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Price Responsive Demand in New York Wholesale Electricity Market using OpenADR

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Notice

Disclaimer

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Abstract

In New York State, the default electricity pricing for large customers is Mandatory Hourly Pricing (MHP), which is charged based on zonal day-ahead market price for energy. With MHP, retail customers can adjust their building load to an economically optimal level according to hourly electricity prices. Yet, many customers seek alternative pricing options such as fixed rates through retail access for their electricity supply. Open Automated Demand Response (OpenADR) is an XML (eXtensible Markup Language) based information exchange model that communicates price and reliability information. It allows customers to evaluate hourly prices and provide demand response in an automated fashion to minimize electricity costs. This document shows how OpenADR can support MHP and facilitate price responsive demand for large commercial customers in New York City.

Keywords: Commercial, demand response, dynamic pricing, mandatory hourly pricing, OpenADR, Open Automated Demand Response, price responsive demand

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Summary

Dynamic pricing provides a vehicle to drive price responsive demand in electricity markets by creating a link between wholesale and retail markets (Barbose et al. 2006; Borenstein et al. 2002). With it, retail customers can adjust their building load to an economically optimal level according to time-varying electricity prices. This ultimately helps mitigate extreme price volatilities in the wholesale market.

In 2005, the State of New York Public Service Commission (NYPSC) ordered utilities to provide market-based hourly pricing as the default service for non-residential customers, also known as Mandatory Hourly Pricing (MHP) (2005). Since then, the utilities in New York State (NYS) incorporated MHP into their rate programs for commercial and industrial customers. Yet, many customers seek alternative pricing options such as fixed rates through retail access for their electricity supply (KEMA 2012). While such trend stimulates the growth of a competitive retail market, it dampers the development of price responsive demand because it removes the incentive for individual retail customers to reduce demand during high-priced periods.

Open Automated Demand Response (OpenADR) is an XML (eXtensible Markup Language) based information exchange model that communicates price and reliability information (Piette et al. 2009). OpenADR allows customers to evaluate dynamic prices and provide demand response (DR) through building control systems during expensive time periods. By automating this process, OpenADR eases the operational burden to manage electricity use in real-time and reduce the cost associated with load control.

The purpose of this document is to:

- identify dynamic pricing and demand response program signals and their transacting entities;
- evaluate how these signals can be used for load optimization and cost minimization in commercial buildings; and
- develop a OpenADR model to map out dynamic pricing and DR program event signals.

The strategies presented in this document focus on large commercial buildings in New York City (NYC) since the proposed demonstration sites are situated in Manhattan.

Dynamic Pricing in New York

Customers in NYC have a choice of receiving electric service from a local utility such as Consolidated Edison (ConEd) or from a Energy Service Company (ESCO) through retail access. Since May 2006, ConEd has offered MHP as the default service to large commercial customers who were subject to the Service Classification No. 9 (SC-9), mandatory Time-of-Day (TOD) rates.

MHP, offered under Rider M, is charged based on:

- New York Independent System Operator (NYISO) posted market-based zonal day-ahead locational based marginal pricing (DA LBMP),
- Ancillary Service Charges, and
- New York Power Authority (NYPA) Transmission Adjustment Charges (NTAC) adjusted for losses.

ConEd uses NYISO's zonal DA LBMP consisting of 24 hourly pricing points published a day-ahead and applies it to customers' hourly electricity consumption to quantify supply cost for each billing period. As for Ancillary and NTAC charges, ConEd uses an average monthly value derived from NYISO's wholesale market data and multiplies it by the total electricity consumed during the billing period (ConEd 2012a). For this reason, Ancillary and NTAC charges used for MHP are not considered dynamic in this document since they do not vary during the billing period.

In addition to MHP, ConEd collects demand charges based on the highest demand usage during the billing period. For customers under SC-9 TOD rates, demand charges are priced high during peak hours on weekdays in summer months when buildings' electricity demand is also high due to increased cooling activities. Therefore, ConEd customers on MHP should respond to both hourly prices and TOD demand charges to avoid high electricity bills.

Demand Response Programs in New York

Demand response programs provide incentives to reduce loads on the electricity grid during peak demand periods. They run episodically based on scheduled events and vary in their rules and incentive structures. NYISO administers several DR programs and customers can participate in these programs through utilities or curtailment service providers, or directly with NYISO. Some utilities offer their own DR programs to respond to critical situations within their distribution system. Customers can participate in multiple DR programs operated by different entities as long as they abide by the participation rules and meet the load relief requirements of each program.

Based on the DR program information and participation rules, we developed the DR prioritization table for a load residing in the ConEd service territory (Table 1). Priorities were given to the programs that require mandatory response and higher load reductions. Using Table 1, Demand Response Automation Server (DRAS) can prioritize DR program event signals and call for load control strategies at facilities based on the priority ranking and program interaction rules. This enables customers to participate in multiple DR programs during concurrent time period and maximize DR incentives.

Table 1. Demand Response Program Prioritization Table

Priority Ranking	DR Program	Operator	Participation	Response Required	Min. Reduction	Penalties	Mutually Exclusive
1	SCR	NYISO	Voluntary	Mandatory	100 kW	Yes	EDRP
2	CSRP - Summer Reservation Payments Program	ConEd	Voluntary	Mandatory	Individual: 50 kW Aggregator: 100 kW	Yes	-
3	DLRP - Summer Reservation Payments Program	ConEd	Voluntary	Mandatory	Individual: 50 kW Aggregator: 100 kW	N/A	-
4	EDRP	NYISO	Voluntary	Voluntary	100 kW	N/A	SCR
5	CSRP - Voluntary Load Relief Program	ConEd	Voluntary	Voluntary	Individual: 50 kW Aggregator: 100 kW	N/A	-
6	DLRP - Voluntary Load Relief Program	ConEd	Voluntary	Voluntary	Individual: 50 kW Aggregator: 100 kW	N/A	-

Price Responsive Demand Analysis

The goal of price responsive demand is to achieve the most optimal load that would yield the lowest achievable electricity cost by applying appropriate load control strategies. Under ConEd's SC-9 TOD rates with Rider M, there are two dynamic charges that significantly affect the electricity cost:

- energy supply charge based predominantly on zonal DA LBMP applied to hourly electricity consumption and
- TOD demand charge imposed on the highest demand in a billing period.

Ancillary and NTAC charges used for ConEd's Rider M are not considered dynamic in this document since they do not vary hourly. The key to minimizing electricity cost is to optimize buildings' electricity demand according to hourly prices as well as demand charges during a billing period.

The minimum energy supply cost for a given day, excluding Ancillary and NTAC charges, can be represented as,

$$\min \sum_{t=1}^{k} C_t \cdot g(u_t, x_t, w_t) \tag{1}$$

where

- C_t is the DA LBMP at time t acquired from DRAS;
- t is the time interval (e.g., 60- or 15 minute);
- k is the total number of time intervals in a day;
- g is the optimal electricity load at time t determined by the objective function using EnergyPlus;
- u_t is the input constraints for load control strategies;
- x_t is the building system states (e.g., operation schedules, HVAC settings); and
- w_t is the weather (e.g., outside air temperature, relative humidity).

The minimum peak demand in a billing period is expressed as,

$$\min\left(\max_{d\in 1,\ldots,N} g(u_t, x_t, w_t)\right) \tag{2}$$

where N is the total number of time intervals in a billing period.

Based on DA LBMP and the baseline load, a building operation mode (i.e., NORMAL, MODERATE, HIGH, and CRITICAL) can be determined for each hour. The building operation mode will activate a set of load control strategies programmed in the building's Energy Management & Control System (EMCS) so that the building can achieve the most economically optimal load given system constraints and weather conditions. For this project, EnergyPlus, a whole building energy simulation software developed by the U.S. Department of Energy, will be used to assess the DR potential of various control strategies for each facility (DOE 2011). When the customer responds to hourly prices and DR program events concurrently, the CRITICAL mode will be assigned where the most aggressive control strategies are activated to satisfy the DR requirements as well as minimizing electricity costs. At the end of each DR event, the control strategies will be designed to recover loads slowly to avoid rebound effects.

