Demand Response Compensation Methodologies: Case Studies for Mexico

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National Renewable Energy Laboratory

Technical Report
NREL/TP-7A40-71431
June 2018

CLEAN ENERGY MINISTERIAL
Accelerating the Transition to Clean Energy Technologies

Contract No. DE-AC36-08GO28308

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Prepared under Task No WACC.11097.01.01.04

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

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NOTICE

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Acknowledgments

This work was performed in response to a solicitation from Deutsche Gesellschaft fur Internationale Zusammenarbeit, in collaboration with the Regulatory Assistance Project, and Mexico's Energy Regulatory Commission (CRE), Secretary of Energy (SENER), and Independent System Operator (CENACE). Many thanks to Francisco Granados, Carlos Godard, Tania Villanueva, and Sergio Domínguez from CRE, and Riccardo Bracho, Elaine Hale, and Patricia Statwick from the National Renewable Energy Laboratory for their comments and consultative guidance in the formation of the paper.

List of Acronyms

AC	air conditioning
C&I	commercial and industrial
CAISO	California ISO
CENACE	National Energy Control Center (Centro Nacional de Control de Energía)
CFE	Federal Electricity Commission (Comisión Federal de Electricidad)
CIDLC	commercial and industrial direct load control
CPP	critical peak pricing
CRE	Energy Regulatory Commission (Comisión Reguladora de Energía)
DR	demand response
DSM	demand-side management
FERC	U.S. Federal Energy Regulatory Commission
FSL	firm service level
HECO	Hawaiian Electric Company
ISO	independent system operator
ISO-NE	Independent System Operator – New England
kW	kilowatt
kWh	kilowatt-hour
LBNL	Lawrence Berkeley National Laboratory
MW	megawatt
MWh	megawatt-hour
PAC	program administrator cost
PG&E	Pacific Gas and Electric Company
PT	participant test
PUC	Public Utilities Commission
RDLC	residential direct load control
RIM	ratepayer impact measure
SDG&E	San Diego Gas and Electric
SEMARNAT	Natural Resources and Environmental Ministry (Secretaría de Medio Ambiente y Recursos Naturales)
SENER	Energy Ministry (Secretaría de Energía)
TOU	time of use

Executive Summary

Demand response (DR) can refer to a variety of approaches to changing the amount and timing of customers' electricity use, allowing the electricity supplier to more easily balance electricity supply and demand. Although there is no single framework for a successful DR program, there are common key ingredients that many existing successful programs share. At a high level, these include: low barriers to entry for potential participants, a compensation methodology that encourages participation, and confidence that there is sufficient reliable DR during peak hours to avoid building new capacity.

Although the objectives of a DR program may be clear, the details of its implementation often involve a tradeoff between the needs of the electricity supplier and the participating customers. Three case studies presented in this paper, including New England, California, and Hawaii, summarize some of the tradeoffs inherent in several common types of DR programs:

1. Residential water heater control programs for DR in the United States have typically been cost effective in comparison to the avoided cost of new generation but require the participation of many households to achieve significant demand reductions, which can result in significant administrative costs.
2. Special DR contracts with large commercial and industrial users provide for greater flexibility in the negotiation of compensation and performance terms and can result in large demand reductions from a small number of participants. However, they often require one-on-one negotiations with each participant unless a standard contract is developed.
3. Incorporating DR services into wholesale power markets can greatly increase DR participation. For Independent System Operator-New England, DR participation rose from 100 megawatts (MW) in the pre-market programs to 1,400 MW of on-peak demand resources in the wholesale market. However, there are significant market design changes and metering and communications requirements involved in this approach, making it a relatively complex DR approach to implement.

Although DR program structure is an important element, the compensation methodology of a program can define its success. DR participation often requires a capital outlay by either the supplier or participant, much like a utility generation resource, and compensation must be sufficient for recovery of the capital investment to incentivize participation.

Some compensation approaches that may be applicable to the energy market context of Mexico include:

- A new rate schedule for commercial and industrial users that includes monthly payments based on participant performance during an event-based request for load shedding. Financial incentives for the installation of DR-enabling equipment at the DR provider's site (e.g., advanced metering infrastructure) can also potentially lower the barrier to entry for new participants and increase participation.
- Special contracts with large commercial or industrial users, with negotiated compensation terms that are equitable to both parties.
- Qualified aggregators can be an effective means to increase participant enrollment.

- Integration of DR services into the Mexican wholesale power market, allowing day-ahead and real-time market pricing to establish the value of the DR services provided.

The level of compensation for a DR program will depend greatly upon both the regulatory context of the electricity supplier, as well as the economic circumstances of the DR providers. For a regulated utility, a proposed compensation level may need to pass regulatory approval. To determine the value of DR resources, a regulatory body typically seeks to determine the costs that the utility would avoid if demand-side resources “produce” energy. Four commonly used avoided-cost formulas developed by the California Public Utilities Commission include the Participant, Ratepayer Impact Measure, Program Administrator Cost, and Total Resource Cost tests. A more detailed approach, used in Hawaiian Electric Company’s Power Supply Improvement Plan, involved calculation of the avoided cost of DR services based on production simulation of the entire Hawaiian Electric Company grid at an hourly level through 2021. As an alternative to the avoided-cost approaches listed above where the electricity supplier must estimate a fair compensation level, a wholesale market approach can dynamically price the value of DR services based on current market conditions.

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1 Fundamentals of Demand Response

1.1 Overview and Definitions of Demand Response

Electricity must be generated at the moment it is needed to reliably meet the demands of all customers. When an individual turns on an air conditioner in the home or when a manufacturer turns on a conveyor in the factory, these utility customers expect their devices to start operating immediately. However, electricity cannot be effectively and efficiently stored in large quantities to meet such instantaneous demand. It must be delivered exactly when it is demanded.

Ensuring reliable grid-scale delivery of electricity requires a constant, real-time effort to match supply from power generation resources with ever-fluctuating demand from residential, municipal, commercial, and industrial customers. For most of history, this has been accomplished with a variety of quickly dispatchable power generating technologies such as diesel engines and gas turbines. The more recent proliferation of variable renewable generating technologies such as solar photovoltaics and wind turbines has added to the challenge of balancing supply and demand of electricity to consumers.

Demand response (DR) refers to a variety of formal approaches to changing customers' amount and timing of electricity use, allowing the electricity supplier to more easily balance electricity supply and demand. DR incentivizes consumers to shift, reduce, or increase their electricity usage during certain periods in response to signals from the electricity supplier. During times of peak load, DR effectively becomes a source of power for the system. With DR programs, the electricity supplier can avoid or delay construction of new, expensive generation resources or even increase the penetration of variable renewable generation.

In Mexico, DR is defined by law as "the demand for electric power that end users or their representatives offer to reduce according to the market rules." Further, "guaranteed DR" is defined as "the demand response that end users or their representatives have committed to offer in the wholesale electricity market in a given period to meet grid requirements for balancing supply and demand" [1].

Other international definitions of DR more broadly include changes—both increases and decreases—in electric usage at various times of day or during various system conditions, and not just reductions intended to shave peak power. In Europe, the following description of DR has been published:

> "… demand response is to be understood as voluntary changes by end-consumers of their usual electricity use patterns – in response to market signals (such as time-variable electricity prices or incentive payments) or following the acceptance of consumers' bids (on their own or through aggregation) to sell in organized energy electricity markets their will to change their demand for electricity at a given point in time. Accordingly, demand response should be neither involuntary nor unremunerated." [2]

The U.S. Federal Energy Regulatory Commission (FERC) currently defines DR as follows:

> "Changes in electric usage by demand-side resources 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." [3]

It should be recognized that implementation by the electricity supplier and participation by certain customers provide both monetary and intangible benefits to the electricity supplier and its customers.

1.2 Electricity Balance and Opportunities for Demand Response

The supply and demand balance of electricity is driven primarily by customer needs for process heat, lighting, cooling, and running appliances (among others). Factors such as the weather, economic activity, and customer mix (e.g., relative proportions of residential, commercial, and industrial customers) strongly influence demand in a given area. Demand forecasts require an intense effort to predict customer demand while considering constraints on the delivery network (transmission and distribution) and attempting to anticipate events that cannot be accurately predicted, such as forced outages.

On the electricity supply side, there are three major components: capacity factor, delivered energy, and ancillary services.

- *Capacity factor* refers to the amount of electricity that can be generated reliably by a power plant to meet load requirements. Capacity factor is less than a plant's rated, or nameplate, capacity due to factors such as scheduled maintenance, outages, and other factors. Nuclear and coal plants tend to have the highest capacity factors. The capacity factor of variable generation plants, such as wind turbines and solar photovoltaic modules, is more difficult to determine, but it is generally much less than the nameplate capacity due to the variability of the wind and sun resources.
- *Delivered energy* refers to the electricity generated and delivered to consumers. For example, a power plant with a nameplate capacity rating of 50 megawatts (MW) may have a reliable market capacity factor of 40 MW, but during a given hour of the day, the power plant may operate at partial load and deliver only 20 megawatt-hours (MWh) of electricity to the grid.
- *Ancillary services,* such as spinning and non-spinning reserves, and frequency regulation, are "those services necessary to support the transmission of electric power from seller to purchaser … to maintain reliable operations of the interconnected transmission system." [4]

On the demand side, the market is often broadly categorized into two types of demand: baseload and peak load. Baseload demand comprises demand that occurs regularly and predictably throughout the day (e.g., lighting, refrigeration) whereas peak load demand is demand that occurs only at certain times and usually at the same time across a group of customers (e.g., air conditioning (AC) on a hot summer afternoon). Figure 1 shows an example of electric power demand for a day in New England.

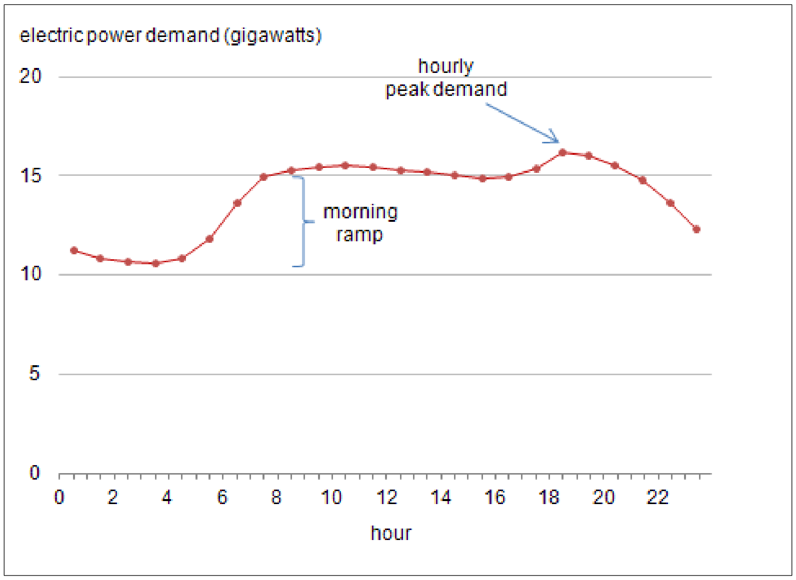

Figure 1. Electric load curve: New England, 10/22/2010 [5]

DR programs are used by suppliers as resource options for balancing supply and demand or deferring investment in transmission and distribution reinforcements. Such programs can lower the cost of providing electric services in vertically integrated systems, for distribution service providers, or in wholesale markets, which in turn, leads to lower retail rates.

DR can be used to supply various products required by the electric system as follows:

- *Resource adequacy* ensures there is sufficient capacity during peak hours.
- *Energy resource* provides or consumes energy, resulting in more efficient use of capital assets and price reductions in the markets.
- *Ancillary services* support grid stability by managing grid frequency or regulation reserves.
- *Zone-specific transmission and distribution* assist with shoring up weak points in the transmission and distribution system, potentially deferring transmission system upgrades.

The most common product supplied by DR is resource adequacy. Load is interrupted when the system becomes short on supply, and DR acts as a peak shaving resource. As variable renewable resources contribute more heavily to the power supply, DR will become a valuable tool to balance supply and demand.

1.3 Types of Demand Response Programs and Characteristics

DR may be categorized in several ways. At the highest level, DR is a subset of demand-side management (DSM). Energy-efficiency efforts represent the other aspect of DSM, focusing on a permanent reduction in demand.[6]

DR may be categorized as dispatchable or non-dispatchable. Generally, for a dispatchable resource, the system operator curtails the resource in response to a system reliability event or market prices. Dispatchable DR resources are most reliable when the provider (utility customer) is obligated to change load by contract, controlled by the system operator, and required to meet measurement and verification standards.

Non-dispatchable resources on the other hand are considered voluntary and may participate as a DR resource by lowering their consumption based on pricing signals. While these resources provide a valuable service to the system, they are less reliable than dispatchable resources. However, as experience is gained with an array of non-dispatchable resources, system operators can gauge the likely response of voluntary DR resources.

Dispatchable DR is further classified into economic decisions and reliability decisions. An economic-based decision for DR would involve a contract for the DR resource to bid into the wholesale electricity market to offer load change at a price or otherwise to identify how much load can be curtailed at a set price. This is referred to as demand bidding and buy-back.

Reliability decisions for dispatchable DR ("event-based") may focus on one of four areas: capacity, reserves, energy, and regulation.

1. *Capacity* refers to the generation supply where DR can augment generation by supplying "negawatts" to the system, lowering the need for traditional generation capacity. Capacity-focused dispatchable DR could include structures such as direct load control management, interruptible load, critical peak pricing, and load as a capacity resource.
2. *Reserves* often refer to generation that is sufficiently responsive to help balance supply and demand during the first few seconds or minutes of a grid event. DR reserves may be similar to spinning reserves that are synchronized and ready for service in that they can be activated automatically or on very short notice. DR reserves can also be similar to non-spinning reserves not connected to the system but capable of serving demand within a specified time to respond to grid imbalance. DR reserves are connected to the system, and using energy, but the user is able to be curtailed under circumstances of stress to the system.
3. *Delivered energy* refers to the specific amount of electricity supply over a period of time. DR resources can be used to reduce demand on the grid in the case of generator or system emergencies, or for peak load reduction.
4. *Regulation*, like operating reserves, is an ancillary service used to maintain the target system frequency within predetermined limits. For example, DR resources may follow a dispatch signal for frequency regulation.

Non-dispatchable DR resources are generally tied on a voluntary basis to time-sensitive pricing decisions ("price-based"). Four pricing scenarios fall into this category: time-of-use (TOU) pricing, critical peak pricing, real-time pricing, and system peak response transmission tariff.

1. *Time-of-use pricing* refers to rates or prices set well in advance of the actual demand response events, which differ according to different blocks of time. Typically, there are peak and off-peak seasons and hours.
2. *Critical peak pricing* sets a high rate for consumption during periods of high wholesale market prices or system contingencies. Customers are notified approximately a day ahead of when the critical peak period will be.

