood 2007).

2.8 Regulatory barriers

Utilities must not only gain full cost recovery on investments as noted above, but also a return on investment for money spent (Vine et al 2003). This return on equity must be high enough to attract capital for further investment (Braithwait et al 2006). Investments in new technology is therefore heavily dependent on regulatory outcomes:

> [Investor owned utilities'] technology choices are strongly influenced by regulation — either mandates that force the utility in one direction, or policies that limit what they can recover through rates. IOUs hesitate on technology purchases

> if it is unclear whether regulators will allow them to recover the investment in their rates. (GEF 2005: 18)

When a utility does not find it economically viable to implement AMI, yet regulators find there is good reason for utilities to implement, they can allow cost recovery and direct utility actions (EEI 2006). Regulators may have a number of reasons why they require utilities to implement AMI, which are independent of AMI's value to the utility (EEI 2006).

A second regulatory barrier is that variability of regulatory standards across many states may prevent utilities from implementing a variety of smart grid technologies (Reilly 2003). The US energy system spreads across state boundaries, and each state has its own regulatory standards. This "patchwork" of standards makes it difficult for utilities with operations in different states to implement large-scale change (Berst 2007b: ; Reilly 2003: 22). Utilities may require multiple regulatory approvals to invest in new technology (GEF 2005: 14).

2.9 Customer participation and the allocation of benefits

Utilities with voluntary DR programs may inefficiently allocate the costs of the programs. Although DR programs create benefits for all customers, sometimes only the participants pay to cover the costs, which may eliminate or severely reduce the size of the incentive these programs provide for customers to participate (Faruqui & George 2006: ; Goldman et al 2006). When customers do not have the opportunity to save very much money, few participate, and only a small amount of peak consumption is shifted to off-peak times (Goldman et al 2006: ; King & Delurey 2005). This prevents the program from creating significant benefit for a utility and all of its customers (Goldman et al 2006).

DR theoretically creates a benefit for all customers by reducing the cost of supplying electricity for the utility (Boisvert et al 2002). However, there are costs associated with setting up and running the programs (Faruqui 2007b: ; Sioshansi & Vojdani 2001). Reductions in energy use that create revenue loss for a utility may also be considered a "cost," which must be recovered (Faruqui 2007b). If the costs of a program are passed only to participants and eliminate or severely reduce participants' savings, then the incentive to participate disappears (Faruqui & Wood 2007). Theoretically, it is economically efficient to spread the costs of a program across all those customers who receive a benefit. However, this does not always occur (Faruqui & Wood 2007). This barrier may be overcome by implementing mechanisms to charge all customers who receive a benefit from a program a small amount, participants and non-participants alike (Faruqui 2007b: ; Faruqui & George 2006: ; Goldman et al 2006).

However, there is contention over whether or not non-participants should cover the cost of DR programs. Brathwait finds that DR programs will not reduce the cost of electricity for all customers, therefore non-participants should not be liable for the cost of the programs (2003). The author claims that this is due to the fact that many utilities have contracts for electricity to hedge against price volatility, in which case reducing peak loads provides no economic benefit (Braithwait 2003).

Additionally, he claims that demand provides a signal for investment in generation (Braithwait 2003). If DR reduces peak demand, less generation will be built, the relative scarcity of capacity will remain constant, and capacity costs will not decline

(2003). This argument is important to notice, however it seems to contrast with the fundamental fact that resources utilized only a small percentage of the year are most costly to operate (Faruqui et al 2007: 2; Kempton & Tomic 2005a). Most authors hold that a flattened LDC will reduce costs by increasing the amount of load served by highly utilized, and therefore less costly, generating plants (Faruqui et al 2007: 2; Kempton & Tomic 2005a).

2.10 Technical barriers

In addition to the barriers cited above, new technologies deployed by utilities must meet a large number of technical requirements (Markard & Truffer 2006: 611). Markard and Truffer (2006) find that electric utilities have an inherent aversion to new, innovative technologies. They believe this is because electric power systems are *large technical systems*, which are

> . . . complex and heterogenous systems of physical structure and complex machinery which (1) are materially integrated, or 'coupled' over large spans of space and time . . . and (2) support or sustain the functioning of very large numbers of other technical systems . . .(Joerges 1998: ; Markard & Truffer 2006: 610)

These authors argue that these systems are strongly interdependent among their component parts, which makes radical innovation difficult.

The technical complexity of these systems necessarily results in incremental innovations on existing technologies instead of radical changes in the absence of external pressures (Sine & David 2003). This is attributed to the fact that new technologies must meet a wide variety of requirements from existing infrastructure in addition to meeting customer needs (Markard & Truffer 2006: ; Sine & David 2003).

While this aversion to change is the product of the technical complexity of systems, the literature suggests it is also a cultural barrier. It may persist not only because change is technically difficult or impossible, but also because utilities do not seek out opportunities for change. The next section addresses this concept.

2.11 Cultural barriers

The literature states that smart grid technologies and energy efficiency are susceptible to electric power utilities' general risk avoidance. Markard and Truffer (2006) find that this is a general barrier to innovation in the electric system. First, with respect to smart grid technologies, GEF (2005) quotes an electric industry analyst who says that utilities have a business "…culture that is, to put it politely, disinclined to use (and certainly not to seek out) new technologies" (16). GEF (2005) also states that utilities have a strong preference for "home grown" solutions to infrastructure problems, which disadvantages smart energy technologies developed and commercialized externally (16). This may result from the fact that new technologies must meet a large number of technical requirements for their adoption in electric power systems (Markard & Truffer 2006).

Second, Reilly (2003) cites the US DOE's *Grid 2030* report, which states that utilities perceive a high level of technical risk in investments in smart energy technology (DOE 2003). He finds that the electric power industry is very cautious about taking risks on new technologies.

The purchasing behavior of electric utilities may also prevent them from buying from the small companies that manufacture innovative energy technology. Reilly (2003) states that because utilities are large, bureaucratic organizations, they generally tend to impose long test periods on new technologies (25-6). Markard and Truffer (2006: 611) find that this is the "prevailing paradigm" that governs purchasing behaviors and limits the ability of utilities to seek out innovative new solutions. Electric utilities may not be willing to take risks by changing the vendors from which they buy (Reilly 2003: 24).

2.12 The state of knowledge

It has been established that barriers to conservation and radical technological change are inherent in utility commercial business goals. Lost revenues from energy efficiency and can disadvantage investments in these resources compared with other generation, transmission and distribution resources. They may also fail to receive regulatory approval. A review of the DR and energy efficiency literature reveals that DR and AMI share some of these barriers with energy efficiency, and also face their own set. From this review, a few conclusions can be drawn.

First, barriers to the adoption of energy efficiency and DR are inherent in the business models of investor-owned electric utilities. Like any other for-profit business, utilities must cover the cost of their operations and attract capital. Investments that prevent this or that reduce revenues will not be made. Investor-owned utilities in the US are generally regulated with regard to rates and expenditures and as a result, large scale investments must meet with regulatory approval. The regulator therefore has the ability to limit activities and investments as well as promote certain programs.

Second, although voluntary DR programs create a benefit for the entire electric system, associated costs are often recouped only from participants. This limits their incentive to participate and as a result, they may not participate. Some authors propose that spreading the costs across all customers who receive a benefit from DR will eliminate this problem and is a more efficient allocation of costs and benefits. When all customers receive benefits from a program, all customers should help to cover its costs.

Third, the fact that a utility's activities are heavily regulated, and regulations are set at the state level, presents a special challenge for utilities with operations in multiple states. These utilities face this uncertainty in multiple places in their service territory. As a result, they are particularly unlikely to implement radical, enterprise-wide change, such as the implementation of smart energy technologies or new rate schedules.

Finally, due to the size of utilities as businesses, the technical complexity of their systems and their essential role in the operation of modern society, they are particularly averse to radical technical and business process change. Utilities prefer incremental change. Additionally, the literature finds that utilities have an affinity for "home grown" systems and solutions, which disadvantages new technologies and systems.

2.13 The contribution of this study

This study identifies barriers to the implementation of AMI and TOU rate programs in the PNW. The region has historically innovated in energy policy and is technically equipped to implement these technologies and programs. Additionally, its resource environment is rapidly changing. These factors, along with the diversity of attributes among the utilities studied, provide a context in which each of the barriers mentioned here can be explored, and new barriers can be identified.

This study makes recommendations based on this analysis to inform future regulations and utility actions. It contributes to the academic literature reviewed here by testing its assertions. Most importantly, this study provides information and analysis to guide the region's utility and regulatory decision makers.

In order to successfully make this contribution, this study identifies the mechanisms by which general barriers found in the literature function among the utilities. It is not only determined if these barriers exist, but also why they exist and how they function. This also refines the state of the knowledge in the literature by generating a set of regulatory and business conditions under which these barriers work.

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Chapter 3
Hydro-Eclectic: The Pacific Northwest Electric Industry

This chapter provides a brief background on some of the key actors and a general explanation of the unique physical attributes of the Pacific Northwest (PNW) electric system. The major actors are explained to situate the cases in this study in the regional context. The fundamental differences between the region's electric system and those across the rest of the country are explained. Four trends that are shaping the regional resource environment then explained. The utilities that are the focus of this study are introduced and background information on each is provided.

3.1 Utilities, regulators and the Northwest Power and Conservation Council

Electricity customers in Washington (WA) and Oregon (OR) are served by 5 investor-owned electric utilities, one of which, PacifiCorp, serves customers in both states (Beyer et al 2006: ; WUTC 2007a). A number of municipally-owned utilities also serve customers in these states (Beyer et al 2006). WA customers are served by Puget Sound Energy (PSE), Avista and PacifiCorp (WUTC 2007a). OR customers are served by Portland General Electric (PGE), PacifiCorp and Idaho Power (Beyer et al 2006). In WA, PSE serves more customers than Avista and PacifiCorp combined by a factor of two (WUTC 2007a). PGE and PacifiCorp serve the majority of the customers who receive electricity from investor-owned utilities in OR (Beyer et al 2006).

Utilities in the PNW must recover the costs of their operations—generation, transmission and distribution (Buckley 2007). Electricity is provided by utilities from their own generation assets, those of government owned utilities, private generators or the

Bonneville Power Administration (NPCC 2007a). The Bonneville Power Administration also owns the majority of the transmission in Oregon and Washington states (Buckley 2007). The sources of energy of the utilities examined in this study are explained in greater depth below.

Investor-owned utilities in each state are regulated by their respective state public utility commissions. In WA, this is the Washington Utilities and Transportation Commission (WUTC) (WUTC 2007a). Utilities in OR are regulated by the Oregon Public Utilities Commission (OPUC) (Beyer et al 2006).

In addition to the state regulatory commissions, utilities actions are supported and to some extent guided by The Northwest Power and Conservation Council (NPCC) (NPCC 2007a). Neither a federal nor state agency, the NPCC is an "interstate compact agency," which guides electricity and natural resources decisions in the PNW (NPCC 2007a: 33). The NPCC is charged with the development of a regional power plan to "assure the Pacific Northwest an adequate, efficient, economical and reliable power supply" (NPCC 2007a: 12). One of the NPCC's primary roles is to plan various aspects of the hydroelectric system use and resource allocation in the PNW (NPCC 2007a). The Bonneville Power Administration, the federal agency that manages the vast hydroelectric system in the Columbia River Basin, is obligated to act consistently with the NPCC's power and natural resource planning (NPCC 2007a).

3.2 Physical attributes of PNW electric systems

Electric systems in the PNW are fundamentally different from those in the rest of the US. Although resource mix varies by utility, a vast hydroelectric system provides over 50% of the electricity supply for the region (NPCC 2007a: 3,5). The remainder is supplied by coal (20%), natural gas (21%), nuclear (3%), biomass (3%) and wind (1%) (NPCC 2005a: 2-5). Another important fact is that there is a low penetration of air-conditioning in the PNW (Carpenter 2007a: ; Casola et al 2005: 24; Corum & Galbraith 2007). The combination of the vast hydroelectric resource and the small amount of air conditioning results in a relatively low difference between the cost of supplying electricity when demand is highest and when demand is lowest compared to the rest of the nation (Byers 2007: ; Carpenter 2007b).

The hydroelectric system is a unique electricity resource because it can serve peak as well as base loads. This is the result of its capacity to store and release water to increase output to meet fluctuations in demand (Corum 2007: 7; Sidran 2006: 1). Engineering literature states that a hydroelectric system can be dispatched to serve the purpose of base load generation as well as peaking generation (Masters 2004: 144). For short periods of high demand, hydroelectric resources in the PNW can deliver nearly twice as much electricity as they normally generate (PGE 2007a: 65). This sets the PNW apart from the rest of the country, where the ability to store energy on a large scale is absent, and multiple types of resources are always required to accommodate fluctuating levels of demand (Corum & Galbraith 2007).

As mentioned above, the PNW does not have the air conditioning load that causes peak loads throughout the rest of the country (Casola et al 2005: 24). Energy demand in the region has historically peaked in the winter, when air temperatures are low and hours of daylight are few (Casola et al 2005: 24). This results in an electricity load profile that differs fundamentally from those in the rest of the nation (Casola et al 2005: 24).

As mentioned above, the nature of the hydro system and the low demand peaks make these peaks of relatively low cost for utilities in the region. It is important to recognize that this low cost is probably the most significant reason that DR has historically not been utilized on a large scale by utilities in the region. However, this situation is changing.