Dynamic Price Mapping on OpenADR

This project will utilize OpenADR version 1.0 specifications (OpenADR v1.0) and OpenADR v1.0-ready products that are currently available on the market. Simple graphical representation of OpenADR v1.0 is displayed in Figure 1.

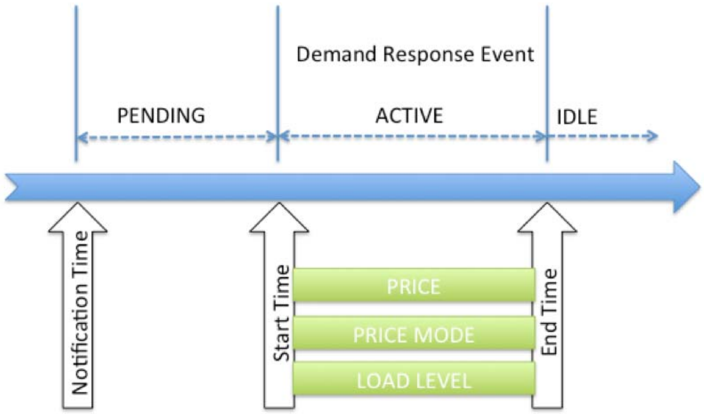

Figure 1. OpenADR v1.0 Graphical Representation

There are three important times that define a DR event: Notification Time, Start Time, and End Time. In the case of MHP, the Notification Time is the time the next day's MHP is posted (typically by 4 p.m. the day before). The Start Time of the DR event is midnight and the end time of the DR event is the minute before midnight. Between Start Time and End Time, a price for each hour is indicated in the data model. Each hour is indicated as an offset from the Start Time. In the case of a DR program on top of an existing MHP structure, an additional Notification Time, Start Time and End Time will be communicated to the facility.

Simple DRAS Clients support four levels of building operation mode signals: NORMAL, MODERATE, HIGH, and CRITICAL. Currently, these signals respond to dynamic prices, demand limits, and/or DR events. While the current mapping structure allows customers to provide DR during expensive time periods and/or to stay below demand limits, it does not respond to the building's unique energy consumption patterns. By looking at both price and consumption, customers can maximize potential energy cost savings. For this project, the team will add the capability for DRAS to respond to energy supply cost introduced in Chapter 4. Since the energy supply cost is a multiplier of MHP and the baseline load, DRAS can send building operation mode signals sensitive to both price and consumption.

Building Operation Modes:

- NORMAL: If energy supply cost is low, there will be no curtailment and the facility will operate as normal.
- MODERATE: If energy supply cost is moderately high, the loads will be curtailed at the moderate load reduction level.
- HIGH: If energy supply cost is high, the loads will be curtailed at the high load reduction level. HIGH can also be activated when the load exceeds a certain demand limit (i.e., historic benchmarks).
- CRITICAL: This mode is only activated when there is a DR program event. The loads will be curtailed at the maximum reduction level.

Through the DRAS Feedback Client, customers will be able to review their energy supply cost based on the actual shed data and keep track of the cost savings resulted from DR.

OpenADR Communication Architecture

Using OpenADR v1.0, the communication architecture was developed for the demonstration sites (Figure 2).

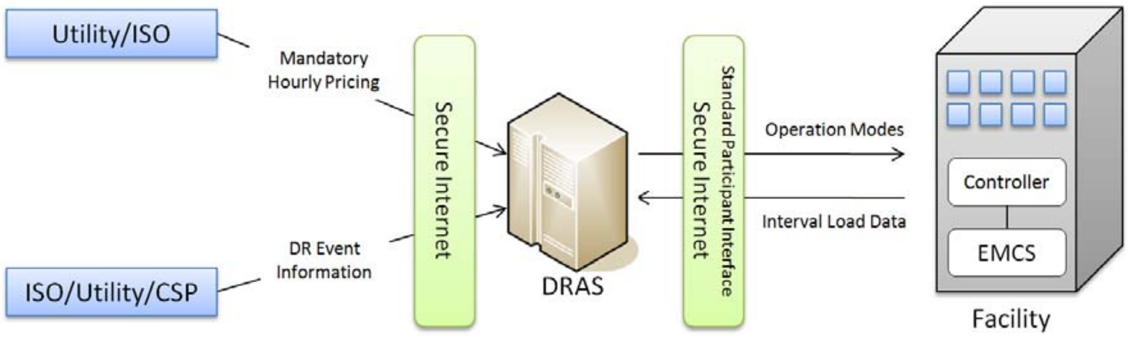

Figure 2. OpenADR Communication Architecture

The day-ahead hourly prices can be obtained from either NYISO or ConEd. The DR program event information will be received from CSPs or directly from NYISO and ConEd depending on the customer's DR programs enrollment agreements. The price and DR program event information will be sent to DRAS and used to determine building operation modes for each hour of the following day. Once they are determined, DRAS will send these information to facilities using a secure Internet connection. The building operation modes assigned to each hour will activate a set of control strategies programmed in the building's EMCS. The customers have an option to opt-out, if they do not wish to participate in DR. During the DR event, DRAS will log the building's electricity usage at 15-minute intervals via kyz pulses to generate the building's current load profile and verify the DR performance.

1 Introduction

Dynamic pricing provides a vehicle to drive price responsive demand in electricity markets by creating a link between wholesale and retail markets (Barbose et al. 2006; Borenstein et al. 2002). With it, retail customers can adjust their building load to an economically optimal level according to time-varying electricity prices. This ultimately helps mitigate extreme price volatilities in the wholesale market.

In 2005, the State of New York Public Service Commission (NYPSC) ordered utilities to provide market-based hourly pricing as the default service for non-residential customers, also known as Mandatory Hourly Pricing (MHP) (2005). Since then, the utilities in New York State (NYS) incorporated MHP into their rate programs for commercial and industrial customers. Yet, many customers seek alternative pricing options such as fixed rates for their electricity supply through retail access (KEMA 2012). While such trend stimulates the growth of a competitive retail market, it dampers the development of price responsive demand because it removes the incentive for individual retail customers to reduce demand during high-priced periods.

According to the study by Hopper et al. (2006), 63% of the customers who were enrolled in Niagara Mohawk Power Corporation's default real-time pricing switched to a competitive retail energy provider and three-quarters of the 63% did not return to the utility after the switch. Many of the barriers identified by this study, including insufficient time or resources to manage hourly prices, can be overcome by enabling automated price alerts and load control strategies. Open Automated Demand Response (OpenADR) is an XML (eXtensible Markup Language) based information exchange model that communicates price and reliability information (Piette et al. 2009). OpenADR allows customers to evaluate dynamic prices and provide demand response (DR) through building control systems during expensive time periods. By automating this process, OpenADR eases the operational burden to manage electricity use in real-time and reduce the cost associated with load control.

Ghatikar et al. (2010) conducted a study to demonstrate how OpenADR can be used to represent dynamic electricity pricing structures. The strategies for mapping dynamic prices to building operation modes (i.e., Normal, Moderate, High) were presented using absolute and relative price ranges. While this approach provides a solution to translate various dynamic pricing signals into building operation modes that can be used to activate load control strategies, it does not indicate how much electricity cost savings DR can provide. Without the ability to communicate the cost savings of DR, it's difficult to convince the customers to stay on dynamic pricing service.

The purpose of this document is to:

- identify dynamic pricing and demand response program signals and their transacting entities;
- evaluate how these signals can be used for load optimization and cost minimization in commercial buildings; and
- develop a OpenADR model to map out dynamic pricing and DR program event signals.

The strategies presented in this document focus on large commercial buildings in New York City (NYC) since the proposed demonstration sites are situated in Manhattan.