3. *Real-time pricing* reflects rates or prices that change with wholesale prices on either a day-ahead or hour-ahead basis.
4. *System peak response transmission tariff* is a rate or price structure that is engaged to reduce transmission congestion.

Although the North American Electric Reliability Corporation classification of DR services is helpful to understand how DR is measured and valued, it is equally important to understand how the customers' load is ultimately managed by curtailing, shifting, shedding, or onsite generating [7]. These are categorized in a report by the Lawrence Berkeley National Laboratory (LBNL) into four "service types": Shape, Shed, Shift, and Shimmy. Although significant additional detail is given in the paper *Final Report on Phase 2 Results: 2025 California Demand Response Potential Study*, Figure 2 demonstrates one potential way to categorize various DR types based on customers' power consumption [8].

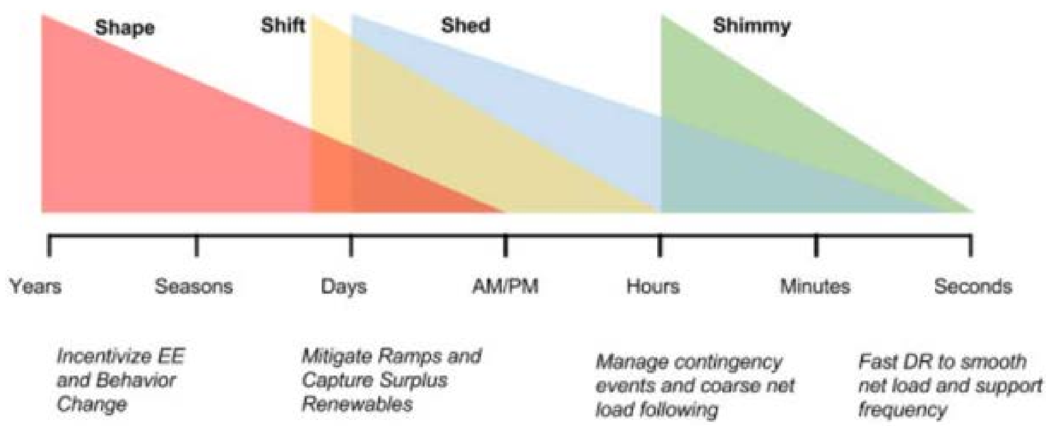

Figure 2. DR service types [8]

When a load is curtailed, power consumption is reduced by accepting the curtailment, and the customer does not intend to make up the foregone energy use at a later time. For example, DR programs that target temperature adjustments to AC do not anticipate the user will increase load later.

When a load is shifted, the power consumption may be rescheduled for a time when the price of power is lower or system reliability concerns are more manageable. In a shifting scenario, the customer intends to make up the energy use later. Some load shifting programs can create new peak loads if not managed carefully. For example, controlling many water heaters can create load issues when a large group is returned to service all at once.

DR achieved through on-site generation reduces demand on the grid without affecting customer service levels. However, on-site fossil fuel generation may be subject to air permitting or other operating requirements limiting their use.

From another broad perspective, there are two types of DR programs: measure based, and performance based. Measure-based DR is targeted at a specific end use, the load interruption is controlled by a third party, and there are limits on the frequency and duration of interruptions.

Performance-based DR gives the customer the flexibility to choose when and how often to reduce its load, as well as how much it will reduce. However, there can be penalties for non-performance.

1.4 Benefits of Demand Response

While early efforts with DR were a reactive measure to prevent brownouts or blackouts, mature DR programs can deliver a wide range of benefits to electricity suppliers, DR participants, non-participating utility customers, and to society more broadly.

At its core, the increased market efficiency and resulting benefits of DR are categorized as follows [9]:

Participant financial benefits: Customers adjust their demand, resulting in a lower bill or incentive payments.

Market-wide financial benefits: With reduced demand during peak periods, the need to dispatch higher-cost power plants is reduced. This results in lower wholesale electricity production costs and prices.

Market performance benefits: Sustained DR can lower capacity requirements and allow utilities to avoid the expense of new power generating capacity. As power prices match production costs more closely, the savings can be passed onto retail customers.

Reliability benefits: DR can lower the likelihood and consequences of forced outages that impose financial costs and inconvenience on customers.

Some of these benefits are more easily quantifiable than others. The cost avoided when a more expensive power plant is not dispatched can be estimated from the avoided variable operating costs associated with the power plant.[1] This cost can be translated into a price that is acceptable to the market. Other DR benefits have value not easily translated into price, including potential environmental benefits from reduced power plant operation, flexible customer usage options,[2] and increased flexibility to respond to system contingencies.

1.5 Measurement and Verification

An effective DR program requires the ability to measure (meter) and verify the impact of a DR program participant, calculating the change in demand during the event from a baseline load profile (shown in Figure 3). Both elements are necessary as measurement quantifies the change while verification provides evidence that the measured change is valid.

[1] In competitive markets, a reduction in use can also reduce the energy clearing price, thereby reducing the price of all power consumed or sold during the period.
[2] Where a customer does not have to accept the rate provided by the utility but can actively manage load to reduce costs.

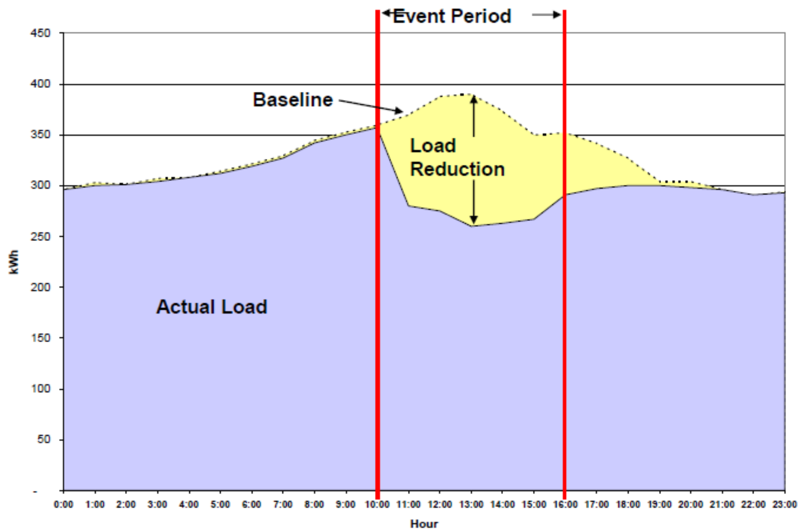

Figure 3. NYISO baseline example [10]

The accuracy of both the baseline estimate and the actual curtailment is important to the utility to avoid paying too high an incentive for DR while still encouraging participation by customers, and to the customer to accurately recognize their value in participating in the DR event and to avoid non-performance penalties.

Every utility customer has a meter installed to measure customer electricity consumption and revenue for the utility. Although a basic electricity meter records the flow of power to a consumer (in watts or kilowatts [kW]), new and developing technologies can provide advanced metering to capture instantaneous usage such as watts, current, voltage, and power factor. Data storage capability varies by technology but can be adapted to a project's specific requirements. As data are captured and communicated to stakeholders, other technologies provide for analysis, automation, and remote load control. Production and consumption meters are essential, though other inputs such as weather data are necessary to achieve valid DR results.

System operators and utilities develop comprehensive manuals that specify equipment, baseline analysis, methods, calculations, audits, certifications, and documentation requirements for participation in a DR program. These manuals are revised from time to time to reflect upgrades across the elements of the DR program, and are essential to the transparent collaboration among the DR program's stakeholders.

1.6 General Compensation Guidelines

Utilities around the world are expected, if not required, to provide reliable electric service at least cost. With respect to DR resources, this means that utilities should be willing to pay up to their avoided costs to acquire equivalent services from DR. The value of avoided air emissions or the value of other externalities, such as avoided greenhouse gas emissions, may be included in these cost calculations.

In determining the level of compensation available for DR resources, answers to the following questions are informative.

- What is the targeted resource worth to the system?
  - Capacity = cost of peaking plant (if the system needs additional capacity)
  - Energy = peak energy price (if the resource is available at peak times)
  - Avoided carrying costs
  - Avoided externalities, such as air emissions.
- Will consumers participate at that price?
- Is participation sufficient to warrant a program?
- Who pays for implementation costs?

Example: Calculating value for interruption of domestic electric hot water heaters.

A simple example is to look at the capacity value of interrupting domestic water heaters. Using a load profile for domestic water heaters, a system or area peak coincident load contribution is established for each appliance. In this example, the average domestic water heater can be expected to draw about 0.25 kW during the summer peak (hour 16 to hour 18), and about 0.5 kW during the winter peak (hour 6 to hour 9). The value of the load interruption to resource adequacy, using an example value of a peaking plant as a proxy, along with the summer peak, would be $35.75 per year, or $2.97 per month.

The calculation is as follows:

Resource adequacy = Gas turbine peaking plant

Carrying cost of a gas turbine = $130.00/kW-yr * Coincident domestic water heater peak load

Coincident domestic hot water heater peak load = 0.25 kW * 1.1 = 0.275 kW (adjusting for marginal losses)

0.275 * $130.00 = 35.75/yr or $2.97/mo

2 Regulatory and Policy Framework for Demand Response in Mexico

2.1 Mexico Electricity Market Authorities

In December 2013, the Mexican Constitution was amended by the Mexican Congress, which began the Energy Reform, a process of modernization of the electricity sector in Mexico. An understanding of the Mexico electricity market requires an understanding of the roles and responsibilities of the principal authorities overseeing the generation, transmission, and distribution of electricity.

2.1.1 Energy Ministry (Secretaría de Energía) (SENER)

SENER is responsible for establishing, supervising, and enforcing Mexico's energy policy within the framework of Mexico's constitution. SENER's role is to guarantee the competitive, sufficient, high quality, economically viable, environmentally sustainable, and fully accessible supply of energy for the people of Mexico.

2.1.2 Energy Regulatory Commission (Comisión Reguladora de Energía) (CRE)

Construction and operating permits for generation, transmission, and distribution of electricity are issued by CRE, the regulatory agency for the markets. Rates and fees for interconnection and power supply are determined by CRE. CRE must regulate the participation of public and private companies in the electricity market, assuring transparency in contracts, permits, and bidding to support efficient market function.

2.1.3 National Energy Control Center (Centro Nacional de Control de Energía) (CENACE)

The Independent System Operator (ISO), the newly formed regulatory authority CENACE, is responsible for operational control of the national electric system, for operation of the wholesale electricity market, and for guaranteeing impartiality in access to the national transmission and distribution networks.

2.1.4 Federal Electricity Commission (Comisión Federal de Electricidad) (CFE)

Historically, the public electricity market in Mexico was predominantly under the purview of CFE, a vertically integrated electric utility created and owned by the Mexican government. Although the market is no longer restricted with the passage of new laws and regulations, CFE has established subsidiary units for power generation, transmission, and distribution, and markets electric power for over 35 million customers (nearly 100 million people).

2.1.5 Natural Resources and Environmental Ministry (Secretaría de Medio Ambiente y Recursos Naturales) (SEMARNAT)

SEMARNAT is Mexico's ministry ensuring the protection, conservation, and use of the country's natural resources. To that end, SEMARNAT is responsible for the environmental interaction of Mexico's power plants and related infrastructure, preventing and controlling pollution, managing water resources, and fighting against climate change. Whereas CRE authorizes power generation, SEMARNAT is responsible for conducting an environmental impact assessment and authorizing federal environmental, safety and health impacts.

2.2 Overview of Laws, Regulations, Policies, and Market Programs

Following a constitutional amendment in 2013 and congressional legislation in 2014, Mexico opened its energy markets, including the competitive sale of electricity, to allow the private sector to compete in activities that were previously integrated vertically and exclusive to the Mexican state. This law, and the subsequent enabling legislation, are summarized in Table 1.

Table 1. Key Laws and Regulations that Affect DR in Mexico

Electricity Industry Law (LIE) [11]
Effective August 12, 2014, the LIE opened electricity generation, transmission, distribution, and power market activities to private sector participation. The LIE provides certain attributes to SENER to determine the use of DR. Article 12 of the LIE explicitly provides CRE with the authority to determine the methodologies and criteria for compensation of DR services from basic service consumers.
Energy Transition Law (LTE) [12]
In December 2015, passage of the LTE superseded all previously enacted legislation and became the cornerstone of Mexico's legislation on clean energy. It provides a new regulatory framework that allows all energy sector participants to coordinate long-term efforts to reduce polluting emissions, and to do so at a lower cost. The LTE establishes that SENER, through the clean energy goals and energy efficiency goals, will promote power generation via clean energy sources to allow industry to comply with standards established in Mexico's General Climate Change Law and Electric Industry Law. Companies incorporated in Mexico as well as multinationals with operations in Mexico must comply with the law's clean energy and energy efficiency goals.
Electricity Market Rules [13]
Released September 2015 by SENER, the Electricity Market Rules specify that DR resources and market will be part of the second stage of the wholesale electricity market, which is scheduled to begin sometime in 2018. DR is covered in Sections 9, 9.6, and 10.3.11 of the Electricity Market Rules.
Manual for Short-Term Energy Market Rules [14]
The Manual, which has rules for short-term energy markets, was released June 2016 by SENER. Although the manual does not address DR directly, it does provide guidance on topics that touch on DR such as types of energy products, services, and reserves (Section 2.3.1), voltage control (Section 3.3.1), and automatic generation control (Section 6.10).
Power Balance Market
Released September 2016, this applies to guaranteed DR. Guaranteed DR is covered in Section 5, Power Accreditation; Section 6.2, Requirement of Demand; and Section 8.7, Non-compliance of Net Power Obligation.

Two categories have been created for the commercialization of electricity and associated products: Supplier[3] and Generator. In the Supplier category, there are three variations: Basic Services Supplier, Qualified Services Supplier, and Last Resort Supplier.

A Basic Service Supplier is an entity that offers basic supply to basic supply users and represents in the wholesale electricity market the exempt generators that require representation in the wholesale market. Basic service suppliers serve customers that cannot participate in the

[3] What would be called a retail supplier in the U.S. context.

wholesale electricity market. Power is supplied to residential and small, commercial consumers under a regulated tariff structure.

A Qualified Service Supplier is an entity that offers a qualified supply to qualified users and represents power supply for exempt generators in the wholesale electricity market. Large energy consumers purchase power from qualified service providers under negotiated power purchase agreements; prices are not regulated. Qualified service suppliers purchase electricity from the wholesale electricity market.

A Last Resort Supplier offers a last resort power supply to qualified users in emergencies under maximum rates.

Basic service suppliers and qualified service suppliers can participate in the DR market by serving as aggregators providing either guaranteed DR services, regular DR services, or both.

There are two types of DR available for basic service suppliers, as shown in Table 2.

