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A Roadmap to Enable the Full Value of Demand Response in Wholesale Operations

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EPRI Project Manager

A. Chuang

ELECTRIC POWER RESEARCH INSTITUTE
3420 Hillview Avenue, Palo Alto, California 94304-1338 ▪ PO Box 10412, Palo Alto, California 94303-0813 ▪ USA
800.313.3774 ▪ 650.855.2121 ▪ askepri@epri.com ▪ www.epri.com

THE FOLLOWING ORGANIZATION PREPARED THIS REPORT:

Electric Power Research Institute (EPRI)

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NOTE

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Electric Power Research Institute (EPRI)
3420 Hillview Avenue
Palo Alto, CA 94304

Principal Investigator
A. Chuang

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ABSTRACT

The report describes a roadmap to enabling the full value of demand response (DR) through careful examination of the role of DR in wholesale environments. The roadmap represents a synthesis of findings from breakout sessions conducted at the Demand Response 2.0 Roadmap Workshop conducted by the Electric Power Research Institute (EPRI) on August 22–23, 2012, in Houston, Texas. Relevant findings from that workshop, along with frameworks published in prior works by EPRI on the potential broad-based roles of DR, provide the foundation for the roadmap described here.

The roadmap depicts a logical progression of stages of DR integration in power system operations and planning by time horizon, along with key capabilities that DR supports at each stage. It identifies technical capabilities and key enablers required to attain each stage of DR integration. The report describes and illustrates how to apply the roadmap, program design process, and other tools to inform the specification of system requirements to automate DR along advancing stages of DR integration.

Application examples are provided to help utilities design programs that are supportive of organizational objectives and to better identify evolving technology requirements with an overall program evolution perspective in order to avoid premature obsolescence of enabling technology. That is, by applying the process described here, a program designer can devise a program roadmap that takes into account the evolution of DR-enabling technology and technical requirements to meet system objectives.

Keywords
Customer engagement model
Demand response integration roadmap
Demand response management system
Program design process and roadmap
Technical requirements
Trigger and actuation methods

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1
INTRODUCTION

Purpose

The purpose of this report is to outline a roadmap for enabling the full value of demand response (DR), through careful examination of the role of DR in wholesale environments. The report synthesizes relevant findings from EPRI's Demand Response Roadmap Workshop conducted August 22-23, 2012 in Houston, Texas, and leverages findings from prior industry publications on the potential broad-based roles of DR.

The synthesized roadmap depicts a logical progression of stages of DR integration in power system operations and planning by time horizon, along with key capabilities DR supports at each stage. Moreover, the resulting roadmap outlines technical capabilities and key enablers required to attain each stage of DR integration.

Discern Value of Demand Response through Wholesale Context

The value of DR originates in wholesale environments based on the extent DR can support existing requirements involved in performance of power industry functions. Existing planning and operational functions performed by "responsible entities" have been defined by NERC in [1] and [2] (References are listed in Appendix A). Examples of relevant functional tasks that DR could support include transmission and resource planning, transmission and distribution service provision, and operational reliability services (e.g., balancing energy, ancillary service reserve, etc.). More specifically based on synthesis of findings in [2] and [3], DR value to responsible entities (power companies) in the electricity industry lies in the extent DR can address any of the following:

- meet system requirements for resource adequacy through capacity provision
- provide defined reliability services recognized or transacted in wholesale environments
- meet or reduce procurement requirements for energy or other valuable services as a qualified resource or in a quantifiable manner
- defer capital investment in more permanent T&D, substation, or generation facility solutions

Application of Roadmap

The report illustrates application of the roadmap plus associated DR program assessment tools and evaluation frameworks developed by EPRI in recent years for devising sustainable demand response implementations, within regional wholesale contexts. Collectively the developed roadmap and program assessment tools are leveraged to address industry challenges by applying:

- the developed tools to effectively design new DR programs that advance system objectives for using demand response
- the roadmap to inform specification of technical requirements for systems needed to automate DR in new applications advancing system objectives

Report Organization

Chapter 2 of this report describes the basic methodology applied for deriving the roadmap presented in Chapter 3. Subsequent chapters illustrate potential applications of the roadmap and developed tools, and discuss implication of findings. In particular, Chapter 4 illustrates application of an evaluation framework to systematically and effectively design new DR programs compatible with regional wholesale contexts in support of identified system objectives while also respecting design constraints. Chapter 5 employs the roadmap to inform specification of technical requirements, including requirements for DR management systems.

2
METHODOLOGY

Approach to Roadmap Development

The general approach to roadmap development was to gather and synthesize input received from a broad base of stakeholders. Input was gathered through a workshop, personnel interviews, and literature review. Stakeholders from both the wholesale (bulk) power environment as well as the retail (customer-facing) organizations were invited to attend EPRI's DR 2.0 Roadmap workshop.

Broad Definition of Demand Response

In the roadmap development effort, a general definition of DR was taken to include demand-side resources that can dynamically adjust consumption in either direction (i.e., increase and/or decrease in load) in support of system or market conditions. That is, as previously described in [3]:

Demand response (DR) is a dynamic change in electricity usage coordinated with power system or market needs.

Under this definition, the coordinated change can be either a decrease *or increase* in electricity consumption. For example, customary DR includes interrupting or curtailing loads to help alleviate potential grid overloading conditions. Conversely, activating electric water heaters or charging distributed storage systems (including plug-in electric vehicles) in response to grid signals to balance night-time over-generation of wind resources would also be considered DR.

Moreover, distributed renewable generation such as solar photovoltaic (PV) and small wind mills can also provide DR if equipped to respond to system conditions (e.g., turning off during over-generation periods). These various types of demand-side resources are also described in [4] under a common taxonomy.

Industry Gathering at Demand Response 2.0 Roadmap Workshop

EPRI held a Demand Response 2.0 Workshop on August 22-23, 2012 at Centerpoint Energy Headquarters in Houston, Texas. The theme of the workshop focused on integrating demand-side resources across electric power operations and planning to enable the full value of demand response (DR).The workshop was attended by over 50 stakeholders representing utilities and other power companies from across the electricity supply chain, as well as RTOs/ISOs, regulators, government agencies, researchers, and others.

The goals of the workshop included: gathering industry practitioners to collaboratively define a DR 2.0 vision and produce a comprehensive industry roadmap for DR, enabling DR in new markets and applications; and discussing technology advancements required to achieve progressive stages of the roadmap. These goals were addressed by three interactive panel discussions, three tracks of four break-out sessions, and structured small group discussion exercises.

The workshop was part of EPRI's multiyear effort to help identify pathways to overcome technological, organizational and procedural gaps that exist in electric power operations and planning, to enable full integration of demand-side resources across the electricity value chain.

The workshop was designed to inform an end-to-end perspective from customer-facing, retail or wholesale trading functions to grid or market operations and resource planning; and to identify actionable steps involving the electric power industry that could lead to widespread demand response.

Although there are a variety of market structures and regulatory frameworks found in different geographic regions, EPRI's approach was to develop a common roadmap applicable for describing advancing stages of DR across the electric power industry in general. The chosen method for framing findings is broadly applicable in restructured markets as well as vertically integrated utility environments. Moreover, the roadmap was designed to be generalized enough to be applicable regardless of regulatory framework in force (e.g., rate decoupling or not). Yet the approach to roadmap development respected diverse perspectives, by grouping and gathering participant input by key differences where they exist in varying regional contexts and regulatory frameworks (e.g., organized wholesale market vs. vertically integrated structure).

Industry Interviews

EPRI conducted phone and in-person interviews to collect additional perspectives on useful applications of DR in wholesale environments, associated capabilities and key enablers. During 2012 and 2013, EPRI conducted interviews with wholesale operations personnel responsible for scheduling, trading, and dispatching resources as well as customer services (or member services) personnel in charge of DR programs. Topics discussed with interviewees included:

- How DR is being utilized now in wholesale operations by the stakeholder's organization
- How DR is envisioned to be used in the future by the stakeholder's organization
- Disconnects in current organization capabilities, systems, or functions for broad-based integration of DR in power system operations or planning

Synthesized, aggregated findings from interviews were considered in presenting the roadmap in a structured fashion applicable across diverse regional contexts.

Leverage Prior Works

The project approach included review of prior works developed on demand response integration in power system or market operations, which are cited in the References in Appendix A.

The project leveraged works that provide taxonomies and conceptual frameworks clarifying relationships between DR programs, technical requirements, wholesale opportunities and functions, and regional drivers for DR. In particular, frameworks published by EPRI in [3]-[6] were leveraged (as applicable) and synthesized to inform roadmap development, and to identify factors driving long-term sustainability of DR implementations.

Prior works in the bulk power realm were also considered in roadmap development. Important efforts paving the way for DR to be integrated into wholesale market and bulk system operations were reviewed. The Federal Energy Regulatory Commission (FERC) has conducted surveys on DR [7] and worked to identify and remove barriers for DR participation in wholesale market environments. In addition, the North American Electric Reliability Corporation (NERC) has published reports and summary papers regarding the functions and tasks or roles of DR to support bulk power system reliability. In particular, NERC publications [1] and [2] were reviewed to study power system operational and planning functions, for which opportunities for DR arise from which value can be derived when DR is employed in support of existing wholesale operations and planning functions.

Applications Emphasis

This report focuses on illustrating applications of roadmap findings. With industry advancement along the DR 2.0 Roadmap discussed in this report, DR has the potential of becoming a fully integrated resource in support of bulk generation and transmission grid, distribution grid, and energy market operations. The report discusses implications on technical capabilities required for DR to be employed in a widespread fashion in new applications and programs designed to more seamlessly support wholesale operations and planning.

3
DEMAND RESPONSE ROADMAP

Overview

This section describes a DR roadmap that encompasses an electric power industry vision for new DR programs and applications to support advanced system objectives. The roadmap is detailed in a fashion that can inform DR program design and specification of requirements to automate DR in emerging applications.

Assumptions

For the purposes of the roadmap development effort, "DR resources" refer to any adjustable end-use or power producing or storage device at the customer premises or along the distribution system, including flexible loads, variable generation, distributed generation, storage, and plug-in electric vehicles. Figure 3-1 depicts the landscape of DR resources considered within the scope of the roadmap development effort. Table 3-1 further explains the landscape by providing concrete examples of traditional as well as emerging types of DR resources and programs.