In this document, *dynamic pricing* refers to prices that are known with certainty no more than a day ahead. Also, following definition is used to describe *demand response*: "changes in electric use by end-use customers in response to changes in the price of electricity over time, or to give incentive payments designed to induce lower electricity use at times of high market prices or when grid reliability is jeopardized" (DOE 2006).

2 Dynamic Pricing in New York

This chapter identifies different types of wholesale electricity markets in NYS and shows the price variations seen in these markets. It also details how electricity prices and related information are published.

2.1 Price Variations in New York's Wholesale Electricity Markets

To understand the price variations in New York's wholesale electricity markets, three types of wholesale electricity markets administered by the New York Independent System Operator (NYISO) were examined.

- Day-ahead (DA) market provides zonal Locational Based Marginal Pricing (LBMP) in one-hour increments for the following day based on expected market conditions.
- Hour-ahead (HA) market provides zonal LBMP in 15-minute increments for the following hour based on market conditions of the same day.
- Real-time (RT) market provides zonal LBMP every five minutes based on market conditions of the same day.

NYISO maintains an archive of DA, RT, and HA LBMP dating from 2009 for 15 geographical zones in NYS. The price data are available in CSV, PDF, and HTML files on their website (NYISO 2012a). Figure 3 and Figure 4 show price variations of all three markets for the NYC zone during a summer week and a winter week of 2011.

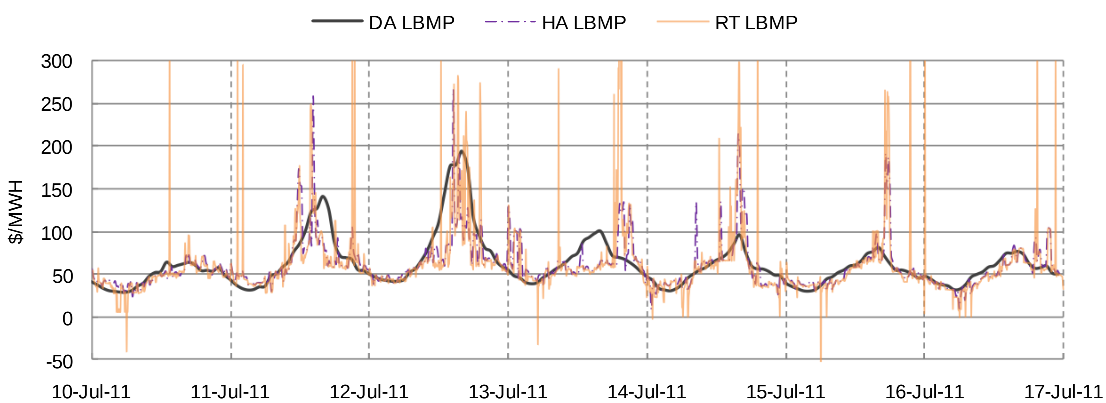

Figure 3. Price Variations of Wholesale Electricity Markets for NYC in Summer Week

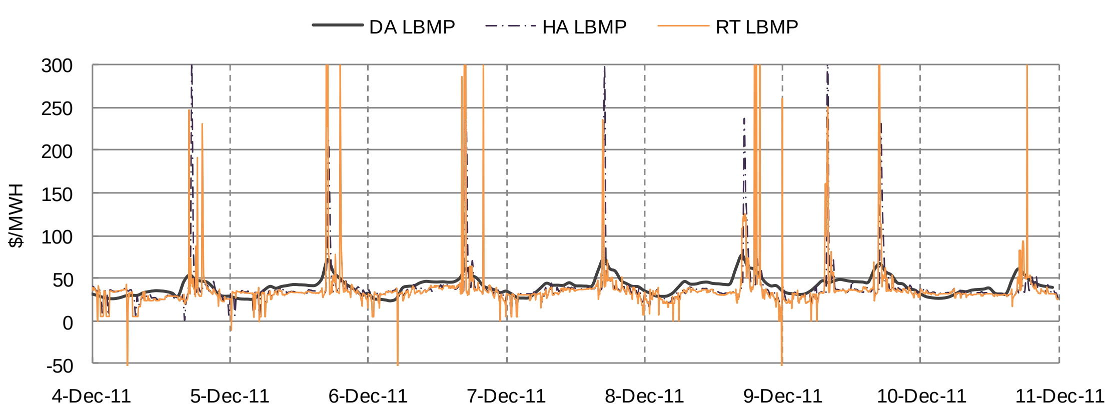

Figure 4. Price Variations of Wholesale Electricity Markets for NYC in Winter Week

As shown, LBMP varied quite dramatically for RT and HA markets compared to that of DA market as they follow the wholesale market conditions more closely. Daily minimum and maximum RT LBMP varied so much that some points could not be shown on the same scale as DA LBMP. Table 2 provides a statistical summary of the three wholesale markets during the weeks shown in Figure 3 and Figure 4.

Table 2. Statistical Summary of Price Variations in Wholesale Electricity Markets for NYC

	July 10, 2011 - July 16, 2011			December 4, 2011 - December 10, 2011		
	DA LBMP	HA LBMP	RT LBMP	DA LBMP	HA LBMP	RT LBMP
Mean	$61.38	$59.06	$61.45	$40.06	$37.56	$38.08
Standard Error	$2.21	$1.07	$0.97	$0.81	$1.05	$0.79
Range	$163.76	$257.70	$618.66	$53.55	$323.98	$561.89
Minimum	$29.24	$7.83	-$109.45	$23.27	$0.02	-$108.61
Maximum	$193.00	$265.53	$509.21	$76.82	$324.00	$453.28

In NYS, the default service for non-residential customers is MHP, which is largely based on zonal DA LBMP published by NYISO on the prior day. As such, customers do not need to face the extreme price volatilities of RT and HA markets. Nonetheless, DA LBMP can fluctuate quite significantly depending on the time and season of the year. Figure 5 shows the range of price variations in DA market for the NYC zone from January 2010 to December 2011.

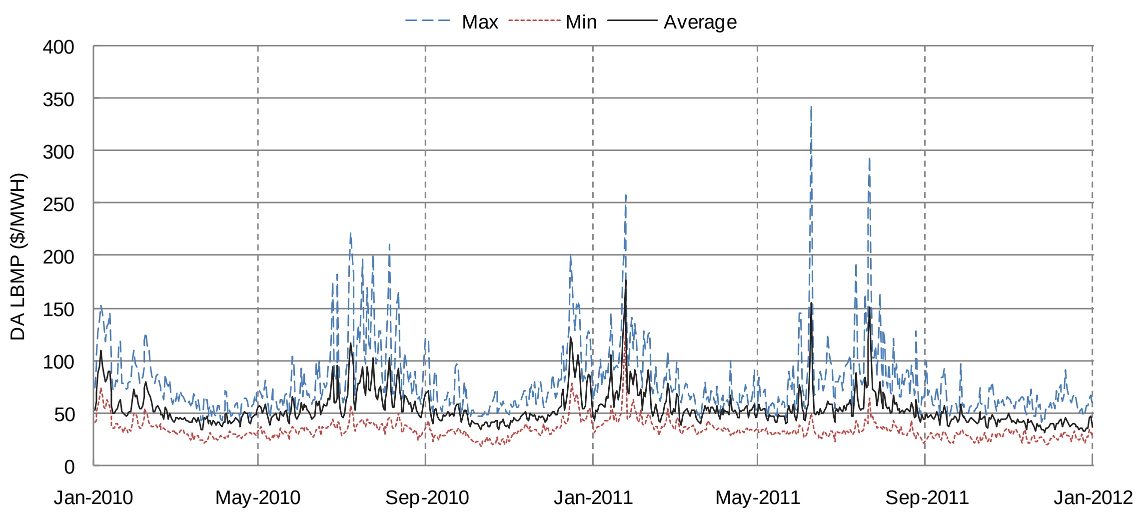

Figure 5. Price Variations in DA Market for NYC during 2010-2011

The highest price per MWH in 2011 was $343 (on June 9, 2011) while the lowest per MWH in the same year was $19 (on November 28, 2011). In 2010, the highest price per MWH was $223 (on July 7, 2010) while the lowest per MWH was $18 (on October 10, 2010).