3.3 A changing industry

Four forces are driving the PNW electric industry to a state where demand response will have significant value to utilities. First, energy and capacity demands are increasing. The PNW's investor-owned utilities project major resource shortfalls in the coming years due to demand growth. PGE expects load growth to create a substantial gap between demand and available resources in the next five years, with peak load demands growing faster than base load demands (Corson 2007: par 8). Avista expects energy and capacity deficits over the next ten years (Storrow 2007: 4). Puget Sound Energy's (PSE) 2006 annual report states that one of the company's top priorities is new resource acquisition, as the company is facing a "…big power supply shortfall" (PSE 2007: 8).

Second, the hydroelectric system is reaching capacity (Corum & Galbraith 2007). The ability of the PNW electric system to meet fluctuations in demand with hydroelectric power is diminishing. Projects have been built at all of the sites along the river system where it is possible (Corum & Galbraith 2007). As demand for energy in the region grows, the existing capacity of the hydroelectric system is "used up" (Corum & Galbraith

2007). PGE's 2007 integrated resource plan states that "…the region is now both energy and capacity constrained" (65).

Third, faced with energy and capacity shortages, purchasing electricity on the wholesale market will prove to be financially risky for the region's utilities. The 2000-2001 west coast energy crisis revealed the region's vulnerability to very high energy prices.[2] Although the crisis was caused by a "perfect storm" of events, and such an exceptional situation that is highly unlikely to happen again (Byers 2007), it revealed the vulnerability of the region's electric power industry to wholesale energy market prices. The NPCC finds that "…the 2000-2001 electricity crisis made it clear that without the ability of electricity use to respond to wholesale electricity market conditions, electricity prices can escalate almost without limit under tight market conditions" (NPCC 2005c: 12). Although recent reductions in demand in the region have resulted in a surplus of capacity overall (NPCC 2007b: par 4), the NPCC holds that the structure of the wholesale electricity market still presents this price risk (2005c: 17).

This risk originates from the fact that electricity markets in the PNW are structured such that supply is responsive to the conditions of the West Coast wholesale market, but local usage is not (NPCC 2005d: 1). Mitigating the effects of this condition is the fundamental reason for implementing DR. As mentioned in Chapter 2, utilities pay varying prices to wholesale providers for the electricity they sell to customers throughout the day, but their customers usually do not. Customers see the effects of increases in the cost of wholesale electricity in their rates only over the long run (NPCC 2005d: 1-2). As

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[2] The crisis was the result of a below average water year in the Northwest and energy shortages in the other places from which the PNW purchases power. During an average water year, the hydroelectric system produces an average of 16,000 megawatts of power (NPCC 2005c: 5). In 2000, the Pacific Northwest's hydroelectric systems had a "critical water deficit" of 4,000 average megawatts (NPCC 2005c: 7).

mentioned in Chapter 2, this is the prevalent rate structure among utilities in the US. The NPCC claims that the fact that the demand side of the market is not exposed to these prices and thus can't respond increases the cost of operating the electric system (2005d: 2).

Fourth, the PNW faces an increasingly congested energy grid and the need for large-scale transmission system upgrades.[3] In the 1980s, energy demand peaks in the PNW occurred in the winter months, and the region would export power to California during the summer (DOE 2006a: 47). Now, summer peaks are increasing and the need for more transmission capacity is increasing with them (DOE 2006a: 47). The effects of this problem may increase as such growth may force utilities and power agencies in the region to make uneconomic investments in transmission infrastructure (BPA 2006: 23; DOE 2006b: 48).

The finding that DR has the potential to play an important role in the future of the PNW's electric industry is supported by the Fifth Northwest Power and Conservation Plan (the Plan), which was published by the NPCC in 2005 (NPCC 2005a). Although it did not specify the impacts of TOU rate schedules, the Plan ran 720 simulations of 20-year futures and found that DR programs in general would be used in most potential futures, although in small amounts (NPCC 2005b: 21). The resource was found to be highly valuable to the region as a whole (NPCC 2005b: 21). Demand response reduced cost and risk of the entire power portfolio to the region significantly (NPCC 2005b: 21).

The evidence presented above shows that the region's electric industry is moving towards a state in which utilities "have the same choices as everywhere else" with regard

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[3] Congestion occurs when "actual or scheduled flows of electricity across a line or piece of equipment are restricted below desired levels—either by the physical or electrical capacity of the line, or by operational restrictions created and enforced to protect the security and reliability of the grid" (DOE 2006a: vii).

to new resources (Corum & Galbraith 2007). Increasing demand, the decreasing ability of the hydroelectric system to meet this demand, the vulnerability of the region to wholesale market prices and increasing transmission congestion are driving this change. How fast this change will occur is unknown (Corum & Galbraith 2007).

3.4 Three PNW TOU programs

This section presents details on the three utilities and their TOU programs, which are the focus of this study: Puget Sound Energy (PSE), Portland General Electric (PGE) and PacifiCorp. PSE's program was in effect from 2000-2002, while PGE and PacifiCorp have had ongoing TOU programs since this time. Data on each utility are presented for the time period that is relevant to the analysis of its program.

3.4.1 Puget Sound Energy (PSE)[4]

Puget Sound Energy (PSE) is one of the three investor-owned utilities serving customers in WA. PSE provides electric and gas service to customers in a region that covers approximately 6,000 square miles (PSE 2003c: 12). This service territory lies primarily in the Puget Sound region of the state (PSE 2001a). It covers the largest metropolitan area North of San Francisco and West of Chicago (PSE 2003c: 12). Figure 3.1 is a map of PSE's electric and gas service territory as of 2002.

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[4] PSE's TOU program was initiated in 2001 and terminated in 2002. Demographic, financial and other information is presented as of the end of 2001.

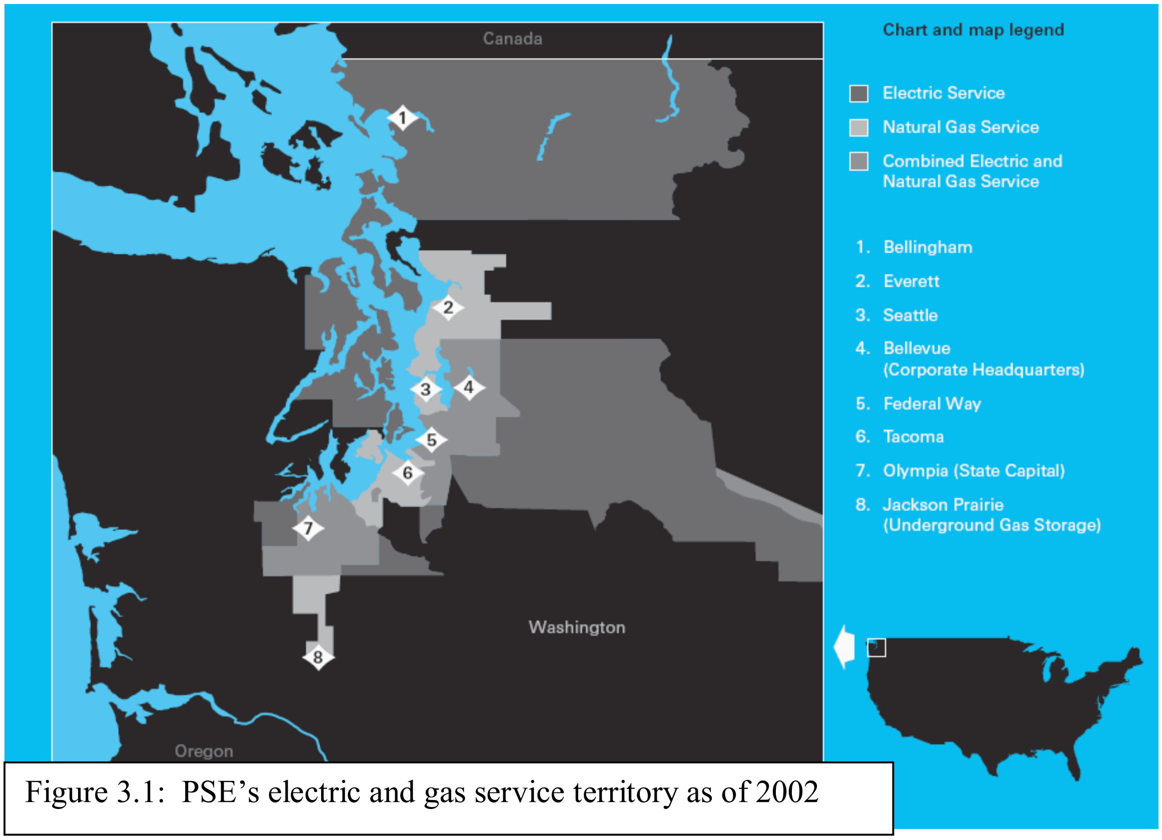


Figure 3.1: PSE’s electric and gas service territory as of 2002

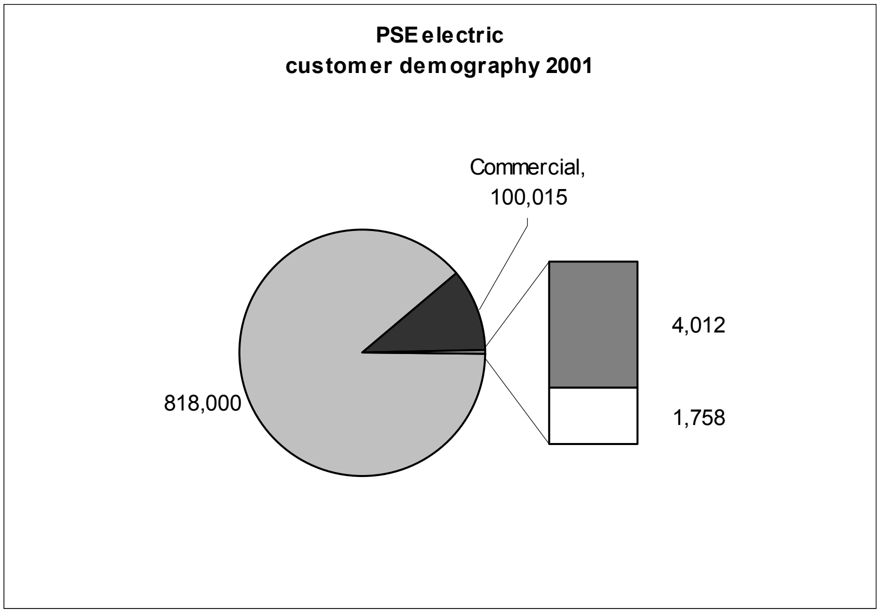
Regulation

PSE is regulated by two government bodies, the Washington Utilities and Transportation Commission (WUTC) and the Federal Energy Regulatory Commission (FERC) (PSE 2001a). The WUTC regulates PSE with regard to retail utility rates, accounting and the issuance of securities (PSE 2001a). FERC regulates PSE with respect to the transmission of electricity, the sale of electricity on the wholesale market and accounting matters (PSE 2001a).

Customer demography

In 2001, PSE served 925,000 electric customers in Western Washington. Of this total, 818,000 were residential customers (Russell et al 2001a: 2). 100,015 were commercial, 4,012 industrial and 1,758 other customers (PSE 2001a).

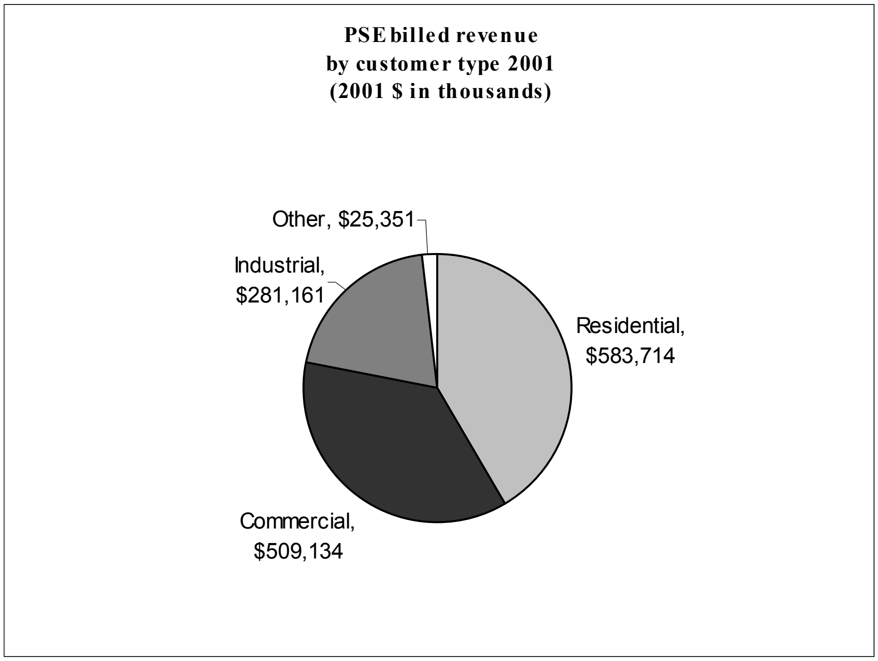
Figure 3.2: PSE electric customer demography 2001



Sources of revenue

Total operating revenue billed to customers in 2001 was approximately $1.4 billion (PSE 2001a). Of this, operating revenue from electricity sales to residential customers was approximately $0.5 billion, or about 41% of total billed revenue (PSE 2001a). The balance was billed to commercial, industrial and other customers (PSE 2001a).

