The Brattle Group

Demand Response Review

Presented to:
AESO

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March 2011

Purpose

***The Brattle Group* was retained by AESO to evaluate opportunities to increase the integration of demand response ("DR") in the Alberta energy-only wholesale electricity market. Our specific tasks included the following:**

- Collect and summarize information about the types and characteristics for a representative sample of DR programs and associated market designs in the U.S. RTO markets
- Review of current and planned AESO DR programs and DR-related market design elements
- Gather and evaluate feedback at focus group meetings with AESO market participants
- Evaluate which of the identified (or potentially new) DR types and DR-related wholesale market designs could be applied in Alberta

This presentation summarizes this effort and presents our recommendations

Contents

A. Overview – Types of Demand Response

Price-Responsive DR

- End user is exposed to time-varying (dynamic) rates
- DR occurs in response to these prices; end use customer implicitly weighs its (dynamic) retail rate against the benefit from consumption
- Customer does not receive an explicit payment as a compensation for curtailing load
- Participation in energy and capacity market only
- Response to dynamic retail rate or direct wholesale market participation

Controllable DR

- End-use customer agrees to curtail under certain circumstances (as specified by a contract between the customer and the load serving entity (LSE) or the aggregator); Retail customer may remain on a fixed retail rate while participating in wholesale programs
- Curtailment occurs (or should occur) in response to dispatch by the LSE, aggregator, or the system operator
- Customer receives an explicit (incentive) payment for curtailing load
- Participation in all three types of wholesale markets: energy, A/S, capacity
- Retail program or direct wholesale market participation

A. Overview – Main Types of Retail DR Programs

Type of Program / Characteristics	Price-Responsive DR		Controllable DR			
	Dynamic Pricing without enabling technology	**Dynamic Pricing** with enabling technology	**Direct Load Control** (DLC)	**Indirect Load Control** (ILC)	**Interruptible Tariff**	**Other Dispatchable DR Programs**
Trigger	Price		Automatic interruption	Dispatch Instruction		
Examples of enabling technology		In-home display, smart thermostat	Remote control of end-use equipment by LSE/ARC	Communications equipment for LSE or RTO dispatch instructions		
Who interacts with RTO?	LSE	LSE	LSE/ARC	LSE/ARC	LSE	LSE
Examples	RTP, CPP, PTR PG&E's SmartRate Program Comed's Residential RTP		Residential A/C cycling programs	Most aggregator programs	LSE interruptible tariffs for C&I customers	LSE demand bidding programs
Notes	Often by large customers	Response to price is automated by technology	Response is controlled by LSE/ARC	Response is typically mandatory	Limited to reliability events	Response may be voluntary

A. Overview

B. DR Programs by Market Type

1. Energy Market Participation
2. Ancillary Services Market Participation
3. Capacity Market Participation

C. AESO DR Programs

D. AESO Customer Feedback

E. Implications for AESO

F. Specific Recommendations for AESO

Appendix: RTO DR Program Descriptions

B.1. Energy Market Participation

Price Responsive DR

- Dynamic pricing *without* technology to enable automated response is not suitable for active bid-based participation
- Dynamic pricing *with* enabling technology in response to market prices can be fully integrated into the wholesale market
    - Load Serving Entity (LSE) can submit Price Responsive Demand (PRD) bids in the wholesale market and align such bidding with its retail dynamic pricing program

Controllable DR

- Controllable retail DR programs can be used for energy market participation only if they have an economic (*i.e.*, price) trigger
- Direct and Indirect Load Control (DLC & ILC) with such trigger are the most likely retail programs to participate because they are either directly controlled or dispatchable
- Interruptible and other controllable DR are less likely to participate because they are less likely to have an economic trigger
    - Most interruptible tariff programs can only be activated during system reliability events

B.1. Energy Market Participation: Price Responsive DR

	Dynamic Pricing without enabling technology	Dynamic Pricing with enabling technology
Type of market participation	Response to observed market prices without bidding	Active, automated response to observed market prices
Enabling wholesale market design element or program	Transparent (ideally, ex-ante) prices, easily accessible to customers, and published in time to allow response	Price Responsive Demand (PRD) bidding that allows LSE to bid for different amounts of energy at various price points
Examples of RTO programs	All areas with organized wholesale markets, however only NYISO has binding ex-ante real-time prices (5 minutes in advance)	No formal DR programs exist; PRD bidding is part of the energy market design. Only day-ahead PRD bidding is enabled in most U.S. RTOs.
Examples of retail programs	Real Time Pricing (RTP) Critical Peak Pricing (CPP) Peak Time Rebate (PTR)	
Comments/ notes/description	Such price response cannot be integrated into the wholesale price setting, and may therefore be inefficient.	Ideally, DR would be allowed to set the market price. In PJM DR can set the RT LMP only if it has telemetry, a requirement that no resource has met.

B.1. Energy Market Part'n: Controllable DR (DLC, ILC)

	Direct Load Control (DLC) Indirect Load Control (ILC)		
Type of market participation	Response to market prices without bidding	Active response to market prices through demand bidding	Offering load reductions as a supply-side resource (comparable to generation offers)
Enabling wholesale market design element or program	Transparent (ideally, ex-ante) prices, easily accessible to customers, and published in time to allow response	PRD bidding that allows LSE to bid for different amounts of energy at various price points	Most important: M&V and compensation mechanism. Other rule changes that may act as a barrier to DR
Examples of RTO programs	All areas with organized wholesale markets, but only NYISO has ex-ante real-time prices	No formal DR programs exist; PRD bidding is part of the energy market design. Only day-ahead PRD bidding is enabled in most U.S. RTOs	**PJM**: Economic Load Response; **MISO**: Demand Response Resource; **CAISO**: Proxy Demand Resource **NYISO**: Day-Ahead Demand Response Program
Examples of retail programs	Retail A/C cycling programs with an economic/price trigger (DLC) Aggregator DR programs (ILC)		
Comments/notes/ description	Price response without bidding cannot be integrated into the wholesale price setting, and may therefore be inefficient.	Ideally, DR would be allowed to set the market price.	DR compensation mechanisms and customer baseline (CBL) definitions are contentious issues.

B.2. Ancillary Services Market Participation

Price Responsive DR

- Retail dynamic pricing programs are not capable of providing reliable response required for ancillary services (A/S)
  - Dynamic pricing programs are triggered by the market price of energy not the market price of ancillary services
  - Unlike energy, end-use customers cannot avoid consuming ancillary services, because the demand for ancillary services is administratively set

Controllable DR

- DLC programs are the most natural candidates to provide A/S (especially regulation and spinning), because their response is automated
- Other types of controllable DR (e.g. ILC, demand bidding) may be able to provide some A/S, if they are capable of meeting notification and response time requirements

B.2. A/S Market Participation: Controllable DR – DLC

	Direct Load Control (DLC)		
Type of market participation	**Regulation market** DR offers comparable to generators	**Spinning Reserves** DR offers comparable to generators	**Supplemental Reserves** DR offers comparable to generators
Enabling wholesale market design element or program	Modify M&V and qualification requirements to enable DR; remove any barriers that discourage/prevent DR participation		
Examples of RTO programs	**MISO**: Demand Response Resource (DRR) - Type II* **ERCOT**: Controllable Load Resources (CLR)	**ERCOT**: Load Acting as a Resource (LaaR); **PJM**: Economic Load Response (synchronized reserves)	**MISO**: Demand Response Resource (DRR) - Type I*
Examples of retail programs	Typical participants are large industrial customers (often direct wholesale customers)	Typical participants are not retail customers, however retail A/C programs have been tested successfully tested in California	Many retail programs with a 30-minute notification time
Comments/notes/ description	Few markets have DR in the regulation market, and participation is small everywhere (highest in MISO).	There is a lot of participation in ERCOT and PJM; LaaRs regularly provide 50% of spinning requirement (50% is the cap for LaaRs)	Supplemental reserves are the least valuable; market prices are often low

* DRR – Type I – resource capable of supplying energy or contingency reserves through physical load interruption; DRR – Type II – resource capable of supplying energy, contingency and regulating reserves through behind-the-meter generation or controllable load