On July 22, 2011, which was recorded as one of the hottest days in the New York City area with the high outside air temperature of 104°F in Central Park, NYC, DA LBMP soared nearly five times higher from the lowest point of $64 per MWH within the same day, as displayed in Figure 6.

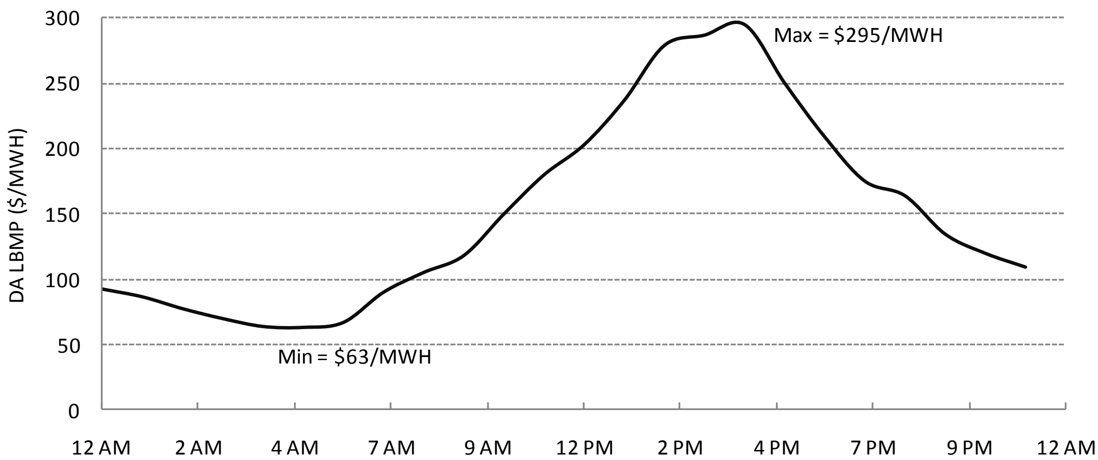

Figure 6. Price Variation in DA Market for NYC on July 22, 2011

If not managed carefully, DA LBMP can affect customers' electricity bills negatively. Therefore, hourly prices should be incorporated into the daily building load management to minimize electricity costs. OpenADR can automate this process by sending price signals to customers and facilitating load optimization so that the customers can reduce both labor and electricity costs.

2.2 Con Edison's Mandatory Hourly Pricing

Customers in NYC have a choice of receiving electric service from a local utility such as Consolidated Edison (ConEd) or from a Energy Service Company (ESCO) through retail access. Since May 2006, ConEd has offered MHP as the default service to large commercial customers who were subject to the Service Classification No. 9 (SC-9), mandatory Time-of-Day (TOD) rates.

MHP, offered under Rider M, is charged based on:

- New York Independent System Operator (NYISO) posted market-based zonal day-ahead locational based marginal pricing (DA LBMP),
- Ancillary Service Charges, and
- New York Power Authority (NYPA) Transmission Adjustment Charges (NTAC) adjusted for losses.

ConEd uses NYISO's zonal DA LBMP consisting of 24 hourly pricing points published a day-ahead and applies it to customers' hourly electricity consumption in order to quantify supply cost for each billing period. As for Ancillary and NTAC charges, ConEd uses an average monthly value derived from NYISO's wholesale market data and applies it to the total electricity consumed during the billing period (ConEd 2012a). For this reason, Ancillary and NTAC charges used for ConEd's Rider M are not considered dynamic in this document since they do not vary hourly.

In addition to MHP, ConEd collects demand charges based on the highest demand usage during the billing period. For customers under SC-9 TOD rates, demand charges are priced high during peak hours on weekdays in summer months when buildings' electricity demand is also high due to increased cooling activities. Therefore, ConEd customers on MHP should respond to both hourly prices and TOD demand charges to avoid high electricity bills

Under ConEd's SC-9 TOD rates with Rider M, there are two dynamic charges that significantly affect the electricity cost:

- hourly energy charge based predominantly on zonal DA LBMP applied to hourly electricity consumption and

- TOD demand charge imposed on the highest demand in a billing period.

Customers are encouraged to evaluate the following day's zonal DA LBMP published on NYISO's or ConEd's websites every day by 4:00 p.m. and manage their building load accordingly. Figure 7 shows a screen capture of NYISO's webpage where the day-ahead pricing data can be obtained (NYISO 2012b). Figure 8 shows a screen capture of ConEd's webpage where MHP is published (ConEd 2012b).

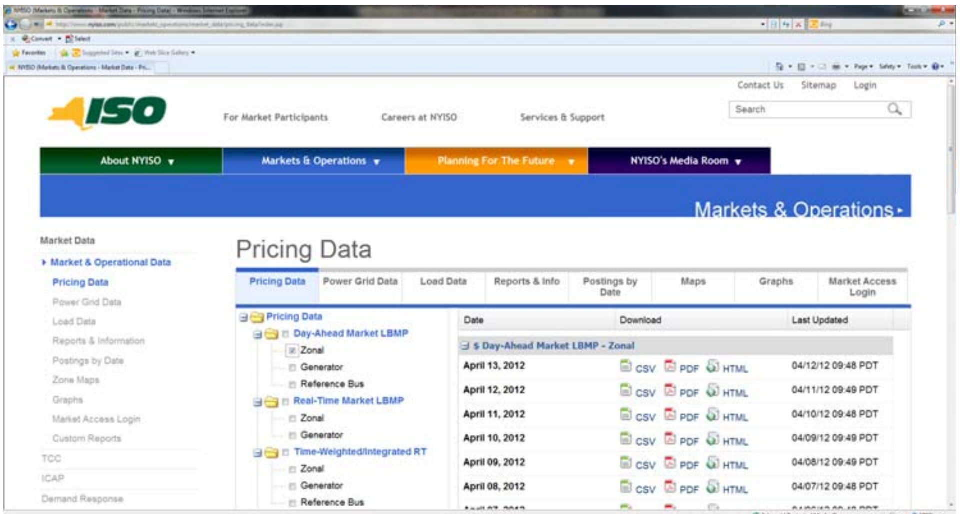

Figure 7. NYISO's Pricing Data Webpage

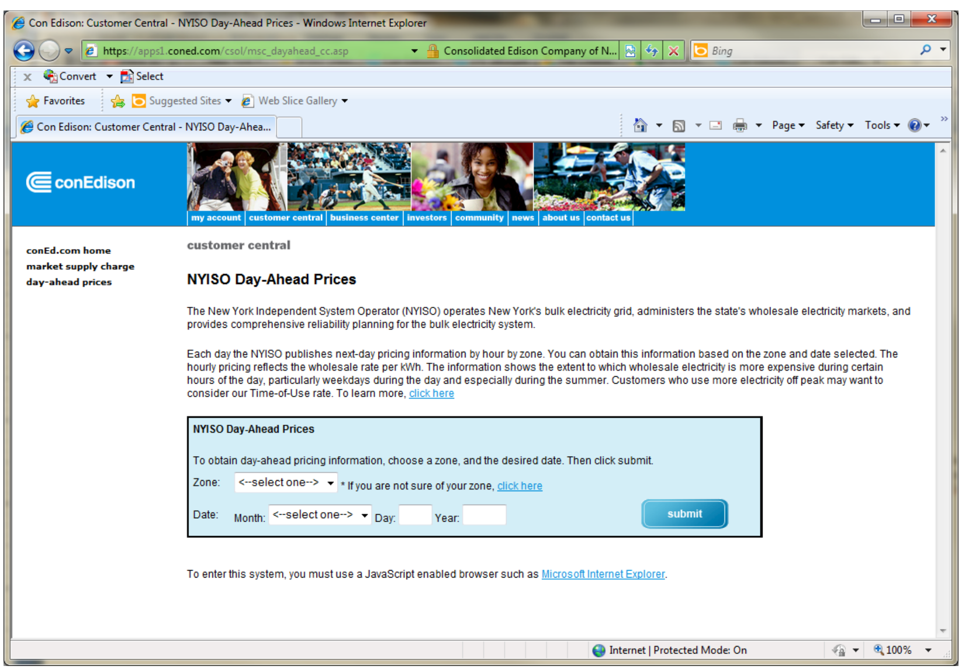

Figure 8. Con Edison's Hourly Pricing Data Webpage

The TOD demand charge, expressed in \$/kW, is imposed on the highest 30-minute integrated demand during the billing period and varies by month of year, day of week, and time of day. Table 3 explains how ConEd's TOD demand charge is applied under SC-9, Rate II (ConEd 2012c).