Figure 3.3: PSE billed revenue by customer type 2001 (2001 $ in thousands)



Electricity supply

In 2001 PSE generated its own energy resources, purchased resources from other utilities and purchased resources on the wholesale market. PSE supplied 33.9% of total customer energy demand with its own resources, and 14.8% was purchased through long-term contracts with several of the Washington Public Utility Districts (PUDs) that own hydroelectric projects on the Columbia River (PSE 2001a). Another 26.8% came from other firm purchases and 24.5% from non-firm purchases (PSE 2001a).[5]

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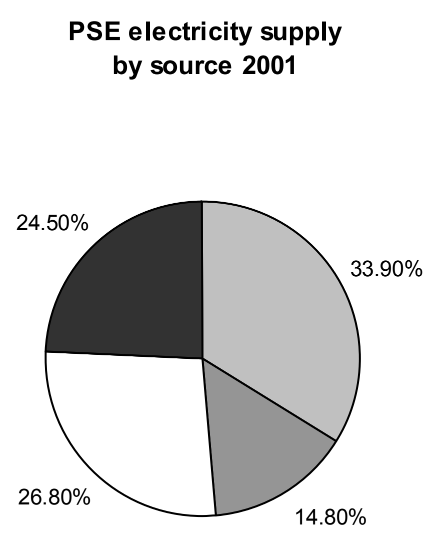
[5] Firm energy is an amount of purchased energy guaranteed to be available at a given time. Non-firm energy "…refers to spot market purchases of available energy which is not likely to be required by other customers who may have arranged for production at that particular time" (EnergyVortex 2007a). Firm energy is guaranteed at a certain price. Non-firm energy is priced on the market. During times of high demand, the price of non-firm energy may become very high (EnergyVortex 2007a).

Figure 3.4: PSE electricity supply by source 2001



The energy crisis and PSE's TOU program

During the energy crisis of 2000-2001, PSE faced "…unprecedented increases in wholesale energy costs" (Du Bois 2006: par 4). As mentioned above, PSE generated only a third of its own electricity in 2001. It relied on the wholesale market for a sizeable portion of its supply (PSE 2001a). As a result, demand peaks during the crisis forced PSE to "buy more [energy] than expected on the spot market at prices several times higher than ever before" (Du Bois 2006: par 6). As a result, PSE instituted a TOU program to mitigate these costs.

PSE did not need to roll out new meters to bill customers on TOU rates. PSE had contracted utility data and communications vendor Cellnet to install and manage an automated meter reading[6] (AMR) system for 96% of PSE's customers in 1997 (Pollom 2005: 7). The contract was for the duration of 15 years (Pollom 2005: 7). Over 90% of

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[6] An AMR system differs from an AMI system in that it does not provide two-way communications between the utility and the customer. It automates the meter read but does not always enable the meter to be read remotely (McClaine 2007).

the meters in this system were installed between 1997-1999 (Pollom 2005: 7). By 2001, PSE was able to implement its TOU program over this existing system without new meters.

In the winter of 2000-2001, PSE initiated its Personal Energy Management (PEM) program to mitigate the effects of the energy crisis and give customers the opportunity to reduce their electricity bills (BW 2001: par 7; Du Bois 2006: pars 10-1). The PEM enabled customers to view their energy usage and its associated costs on their bills and in real time over the internet (Cellnet 2005: 2). In order to reduce the cost of the crisis, on March 27th, 2001 PSE filed new tariffs to implement TOU rates as part of PEM (Russell et al 2001d: 1). On May 1st 2001, the docket became effective, and PSE was authorized to charge all eligible residential customers a TOU rate (Russell et al 2001c: 1).

Participation in the TOU rate program was mandatory for all eligible residential customers. Residential customers whose installed AMR equipment worked properly for TOU billing purposes were charged TOU rates (Russell et al 2001a: 2). Approximately 330,000 existing residential customers met this criteria and were billed under this rate schedule beginning in June 2001 (Russell et al 2001a: 2).

The TOU rate schedule changed the existing rate schedule by charging different prices for energy at different times of day. The rate schedule for residential customers in effect when TOU was implemented (Schedule 7, Residential Service) charged a flat rate for electricity usage throughout the day (Russell et al 2001a: 2). Under the TOU rate, customers were charged different prices during each of the four TOU rate periods (Russell et al 2001d: 2).

Table 3.1: PSE’s TOU rate schedule

Schedule 7	
First 600 kWh per month	$ 0.061376 / kWh
>600 kWh per month	$ 0.070162 / kWh

TOU Rate	
6 am -10 am	$ 0.079108 / kWh
10 am - 5 pm	$ 0.070162 / kWh
5 pm – 9 pm	$ 0.079108 / kWh
9 pm – 6 am a	$ 0.063585 / kWh

PSE’s TOU program was terminated on November 18th, 2002, and all customers on the rate were returned to the regular residential service rate schedules (WUTC 2002: 6). This termination date was just under a year earlier than the previously proposed termination date of the program (WUTC 2002: 6). PSE requested that the WUTC approve its early termination of the program after it had found that the majority of customers were no longer saving money under the rate schedule (WUTC 2002: 5).

3.4.2 Portland General Electric (PGE)[7]

Portland General Electric (PGE) is an investor-owned utility incorporated in Oregon (PGE 2007b: 11). PGE sells electricity to the retail market in the state and sells electricity and natural gas to other utilities and power marketers in the wholesale market throughout the Western US (PGE 2007b: 6). PGE’s service territory is 4,000 square miles and includes the cities of Portland and Salem (PGE 2007b: 6). Figure 4.5 shows PGE’s service territory as of 2007.

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[7] PGE’s TOU program was initiated in the early 2000s, but is still active in 2007. Information on PGE and its program is presented as of 2007.

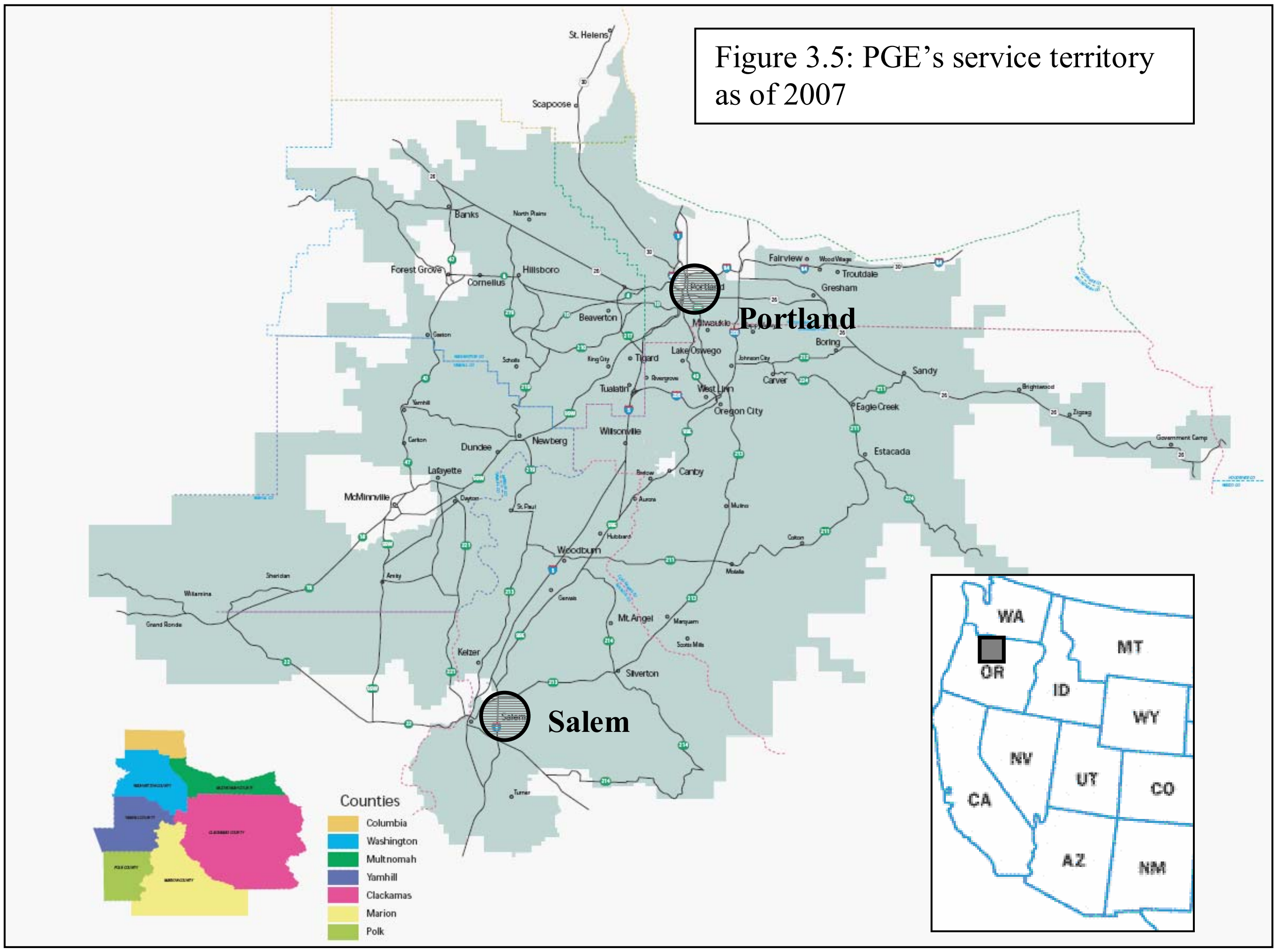


Figure 3.5: PGE's service territory as of 2007

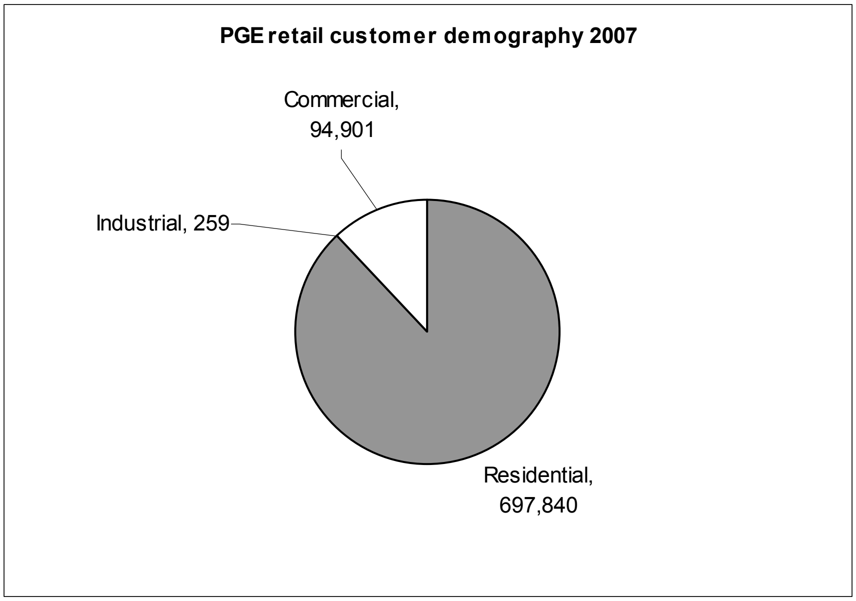
Regulation

PGE falls under the regulatory jurisdiction of four government bodies: the Oregon Public Utilities Commission (OPUC), FERC, the Energy Facility Siting Council (EFSC) and the Nuclear Regulatory Commission (NRC) (PGE 2007b: 9). The OPUC approves PGE' retail prices and establishes conditions of utility service. It ensures that prices and terms of service are fair, non-discriminatory, and that they provide PGE an opportunity to earn a fair return on its investment (PGE 2007b: 9). The OPUC also regulates PGE with respect to accounting issues (PGE 2007b: 9). FERC regulates PGE's accounting policies and practices, licensing of hydroelectric projects, transmission services, wholesale sales, and other matters (PGE 2007b: 9). The EFSC issues permits for new generating projects (PGE 2007b: 9). The NRC regulates the permitting and decommissioning of nuclear plants (PGE 2007b: 9).

Customer demography

PGE serves 793,000 retail customers (PGE 2007b: 6). Of this total, approximately 697,840, or 88% are residential customers (PGE 2007b: 8). PGE also serves approximately 94,900 commercial customers and 259 industrial customers, each comprising 11.9% and 0.1% of PGE's retail customer base, respectively (PGE 2007b: 8).

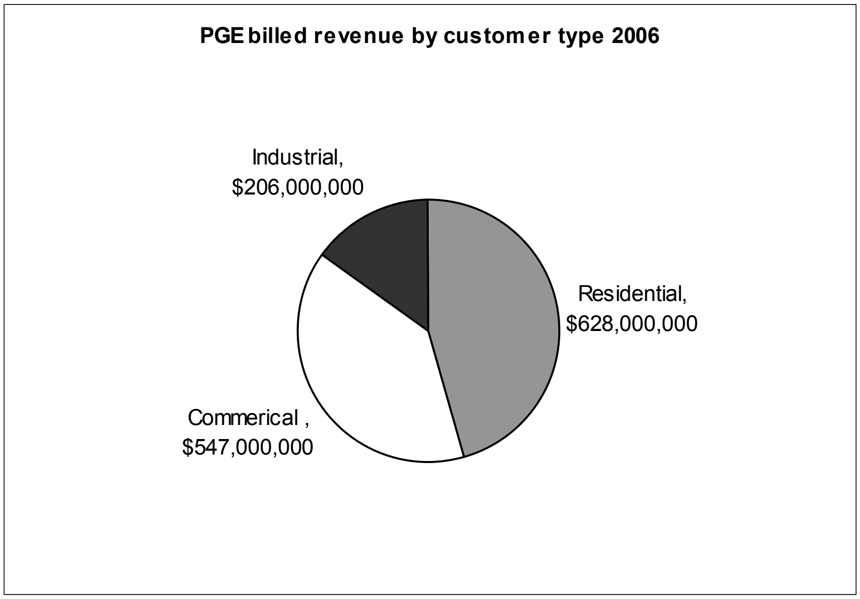
Figure 3.6: PGE retail customer demography 2007



Sources of revenue

Total operating revenue billed to retail customers in 2006 was approximately $1.3 billion (PGE 2007b: 49). Of this, operating revenue from electricity sales to residential customers was $628 million or approximately 46% of total billed revenue (PGE 2007b: 49). $547 million was billed to commercial and $206 million was billed to industrial customers (PGE 2007b: 49).