Table 2. Guaranteed and Regular DR

Guaranteed DR

- For large energy users
- Participate in energy market; committed by end users to meet grid requirements for balancing supply and demand
- Can offer three types of services:
  - Energy/avoided energy
  - Power/avoided demand
  - Ancillary services
    - Frequency reserves
    - Spinning reserves
    - Operating reserves
    - Supplementary reserves
    - Reactive power for voltage support
- Directly modeled by CENACE
- Directly metered
- Remotely controlled by CENACE
- Dispatchable

Regular DR

- For small energy users
  - Can be residential, commercial, or industrial; do not directly participate in wholesale market, but instead offer reductions to Basic Service Supplier
- Energy market participation optional
- Can provide two types of services:
  - Energy/avoided energy
  - Ancillary services
    - Voltage support
- Indirectly modeled by CENACE; data provided by supplier to CENACE
- May or may not be directly metered
- Can be remotely controlled by CENACE or other mechanisms (e.g., incentives)
- Dispatchable, but may not respond, depending on the incentives and the effort of the provider to inform users about the benefits

The Basic Service Supplier aggregates small reductions from many customers. Customers are compensated by the Basic Service Supplier at a rate determined by CRE. The Basic Service Supplier in turn sells the aggregated reduction to the energy market and receives wholesale electricity market rates.

Basic Service Suppliers can benefit from DR in three ways:

1. Reduced energy purchases in the day-ahead or real-time markets
2. Reduced capacity purchases to meet their obligations
3. Reduced renewable energy certificate obligations, because the renewable energy certificate requirement is based on energy purchased.

A third-party DR provider can be an intermediary between the customer and the Basic Service Supplier. Third-party DR providers are not explicitly mentioned in Mexican legislation, but nothing forbids their existence at this time. Third-party managers of DR programs will not have a direct relationship with CENACE. In other words, they will not directly sell DR products to the wholesale electricity market but must work with a Basic Service Supplier who receives payment from CENACE for these products. Basic Service Suppliers can also choose to provide DR services directly to customers or go through a third-party intermediary.

CRE will issue the models for contracts, the criteria for participation, and the methodologies for compensation, which must reflect the economic value to the Basic Services Supplier.

2.3 Mexico Priorities for Demand Response

Mexico is still in a phase of definition for DR, but the priorities are clear: focus on the development of a payment mechanism and contract model for the basic supply service (CRE) along with the definition and technical criteria for the wholesale market (CENACE).

In the 1990s, Mexico established Interruptible Rate Tariffs, which applied to the largest users (greater than 10 MW of average maximum load, minimum of 7 MW available for DR). The tariff has a minimum period of performance of one year and can include up to 20 events of up to 6 hours per year. Participants must be notified at least 15 minutes before an event, but face nonperformance penalties of six times the monthly rate for demand that was not reduced. DR compensation in 2017 ranges from $US46 to $US50/kW in monthly payments.

The next step in the development of DR in Mexico is evaluation of potential DR resources in Mexico and a general characterization of the technical requirements needed for implementation. DR programs can be designed to deliver additional resources to the system and provide cost savings for all participants. It is necessary to determine what DR resources are needed by the system and to design a program to acquire those DR resources at a competitive cost, while paying a price that encourages continued participation in the DR program. Mexico’s authorities are evaluating both price-based and event-based demand response options for Basic Service Suppliers, as well as the wholesale market.

2.4 Demand Response and the Wholesale Market

In the future, users of Basic Supply with Controllable Demand will be able to offer DR and associated products through a Basic Service Supplier, which will act as a DR aggregator. Basic Service Suppliers representing Controllable Demand Resources will then be able to offer capacity, energy, and eventually ancillary services into the wholesale electricity market. Participation will be based on the methodologies and contract models issued by the CRE, which will reflect the economic value that these services provide to the supplier.

In particular, CRE is empowered by law to issue the following regulatory instruments:

- Purchase and sale contract models for users of basic services with controllable demand
- Authority to determine and update the applicable compensation mechanisms and participation criteria for the program.

Controllable Demand Resource offers will be implemented in the second stage of the Mexican Wholesale Electricity Market. The second stage of the Short-Term Energy Market (which includes both the day-ahead market and the real-time market) will begin operations between 2017 and 2018, in accordance with the specific component of the wholesale electricity market in question.

The market rules define two types of controllable demand resources:

1. *Guaranteed Controllable Demand Resources* are controllable demand resources where providers are required to submit price purchase offers to the day-ahead and real-time markets for all capacity or other service bid into the market:
   A. The purchase offers shall correspond to a 100% reduction in guaranteed controllable demand resources at a price equal to or less than the maximum bid established by the market surveillance unit.
   B. In the second stage market, CENACE may calculate the opportunity costs for guaranteed controllable demandable resources with limited energy. In that case, the use of such opportunity costs in the guaranteed controllable demand resource offers will be optionally includable as well.
2. *Non-guaranteed Controllable Demand Resources* consist of purchase offers sensitive to the short-term energy market prices below the top bid and are exempt from bidding requirements, so that the use of price-sensitive purchase orders is optional.

In addition, the power balance market establishes that the activation of a controllable demand resource will imply a reduction of the annual power requirement for the responsible supply entities that represent them.

3 Demand Response Compensation in Practice

3.1 Case Studies

DR is an established approach utilized by utilities worldwide to incentivize consumers to reduce or shift their load during peak periods. The United States has led the development and implementation of DR programs as early as the 1970s, as central AC proliferated, resulting in sharp peak loads. Rate design and incentive programs were incorporated into the integrated resource plans of the vertically integrated utilities. In the 1990s, restructuring of the electric industry toward more competitive energy markets resulted in independent power producers participating in wholesale markets, and a transformation of utilities into stand-alone generation companies, regulated distribution companies, and regional grid operators.

Three key DR markets in the United States have been studied in depth to provide Mexico with potential DR compensation frameworks. The markets studied were New England, California, and Hawaii. Appendix A provides a detailed assessment of the historic and current DR programs in these markets, including residential, commercial, and industrial participants. Given that Mexico's current focus is on commercial and industrial (C&I) participants, approaches for these customer types are summarized below.

3.1.1 New England

New England has implemented three DR programs that have proven successful for C&I participation but require different implementation approaches. Peak/off-peak rates would require the creation and approval of a new tariff, special contracts would require regulatory approval for bilateral contracts, and a market program would require careful rule planning, design of an interface for participants to bid into the market, among many other considerations.

3.1.1.1 Peak/Off-Peak Rates

The utility developed a two-tiered rate structure for this DR program that reflected cost-of-service differences, with on-peak rates up to 2 to 3 times higher than off-peak rates. The rate structure required formal regulatory review and approval. Customers could opt in to this DR program, voluntarily enrolling and adjusting their energy consumption habits to greater usage during off-peak times. Compensation for participation was not direct, rather participants saved money on their utility bills as they shifted energy consumption to the off-peak periods.

3.1.1.2 Special Contracts

The utility established bilateral contracts with C&I customers with controllable loads, shifting demand to off-peak periods (from time of day to seasonal shifts). While negotiations were case by case, requiring significant upfront effort, the result was successful for controlling a large amount of demand through relatively few participants. Compensation was specific to each participant, based on avoided system energy and capacity costs.

3.1.1.3 Market Program

Independent System Operator – New England (ISO-NE) now operates one of the most advanced market programs for DR. In essence, a DR resource can participate by bidding into the market, and this competition in the open market increases the market efficiency (lowest cost provider) for

ISO-NE. Customers volunteer to participate and can be established with the assistance of the utility or an aggregator.

If a DR participant's bid in the day-ahead market is at an acceptable price compared to competing bids from other load, generation, and demand resources, the DR participant is paid for its supply at this clearing price. If the DR participant delivers more supply during the real-time market, they are compensated for the additional supply at the real-time price. If the DR participant delivers less supply, they are required to pay the real-time clearing price for that amount of supply they failed to deliver.

There is a threshold price below which a DR resource cannot bid, which ensures net benefits for the system and fair compensation for the DR participant. The threshold price methodology was established by FERC Order 745 [16]. Additional detail on the specific calculation of the ISO-NE market compensation for DR is included in Appendix A.

3.1.2 California

California continues to set a high standard for DR programs, achieving considerable load reductions over the last decade and increasing the contribution of DR to the wholesale energy and ancillary services markets. A four-part cost-effectiveness evaluation drives the selection and evaluation of DR programs by the California Public Utilities Commission (PUC), as outlined in greater detail in Appendix B.

3.1.2.1 San Diego Gas and Electric Summer Saver

The San Diego Gas and Electric (SDG&E) Summer Saver program includes small commercial customers who volunteer to allow the utility to cycle their AC load. At the participant's choice, the AC load can be turned down 30% or 50% during the event. The annual bill credit is the product of the tonnage of the AC system and the credit value of $9 per ton for 30% cycling or $15 per ton for 50% cycling [17].

3.1.2.2 Capacity Bidding Program

The Capacity Bidding Program is a tariff-based program that allows participants to receive from $2.43 to $28.65/kW-month for providing DR, depending on the duration of the reduction (1 – 8 hours), response time (day-ahead or day-of), and calendar month (May through October). Qualified aggregators are responsible for recruiting participants to the Capacity Bidding Program, available through all three of the largest investor-owned utility markets. Participants are allowed to enroll directly with their utility but will only receive 80% of their available capacity payment, rather than 100% through a qualified aggregator [18].

3.1.2.3 Base Interruptible Program

Under a bilateral special contract negotiation with the utility, C&I customers can determine their Firm Service Level (minimum load requirement) and receive a monthly capacity credit in exchange for a commitment to reduce energy consumption to the minimum during events. In addition to the direct capacity credit, the participant saves money with reduced energy consumption.

3.1.2.4 California ISO Market Programs

There are several open market programs available in California for C&I customers. These involve bidding into the capacity market, the day-ahead market, the real-time market, and the ancillary services market. Compensation is based on successful bidding in the market. Additional detail on the various markets available to participants is included in Appendix A.

3.1.3 Hawaii

Hawaii offers an atypical perspective to DR, given the relatively small and isolated nature of the separate island grids. With a long-term goal of 100% renewable energy, advanced DR capability is a necessity to balance load at high photovoltaic penetrations.

3.1.3.1 Commercial and Industrial Direct Load Control

With regulatory approval, Hawaiian Electric Company (HECO) developed a rate schedule rider allowing participants to reduce load when requested in exchange for a reduction in demand charges. Compensation was $5 to $10 per kW-month of nominated load and $0.50 per kWh during the load shedding event. The pricing was intended to match utility resources. However, in practice, the compensation level was not cost effective, as it was determined to be more expensive than dispatching the highest cost existing generation.

3.1.3.2 Fast Demand Response

As the name implies, C&I customers choosing to participate in this DR program are required to respond quickly to a load shedding event. Compensation to participants included a $3,000 upfront incentive to defray the cost of a 5-minute interval meter and other system upgrades; a $3,000 or $6,000 payment for election to participate in 40 or 80 events, respectively; a base incentive of $300 or $600 per kW-year for semi-automated or automated control, respectively; and a performance incentive of $0.50 per kWh for energy reduction (5-minute basis). The compensation level for Fast DR was not cost effective, as it was determined to be more expensive than dispatching existing peaking capacity.

3.1.3.3 Proposed Hawaii Demand Response Programs

In the last quarter of 2017, Hawaii is set to rollout a revised, sophisticated DR portfolio based on various forms of DR grid services: capacity, fast frequency response, regulating reserve, and replacement reserve. Initially, pricing is based on a tariff, though the utility intends to transition to real-time pricing. Participants will be recruited primarily by aggregators contracted with and paid by the utility. Compensation includes an initial allowance of $600/kW for DR equipment; a bill credit of $36 to $96 per kW-year of nominated capacity; and a monthly Capability Incentive payment of $3 to $8 per kW based on the DR program and actual participation level each month.

3.2 Success Factors

Implementation of DR programs in the United States has been relatively cost effective in comparison to the avoided cost of new generation. Given that utilities face significant costs related to annual peak load and residential water heaters are a controllable load where cycling does not greatly impact the participant's end-use experience (in comparison to a load like lighting, where the lights go off), residential electric hot water load control programs are a common initial approach to DR. These programs have proven to be cost effective based on avoided-capacity costs in multiple utility service areas, although their cost effectiveness varies based on incentive and administration costs. For example, residential water heater programs have resulted in capacity costs of $200/kW-year in Hawaii and under $130/kW-year in ISO-NE. Another common approach to DR is special contracts with large C&I users. The specific costs of these contracts are non-public business information, but their ubiquity among utilities and relative ease of implementation in comparison to a large-scale residential DR program are suggestive of their effectiveness. The costs of DR contracts with large C&I users are proprietary but are widely applied by the utilities discussed in the case studies and result in some of the largest total peak demand reductions in megawatt capacity.

Finally, for both ISO-NE and California ISO (CAISO), the extent of DR's impact as a grid service was clearly limited by the programmatic approach. Once DR was included as an eligible resource for participation in wholesale markets, ISO-NE participation in DR rose from 100 to 1,400 MW. Although market-based approaches require significant effort to develop and administer, where there is an existing wholesale power market, DR has been proven to be a reliable resource for both energy and capacity services.

3.3 Challenges and Barriers

Some challenges that pre-market DR programs have encountered to date include large administration costs relative to the demand reduced, low reliability of DR from a capacity reserve requirements standpoint, and the relatively small impact of DR under a programmatic approach in comparison with the scale of reduction achieved by a market approach.

Several programs examined, such as the Residential Direct Load Control (RDLC) program in Hawaii and the SDG&E Summer Saver program in California, required tens of thousands of participants to reach 10 to 20 MW of peak demand reduction. Although these programs are cost effective, they require substantial effort to administer and have limited reliability for reserve planning purposes. A potential solution to this challenge is to rely on commercial aggregators to handle the customer acquisition and management side of the program.

C&I programs in the case examples, although much more efficient on a customer per megawatt of demand reduction basis, also had limited reliability for reserve planning purposes. Customer acquisition and retention was also a common challenge for these programs, with recruitment to programs such as the Fast DR program in Hawaii requiring a $3,000 incentive for equipment installation and guaranteed minimum compensation of $3,000 to $6,000 regardless of performance.

In the C&I DR programs, there was also tension over the minimum required notification times for the utility. In the case of Hawaii, the notification times of one hour for the Commercial and Industrial Direct Load Control (CIDLC) program, and 10 minutes for the Fast DR program, made them unusable for the utility's current needs. However, lowering minimum notification times may also cause participant attrition, as this limits their ability to avoid business losses from the interruption. Penalties for these programs were also a key risk to participants, who often opted not to participate at all rather than risk business losses.