Table 3. Con Edison's Time-of-Day Demand Charge for SC-9, Rate II

	ConEd SC-9, Rate II	
	Low Tension	High Tension
Demand Delivery Charge, per kW for June - Sept		
Monday - Friday, 8AM - 6PM, per kW	$7.81	$7.81
Monday - Friday, 8AM - 10PM, per kW	$14.62	$14.62
All hours - all days, per kW	$15.69	N/A
Demand Delivery Charge, per kW for Oct - May		
Monday - Friday, 8AM - 10PM, per kW	$10.78	$10.78
All hours - all days, per kW	$5.03	N/A

Based on the current tiered pricing structure, customers can face a TOD demand charge as high as $38.12 ($15.69 + $14.62 + $7.81) per kW during peak hours in summer months while it is only $15.81 ($5.03 + $10.78) per kW during the same peak hours in winter months. Since the demand delivery is charged based on the maximum power used during the billing period regardless of the duration or frequency of that power usage, it is essential to reduce the demand as low as possible or below certain threshold.

For demonstration sites, the actual power usage data will be sent to Demand Response Automation Server (DRAS) in a 15-minute interval. This allows the continuous monitoring of the building's demand. At any moment, if the demand gets close to a pre-defined threshold, warnings will be issued and load control strategies will be activated to bring down the demand until it reaches the satisfactory range

3 Demand Response Programs in New York

Demand response (DR) programs provide incentives to reduce loads on the electricity grid during peak demand periods. They run episodically based on scheduled events and vary in their rules and incentive structures. This chapter gives an overview of different DR programs available in New York.

3.1 Program Description

In NYS, DR programs are administered by NYISO and utilities. NYISO currently offers four DR programs:

- Installed Capacity Special Case Resource (SCR)
- Emergency Demand Response Program (EDRP)
- Day-Ahead Demand Response Program (DADRP)
- Demand-Side Ancillary Service Program (DSASP)

Customers can participate in NYISO's DR programs through utilities or curtailment service providers (CSPs), or directly with NYISO. Some utilities offer their own DR programs to respond to critical situations within their distribution system. For example, ConEd offers

- Distribution Load Relief Program (DLRP) and
- Commercial System Relief Program (CSRP).

Customers can participate in multiple DR programs operated by different entities as long as they abide to the rules and meet the load relief requirements of each program. Exceptions apply to a few DR programs that are mutually exclusive:

- DSASP and DADRP
- ICAP SCR and EDRP

If a customer responds to more than one program during concurrent hours, the DR compensation will be calculated according to program operators or service providers.

For this project, we examined five DR programs that were most relevant to the proposed demonstration sites: SCR, EDRP, DADRP, DLRP, and CSRP. Appendix A provides a summary of these programs including program description and participation rules and Appendix B provides a summary of the event evaluation and payment methods (ConEd 2012a; NYISO 2003; NYISO 2010; NYISO 2012c).

3.2 Program Prioritization

Based on the DR program information in Appendix A: Demand Response Program Rules and Appendix B: Demand Response Program Evaluation and Payment Methods, we developed the DR prioritization table for a load residing in the ConEd service territory (Table 4). Priorities were given to the programs that require mandatory response, higher load reductions, and incentive/penalty amounts. DADRP is excluded because it is based on customer's bids instead of the system's emergency. This means that customers enrolled in DADRP can plan when to participate and how much load to reduce prior to the event day.

Table 4. Demand Response Program Prioritization Table

Priority Ranking	DR Program	Operator	Participation	Response Required	Min. Reduction	Penalties	Mutually Exclusive
1	SCR	NYISO	Voluntary	Mandatory	100 kW	Yes	EDRP
2	CSRP - Summer Reservation Payments Program	ConEd	Voluntary	Mandatory	Individual: 50 kW Aggregator: 100 kW	Yes	-
3	DLRP - Summer Reservation Payments Program	ConEd	Voluntary	Mandatory	Individual: 50 kW Aggregator: 100 kW	N/A	-
4	EDRP	NYISO	Voluntary	Voluntary	100 kW	N/A	SCR
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6	DLRP - Voluntary Load Relief Program	ConEd	Voluntary	Voluntary	Individual: 50 kW Aggregator: 100 kW	N/A	-

Using Table 4, DRAS can prioritize DR program event signals and call for load control strategies at facilities based on the priority ranking and program interaction rules. This enables customers to participate in multiple DR programs during concurrent time period and maximize DR incentives.

3.3 Baseline Load Calculation Methods

NYISO evaluates the performance of the DR program events by determining the deviation from the baseline load. The customer has the option of electing the Average Day Customer Baseline Load (CBL) formula or the Weather-Sensitive CBL formula to establish their baseline load. ConEd also uses NYISO's baseline load calculation methods to evaluate the performance of its DR programs. Table 5 summarizes the NYISO's baseline load calculation methods (NYISO 2010).

Table 5. NYISO's Baseline Load Calculation Methods

Evaluation Method	Baseline Window	Calculation Type	Baseline Adjustments	Adjustment Window
Average Day CBL	Weekday Event: previous 10 weekdays within the last 30 days, excluding day preceding event, holidays, and any weekdays where a curtailment event occurred within the CBL Window Weekend Event: previous 3 weekends, no exclusions	Weekday Event: hourly average of the 5 highest total event period load days in CBL Window Weekend Event: hourly average of the 2 highest total event period load days in CBL Window	N/A	N/A
Weather-Sensitive CBL	same as above	same as above	Apply adjustment factor of +/- 20%	2 Hours

4 Price Responsive Demand

The goal of price responsive demand is to achieve the most optimal load that would yield the lowest achievable electricity cost by applying appropriate load control strategies. In this chapter, we present a framework to assess cost minimization capabilities of DR.

4.1 Cost Minimization Analysis

Under ConEd's SC-9 TOD rates with Rider M, there are two dynamic charges that significantly affect the electricity cost:

- energy supply charge based predominantly on zonal DA LBMP applied to hourly electricity consumption and
- TOD demand charge imposed on the highest demand in a billing period.

Ancillary and NTAC charges used for ConEd's Rider M are not considered dynamic in this document since they do not vary hourly. The key to minimizing electricity cost is to optimize buildings' electricity demand according to hourly prices as well as demand charges during a billing period.

The minimum energy supply cost for a given day, excluding Ancillary and NTAC charges, can be represented as,

$$\min \sum_{t=1}^{k} C_t \cdot g(u_t, x_t, w_t) \tag{3}$$

where

- C_t is the DA LBMP at time t acquired from DRAS;
- t is the time interval (e.g., 60- or 15 minute);
- k is the total number of time intervals in a day;
- g is the optimal electricity load at time t determined by the objective function using EnergyPlus;
- u_t is the input constraints for load control strategies;
- x_t is the building system states (e.g., operation schedules, HVAC settings); and
- w_t is the weather (e.g., outside air temperature, relative humidity).