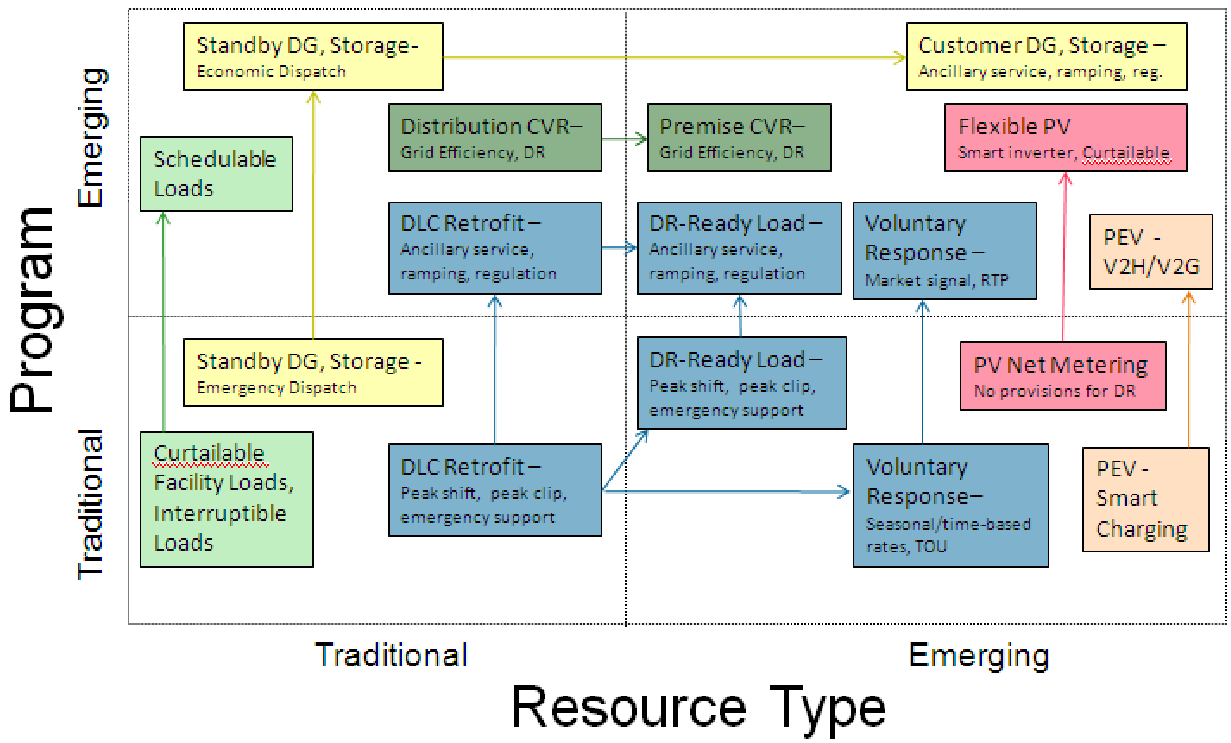

Figure 3-1
Landscape of Traditional and Emerging DR Programs and Resource Types

Table 3-1
DR Program and Resource Examples Corresponding to Quadrants in Landscape Figure

	Traditional Resource Types	Emerging Resource Types
Emerging DR Services/ Programs	• DLC (retrofitted large residential loads) for Ancillary Service, Ramping Energy, Regulation • Interruptible/Curtailable/Schedulable Load for Day-ahead Energy • Backup/Standby Building DG for economic support • Industrial Storage for economic support	• Residential voluntary response to market signals using small plug load (DR-Ready appliance, CE, etc.) • DLC of DR-Ready end uses (with integrated communications and controls) for Ancillary Service, Ramping Energy, Regulation • PV/Wind curtailment for system emergency support • Customer storage for Ancillary Service, Ramping Energy, Regulation • Plug-in Electric Vehicles (PEV) for Vehicle-to-Home (V2H) or Vehicle-to-Grid (V2G)
Traditional DR Services/ Programs	• DLC (retrofitted A/C, pump, water heater, etc.) under rate discount or incentive program for peak shifting, clipping, or emergency support • Curtailable/interruptible C&I (FSL, GLD Programs), • Standby DG for emergency grid support (e.g., backup diesels in commercial buildings for emergency support); • Industrial Storage for emergency support;	• Residential voluntary response to public appeal using small plug-load (DR-Ready appliances, consumer electronics, etc.) • DLC of DR-Ready end uses (with integrated communications and controls) for peak shifting, clipping, or emergency support • Wind feed-in tariff (with no provisions for DR) • PV on net metering (with no provisions for DR) • PEV charging for valley filling and local grid support

Roadmap to Full Value of Demand Response

The Demand Response Integration Roadmap depicts progressive levels of integration of DR in power systems operations and planning. Distinct stages of the roadmap demarcate capability of DR to support a class of system needs. The ordering of the stages is by Time Horizon (i.e., Short, Mid, or Long-term) which designates the earliest anticipated availability of commercial products for each corresponding stage of DR integration. Table 3-2 depicts the DR Integration Roadmap, by denoting the identifying name, Time Horizon, and DR integration purpose of each stage of the roadmap. The roadmap is followed by a series of tables that elaborate on the characteristics of each stage and how they differ in terms of level of DR capability and trigger requirements to employ DR.

By designing programs to enable DR for expanding purposes as demarcated by the stages of integration, program designers can equip DR to support multiple power system planning and operational functions, as they advance their organizations on the roadmap to enable the full value of demand response. Moreover, by understanding the characteristics of each stage and progression of capabilities and requirements for triggering DR, program designers can better prepare current programs for supporting future requirements, and better future-proof existing investments in DR enabling technologies and systems. The logical progression of DR capabilities and requirements associated with the roadmap provide a long-term perspective for capturing increasing utility from DR that can be factored into program design and implementation requirements on the pathway to enabling the full value of DR.

Stages

Table 3-2
Stages of Demand Response Integration Roadmap

Stage	Time Horizon	Demand Response Integration Purpose
Resource Adequacy	Now to Short	Defer generation expansion by planning to be available and respond during system-wide peak times
Forward Economics	Short-term (2012-14)	Enhance energy economics by following a schedule received in advance of the operating day
Distribution Management	Short to Mid-term	Mitigate unpredicted operational issues in the distribution system
T&D Deferral	Mid-term (2015-20)	Resolve operational issues resulting from avoided network upgrades
Ancillary Service Reserve	Mid-term	Mitigate unpredicted major outages or other contingency events
Balancing Resource	Mid to Long-term	Support real-time system balance
Elastic Demand	Long-term (2020+)	Support added dimensions of customer choice by adjusting on the basis of designated consumer choices

Resource Adequacy: In the first stage of the roadmap, commercial products are available for enabling widespread integration of DR for the purposes of deferring generation expansion, particularly through programs that are designed to enable planning for DR to be available and respond during system-wide peak times. Other program examples of DR for resource adequacy include DR procured in capacity markets, like the installed capacity markets in regions of the Northeast U.S., where resources that clear the market receive the capacity price as payment for being committed to respond during system emergencies. Cleared resources are subsequently triggered as needed during actual system peaks or emergencies. Moreover, DR procured to satisfy a regional resource adequacy requirement is essentially also for the purpose of deferring generation expansion. For example, the resource adequacy requirement in California is meant to ensure adequacy of capacity already built to serve the CAISO operating region. Moreover, different types of DR programs fully count toward the resource adequacy requirement in that region, and not just those triggered based on system emergencies. Participants of the DR 2.0 Workshop indicated that DR is already widely integrated or will be in the short-term for resource adequacy. The long-term impact of DR investment on resource adequacy is the subject of industry discussion and debate. A recently published EPRI whitepaper discusses the long term resource adequacy considerations of DR in more detail. [17]

Forward Economics: In the second stage of the roadmap, commercial products are available for enabling widespread integration of DR for the purposes of enhancing energy system economics, particularly through programs that are designed to commit DR to follow a schedule received in advance of the operating day. Distinguished from economic dispatch which occurs day-of, DR integrated to enhance forward economics generally results in a forward (e.g., day-ahead) energy or pricing schedule designed to impact actual energy consumption. Examples include DR integrated in day-ahead energy markets, which produce day-ahead schedules for resources like DR to follow on the operating day. Examples in vertically integrated utility regions include day-ahead self-commitment or self-scheduled DR as well as DR factored into unit commitment for forward scheduling purposes based on economics like start-up, no load, and fuel costs. Participants of the DR 2.0 Workshop indicated short-term commercial availability of products enabling widespread integration of DR for enhancing energy economics on a forward basis (e.g., day-ahead or weeks ahead).

Distribution Management: The third stage of the roadmap depicts commercial availability of products for widespread DR integration to support distribution management. That is, DR is employed to mitigate unpredicted operational issues along the distribution system, such as line faults, feeder outages, and transformer overloads. Workshop participants envisioned short to mid-term commercial availability of products enabling DR to support distribution management in a widespread fashion.

Transmission and Distribution Deferral: DR integrated for deferral of grid expansion is a subsequent stage of the roadmap that workshop participants indicated can be reached in the mid-term. In this stage, DR is integrated to resolve operational issues resulting from avoided network upgrades. Given the large amounts of DR required in-mass to defer transmission facility expansion, distribution deferral purposes of DR were viewed by workshop participants as less of an obstacle than transmission facility deferral.

Ancillary Service Reserve: Another stage of the roadmap envisioned as reachable in the mid-term is DR integrated for provision of ancillary service operating reserve. In this stage, DR is employed to mitigate unpredicted major outages or other contingency events (e.g., N-1 contingencies). Operating reserves include spinning/synchronous reserves, non-spinning reserves, and supplemental/replacement reserves. Although there are additional ancillary services defined and procured in various regions, this stage focuses on employing DR for operating reserves only. For example, DR programs designed to trigger interruption or curtailment of loads quickly on the order of 10 to 30 minutes may satisfy reserve requirements.

Balancing Resource: The next stage of the roadmap demarcates commercial availability of products in the mid to long-term for widespread DR integration to support real-time system balance. Examples include DR provision of frequency regulation and other flexible, fast-response services (e.g., flexible ramping for balancing variable generation output). This stage is distinguished from the prior stage by the complexity of DR capability required, since balancing services may require increasing as well as reducing load in response to real-time dispatch, whereas operating reserves only require reducing load.