B.2. A/S Market Participation: Emergency Reserves

In addition to providing A/S, DR may participate in RTO programs to provide emergency reserves. These resources are not procured on a daily basis in the A/S markets. Examples of RTO programs:

- **MISO**: Emergency Demand Response (EDR)
- **NYISO**: Emergency DR Program (EDRP)
- **PJM**: Emergency Load Response Program
- **ERCOT**: Emergency Interruptible Load Service (EILS)
- **AESO**: Load Shed Service (LSS), Load Shed Service for Imports (LSSi), Import Load Remedial Action Scheme (ILRAS), Demand Opportunity Service (DOS), Voluntary Load Curtailment Program (VLCP), Under-Frequency Load Shedding Scheme (UFLS)

B.3. Capacity Market Participation

Price Responsive DR

- In markets with a resource adequacy requirement, dynamic pricing programs can earn capacity value in three ways:
  - Price responsive DR does not receive a capacity credit, but its impact on peak loads reduces the load forecast and thus capacity obligations
  - DR receives a capacity value, and load forecast may be explicitly adjusted
  - DR participates as a capacity supply resources and competes with generators in the capacity market

Controllable DR

- Most resource adequacy constructs require DR to respond during system emergencies (often the number of DR calls per year are limited)
- Therefore, most retail controllable DR programs are eligible/capable to participate in the capacity market
- Controllable DR can participate in the capacity market in three ways, as described above for Price Responsive DR

B.3. Capacity Market Part'n: Price Responsive DR

	Price Responsive DR		
Type of market participation	No capacity value or direct market participation; DR is used to reduce load forecast	Capacity obligation (or load forecast) may be reduced by capacity value of DR	DR can be offered as capacity supply resource to directly compete with generation
Enabling wholesale market design element or program	N/A	Allow explicit adjustment to load forecast; M&V and qualification mechanism	Allow DR to compete with generation; M&V, qualification, and compensation mechanism
Examples of RTO programs	N/A	PJM has a proposal to allow price-responsive demand to reduce peak load forecast	N/A
Examples of retail programs	Real Time Pricing (RTP) Critical Peak Pricing (CPP) Peak Time Rebate (PTR)		
Comments/notes/ description	Peak load forecast will only be reduced if high-load periods coincide with high-priced periods and response to price materializes	Currently not available in any RTO	Currently not available in any RTO

B.3. Capacity Market Participation: Controllable DR

	Controllable DR		
Type of market participation	No capacity value or direct market participation; DR is used to reduce load forecast	Capacity obligation (or load forecast) may be reduced by capacity value of DR	DR can be offered as capacity supply resource to directly compete with generation
Enabling wholesale market design element or program	N/A	Allow explicit adjustment to load forecast; M&V and qualification mechanism	Allow DR to compete with generation; M&V, qualification, and compensation mechanism
Examples of RTO programs	N/A	**MISO**: Load Modifying Resource (LMR)	**PJM**: DR in RPM; **ISO-NE**: RT DR, On-Peak DR, RTEG in FCM; **NYISO**: Special Case Resources (SCR)
Examples of retail programs	Most controllable DR that can be dispatched during high-load hours	Any controllable DR that can meet RTO qualification requirements	
Comments/notes/ description	DR is not visible to RTO (only through reductions in load forecast)		Most common form of DR participation in U.S. capacity markets

C. AESO DR Programs

1. Load Participation in Energy Market

- Currently DR provides only response to observed market prices without demand bidding

2. Load Participation in Supplemental Reserve Market

- WECC currently restricts DR provision of spinning and regulation reserves

3. Reliability DR Programs

- Load Shed Service (LSS)
- Load Shed Service for Imports (LSSi) – *new; expected operational in Q2 2011*
- Import Load Remedial Action Scheme (ILRAS)
- Voluntary Load Curtailment Program (VLCP)
- Under-Frequency Load Shedding Scheme (UFLS)

4. Other Programs

- Demand Opportunity Service (DOS)

C. AESO DR Programs
1. Load Participation in Energy Market

Energy Market participation is possible either by (1) formally bidding demand into the AESO energy market or (2) simply responding to observed prices

- **Currently, no load participates directly in the AESO energy market by <u>bidding in</u> price-responsive demand bids**
  - Price-responsive demand bidding refers to submitting bids to purchase a given amount of energy only up to a specified price
  - If the market price rises above the specified price, the load is curtailed in response to AESO direction
  - Customer obtain <u>certainty</u> about avoiding purchase of high-priced energy
  - Lack of participation means uncertainty about bidding and compliance rules
- **Some other markets also enable DR to bid load curtailments into the energy market as a supply-side resource.**
  - These programs require uplift or side-payments
  - This option is not currently available in AESO

C. AESO DR Programs
1. Load Participation in Energy Market (cont'd)

- **There is evidence of price response based on observed energy market prices (i.e., <u>without bidding</u> demand into the AESO market)**
  - AESO has identified six Price Responsive Loads (PRL) where a strong correlation between market price and energy use can be observed
  - These customers voluntarily reduce loads when prices increases
  - Given the design of the AESO's ex-post energy market, PRL respond to observed prices
  - Combined consumption of identified PRL is approximately 200 MW
- **We also found that some DR service providers have created real-time price-response capability for smaller customers**
  - One third-party DR provider stated that they have signed up 45 MW of price-responsive load
  - Therefore total voluntary price responsive load is likely to be higher
- **Main barrier for broader participation: fixed monthly retail tariffs by retail service providers**
  - Unclear whether any of the incumbent retail suppliers offer DR service options

C. AESO DR Programs
1. Participation in Energy Market – Savings Potential

Meaningful savings are available for price responsive load.

Scenario A
Flat consumption pattern; 1 MW consumed in every hour of the year

Scenario B
Customer consumes no energy in hours when current-hour pool price > $200; consumes 1 MW in all other hours. Customers can perfectly predict pool price.

Scenario C
Customer curtails load when previous-hour pool price > $200; consumes 1 MW in all other hours. Customer assumed current-hour pool price will be the same as previous-hour pool price. (Does not take advantage of within-hour pool price information.)

Year	Annual Average Price *($/MWh)*	Avg. Bill Reduction A vs. B *(%)*	Avg. Bill Reduction A vs. C *(%)*	Avg. Rate Reduction A vs. B *($/MWh)*	Avg. Rate Reduction A vs. C *($/MWh)*	# Hours > Threshold *(%)*	Avg. Price > Threshold *($/MWh)*	Avg. Price < = Threshold *($/MWh)*
2001	$71.3	-15%	-12%	-$8.1	-$6.3	3.9%	272.5	63.1
2002	$43.9	-18%	-11%	-$7.1	-$4.1	1.8%	423.0	36.8
2003	$63.0	-21%	-12%	-$11.2	-$5.4	4.0%	334.4	51.8
2004	$54.7	-12%	-6%	-$5.5	-$2.3	2.0%	325.1	49.1
2005	$70.4	-25%	-17%	-$15.0	-$8.9	5.3%	340.3	55.4
2006	$80.8	-39%	-30%	-$27.7	-$19.5	7.4%	428.2	53.1
2007	$67.0	-29%	-21%	-$17.5	-$11.4	4.4%	450.8	49.5
2008	$90.1	-38%	-30%	-$30.0	-$22.6	7.2%	476.8	60.1
2009	$47.8	-22%	-17%	-$9.9	-$7.2	2.0%	528.9	37.9
2010	$51.2	-30%	-24%	-$13.9	-$11.1	3.1%	471.8	37.3
2001 -2010 Total		***-26%***	***-19%***	***-$14.6***	***-$9.9***			

- **Given the pool prices for the past 10 years, potential savings for a customer (with perfect-foresight) who curtails whenever current-hour pool price rises above $200/MWh would have been 26% relative to the baseline (Scenario A)**
- **Fast response is needed because many price spikes last only one hour**
- **If the customer responded with significant delay (e.g., to the previous-hour pool price), the savings would be only three quarters of that (19%)**
- **Consistent with a DR provider's claim of 18-33% of annual savings**