Similarly, the California utilities' 2016 Demand Response Auction Mechanism resulted in more than 80 MW of combined DR contracts. However, in California, the cost for DR was considerably higher. The Demand Response Auction Mechanism allowed California utilities to contract for DR with a few aggregators at a much larger scale of 40 to 80 MW per auction, at a total cost of $12 million for 21.4 MW in the Pacific Gas and Electric Company (PG&E) territory and $12 million for 52.6 MW in Southern California Edison territory. The implied cost per kilowatt-year of this DR to the California utilities is $228 to $560 per kW-year. In California, the 2017 Demand Response Auction Mechanism is targeting a minimum cost of $600 per kW-year. This demonstrates that although market-based mechanisms have the potential to tap into considerably larger DR assets, they are not necessarily cheaper

3.4 Compensation Methodologies

As discussed in Section 1, DR should be remunerated at a level which compensates generation and DR providers commensurate with the value of the services they are providing. Although the investment amount, timing, and terms may vary, DR participation does often require a capital outlay not unlike a utility generation resource. Compensation must be sufficient for recovery of this initial capital investment, otherwise customers will not be inclined to participate. Some options for DR compensation are described in greater detail below.

Fixed monthly payments for enrolling in a program (e.g., hot water cycling)

This option is typically utilized for programs oriented at residential users that involve tens of thousands of participants. The compensation approach is simplified and standardized across all customers to reduce administrative costs and measurement and verification requirements.

- SDG&E Summer Saver: Annual bill credit based on the one-hour cooling capacity of air conditioners. One ton is 12,000 Btu of cooling/hour, and one ton will cool from 400 to 700 square feet in a residential application [17].
  - Residential: $11.50 per ton for 50% cycling, $30 per ton for 100% cycling.
  - Commercial: $9 per ton for 30% cycling, $15 per ton for 50% cycling
- HECO RDLC: Monthly bill credit for each eligible technology nominated to participate
  - $3/water heater-month
  - $5/air conditioner-month

Performance-Based Payments ($/kW-month)

Performance-based incentives can be per event or a fixed payment for participation.

- HECO proposed DR programs (e.g., Critical Peak Incentive–Commercial): $3/kW of nominated capability, de-rated by the performance ratio.
  - $Monthly\ Incentive = Nominated\ Capability\ (kW) * Monthly\ Performance\ Factor * Nominated\ Capability\ Incentive$
  - $Event\ Performance\ Factor = \frac{Event\ Load\ Shed\ (kW)}{Nominated\ Capability\ (kW)}$
  - $Monthly\ Performance\ Factor = \frac{Sum\ of\ Event\ Performance\ Factors}{Number\ of\ Events}$

- PG&E/SDG&E Capacity Bidding Program: This program is composed of monthly capacity payments (nominated kilowatts), and energy payments (kilowatt-hour reductions during events). Participants can choose a day-ahead, day-of, or 30-minute notification requirement, with shorter notification times resulting in higher compensation rates (up to $8/kW-month).
    1. Monthly Capacity Payments: Participants receive this nomination capacity payment regardless of whether events are called [18]. For example, for the day-ahead program, this payment varies from $2.43 to $20.76 per kW, as shown in Table 3.

Table 3. SDG&E Capacity Bidding Program Monthly Incentives

Load Reduction Incentive Payment, Day-Ahead Program Option ($/kW-month):

Product	May	Jun	Jul	Aug	Sep	Oct
1 to 4 hours	2.43	6.55	14.21	17.56	11.60	3.50
2 to 6 hours	2.74	7.39	16.25	19.99	13.14	3.94
4 to 8 hours	2.81	7.61	16.99	20.76	13.71	4.05

2. Energy Payments: Participants receive a rate based on the “daily Utility city gate natural gas price multiplied by the Program dispatch heat rate of 15,000 Btu/kWh for each kilowatt hour of energy reduction during Events.”

Rate Schedule-Based Compensation

- PG&E Time of Use Rate: This residential rate plan charges 10 to 30 percent more during on-peak periods than off-peak periods, sending a price signal to encourage participants to use less during peak periods.
- Critical Peak Day Rate Structure (e.g., PG&E Residential Smart Rate): Under this program, participants receive a $0.024 per kWh discount from June 1 – September 30 but pay a $0.60 per kWh premium on top of the existing rate between 2 p.m. to 7 p.m. on up to 15 SmartDays (critical peak load days in the summer). Note that this program also provides bill protection in the first year of enrollment to prevent customers from exceeding the costs of a regular residential pricing plan.

Real-Time or Day-Ahead Market

An approach where prices (dollars per megawatt and dollars per megawatt-hour) are established based on competitive bidding by qualified participants is referred to as a real-time or day-ahead market approach. Real-time and day-ahead markets vary considerably by ISO, but generally involve multiple market participants, such as large C&I entities, DR aggregators, and battery storage integrators, submitting a megawatt and dollar per megawatt bid for their services. If their bid is selected by the ISO, then they are expected to provide the selected MW of DR services during the corresponding window.

In-Kind Arrangements

Seasonal industries may agree to reduce peak load during their slow seasons in exchange for cheaper power at other times of the year. Such arrangements are case-by-case contracts recognizing the specific value of the DR given the participant's specific contribution to DR based on location, load, season, and other characteristics.

3.5 Program Evaluation Methodologies

A common, relatively simple, approach to DR program evaluation is to compare the cost of the program with the cost of avoided generation. This calculation can be refined by incorporating sensitivities such as installed capacity cost and carrying costs with many detailed assumptions like financing and fuel costs underlying these values.

Black & Veatch, in its analysis for HECO's Power Supply Improvement Plan and Demand Response Applications, has developed an avoided-cost methodology to calculate the avoided cost of various discrete services that DR can provide on a system-wide level [19]. Detailed cost estimates of the total cost of implementation of various scenarios, such as a 100% renewable portfolio standard, were developed. Then production simulation modeling of the full HECO portfolio of assets at an hourly level was applied, and Black & Veatch compared the overall cost on a net-present-value basis with the "base" scenarios that did not include DR. For this approach to work, a utility needs to have a clear idea of its DR targets and estimated costs, as well as the estimated costs of its "business as usual" scenario. Although more involved, this approach accounts for system-level impacts of DR, such as deferred transmission upgrades, better than comparison against a single criterion. Apparent drawbacks to this approach include the intensive work associated with production simulation modeling and the heavy reliance on assumptions within resource plans to define the avoided cost.

The compensation level is primarily driven by the value of the service provided as measured by the value of the impact and the cost of providing that service through traditional methods. The compensation may also include incentives in recognition that some of the benefits of a non-generation solution are not reflected in market values (such as emission savings). The task is to determine if a program is cost effective and if compensation to the customer providing the DR resource is reasonable. However, the reasonableness of compensation can be evaluated using California PUC's Cost Effectiveness Protocols, discussed in detail in Appendix B.

Fair compensation for a DR resource is driven by the capabilities the resource provides and the value of those capabilities. A DR resource may avoid energy requirements, peaking capacity, flexible capacity, transmission and distribution capacity, location-specific generation, or transmission and distribution capacity. The contribution of DR resource capabilities to avoiding these needs can be determined by a "load impact study." The load impact study methodology is driven by the "Load Impact Protocol" [20]. The decision adopting the load impact protocols, California PUC Decision 08-04-050, is helpful in providing guidance on applying the load impact protocols.

The contribution of a particular DR resource towards avoiding these capacity, energy, and capability attributes is adjusted by several factors that inform the specific capability of a specific resource located in a specific place, as summarized in Table 4.

Table 4. DR Load Impact Adjustment Factors

Factor	Name	Description
A	Availability	Adjusts the capacity value that can be captured by the DR program based on the time of operation and the frequency and duration of calls permitted.
B	Notification Time	Accounts for differences in value of various notification times (e.g., day-ahead, day-of, 30 minute, 15 minute)
C	Trigger	Accounts for value of flexibility of the triggers or conditions that permit the utilities to call each DR program
D	Distribution	Adjusts estimated benefits based on avoided transmission and distribution (T&D) costs related to "right time," "right place," "right certainty," and "right availability" of DR programs
E	Energy Price	Adjusts estimated benefits based on avoided energy costs attributable to DR programs

Taken together, the California PUC cost effectiveness protocol and tool, the cost of generation tool and guidebook, and the load impact study protocol and regulatory guide provide a pathway to establishing reasonable cost-effectiveness evaluation as well as the reasonableness of DR compensation. One way to use the cost effectiveness tests is to bound DR compensation between a lower bound established by the participant test and an upper bound established by the program administrator (or Program Administrator Cost [PAC] test). However, as discussed in Appendix B, all four cost-effectiveness tests are intended to be performed concurrently.

To establish an upper bound, the PAC test measures benefits from the perspective of the utility or load serving entity provider. If the result of the PAC test is less than 1, then the savings to the utility system through cost reductions are outweighed by the costs of the DR program (or resource). The costs of the DR resource include administrative and capital costs incurred by the administrator (usually the utility) and any compensation (including incentives) paid to the DR resource provider. Thus, compensation to the DR resource provider can be said to be "too high" from a system cost perspective if that compensation drives the PAC test to fall below 1.

Benefits include the avoided costs of supplying electricity, revenue earned from CAISO market participation, utility non-energy benefits, and market benefits. Costs include administrative and capital costs incurred, incentives paid, and increased supply costs.

To establish a lower bound, the Participant Test (PT) measures benefits from the perspective of the Participant. If the PT falls below 1, then the compensation (including bill reductions and incentives) is too low to engage customer participation. Benefits include bill reductions, incentives received, tax credits received, and participant non-energy benefits. Costs include bill increases, DR equipment costs, value of service lost (productivity, comfort), and transaction and opportunity costs.

If all sources of DR financial compensation (payments, bill reductions, incentive payments) result in a PT value greater than 1 and a PAC greater than 1, then the DR compensation and DR cost effectiveness are both reasonable. The range of DR compensation values that meet these criteria is relatively large, and ideally results in the participant and utility sharing in the benefits of the DR resource.

4 Options for Demand Response in Mexico

4.1 Mechanism for Implementation

As demonstrated in Section 3, DR approaches vary considerably depending on the utility's size, circumstances, and prior experience. Although several of the larger ISOs in the United States have transitioned to market-based approaches, they previously relied upon pre-market programs to "pilot" their approaches. These programs can be broadly categorized into measure-based or performance-based approaches.

Measure-based programs compensate participants who offer to reduce their load at a set amount per month or year, regardless of how often they provide service. These programs can involve utility control of the customers' loads or rate schedules that do not require performance, such as TOU and peak/off-peak rates.

Utility control of customer loads, such as cycling AC or hot water units are typically cheap and straightforward to implement, as they do not require performance auditing or sophisticated load control equipment. However, this approach also has disadvantages: these programs typically have limited flexibility to provide different types of DR services (typically these programs are used to reduce peak capacity). Also, these programs often have not provided as much operational data to the utility due to their historic reliance on one-way paging communications infrastructure. To measure the impact of these programs, utilities have performed test events by calling on all units to cycle at a given time and comparing the pre-event load with the load during the event. This challenge may also be obviated by the installation of two-way communications infrastructure. Finally, the actual load reduced these programs has been subject to variability over time due to attrition in customer participation and varying levels of participation in events, making this a somewhat unreliable asset for resource adequacy planning purposes.

TOU and peak-off-peak rates provide consistent price signals to consumers to adjust their behavior to avoid consumption during typical periods of peak demand.

Performance-based programs are defined here as programs that compare a pre-determined baseline load with a participant's response during an event. They vary considerably in their composition and objectives. The performance-based programs surveyed are broadly categorized into rate schedule-based and contract-based programs. The advantage of these programs is that they typically provide the utility with real-time information of the load reduced. These programs are more (but not fully) reliable, since participants are typically penalized for nonperformance, and they are more versatile in providing multiple types of DR services. Some disadvantages of these approaches are their higher upfront costs for the installation of load control equipment, performance audits to establish a baseline energy demand upon which to judge performance, and monitoring and communications infrastructure for operational control. These costs pose a significant barrier to entry for potential participants; to incentivize participation, these services may need to be adequately compensated or the upfront cost may need to be defrayed by utility rebates.

4.2 Value Proposition

At a high level, for a DR program to be effective and sustainable, it will likely need to provide a sufficiently valuable DR service, and the value of that service will need to be allocated fairly between the utility and suppliers to ensure continued participation by all the parties. The DR programs discussed above vary in their compensation structures, with some being easier than others to implement. All the measure-based programs, and several of the performance-based programs, put the onus on the utility to fairly define the value for all parties whereas other programs allow for market competition to reveal participants' economic preferences (although the utility will still need a clear understanding of their avoided costs to establish acceptable thresholds).

4.2.1 Value to Utility

The value of DR programs can be measured by comparing their all-in administrative and incentive costs, on a dollar per kilowatt-year basis, against the cost of either a new build of peaking capacity, or if sufficient peaking capacity already exists, the carrying costs of the capacity. This is a relatively simple measure, and other important operational factors should be considered as well. For example, since these programs have typically been cost effective for utilities and there is no marginal cost for their use, a utility might be tempted to utilize these resources as much as possible. However, excessive use of the program (from either a frequency or duration perspective) may result in customer attrition as they experience interruptions in their daily routines.

Another potential approach to valuing DR programs is on a grid-wide scale. As discussed in greater depth in Section 3.4, a system-wide study to calculate the avoided cost of various discrete services that DR can provide on a system-wide level can account for system-level impacts of DR, such as deferred transmission upgrades, better than comparison against a single criterion. Apparent drawbacks to this approach include the intensive work associated with production simulation modeling, and the heavy reliance on generation mix assumptions within resource plans to define the avoided costs.

4.2.2 Value to Supplier

Once the value of DR services to the utility has been established, the value of the programs to the program participants (suppliers) must also be sufficiently attractive to encourage their participation in the program. Among the utilities and programs studied, details on this methodology are unavailable due to the sensitivities surrounding sharing this information. For DR programs where the utility determines this value, the value to the supplier must be less than the total cost savings of the DR program, but this allocation is unclear.

Some potential approaches to valuing these services include: piloting a proposed program to gauge customer response, submitting a Request for Information to gauge commercial interest, and conducting a cost-benefit analysis of commercial returns by developing a bottom-up financial model of a hypothetical participant. Finally, some performance-based programs are structured to allow participants to value these services competitively or to negotiate this value directly with the utility. These approaches would likely provide additional benefit when combined and are each discussed at a high level below.

Pilot Approach: Several of the DR programs within the case studies involved a pilot program period prior to expanded implementation, such as the Fast DR program. This allowed the utility to gauge commercial reaction to the proposed DR compensation and measure participation prior to a full roll-out.

Request for Information Approach: During the program design phase, a utility could also submit a Request for Information or conduct informational interviews with potential participants to gauge responsiveness and get input. This approach is obviously caveated with the observation that suppliers will seek to maximize their allocation of the value of DR services and may not accurately characterize their required returns.