The minimum peak demand in a billing period is expressed as,

$$\min\left(\max_{d\in 1,\ldots,N} g(u_t, x_t, w_t)\right) \tag{4}$$

where N is the total number of time intervals in a billing period.

When DA LBMP is obtained from DRAS, a building operation mode (i.e., NORMAL, MODERATE, HIGH, and CRITICAL) will be determined for each hour based on the baseline load and hourly prices. The building operation mode will activate a set of load control strategies programmed in the building's Energy Management & Control System (EMCS) so that the building can achieve the most economically optimal load given system constraints and weather conditions. For this project, EnergyPlus, a whole building energy simulation software developed by the U.S. Department of Energy, will be used to assess the DR potential of various control strategies for each facility (DOE 2011). When the customer responds to hourly prices and DR program events concurrently, the CRITICAL mode will be assigned where the most aggressive control strategies are activated to satisfy the DR requirements as well as minimizing electricity costs. At the end of each DR event, the control strategies will be designed to recover loads slowly to avoid rebound effects.

4.2 Case 1: Mandatory Hourly Pricing

For large commercial buildings in NYC, the default electricity service is MHP served under ConEd's Rider M. Figure 9 displays NYC zonal DA LBMP of a random day and Figure 10 shows a hypothetical building's electricity loads of the same day and historic benchmarks.

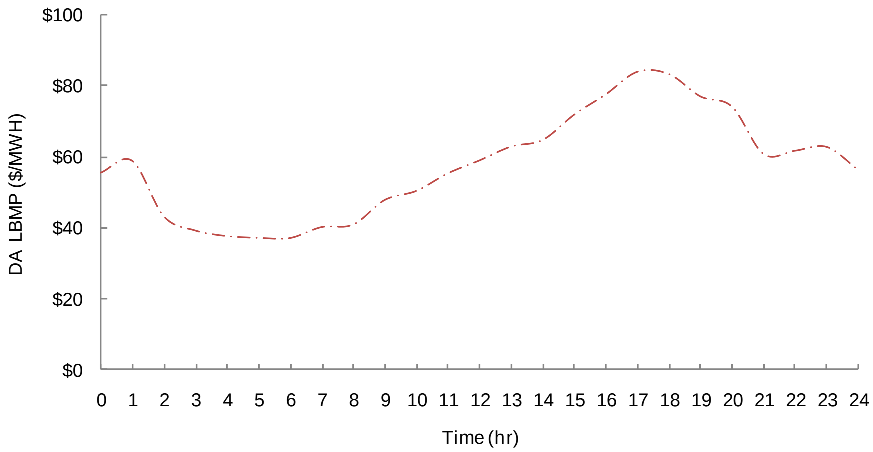

Figure 9. Case 1: Sample DA LBMP

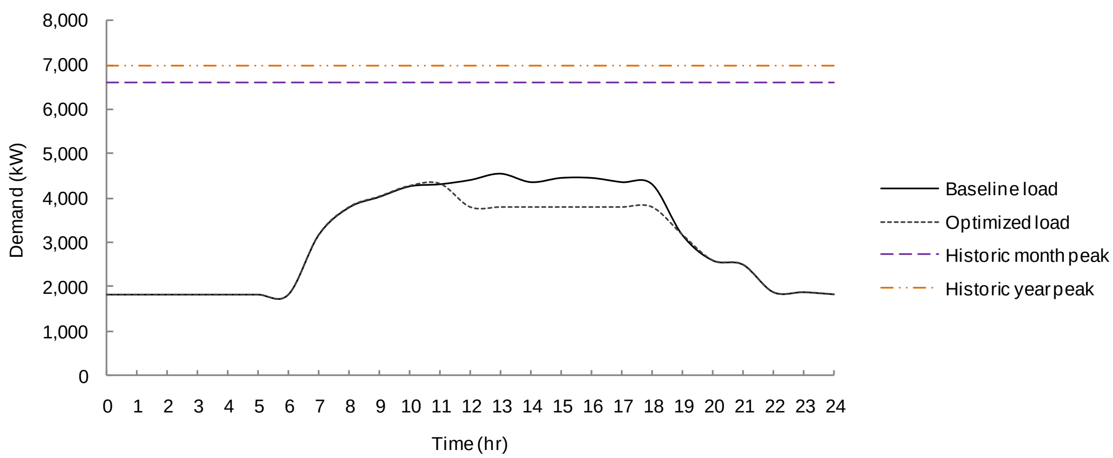

Figure 10. Case 1: Hypothetical Building Loads and Historic Benchmarks

Based on zonal DA LBMP and the building's baseline load, a building operation mode will be assigned for each hour and load control strategies will be activated accordingly to achieve the most economically optimal level. To minimize demand delivery charges, demand limiting strategies will be used when the load approaches certain thresholds. This can be accomplished by comparing the baseline load against historic peak loads such as historic year peak load or historic month peak load. If the historic month peak load is lower than the historic year peak load (i.e., December), the historic month peak load becomes the limit.

Using Equation 3, the energy supply cost can be estimated by multiplying building demand with zonal DA LBMP. For our hypothetical building, the energy supply cost for the baseline load and optimized load are shown in Figure 11. The energy cost savings would be the difference between the area under the baseline and optimized curves.

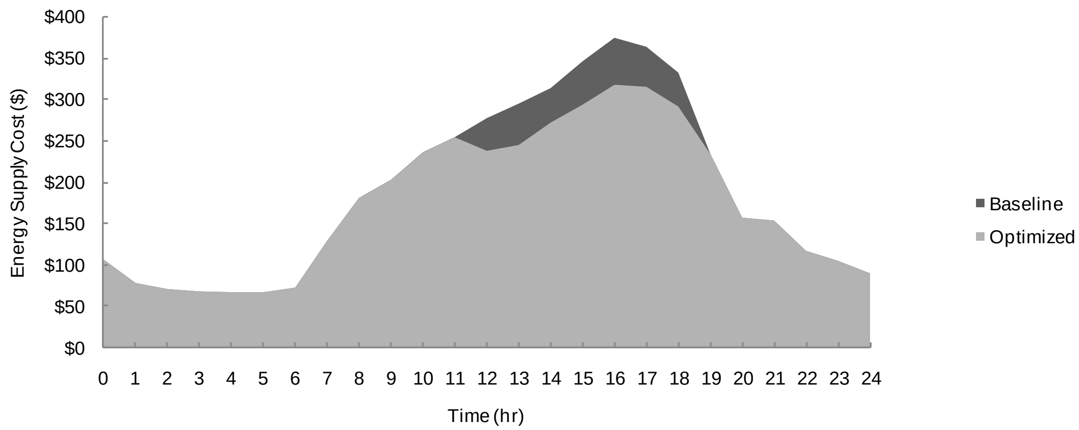

Figure 11. Case 1: Potential Energy Supply Cost Savings

4.3 Case 2: Mandatory Hourly Pricing + Demand Response Program

Building on Case 1, if the customer responds to MHP and participates in a DR program event on the same day, building load has to respond to both price and DR program event signals. Assume that a DR program event is called for next day during a specific time period and the load needs to be reduced by a minimum of 100 kW during the event period (Figure 12).