C. AESO DR Programs
1. Participation in Energy Market – Savings Potential

On-Peak Hour Scenarios

A: Consume every on-peak hour

B: Consume every on-peak hour, except when current-hour price > $200

C: Consume every on-peak hour, except when previous-hour price > $200

Year	Annual Average Price *($/MWh)*	Avg. Bill Reduction A vs. B *(%)*	Avg. Bill Reduction A vs. C *(%)*	Avg. Rate Reduction A vs. B *($/MWh)*	Avg. Rate Reduction A vs. C *($/MWh)*	# Hours > Threshold *(%)*	Avg. Price > Threshold *($/MWh)*	Avg. Price < = Threshold *($/MWh)*
2001	$84.4	-19%	-15%	-$11.6	-$8.6	3.1%	279.4	72.8
2002	$55.9	-20%	-12%	-$10.0	-$5.3	1.5%	421.1	45.9
2003	$76.2	-25%	-14%	-$15.3	-$6.7	3.1%	337.4	60.8
2004	$65.2	-14%	-8%	-$7.7	-$3.3	1.6%	328.8	57.5
2005	$87.9	-30%	-20%	-$20.9	-$12.5	4.3%	339.0	66.9
2006	$105.3	-46%	-35%	-$41.3	-$28.5	6.3%	433.1	64.0
2007	$86.3	-34%	-23%	-$25.5	-$15.7	3.7%	447.0	60.9
2008	$117.6	-46%	-37%	-$46.1	-$34.8	6.2%	489.1	71.5
2009	$61.2	-29%	-22%	-$16.0	-$12.0	1.8%	542.6	45.2
2010	$66.1	-36%	-29%	-$21.6	-$17.1	2.7%	476.4	44.5
2001 -2010 Total		***-32%***	***-23%***	***-$21.6***	***-$14.4***			

Off-Peak Hour Scenarios

A: Consume every off-peak hour

B: Consume every off-peak hour, except when current-hour price > $200

C: Consume every off-peak hour, except when previous-hour price > $200

Year	Annual Average Price *($/MWh)*	Avg. Bill Reduction A vs. B *(%)*	Avg. Bill Reduction A vs. C *(%)*	Avg. Rate Reduction A vs. B *($/MWh)*	Avg. Rate Reduction A vs. C *($/MWh)*	# Hours > Threshold *(%)*	Avg. Price > Threshold *($/MWh)*	Avg. Price < = Threshold *($/MWh)*
2001	$54.6	-8%	-7%	-$3.3	-$2.9	0.8%	243.5	51.3
2002	$28.7	-12%	-9%	-$3.3	-$2.3	0.4%	431.2	25.4
2003	$46.2	-14%	-9%	-$5.5	-$3.2	0.9%	323.3	40.7
2004	$41.1	-7%	-3%	-$2.6	-$0.9	0.4%	310.8	38.6
2005	$48.0	-16%	-10%	-$6.6	-$3.6	0.9%	346.5	41.4
2006	$49.7	-20%	-17%	-$9.1	-$6.8	1.1%	400.8	40.6
2007	$42.2	-17%	-14%	-$6.6	-$5.3	0.7%	472.0	35.6
2008	$55.0	-17%	-13%	-$8.1	-$5.5	1.0%	400.7	46.9
2009	$30.7	-6%	-3%	-$1.8	-$0.8	0.2%	408.5	28.9
2010	$32.1	-12%	-11%	-$3.7	-$3.1	0.4%	439.0	28.5
2001 -2010 Total		***-13%***	***-10%***	***-$5.0***	***-$3.4***			

C. AESO DR Programs
2. Load Participation in Supplemental Reserve Market

Active DR participation in the AESO supplemental reserve market

- Current participation is approximately 60 MW, representing 2-3 resources
- DR provides on average approximately 10% of the AESO's supplemental reserve requirement
- Loads providing supplemental reserves must be able to curtail within 10 minutes
- Loads providing supplemental reserves cannot participate in LSS, ILRAS, or LSSi
- AESO has indicated that more load participation in the supplemental reserve market could be accommodated

♦ **Currently WECC standards do not allow participation by DR in the other AESO ancillary service markets (regulation and spinning reserves)**

- However, this is expected to change since FERC has ordered WECC to revise the standard so that DR participation is explicitly allowed
- This will likely increase DR participation in the ancillary services market
- For example, ERCOT (which until recently had a similar market design) has half of its spinning reserve requirement provided by DR (the maximum allowed)

C. AESO DR Programs
3. Reliability DR Programs

AESO reliability DR programs serve one or two very specific purposes:

- ♦ **Supporting and/or restoring available import capability**
  - The Alberta-British Columbia interconnection ("BC interconnection") is a key intertie for Alberta, but it is currently restricted to operate below its rated import capacity for reliability reasons
  - Available Transfer Capacity (ATC) for imports is currently 700 MW, significantly below its rated capacity of 1,200 MW
  - AESO is required to restore the Available Transfer Capacity (ATC) on existing interties to their rated capacities to ensure an adequate supply of electricity to Alberta
  - AESO has been using existing DR products to support the import capability (LSS, ILRAS)
  - LSSi , a new DR product, will also be used to support the import capability on the BC interconnection. AESO's goal is to replace LSS and ILRAS with LSSi.
- ♦ **Managing supply shortfall events**
  - Such events occur when insufficient energy is offered to serve internal AESO load
  - Curtailing loads helps restore the generation-load balance. Some loads (e.g., LSS) automatically trip when system frequency drops.
  - VLCP is the only reliability program that is exclusively used during supply shortfalls

C. AESO DR Programs
3. Reliability DR Programs: Load Shed Service (LSS)

LSS is primarily used to support the import capacity on the BC interconnection

- **Curtailment of LSS loads occurs either:**
  - **Automatically** when system frequency drops below 59.5 Hz (which is typically the result of a large transmission or generation contingency event); or
  - **Manually**, dispatched by AESO to support imports when the system frequency does not drop below 59.5 Hz.
- LSS is procured through an RFP process.
- LSS loads are not allowed to concurrently provide ancillary services (supplemental reserves), but they are allowed to be price-responsive.
- **Current Level of Participation**: 150 MW
- **Compensation of LSS:** fixed per-MW availability payments (as specified by non-public LSS contracts between AESO and the provider)
- AESO and its market participants have recently explored options to further increase the ATC on the BC interconnection using an armable LSS-like product *(see LSSi on next slide)*

C. AESO DR Programs
3. Reliability DR: Load Shed Service for Imports (LSSi)

LSSi, a new armable load shed service, was identified as one of the ways to restore the ATC for imports to the rated capacity on the BC interconnection

- LSSi is intended as a "non-wires" solution to address congestion problems
- LSSi loads are armed and disarmed by AESO
- LSSi loads must comply with the same requirements as LSS and ILRAS (as specified in OPP 312; and also with the proposed ISO Rule 303.1 when it comes into effect)

♦ **Curtailment of LSSi loads occurs automatically**:

- Curtailment must occur within 0.2 seconds (12 cycles) of the frequency reaching 59.50 Hz (+/- 0.02 Hz);

♦ **Expected Level of Participation:**

- LSSi will be procured through an RFP process in early 2011
- Based on the responses to its recent Request for Expression of Interest, AESO received an expression of interest from 800 MW of load; it expects that at least 300-400 MW will participate

♦ **Compensation** consists of three components:

- **Availability payment -** for making resource available for arming; $5/MW;
- **Arming payment** – for hours when the resource is dispatched in armed state; arming price is specified in the LSSi bids;
- **Tripping payment –** for hours when actual curtailment occurs; $1000/MW

C. AESO DR Program
3. Import Load Remedial Action Scheme (ILRAS)

ILRAS is a legacy DR product (originally implemented by TransAlta in 1998; now provided by Fortis)

- ILRAS has been used by AESO **to support import capacity over the BC interconnection**
- ILRAS is an **armable** service that allows loads to be tripped when the intertie becomes unavailable under high import conditions
  - ILRAS is **only armed when AESO anticipates a supply shortfall**
  - Load breakers are tripped by relay should the intertie trip with high imports
  - ILRAS may not be available under certain conditions (high wind speeds, lightning activity in the area, increased risk to equipment damage, personnel or public safety)
- **Current Level of Participation**: 200-400 MW
- **Compensation of ILRAS:** fixed per-MW availability payments to wires company
- AESO goal is to replace ILRAS with LSSi (provider also wishes to discontinue the service)

C. AESO DR Programs
3. Voluntary Load Curtailment Program (VLCP)

VLCP was first implemented in 1998. Program is voluntary. Participants agree to be curtailed prior to firm load reductions.