Elastic Demand: The ultimate stage of the roadmap demarcates commercial availability of products to support implementing added dimensions of customer choice for electric service, which can be managed through system operations. In this stage, the power system is operated and resources are adjusted on the basis of designated consumer choices (e.g., premium, green, priority, or local power).

Choices enabled at this stage may also translate to more affordable levels of electric service. For example, PJM's Price Responsive Demand program was approved by FERC to enable demand-side integration of DR in PJM's capacity and energy markets [8]. The program essentially enables

PJM to clear select markets by factoring demand-side bids, thereby introducing elasticity in the demand curve for the market products. This is unlike the status quo of supply-side integration of DR in ISO/RTO markets, in which demand is essentially treated as inelastic so that procurement may occur at any price in the absence of price caps. Factoring the elasticity of demand into the procurement processes (i.e. considering the willingness of customers to pay for electric services) should translate to greater affordability of electric services for customers.

Comparison of Stages

Whereas the DR Integration Roadmap in Table 3-2 was developed through workshop participant feedback, subsequent analyses were conducted by EPRI to further differentiate between the stages of the developed roadmap. Table 3-3 and Table 3-4, respectively, distinguish the stages in terms of DR capabilities and implied trigger requirements.

Table 3-3
Stage Characteristics

Stage	Motivation	Resource Level	Coordination Timeframe
Resource Adequacy	Economic	System-wide	Planning
Forward Economics	Economic	Generation/Energy Node	Day(s)-Ahead
Distribution Management	Reliability	Distribution Facility	Real-Time
T&D Deferral	Economic	Network Node	Planning
Ancillary Service Reserve	Reliability	Transmission Facility	Real-Time
Balancing Resource	Reliability	System-wide or Network Node*	Real-Time
Elastic Demand	Customer Choice	Customer Facility	Timeframe of choice

* In interconnected systems, resource is system-wide when used for bulk system balancing; but localized for distribution-level feeder balancing

Table 3-3 highlights key differences in DR capabilities required at each stage. The stage characteristics in the column headings are defined as follows.

Motivation: The primary motivation of the program designer or planner for devising DR programs to support the stage of integration

Resource Level: Considering the topological hierarchy of the power system, the level that a DR asset would serve as a resource for the purpose of the stage.

Coordination Timeframe: Timeframe that resources are coordinated by design for the purpose of the stage. (This is not necessarily the timeframe of determination of resource commitment to follow a dispatch.) More specifically:

- For stages motivated by economics, this refers to the timeframe resources are procured by design.
- For stages motivated by reliability, this refers to the timeframe resources are coordinated for dispatch.

Each stage of the roadmap can be characterized by DR program design motivation, resource level, and coordination timeframe. As Table 3-3 indicates, each stage can be described by a unique combination of these three characteristics. For example, although all the reliability-motivated stages are associated with real-time coordination timeframes for DR dispatch, they differ by level of resource served. That is, the reliability-motivated stages Distribution Management, Ancillary Service Reserve, and Balancing Energy, respectively, each coordinate DR through real-time dispatch. However, these three stages differ by level of resource served, since DR resources are targeted by distribution facility under Distribution Management; transmission facility under Ancillary Service Reserve provision; or network node when providing Balancing Resource services. In interconnected systems, however, balancing services such as frequency regulation is generally not differentiated by location, unlike resources employed for distribution-level feeder balancing.

The economically-motivated stages are associated with forward coordination timeframes. In particular, DR procurement for Resource Adequacy or T&D Deferral purposes occurs in planning timeframes; whereas DR for enhancing Forward Economics is procured in forward timeframes such as day(s)-ahead of the operating day. These three economically-motivated stages primarily differ by the level of topological hierarchy on the power system that DR contributes as a resource. Namely, DR triggered for Resource Adequacy is considered a system-wide resource, such that the location of the resource within the inter-connected system generally does not matter to count towards Resource Adequacy. However, under which network node the DR resource is located generally matters for the purpose of T&D Deferral. Moreover, DR bid or factored into forward market-clearing or unit commitment may impact energy or pricing schedules within the energy or pricing node the resource is located within, especially in nodal markets or regions employing locational marginal pricing for energy services.

DR programs devised for the purpose of the last stage of the roadmap, Elastic Demand, serve the motivation of enhancing customer choice or dimensions of electric service they receive. Examples include customer-facility level subscriptions for premium, local, or green power. In various regions around the world there have been examples of demand subscription or demand-limiting service offered to mass market customers to differentiate rates by level of demand served in addition to quantity of energy received. The coordination timeframe whereby resources are adjusted to serve the customer's designated choice levels depends on the timeframe choices or subscription levels can be elected or adjusted. Consequently, the coordination timeframe reflects the timeframe possible for customer election of choices.

Comparison of DR Trigger Requirements

Table 3-4 highlights key differences in DR trigger characteristics required at each stage. The trigger characteristics the table compares are listed in the column headings. The table differentiates the stages by the following characteristics of the trigger for DR.

Trigger Conditions: The driving condition(s) for the decision to trigger DR by the system operator.

Trigger Mechanism: The primary mechanism relied on by the program operator to trigger a response from DR resources when operationally needed.

Trigger Communications: The minimum communications method required to trigger resources to support the purpose of the stage (in an operational context).

Table 3-4
Trigger Characteristics

Stage	Trigger Conditions	Trigger Mechanism	Trigger Communications (at minimum)
Resource Adequacy	Annual System Peaks (Long-term Forecasts)	Notification	1-way broadcast (system-wide event)
Forward Economics	Day(s)-Ahead Economics (DA Forecasts)	DA Schedule	1-way communications (energy schedule and/or pricing schedule)
Distribution Management	RT Conditions (Overloads, Faults)	RT Dispatch	2-way communications (direct dispatch and monitoring response to local event)
T&D Deferral	RT Conditions (Congestion)	RT Dispatch	2-way communications (direct dispatch or set-point and monitoring response to network event)
Ancillary Service Reserve	Contingency Event (Major Outages)	RT Dispatch	2-way communications (direct dispatch or set point and monitoring response to contingency event)
Balancing Resource	RT Conditions (System Imbalance, Schedule Deviations)	RT Dispatch or AGC	2-way communications (direct dispatch or control and monitoring progress of following AGC or DLC)
Elastic Demand	Conditions driven by customer choice	Mechanism for effecting choice	Minimum communications for effecting choice

Each stage of the roadmap can further be differentiated by DR trigger characteristics associated with the stage. The trigger characteristics are a combination of conditions, mechanism, and communications utilized to trigger DR. As Table 3-4 indicates, each stage is associated with a unique combination of these three trigger characteristics.

Under the first two economically-motivated stages, DR is triggered by conditions reviewed on a forward basis (e.g., long-term forecasts and day-ahead forecasts). In contrast, the next four stages in the roadmap trigger DR based on system operator review of real-time conditions. However, the particular real-time conditions being monitored vary by stage and level of network topology being monitored. For example, the real-time conditions that may arise for triggering DR include ameliorating: distribution outages or faults under Distribution Management, transmission congestion under T&D Deferral, major generation outages or other contingency events under Ancillary Service Reserve, and system imbalance or schedule deviations under Balancing Resource stage.

Moreover, the particular conditions driving the decision of the system operator to trigger DR under the Elastic Demand stage depend on the particular implementation or dimension of customer choices offered. For example, under a demand subscription service model, DR may be triggered to enforce customer choice of maximum demand service levels during critical peak periods. So the trigger condition is aligned with critical peaks as defined by the subscription service choice of the customer (e.g., critical peak prices, critical peak demand periods for the customer facility, or system-wide peak periods). That is DR is triggered to help the customer avoid exceeding its demand subscription when a critical peak is detected during the course of day-to-day operations.

Although DR is often procured and committed in forward timeframes (e.g., seasonally, day-ahead), a response is generally triggered under varying mechanisms that depend on the purpose for employing DR. For example, the mechanism for triggering DR for Resource Adequacy purposes or to defer generation expansion is at least a notification from the program operator of an impending system-wide emergency. For enhancing forward market economics or unit commitment, the resulting forward (e.g., day-ahead) schedule can generally serve as the trigger mechanism for the resource. The resource may be expected to follow a forward energy schedule or adjust in response to a pricing schedule published in advance of the operating day. In contrast, under the remaining stages with real-time trigger conditions, the trigger mechanism is real-time dispatch coordinated by the system operator based on latest operating conditions. Under the last stage Elastic Demand, the trigger mechanism again varies according to the implementation of choice, and generally ranges from notification and forward schedule to real-time dispatch and automated response via direct load control or local response to an operator-coordinated set-point.

The third column of Table 3-4 associates the minimum method of communications for triggering DR with each stage. DR used for the purposes of the first two stages generally requires one-way communications. Two-way communications has not been generally required when DR is used for Resource Adequacy or generation deferral purposes (e.g., triggered during system-wide emergencies), nor for forward economic purposes (e.g., shift load to lower cost period). Rather, traditional DR implementations have generally utilized one-way broadcast communications to trigger DR in response to system-wide events, and more targeted one-way communications to trigger DR for opportunities to enhance forward energy economics. However, two-way communications is generally desired by system operators when relying on DR to mitigate real-time conditions that can jeopardize maintaining real-time system reliability. Two-way communication requirements generally include targeted dispatch of DR resources and monitoring of response individually or in aggregate. Moreover, monitoring via real-time telemetry is generally required at the Ancillary Service Reserve stage, although some RTOs/ISOs have made provisions to relax the telemetry requirement for certain DR resources [9]. The communications requirements under Balancing Resource stage is generally more aggressive since certain balancing services like frequency regulation can require resources to follow a signal that is updated continuously on the order of seconds.

Application of Roadmap to Identify Required Capabilities of DR-Ready Devices

The DR Integration Roadmap depicts progressive stages of demand response integration over the next ten years. The roadmap presents a progressive time line of distinct classes of system needs that DR can be employed to meet. It also identifies technical capabilities and requirements, and can be applied to identify key technology advancements required to achieve widespread DR integration at each stage of the roadmap. Among key advancements, DR-Ready devices play a critical role in enabling widespread integration of DR in support of power system operations and planning. The key features of DR-Ready devices required at each stage of roadmap advancement can be inferred from careful study of Trigger Characteristics in Table 3-4.

The primary trigger characteristic driving DR-enabling technology requirements is the minimum communications required to trigger DR in response to specific trigger conditions in each stage of the roadmap. The last column of Table 3-5 illustrates the progression of DR-enabling technology advancement to support DR integration, considering the trigger communications required at each stage.