Modeled Participant Returns: Although the financial and operational characteristics of participants will vary, utilities could potentially develop a rough understanding of the required cost of capital for various participant types (e.g., hospitality, manufacturing) and evaluate whether a proposed DR program provides a reasonable return. This modeling effort could also potentially be informed by the Request for Information discussed above. Another essential aspect to a modeling approach would be to consider the opportunity cost of the lost load during a DR event; for example, if a manufacturing participant loses 20% of its production capacity for an hour, the DR program's compensation would probably need to exceed the value of this lost capacity.

Competitive Solicitations: Another approach to valuing DR services is to allow participants to competitively bid to provide these services to the utility. As an example, the California Demand Response Auction Mechanism allows suppliers to submit bids to provide a specific capacity of DR at a given dollar per kilowatt-month price. An example of the quantity-price matrix provided under the Demand Response Auction Mechanism is included as Table 5.

Table 5. PG&E Demand Response Auction Mechanism Offer Form Excerpt [21]

[A]												[B]	[C]											
2017 Monthly Quantity (kW) PDR--if not 0 kW, minimum is 100 kW RDRR--if not 0 kW, minimum is 500 kW August cannot be 0 kW												Total Annual Scheduling Coordinator (SC) Costs	2017 Monthly Contract Price ($/kW-month)											
Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec	($)	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec
100	100	100	100	100	100	100	100	100	100	100	100	1,000	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00
-	-	-	-	-	-	-	500	-	-	-	-	2,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$1.50	$ -	$ -	$ -	$ -
300	300	300	300	300	300	300	300	300	300	300	300	3,000	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
500	500	500	500	500	500	500	500	500	500	500	500	4,000	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50

Bilateral Negotiations: DR contracts can also be negotiated on an ad-hoc basis with various large C&I suppliers. They are based on avoided system capacity costs and will likely require individual negotiation. When negotiated with participants with large loads, they can be very cost effective as they allow the utility to provide large amounts of DR by relying on a relatively small number of participants. The negotiation of the value-sharing between utility and supplier is variable and depends on the circumstances of each contract.

5 Conclusions and Recommendations

DR programs can create significant value for the grid by delivering system benefits ranging from reductions in energy and capacity demand to regulation and reserve resources while still providing cost savings for both utilities and DR participants. However, the details of a DR program, such as its administration, compensation approach, and performance requirements, are critical to its ultimate success. The implementation of a new DR program requires significant upfront planning to determine what resources are needed by the system and design a program to acquire those resources at a competitive cost, with a price that encourages continued participation in the program.

Although CRE and SENER expressed interest in building market-based compensation for DR in the future, the best near-term approach may be to develop a utility-run DR program portfolio to avoid near term peaking capacity additions. Utility-run DR programs can be operated by the utility, or by a third-party aggregator who manages the customer relationships and DR integration for the utility. Another key design consideration for a DR program portfolio is whether compensation for DR services should be measure or performance based. Measure-based compensation, such as a fixed monthly payment for enrollment in a program, is often simpler to develop and administer, but less reliable as a capacity resource. By contrast, performance-based compensation (i.e., paying participants per kilowatt-hour of reduced demand), requires greater upfront investments in DR measurement and communications infrastructure, but can result in greater utility confidence in demand reductions, and pave the way for future market-based DR approaches that are typically performance based as well.

Although the most appropriate mix of DR options for Mexico should ultimately be determined by CRE in consultation with its regulated utilities, there are some potential program options for building a DR program portfolio could include the following approaches highlighted in the case studies:

- A new rate schedule for C&I users that includes monthly payments based on participant performance during an event. An equipment installation incentive can also potentially lower the barrier to entry for new participants and increase participation.
- Special contracts with large commercial or industrial users, with negotiated compensation terms that are equitable to both parties.

In California, most DR resources currently bid into the CAISO markets were originally developed under prior DR programs, meaning that focusing on utility DR programs in the near term may be a reasonable first step towards DR resources being compensated by wholesale markets. If CENACE ultimately decides to be more closely linked to the CAISO markets, including the Western Energy Imbalance Market, then Mexico may also have the opportunity to market qualifying DR resources into CAISO markets. Future study of the applicability and potential impact of DR programs in Mexico would require additional demand data (ideally hourly) by sector and region. Analysis of the most appropriate technological solutions would require a more detailed understanding of the major types of C&I loads.

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Appendix A: Demand Response Case Studies

Demand response as a component of DSM has continued to evolve into a sophisticated market segment across the regions of the United States [22]. Based on the significant depth and breadth of U.S. experience with DR, the case studies presented in this appendix are focused on three states/regions with some of the best DR programs established in the United States – New England, California, and Hawaii.

The discussion of pre-market DR programs in New England examines discontinued pre-market programs such as ripple water heater control and special contracts. Then, the ISO-NE wholesale DR markets are discussed, including the compensation mechanisms and auction structure. Finally, the approach in ISO-NE to baseline performance calculations is summarized, including "true-up" mechanisms to account for DR underperformance.

In California, the majority of DR compensation is program based and organized by each utility. Most DR resources bidding into CAISO are paid for by utility programs, and then aggregated and sold into CAISO markets, making CAISO the end of the DR value chain, with utilities administering the DR programs. So, while the savings from these programs may ultimately get bid into a market, the process of developing, operating, and providing compensation in the program is similar to a non-market-based program. This contrasts with New England, where the ISO-NE manages much of the DR participation.

The Hawaii case provides a contrast to the prior examples, and demonstrates the role of DR on relatively small, isolated grids with high renewable energy penetration. HECO is still in the midst of implementing its new DR program and will utilize a different approach than mainland Regional Transmission Organizations, such as tariff-based DR and reliance on commercial aggregators to administer customer loads and manage payment.

In describing each of the DR programs, the following aspects will be discussed:

- *Technical Requirements:* There are technical requirements for both the DR aggregator/utility, as well as the participant. For the participant, these requirements may include metering and load control infrastructure, as well as loads that conform to the size and performance requirements of the program. The DR aggregator or utility, on the other hand, may need additional monitoring equipment and a communications system for dispatching the DR resources.
- *Participation Terms:* Each DR program's specific performance requirements for participants are described, including the minimum response time, performance duration, load reduction requirements, number of annual performance hours, and penalties for nonperformance.
- *Compensation Mechanism:* The compensation methodology for each program is described in detail, including the formulas, billing, and contracting approach. If compensation is variable or market-based, the valuation and market methodologies are presented.
- *Implementation Ease*: The ease of implementation of DR programs can vary depending on the number of participants, program goals, and numerous other factors. Challenges and obstacles encountered by the utility in implementing the DR program are described.

- *Evaluation Results*: In addition to the load impact of the DR program, where information is publicly available, the cost effectiveness of the program is evaluated as well. Program ability to acquire and retain participants, technical barriers to program implementation, and lessons learned from program implementation are offered.

A.1 New England

Before 2002, DR programs in New England were operated by vertically integrated utilities as peak management tools. These DR programs, oriented toward peak demand savings, included ripple control water heating, peak/off peak rates, and special contracts with large users. They acted in response to the price structure under which the utilities were charged by the power pool.

Although these DR programs were cost effective, they were limited in scope. In 2002, New England created a competitive wholesale power market that allowed DR participants to submit bids. This resulted in participation in DR programs rising from 100 MW to 1,400 MW. Some of these pre-market programs are described below.

A.1.1 Ripple Control

Technical Requirements: Ripple control was a simple interruptible load program applied to residential electric hot water heaters. Technically, ripple control only required specific water heaters with a controllable load switch, a known demand profile, and a system that allowed the utility to interrupt power to the water heaters for up to four hours per day.

Participation Terms: To participate in ripple control, utility customers simply enrolled in the program, which allowed the utility to interrupt power to their hot water tank for up to four hours per day. There was no annual limit on the utility’s usage of this program. The utility paid for the installation of the control device.

Compensation Mechanism: Program participants received a fixed payment of $2.50/month. This price was established by the utility based on the charges for capacity and network transmission service and was a cost-effective means of reducing peak demand on the system.

Implementation Ease: Setting up customers typically only required installation of a load control device (receiver) and establishment of a central load control system (transmitter) and billing system on the utility’s side.

Evaluation Results: The program was cost effective in comparison to gas turbine carrying costs of $130/kW-year. However, there were limitations on its use: overreliance on these programs can shift rather than eliminate peak load. For example, as the load flattened during peak hours, the utility had difficulty restarting water heaters while keeping the peak load low in later hours.

A.1.2 Peak/Off-Peak Rates

Technical Requirements: This DR program allowed customers to opt in to the utility-developed rate structure that reflected cost-of-service differences, with on-peak rates up to 2 to 3 times higher than off-peak rates. When the program was implemented originally, the utility required installation of a second meter. Today, advanced meters obviate the need for a second meter.

Participation Terms: Customers volunteered to enroll in the program and were simply billed according to their consumption under the new rate structure during the various time periods.

Compensation Mechanism: Participants were not compensated directly for their participation but had the opportunity to save money on their utility bills by adjusting their energy consumption habits to greater usage during off-peak times.

Implementation Ease: The new rate structure required regulatory review and approval. Obtaining regulatory approval for a new rate structure is a significant hurdle, while customer awareness and retention are also challenges.

Evaluation Results: Recruiting customers was a challenge. Generally, commercial customers with controllable loads were easier to recruit.

A.1.3 Special Contracts

This type of program is a one-on-one program usually involving industrial loads, and perhaps some unique circumstances. For example, a contract with a ski resort operator provided for unlimited demand in the off-peak winter months at a reduced price in exchange for the resort reducing its load by a set amount for a limited number of requests in the summer. This allowed for unrestricted snowmaking in the fall prior to the ski season in exchange for a lower demand during the peak winter months.

Technical Requirements: With insight into one specific example, this DR program required baseline load data and advanced meters. Other projects may have required automated load control equipment depending on the terms of each agreement.

Participation Terms: This program required negotiations on a case-by-case basis with C&I customers with controllable loads (e.g., ski resorts, irrigators, refrigerated warehouses, hotels, industrial processes with large energy/heat loads).

Compensation Mechanism: These special contracts were negotiated based on avoided system energy and capacity costs and could involve in-kind contributions as well.

Implementation Ease: Each contract requires individual negotiation and verifiable performance audits.

Evaluation Results: These are common and effective DR programs due to their flexibility. Although there was significant upfront effort negotiating contracts, performing energy audits, and installing control equipment, these special contracts were effective from an implementation standpoint due to the efficiency of controlling a large amount of demand through a few customers.

A.1.4 Market Program

ISO-NE is the regional transmission operator for the six New England states.[4] ISO-NE also operates the wholesale power market in the region. In New England, more than 400 generators, importers, demand resources, and others compete to sell three types of wholesale electricity products and services through New England's markets.[5] The markets select the lowest-priced offers that can meet real-time demand and ensure system reliability. ISO-NE is neutral to resource type, meaning that DR can compete with generators to provide energy services.

ISO-NE operates a day-ahead market, a real-time market, and a capacity market. In the day ahead market, suppliers and load servers make offers to sell or buy for the next day. The market "clears" at a price which balances sellers' offers with load servers' needs. This creates financially binding transactions among the parties (about 90% of the market settles day ahead). Any deviations from the day-ahead amounts are settled at the real-time price, which is calculated by clearing the real-time offers from generators and real-time demands from suppliers.

As part of its market design, ISO-NE supports resource providers who wish to bid DR resources into its market. These DR resources compete with traditional suppliers to supply the services needed by the grid. DR providers participate in this market by making day-ahead offers and adjusting that with real-time price deviations.

Technical Requirements: To participate in the DR market, each asset must have a meter capable of recording 5-minute interval data to accurately measure performance before and after the performance period. In addition, an asset must have a Demand Designated Entity to transmit the asset real-time interval data from the customer meter to ISO-NE. A third party (other than ISO-NE) is responsible for assuring the asset is prepared to participate in the market. Finally, the asset must have a Lead Market Participant who is financially obligated for the asset performance. Should the asset fail to perform, the promised services are procured in the real-time market, and the Lead Market Participant is required to cover any additional cost.

In addition, each asset is required to have an annual performance audit to determine the capability of the asset to provide service. Once this value is determined, the asset cannot bid in excess of capability. This Annual Certification of Accuracy of Measurement and Verification document must be filed by each Lead Market Participant annually for each asset. The audit establishes the Demand Reduction Value for a DR asset and verifies that the asset remains in commercial operation. The audit can be performed by a third party and must show a minimum of 100 kW[6] of demand reduction capability for the asset to be part of the program.

Participation Terms: The performance for assets responding to dispatch signals is calculated as the difference between actual usage and a historical baseline in 5-minute increments. Baselines for each day are calculated using 5-minute intervals from meter data submitted to ISO-NE by the

[4] The six states are Vermont, New Hampshire, Maine, Massachusetts, Connecticut, and Rhode Island. Except for Vermont, retail sales of electricity have been deregulated within the ISO-NE market area, and retail suppliers compete for customers. Only Vermont maintains a vertically integrated retail structure.

[5] The products bid into the market are energy, long-term reliability services, and short-term reliability services, including operating reserves, frequency regulation, and voltage support.

[6] ISO-NE is moving to a 10-kW threshold in the near future.

Demand Designated Entity. Baselines are calculated as a 90/10 weighted average of historical usage to previous-day usage (90% of current-day baseline plus 10% current day meter data).[7]

For example, if an asset's previous baseline load was 500 kW for a particular 5-minute period, and the current day load for the same 5-minute period is 480 kW, the new baseline load would be 498 kW.[8]

Participants are financially obligated to provide market products in the amounts for which they were selected in the day-ahead auction. If they do not deliver, deviations must be purchased at the real-time price, which may or may not result in a penalty.[9]

Participants choose whether or not to participate, as well as how much load to include, for each event. They may sign up individually or through an aggregator. There are no financial consequences for non-participation, as the DR participant is treated like a generator. If they bid, they are financially responsible for their bid. If not, there is no penalty. Once they meet the technical requirements, they are an active asset in the market. Participation levels during an event are determined by the bid amount and the real-time performance.

Compensation Mechanism: ISO-NE uses a day-ahead market to transact energy purchases. Load, generation, and DR bid in their anticipated requirements during the previous day for performance during the next day. Supply, demand, and DR "clear" at a price that reflects their bid preferences. All day-ahead transactions are settled at this clearing price. Any deviations from these settled amounts of supply or demand are settled at the real-time price.

For example, if a DR resource bids 450 kW of supply into the day-ahead market, and the clearing price is $150.00/MWh, that DR resource would be paid $5.63[10] for that 5-minute period in the day-ahead market. If during the real-time market, the DR resource delivered more supply than bid, the additional supply would be compensated at the real-time price. Conversely, if the DR resource delivered less than bid, the asset would have to pay the real-time clearing price for the supply it failed to deliver, typically a higher price than the day-ahead price.