- VLCP is used in supply shortfall procedures when the system is operating under **OPP 801 (Supply Shortfall) protocol**
- VCLP loads are dispatched manually (via phone) in Step 23 of OPP 801 with a minimum 1-hour notice
- Current VLCP is an out of market mechanism to balance supply and demand (under OPP 801), but the AESO has indicated that it is open to exploring ways to bring voluntary load curtailment into the market (provided there is sufficient interest from loads to justify developing the product)
  - AESO has identified a need for up to 400 MW of voluntary load curtailment
- **Current Level of Participation**: negligible
- **Compensation**: payments are made only for hours when resource is dispatched (based on monthly contract with AESO)

C. AESO DR Programs
3. Under Frequency Load Shedding (UFLS) Scheme

UFLS refers to load curtailments by system operator to avoid uncontrollable system reliability events. Because it is involuntary, we do not consider it to be a form of "demand response."

- **NERC and the WECC require** all transmission regions **to implement a coordinated automatic UFLS** program to help preserve system security during major system frequency events
  - Not used for transmission-related curtailments
- **The purpose of UFLS program is to**:
  - Minimize the risk of total system collapse
  - Protect generating equipment and transmission facilities against damage
  - Provide for equitable load shedding (interruption of electric supply to customers), and help ensure the overall reliability of the interconnected systems
- **Roughly half of all AESO load** is available for instantaneous shedding under UFLS
- There is **no compensation** for UFLS end-use curtailments (although wires companies receive a credit through the transmission tariff)

C. AESO DR Programs
4. Other DR: Demand Opportunity Service (DOS)

DOS is a temporary, interruptible class of transmission service that allows loads to increase demand in excess of the customer's contracted capacity for firm transmission service:

- There are **three options** available under DOS:
  - Term (excess load must be curtailed within 7 minutes)
  - 1-hour (must be curtailed within 1 hour)
  - 7-minute (must be curtailed within 7 minutes)
- If system conditions require (e.g., supply shortfall or transmission constraints), **AESO may curtail DOS loads**. Curtailment (prior to firm load shedding) is performed in the following order:
  - 7-minute DOS load (first)
  - 1-hour DOS load
  - Term DOS load (last)
- Restoration of DOS loads after curtailment is done in the reverse order
- **Current Level of Participation**: approximately 100 MW

D. AESO Customer Feedback

We conducted focus group meetings with AESO market participants in Edmonton on December 2, 2010 and in Calgary on December 3, 2010. In addition, we have circulated a questionnaire asking for input regarding the role of DR in AESO markets. The following is a high-level summary of market participant comments:

- **There is a perceived lack of policy-level leadership in Alberta;** AESO should take the lead to educate market participants and policy-makers about DR
- **AESO is perceived to view DR only as temporary, reliability resource.** This creates weak long-term incentives for DR development
- **There is a perceived need for policy change:** DR should be looked at from both an operations and a long-term planning perspective
- **Energy-only market design is perceived to discourage DR participation:**
  - Lack of price certainty due to price variability and ex-post pricing
  - Some supply-side services (e.g., Dispatch Down Service, DDS) are not available to DR
  - Bidding demand into the real-time market is perceived to be difficult because most loads can curtail but not ramp back up based on ISO instructions; market participants are unclear about demand bidding rules, compliance requirements, and other obligations
  - It was suggested that load bidding would work better if the dispatch amount remained fixed for one hour (like in other markets or as available for scheduled imports)

D. AESO Customer Feedback (cont.)

- **Ancillary services markets provide very limited opportunities for DR**
  - DR not allowed to provide spinning and regulating reserves under WECC rules; AESO should request an exemption
  - Supplemental A/S market is too small and participation is too limited; unclear how AESO selects between DR and generation resources bidding into supplemental reserves
- **Aggregation should be allowed by AESO**
  - Enables hedging and portfolio management across multiple resources, including possible dispatch of small behind-the-meter backup generators
- **Examples of perceived barriers to DR in AESO markets**
  - Some rules too prescriptive (e.g., requirement to restore/"re-arm" load within one hour after a curtailment is not possible for many loads), unclear, or too complicated
  - Aggregation of multiple resources is not allowed
  - Overall, absence of capacity payments seen as most significant barrier compared to other markets
- **Localized firm load shedding happens too frequently** (is used as an involuntary, uncompensated form of DR)
- **Inactive incumbent retail suppliers**: perceived lack of interest (if not actual disincentive) to offer DR programs as alternatives to fixed-priced retail rates
- **T&D rate structures as additional barrier**: unlike prior to restructuring, non-firm load cannot avoid charges

E.1. Implications for AESO - Overview

Our perspective on the AESO's role in DR:

- DR can play an important role in any market's (including the AESO's) ability to operate in a manner that is "fair, efficient and openly competitive" (FEOC).
  - Though demand response has been addressed in the DOE's 2005 Alberta Electricity Policy Framework and the Provincial Energy Strategy (PES), it appears that one of the limiting factors to achieving efficient levels of economic DR penetration in the Alberta retail and wholesale power market is less guidance by Alberta policy makers and industry regulators compared to other jurisdictions (e.g., FERC and some U.S. state regulators).
- Compared to U.S. RTOs, the AESO is perhaps in a unique position to more actively facilitate efficient DR programs under its dual duties to:
  - Operate a power market that is FEOC and
  - Provide for the safe, reliable and <u>economic</u> operation of the electric system
- Some market participants call for special public policy or regulatory initiatives that would "jump start" demand response by providing payments that go beyond what individual market participants would earn in the existing markets
  - We do not offer opinion as to the desirability of such policies, but examples are: US DOE smart grid funding grants; existing or past ON, CT, MD DR mandates for distribution companies
  - We recommend system operators should facilitate efficient DR participation but not go beyond removing barriers and facilitating DR through market-based mechanisms

E.2. Implications for AESO – Alberta-specific Factors

Fundamental differences between Alberta and other regions have potentially important (but unclear) implications for DR

- Alberta has a much higher load factor than most other markets (~80%)
- Characteristics of Alberta peak demand are different
  - Load peaks in the winter
  - There is little electric heat
  - There is little air conditioning load
- Share of industrial load is higher (~55%)
- Different industry mix (e.g., mining industry with high VOLL)

Special considerations related to AESO's market design

- **Energy-only market design** – does not provide for separate capacity payments directly from AESO although retail suppliers are free to offer capacity payments based on option value of avoided energy purchases (capacity payment associated with enforced resource adequacy requirements are main driver of DR growth in US RTO markets)
- **Ex-post, real-time-only market** – no advance scheduling; no price certainty unless demand is bid
- The Fair, Efficient and Openly Competitive (FEOC) market philosophy is interpreted to mean that there should be no market designs provisions specifically and solely for DR

These differences may nevertheless leave significant additional DR potential

E.3. Implications for AESO – Synthesis of Research

- **Our recommendations for AESO were developed using the following inputs:**
  - Our DR experience in U.S. RTO markets and the review of design details for a sample of wholesale DR programs of U.S. RTOs
  - Review of AESO DR programs and market design elements
    - Some market participants have provided input for recommendations regarding specific program design issues, however we were unable to analyze fully the merits of these proposals. Detailed program design was beyond the scope of our assignment.
  - AESO market participant feedback
- **AESO market participants have confirmed that DR has a larger potential role to play in AESO markets**
- **There are lessons to be learned from other RTOs, however not all wholesale DR programs are transferrable to AESO, given differences in:**
  - Market fundamentals (load shape, share and type of industrial load, lack of significant electric heat and A/C load, winter peaking etc.); and
  - Market design – not all types of DR programs are suitable for energy-only markets or consistent with FEOC principles