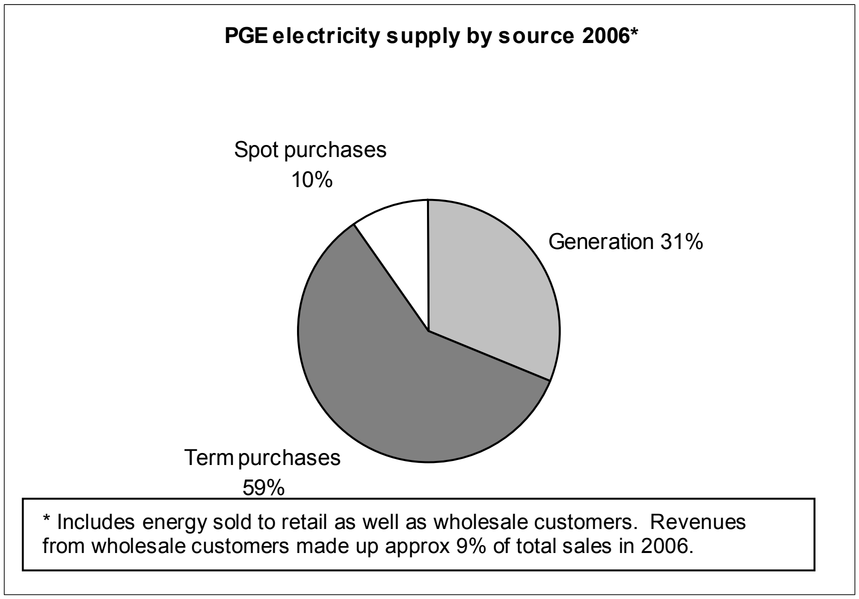
Figure 3.7: PGE billed revenue by customer type 2006



Electricity supply

PGE generates its own electricity, purchases wholesale electricity in long-term and short-term energy contracts from a variety of sources (PGE 2007b: 15). PGE also makes spot market purchases (PGE 2007b: 15). Long and short term purchases come from federal hydropower projects, other PNW and California utilities and an independent power producer (PGE 2007b: 15). In 2007, PGE generated 31% of its own electricity, purchased 59% in long- and short-term power purchases, and purchased 10% on the spot market (PGE 2007b: 50).

Figure 3.8: PGE electricity supply by source 2006



PGE's residential TOU program

PGE has offered its residential customers a TOU rate option since November 2001 (PGE 2004: 2). PGE is obliged to offer a market-based rate to customers by state law, and the TOU program satisfies that obligation (Fairchild 2002: 2). Participation in PGE's residential TOU rate option is voluntary (Schwartz 2003: 12). Customers are allowed to enroll at any time and must stay enrolled for a minimum of one year (Schwartz 2003: 12). Customers are protected from paying more than 10% above what they would have paid on the normal rate schedule (not including the meter charge) for their first year of enrollment (Schwartz 2003: 12). This is PGE's "12-month guarantee" (Schwartz 2003: 12). As of 2006, approximately 1,875 residential customers were enrolled in the TOU rate option (Rooke 2006).

A meter must be installed as each new customer joins the TOU rate option (Schwartz 2003: 12). The meter costs approximately $150 including installation (Eustis 2007b). This cost is offset by a monthly charge that is passed on to the enrolled customer (Schwartz 2003: 12). The TOU rate schedule charges customers a range of prices during on-peak, mid-peak and off-peak periods of the day and the week (see Table 4.2) (PGE 2007c).

Table 3.2: PGE's TOU basic service and TOU rate schedule

Basic Service
$ 0.0576/kWh

TOU Rate Schedule

	Cost
On-peak	$ 0.10686/kWh
Mid-peak	$ 0.06204/kWh
Off-peak	$ 0.03562/kWh

Rate	Time of Day	Day of Week
Summer months — begins May 1 of each year		
On-peak	3–8 p.m.	Monday-Friday
Mid-peak	6 a.m. – 3 p.m.	Monday-Friday
	8 – 10 p.m.	
	6 a.m. – 10 p.m.	Saturday
Off-peak	10 p.m. – 6 a.m.	Every day
	6 a.m. – 10 p.m.	Sunday and specified holidays
Winter months — begins Nov. 1 each year		
On-peak	6 – 10 a.m.	Monday-Friday
	5 – 8 p.m.	
Mid-peak	10 a.m. – 5 p.m.	Monday-Friday
	8 –10 p.m.	
	6 a.m. — 10 p.m.	Saturday
Off-peak	10 p.m. – 6 a.m.	Every day
	6 a.m. – 10 p.m.	Sunday and specified holidays

3.4.3 PacifiCorp[8]

PacifiCorp is a vertically integrated investor-owned utility serving electric customers in the western United States, including OR (PacifiCorp 2006a). PacifiCorp provides electric service to customers across a 136,000 square mile area including parts of Utah, Oregon, Wyoming, Washington, Idaho and California (PacifiCorp 2006a: ; 2006c). PacifiCorp is owned by Mid-America Energy Holdings (PacifiCorp 2006a). The utility sells electricity into the retail market, mines coal, and trades energy in the wholesale market (PacifiCorp 2006a)

Figure 3.9: PacifiCorp's electric service territory 2006

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[8] PacifiCorp's TOU program was initiated in the early 2000s, but is still active in 2007. Information on PacifiCorp and its program is presented as of 2007.

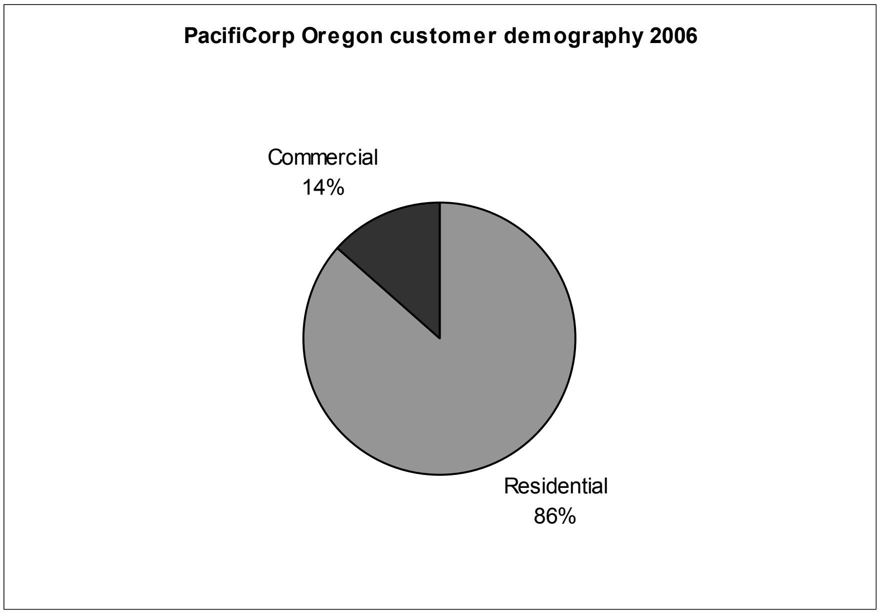
Regulation

In Oregon, PacifiCorp is regulated by the OPUC and FERC (PacifiCorp 2006a). The OPUC regulates PacifiCorp with regard to customer rates, service territories, sales of securities, asset acquisitions and sales (PacifiCorp 2006a). FERC regulates PacifiCorp with respect to wholesale sales and purchases of electricity, the operation of its electric generation and transmission facilities, and accounting policies and practices (PacifiCorp 2006a).

Customer demography

PacifiCorp serves 532,384 customers in Oregon (Kelly 2006: 2). Of these, 460,000 are residential customers in (Kelly 2006: 2). The remaining 72,384 customers are commercial (Kelly 2006: 2).

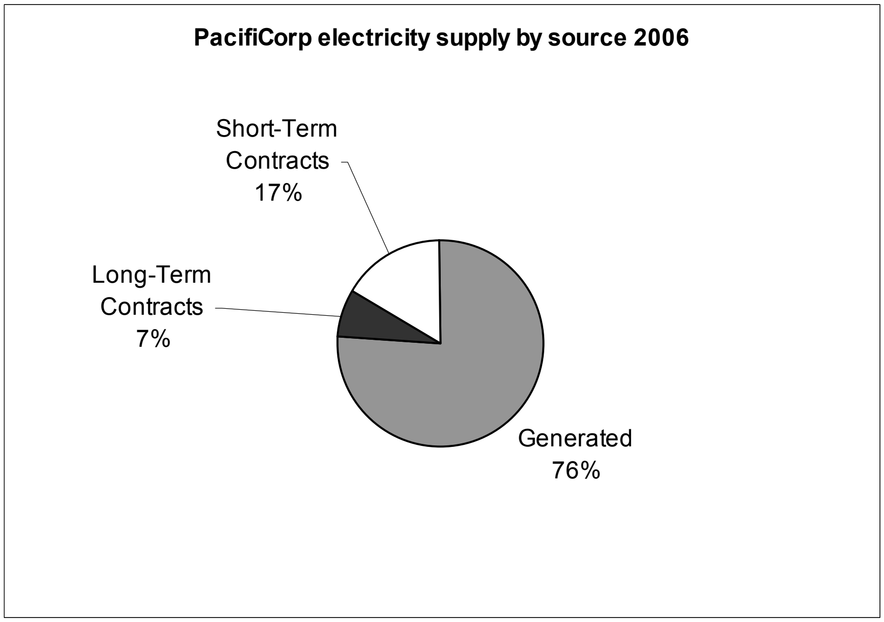
Figure 3.10: PacifiCorp Oregon customer demography 2006



Electricity supply

PacifiCorp generates most its own electricity, but also purchases wholesale electricity in long-term and short-term contracts (PacifiCorp 2006a). In 2007, PGE generated 75.8% of its own electricity, purchased 7.4% in long-term contracts and purchased 16.8% in short-term contracts (PacifiCorp 2006a). The majority of PacifiCorp's generated electricity is from coal-fired thermal generation (PacifiCorp 2006a). This may be part of the reason that PacifiCorp bills itself as one of the "lowest-cost electricity producers in the United States" (PacifiCorp 2006b).

Figure 3.11: PacifiCorp electricity supply by source 2006



PacifiCorp's TOU program

Falling under the same state regulation as PGE, PacifiCorp has been obligated to offer residential customers a TOU option since 2002 (Fairchild 2002: 3). Participation in

PacifiCorp's residential TOU rate option is voluntary and requires the deployment of a meter when customers join the program (Schwartz 2003: 12). The meter costs approximately $150 including installation (Marx 2007a). This cost to the utility is offset by a monthly charge of $1.50 that is collected from each enrolled customer (Marx 2007a: ; PacifiCorp 2007: ; Schwartz 2003: 12).

PacifiCorp's program is very similar to PGE's in other ways. Customers are allowed to enroll at any time and must stay enrolled for a minimum of one year (Schwartz 2003: 12). Customers are protected from paying more than 10% above what they would have paid on the normal rate schedule (not including the meter charge) for their first year of enrollment (Schwartz 2003: 12). As of early August 2006, 1,215 residential customers participated in PacifiCorp's TOU program (Kelly 2006: 2).

PacifiCorp's TOU rate schedule differs from PGE's and PSE's. The rate schedule charges customers an on-peak rate during on peak hours and gives customers an off-peak credit for every kWh used during off peak periods of the day and the week (PacifiCorp 2007). The on-peak charge is $0.06124 (PacifiCorp 2007). The off-peak credit is (-$0.01125) added to the charge for each kWh used during off-peak times (PacifiCorp 2007). The basic service rate for residential customers is $0.06844/ kWh (PacifiCorp 2007). The timing of these different periods varies seasonally (see Table 4.3 and Figure 4.11).