Since the DR asset is participating in the market and being paid the market price, there is no prescribed cost-effectiveness test. The market, based on the bid and performance of an asset, naturally chooses the lowest-cost provider at any one time. A participant can bid different amounts in each hour. Payment, or settlement, is calculated in 5-minute increments. The interruption is bid into the day-ahead market, and deviations, above or below, are settled at the real-time price.

Cost effectiveness is assured also through a threshold price. The threshold price is a price based on past unit performance and demand that assures operation of the program will result in net benefits for the system and will compensate DR fairly. DR resources cannot enter a bid below

[7] Days included are non-holiday weekdays and non-interruption days.
[8] (500 kW * 0.9) + (480 kW * 0.1)
[9] For example, if a DR provider's bid for 1 MWh cleared in the day-ahead market at $100/MWh, the DR provider was paid $100. If the real-time price is $75/MWh and the DR provider fails to provide the 1 MWh, they would have to pay $75.
[10] $150 * 0.450 * 5/60

this threshold price. The threshold price for demand reduction as of April 2017 was $45/MWh [23]. FERC Order 745 established this threshold price methodology in 2011 in response to concerns that DR was undercompensated [16].

Implementation Ease: Participants are self-selected and may be signed up by the utility or a DR aggregator. The utility must be aware of each program participant's activities so they do not commit to purchase energy in the day-ahead market to serve load that will be interrupted.

Evaluation Results: According to a report published by FERC, ISO-NE DR resources had the potential to provide 2,696 MW of load reduction, or roughly 11% of peak load [24].

A.2 California

According to the U.S. Department of Energy's Energy Information Administration, California's total use of energy is among the highest in the United States. However, California's per capita energy use is near the bottom due to temperate weather and years of DSM programs (energy efficiency). Energy prices compared to the U.S. average range from about 40% higher for residential customers to nearly 100% higher for industrial consumers. About 75% of California's electricity is provided by the three largest investor owned utilities, SDG&E, PG&E, and Southern California Edison.

In California, all DR programs are selected through a four-part cost-effectiveness evaluation described in more detail in Appendix B. DR program contributions to load reductions have increased over the last decade, and DR is increasingly playing a role in California's wholesale energy and ancillary services markets.

A.2.1 San Diego Gas and Electric Summer Saver

Technical Requirements: This DR program is offered to residential and small commercial customers with AC load. SDG&E cycles a participant's AC load using direct AC load control switches activated by one-way paging communication. The AC fan continues to circulate air during an event, while the AC compressor is cycled. The program offers participation options where cycling can be 100% (totally off for the duration) or 30% or 50% (off for 30% or 50% of the time).

Participation Terms: The AC load must be available May to October on non-holidays for two- to four-hour periods. Program rules limit events to no more than three days per week.

Compensation Mechanism: The annual bill credit is based on the tonnage of the AC system and the participation level. For residential customers, the credit is $11.50 per ton for 50% cycling or $30 per ton for 100% cycling. For commercial customers, the credit is $9 per ton for 30% cycling or $15 per ton for 50% cycling.

Implementation Ease: Enrollment is easy for both customers and utilities. A third party is responsible for installation and removal of the necessary equipment as well as measurement and verification.

Evaluation Results: SDG&E called for 15 events in summer 2015. The residential AC load reduction ranged from 7.6 to 17.8 MW, and the small commercial AC load reduction ranged from 0.4 to 2.5 MW. This AC load interruption coincided well with the SDG&E peak as shown in Table A-1.

Table A-1. Comparison of SDG&E Peak Loads

- SDG&E Peak: 9/9/2015 at 3:43 PM

Event Date	Hour Ending	Load Impact (MW)	
		Residential	Nonresidential
9/9/2015	16	14.5	2.13
	17	18.3	1.42
	18	17.7	1.19
	19	18.4	-0.07

- CAISO Peak: 9/10/2015 at 4:43 PM

Event Date	Hour Ending	Load Impact (MW)	
		Residential	Nonresidential
9/10/2015	16	10.3	2.73
	17	13.3	2.33
	18	11.7	1.12
	19	10.3	0.44

The summary of program information and evaluation results can be found at the May 10-11, 2016, DR Workshop links posted at the California PUC Demand Response Workshops page [25].

A.2.2 Pacific Gas and Electric Residential Smart Rate

Technical Requirements: The Smart Rate is a voluntary Critical Peak Pricing ("CPP") program for PG&E residential customers. The CPP rate design features significantly higher prices in certain critical peak hours and much lower prices in all other hours. To participate in the program, a customer must have real-time or hourly metering on their premises.

Participation Terms: The program design targets 12 event-days per summer and has a limit of 15 events. During these events, the much higher rates are applicable. A customer may dual enroll in the Smart AC program, which offers automatic control of AC load for residences.

Compensation Mechanism: Under the program, the typical electric rate is reduced from June 1 to September 30, except on SmartDays (event days). Program participants are charged $0.60/kWh from 2 p.m. to 7 p.m. on SmartDays which gives them a financial incentive to control loads during those times. To ease concerns, PG&E offers bill protection through the first full season. This means that customers are protected against higher bills should they fail to control their loads sufficiently.

Implementation Ease: The program is easy for both the utility and the customer once the meter is installed. Measurement and verification are contracted to a third party who is also responsible for arranging the meter installation.

Evaluation Results: The program has nearly 100,000 customers enrolled, with 28% in both Smart Rate and Smart AC. In 2016, 15 events were called, resulting in the load impacts shown in the Table A-2 [26].

Table A-2. PG&E SmartRate Results

Result Type	Hour Type	SmartRate Only			SmartRate + SmartAC		
		Load Impact	# Custs	Temp. °F	Load Impact	# Custs	Temp. °F
Aggregate (MW)	Avg. Event Hour	19.5	92,288	94.9	20.0	36,598	97.6
	PG&E Peak Hour	23.4	88,248	99.0	28.8	36,989	102.4
	CAISO Peak Hour	23.7	97,613	98.7	24.3	36,044	101.1
Per customer (kW)	Avg. Event Hour	0.21	92,288	94.9	0.55	36,598	97.6
	PG&E Peak Hour	0.27	88,248	99.0	0.78	36,989	102.4
	CAISO Peak Hour	0.24	97,613	98.7	0.67	36,044	101.1

PG&E peak hour = June 30, 2015, HE 18 (5 to 6 p.m.)
CAISO peak hour = September 10, 2015, HE 17 (4 to 5 p.m.)

A.2.3 Capacity Bidding Program

Technical Requirements: The Capacity Bidding Program is available in the markets of the three largest investor-owned utilities in California, there are technical requirements for aggregators and participants in the capacity bidding program. The program is managed by qualified aggregators who are responsible for recruiting participants [27]. Participants meet certain eligibility requirements which are defined in the tariff [28]. The program operates May through October for PG&E and SDG&E and year-round for Southern California Edison.

Participation Requirements: Event participation is triggered by a utility or CAISO market award, meaning that the bid submitted by the participant was accepted by the market. There are both day-ahead and day-of notice options. Event durations were 1 to 4 hours and 2 to 6 hours in 2015. Program guidelines permit up to 30 event hours/month for Southern California Edison and PG&E and 44 hours/month for SDG&E.

Compensation Mechanism: Participants receive a monthly capacity payment based on their nominated DR load as well as energy payments based on their kilowatt-hour reductions during events. The capacity payment may be adjusted based on performance during events. Participants receive monthly nomination capacity payment even if no events are called. Dual enrollment in an energy-only DR program with a different notification type is allowed.

Implementation Ease: The program is experiencing declining enrollments due to participant fatigue (number of calls). This fatigue was also noted by some aggregators. Complaints from customers have been received about the level of compensation. These complaints mostly centered on the baseline calculation and the size of the incentive being too low.

Evaluation Results: Table A-3 and Table A-4 show the number of events called and the hours of program applicability, as well as the load impact of the program [29]. There was much better participation in the day-of option.

Table A-3. Capacity Bidding Program Participation Hours

Program	IOU	Day-Ahead Number of events	Day-Ahead Hours of Availability	Day-Ahead Actual Hours of Use	Day-Of Number of events	Day-Of Hours of Availability	Day-Of Actual Hours of Use
CBP	PG&E	16	150	72	18	150	63
	SCE	61	150	126	42	150	138
	SDG&E	42	220	168	24	220	96
AMP	PG&E	*not applicable*			18	80	75
	SCE	*not applicable*			10	80	23

Table A-4. Capacity Bidding Program Load Impact

Program	IOU	Day-Ahead Aggregate Impact (MW)	Day-Ahead Nominated Capacity (MW)	Day-Ahead Event Temp (°F)	Day-Of Aggregate Impact (MW)	Day-Of Nominated Capacity (MW)	Day-Of Event Temp (°F)
CBP	PG&E	15.9	23.7	90	20.0	23.9	90
	SCE	1.0	2.2	85	16.4	25.7	87
	SDG&E	7.8	7.6	80	5.7	6.8	82
AMP	PG&E	*not applicable*			96.9	120.4	93
	SCE	*not applicable*			*Confidential*		

Results are average event-hour impacts for average summer (May-Oct) event day in 2015. Average event hours are HE 16 – 19 for all but SCE AMP. which is HE 14 – 15.

A.2.4 Base Interruptible Program

Technical Requirements: Also available in the market of California's big three utilities, the Base Interruptible Program provides C&I customers with a monthly capacity credit in exchange for a commitment to reduce energy consumption to their Firm Service Level (FSL) during events. Customers must have the required metering to document that their operation did achieve its FSL. They must also have operational controls to reduce the load at the facility to FSL within a 15-minute notification period for Southern California Edison or a 30-minute notification period for PG&E and SDG&E.

Participation Terms: Customers were required to reduce their load within a 15- or 30-minute notification period and were required to provide up to 180 hours of availability annually.

Compensation Mechanism: C&I customers receive a monthly capacity credit in exchange for a commitment to reduce energy consumption to their FSL. Failure to reduce load to the FSL can result in excess energy charges, an increase in the FSL (and commensurate reduction in capacity credits), re-test events, or de-enrollment, depending on the severity and frequency of underperformance.

Implementation Ease: Enrollment involves negotiation of a special contract to establish the desired FSL. This involves a demonstration of the capability of the facility to achieve the FSL.

Evaluation Results: Program results are shown in Table A-5. As one example, PG&E experienced a 3 p.m. to 7 p.m. test event involving 204 participating service accounts with a reference load of 292.4 MW. During the event, they had an observed load of 46.2 (FSL = 48.1 MW), resulting in a load impact of 246.2 MW, or 102% of program requirement [29].

Table A-5. Base Interruptible Program Results

Utility	Hours of Availability	Hours of Actual Use	No. of Available Dispatches	No. of Actual Dispatches
PG&E	180 / year 4 / day	12	10 / month 1 / day	5
SCE	180 / year 6 / day	2.5	10 / month 1 / day	1
SDG&E	120 / year 4 / day	4	10 / month	1

A.2.5 Southern California Edison Save Power Days

Technology Requirements: Southern California Edison may call Peak Time Rebate offers on a day-ahead basis year around. Customers can choose one of three technology participation options offered:

- Opt-in participation in response to notification
- In-home display
- Programmable communicating thermostat.

Participation Requirements: Customers sign up to receive phone, text message or email alerts that Peak Time Rebate credits are in effect from 2 p.m. to 6 p.m. the following day.

Compensation Mechanism: Participating customers earn a rebate of $0.75/kWh reduced. Customers with approved enabling technology (e.g., programmable communicating thermostats are eligible to earn a total incentive of $1.25/kWh. The bill credit is calculated based on the load reduction between 2 p.m. and 6 p.m. The reduction is calculated based on customer-specific reference level. The customer-specific reference level is defined as the average 2 p.m. to 6 p.m. usage for the highest three of five previous weekdays, excluding peak time rebate event days and holidays. Participants with event period usage below their customer-specific reference level receive peak time rebate credits.

Evaluation Results: The evaluation showed that the largest number of customers choose the opt-in option. However, the total load impact was much larger for programmable communicating thermostat customers (Table A-6 and Figure A-1) [30].

Table A-6. Save Power Days Results

Participant Group	Number of Customers	Avg. Reference Load (kW)	Avg. Load w/ DR (kW)	Avg. Load Impact (kW)	% Load Impact	Aggregate Load Impact (MW)	Heat Buildup (Avg. °F, 12 AM to 5 PM)
Opt-in PTR	324,681	1.86	1.79	0.08	4.1%	24.5	80.4
IHD	634	2.19	2.12	0.07	3.5%	0.05	81.3
PCT	2,682	2.31	1.53	0.78	34.2%	2.08	80.4

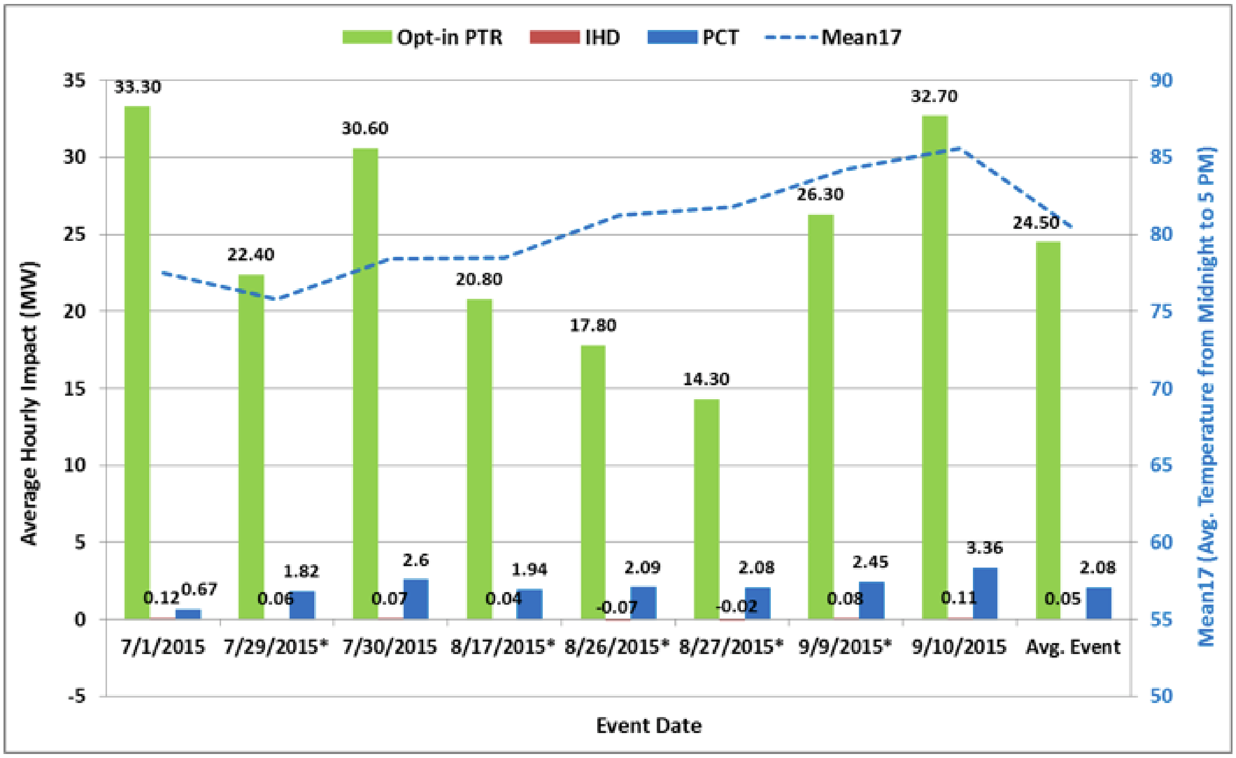

Figure A-1. Save Power Days: Aggregate load impact by type

A.2.5 CAISO Market Programs

The Proxy Demand Response program was established in 2010 per FERC Order 719 [31]. This DR program allows a curtailment service provider to bid into the day-ahead market, the real-time 5-minute market, and the day-ahead non-spinning reserve market. Both controlled load and price responsive DR programs are eligible to participate.