E.4. Implications for AESO - Lessons from U.S. RTOs

- **Most DR growth has occurred in capacity-type DR programs**
  - Capacity payments compensate emergency-type, dispatchable DR that can be used towards meeting administratively set resource adequacy requirements
  - Payments, which provide a stable revenue stream for DR for up to a year, created a strong financial incentive to offer new DR, most from aggregators who do not supply energy
  - Participants are usually required to respond only in system emergencies or only for a limited number of times per year (e.g., no more than 10 times and only during peak months)
  - Participation in DR programs that only provide an energy payment has declined as resources have been switching to capacity market programs
- **Participation in energy market DR programs**
  - Price-responsive demand bidding is exercised in most day-ahead markets, but it represents a small share of total load
  - Most load curtailments occur in the real-time market; however they are mostly “self-scheduled” (notification provided to RTO) instead of bid in as a market offer
  - Enrollment in supply-side DR program is significant in some RTOs, however actual bidding and curtailments have recently declined with market prices
  - There are a number of controversial program design issues (see next slide)
- **Participation in A/S market DR programs**
  - Significant participation only in a few RTOs (spinning reserve market participation in ERCOT and PJM, and some regulation market participation in MISO)

E.5. Implications for AESO - Key U.S. Controversies

The most controversial design elements in U.S. relate to programs where DR programs offer load reduction as a supply-side resource:

- Since load reductions are "negawatts" (i.e., MWs not consumed), the **RTO needs to create a funding mechanism for payments to DR**
- **Controversy over the amount DR should be paid in energy market in addition to receiving capacity payments**
  - Some argue DR should receive the market clearing price for energy ("LMP"), same as generation
  - Others argue paying DR the full LMP, overcompensates it for the load reduction, since the customer have never bought the MW sold back (i.e., saves the avoidable portion of its retail rate by curtailing); consequently, DR should be paid the LMP reduced by the avoided portion of the retail rate
- **Controversial customer baseline load definition and measurement and verification (M&V)**
  - Correct calculation of hypothetical baseline loads for DR customers is critical for value and ultimately the success of supply-side DR programs (simplicity is also important)
  - Skepticism about whether baselines and claimed load reductions are real. There were instances when deficiencies in the baseline methodology created opportunities for gaming (e.g., in ISO-NE)
  - RTOs have been working with the North American Energy Standards Board to develop common M&V standards

Price-responsive DR programs may be preferable to supply-side DR programs because they neither require a separate funding mechanism nor a baseline

A. Overview

B. AESO DR Programs

C. DR Programs by Market Type

D. AESO Customer Feedback

E. Implications for AESO

F. Specific Recommendations for AESO

Appendix: RTO DR Program Descriptions

F. Specific Recommendations for AESO

We have developed a set of recommendations that we believe could enhance the role of DR, as well as, tap into the benefits of DR in AESO markets

- These recommendation solely reflect our views
- All recommendations should be viewed as possible action items for further consideration and evaluation by the AESO and stakeholders
- Our recommendations are not listed in any particular order of priority. The priority of each item will have to be determined.

F. Specific Recommendations for AESO

We offer the following recommendations for further evaluation:

1. Reduce uncertainties related to loads' participation in the ex-post energy market
2. Allow participation by curtailment service providers and resource aggregators
3. Improve customer education and information sharing
4. Recognize and enable unique capabilities of different resource types (both within and across generation and demand response resource categories)
5. Allow participation of DR resources in a broader range of existing ancillary services, including spinning reserves and regulation
6. Explore offering new programs to address emerging system needs
7. Simplify participation in existing and proposed new programs
8. Raise the price cap and consider allowing emergency reserves to set the energy price

F. Specific Recommendations for AESO – Nos. 1 and 2

1. **Reduce uncertainties related to loads' participation in the ex-post energy market**
   - Improve accuracy of the AESO energy price forecast and increase the horizon of the AESO energy price forecast (e.g., 6 to 24 hours out)
   - Clarify, simplify, and explain rules (and benefits) of demand-side bidding option
   - In the longer term, consider decreasing the settlement period for loads (e.g., to 15 minutes)
   - Also explore the possibility of redesigning the ex-post real-time energy market into an ex-ante real-time energy market (e.g., NYISO)
   - Evaluate the possibility and long-term benefits of developing an hour-ahead or a day-ahead energy market (e.g., along with centralized unit commitment as in recent ERCOT market redesign)
2. **Allow participation by curtailment service providers and resource aggregators**
   - Allow aggregation of small DR resources (including behind-the-meter backup generation) so they can
     - Reach minimum size thresholds; and
     - Achieve portfolio benefit of resource/load diversification
   - Most if not all other RTOs allow such aggregation
     - Aggregators have been the source of most new DR and of significant DR innovation in the eastern U.S. RTOs

F. Specific Recommendations for AESO – Nos. 3 and 4

3. **Improve customer education and information sharing**
   - Prepare and/or improve educational materials on how load can participate directly in AESO markets (e.g., a website on DR issues)
   - Educate customers about options on how to participate indirectly (e.g., by explaining role of and posting contact information for curtailment service provider and resource aggregators) (e.g., http://pjm.com/markets-and-operations/demand-response/csps.aspx)
   - Communicate the value proposition of responding to energy market prices (e.g., the fact that customers might save, for example, 20% by reducing load during 3% of highest-priced periods) and participating in ancillary service markets
   - Work with AUC to explain DR role of AESO and Alberta retail suppliers
4. **Enable valuable capabilities of different resource types (both within and across generation and demand response resource categories)**
   - Market design should avoid strong one-size-fits-all approaches; just like different types of generation technologies have unique capabilities and constraints (e.g., different ramp rates and dispatch flexibility), DR resources have unique capabilities and constraints
   - Different resource types should be allowed to compete even if they are not identical
   - The challenge is to develop market designs (e.g., ancillary service products) that do not exclude participation by resources with unique capabilities that are valuable in the market
     - For example, wind-generation-related ramping (or net load following) requirements impose considerable costs on generators and load alike
     - Some resources can provide ramp up (e.g., wind generator) or ramp down (e.g., many loads) capability but not both

F. Specific Recommendations – Nos. 5 and 6

5. **Allow participation of DR resources in a broader range of existing ancillary services, including spinning reserves and regulation**
   - Explore the possibility to obtain exemptions from current WECC restrictions or, alternatively, facilitate changes to WECC policies (e.g., as mandated by FERC Order 740)
   - Examples of DR providing ancillary services in other markets:
     - ERCOT's LaaR (Load acting as a Resource) service, which can provide up to 50% of spinning reserve capability (or 1,150 MW in the roughly 75,000 MW ERCOT market)
     - DR provides a significant amount of spinning reserves in PJM
     - Uniquely among U.S. RTOs, some DR provides regulation in MISO, although most loads provide only supplemental reserves
   - Consider allowing DR resources to compete for TMR and DDS services
6. **Explore offering new programs to address emerging system needs**
   - Similar to current efforts to develop LSSi services to support tie line capabilities, examples of might include:
     - Wind-integration-related A/S (e.g., ramping up or down) to reduce over-reliance on real-time energy market and partially-uncompensated burden on existing resources
     - Emergency curtailment programs to reduce under-frequency load shedding events and increase price elasticity in vertical segment of supply curve (e.g., ERCOT's EILS and other RTOs' programs with dispatch-only payments)
     - Voluntary, alert-based programs that increase awareness of resource shortages and price spikes (e.g., CAISO's "Conserve-O-Meter" or former Enmax "electricity rush hour")