Table 3.3: PacifiCorp’s TOU rate schedule

	Basic Service
Residential	$0.06844/ kWh

	TOU Rate			
	Summer		Winter	
	On Peak Charge	Off Peak Credit	On Peak Charge	Off Peak Credit
Residential	$0.06124/ kWh	$-0.01125/ kwh	$0.03316/ kWh	$-0.01125/ kWh

Figure 3.12: PacifiCorp’s TOU rate schedule time periods (PacifiCorp 2007)

Summer (April-October)

	6am	4pm	8pm	6am
Mon	Off Peak	On Peak	Off Peak	
Tues	Off Peak	On Peak	Off Peak	
Wed	Off Peak	On Peak	Off Peak	
Thurs	Off Peak	On Peak	Off Peak	
Fri	Off Peak	On Peak	Off Peak	
Sat	Off Peak			
Sun	Off Peak			

Winter (November-March)

	6am	10am	5pm	8pm	6am
Mon	On Peak	Off Peak	On Peak	Off Peak	
Tues	On Peak	Off Peak	On Peak	Off Peak	
Wed	On Peak	Off Peak	On Peak	Off Peak	
Thurs	On Peak	Off Peak	On Peak	Off Peak	
Fri	On Peak	Off Peak	On Peak	Off Peak	
Sat	Off Peak				
Sun	Off Peak				

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Chapter 4
Analysis of the Barriers to Time of Use Rates in the Pacific Northwest

The TOU programs described above have been considered unsuccessful. PGE states that its program has not been cost-effective, nor has it had any effect on the amount of capacity PGE must have to meet demand (PGE 2004: IV-2). PacifiCorp also finds that its program has not been cost effective, and the low rate of participation indicates it has also had little or no effect on capacity requirements (Kelly 2006: 2). While PSE's program may or may not have been cost effective for the utility, in the end, it cost
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participants more than a flat rate and was terminated for this reason (PSE 2003a: ; WUTC 2002: 5). This general assessment is nuanced, however. PGE's and PacifiCorp's programs do in fact save money for the very small percentages of PGE's and PacifiCorp's customers who participate. However, this solves little and merely reshuffles costs: there is no effect on capacity requirements and the OPUC's POC finds that these savings are so low that on net they are subsidized by each utility's rate payers (OPUC 2005).

Similarly, there is contention among the WUTC, PSE and Public Counsel about the cost-effectiveness and general benefit created by PSE's TOU program even before participants stopped saving and the program was terminated (PSE 2003a). In an evaluation of the program after its termination, WUTC Staff and Public Counsel found that program participants did not comprise a representative sample of PSE's customer base, which meant the findings could not be used to predict the future success of a larger TOU rate program for PSE (PSE 2003a). Additionally, both parties believed that the magnitude of customer load shift was increased by the general heightened awareness of the cost of electricity due to the media coverage of the west coast energy crisis (PSE 2003a).

Yet, with little or no effect on capacity requirements and almost no economic benefit to the utilities, these programs have not solved the economic and environmental problems mentioned in Chapter 3.[9] PGE continues its program because a small number of customers value it, and it would cost more to terminate than to continue (PGE 2004: VI-3). The utility also anticipates that the program will serve as a platform for launching a cost effective TOU program in the future (OPUC 2005: 4). PGE's and PacifiCorp's

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programs also exist to meet the requirements of Oregon state law (Fairchild 2002: 3). PSE's program was the only program that provided a significant DR resource, yet the program no longer exists (PSE 2003a: ; WUTC 2002).

4.1 Barrier #1– high costs

One of two primary reasons these programs have failed is that their costs have been too high to justify the small amount of the load shifted. Program costs are a combination of the cost of meters and their installation and data management and billing costs. PacifiCorp emphasizes the high cost of meters and installation (Kelly 2006: 2). The cost of data management for PacifiCorp has also been cited as prohibitively high (OPUC 2005: 4). High meter costs have prevented PGE's program from being cost effective (PGE 2004: IV-2). In fact, PGE finds that its TOU program would only be cost effective if meter costs were dramatically reduced[10] (PGE 2004: IV-2). Even PSE, without meter costs, found that the high cost of meter reading and data management prevented its program from being cost effective (PSE 2003a). Table 4.1 shows estimates of the cost of each program per customer for the first year of enrollment.[11]

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[10] There is a difference of opinion on this between Quantec, firm PGE contracted to study its TOU program, and PGE staff (Rooke 2007a). PGE staff find that while removing the cost of the meter will dramatically reduces the costs of the program, it not quite make the program cost effective (Rooke 2007a).

[11] Estimates of the cost of PGE's TOU program were obtained from interviews with Laura Rooke, Manager of Demand-Side Management and Conrad Eustis, Director of Retail Technology Development at PGE (Eustis 2007c: ; Rooke 2007b). Estimates of the cost of PSE's program were obtained from interviews with Eric Englert, Manager of Regulatory Initiatives and Tariffs at PSE (Englert 2007a). The estimate of the cost of meters for PacifiCorp's program was obtained from interviews with Douglas Marx, Manager of Regulatory Affairs at PacifiCorp (Marx 2007c). The estimate of the cost of data collection for PacifiCorp's program was obtained from OPUC (2005). The costs for each program displayed in Table 4.5 include some or all of the following: marketing and administrative costs; the cost of meters (when new meters are installed); and the cost of meter reading, data storage and billing.

Table 4.1: Costs of TOU programs per customer, first year enrollment

PORTLAND GENERAL ELECTRIC (PGE) EXISTING*	
Marketing costs per customer	
Brochure printing/enrolled customer	$ 12.82
Call and processing	$ 2.00
12-month guarantee letters	$ 1.00
TOTAL MARKETING/VARIABLE PER CUSTOMER	$ 15.82
Data management costs per year	
Meter reading	$ 6.00
TOTAL DATA MANAGEMENT PER CUSTOMER	$ 6.00
Meter costs per customer	
Residential meter install	$ 20.00
Residential meter	$ 80.00
Old meter removal	$ 10.00
TOTAL METER PER CUSTOMER	$ 110.00
TOTAL FIRST YEAR COST PER ENROLLED CUSTOMER	$ 131.82

PACIFICORP**	
Data management costs per customer	
Data retrieval	$ 189.60
TOTAL DATA MANAGEMENT/VARIABLE PER CUSTOMER	$ 189.60
Meter costs per customer	
Residential meter and install	$ 150.00
TOTAL METER PER CUSTOMER	$ 150.00
TOTAL FIRST YEAR COST PER ENROLLED CUSTOMER	$ 339.60

PUGET SOUND ENERGY (PSE)**	
Marketing costs per customer	
Website cost	$ 0.40
Info and education	$ 0.60
Extra postage (for mult. meter)	$ 0.13
TOTAL MARKETING PER CUSTOMER	$ 1.13
Data management costs per customer	
Meter reading	$ 11.51
TOTAL DATA MANAGEMENT PER CUSTOMER	$ 11.51
TOTAL VARIABLE PER CUSTOMER	**$ 12.64**
Meter costs per customer	
Residential meter and install	$ -
TOTAL METER PER CUSTOMER	$ -
TOTAL FIRST YEAR COST PER ENROLLED CUSTOMER	$ 12.64

*Estimates only, not inclusive of all program costs

**Estimates only

There is wide variation in per customer cost among these programs. Meter costs make up huge portions of the per customer costs for PGE and PacifiCorp, which must deploy them one at a time as customers enroll in the programs. PSE's program, which did not require new meters cost just 10% of what PGE's program costs and just over 4% of what PacifiCorp's program costs per customer for the first year of enrollment. However, despite the fact that it has no meter costs, PSE's data management costs are almost twice those of PGE. PacifiCorp's data management costs are many times those of the other two utilities.

4.1.1 Failure to capture operational benefits

The first key determinant of the cost effectiveness of TOU programs is whether or not the costs of metering and communications are attributed to a program. Using an AMI system for other operations in addition to TOU pricing improves the cost-effectiveness of a TOU program because not all meter costs are attributed to it. As noted in Chapter 3, AMI systems can provide economic benefits to a utility in addition to those benefits from TOU programs. These are referred to as operational benefits (as opposed to TOU benefits). If a utility deploys AMI to capture these benefits, TOU and other DR programs will have much less cost associated with them than they would have otherwise. It is this difference between the programs that explains why PGE's and PacifiCorp's programs cost many times what PSE's cost per customer.

To date, PGE and PacifiCorp have not rolled out meters to capture operational benefits. They deploy them strictly to support TOU rates (Schwartz 2003: 13). As a result, all of the costs of the meters and data management are attributed to the TOU programs. There is, however, another way to deploy TOU. Three PNW utilities have recovered or plan to recover the cost of their AMI or AMR systems with operational benefits alone (Carpenter & Tooman 2007a: ; Cummins 2007: ; Englert 2007b). They have dramatically reduced or expect to reduce the cost of TOU and DR programs in comparison with those of PGE and PacifiCorp. These outcomes support the claim that implementing AMI to capture operational benefits will keep the cost of TOU dramatically lower than if advanced meters were implemented solely to do TOU.

PSE's AMR system

As mentioned above, PSE's TOU program did not require new metering infrastructure. PSE rolled out its AMR system between 1997 and 2001 in order to reduce the cost of meter reading and improve customer service (Pollom 2005: 7). Therefore PSE's TOU program differed from PGE and PacifiCorp's programs in that it required no investment in new metering (Englert 2007b). When PSE initiated its TOU program in 2001, it was able to put customers on TOU pricing over its existing AMR infrastructure (Russell et al 2001b: 2). PSE's Manager of Regulatory Initiatives and Tarriffs states, "We put in AMR before we ever thought of time of use" (Englert 2007b).[12] That PSE didn't require new meters and communications to run its TOU program was one of the main reasons its costs were lower than PGE and PacifiCorp's TOU programs (Englert 2007b).

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[12] An anonymous interviewee mentioned that he/she had heard that PSE planned to do TOU when it rolled out its AMR system in the late 1990s. The business case presented in (Pollom 2005) does not reflect this, nor do the comments of other interviewees in this study. However, PSE rolled out its AMR system without filing for cost recovery from the WUTC (Englert 2007b). It never presented a business case for this system to its regulators (Englert 2007b). It is plausible PSE originally intended to deploy TOU rates over its AMR system, but this has not been made public.

PGE's AMI plans

As mentioned above, PGE's existing program rolls out meters one at a time, and does not capture operational benefits. This will soon change. PGE plans to roll out an AMI system for all of its customers beginning in 2008 (Carpenter & Tooman 2007b: 3). Over time, this system will provide operational benefits great enough to cover the cost of the system (Carpenter & Tooman 2007b: 9). Such benefits include reducing the cost of reading customer meters, reducing stolen power and improving outage detection (Carpenter 2007a). PGE's manager of revenue operations states that this will significantly reduce the cost of PGE's entire TOU program (Carpenter 2007a). This is largely because meters will not need to be rolled out for TOU or other DR programs. Similar to PSE's position in 2001, PGE will already have the metering and communications systems to implement its TOU program (Carpenter 2007a).[13] Once the AMI system is rolled out, "the cost [to PGE] of putting someone on TOU will effectively be nil" (Eustis 2007a).[14] A comparison of the costs of PGE's TOU program before and after the AMI system is rolled out are shows in Table 4.2 below.

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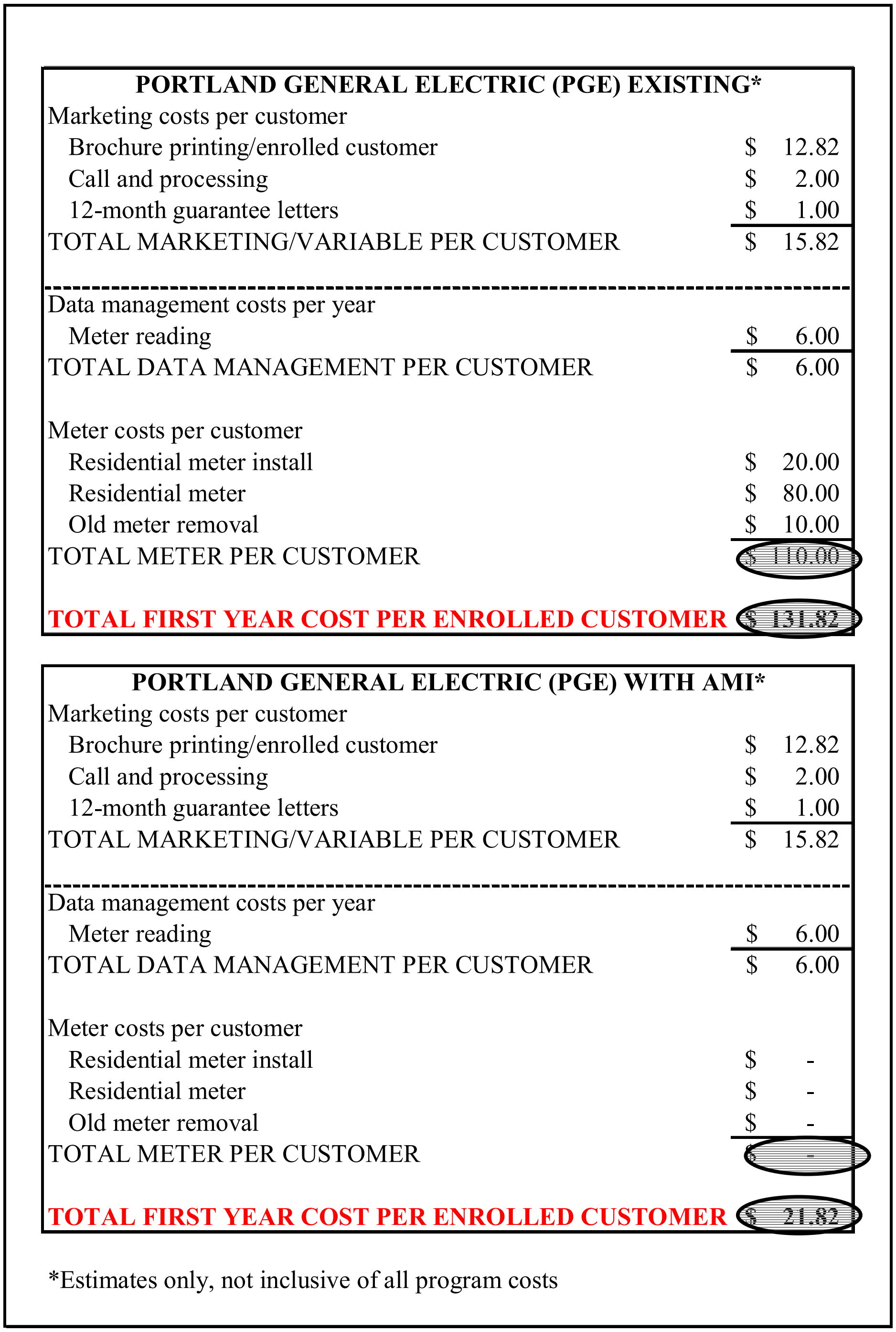
[13] Additional costs and in investments are necessary for the implementation of some demand response programs (Carpenter & Tooman 2007b). Despite these costs, the total cost of implementing TOU is dramatically lower if an AMI system is already in place.