Table 3-5
DR-Enabling Technology Advancement

Stage	Trigger Communications (at minimum)	DR-Enabling Technology Advancement
Resource Adequacy	1-way broadcast (system-wide event)	Economic DR-enabling communications retrofits
Forward Economics	1-way communications (energy schedule or pricing)	Economic one-way communicating DR-enabling technologies
Distribution Management	2-way communications (direct dispatch and monitoring response to local event)	DR-Ready devices with two-way communications
T&D Deferral	2-way communications (direct dispatch or set-point and monitoring response to network event)	DR-Ready devices with demand-limiting controls / set points
Ancillary Service Reserve	2-way communications (direct dispatch or set point and monitoring response to contingency event)	DR-Ready devices with automated controls
Balancing Resource	2-way communications (direct dispatch or control and monitoring progress of following AGC or DLC)	DR-Ready devices with flexible / fast automated controls
Elastic Demand	Minimum communications for effecting choice	DR-Ready devices with customer choice-driven automation

This example of applying the roadmap depicts DR-enabling technology advancements needed to support widespread integration of DR at each stage of the roadmap. Resource Adequacy suffices with technology retrofits, which provide the communications which are typically one-way to trigger response to system emergencies. The example progresses in higher stages to DR-Ready devices with integrated one-way communications, two-way communications, integrated demand-limiting controls, automated controls, fast or flexible controls, and customer choice-driven controls. The enabling technology advancement required for attaining the last stage is stated generally since the particular implementation of choice could vary widely.

4

APPLICATION ILLUSTRATION: DEVELOPING NEW RETAIL DEMAND RESPONSE PROGRAMS

Context

This section illustrates how to apply the roadmap described in Chapter 3 to devise new programs that advance system objectives for using demand response. This section also illustrates how the roadmap can inform specification of requirements for systems needed to automate DR in new applications. Furthermore, the section illustrates how the roadmap can serve as a technology readiness guide for identifying technical requirements for supporting advancing stages of DR integration, in order to mitigate premature obsolescence of DR system investments, by building upon established technical capabilities.

Process

The process for devising new programs to advance organizational objectives begins with identifying the organization's primary purpose for employing DR. Program design options are ideally chosen based on the identified purpose. The roadmap in Chapter 3 is extended in this chapter to associate program design options with objectives supported. By following the process outlined here, a program designer can systematically identify supportive program design options and quickly filter out incompatible options while factoring in key considerations within the broad realm of program design possibilities.

The steps in the program design process illustrated in this chapter are:

1. Identify organizational purpose or objective for using DR
2. Identify special considerations like constraints surrounding technology environment (e.g., interval meter reading capability ruled out)
3. Select program design options supportive of purpose for DR

Under Step 3, program design choices to be made in support of the chosen purpose (designated in Step 1) include:

a) **Technical requirements**: DR coordination timeframe, DR actuation method

b) **Retail contract specifics**: Customer engagement model, DR program type

The next subsections expand on the last step in the process, along with the program design choices compatible with the chosen design objective.

Program Design Options

DR Coordination Timeframe

Based on review of Table 3-3, the coordination timeframe (the last column of the table) is directly associated with the targeted purpose for employing DR (the first column of the table). For convenient reference, the relevant columns are presented in Table 4-1 below.

Table 4-1
DR Coordination Timeframe Associated with Roadmap Stage (or Purpose for DR)

Stage	Coordination Time Frame
Resource Adequacy	Planning
Forward Economics	Day(s)-Ahead
Distribution Management	Real-Time
T&D Deferral	Planning
Ancillary Service Reserve	Real-Time
Balancing Resource	Real-Time
Elastic Demand	Timeframe of choice

Based on the program designer's chosen purpose for employing DR, the coordination timeframe is determined. The timeframe drives viable program design options to be discussed next.

DR Actuation Method

Background Explanation

DR programs that are supportive of wholesale products and purposes for DR are identifiable based on the method by which a response from the customer's DR asset is physically actuated. Actuation methods are described below.

Voluntary: DR is neither directly dispatchable by the utility nor any other DR program operator. Rather, any response produced comes purely from the customer's decision to curtail or not, regardless of whether or not notification of a DR event is given. Varieties of voluntary actuation of DR include:

- "Voluntary DR with notification": The customer actuates load curtailment as desired upon receipt of notification (and generally without penalty for deciding not to curtail).
- "Voluntary DR without notification": The customer decides to actuate load curtailment or not based on a general notion of when would be helpful to do so (e.g., public appeal on TV or newspaper).

Demand-limiting Control: This actuation method is found in contexts where the customer has subscribed to a program that can limit demand at a specified level. Varieties of demand-limiting control include:

- "Demand-limiting control with notification": The customer's demand limit is in effect upon receipt of notification. Based on local sensing of power demand (kW) or other local line condition (e.g., frequency), DR is curtailed automatically when a designated threshold (applicable upon notification) is reach.
- "Demand- limiting without notification": The customer's demand limit is in effect regardless of system operational conditions. Based on local sensing of power demand (kW) or other local line condition (e.g., frequency), DR is curtailed automatically when a designated threshold is reach

That is, the limiting threshold may be in effect only upon notification or in effect continuously. The former supports dispatchable DR, whereas the latter is a non-dispatchable actuation method.

Firm Commitment: Typically established with commercial and industrial (C&I) customers that have dedicated energy managers or operator, who make a firm commitment to curtail load upon notification to a designated firm service level or guaranteed load drop.

Direct Load Control: DR is directly controlled by a utility, third party aggregator, or customer affiliate/operator, which has deployed enabling technologies like data communications and control equipment, so that customer loads can be directly controlled in coordination with system operational needs. Varieties of actuation methods employing direct load control include:

- "Direct load control with notification": Operator-initiated controls actuate DR at times needed in coordination with system needs, after customer receipt and/or acceptance of notification.
- "Direct load control without notification": Operator-initiated controls actuate DR automatically at times needed in coordination with system needs, without customer notification.

Direct load control can be in effect routinely, as in the former case, or only based on notification of the customer by the program operator. Both varieties of direct load control support dispatchable DR.

Each actuation method listed, except for firm commitment, has an option with or without notification involved to initiate a response from the DR asset. In contrast, firm commitment generally involves notification of customers who in turn initiate actuation of a response (e.g., overseen by the customers' energy manager). Firm commitment is often employed with large C&I customers who disfavor direct control of their loads by a third party, or prefer to retain the liberty to decide which loads to curtail upon notification of an impending DR event.

Based on the program designer's chosen purpose for employing DR (in Step 1 of the process), the coordination timeframe is determined. The timeframe drives viable DR actuation methods, as is described next.

Viable DR Actuation Methods for Wholesale Purposes

Figure 4-1 is derived from leveraging prior work [3] and applying the roadmap in Chapter 3 to include additional stages in the DR Integration Roadmap missing from the original work. The figure associates DR actuation methods with the wholesale products or purposes for DR the method can be applied to support. The column headers identify the purpose for DR while the rows list the methods for actuating DR. Although not separately identified as a stage or purpose for DR in the roadmap detailed in Chapter 3, real-time energy is nevertheless a defined product or purpose for DR that many regions have established provisions to employ DR to meet. Real-time energy therefore is included in the column header of the figure.

Meanings of table entries are as follows:

Full Moon: A program with characteristics in the row can be applied to provide the wholesale product or meet the purpose in the column.

Half Moon: A program with characteristics in the row may be possible to be applied to provide the product or purpose in the column, depending on program specifics.

Empty Moon: Improbable for the actuation method to be applied to provide the product or purpose in the column, based on the nature of wholesale requirements for the product's provision

An entry containing an asterisk denotes large C&I customers typically can provide.

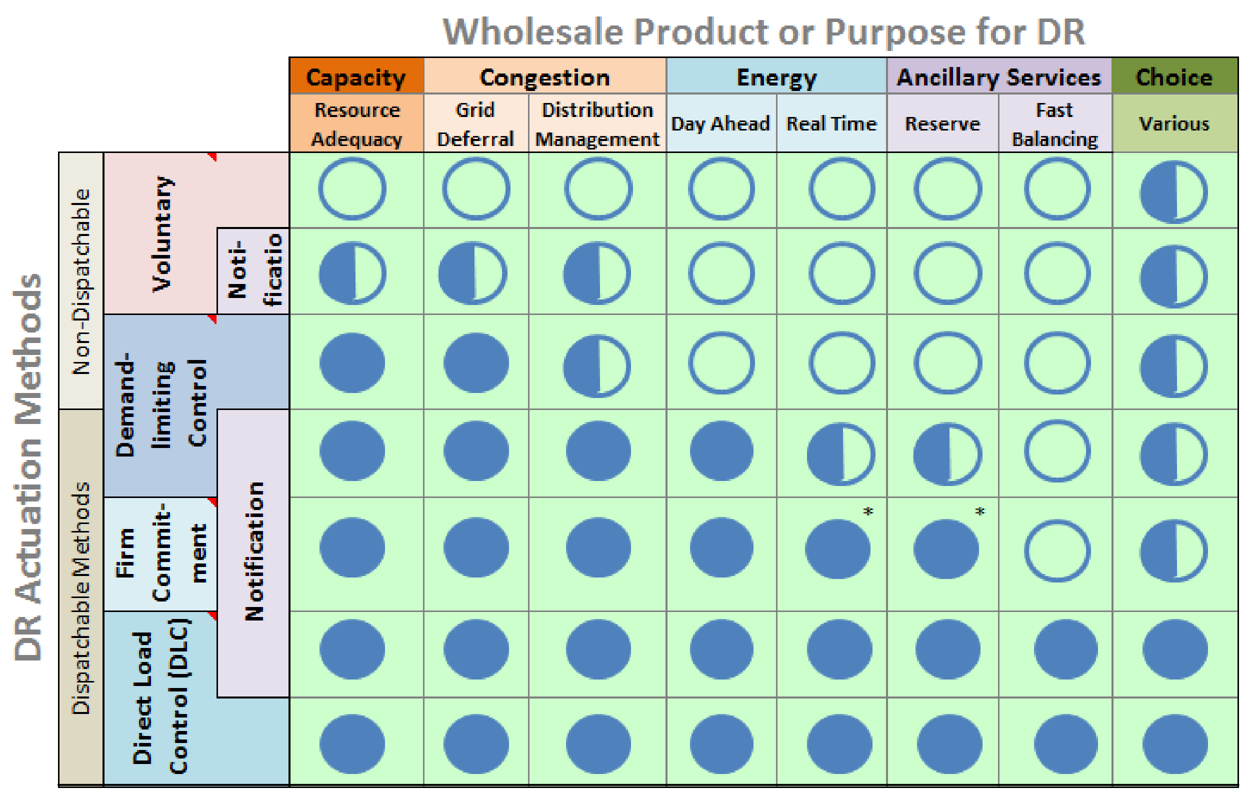

Figure 4-1
DR Actuation Methods Applicable to Providing Wholesale Products or Purposes for DR

The figure first lists non-dispatchable methods in the rows, followed by methods that can be used to dispatch DR. The notion of dispatchable DR is paramount in power systems operations and planning, due to the nature of operational requirements to maintain system reliability, which in turn drive operator focus on firm resources, for which a response can be directly relied on.