The Reliability Demand Response Resource program was implemented in 2012 and is designed to integrate large resources that can be interrupted in system emergency conditions. It is offered as an emergency reliability resource in the day-ahead market for system emergencies. Telemetry is required for a resource greater than 10 MW.

The Distributed Energy Resource Provider program was established in 2016. The program is for aggregated distributed energy capacity of greater than 500 kW. Aggregators can curtail load or dispatch generation. Participants can bid as a generator in the day-ahead, real-time balancing, and ancillary service markets.

The Energy Storage and Distributed Energy Resource program was started 2015 and is ongoing. This program is aimed at lowering barriers for transmission-connected storage and distribution-connected distributed energy resources to participate in markets. Participants may include non-generator resources, DR, multiple-use application storage, and station power for storage resources. This program enables bi-directional DR, allowing these resources to be dispatched to absorb energy from intermittent resources.

The Demand Response Auction Mechanism program allows DR, electric vehicles and storage providers to bid into utility solicitations. The winning bids, selected by each utility, will be used by utilities to provide day-ahead resource adequacy capacity to CAISO at an established price.

There are plans to expand the Demand Response Auction Mechanism program to include flexible capacity and other capabilities. The program was piloted in 2016, and the uptake was below registration targets. One reason was that program awardees were new to CAISO markets.

The California PUC issued a decision in December 2016 to provide incentive compensation to DR provider portfolios that defer or obviate utility investment in transmission and distribution. The process requires that each utility nominate distribution investment projects that are candidates for deferral. The California PUC will then select deferral projects to put out to bid.

Under this decision, utilities run a competitive solicitation for local resources that defer or obviate the need for the distribution investment. The utility then selects top-ranking preferred bids. The Procurement Review Group (third parties such as California PUC staff) then reviews the bids and evaluates the recommended selection. The utility is allowed to earn 4% on a portion of the cost that is deferred or obviated.

A.3 Hawaii

HECO serves 95% of Hawaii's population and operates five separate island grids on Hawaii, Maui, Oahu, Molokai, and Lanai. It faces unique challenges, such as high renewables penetration, large reserve requirements, and significant load shedding capability requirements to maintain grid stability. It also has aggressive renewable energy targets, with 30% renewables by 2020 and 100% renewables required by 2045.

As a part of its renewable energy strategy, HECO has developed a near-term plan to dramatically increase its DR capabilities to roughly 115 MW. [32] HECO's current DR capacity from its direct load control programs is under 20 MW.

HECO originally implemented two major types of DR programs: direct load control programs with all classes of customer and a Fast Demand Response program with C&I customers. The original approach to DR was driven by Hawaii PUC requirements to include DR in HECO's portfolio, but these programs were each administrated separately, in contrast with the new proposed Integrated Demand Response Plan.

Each of these programs, as well as their history and the challenges encountered during their development, is discussed below.

A.3.1 Residential Direct Load Control

The RDLC program was originally proposed to the Hawaii PUC in 2003, with a target of 17 MW of demand reduction from water heaters and AC systems. To develop program terms, HECO commissioned a telephone survey with 400 residents. This survey polled likelihood to participate at various incentive levels; type and size of systems; whether systems had timers or insulation; and location, home type, and demographic information. These surveys also served as a useful customer awareness and promotion tool for when the programs were rolled out, since respondents were already familiar with the program.

Technical Requirements: To participate in the RDLC program, a customer would subscribe, and the utility would install a one-way paging load control receiver allowing the utility to cycle the load (typically electric water heater or AC) for up to one hour. The RDLC program required a minimum 30-gallon water heater.

Participation Terms: RDLC participants are required to make their loads available at all times and have no notification requirement. The utility can utilize this program at any time throughout the year for an unlimited number of events.

Compensation Mechanism: Once enrolled, residential participants receive a monthly utility bill credit of $3 to $5, regardless of how often the utility cycles their equipment. This equates to $36 to $60 per year for participation in the program, regardless of how many times their load is called upon for DR.

Implementation Ease: RDLC participants were typically dispatched for one hour at a time. Longer durations were possible, but there was a risk of customer attrition due to the inconvenience of extended outages. Operationally, calling upon these resources was relatively simple via the one-way paging communications system, but because of this, HECO had no visibility at a household level as to whether its dispatches were being followed.

The RDLC program encountered resistance from the Hawaii Customer Advocacy group, which argued that participants were undercompensated and that the program would adversely impact ratepayers. This dispute was ultimately settled and resulted in slightly higher monthly compensation for participants. Once approved, it took two years (2004 and 2005) and approximately $400,000 to fully develop the program with a load management system to dispatch the loads.

Evaluation Results: The RDLC program was rolled out in 2005, includes approximately 36,000 residential participants, and has provided 7.2 MW of average peak load shed per event.

A.3.2 Commercial and Industrial Direct Load Control

The CIDLC program was proposed by HECO to Hawaii PUC in 2003, with a target of 21 MW of demand reduction. This program was preceded by a rate schedule rider (Rider I), which allowed participants to reduce their load when requested by HECO in exchange for reductions in demand charges in their existing rate schedules.

HECO commissioned a series of 104 site visits with 104 participants out of a total population of 354. These site visits gathered information on the total potential load available and how much load prospective participants estimated that they could reduce. They also examined the respondents' interest in participation at various incentive levels, their required minimum advance notification requirement, the maximum hours of participation, and the importance of decision elements like incentive level and criticality of loads. The survey found that at the originally proposed incentive levels ($5 per kWh-month and $0.25 per kWh), 65% of respondents were interested in participating in the program.

Technical Requirements: To participate in the CIDLC program, a participant must install a one-way paging load control receiver allowing the utility to cycle its load. C&I participants can nominate multiple kinds of loads, such as fountains, lighting, hot water systems, and heating/ventilation/AC systems, among others.

Participation Terms: The minimum size for participation in the CIDLC program was 50 kW. Participants are required to make their loads available at all times, but the utility must provide a minimum of 1-hour prior notification. CIDLC participants are also only required to provide up to 300 hours annually. Non-performance under the CIDLC program results in the loss of the incentives and penalty payments.

Compensation Mechanism: CIDLC participants receive $5 to $10 per kW of nominated load per month. This equates to $60 to $120 per kW per year, depending on whether they elect for their load to be manually or automatically reduced. In addition, participants receive an additional $0.50 per kWh for the load shed during events.

Implementation Ease: When the program was rolled out in 2004, only six participants had elected to join by the end of the year. The complaints included the following:

1. Minimum controlled load program requirement of 200 kW was too high.
2. Perceived risk to customer operations and/or customer sales if load control events occur was unacceptable at the current incentive levels.
3. The penalty charge for non-compliance was excessive and not worth the risk of enrollment at the current incentive levels. (The charge was equal to two times the normal monthly charge for demand for the billing period.)
4. The $5/kW month and $0.25/kW-hour during load control event were not lucrative enough.
5. The Program's contractual language and terms were not sufficiently flexible.
6. Customers could not aggregate controlled loads from separate customer sites and/or dispersed customer equipment within a site.
7. Customer equipment could be damaged by an under-frequency relay.
8. Customer installation costs associated with equipment installation necessary for participating in the CIDLC program was proven to be a barrier with many customers.

After 2004, the CIDLC program was revised to $5 to $10 per kW-month and $0.50 per kWh. Although this increased enrollment to 20 participants and 12.1 MW of load reduction, HECO only utilized the program for 1 hour in 2015 as it was more expensive to operate than dispatching oil-fired peaking plants (their most expensive generation assets). In addition, the 1-hour advance notification requirement, as well as limited or nonexistent need for additional capacity on Oahu, made the program of limited usefulness to the utility.

Evaluation Results: The CIDLC includes roughly 200 residential participants and had 12.8 MW of average peak load shed per event. This CIDLC program's implementation demonstrates that, although surveys may be a useful tool for developing an initial set of program terms (including compensation levels), a pilot approach may be still more useful to gauge actual interest in the program. Further, determining compensation levels for participants must strike the difficult balance between the need for voluntary customer participation with utility requirements that programs be cost effective.

A.3.3 Fast Demand Response (Fast DR)

The Fast DR program was piloted in 2012 and was intended to contract with C&I participants to reduce at least 50 kW of load within 10 minutes of notification. The Fast DR program had a 7-MW target for the provision of non-spinning reserve services.

Technical Requirements: To participate in the Fast DR program, participants received preliminary assessments and technical audits at the utility's cost, as well as a $3,000 incentive to defray the cost of a 5-minute interval meter and upgrades of the participants' systems. Participants in the Fast DR program were also required to have a performance audit to determine the capability of the nominated load to provide service and to verify the 10-day baseline load.

Participation Terms: Fast DR participants have a 10-minute advance notice before an event but are only required to provide services between 7 a.m. and 9 p.m., Monday through Friday. They are also limited to a maximum of 80 performance hours annually and have three penalty-free opt outs per year.

Compensation Mechanism: Fast DR participants receive minimum compensation of $3,000 to $6,000 for election to participate in 40 or 80 events. In addition, they receive a base incentive of $300 to $600 per kW-year depending on whether they elect for a semi-automated or automated control mechanism. Finally, they also receive a $0.50 per kWh performance incentive for each hour that energy is not consumed. However, given that performance periods for the Fast DR program are relatively short, it may require several events to reach a single hour of performance.

Implementation Ease: Fast DR implementation was considerably more involved, as each site required installation of a 5-minute meter and load control equipment, as well as a detailed energy audit to establish a 10-day energy baseline. HECO also developed an elaborate website, called AutoDR, which was a secure website showing energy use data, DR event history, and opt-out processing to temporarily withdraw from participation, either before or during a DR event. HECO faced several challenges with the Fast DR program, such as the 10-minute notification requirement, which was not fast enough to meet regulation reserve requirements.

Evaluation Results: The Fast DR program ultimately enrolled 6.1 MW of participating load, with an average load impact of 0.7 MW. The program was never relied upon for regular non-spinning reserve events but was tested 54 times in 2013. The proposed compensation of $0.50

per kWh, although utilized for shorter durations than the CIDLC program, was still well in excess of the dispatch cost of existing gas peaking plant capacity, making it uneconomic in relation to existing generation assets.

A.3.4 Initial Programs Summary

The early DR programs in Hawaii required a substantial investment of administrative effort. The programs had a combined administrative cost of approximately $2.3 million in 2015. These administrative costs included materials, outside services, labor, transportation, and other miscellaneous costs. The Fast DR program in particular had high administration costs of $1.2 million in 2015, which was 2 to 4 times larger than the costs of the RDLC and CIDLC programs. This may be due in part to the cost of the AutoDR website developed to administer the program, as well as the additional complexity of the program, which was intended to provide regulation reserves, rather than just capacity.

The RDLC and CIDLC programs were cheaper than the avoided cost of new generation (estimated by HECO at $210 to $260 per kW-year), but the CIDLC program had little applicable use due to a 1-hour notification requirement. The RDLC program cost was approximately $200 per kW-year, and the CIDLC program cost was $250 per kW-year.

HECO faced several challenges with the Fast DR program, such as the 10-minute notification requirement, which was not fast enough to meet regulation reserve requirements. HECO is targeting a 1- to 2-minute response time in the future. Further, the proposed compensation of $0.50 per kWh, although utilized for shorter durations that the CIDLC program, was still well in excess of the dispatch cost of existing gas peaking plant capacity, making it a somewhat uneconomic program.

A.3.5 Proposed Hawaii DR Programs

In February 2017, HECO filed a revised DR portfolio with the Hawaii PUC. The rollout goal of the revised DR program is the last quarter of 2017. The revised approach by HECO identifies various forms of DR services (capacity, fast frequency response, regulating reserve, and replacement reserve), and HECO proposes to administer them through an integrated Demand Response Management System.

By 2020, HECO intends to transition to real-time pricing for these services, but in the interim, HECO will implement a tariff-based system. Under this system, participants would opt in to a variant of their existing utility rate schedule. For example, a residential TOU subscriber would opt into a TOU/DR tariff. The proposed services and future DR programs are summarized in Table A-7.

Table A-7. Hawaii Proposed DR Programs and Services

DR Program	Grid Service Delivered
Real-Time Pricing (RTP)	Capacity
Time-of-Use (TOU)	
Day-Ahead Load Shift (DALS)	
Minimum Load (ML)	
PV Curtailment (PVC)	
Critical Peak Incentive (CPI)	
Fast Frequency Response (FRR)	Fast Frequency Response 1 and 2
Regulating Reserve (RegUp)	Regulating Reserve (RegUp)
Non-Spin Auto Response (NSAR)	Replacement Reserve (RR) (10-Minute)

Compensation Mechanism: Under the proposed tariffs, participants would receive between $36 and $96 per kW-year of nominated capacity as a bill credit under their existing rate structure, plus a $600 per kW allowance for initial DR equipment installation (commercial subscribers only).

Subscribers will receive a monthly incentive based on their performance in comparison to their nominated capability. This performance is calculated as a simple ratio between the actual load reduction versus the expected load reduction from the nominated capacity.

$$Event\ Performance\ Factor = \frac{Event\ Load\ Shed\ (kW)}{Nominated\ Capability\ (kW)}$$

Monthly Incentive = Nominated Capability (kW) * Monthly Event Performance Factor * Nominated Capability Incentive

Event load shed is calculated in comparison to the estimated baseline of the customer's normal energy usage. The estimated baseline takes the average demand of the 10 previous similar usage days (weekdays, non-holidays, and non-event days), using five-minute interval data for the same time period as the critical peak incentive event.