[14] The interviewee noted that although metering costs, which make up the bulk of the per-customer costs, will be eliminated, marketing, enrollment and data management costs will still be incurred for new enrollees.

Table 4.2: Costs of PGE's existing and future TOU rate programs per customer, first year enrollment



PORTLAND GENERAL ELECTRIC (PGE) EXISTING*	
Marketing costs per customer	
Brochure printing/enrolled customer	$ 12.82
Call and processing	$ 2.00
12-month guarantee letters	$ 1.00
TOTAL MARKETING/VARIABLE PER CUSTOMER	$ 15.82
Data management costs per year	
Meter reading	$ 6.00
TOTAL DATA MANAGEMENT PER CUSTOMER	$ 6.00
Meter costs per customer	
Residential meter install	$ 20.00
Residential meter	$ 80.00
Old meter removal	$ 10.00
TOTAL METER PER CUSTOMER	$ 110.00
TOTAL FIRST YEAR COST PER ENROLLED CUSTOMER	**$ 131.82**

PORTLAND GENERAL ELECTRIC (PGE) WITH AMI*	
Marketing costs per customer	
Brochure printing/enrolled customer	$ 12.82
Call and processing	$ 2.00
12-month guarantee letters	$ 1.00
TOTAL MARKETING/VARIABLE PER CUSTOMER	$ 15.82
Data management costs per year	
Meter reading	$ 6.00
TOTAL DATA MANAGEMENT PER CUSTOMER	$ 6.00
Meter costs per customer	
Residential meter install	$ -
Residential meter	$ -
Old meter removal	$ -
TOTAL METER PER CUSTOMER	$ -
TOTAL FIRST YEAR COST PER ENROLLED CUSTOMER	**$ 21.82**

*Estimates only, not inclusive of all program costs

Avista's AMI plans

Avista has alerted the WUTC of its plans to roll out an AMI system in the near future (Cummins 2007). Avista plans to implement the system for customers in its

Washington service territory (Cummins 2007). Avista has not yet released a formal analysis of the costs and benefits of the system. However, operational benefits were emphasized as justification for the program in a testimony before the WUTC during Avista's last general rate case (Cummins 2007: 6-7). Particular emphasis was given to the need to mitigate the rising cost of meter reading (Cummins 2007: 2-3). The senior director of demand side management was asked about Avista's cost recovery plans for the program and directed the author to treatment of this topic in Cummins' (2007) testimony (Folsom 2007). This indicates that this testimony provides the most current cost recovery plan for Avista's AMI system.

4.1.2 AMI may lead to TOU programs

In addition to simply reducing the fixed costs of TOU programs, utilities with AMI systems installed for operational benefits are more amenable to the implementation of TOU pricing. This is evident in the fact that utilities in the PNW that have or plan to roll out AMI systems for operational benefits then roll out systems that can be used for DR. PGE and Avista indicate that their AMI systems are designed to be used for various DR programs (Carpenter & Tooman 2007a: 1; Cummins 2007: 6). PSE's 2001 TOU program was implemented quickly and easily because PSE had the appropriate technology in place before the crisis (Englert 2007b). This indicates that if the tools to do TOU and other demand response programs are put in place, then they will be used.

While operational benefits provide the business cases for AMI roll outs by Avista and PGE, both utilities state that their systems will also enable demand response functionality. Cummins (2007) says "…this technology will… provide the foundation for the later adoption of retail electric energy pricing that may vary by hour of the day or day of the week" (6). PGE also plans to use its AMI system to expand its demand response programs in the future. While it is not quantified in the business case for AMI, PGE states that it is one of the planned uses of the AMI system in the future (Carpenter & Tooman 2007b).

4.1.3 Operational benefits business models will pave the way to low cost TOU

It is clear that a high cost benefit ratio for AMI has been a barrier to the use and expansion of TOU pricing programs in the PNW (OPUC 2005: 4; PGE 2004: IV-3). It is also clear that the level of cost that a TOU program has is dependent upon the business model used to implement TOU. With AMI implemented based on operational cost savings, TOU metering becomes a sunk cost; consequently the benefit/cost evaluation of the TOU program improves significantly. It follows naturally, and is shown explicitly, that utilities that deploy AMI systems for operational benefits will be more amenable to the use of TOU pricing than those that deploy them in a one-off fashion. These findings provide valuable knowledge for the design of low cost TOU programs in the PNW.

4.1.4 Other determinants of cost levels among TOU programs

Whether or not an operational benefits business model is used to deploy AMI determines the cost of a TOU program, but the details of that business model are also extremely important. One of the reasons for the high costs of PGE and PacifiCorp's programs is that meters were rolled out one by one, rather than all at once. A study of these programs explicitly states that the failure to capture economies of scale in meter roll outs has driven up their costs (Schwartz 2003: 32). It projects that in each case, "Mass deployment of the meters would reduce installed costs per unit" (Schwartz 2003: 25,32).

Other utilities in the region have found this to be true when investigating the deployment of TOU programs. Avista states that installing interval meters "only upon request" is not economic (Folsom 2006: 2). It validates the OPUC's assertion that mass deployments are more cost effective (Folsom 2006: 2). Avista states that if it were to offer a voluntary TOU program, meters would need to be rolled out for all customers (Folsom 2006: 2).

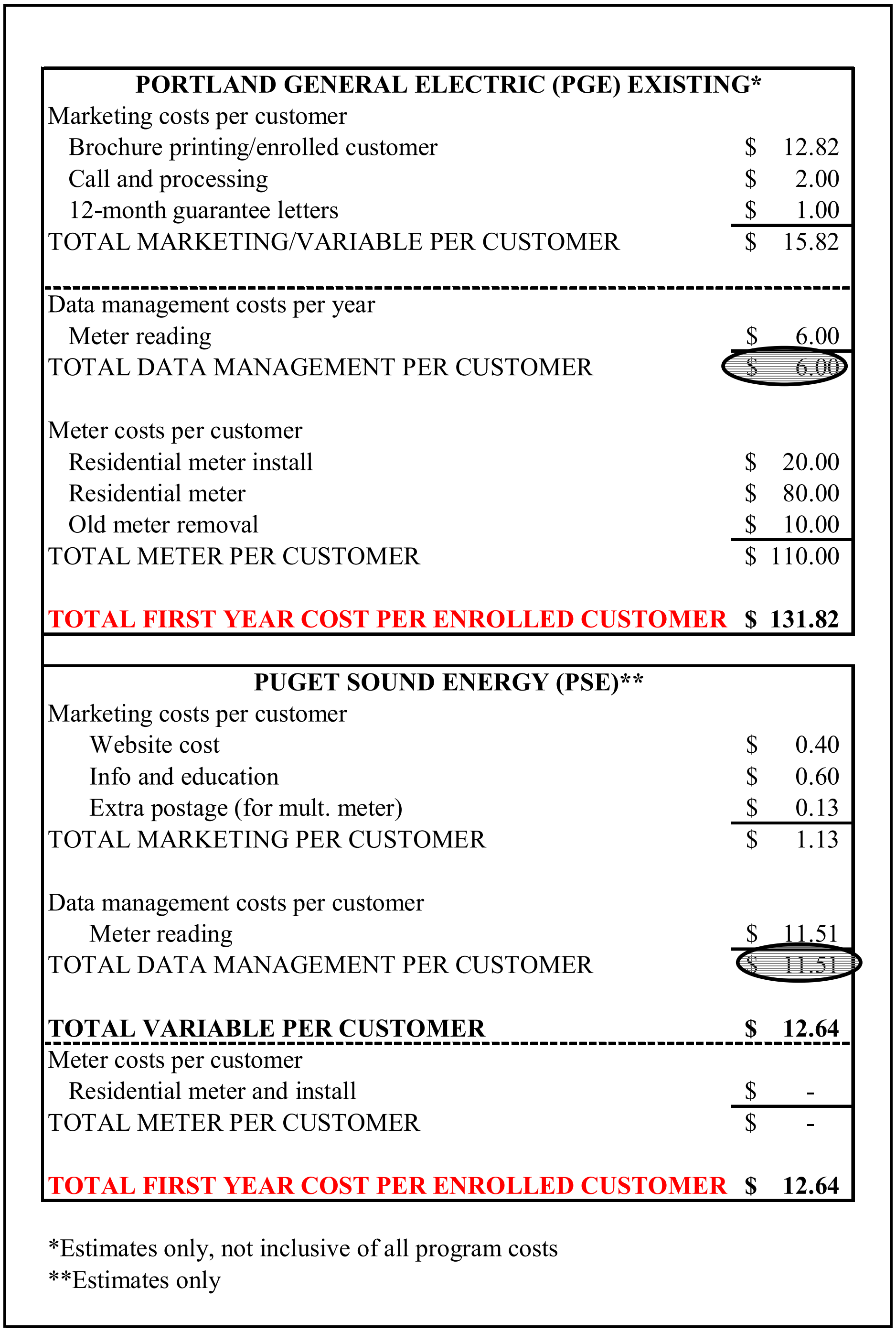
These cases also show that the way in which meters are read and data is managed within an operational benefits business model is also an extremely important determinant of the cost of a TOU program. Although PSE deployed metering infrastructure for all of its customers prior to its TOU program, its program was not cost effective (PSE 2003b: 9). It is possible that costs could have been lower if PSE had used a different strategy for meter reading and data management. As mentioned above, PSE outsourced its data management functions to Cellnet. This may have cost more than bringing this service in house. Or, this service might cost less today if another contract were renegotiated (Englert 2007b).

This is very important because the costs of PSE's TOU program would not need to be reduced by very much to make it cost effective given the level of benefit that the program created for the utility. A sensitivity analysis of the inputs PSE used to analyze its program revealed it would have been cost effective if per month per customer costs could have been reduced from about $1.05 to $0.92, or by about 12% (PSE 2003b: 9).

Data management costs were over 91% of PSE's per customer cost, therefore providing the greatest opportunity for reduction (Englert 2007a).

This is significant because, as mentioned above, PGE's meter reading and data management costs for TOU are much lower than PSE's (see Table 4.3). This may be related to the business model PGE uses for this function. Instead of outsourcing its meter data management, PGE has created a proprietary system for this purpose (Carpenter 2007a). This comparison suggests that PSE paid too much for meter reading and data management. PGE's experience suggests that these costs can be reduced.

Table 4.3: Costs of PGE’s and PSE’s TOU programs per customer, first year enrollment



PORTLAND GENERAL ELECTRIC (PGE) EXISTING*	
Marketing costs per customer	
Brochure printing/enrolled customer	$ 12.82
Call and processing	$ 2.00
12-month guarantee letters	$ 1.00
TOTAL MARKETING/VARIABLE PER CUSTOMER	$ 15.82
Data management costs per year	
Meter reading	$ 6.00
TOTAL DATA MANAGEMENT PER CUSTOMER	$ 6.00
Meter costs per customer	
Residential meter install	$ 20.00
Residential meter	$ 80.00
Old meter removal	$ 10.00
TOTAL METER PER CUSTOMER	$ 110.00
TOTAL FIRST YEAR COST PER ENROLLED CUSTOMER	**$ 131.82**

PUGET SOUND ENERGY (PSE)**	
Marketing costs per customer	
Website cost	$ 0.40
Info and education	$ 0.60
Extra postage (for mult. meter)	$ 0.13
TOTAL MARKETING PER CUSTOMER	$ 1.13
Data management costs per customer	
Meter reading	$ 11.51
TOTAL DATA MANAGEMENT PER CUSTOMER	$ 11.51
TOTAL VARIABLE PER CUSTOMER	**$ 12.64**
Meter costs per customer	
Residential meter and install	$ -
TOTAL METER PER CUSTOMER	$ -
TOTAL FIRST YEAR COST PER ENROLLED CUSTOMER	**$ 12.64**

*Estimates only, not inclusive of all program costs

**Estimates only

4.2 *Barrier #2—low customer participation*

Low customer participation is the second barrier to TOU programs among PNW utilities. Table 4.4 summarizes the participation statistics for PSE's, PGE's and PacifiCorp's TOU programs. Low participation is the result of two main factors. First, many customers do not have or have lost the opportunity to save under a TOU rate schedule (Schwartz 2003: ; WUTC 2002: 2-4). This depresses participation because a TOU program must offer an adequate incentive to participate in order to retain participants (Eustis 2007a: ; Faruqui & George 2003: par 9; Rooke 2007a: ; WUTC 2002). Second, marketing of TOU programs may be inadequate.