In general, dispatchable resources are established through program design and retail contracts with customers containing provisions that are supportive of dispatchability (e.g., contracts that impose high customer penalties for failure to meet agreed upon firm commitments or guaranteed load drops, and programs that require employing enabling technologies for direct load control). As Figure 4-1 indicates, dispatchable DR is triggered via direct load control or via notification of resources under firm commitment or demand-limiting control.

Real-time energy is included under the column labeled “Energy” in the figure. Moreover, entries under real-time entry match those under ancillary service reserves. Though not a reserve product, real-time energy is technically considered a type of ancillary service. The broad category of ancillary services includes imbalance energy services, which are generally provided through established real-time energy markets in competitive market environments. Like ancillary service reserves, real-time energy is dispatched based on real-time conditions, and essentially shares the same DR trigger characteristics (depicted in Table 3-4) and actuation methods (depicted in Figure 4-1) as ancillary service reserves.

Customer Engagement Model

Based on the program designer’s chosen purpose for employing DR (in Step 1 of the process), the coordination timeframe is determined. Not only does the timeframe drive viable DR actuation methods, but it is considered along with Customer Engagement Models to determine via program types, as described below.

The methods for engaging or motivating customer participation in a DR program are very distinct and can be categorized as follows.

Alternative Pricing and Rates: Pricing structures that determine what customers pay for electric service to motivate customer response.

Direct Incentive: Financial incentives that determine direct rewards to program participants.

Public Cooperation: Information exchange to engage customers or encourage voluntary behavior, with no financial exchange for DR expected by the participant from the program administrator.

Variable Service Subscription: Customer participation and engagement by providing added dimension of choice for electric service through service subscription levels (e.g., local, green, or premium power or priority service) involving DR to support implementation of the choice.

DR Program Type

Figure 4-2 stems from prior demand-side integration framework development efforts by EPRI [11]. The figure illustrates how DR program types are associated with the Customer Engagement Model and Timeframe of DR Coordination employed. DR program types are related to one another by these two parameters, values of which are listed in the column and row headers of the table. The row headers are basically the coordination timeframe options, ranging from seasonal planning to day-ahead operations, to day-of or real-time operations. The column headers are methods for engaging or motivating customer participation in the DR program.

Engagement Model / Timeframe	Alternative Pricing & Rates *(participant pays more without DR)*	Direct Incentive *(participant is paid for DR)*	Public Cooperation *(no financial exchange for DR)*	Variable Service Subscription *(more participant choice using DR)*
Seasonal	**Time-of-Use of:** Energy Demand	**Conservation Credit** **Capacity Program**	**Public Conservation Appeal**	**Demand Limiting upon**: Service Connect Seasonal Peaks
Day-ahead	**Dynamic Pricing:** Critical Peak Pricing Day-ahead Pricing	**Day-ahead Energy Program**	**Public Appeal for:** Voluntary Economic Demand Response	**Demand Subscription for:** Critical Days Only
Day-of	Real-time Pricing **Discounted Rate for Dispatchable:** Direct Load Control Interruptible Load Curtailable Load Standby Generation	**Paid-for-Performance for Dispatchable:** Direct Load Control Interruptible Load Curtailable Load Standby Generation	Voluntary Emergency Demand Response Pre-planned Voluntary Interruptible / Curtailable Load **Rolling Blackout**	Critical Hours Only **Premium Power** **Better-Served-for-Performance** **Priority Service**

Figure 4-2
DR Program Types by Customer Engagement Model and Coordination Timeframe Employed

Application of Program Design Process

In summary, the wholesale purpose or objective of employing DR drives viable coordination timeframes, which in turn drives viable DR actuation methods. Coupled with the program designer's choice of customer engagement model to employ, the coordination timeframe implies program types supportive of overall design choices (e.g., objectives and customer engagement model). The final step in the process is to establish program particulars, among the viable options that remain in the down-selection process, based on the chosen DR actuation method and program type.

Figure 4-3 was previously published by EPRI and developed as part of an evaluation framework for assessing sustainable demand response implementations. [3] The figure identifies many new program examples in the table entries. Each program example employs the DR actuation method in the column and program type identified in the row. The table is not intended to provide an exhaustive list of program examples compatible with the actuation and customer engagement models listed. Rather, it is intended as a reference to help program designers in devising new alternative programs based on particular organizational objectives and constraints.

The column to the far right of the figure indicates whether interval meter reading is generally required by the program type in the row. This column can be utilized to rule out program types based on whether interval meter reading is acceptable for consideration in new program design or ought to be excluded as a constraint.

DR Actuation Method

Program Type or Group		Non-Dispatchable Methods		Dispatchable Methods					
		Voluntary		Demand-limiting Control		Firm Commitment	Direct Load Control (DLC)		Interval Meter Reading
			Notification		Notification	Notification	Notification		
	Public Cooperation	Conservation Appeal	Public Appeal for Voluntary DR				Rolling Blackout	Utility CVR	
	Fixed Direct Incentive	Fixed Conservation Credit	Fixed Incentive for Voluntary DR (e.g., gift card)	"Fixed Incentive for Demand-Limited PEV Charging"	"Fixed Incentive for Demand-Limited PEV Charging, with opt-out provision upon notification"	Fixed Incentive FSL, GLD, or Capacity Program	Fixed incentive for DLC, with opt-out provision upon notification (e.g., gift card upon enrollment)	Bill Credit for DLC	
Dynamic Pricing	Time of Use (TOU)	Time-of-Use		"TOU for Demand-Limited PEV Charging"	"TOU for Demand-Limited PEV Charging, with opt-out provision upon notification"	TOU with firm commitment during event	TOU for DLC with opt-out provision upon notification (e.g., air conditioner DLC)	TOU for DLC (e.g., water heater DLC)	√ (except seasonal programs)
Dynamic Pricing	Critical Peak Pricing (CPP)		CPP	"CPP for Demand-Limited PEV Charging"	"CPP for Demand-Limited PEV Charging, with opt-out provision upon notification"	"CPP with firm commitment during event"	"CPP with DLC provision during event and opt-out provision upon notification"	"CPP with DLC provision during event"	√
Dynamic Pricing	Real-time Pricing (RTP)	RTP		"RTP for Demand-Limited PEV Charging"	"RTP for Demand-Limited PEV Charging, with opt-out provision upon notification"	"RTP with firm commitment during event"	"RTP with DLC provision during event and opt-out provision upon notification"	"RTP with DLC provision above a threshold"	√
	Discounted Rate			"Discounted Rate for Demand-Limited PEV Charging"	"Discounted Rate for Demand-Limited PEV Charging upon notification"	Discounted rate FSL or GLD Program	Discounted Rate for DLC with notification (e.g., standby generation)	Discounted Rate for DLC (e.g., water heater)	√ (except DLC of residential customers)
	Paid for Performance	Seasonal Conservation Credit	Peak Time Rebate			Paid for Performance FSL, GLD, or DA Economic Program	"Paid for Performance of PEV Charging under DLC, with opt-out provision upon notification"	"Paid for Performance of PEV Charging under DLC"	√ (except seasonal programs)
	Variable Service Subscription			Demand Limiting Service	Demand Subscription Service	Better-Served-for-Performance	Premium Power (with notification)	Premium Power	√ (except seasonal)

Figure 4-3
DR Program Types by Actuation Method

By following the outlined process in this chapter, new programs can be systematically devised that are aligned with organization objectives for DR while respecting technology constraints. Moreover, unfamiliar programs originating from external regional jurisdictions can be quickly understood and systematically categorized, when framed in relation to existing known programs. Gaps in existing program portfolios can also be readily identified using the tools presented under the program design process. This chapter concludes with examples of each of these three possible applications of the process presented.

Example of Devising New Program Roadmap

Consider a load serving entity or utility distribution company in a restructured market environment that has in the last year completed deployment of advanced metering infrastructure (AMI) to its mass market customers. The utility is under pressure from its regulatory commission to show value derived from its AMI investment and also charged with meeting an aggressive peak demand reduction target in the short term, while it faces distribution capacity constraints in the mid-term due to growing popularity of electric vehicles adopted by customers, particularly in select neighborhoods within the utility's service territory. In a resource constrained region with aggressive renewable portfolio standards calling for 30% renewable generation by Year 2020, and where bulk asset expansion is very difficult and costly, the utility foresees long-term needs for increased flexibility to integrate high penetrations of renewable resources.

A utility program designer is charged with the task of quickly devising new DR programs to address short-term peak demand reduction targets while leveraging existing technology investments. In response, the designer applies the program design process to systematically create a plan over the short, mid and long-term, in order to support immediate as well as foreseen organizational needs for DR.

The decisions made at each step of the program design process are summarized below, along with the designer's rationale.

1. The utility's organizational purposes or objectives for using DR are resource adequacy in the short-term, distribution management in the mid-term, and fast balancing for operational flexibility in the long-term. The designer identifies this short to long-term progression of DR objectives in order to better leverage enabling technology investments made at each stage of the organization's roadmap for DR.
2. The program designer takes into special consideration the charge to show value from AMI investments the utility has made. Consequently, the designer treats as a constraint to favor program design options that leverage interval meter reading, two-way communications, remote connect/disconnect relay configuration like demand-limiting control, or other capabilities of the deployed infrastructure.
3. The designer makes the following program design choices supportive of peak load reduction (i.e., resource adequacy) in the short-term:
   a) Technical requirements: DR coordination timeframe is **seasonal planning** and DR actuation method is **voluntary response with notification**.

   b) Retail contract specifics: Customer engagement model is **alternative pricing and rates**, and DR program type is specifically **time of use** of energy.
4. Program design choices supportive of distribution management in the mid-term include:
   c) Technical requirements: DR coordination timeframe is **real-time** and DR actuation method is **demand-limiting control with notification**.

   d) Retail contract specifics: Customer engagement model is **variable service subscription**, and DR program type is specifically **demand subscription** for critical hours only.
5. Program design choices supportive of fast balancing for system flexibility needs in the long-term include:

e) Technical requirements: DR coordination timeframe is **real-time** and DR actuation method is **direct load control with notification.**

f) Retail contract specifics: Customer engagement model is **alternative pricing and rates**, and DR program type is **discounted rate** for dispatchable direct load control.