F. Specific Recommendations – Nos. 7 and 8

7. **Simplify participation in existing and proposed new programs**
   - Review DR program designs for ways to simplify them, clarify participation rules, and to remove unnecessary requirements
   - Examples:
     - AESO demand bidding rules unclear or insufficiently specified
     - MISO initially required real-time telemetry for demand-response resource participation in all types of ancillary services; review found this was unnecessary to provide reliable spinning and non-spinning reserves
8. **Consider raising the price cap and consider allowing emergency reserves to set the energy price**
   - Efficient energy-only market designs require that the energy is able to reach the value of lost load (VOLL) for at least a portion of customer loads. The lowest estimates of VOLL are usually for residential customers and tend to be in the $1,500 to $3,000/MWh range
   - Today, scarcity pricing is achieved by setting energy prices equal to the price cap whenever the AESO runs out of energy bids
   - During emergency or shortage events, consider treating emergency DR programs as energy market resources that would set the real-time energy clearing price when dispatched (if energy bid is below price cap)
     - Most RTOs treat emergency DR as an out-of-market resource; however PJM recently filed a proposal with FERC (June 2010) that would allow emergency DR to set the market price of energy during shortage conditions

Appendix: RTO Demand Program Descriptions Criteria for RTO DR Program Selection

- **After an initial review of all existing RTO demand response programs, the following criteria were used to select programs for a more detailed review:**
  - Programs in RTOs with market designs most similar to AESO (e.g., ERCOT prior to the 12/1/2010 implementation of its new nodal market design)
  - Programs that have been in place for several years
  - Programs that have attracted significant participation ("success stories")
  - Programs/proposals that are innovative and have a potential in AESO
- **Our sample of DR programs for a detailed review included 12 programs from 5 U.S. RTOs (listed on next slide)**

Appendix: RTO Demand Program Descriptions
RTO Programs Selected for Detailed Review

RTO	DR Program
ERCOT	Load Acting as a Resource (LaaR)/Load Resource Emergency Interruptible Load Service (EILS)
ISO-NE	Real-Time Price Response Program (RTPRP) Day-Ahead Load Response Program (DALRP) Demand Response in Forward Capacity Market (FCM)
NYISO	Day-Ahead Demand Response Program (DADRP) Special Case Resource (SCR) Emergency Demand Response Program (EDRP)
PJM	Economic Load Response (A/S market) Economic Load Response (energy market) Load Management (RPM)
MISO	Demand Response Resources (DRR)

Appendix: RTO Demand Program Descriptions
ERCOT – Load Acting as a Resource/Load Resource

RTO	**ERCOT**
Program name	***Load Acting as a Resource*** ("LaaR") under ERCOT zonal market design ***Controllable and Non-Controllable Load Resource*** ("CLR" and "Non-CLR") under ERCOT nodal market (after 12/1/2010)
Type of DR	**Controllable DR** (large industrial)
Main facilitating market design elements	Registration, metering, communications, qualification, performance and testing requirements
Description	Eligible to provide Non-Responsive Reserves (10-minute non-spinning reserves) and up to 50% of Responsive Reserves (spinning reserves) and Balancing Energy Service.

- ♦ Approximately 160 resources are registered, providing 2,200 MW of capacity (as of March, 2010).
- ♦ Most participants are large industrial customers that have been providing A/S since prior the creation of the ERCOT market.
- ♦ Most active participation has been in the day-ahead spinning reserve market – LaaRs provide 50% of spinning reserves (usually 1,150 MW) in most hours.
- ♦ LaaRs must have Interval Data Recorder (IDR), real-time telemetry, complete qualification test.
- ♦ In order to provide spinning reserves, LaaRs must be equipped with Under Frequency Relay (UFR) that drop the resource's load automatically when system frequency drops below a pre-specified set point.
- ♦ ERCOT can deploy LaaRs in four ways: (1) automatic trip via UFR, (2) verbal dispatch instruction (VDI) during an emergency event; (3) VDI during a frequency event; (4) VDI to solve localized emergency.
- ♦ LaaR activations in recent years: Up to 4 times/year, usually to solve system-wide events.
- ♦ Compensation is the same as for generators: ancillary service market clearing price.

References: http://www.ercot.com/services/programs/load/eils/index; see also Sections 3, 4, 6, 8 of ERCOT nodal protocols: http://www.ercot.com/mktrules/nprotocols/current

Appendix: RTO Demand Program Descriptions ERCOT – Emergency Interruptible Load Service

RTO	**ERCOT**
Program name	***Emergency Interruptible Load Service*** **("EILS")**
Type of DR	**Controllable DR**
Main facilitating market design elements	Baseline methodology, RFP process and compensation mechanism; evaluation methodology to determine the reasonableness of submitted offers
Description	Load reductions offered to alleviate emergency conditions on the ERCOT grid. EILS is used as a last-resort measure prior to load shedding.

- EILS is procured through RFPs for 4-month contract periods: February-May; June-September; October-January. EILS may be offered for different periods: Business hours during Monday - Friday (excl. ERCOT holidays): 8 AM - 1PM, 1 PM - 4 PM, 4 PM - 8 PM; or non-business hours (all other hours).
- Minimum offer is 1 MW; aggregations are allowed. Maximum total amount of EILS procured for any period is 1,000 MW.
- EILS must shed committed load reduction within 10 minutes after receiving dispatch instructions and maintain load curtailment until resource is released by ERCOT; EILS resources are released after LaaRs are recalled and spinning reserves are restored. EILS resources must be able to curtail within 10 hours after being released from dispatch.
- Resource must have 15-minute interval metering or a statistically valid sample approved by ERCOT; telemetry and under-frequency relay (UFR) are not required. Must have 24x7 operations that can receive the verbal dispatch instruction; dispatch is through the resource's scheduling entity.
- Selected resources receive their own bid as compensation. ERCOT may reject an offer that it determines to be unreasonable (ERCOT has a written process of determining the reasonable of offers).
- EILS was implemented in 2007, following rolling blackouts in the previous year. Due to the initial PUCT minimum participation requirement of 500 MW (no longer in effect), no EILS capacity was procured during the first three contract periods in 2007. By 2010, up to 410 MW of emergency DR was procured under the EILS program.

References: http://www.ercot.com/services/programs/load/eils/index; see also Sections 3.14.2 and 22 (Attachment G) of ERCOT nodal protocols: http://www.ercot.com/mktrules/nprotocols/current

Appendix: RTO Demand Program Descriptions
ISO-NE – Real Time Price Response Program

RTO	**ISO New England**
Program name	***Real-Time Price Response Program (RTPRP)***
Type of DR	**Price Responsive DR; Controllable DR (with economic/price trigger)**
Main facilitating market design elements	Compensation mechanism; measurement and verification methodology; communications interface.
Description	Voluntary curtailments in response to forecasted price during an eligibility window established by the ISO are eligible for compensation.

- Eligibility period is declared on weekdays when the zonal price forecast (day-ahead LMP or LMP from Reserve Adequacy Analysis; RAA) exceeds $100/MWh during hours ending 8 AM through 6 PM.
- Notification is provided via email and posted on the ISO-NE website the night before or the morning of the operating day.
- Participants must have an hourly interval meter.
- Participants do not submit offers directly into the RT energy market. They receive compensation for verified load curtailments during the eligibility period. In order to receive compensation, they must curtail during 2 PM to 5 AM in the winter; during 12 PM to 5 PM in the summer.
- Participants are paid the higher of $100/MWh or the real-time LMP (an ex-post price). There is no penalty for failing to curtail.
- As of December 2009, only about 72 MW of DR was enrolled in RTPRP.
- In 2009, RTRP was activated on 78 days, primarily as a result of high RAA LMPs.
- ISO-NE's market monitor is recommending to exclude RAA LMPs as a trigger for activating RTPRP, arguing that RAA LMP is a poor predictor of real-time energy prices. It recommending the use of DA LMP only.
- RTPRP is set to expire on 6/1/2012. By then ISO-NE and its stakeholders should decide how to integrate price-responsive demand into the ISO-NE energy markets.