This performance factor is based on the participant's average performance in all the events in a month, as shown below:

$$Monthly\ Performance\ Factor = \frac{Sum\ of\ Event\ Performance\ Factors}{Number\ of\ Events}$$

If a participant does not perform above a 0.50 performance factor for three consecutive events, it may be suspended from the program. Also, to account for days when a critical peak incentive event is triggered and abnormal energy usage may occur (e.g., higher or lower demand than normal due to weather conditions or other anomalies), the estimated baseline is adjusted by using an adjustment factor. The actual baseline is established during a 3-hour calibration period prior to the event.

$$Adjustment\ Factor = \frac{Actual\ Baseline}{Estimated\ Baseline}$$

Participants will be able to select or combine the DR services that they wish to provide but will not be able to determine whether or not they participate in a given DR event. Although they do not pay a penalty for underperformance, they will receive a lower incentive based on their reduced Performance Factor. A summary of the compensation levels of the programs is included in Table A-8.

Table A-8. Summary of Proposed Hawaii DR Programs

Program Type	Commercial Critical Peak Incentive	Fast Frequency Response	Commercial Fast Frequency Response	Non-Spin Auto Response	Commercial Non-Spin Auto Response
Capability Incentive (monthly)	$3.00/kW	$8.00/kW	$4.00/kW	$6.00/kW	$3.00/kW
Equipment Installation Incentive	$600/kW	N/A	$600/kW	N/A	$600/kW
Permitted Rate Schedules	General Service Demand General Service Non-Demand Large Power Service Large Power Directly Served Service TOU Service Commercial TOU Service	General Service Demand General Service Non-Demand Small Commercial TOU Residential Service Residential Interim TOU Service	General Service Demand General Service Non-Demand Large Power Service Large Power Directly Served Service TOU Service Commercial TOU Service	General Service Demand General Service Non-Demand Small Commercial TOU Residential Service Residential Interim TOU Service	General Service Demand General Service Non-Demand Large Power Service Large Power Directly Served Service TOU Service Commercial TOU Service
Compatible Services	FFR-C	NSAR	CPI-C or NSAR-C	FFR	FFR-C

CPI = critical peak incentive
FFR = fast frequency response
FFR-C = fast frequency response – commercial
NSAR = non-spin auto response
NSAR-C = on-spin auto response – commercial

Another facet of HECO's proposed plan is the reliance on aggregators to perform the customer outreach and administration of the DR programs. These aggregators will be compensated slightly differently than end users directly enrolling in the program. Whereas the end users would receive $36 to $96 per kW-year for their DR services, an aggregator will contract directly with HECO to provide a specific amount of grid service at a negotiated price. If aggregators do not meet HECO's DR targets under their Power Supply Improvement Plan, HECO will issue competitive Requests for Proposals on a rolling 5-year basis.

Although the proposed approach discussed above is a near-final version of HECO’s DR plan, it is still subject to Hawaii PUC approval and has not yet been implemented. It is scheduled to commence implementation by the fourth quarter of 2017.

Appendix B: Utility Avoided-Cost Formulas

Four common metrics used for economic analysis of demand-side programs are summarized below. These were developed in 2001 by the California PUC, and have been adopted by several states, including Hawaii. More detailed discussion of this approach is included in the *California Standard Practice Manual* [33].

This approach examines the cost-benefit and cost-effectiveness of a DR program from four perspectives: Participant, Ratepayer Impact Measure (RIM), PAC, and Total Resource Cost. A fifth perspective, the Societal, is treated as a variation on the Total Resource Cost test. These are primarily summarized in net present value, although the lifecycle revenue impact for kilowatt-hours or kilowatts are also included. These tests are intended to be performed together, to consider the tradeoffs of programs, and their strengths and weaknesses are summarized in the manual.

Note that the California PUC has already developed a spreadsheet tool that greatly facilitates the computation of the following formulas. This tool is located at: http://www.cpuc.ca.gov/General.aspx?id=7023

The following formulae have been excerpted from the manual referenced above.

B.1 Participant Test

The following are the formulas for discounted payback, the net present value (NPVp) and the benefit-cost ratio (BCRp) for the Participant Test.

$$NPVp = Bp - Cp$$

$$NPVavp = (Bp - Cp) / P$$

$$BCRp = Bp / Cp \quad DPp = \text{Min } j \text{ such that } Bj > Cj$$

where:

NPVp = Net present value to all participants

NPVavp = Net present value to the average participant

BCRp = Benefit-cost ratio to participants

DPp = Discounted payback in years

Bp = NPV of benefit to participants

Cp = NPV of costs to participants

Bj = Cumulative benefits to participants in year j

Cj = Cumulative costs to participants in year j

P = Number of program participants

J = First year in which cumulative benefits are cumulative costs

d = Interest rate (discount)

The benefit (BP) and cost (Cp) terms are further defined as follows:

$$BP = \sum_{t=1}^{N} \frac{BR_t + TC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{AB_{at} + PA_{at}}{(1+d)^{t-1}}$$

$$C = \sum_{t=1}^{N} \frac{PC_t + BI_t}{(1+d)^{t-1}}$$

where:

BR_t = Bill reductions in year t

BI_t = Bill increases in year t

TC_t = Tax credits in year t

INC_t = Incentives paid to the participant by the sponsoring utility in year t[11]

PC_t = Participant costs in year t to include:

- Initial capital costs, including sales tax[12]
- Ongoing operation and maintenance costs include fuel cost
- Removal costs, less salvage value
- Value of the customer's time in arranging for installation, if significant.

PAC_{at} = Participant avoided costs in year t for alternate fuel devices (costs of devices not chosen)

AB_{at} = Avoided bill from alternate fuel in year t

[11] Some difference of opinion exists as to what should be called an incentive. The term can be interpreted broadly to include almost anything. Direct rebates, interest payment subsidies, and even energy audits can be called incentives. Operationally, it is necessary to restrict the term to include only dollar benefits such as rebates or rate incentives (monthly bill credits). Information and services such as audits are not considered incentives for the purposes of these tests. If the incentive is to offset a specific participant cost, as in a rebate-type incentive, the full customer cost (before the rebate) must be included in the PC_t term

[12] If money is borrowed by the customer to cover this cost, it may not be necessary to calculate the annual mortgage and discount this amount if the present worth of the mortgage payments equals the initial cost. This occurs when the discount rate used is equal to the interest rate of the mortgage. If the two rates differ (e.g., a loan offered by the utility), then the stream of mortgage payments should be discounted by the discount rate chosen.

The first summation in the B_p equation should be used for conservation and load management programs. For fuel substitution programs, both the first and second summations should be used for B_p.

Note that in most cases, the customer bill impact terms (BR_t, BI_t, and AB_{at}) are further determined by costing period to reflect load impacts and/or rate schedules, which vary substantially by time of day and season. The formulas for these variables are as follows:

$$BR_t = \sum_{i=1}^{I} (\Delta EG_{it} \times AC:E_{it} \times K_{it}) + \sum_{i=1}^{I} (\Delta DG_{it} \times AC:D_{it} \times K_{it}) + OBR_t$$

AB_{at} = (Use BR_t formula, but with rates and costing periods appropriate for the alternate fuel utility)

$$BI_t = \sum_{i=1}^{I} (\Delta EG_{it} \times AC:E_{it} \times (K_{it} - 1)) + \sum_{i=1}^{I} (\Delta DG_{it} \times AC:D_{it} \times (K_{it} - 1)) + OBI_t$$

where:

ΔEG_{it} = Reduction in gross energy use in costing period i in year t

ΔDG_{it} = Reduction in gross billing demand in costing period i in year t

$AC:E_{it}$ = Rate charged for energy in costing period i in year t

$AC:D_{it}$ = Rate charged for demand in costing period i in year t

K_{it} = 1 when ΔEG_{it} or ΔDG_{it} is positive (a reduction) in costing period i in year t, and zero otherwise

OBR_t = Other bill reductions or avoided bill payments (e.g., customer charges, standby rates).

OBI_t = Other bill increases (i.e. customer charges, standby rates).

i = Number of periods of participant's participation

In load management programs such as TOU rates and AC cycling, there are often no direct customer hardware costs. However, attempts should be made to quantify indirect costs customers may incur that enable them to take advantage of TOU rates and similar programs. If no customer hardware costs are expected or estimates of indirect costs and value of service are unavailable, it may not be possible to calculate the benefit-cost ratio and discounted payback period.

B.2 Ratepayer Impact Test

The formulae for the lifecycle revenue impact (LRI RIM)' net present value (NPV RIM), benefit-cost ratio (BCR RIM)' the first-year revenue impacts and annual revenue impacts are presented below:

LRIRIM = (CRIM – BRIM) / E

FRIRIM = (CRIM – BRIM) / E   for t = I

$ARIRIM_t$ = FRIRIM   for t = I

= ($CRIM_t$ – $BRIM_t$)/E_t for t = 2, …, N

NPVRIM = BRIM – CRIM

BCRRIM' = BRIM/CRIM where:

LRIRIM = Lifecycle revenue impact of the program per unit of energy (kWh or therm) or demand (kW) (the one-time change in rates) or per customer (the change in customer bills over the life of the program). (Note: An appropriate choice of kWh, therm, kW, and customer should be made)

FRIRIM = First-year revenue impact of the program per unit of energy, demand, or per customer.

ARIRIM = Stream of cumulative annual revenue impacts (ARI) of the program per unit of energy, demand, or per customer. (Note: The terms in the ARI formula are not discounted; thus, they are the nominal cumulative revenue impacts. Discounted cumulative revenue impacts may be calculated and submitted if they are indicated as such. Note also that the sum of the discounted stream of cumulative revenue impacts does not equal the LRI RIM')

NPVRIM = Net present value levels

BCRRIM = Benefit-cost ratio for rate levels

BRIM = Benefits to rate levels or customer bills

CRIM = Costs to rate levels or customer bills

E = Discounted stream of system energy sales (kWh or therms) or demand sales (kW) for first-year customers.

The B_{RIM} and C_{RIM} terms are further defined as follows:

$$B_{RIM} \sum_{t=1}^{N} \frac{UAC_t + RG_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{RIM} \sum_{t=1}^{N} \frac{UIC_t + RL_t + PRC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{RL_{at}}{(1+d)^{t-1}}$$

$$E = \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

where:

UAC_t = Utility avoided supply costs in year t

UIC_t = Utility increased supply costs in year t

RG_t = Revenue gain from increased sales in year t

RL_t = Revenue loss from reduced sales in year t

PRC_t = Program Administrator program costs in year t

E_t = System sales in kWh, kW or therms in year t or first year customers

UAC_{at} = Utility avoided supply costs for the alternate fuel in year t

RL_{at} = Revenue loss from avoided bill payments for alternate fuel in year t (i.e., device not chosen in a fuel substitution program)

For fuel substitution programs, the first term in the B_{RIM} and C_{RIM} equations represents the sponsoring utility (electric or gas), and the second term represents the alternate utility. The RIM test should be calculated separately for electric and gas and combined electric and gas.

The utility avoided-cost terms (UAC_t, UIC_t, and UAC_{at}) are further determined by costing period to reflect time-variant costs of supply:

$$UCA_t = \sum_{i=1}^{I}(\Delta EN_{it} \times MC:E_{it} \times K_{it}) + \sum_{i=1}^{I}(\Delta DN_{it} \times MC:D_{it} \times K_{it})$$

UAC_{at} = (Use UACt formula, but with marginal costs and costing periods appropriate for the alternate fuel utility.)

$$UIC_t \sum_{i=1}^{I}(\Delta EN_{it} \times MC:E_{it} \times (K_{it}-1)) + \sum_{i=1}^{I}(\Delta DN_{it} \times MC:D \times (K_{it}-1))$$

where:

[Only terms not previously defined are included here.]

ΔEN_{it} = Reduction in net energy use in costing period i in year t

ΔDN_{it} = Reduction in net demand in costing period i in year t

$MC:E_{it}$ = Marginal cost of energy in costing period i in year t

$MC:D_{it}$ = Marginal cost of demand in costing period i in year t

The revenue impact terms (RG_t, RL_t, and RL_{at}) are parallel to the bill impact terms in the Participant Test. The terms are calculated the same way with the exception that the net impacts are used rather than gross impacts. If a net-to-gross ratio is used to differentiate gross savings from net savings, the revenue terms and the participant's bill terms will be related as follows:

$RG_t = BI_t$ * (net-to-gross ratio)

$RL_t = BR_t$ * (net-to-gross ratio)

$Rl_{at} = Ab_{at}$ * (net-to-gross ratio)

B.2.1 Total Resource Cost Test

The formulas for the net present value (NPVTRC)', the benefit-cost ratio (BCRTRC), and levelized costs are presented below:

NPVTRC = BTRC – CTRC

BCRTRC = BTRC /CTRC

LCTRC = LCRC / IMP

where:

NPVTRC = Net present value of total costs of the resource

BCRTRC = Benefit-cost ratio of total costs of the resource

LCTRC = Levelized cost per unit of the total cost of the resource (cents per kilowatt-hour for conservation programs; dollars per kilowatt for load management programs)

BTRC = Benefits of the program

CTRC = Costs of the program

LCRC = Total resource costs used for levelizing

IMP = Total discounted load impacts of the program

PCN = Net participant costs

The BTRC, CTRC, LCRC, and IMP terms are further defined as follows:

$$BTRC = \sum_{t=1}^{N} \frac{UAC_t + TC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$CTRC = \sum_{t=1}^{N} \frac{PRC_t + PCN_t + UIC_t}{(1+d)^{t-1}}$$

$$LCRC = \sum_{t=1}^{N} \frac{PRC_t + PCN_t - TC_t}{(1+d)^{t-1}}$$

$$IMP = \frac{\sum_{t=1}^{n} \left[(\sum_{i=1}^{n} \Delta EN_{it}) \; or \; (\Delta DN_{it} \; where \; I = peak \; period) \right]}{(1+d)^{t-1}}$$

[All terms have been defined in previous chapters.]

The first summation in the BTRC equation should be used for conservation and load management programs. For fuel substitution programs, both the first and second summations should be used.

B.3 Program Administration Cost Test

The formulas for the net present value, the benefit-cost ratio, and levelized cost are presented below:

$NPV_{pa} = B_{pa} – C_{pa}$

$BCR_{pa} = B_{pa}/C_{pa}$

$LC_{pa} = LC_{pa}/IMP$

where:

NPV_{pa}	Net present value of PACs
BCR_{pa}	Benefit-cost ratio of PACs
LC_{pa}	Levelized cost per unit of PAC of the resource
B_{pa}	Benefits of the program
C_{pa}	Costs of the program
LC_{pc}	Total PACs used for levelizing

$$B_{pa} = \sum_{t=1}^{N} \frac{UAC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{pa} = \sum_{t=1}^{N} \frac{PRC_t + INC_t + UIC_t}{(1+d)^{t-1}}$$

$$LCpc = \sum_{t=1}^{N} \frac{PRC_t + INC_t}{(1+d)^{t-1}}$$

[All variables are defined in previous chapters.]

The first summation in the B_{pa} equation should be used for conservation and load management programs. For fuel substitution programs, both the first and second summations should be used.