Table 4.4: Customer participation in TOU programs

	PSE*	PGE**	PacifiCorp**
Total residential customer base	818,000	697,840	460,000
Number of residential participants	330,000	1,875	1,215
% of residential customers participating	40%	0.27%	0.26%

*PSE figures as of 2001. Note that PSE's program was mandatory for eligible customers, but allowed participants to opt-out of the rate schedule at any time
**Voluntary program

4.2.1 *Customer participation and the effect of the monthly service charge*

PSE's program provides a before and after case that demonstrates the effect of a service charge on customer participation in a TOU program in the PNW. Before PSE began passing on the incremental meter reading and marketing costs of its program to participants, most of its participants saved money (Englert 2007b: ; WUTC 2002: 3). When PSE started passing on these costs, 94% began paying more than they would have under a traditional rate schedule (WUTC 2002: 4-5). When the savings evaporated, many customers dropped out of the program. In the four month period after the charge was added to customer bills—July 1st to October 31st, 2002—10% of participants dropped out (Faruqui & George 2003: par 9). By comparison, between May and September of the previous year, only 0.7% of participants opted out of the program (Russell et al 2001e: 1). PSE's program was ended in late 2002 due to the lack of customer savings (WUTC 2002).

Similar to PSE's experience, service charges paid by customers in PGE and PacifiCorp's TOU programs kept participant savings low. After the first year of each program, the average residential participant at each utility was not saving (Schwartz 2003: 12-5). When the monthly charges to cover the cost of the meters were subtracted from participants' bills, the average residential participant saved money (Schwartz 2003: 12-5). This indicates that if the service charges would have been lower, participants would have saved.

PGE's program also shows that even when participants do save, service charges will cut into a customer's potential savings. This suggests that the opportunity to save will be available to fewer customers than if the service charge had not existed. Since 2003, PGE's average TOU participant has been saving under the rate schedule (Rooke 2006). A close look reveals that the service charge dramatically limits these savings (PGE 2004: IV-1; Rooke 2006). PGE's average participant in 2004 paid 47% of the value of the money she saved under the TOU schedule to PGE as a service charge (PGE 2004: IV-1). Eliminating this charge would both enable customers to save more and enable more customers to save. Given that savings are a necessary condition for customer participation, this strongly suggests that reducing the monthly service charge would increase customer participation in these programs.

These cases suggest that the magnitude of the service charge can prevent many customers from saving. This is supported in the literature presented in Chapter 2. This suggests that reducing metering and data management costs will increase customer participation by reducing the cost of joining the program.

4.2.2 Low marketing of TOU: a self-fulfilling prophecy

Lack of marketing has been another cause of low participation in residential TOU programs offered by two of these utilities. Official estimates of the number of customers who could save under PGE and PacifiCorp's TOU programs with more marketing do not exist (Marx 2007b: ; Rooke 2007b). However, PGE believes it could increase enrollment by increasing the marketing of its program (Eustis 2007a: ; Rooke 2007a). This is based on PGE's knowledge of the relative success of other utilities' marketing efforts (Rooke 2007b).

Despite this potential for expanding enrollment, marketing of TOU rate schedules to residential customers is kept to a minimum by order of the OPUC (Beier 2006: 2; Koho et al 2007: 2). This order states that Oregon utilities must limit the amount of promotional and educational information given to residential customers about TOU rate options (Koho et al 2007: 3-4). The basis for this decision is that customer participation in voluntary TOU programs has been low, and marketing and data collection costs have been high (OPUC 2005: 4).

This decision, while intending to minimize costs, may, however, prevent TOU programs from overcoming the high costs associated with them. In this way, the order is a "self-fulfilling prophecy" (Eustis 2007a). As mentioned above, low customer participation is one of the barriers to cost-effectiveness of PGE and PacifiCorp's TOU programs. Increasing marketing efforts is one way to increase participation (Rooke 2007a). By preventing marketing based on the high costs of the programs, these costs will remain high and utilities will not have the opportunity to reduce them in this way.

4.3 Conclusion

This chapter analyzes the high cost of metering and infrastructure and low participation rates as separate barriers to cost effective TOU programs in the PNW. This is necessary for the analysis of the causes of each barrier, but in reality, participation rates affect costs and costs affect participation rates. The higher the rate of participation in a TOU program, the greater the benefit a program affords to a utility. Fixed costs are spread over a larger number of customers. When enough of a utility's load is shifted, it serves as a capacity resource. If the costs of a program are low, then service charges, which affect participation rates, can be low or non-existent.

A high benefit from a TOU program will justify high costs. PacifiCorp's and PGE's TOU programs are not currently cost effective because their costs are too high compared to the benefit that these programs create for the utilities (Kelly 2006: 2; PGE 2004: IV-2). If participation were to increase, then these programs could be justified in having a high cost level. PacifiCorp estimates its current TOU program would break even if participation increased to 10,000 participants (Kelly 2006: 2). PGE finds that the cost-effectiveness of its program is highly sensitive to the rate of participation (PGE 2004: IV-2).

PSE's experience with TOU showed that if a program has low costs compared to benefits, then it can have low service charges. When PSE's program had a high benefit cost ratio, it did not charge a service charge, customers saved and the dropout rate was low (PSE 2001b). When PSE's program's benefit cost ratio changed, it instituted a service charge (WUTC 2002). This reduced customer savings, increased the program's drop out rate and eventually led to its termination (WUTC 2002).

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Chapter 5
Solving the TOU Puzzle

This chapter summarizes the original findings of this thesis and evaluates them in light of the barriers to the implementation of AMI and TOU suggested by the energy efficiency and smart grid literature. Based on these findings, specific recommendations on how to improve the cost-effectiveness and penetration of TOU programs in the PNW are suggested. These are directed at public utilities commissions and state level policymakers as well as utilities in the region.

5.1 Assessment of barriers suggested in the literature

The smart grid and energy efficiency literature presented a number of financial, technical, regulatory and cultural barriers to utility implementation of energy efficiency programs, DR programs and the enabling technologies. These are listed below and briefly described. Then, their relevance to the cases studied is discussed.

5.1.1 Revenue loss as a barrier to TOU

The first financial barrier identified in the literature is revenue loss. Revenue loss occurs when utility DR or energy efficiency programs reduce the amount of electricity sold, and lose revenue they would otherwise collect. Revenue loss was cited as a key issue for energy efficiency in the literature. Although DR programs do not intend to reduce overall consumption, the literature shows that very often, the conservation effect is observed. It was noted that this reduction in energy usage may require policies to mitigate its effects on utility revenues. However, this study finds that revenue loss from

TOU rates has not prevented the implementation of the rate schedule in the PNW. Furthermore, PNW utilities have a long history of overcoming revenue losses from energy efficiency (Bull 1989: ; Byers 2007: ; NPCC 2007a). As a result, these utilities may be well suited to overcome revenue losses from other or expanded DR programs in the future.

There are key exceptions to the finding that utilities in the PNW do not face revenue losses that require recouping as a result of TOU rate programs. Revenue loss will prevent expansion of TOU programs for utilities that offer an "exaggerated" rate differential to TOU participants (Rooke 2007a). An exaggerated rate differential is offered to TOU participants to give them an incentive to shift load when the on-peak/off-peak power cost differential to the utility is not high enough to do so. Utilities with TOU programs that exaggerate this on-peak/off-peak differential to customers may see revenue losses if participation expands (Rooke 2007a).

PGE currently offers TOU participants an exaggerated rate differential in order to give them an incentive to shift load (PGE 2004: ; Rooke 2007a). If participation increases, increased total customer load shift in response to these prices, which do not accurately reflect the cost of power, may result in revenue losses for PGE (PGE 2004: ; Rooke 2007b). As a result, PGE expects increasing participation would require the utility to shrink the rate differential offered to TOU participants, which will in turn reduce participation in the program (PGE 2004: ; Rooke 2007b).

5.1.2 Improper allocation of costs and benefits

The literature states that DR programs create a benefit for the entire system and as a result, all customers, even those who do not participate, should help to cover the program's costs. When participants bear the costs of TOU alone, their savings are so low that they have no incentive to participate, and the program collapses. This study supports this assertion. Participants have been charged a large part of program costs in each program via service charges and no mechanisms have been used to cover these costs via non-participants. Charges paid by participants have been so great that customers have had little incentive to participate and participation rates have remained low.

5.1.3 Inability of utilities to gain cost recovery on AMI

The literature states that the inability of utilities to gain cost recovery on smart grid investments can be a barrier to investment. This may result from a utility's inability gain regulatory approval to recover the upfront costs of an investment from its customer rates. The existence of this barrier emphasizes the necessity for the utility to build a positive business case for investments in new technologies. It also emphasizes the role of the utility's regulator in promoting specific technologies and programs.

This study finds that cost recovery is extremely important for utilities investing in AMI and TOU programs. First, utilities will implement AMI and TOU if they can utilize a business model that results in economically viable AMI and TOU. For PNW utilities, this has required very low costs in order to justify the benefit. This has necessitated the deployment of AMI for operational benefits, over which DR can be implemented.

Second, regulators have an important role in promoting AMI and TOU. They must not only enable utilities to carry out initiatives by allowing them to gain cost recovery on their investments, but should encourage it.

Three PNW utilities have shown the importance of regulatory approval for investments in AMI. Avista, which is in the planning stages of its AMI roll out, states that it will seek cost recovery on this investment in the future (Cummins 2007). PGE plans to implement its AMI system because of its ability to recover the upfront costs of the system through rates (Carpenter & Tooman 2007b). PSE, while it did not seek cost recovery through rates for its AMR system in the late 1990s, explicitly states in a comment to the WUTC that cost recovery is the most important driver of utility investment in AMI (Deboer 2006).

5.1.4 Cultural barriers

Another set of barriers to utility investment in smart energy technologies and energy efficiency suggested by the literature are those resulting from cultures of utilities. As mentioned above, these are as follows: a) utility aversion to radical change, b) utility purchasing behavior that excludes smart grid technology vendors, which reduces access to and use of these technologies, c) utilities do not implement smart grid technology because they face regulatory uncertainty across large areas, and d) utilities lack an "adequate paradigm" and do not consider DR as a resource (GEF 2005: ; Reilly 2003: ; Vine et al 2003: 248).

For the most part, these normative barriers were not found among the utilities in this study. It is demonstrated here that regulatory approval can be an extremely important determinant of whether or not utilities implement new technologies. However, this study finds that utilities can also push this change.

It can be debated if AMI and TOU are radical because they have existed for a number of years and may be less new to utilities than other technologies and programs. However, assuming that they are radical as defined by Markard and Truffer (2006), this study is significant because it shows that the cultural bias of utilities against radical business and technological changes in the form of AMI and TOU has not affected their willingness to implement them. It is true that utilities in this study do not currently consider load shift from their TOU programs a capacity resource. However, the prevailing reasons for this decision result from the economics of these programs. These cases show that the fact that TOU is not a cost-effective resource option is the primary reason utilities do not pursue it. Utilities may be skeptical of TOU, but this study suggests this is attributable to the economics of the programs as they have been carried out, instead of normative barriers.

There is further evidence in the finding that while utilities can be pulled by regulators to implement smart grid technologies, they can also push regulators to approve AMI and TOU programs. In the cases studied, regulators have encouraged utilities to implement TOU programs and utilize AMI with specific capabilities in Oregon. In regulatory proceedings, regulators have asked utilities to implement AMI systems that accommodate time-based ratemaking as well as other DR programs. However, the PGE, PSE and Avista programs are self-initiated. PSE implemented AMI and TOU on its own independently of the regulatory. PGE has also initiated its AMI program, and sought regulatory approval. Avista has also proposed an AMI system.

These findings must be qualified. The PNW has long lead the nation in energy efficiency programs and policies. Utilities may be predisposed seek out alternative energy resources, including DR. This may be the reason that a cultural aversion to DR and AMI is not observed here, while it may be observed elsewhere.

5.1.5 Utility buying behavior as a barrier to AMI

Utilities may be unable to access vendors of new technologies because of their existing relationships with large vendors. This can prevent them from implementing innovative new technologies. Or, by restricting access to a competitive market, relationships with existing vendors may prevent utilities from finding the vendors that will best serve their needs.

This study finds a significant difference between the cost profile of PSE's TOU program and PGE's. It finds that different business models for TOU meter reading and data management—even when utilities roll out AMI on a large scale to capture operational benefits—can result in vastly different cost profiles for TOU programs. This study does not find that different access to vendors explains the difference in cost between PSE's and PGE's programs. However, the business model that a utility chooses for its AMI implementation and TOU program may be affected by utility's access to vendors. It is worth noting that the effect of this variable would be well served by further research.

This study finds that variables other than utility buying behavior may have created the difference in cost between PSE's and PGE's TOU programs. PSE is locked into a long-term contract for data management that started in 1997. By contrast, PGE is implementing AMI at a time when the technology as well as DR capabilities are gaining popularity among utilities (GEF 2005: ; Harper-Slaboszewicz 2007: ; WUTC 2007b). Energy technology vendors are quickly growing and innovating (GEF 2005: ; Harper-Slaboszewicz 2007: ; WUTC 2007b). The difference in the cost of AMI technology and service between these two utilities may result from technological innovation. If access to vendors in these specific cases or others is studied in greater depth, then these variables must be taken into consideration.

5.1.6 Regulatory uncertainty across large areas

A final barrier to AMI and smart grid technologies identified in the literature is that utilities with operations across multiple political boundaries face a different regulatory body in each. Uncertainty regarding regulatory approval of new technologies and programs across political boundaries may prevent implementation of enterprise-wide business and technology change.