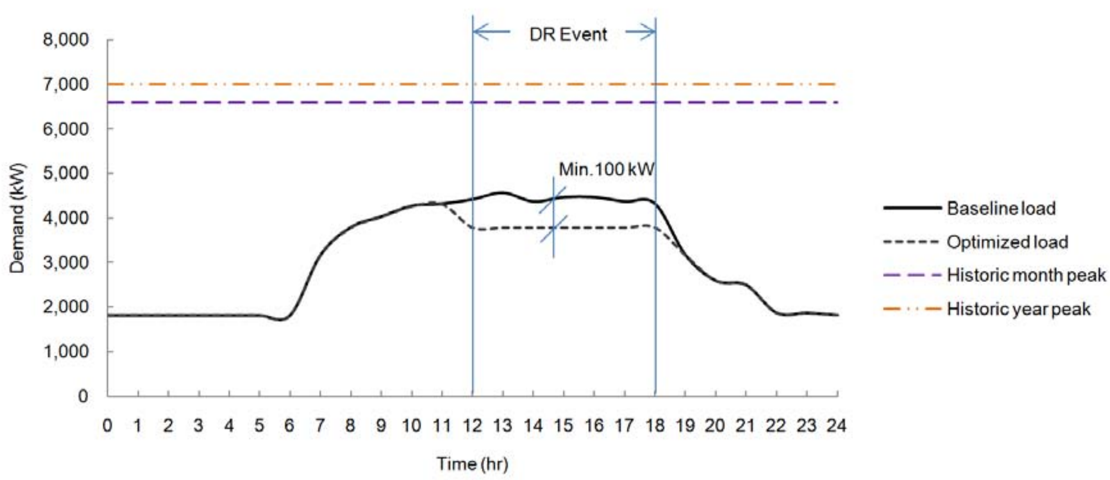

Figure 12. Case 2: Hypothetical Building Load and DR Program Event

During a DR event, the load will be curtailed at the maximum reduction level so that the customer can meet the minimum DR requirements. It is possible that some customers who have been on MHP for an extended period of time has an optimized baseline load as a result of successful ongoing demand monitoring and response. For them, shedding additional 100kW from an already optimized baseline load maybe difficult. This makes DR programs less attractive for efficiently operated customers on MHP. Since DR program events are called only a few days a year, the incentives collected from DR programs are likely to be small compared to the electricity cost savings achieved under MHP with successful load optimization.

5 Dynamic Price Mapping on OpenADR

OpenADR is an XML based information exchange model that communicates price and reliability information (Piette et al. 2009). After its publications as OpenADR version 1.0 specifications in 2009, it was donated to the Organization for Structured Information Standards (OASIS) to be fully developed into an international standard and coordinated with the National Institute of Standards and Technology's (NIST) Smart Grid Standards development effort. OASIS established the Energy Interoperation Technical Committee (EI TC) and developed the EI standards. OpenADR version 2.0 is a set of profiles under the OASIS EI standards. In 2010, an industry-led organization, called the OpenADR Alliance, was established. The goal of this organization is to develop conformance and compliance path for OpenADR v2.0 and develop a certification program. The Smart Grid Architectural Council approved OpenADR v2.0 as a NIST supported standard in March 2012. The fist OpenADR v2.0 certified products are expected to be available by the end of 2012. In the absence of products for OpenADR v2.0, this project will utilize OpenADR v1.0 and OpenADR v1.0-ready products that are currently available on the market. This chapter describes the OpenADR communication architecture and dynamic pricing data model for communicating both price and DR program event information to the demonstration sites in NYC.

5.1 Dynamic Pricing Data Model

Simple graphical representation of OpenADR v1.0 is displayed in Figure 13. There are three important times that define a DR event: (1) Notification Time, (2) Start Time and (3) End Time. Notification Time starts the PENDING period. The Notification Time can be day(s)-ahead, day-of, or can be equal to the Start Time. When the Start Time is received, the DR event starts its ACTIVE period. During this period, the facilities can receive absolute or relative price information, price modes, or load levels. End Time ends the DR event's ACTIVE period and starts the IDLE period. After a DR event, the loads are slowly returned to their normal operation to avoid rebound effects.

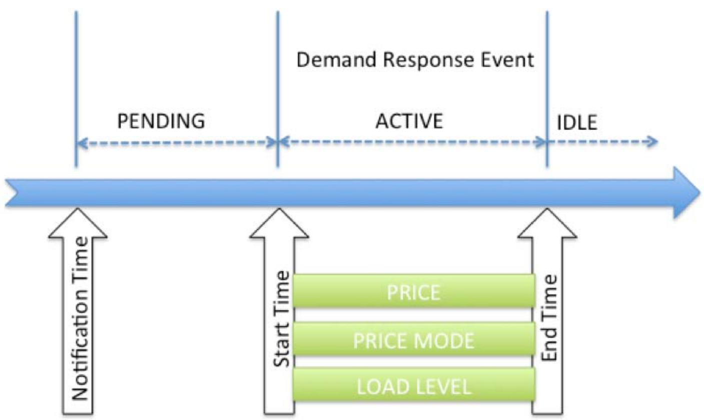

Figure 13. OpenADR v1.0 Graphical Representation

The two cases that were discussed in Chapter 4 were (1) MHP and (2) MHP with a DR programs. In the case of MHP, the Notification Time is when NYISO publishes the next day's hourly prices (typically by 4 p.m. every day). The Start Time of the DR event is midnight and the End Time of the DR event is the minute before midnight. This is highlighted in the hypothetical real-time price data model in Appendix C: OpenADR Dynamic Pricing Schema. Between Start Time and End Time, the price for each hour is indicated in the data model. Each hour is indicated as an offset from the Start Time.

In the case of a DR program on top of an existing MHP structure, an additional Notification Time, Start Time and End Time will be communicated to the facility. These parameters are summarized in Appendix A: Demand Response Program Rules. Most programs have a two-hour pending period with varying durations anywhere from one hour for test events to seven hours for immediate DLRP events. Since most of these programs have minimum load reduction requirement for individual facilities, this load level will be communicated to the facility. If the customers are enrolled in DR programs through a CSP, they will receive Notification Time, Start Time and End Time from the CSP when their resources are called in for DR events.

5.2 OpenADR Mapping Structure

Simple DRAS Clients support four levels of building operation mode signals: NORMAL, MODERATE, HIGH, and CRITICAL. Currently, these signals respond to dynamic prices, demand limits, and/or DR events. For the first phase of the project, the team will implement the current mapping structure of DRAS.

<u>Phase I</u>:

- NORMAL: If MHP is low, there will be no curtailment and the facility will operate as normal.
- MODERATE: If MHP is moderately high, the loads will be curtailed at the moderate load reduction level.
- HIGH: If MHP is high, the loads will be curtailed at the high load reduction level. HIGH can also be activated when the load exceeds a certain demand limit (i.e., historic benchmarks).
- CRITICAL: This mode is only activated when there is a DR program event. The loads will be curtailed at the maximum reduction level.

While the current mapping structure allows customers to provide DR during expensive time periods and/or to stay below demand limits, it does not respond to the building's unique energy consumption patterns. By looking at both price and consumption, customers can maximize potential energy cost savings. During the second phase of this project, the team will add the capability for DRAS to respond to energy supply cost introduced in Chapter 4. Since the energy supply cost is a multiplier of MHP and the baseline load, DRAS can send building operation mode signals sensitive to both price and consumption.

<u>Phase II</u>:

- NORMAL: If energy supply cost is low, there will be no curtailment and the facility will operate as normal.
- MODERATE: If energy supply cost is moderately high, the loads will be curtailed at the moderate load reduction level.
- HIGH: If energy supply cost is high, the loads will be curtailed at the high load reduction level. HIGH can also be activated when the load exceeds a certain demand limit (i.e., historic benchmarks).
- CRITICAL: This mode is only activated when there is a DR program event. The loads will be curtailed at the maximum reduction level.

Through the DRAS Feedback Client, customers will be able to review their energy supply cost based on the actual shed data and keep track of the cost savings resulted from DR.

5.3 OpenADR Communication Architecture

Using OpenADR v1.0, the communication architecture was developed for the demonstration sites. Figure 14 shows the price and DR program information is communicated to facilities via DRAS.