The designer's rationale was to start with identifying the organizational objectives for DR in the short, mid, and long-term, respectively. Then for each, the designer referenced Table 4-1 to identify the minimum coordination timeframe required, which is directly determined by the purpose for employing DR.

In order to minimize new technology deployment costs, the designer references Figure 4-1 to identify the simplest actuation method (in the rows of the figure) that is compatible with meeting the primary purpose for DR at each term (short, mid, long). The designer simultaneously checks the capabilities of the utility's AMI deployment to verify support for actuation methods selected. Through this process, the designer determines the utility's existing technology deployments support notification through voluntary DR, as well as demand-limiting control with notification. Moreover, although the utility's AMI system is configurable to support actuation of DR via demand-limiting control, the designer learns the AMI communications infrastructure has limited bandwidth and may not be able to support the fast communications requirements often associated with balancing resources. Therefore, the designer notes that additional investments in DR enabling technology for direct load control are likely required to support long-term objectives for DR.

The designer presents a summary of the resulting program design roadmap shown in Table 4-2. The table summarizes the program design options chosen, followed by examples of program particulars and trigger communication requirements (in the last two columns) that are compatible with the design options.

Table 4-2
Example Roadmap of DR Program Design Characteristics

Term	Purpose	Coordination Timeframe	DR Actuation Method	Program Type	Program Example	Trigger Communications Example
Short-term	Resource Adequacy	Planning	Voluntary response with notification	Time of Use	Time of Use of Energy, with optional voluntary response upon customer notification	1-way broadcast notification to all participants based on system-wide peak event
Mid-term	Distribution Management	Real-Time	Demand-limiting control with notification	Demand Subscription	Demand Subscription for Critical Hours Only, with limit set during critical hours upon customer notification	2-way communications for coordinated configuration of demand-limits (using AMI) and monitoring response to local event using D-SCADA
Long-term	Balancing Resource	Real-Time	Direct load control with notification	Discounted Rate	Discounted Rate for Dispatchable Direct Load Control, upon customer notification	2-way communications (direct load control and monitoring progress of following DLC signal)

Having followed the systematic design process, the designer can readily describe the rationale for design choices made and how they support the organization's purposes for DR in the short, mid, and long-term. Moreover, the designer recognizes the compatibility of leveraging the utility's deployed AMI system to provide the interval meter reading capabilities needed in the short-term, and the demand-limiting control needed in the mid-term for actuating DR. Finally, demonstrating foresight the designer recommends to the boss further investigation into the limits of two-way communications capability of the deployed AMI system for actuating DR through direct load control, towards supporting long-term needs for fast balancing and renewable integration.

Example of Program Classification

A foreign utility makes mention of its DR program named Tempo to a group of domestic utilities. The program is described as a domestic water heater DR control program using pricing signals with customers on time-of-use rates. The combination of program characteristics perplexes the audience of domestic utilities, who attempt to discern whether the program is a type of dynamic pricing program or other.

One domestic utility personnel familiar with the program design process described above, uses the process to answer a series of key questions about the program, ask clarifying questions, and rapidly discern the Tempo program's classification relative to all other programs the utility personnel is familiar with.

The process of classification is described below.

1. The personnel discerns that the Tempo program has been designed to address forward energy economics, given the following information conveyed about its historic origins. Namely, the Tempo program was created over thirty years ago to absorb night-time over-generation by base-load nuclear power plants in the foreign utility's service territory. The program and DR enabling technology have been running automatically and predictably to shift water heater load from day to night time periods, so well that many have forgotten the program exists. The program does this by having water heaters operate according to a schedule received in advance of the operating day.
2. The coordination timeframe is discerned to be day(s)-ahead, given the foreign utility's description of price signals established in advance of the day of operation, and serving to control water heaters.
3. Customer motivation to participate in the Tempo program is described to be attractiveness of receiving lower rates during times of water heater operation at night. Rates are pre-established for seasons at a time, and applied based on measured energy consumption at two distinct periods of the day (high and low periods). So the customer engagement method is discerned as alternative pricing through a time of use type program that bills customers according to the applicable rate and measured energy consumption during each of two distinct periods during each day.
4. The physical means of actuating DR is through water heater control, which the foreign utility described as each water heater following price signals (i.e., high and low rates) communicated by the utility through power line carrier technology. Therefore the actuation method is discerned to be direct load control through signals that convey the applicable high or low rate at the time of control.

By employing the outlined program design process to identify key questions, the personnel is able to readily discern program characteristics (e.g., coordination timeframe, customer engagement model) and ask clarifying questions about the DR actuation method. As a result, the personnel quickly discerned the program type for Tempo and confidently distinguished it from other known domestic programs.

Despite the potentially confusing terms used by some in the audience to describe the program initially (e.g., as price sent to device), the personnel distinguished Tempo as a **time of use program utilizing direct load control** to actuate response from water heaters, as opposed to a dynamic pricing type program. That is, Tempo controls water heaters through a signal conveying the applicable rate, as the mechanism for implementing direct load control by the utility. On the other hand, the actuation method typically associated with dynamic pricing programs is voluntary customer response.

In this way, the utility personnel rapidly classified the Tempo program and became more familiar with the technology orientation and particular purpose for DR of the foreign utility. The clarity afforded by applying the process described is useful for facilitating collaboration, especially across utility jurisdictions where varying terminology and DR program naming conventions exist.

Example of Program Gap Identification

Consider a DR program designer of a vertically integrated utility tasked to review all DR programs in the utility's portfolio. The program designer is asked to provide one presentation slide to accompany a high-level briefing that describes the relationship of existing programs to one another and identifies gaps in program offerings. The designer applies part of the program design process to meet this challenge.

The designer sketches a table template on a sheet of paper resembling that of Figure 4-2, with customer engagement models as the column headers and coordination timeframes as the row headers. The designer proceeds to populate the template with entries of program types among the utility's existing portfolio that utilize the respective coordination timeframe and engagement models indicated in the headers of the matrix. When this exercise is complete and all DR programs are accounted for, the designer reviews the matrix for gaps, by identifying areas in the table with lack of entries or program examples.

For example, Figure 4-4 summarizes the results of a DR program inventory assessment EPRI conducted in 2008 based on review of existing DR programs of two California investor-owned utilities. Several areas of program gaps were identified. Namely, there was lack of example at the time of programs employing Public Cooperation to provide dispatchable DR on the day-of the operating event. Moreover, there was lack of example of existing Variable Service Subscription programs that coordinated DR on a seasonal or day-ahead basis, although pilots had been conducted in the past in California to trial demand subscriptions enforced during critical hours only (e.g., Demand Subscription Service pilot conducted by Southern California Edison in the 1980's [12]). Details on variable service subscription type programs like Demand Subscription Service are provided in [13].

Engagement Model / Time-frame	Alternative Pricing	Direct Incentives	Public Cooperation	Variable Service Subscription
Operational Planning (months)	• **Time of use** o Energy o Demand	• **Paid for Performance** o Seasonal Conservation Credit o Installed Capacity	• **Public conservation appeal** (e.g., radio, TV, newspaper)	
Day-ahead Operations (days)	• **Dynamic Pricing** o Critical peak pricing	o Aggregator Economic DR o Demand bidding of forward energy	• **Public Appeal for Voluntary DR** o Flex Alert	
Day-of Operations (minutes to hours)	o Real-time Pricing • **Discounted Rate** o Interruptible Load o Direct Load Control	o Regional operator emergency DR and o Ancillary services o Interruptible load o Direct load control	• **Emergency Operating Procedures** o Rolling blackout	• **Premium Power** • **Optional binding mandatory curtailment**

Figure 4-4
Example of California DR Program Portfolio and Gap Assessment (Conducted in 2008)

The next two figures illustrate performing a broader program gap assessment by first identifying program types published in the literature (Figure 4-5), before identifying domestic and international DR programs that exist (Figure 4-6). The regions in Figure 4-6 overlain with yellow shading denote existing DR programs types in CA at the time of program assessment, while the regions overlain with reddish shading indicate existing DR program examples identified by EPRI amongst international utilities in Europe and Asia. The regions in Figure 4-6 remaining in white background indicate gaps where program types had yet to be identified among existing implementations evaluated.

Engagement Model / Time-frame	Alternative Pricing	Direct Incentives	Public Cooperation	Variable Service Subscription
Operational Planning (months)	• **Time of use** o Energy o Demand	• **Paid for Performance** o Seasonal Conservation Credit o Installed Capacity	• **Public conservation appeal** (e.g., radio, TV, newspaper)	• **Demand Limiting upon** o Service Connect o Seasonal Peaks
Day-ahead Operations (days)	• **Dynamic Pricing** o Critical Peak Pricing o Day-ahead Pricing	o Aggregator Economic DR o Demand bidding of forward energy	• **Public Appeal for Voluntary DR** o Economic (Flex Alert)	• **Demand Subscription for** o Critical Days Only
Day-of Operations (minutes to hours)	o Real-time Pricing • **Discounted Rate** o Interruptible Load o Direct Load Control o Standby Generation	o Regional operator emergency DR and o Ancillary services o Interruptible load o Direct load control o Standby Generation	o Emergency • **Emergency Operating Procedures** o Rolling blackout	o Critical Hours Only • **Priority Service** • **Premium Power** • **Optional binding mandatory curtailment**

Figure 4-5
Examples of Known Program Types Published in the Literature

Engagement Model / Timeframe	Alternative Pricing	Direct Incentives	Public Cooperation	Variable Service Subscription
Operational Planning (months)	• Time of use o Energy o Demand	• Paid for Performance o Seasonal Conservation Credit o Installed Capacity	• Public conservation appeal (e.g., radio, TV, newspaper)	• Demand Limiting upon o Service Connect o Seasonal Peaks
Day-ahead Operations (days)	• Dynamic Pricing o Critical peak pricing	o Aggregator Economic DR o Demand bidding of forward energy	• Public Appeal for Voluntary DR o Flex Alert	• Demand Subscription for o Critical Days Only o Critical Hours Only
Day-of Operations (minutes to hours)	o Real-time Pricing • Discounted Rate o Interruptible Load o Direct Load Control	o Regional operator emergency DR and o Ancillary services o Interruptible load o Direct load control	• Emergency Operating Procedures o Rolling blackout	• Priority Service • Premium Power • Optional binding mandatory curtailment

CA Utility DR Program Examples European and Asian Utility Examples

Figure 4-6
Example of Broad DR Program Gap Assessment

In particular, Priority Service is a type of Variable Service Subscription program that has been identified in [13] and discussed historically in literature [14][15], but for which no program implementations have been identified among the domestic, European, and Asian programs reviewed.