References: ISO-NE Manual M-RTPRP/DALRP, Real-Time Price Response and Day-Ahead Load Response Programs; Manual M-RTPRP/DALRP
http://www.iso-ne.com/rules_proceds/isone_mnls/m_rtprp_dalrp_revision_0_06_01_10.doc

Appendix: RTO Demand Program Descriptions ISO-NE – Day Ahead Load Response Program

RTO	**ISO New England**
Program name	***Day-Ahead Load Response Program (DALRP)***
Type of DR	**Price Responsive DR; Controllable DR (with economic/price trigger)**
Main facilitating market design elements	Compensation mechanism; measurement and verification methodology; communications interface; bidding parameters.
Description	Participation in DALRP is voluntary for RTPRP and Real-Time Demand Response (RTDR) participants. DALRP participants submit offers in the DA energy market. If offer clears, response is mandatory.

- DALRP offers specify (a) MW amount (minimum 100 kW); (b) offer price ($/MWh); (c) shut-down cost per curtailment (optional); (d) minimum interruption duration (1-4 hours).
- Maximum offer price: $1000/MWh; Minimum offer price: 11.37 MMBTU*monthly fuel index. The minimum DALRP offer price is published by the ISO prior to the 1st business day of each month.
- DALRP offers are treated like generation offers.
- Deviations from DA schedules are charged/credited at the RT LMP.
- DALRP curtailments occurred on 128 days in 2009.
- DALRP activity significantly declined after ISO-NE made changes to the program to address baseline issues in February 2008, but also due to lower energy prices in 2009.
- DALRP is set to expire on 6/1/2012. By then ISO-NE and its stakeholders should decide how to integrate price-responsive demand into the ISO-NE energy markets.

References: ISO-NE Manual M-RTPRP/DALRP, Real-Time Price Response and Day-Ahead Load Response Programs; Manual M-RTPRP/DALRP http://www.iso-ne.com/rules_proceds/isone_mnls/m_rtprp_dalrp_revision_0_06_01_10.doc

Appendix: RTO Demand Program Descriptions ISO-NE – DR in Forward Capacity Market

RTO	**ISO New England**
Program name	***Forward Capacity Market***
Type of DR	**Controllable DR**
Main facilitating market design elements	Measurement and verification, testing, capacity accounting mechanism; capacity auction.
Description	DR can participate in the Forward Capacity Market (FCM) and, if the resource clears in the capacity auction, receive capacity payments.

- DR (and energy efficiency) is allowed to participate in the Forward Capacity Auction (FCA). If the resources offer clears, they receive the FCA clearing price for one year.
- Rules of FCM define Demand Resources by the way in which they reduce load, not by technology. Demand Resource types include: On-Peak Demand Resources (non-dispatchable DR; must respond during peak hours on business days); (2) Seasonal Peak Demand Resources (weather-sensitive DR; must respond when real-time hourly load is greater than or equal to 90% of the most recent 50/50 system peak load forecast for the applicable season); (3) Real-Time Demand Response Resources (RTDR; dispatchable DR; must respond within 30 minutes); (4) Real-Time Emergency Generation Resources (RTEG; emergency generators with air quality permit restrictions).
- DR participation in FCM is subject to meeting qualification requirements and milestone checks for new projects. Non-performance penalties for DR are comparable to generation.
- Committed resources must respond during emergencies. There is no annual limit on the number of calls, but ISO-NE prepares the Demand Resources Operable Capacity Analysis (DROCA) that provides a system-wide and load zone forecast of potential DR usage prior to the FCA; it gives DR additional information for use during the auction process (FCA is a descending-clock, multi-round auction).
- As of 12/1/2010, 2,681 MW of DR were enrolled in the above four categories, of which 1,222 MW as RTDR; 667 MW as RTEG; 533 as On-Peak DR; and 259 as Seasonal Peak DR.

References: ISO-NE Market Rule 1, Section III.13. http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_sec%2013_14.pdf

Appendix: RTO Demand Program Descriptions NYISO – Day Ahead Demand Response Program

RTO	**New York ISO (NYISO)**
Program name	***Day-Ahead Demand Response Program (DADRP)***
Type of DR	**Price Responsive DR; Controllable DR (with economic/price trigger)**
Main facilitating market design elements	Compensation mechanism; measurement and verification methodology; communications interface; bidding parameters.
Description	DR resource can offer load reductions in a manner comparable to generation offers in the day-ahead energy market.

- ♦ Loads with hourly interval meter are eligible to participate; behind-the-meter generation cannot participate.
- ♦ Minimum bid is 1 MW. Aggregation is allowed, however aggregations must be at least 2 MW.
- ♦ Under DADRP, DR bids load reduction into the day-ahead energy market. In these offers, the DR provider specifies the amount of load reduction, start time, duration, bid price, and curtailment initiation (shut-down) cost.
- ♦ DADRP offers are subject to a floor price of $75/MWh. Offers below this thresholds are rejected.
- ♦ DADRP bids are compared to other supply-side offers, and they are eligible to set the day-ahead market price (Locational Based Marginal Price; LBMP, known as LMP in other markets)
- ♦ If a DARDP offer clears in the day-ahead market, the resource is obligated to curtail. Failure to curtail in real-time results in a penalty that is the higher of the day-ahead and real-time LBMP.
- ♦The amount of actual load reduction is determined by subtracting from the customer baseline load (CBL) the actual real-time (metered) consumption.
- ♦ DADRP was established in 2008, but participation has been small; average cleared volume is small (e.g., only 2.1 MW during the September 2008 - August 2009 period).

References: NYISO DADRP Manual http://www.nyiso.com/public/webdocs/products/demand_response/day_ahead/dadrp_mnl.pdf

Appendix: RTO Demand Program Descriptions
NYISO – Special Case Resources

RTO	**New York ISO (NYISO)**
Program name	***Special Case Resources (SCR)***
Type of DR	**Controllable DR**
Main facilitating market design elements	Measurement and verification, testing, capacity accounting mechanism; capacity auction.
Description	SCR (interruptible load and distributed generation) can sell capacity in the NYISO capacity market; as capacity resources they are obligated to curtail when called.

- Minimum size to participate in the SCR program is 100 kW.
- SCR resources must curtail following a 2-hour notice.
- SCRs are paid the higher of their strike price (max. $500 per MWh) or the real-time LBMP (when curtailed in RT) + zonal capacity prices.
- Current SCR baseline methodology is based on monthly peak loads. NYISO is conducting an evaluation of the baseline methods used for existing SCRs to determine whether they should be revised.
- SCR's availability rates are based on the performance during tests and events.
- SCR resources in New York City can participate in the Targeted Demand Response Program (TDRP) program on a voluntary basis. TDRP, implemented in July 2007, enables the local transmission owner in New York City to dispatch SCR (and Emergency Demand Response Program) resources in blocks smaller than an entire zone.
- SCR is the fastest growing program in NYISO; it represents over 80% of all DR in NYISO (2 GW out of total of 2.4 GW in 2009 SCR participation has grown steadily since 2001, while EDRP participation has gradually declined since 2002, reflecting the fact that EDRP participants switched to the SCR program in order to earn capacity payments.

References: NYISO Installed Capacity Manual, http://www.nyiso.com/public/webdocs/products/icap/icap_manual/icap_mnl.pdf

Appendix: RTO Demand Program Descriptions NYISO – Emergency Demand Response Program

RTO	**New York ISO (NYISO)**
Program name	***Emergency Demand Response Program (EDRP)***
Type of DR	**Controllable DR**
Main facilitating market design elements	Compensation mechanism; measurement and verification methodology; communications interface.
Description	DR program to enroll and compensate DR for load curtailment during emergency conditions.