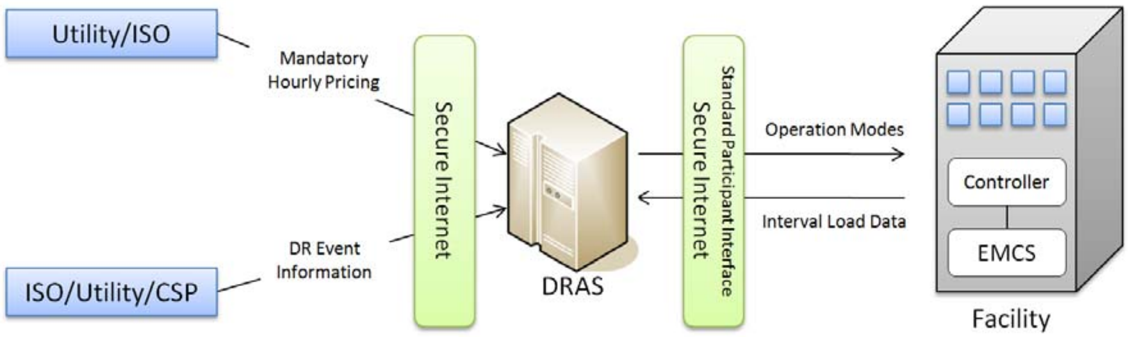

Figure 14. OpenADR Communication Architecture

The day-ahead hourly prices can be obtained from either NYISO or ConEd. The DR program event information will be received from CSPs or directly from NYISO and ConEd depending on the customer's DR programs enrollment agreements. The price and DR program event information will be sent to DRAS and used to determine building operation modes for each hour of the following day. Once they are determined, DRAS will send these information to facilities using a secure Internet connection. The building operation modes assigned to each hour will activate a set of control strategies programmed into the building's EMCS. The customers have an option to opt-out, if they do not wish to participate in DR. During the DR event, DRAS will log the building's electricity usage at 15-minute intervals via kyz pulses to generate the building's current load profile and verify the DR performance.

6 Conclusions

This document shows how OpenADR can support MHP and facilitate price responsive demand for large commercial customers in NYC. First, the usefulness of market-based hourly prices and DR programs on price responsive demand were evaluated. Second, the demand response program prioritization table was developed for DRAS to prioritize multiple DR program signals and send them to facilities based on the priority ranking and program interaction rules. This allows customers to participate in more than one DR program during concurrent time periods. Third, an analysis framework was presented to assess cost minimization capabilities of DR under MHP and DR programs. Lastly, OpenADR data models and communication architecture were developed to map hourly prices, demand limits, and DR event signals into building operation modes using Simple DRAS Clients. The findings from this document will be used to design load control strategies for demonstration sites in NYC during Summer of 2012.

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Appendix A: Demand Response Program Rules

DR Program	Operator	Participation	Response Required	Primary Driver	Min. Reduction	Min. Duration	Award Notification	Deployment	Advance Notification
SCR	NYISO	Voluntary	Mandatory	Reliability	100 kW	4 hr	phone call / e-mail	phone call / e-mail	Day-ahead advisory and 2-hr advance notice
EDRP	NYISO	Voluntary	Voluntary	Reliability	100 kW	4 hr	phone call / e-mail	phone call / e-mail	Day-ahead advisory and 2-hr deployment
DADRP	NYISO	Voluntary	Mandatory	Economic	100 kW	As scheduled	Web page (MIS)	Fixed schedule	Customer submits the bid 2 business days prior to the dispatch day
DLRP - Voluntary Load Relief Program	ConEd	Voluntary	Voluntary	Reliability	Individual: 50 kW Aggregator: 100 kW	- Contingency event: 5 hrs or more - Immediate event: 7 hrs or more	phone call / e-mail	phone call / e-mail	- Contingency event: 2-hr advance notice - Immediate event: less than 2-hr advance notice
DLRP - Summer Reservation Payments Program	ConEd	Voluntary	Mandatory	Reliability	Individual: 50 kW Aggregator: 100 kW	- Contingency event: 5 hrs or more - Immediate event: 7 hrs or more - Test event: 1 hr	phone call / e-mail	phone call / e-mail	- Contingency event: 2-hr advance notice - Immediate event: less than 2-hr advance notice - Test event: less than 2-hr advance notice
CSRP - Voluntary Load Relief Program	ConEd	Voluntary	Voluntary	Reliability	Individual: 50 kW Aggregator: 100 kW	- Contingency event: more than 5 hrs - Planned event: 5 hr	phone call / e-mail	phone call / e-mail	- Contingency event: less than 21-hr advance notice - Planned event: not less than 21-hr advance notice, plus 2-hr advance notice
CSRP - Summer Reservation Payments Program	ConEd	Voluntary	Mandatory	Reliability	Individual: 50 kW Aggregator: 100 kW	- Contingency event: more than 5 hrs - Planned event: 5 hr - Test event: 1 hr	phone call / e-mail	phone call / e-mail	- Contingency event: less than 21-hr advance notice - Planned event: 21-hr advance notice - Test event: 21-hr advance notice, plus 2-hr advance notice

Appendix B: Demand Response Program Evaluation and Payment Methods

DR Program	Evaluation Method	Energy Payment	Capacity Payment	Penalties
SCR	Average Day CBL or Weather-Sensitive CBL	equal to the higher of the zonal real-time LBMP, or an amount specified by the customer, but no more than $.50 per kWh	paid at ICAP auction clearing price	NYISO will reduce future capacity payments if the NYISO calls for operation and the SCR does not perform.
EDRP	Average Day CBL or Weather-Sensitive CBL	1) For the event lasting 2 hrs or fewer: the payment during the first 2 hrs will be equal to the higher of the zonal real-time LBMP or $.50 per kWh. The payment for the remaining hour will be paid the zonal real-time LBMP. 2) For the event lasting between 2 and 3 hrs: the payment during the first 3 hrs will be equal to the higher of zonal real-time LBMP or $.50 per kWh. The payment for the remaining hour will be paid the zonal real-time LBMP. 3) For the event exceeding 3 hrs: the payment will be equal to the higher of the zonal real-time LBMP or $.50 per kWh.	N/A	N/A
DADRP	Average Day CBL or Weather-Sensitive CBL	paid at zonal day-ahead LBMP plus a supplement, if needed, to allow full recovery of the curtailment initiation cost	N/A	A penalty equal to the higher of the day-ahead LBMP or the real-time LBMP for the amount of the incomplete scheduled load reduction will be applied.
DLRP - Voluntary Load Relief Program	Average Day CBL or Weather-Sensitive CBL	equal to $.50 for each kWh reduced	N/A	N/A
DLRP - Summer Reservation Payments Program	Average Day CBL or Weather-Sensitive CBL	equal to $.50 for each kWh reduced	1) Tier I: paid at $3.00 per kW-month, multiplied by performance factor for up to 6 load events up to 5 hrs each in a designated network 2) Tier II: paid at $6.00 per kW-month, multiplied by performance factor for 6 load events up to 5 hrs each in a designated network 3) Bonus payments: a) $1.00 per kW per month, multiplied by performance factor for a response to 7 to 9 load events or 6th to 7th hr in an event b) $1.50 per kW per month, multiplied by performance factor for a response to 10 or more load events or 8th or greater hr in an event	N/A
CSRP - Voluntary Load Relief Program	Average Day CBL or Weather-Sensitive CBL	1) equal to $1.50 for each kWh reduced during a 5-hr planned event; and 2) equal to $5.00 for each kWh reduced during a contingency event	N/A	N/A

CSRP - Summer Reservation Payments Program	Average Day CBL or Weather-Sensitive CBL	1) equal to $.50 for each kWh reduced during planned or test events 2) no energy payments during contingency events	1) For 4 or fewer cumulative planned events: $5.00 per kW-month, multiplied by performance factor 2) For 5 or more cumulative planned events: $10.00 per kW-month, multiplied by performance factor 3) Bonus payment: $5.00 per kW for the highest average kW reduced during each contingency event, multiplied by performance factor	two times the capacity payment for each kW reduction in the month not achieved and derating-based on performance in planned events with not less than 21-hr notification

Appendix C: OpenADR Dynamic Pricing Schema


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            </p:eventInfoValues>
        </p:eventInfoInstances>
    </p:drEventData>
    <p:customData/>
</p:eventStates>
</p:listOfEventState>
```