Performing DR program and gap assessments in this manner, the program designer is able to meet the one-slide challenge for summarizing the utility's program portfolio, while conveying distinguishing program characteristics on the slide. The key parameters depicted, DR coordination timeframe and customer engagement model, are useful for framing and explaining at a high-level how programs differ from one another yet are also related.

5

APPLICATION ILLUSTRATION: IDENTIFYING TECHNICAL REQUIREMENTS

Context

This section illustrates how to apply the DR Integration Roadmap (from Chapter 3) and DR Program Design Roadmap (from Chapter 4) to inform specification of requirements for systems needed to automate DR to support new applications along advancing stages of integration.

Technical Requirement Mapping

Figure 5-1 provides a comparison of the requirements for the provision of wholesale products and services listed in the column header of the figure. It is derived from leveraging prior work in [6] and applying the roadmap in Chapter 3 to include additional stages in the DR Integration Roadmap missing from the original work. The figure indicates technical requirements for provision of wholesale products or purposes through DR resources. Requirements are from a power systems operations perspective and generally apply to the DR aggregator or other entity providing the DR resource, versus the individual DR asset being aggregated into a resource for wholesale purposes.

The column headers identify the purpose for DR while the row headers list the requirements on DR resources and supporting enabling-technology infrastructure. Although not called out separately as a stage in the DR Integration Roadmap, real-time energy is also included as a column in the figure since it is a defined product or purpose for DR that many regions have established provisions for DR to meet.

Wholesale Product or Purpose for DR

Requirements	Capacity	Congestion		Energy		Ancillary Services		
	Resource Adequacy	Grid Deferral	Distribution Management	Day Ahead	Real Time	Replace-ment Reserve	Contingency Reserve	Fast Balancing
Response Time	Notified day-ahead; Seasonally committed.	Notified day-ahead; Seasonally committed.	Seconds to hours	1 day	5-15 min	30-60 min	10 min	Seconds to minutes
Telemetry	Not required	Not required	Not required	Not required	Not required	Not required	Required	Required
Interval Metering	May be required	May be required	May be required	Required	Required	Required	Required	Required
Procurement Method	Forecasted load plus reserve margin	Forecasted loading plus reserve margin where congested	% Day-of distribution facility load	Day-ahead forecasted load	Day-of forecasted load	% DA peak forecasted load	N-1 Contingency	% Day-of peak or valley load

Figure 5-1
Technical Requirements for Wholesale Product Provision by DR

The rows address regional operator requirements for response time, real-time monitoring of resources via telemetry, interval metering, and method of determining the amount of the service to be procured. The requirements indicated by the entries in the figure are representative in nature. Although different regions and markets have specific requirements that may vary, the figure provides a general comparison based on prior research conducted under [3], [6], and [16].

Application Example

Take for example the program design roadmap resulting from the illustrative example in Chapter 4 of a load-serving entity or utility distribution company applying the DR Integration Roadmap to devise new DR programs. For convenient reference, the demand response integration purpose of the utility at each progressive step along its roadmap is copied from Chapter 4 into Table 5-1.

Table 5-1
Example of DR Program Design Roadmap

Term	Purpose	Demand Response Integration Purpose	DR Program
Short-term	Resource Adequacy	Defer generation expansion by planning to be available during system-wide peak times and to respond	Time of Use of Energy, with optional voluntary response upon customer notification
Mid-term	Distribution Management	Mitigate unpredicted operational issues in the distribution system	Demand Subscription for Critical Hours Only, with limit set during critical hours upon customer notification
Long-term	Balancing Resource	Support real-time system balance	Discounted Rate for Dispatchable Direct Load Control, upon customer notification

The remainder of this chapter illustrates how to apply roadmaps, tools or frameworks previously introduced in this report to inform specification of requirements for systems needed to automate DR, along advancing stages of integration.

Discerning Resource Aggregation Requirements

Table 5-2 leverages the DR Integration Roadmap to inform resource aggregation requirements at each term (short, mid, long) of the program design roadmap outlined in Table 5-1. Table 5-2 combines relevant Stage and Trigger Characteristics from Table 3-3 and Table 3-4, discussed in Chapter 3, to identify topologically the specific level that DR resources are serving power system needs and to identify key trigger characteristics at each term. Both considerations drive requirements for systems aggregating and coordinating response from DR assets.

As the second column of the table indicates, in the short-term DR is employed in response to system-wide peaks, so that DR assets count as system-wide resources that can contribute to peak load reduction, regardless of where within the power system the assets are physically located. Consequently, one-way broadcast communications are sufficient for notification to trigger response from DR resources in the short-term.

Table 5-2
Requirements Associated with Program Design Roadmap (for Illustrative Example)

Term	Resource Level	Trigger Conditions	Trigger Communications
Short-term	System-wide	Annual System Peaks (Long-term Forecasts)	1-way broadcast (system-wide event)
Mid-term	Distribution Facility	RT Conditions (Overloads, Faults)	2-way communications (direct dispatch and monitoring response to local event)
Long-term	Systemwide or Network Node	RT Conditions (System Imbalance, Schedule Deviations)	2-way communications (direct dispatch or control and monitoring progress of following AGC or DLC)

In the mid-term, however, when DR is to support distribution management, the locations of DR resources along the distribution system network matter. Consequently, aggregation of DR assets into resources to support distribution needs (e.g., mitigate transformer or line overloads) is required. This implies that DR management systems (DRMS) must be able to track DR assets surgically enough so that they can be aggregated by distribution facility or node. This requirement is a significant advancement that traditional load management systems employed for peak load reduction and system-wide emergencies generally have not supported in the past.

Moreover, as the table indicates for the long-term, DR assets contributing fast balancing or flexibility services (e.g., frequency regulation and ramping) must be amassed in sufficient large quantities to contribute at the transmission location level.[1] Serving a transmission network need implies requirements for DRMS to be able to map DR assets (which are often connected at distribution level) to transmission facilities the assets are electrically and topologically connected under. Utilities and other DR aggregators employing DR for ancillary services generally must perform the mapping from distribution-level to transmission-level resources, in order to aggregate DR to be considered a resource for provision of ancillary services, including fast balancing and flexible ramping services. In this way, resource aggregation requirements advance in complexity and asset tracking needs with advancing stages of DR integration. Consequently, DR asset tracking and management capabilities of DRMS would also advance in sophistication at each progressive step of the utility's program design roadmap.

Discerning Resource Response Time Requirements

Response time refers to the maximum lapse of time for resource response to be actuated upon being triggered under coordination by a system operator. The mapping of wholesale product and service requirements in Figure 5-1 is directly applicable as a tool for discerning resource response times required at each step of a utility's program design roadmap. For the sample program roadmap outlined in Table 5-1, required response times increase with each step of the roadmap. This trend can be inferred by referencing the purpose of DR at each step in the program roadmap against the corresponding column for that purpose in the technical requirement mapping found in Figure 5-1, as follows.

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[1] However, system-wide treatment may suffice in the case of frequency regulation, since frequency is relatively uniform across interconnected systems.

From the first row of the figure, the reader will note that resources providing resource adequacy, are coordinated to be committed in planning timeframes and notified day-ahead of impending peak system emergencies, in order to better prepare for response. Although resource response times can be longer than a day if given day-ahead notification, they may also be shorter than day (e.g., hours) if given intra-day advance notification of system-wide emergencies. Such relatively long response times required for resource adequacy implies that notification systems that rely on existing telecommunication options of mass market customers (e.g., email, text, page, phone call, and fax) may suffice to trigger DR. Moreover, DR management systems may be required to interface with such notification systems, in order to automate the generation of notification message delivery to mass market customers.

For the mid-term along the program roadmap, DR resources are employed to support distribution management. Figure 5-1 indicates required response times on the order of seconds to hours, for this purpose. Such response times stem from physical impacts of extended overload conditions on distribution equipment, requiring sufficient response to avoid equipment damage and other operational considerations. The actual response time required depends on the overload situation faced. For example, if load suddenly appears on the system bringing the situation into overload and pulling voltage down, then generally response times required are within a minute. But for thermal rating issues (e.g., maximum amount of current can carry in a cable is exceeded) required response times are on the order of minutes to hours.[2] Such short intra-day response times required for distribution management implies use of automated controls and communications enabling coordination of response between the distribution operator and DR resources. Consequently, DR management systems must interface with communication systems capable of dispatching DR within hours or minutes, and/or configuring set-points to automate response from DR assets within such response times (e.g., set-points on demand-limiting controls).

For the long-term along the program roadmap, resources are employed for providing fast balancing services. Such services include frequency regulation, ramping energy, and other fast response services, which may each require energizing load and not just curtailing load. Based on the figure, required response times for fast balancing services are on the order of seconds to minutes. This level of rapid response is typically achieved through automation (e.g., water heaters adjusting loading by following a rapidly changing signal like generators on automatic generation control). That is, automated controls and communications enabling continuous control of DR assets are typically required. Moreover, the assets may be required to either decrease or increase load. Consequently, DR management systems must interface with communication systems capable of controlling DR on the order of seconds or minutes, and/or configuring set-points to automate response from DR assets under automated load control (analogous to

[2] In the event of line loading conditions that exceed a substation transformer's nameplate capacity, generally a few hours response time can avoid overheating of the transformer. However, for distribution substations with underground get-away cables located inside conduits, there is also a possibility of cable overheating causing insulation failure on the order of tens of minutes (e.g., 10-30 minutes). Consequently, response times required may be shortened to minutes depending on substation equipment deployed (e.g., whether under-ground cables and cooling technology are deployed) and the particular overload conditions faced. However, if voltage overload is an issue on the distribution system, as opposed to thermal overload associated with exceeding current-carrying limits, then required response times are on the order of seconds (e.g., 30 seconds before distribution relays automatically respond to adjust to under-voltage conditions).

automatic generation control). Moreover, DR management systems would be required to track DR assets by ability and availability to energize or increase load, and not just curtail or decrease load.