The only utility in this study susceptible to regulatory uncertainty across its service territory, PacifiCorp, stated that other reasons have had more weight in its decision not to invest in AMI in the past (Marx 2007a). The presence or absence of the regulatory uncertainty barrier cannot be determined until the other barriers facing the utility are overcome. This study informs this line of inquiry, however, because it finds that large utilities may stand to benefit less than small utilities from AMI's operational benefits. This may be due to the business size and the physical (rather than political) geography of their service territories. These variables of business size and physical geography must be considered when determining the effect of multiple regulators on a utility's decision to invest in AMI.

5.2 Distilled research findings

As shown above, the barriers to the implementation of energy efficiency and smart grid technologies suggested in the literature hold true to varying degrees for the TOU programs of the three utilities studied here. In addition, it is clear these utilities face other barriers not mentioned in the literature reviewed, which have prevented programs from creating economic benefits for utilities and customers. High metering and infrastructure costs coupled with low participation have been identified as reasons why these programs have not been cost-effective. The comparative analysis reveals that high costs have resulted from initiating TOU programs without an existing AMI system. Also, charging part of this cost to customers reduces customer savings and prevents customers from participating. Finally, a mandate that prevents utilities from marketing programs to their customers halts any potential for increasing participation.

5.2.1 Existing AMI systems are necessary for low cost TOU

This study finds that the implementation of TOU programs when AMI is not already in place results in TOU programs that are not cost-effective. The comparison presented here of the costs of TOU across utilities that have and have not had AMI in place prior to initiating their TOU programs reveals this explicitly. In addition, the analysis contained in this study provides benchmarks for utilities and regulators in the region when assessing future TOU programs.

Not only does rolling out AMI for operational benefits reduce the costs of TOU, but this study finds that it may in fact reduce costs to the point at which TOU becomes cost effective for utilities in the region. This is significant because PSE's program, which had an AMR system in place before doing TOU, yet failed with TOU, was recently cited as part of the basis for a policy decision about TOU in Washington (WUTC 2007b). Partially on the basis of the failure of PSE's programs and others in the region (including PacifiCorp's program in Oregon), the WUTC decided not to mandate the use of TOU rates for all utilities (WUTC 2007b). This study cautions that the factors that resulted in the failure of PSE's program may not apply to all utilities in the region going forward. In the comparative analysis in Chapter 4, PSE's program had lower costs than PacifiCorp's and PGE's present program, but it did not necessarily reduce costs to the point of making the program cost-effective. PGE's future program, on the other hand, projects data management costs for TOU customers far below what PSE incurred. This suggests that the operational benefits business model will not only reduce costs for utilities, but may make TOU programs cost-effective in the PNW.

5.2.2 Service charge depresses participation

Charging a service charge to TOU participants has caused low participation in the three programs examined here. This charge dramatically reduced customer savings and customer participation in PSE's program when it was implemented. It has also cut into the savings of participants in PGE and PacifiCorp's programs, resulting in a small incentive for customer participation.

This study finds that this service charge penalizes participants, when participation should be rewarded. As is shown in Chapter 2, customers who shift load to off-peak times provide a net benefit to the electric system. By increasing utilization, load shifting reduces the amount of new resources that must be built to meet demand. In that it reduces the cost of meeting demand, investing in TOU produces a similar effect to investing in energy efficiency. Both eventually reduce electricity costs for the utility, which result in lower costs for all customers. TOU participants produce a benefit for the entire system, however, under current billing practices they must pay extra to do so. This depresses participation, which prevents the program from creating benefits, and keeps its costs high.

5.2.3 Preventing the marketing of TOU programs depresses participation

This study finds that the OPUC's mandate that prevents the marketing of TOU has kept customer participation low for PGE and potentially for PacifiCorp. Through interviews with utility executives, it has become clear that there may be potential for increased participation if marketing were allowed to expand. By preventing marketing, it seems that the OPUC's mandate prevents participation rates from increasing. As a result, although it was enacted to control the costs of cost ineffective programs, it actually prevents them from achieving cost-effectiveness.

This is a particularly significant finding given the rising public concern with the environmental impacts of electricity generation (EIA 2007a). As noted above, the WUTC argued that PSE's TOU program induced high customer load shifts due to public awareness of the societal costs of electricity. More sustained recent increases in public awareness of these issues may give reason to believe that marketing of TOU programs would be increasing effective as time goes on.

5.3 Potential solutions

The findings of this study suggest several solutions to overcome the barriers presented above. First, utility commissions should provide utilities with a measure of security about receiving cost recovery for AMI roll outs. Second, utilities must find ways to reduce or eliminate the service charge to TOU participants. Public utility commissions should cooperate to facilitate this by approving mechanisms that pass these formally costs on to all customers.

5.3.1 Create a regulatory environment to support AMI

It is clear that radical change to utility businesses can originate from both utilities and regulators. This contradicts the assertion that utilities are necessarily averse to change. More importantly, this finding emphasizes that PNW regulators and utilities both have a role in encouraging and facilitating the growth of TOU implementation in the region.

State utility commissions in the PNW should give high priority to enabling utilities to receive cost recovery on AMI investments. They should consider the fact that TOU will likely become a valuable resource option for utilities in the region in the coming years. This study shows that implementing AMI based on operational benefits removes the meter cost from the TOU cost benefit analysis. As a result, PUCs should count these future benefits among their reasons for supporting AMI when it is proposed by utilities. It should be used to supplement “slim” business cases built on other benefits. Additionally, as the OPUC has done when approving PGE’s AMI proposal, PNW regulators should encourage utilities to implement AMI systems that can be used for TOU and other DR programs in the future (Carpenter & Tooman 2007b).

This is significant at this point in time because Avista plans to request cost recovery for an AMI system in its Washington service territory in the near future. The WUTC should analyze Avista’s proposal in light of the fact that AMI is proven to increase the cost-effectiveness of TOU in the PNW, and the fact that TOU is becoming an increasingly important resource. Avista plans to count this among the reasons for its AMI roll out (Cummins 2007). The WUTC is now well-informed to justify the same.

5.3.2 Eliminate the service charge to properly allocate costs and benefits of TOU

PUCs and utilities should eliminate or reduce the extra service charge currently charged to TOU participants in the PNW. This charge is shown to be a significant barrier to participation in TOU programs in the region. Eliminating it will a) properly allocate the costs and benefits of flat and time-based rate structures and b) reduce power costs for all customers by increasing participation in TOU programs.

How will the money currently collected by the utility via this service charge be recovered? First, if and when possible, the amount that must be recovered should be reduced by rolling out AMI for operational benefits. This will mitigate the high cost of TOU to the utility and to customers.

Second, the remaining cost that must be recovered should be recovered from all customers, not just TOU participants. The recovery mechanism may take the form of a public benefits charge or a tariff rider, which have for many years recovered revenues lost from the aggressive implementation of energy efficiency programs in the PNW (NPCC 2007a: ; ODOE 2007: ; PGE 2007b: ; PSE 2001a). DR should be funded via similar charges levied on all customers.

5.4 Long-term prospects for AMI and TOU in the PNW

In planning for the future of the PNW electric system, there are important reasons that utilities, regulators and policymaker in the PNW should encourage investment in AMI and DR capabilities. First, the "smart grid," of which AMI is a key technology and dynamic pricing is a key capability, is a long term vision (Loeff 2007a: ; Pullins 2007). Smart grid experts find that long term planning and early adoption is necessary if the benefits of the smart grid are to materialize (Loeff 2007a: ; Pullins 2007). As noted above, utilities in other regions of the country are in the process of deploying AMI systems with visions of future capabilities. While the PNW may not be currently facing a capacity crisis, borrowing this idea of early deployment of AMI in the interest of long-term planning will undoubtedly pay off.

Second, state and local policymakers in the PNW should also aggressively encourage utility deployment of AMI and other smart grid technologies to grow the local regional energy technology industry. Regardless of the reader's opinion of the value of DR for the PNW, its energy technology industry stands to benefit from local implementation of smart grid technologies. The region has recently been identified as regional cluster of smart energy technology firms and innovation (Anderson 2005: ; Du

Bois 2007: ; Mazza 2005: ; Pernick 2007: ; Suter 2005). The region has long been home to prominent smart energy firms, including one of the largest global meter technology companies, Itron (Reilly 2003). The PNW is also endowed with a number of important energy research facilities at universities and national labs that focus on power engineering and smart energy technologies (Reilly 2003). Many analysts believe that the key to growing this regional cluster is to create local markets through policies that encourage the use of these technologies by utilities (Du Bois 2007: ; Pernick 2007).

5.5 Beyond the PNW

Chapter 1 described the energy crisis facing the US. Chapter 2 described the way in which TOU rates administered via AMI can mitigate the negative effects of this crisis and reduce energy costs to utilities, customers and the environment. This chapter has asserted the strategies that utilities and regulators should employ to make these innovative solutions a reality. A brief look at recent developments in utility implementation of AMI and TOU rates across the US supports the findings and recommendations in this study.

As mentioned in Chapter 3, only about 6% of all electricity customers in the US have smart meters, and only 2% of utilities with meters installed utilize them for TOU rates (FERC 2006: 26). Yet, recent actions by utilities, regulators and policymakers show that implementation of AMI and DR programs is increasing across the US. Just months before the completion of this study, utilities and regulators made it clear that this is beginning to change (FERC 2006: 26, 31; Kathan et al 2007).

For example, Duke Power, a large investor-owned utility serving over four million customers in the Southeast and Midwest US, has recently decided to roll out AMI on a large scale over the next few years (Berst 2007a: par 3). Duke plans to implement a variety of DR programs over its AMI system in the future. Operational benefits serve to justify the AMI rollout before these programs are implemented. The eventual goal of Duke's program is the facilitation of widespread DR programs (Berst 2007a: par 15).

Southern California Edison (SCE) has also recently filed a business case with the California Public Utilities Commission (CPUC) to deploy AMI for many of its customers (SCE 2007: par 1). Similar to Duke Power, SCE's business case was comprised largely of operational benefits, but also the expectation of future DR benefits (SCE 2007). Supporting the idea that regulators must be active in promoting the use of TOU and AMI, SCE's initiative has been supported by the CPUC. First, the CPUC is allowing SCE to gain cost recovery on its investment (Du Bois 2007). Second, the CPUC is encouraging this action among all utilities in California by mandating that utilities must implement widespread DR and TOU rate schedules (Du Bois 2007).

Other government bodies have also begun to push the deployment of AMI by the utilities in their states (Kathan et al 2007: 31). For instance, Connecticut has made it mandatory for utilities to offer TOU rates to customers, and obliged utilities to develop AMI deployment plans before the rate schedules take effect (Kathan et al 2007: 14). Connecticut's program is particularly interesting because all customers may have meters installed on their premises on demand, and the costs of these meters are recovered through surcharges added to *all* customers' rates (Kathan et al 2007: 14; McNamara 2007).

The experiences of utilities across the US support the findings and recommendations of this study. First, they suggest that operational benefits business cases are indeed the solution to overcoming the high cost of AMI barrier. It is also evident that sometimes, operational benefits do not necessarily have to cover the full cost of these systems, and the difference can be made up with the anticipated future benefits of DR. Second, the Connecticut program supports the assertion in this study that the cost of a program that creates a system wide benefit should be spread across all customers, rather than born solely by participants. Connecticut's model of distributing this cost is exactly what is recommended in this study. It is also very clear that regulatory support has been instrumental in these future implementations of AMI and TOU programs.

5.6 Future research directions

This study has identified a number of issues that would benefit from more in-depth treatment with future research. The effects of cultural barriers to DR should be analyzed further. Quantifying the system benefits of customer participation in TOU per customer would be useful for supporting policies to spread costs of these programs across all customers. Further research into the costs of different meter reading and data management strategies would also support regulatory and utility decisions about AMI systems.

Cultural barriers to DR in different states across the country should be analyzed as a function of a state's past policies and experiences with energy efficiency. This study finds that the PNW's utilities are not culturally averse to DR investments, while the literature suggests that they should be. It is possible that this is due to the PNW's history of aggressive implementation of efficiency programs. To confirm or deny this for the PNW or other regions of the country requires analysis of other cases with the state or utility as the unit of analysis. This research would be useful to the marketing departments of AMI technology vendors, state and national policymakers.

Further research should also analyze the amount of load shifted as a function of a TOU program's attributes. This study finds that the size of the incentive available is a determinant of participation. Participation rates partially determine program costs and serve as a proxy for the level of benefit a program creates. However, to properly value AMI systems and DR programs, it is necessary to understand in detail what determines the level of benefit each participant creates for the system.

More research is also needed to identify how the costs and benefits of voluntary TOU programs should be allocated, and the mechanisms by which costs should be recouped. How much cost should a utility pass on to all customers to 1) remove the need for a service charge for participants and 2) more accurately charge non-participants for the costs that they impose on the electric system? What model can be used to determine the level of cost per customer justified by the system benefits created? Also, which policy mechanisms are most appropriate for distributing these costs? Is the tariff rider model, which PNW utilities have employed for years to recover the costs of energy efficiency, applicable to DR? Can new models of allocating costs be enabled by AMI systems?

Finally, a systematic investigation of the determinants of meter reading and data management costs would build on one of the most important issues identified in this study, which is the vast discrepancy in meter reading and data management costs among the programs analyzed. This study identifies some characteristics that seem to determine the cost of adding these technologies and processes, yet further case study research or analysis of existing case studies should identify others. Then, the costs of adding these technologies and processes as a function of these characteristics could be analyzed systematically. This would provide a decision tool for utilities considering different business models for meter reading and data management systems.

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