In this fashion, DR program roadmaps devised by applying the program design process in Chapter 4 may be leveraged to discern technical requirements like resource response times. Furthermore, identified response times in turn infer requirements that DR management systems are to support in the short, mid, and long-term, in order to meet the targeted purposes for DR of the utility along its program roadmap.

Discerning Technology Infrastructure Requirements

Additional technical requirements can be derived by referencing other rows in Figure 5-1 for each step of the program design roadmap. In particular, technology infrastructure requirements are discerned next.

Telemetry Requirements

Supervisory control and data acquisition systems (SCADA) provide information on the operating states of bulk generators, transmission assets, substation equipment, and in some cases also distribution assets, as well as loading conditions along the power system. However, individual customer loads are generally not monitored in real-time by a system operator, albeit select large industrial loads may be. By exception, some loads are individually monitored in real-time if participating in a program requiring real-time operator visibility.

The second row in Figure 5-1 indicates whether telemetry is required for a DR resource to provide the product or service in the column. From examination of the figure, the reader will note that telemetry is not required under resource adequacy, but may be required for distribution management, and is generally required for provision of fast balancing services. Such a progression of increasing telemetry requirements occurs over the short to long-term along the program design roadmap in Table 5-1.

Although not required in the short-term, telemetry of DR resources may be required in the mid-term to support distribution management; that is, if existing real-time monitoring of aggregate conditions along the distribution system through D-SCADA[3] does not suffice. If real-time view through D-SCADA does suffice for the distribution system operator, then individual telemetry of individual DR resources could be avoided. Nevertheless, in the long-term telemetry is expected to be required for DR resources providing fast balancing services, considering existing regional reliability coordinator requirements for the provision of fast response services like frequency regulation. However, real-time telemetry is not a trivial requirement in terms of cost justification.

Considering telemetry is anticipated to be required in the long-term, but maybe also in the mid-term though not in the short-term along the program design roadmap, the program designer may apply the technical findings to recommend investment in advancing telemetry technologies in the short-term to improve their cost-effectiveness in preparation for mid and long-term needs of the utility. Alternatively, the designer may recommend research activities to investigate how to relax

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[3] In select cases distribution operators may have real-time monitoring of distribution assets conditions via distribution SCADA (D-SCADA).

existing telemetry requirements, so that commercially available technologies can better meet visibility requirements of the system operator.

Interval Metering Requirements

The third row in Figure 5-1 indicates whether interval meter reading is required to provide the product or service in the column. From examination of the figure, the reader will note that interval metering may be required for resource adequacy and distribution management, and is generally required for provision of fast balancing services. Such a progression of increasing interval metering requirements occurs over the short to long-term along the program design roadmap in Table 5-1.

As Figure 4-3 indicates, whether interval metering is required depends on the program type employed to motivate DR participation. From a wholesale requirement perspective, interval metering requirements also stem from published wholesale market participation requirements of regional system operators like ISO/RTOs, which define the technical requirements for the provision of defined wholesale products and services. ISO/RTOs with long-term capacity markets for resource adequacy procured through auction mechanisms (e.g., installed capacity markets in Northeast U.S.) generally require interval metering, which is needed to measure and verify performance of resources being compensated for capacity provision. However, many emergency programs designed for peak load reduction (e.g., direct load control programs using one-way broad communications) may not require interval metering at customer sites. Moreover, interval metering may not be required for distribution management purposes especially where operator-configured set-points and controls (e.g., demand-limiting controls) are deployed for actuating DR.

Consequently, requirements for interval metering depend on various factors, including wholesale product requirements and the particular regional system in question, as well as retail program type and the DR actuation method employed. Although interval metering is generally required for the provision of energy and ancillary services, as indicated in Figure 5-1, it may not be required for ameliorating capacity and congestion type conditions. However, interval metering may be required for provision of resource adequacy, especially in the absence of operator-driven and configured controls. Interval metering will also assist more accurate verification of response, as more and more DR programs are (re)designed to avoid rewarding non-performers participating in DR programs.

For retail DR programs and wholesale products that require interval metering, the performance of DR is commonly assessed or verified using interval meter data. The data is needed for settlement purposes in the computation of performance-based direct incentives. Consequently, DRMS requirements include interfacing with interval metering systems for settlement purposes, where interval meter data is recorded for this purpose. However, if interval data is not required, then generally the program operator utilizes another method for verifying demand response (e.g., truck rolls to verify direct load controlled technologies are connected at the customer site, or polling/pinging targeted DR-enabling technologies through remote messaging to verify device connectivity status).

Summary

The tables below summarize the requirements identified in this chapter resulting from application of the DR Integration Roadmap plus associated mappings and tools to infer technical requirements for the Program Design Roadmap presented in Table 5-1. Table 5-3 concisely summarizes basic requirements for resource aggregation, response time, and technology infrastructure along each progressive step of the program roadmap. Table 5-4 summarizes DRMS requirements associated with each step of the program roadmap.

Table 5-3
Summary of Resource Aggregation, Response Time, and Infrastructure Requirements

Term of Stage	Resource Level for Aggregation	Response Time	Telemetry	Interval Metering
Short-term (Resource Adequacy)	System-wide	Hours to Day-ahead	No	Maybe
Mid-term (Distribution Management)	By Distribution Facility	Seconds to Hours (e.g., 30sec to 30 min)	Maybe	Maybe
Long-term (Balancing Resource)	By Transmission Facility or System-wide	Seconds (e.g., 2 to 10 sec)	Yes	Yes

Table 5-4
Demand Response Management System Requirements Associated with Program Roadmap

Term of Stage	DRMS Requirements
Short-term (Resource Adequacy)	System-wide notification Asset tracking by type Asset aggregation by type Interface with notification systems (e.g., email, page, FAX, telephone) Interface with metering system to verify response.
Mid-term (Distribution Management)	Distribution facility-wise or system-wide dispatch Asset tracking by type, distribution location, response time Asset aggregation by response capability and distribution facility Interface with communication or control systems for dispatch or load control Interface with with telemetry systems for monitoring of resource, or D-SCADA for aggregated view Interface with meting system to verify response.
Long-term (Balancing Resource)	Transmission facility-wise or system-wide dispatch Asset tracking by type, transmission location, response time, capability to energize Asset aggregation by response capability and transmission facility Interface with fast communication and control systems for dispatch or load control Interface with real-time telemetry systems for monitoring of resource Interface with settlement systems for verifying response and computing performance

The progressive nature of the identified requirements depicted in each table above, over the short, mid, and long-term, compel gradual build-up of DR enabling technologies and DRMS capabilities, so as to avoid premature technology obsolescence. By devising a program design roadmap using the process described in Chapter 4 to identify implied technical requirements with the tools described in Chapter 5, the program designer can broaden perspectives of program evolution to include DR-enabling technology system evolution.

A
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B

DEMAND RESPONSE 2.0 WORKSHOP PARTICIPANTS

Over 50 individuals participated in the Demand Response 2.0 Workshop, which was conducted by EPRI and hosted by Centerpoint Energy in Houston, Texas on August 22-23, 2013. Participants are listed in Table B-1 below.

Table B-1
Webcast Participants

First Name	Last Name	Affiliation
Tony	Abate	New York State Energy R&D Authority
Ammi	Amarnath	Electric Power Research Institute
Saurabh	Bansal	NRG Energy, Inc.
Michael	Barber	Midwest ISO
Billy	Berny	American Electric Power Service Corp.
Ingrid	Bran	Electric Power Research Institute
Stu	Bresler	PJM Interconnection
Calvin	Burnham	CenterPoint Energy Houston Electric, LLC
Angela	Chuang	Electric Power Research Institute
Hank	Courtright	Electric Power Research Institute
Susan	Covino	PJM Interconnection
Samuel	DeLay	Tennessee Valley Authority (TVA)
Kevin	Ding	CenterPoint Energy Houston Electric, LLC
Mauro	Dresti	Southern California Edison Co.
David	Dzierski	CenterPoint Energy Houston Electric, LLC
Robert	Entriken	Electric Power Research Institute
Charles	Flynn	CenterPoint Energy Houston Electric, LLC
Oscar	Gans	Florida Power & Light Co.
Jared	Green	Electric Power Research Institute
John	Halliwell	Electric Power Research Institute
John	Hernandez	Pacific Gas & Electric Co.
Justin	Hill	Southern Company Services, Inc.
Dave	Hunger	FERC
Nicholas	Ingman	IESO
Garry	Jones	Oncor Electric Delivery Co.
Haresh	Kamath	Electric Power Research Institute
Jose	Koch	Bonneville Power Administration (BPA)

Table B-1 (continued)
Webcast Participants

First Name	Last Name	Affiliation
Seungwook	Ma	U.S. Dept. of Energy
Jason	MacDonald	Lawrence Berkeley Laboratory
Eric	Martinez	San Diego Gas & Electric Co.
Michio	Matsuda	EPRI International
Mark	McGranaghan	Electric Power Research Institute
Paul	Miles	Exelon Corporation
Bill	Muston	Oncor Electric Delivery Co.
Joseph	O'Donnell	Kansas City Power & Light Co.
Adrianne	Ortizo	Consolidated Edison Co. of New York, Inc.
Joshua	Phillips	Southwest Power Pool, Inc.
Rachel	Radell	Sacramento Municipal Util. Dist.
Tom	Reddoch	Electric Power Research Institute
Mike	Rowand	Duke Energy Corp.
Brian	Seal	Electric Power Research Institute
Omar	Siddiqui	Electric Power Research Institute
Michael	Stockard	Oncor Electric Delivery Co.
Shinya	Sugita	Tokyo Electric Power Co.
Aidan	Tuohy	Electric Power Research Institute
Matt	Wakefield	Electric Power Research Institute
John	Wharton	Electric Power Research Institute
Vikki	Wood	Sacramento Municipal Util. Dist.
Christine	Wright	Texas Public Utility Commission
Takuaki	Yamamoto	Chubu Electric Power Co., Inc.
Henry	Yoshimura	ISO New England

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Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com