- Main requirements to participate: minimum size of 100 kW per load zone; ability to respond to NYISO notice within 2 hours; hourly interval meter. Aggregations are allowed; minimum size for aggregated loads is 500 kW.
- NYISO deploys EDRP during emergencies (pursuant to emergency procedures) on a zonal basis.
- EDRP pays for energy during times of emergency, but does not pay for capacity. These resources are paid the higher of $500 per MWh or the real-time clearing price (LBMP).
- EDRP resources are not required to respond; there is no penalty for not responding to NYISO notice to curtail.
- EDRP resources in New York City can participate in the Targeted Demand Response Program (TDRP) program on a voluntary basis (not required to respond). TDRP, implemented in July 2007, enables the local transmission owner in New York City to call EDRP (and SCR resources) in blocks smaller than an entire zone.
- A DR resource can either participate in NYISO's EDRP or SCR program, but not both. EDRP participation has gradually declined since 2002, reflecting that EDRP participants switched to SCR in order to earn capacity payments.
- EDRP participants are allowed to participate in DADRP. If during an emergency the EDRP resource has a cleared DADRP offer in the day-ahead energy market, they receives compensation from DADRP only.

References: NYISO Emergency Demand Response Manual
http://www.nyiso.com/public/webdocs/products/demand_response/emergency_demand_response/edrp_mnl.pdf

Appendix: RTO Demand Program Descriptions
PJM – Economic DR in Ancillary Services Markets

RTO	**PJM**
Program name	***Economic Load Response (A/S market)***
Type of DR	**Controllable DR**
Main facilitating market design elements	Remove any explicit barriers to DR (e.g. DR not defined as a resource that can provide A/S); qualification requirements; measurement and verification.
Description	Program allows DR to compete with generation in the provision of regulation, spinning, and supplemental reserves.

♦ Types of reserves that DR can provide: (1) spinning reserves ("Synchronized Reserves"); (2) regulation; (3) and 30-minute supplemental reserves ("Day Ahead Scheduling Reserves").

♦ Requirements to participate in the spinning reserve market: (a) ability to curtail load within 10 minutes; (b) 1-minute interval metering; (c) minimum 0.5 MW offer; (d) 24-hour All-Call availability.

♦ Requirements to participate in the regulation market: (a) ability to receive and react to PJM regulation control signal; (b) real-time telemetry; (c) five-minute response to assigned regulation; (d) minimum 0.5 MW offer; (e) resource certification and testing requirements.

♦ In order to participate in the day-ahead supplemental reserve market, DR must be (a) able to be dispatched in RT by PJM; (b) 1-minute interval metering, meter information is not required to be sent to PJM in real time (performance evaluation is done after the fact)

♦ DR is not allowed to provide more than 25% of the market requirement for synchronized reserve, regulation and day-ahead scheduled reserve. Payment to DR for each type of reserve in general is the market clearing price.

♦ As of September 2010, 2,400 MW of DR was enrolled in the Economic Load Response Program. There is a significant DR participation in the synchronized (spinning) reserve market: On average 70-80 MW of DR clears; in 12% of hours DR provided all Tier 2 synchronized reserves in 2009 (32% in 2008). A/S payments are now the second largest source of revenue for DR (after capacity payments) in PJM. There is currently little DR participation in the regulation and day-ahead supplemental reserve market.

References: http://www.pjm.com/training/~/media/training/core-curriculum/ip-dsr/dsr-in-the-ancillary-service-markets.ashx

Appendix: RTO Demand Program Descriptions
PJM – Economic DR in Energy Market

RTO	**PJM**
Program name	***Economic Load Response (Energy market)***
Type of DR	**Price Responsive DR; Controllable DR (with economic/price trigger)**
Main facilitating market design elements	Compensation mechanism; measurement and verification methodology; communications interface; bidding parameters.
Description	DR program designed to enable end users on fixed retail rates to offer load reductions as a supply-side resource and to receive compensation as if they were exposed to the day-ahead or real-time market price of energy.

♦ There are three ways to participate: (1) offering load reductions in DA energy market; (2) allowing PJM to dispatch the resource in RT; (3) self-scheduling load reductions (up to 5 minutes prior to curtailment) in RT (notification to PJM is required). Participation in all three options is voluntary (even during emergencies); however cleared DA offers are charged at RT LMP if there is a shortfall. There is no charge for non-performance in RT. Aggregation of multiple loads is allowed.

♦ DR with verifiable load reductions (as measured by the difference between the Customer Baseline Load (CBL) and metered load) receive compensation for the amount of curtailed load at the rate of LMP - (generation + transmission portion of the customers retail rate). Until 2007, there was an incentive payment in place: when the LMP was greater than, or equal to, $75/MWh, DR customers were paid the full LMP. The funds for the incentive payments were collected from all LSEs in the load zone. Load reduction offers may include shut-down cost and minimum downtime. If LMP is not high enough to cover these costs, PJM will make the DR offer whole.

♦ Both enrollment and load reductions have had a decreasing trend since 2007-2008 (annual load reductions decreased from 714.2 GWh in 2007 to 50.7 GWh in 2009; enrollment decreased from around 3,300 MW at the end of 2008 to 2,400 MW in September 2010).

♦ Some of the factors identified by PJM's market monitor behind the recent decline in participation and measured load reductions: (1) expiration of incentive payments at the end of 2007; (2) decline in energy prices since 2008; (3) revisions to CBL calculations effective June 12, 2008; (3) and implementation of activity review process effective November 3, 2008.

References: http://www.pjm.com/markets-and-operations/demand-response/dr-reference-materials.aspx
http://www.pjm.com/training/~/media/training/core-curriculum/ip-dsr/pjm-demand-side-response-slides.ashx

Appendix: RTO Demand Program Descriptions
PJM – Demand Response in Capacity Market (RPM)

RTO	**PJM**
Program name	***Load Management***
Type of DR	Dispatchable DR
Main facilitating market design elements	Measurement and verification, testing, capacity accounting mechanism; capacity auction.
Description	Allows DR to participate in the RPM forward capacity market and to compete with generation in meeting the resource adequacy requirement.

♦ Load Management (LM) includes DR that can respond during emergencies and sell capacity in RPM (implemented in 2007). To qualify as LM, DR must be able to curtail up to (a) 10 times a year; (b) maintain load reduction for up to 6 hours; and (c) implement curtailment within 2 hours.

♦ Demand Resources (part of LM) participate directly in RPM forward capacity auctions (three years prior to delivery). For the first few delivery years, DR could also participate without making a forward commitment, as Interruptible Load for Reliability (ILR). ILR could be certified up to 3 months prior to delivery and did not have to participate in the RPM forward capacity auctions. In most other respects, ILR and DR were subject to the same requirements, and usually received the same compensation. The ILR option was eliminated starting with the 2012/2011 delivery year.

♦ Demand Resources may be existing and planned capacity. Committed planned capacity is subject to milestone reviews. Committed DR capacity is subject to testing. There is a penalty for failing a test and for not meeting the capacity obligation by the delivery year.

♦ In order to participate in RPM, DR must be registered in PJM's Emergency Load Response Program, either under the "Capacity Only" option or the "Full" option. Under the "Full" option, DR receives energy payments when dispatched during emergencies.

♦ DR committed in RPM receives the capacity auction clearing price for one (delivery) year. Capacity payments have been the primary source of revenue for DR in the PJM market (as much as 98% of all market revenues for DR in 2009).

♦ DR participation in RPM has been steadily increasing. In the last RPM forward capacity auction, approximately 9,300 MW of DR cleared for the 2013/2014 delivery year.

References: PJM Manual 18 http://ftp.pjm.com/~/media/documents/manuals/m18.ashx

Appendix: RTO Demand Program Descriptions Midwest ISO – Demand Response Resources (DRR)

RTO	**Midwest ISO**
Program name	***Demand Response Resource*** (resource type, not a formal program)
Type of DR	**Price Responsive DR; Controllable DR (with economic/price trigger)**
Main facilitating market design elements	Current design: resource type definitions, bidding parameters. Proposed design: compensation and M&V mechanism.
Description	Allows DR to participate in the energy and ancillary services markets. DRRs can also be nominated as capacity resources (counted towards the resource adequacy requirement).

♦ There are two types of DRRs: Type I – resource capable of supplying energy or contingency reserves through physical load interruption; and Type II – resource capable of supplying energy, contingency and regulating reserves through behind-the-meter generation or controllable load. DRR Type II may provide energy, capacity, and all types of ancillary services. DRR Type I is not allowed to participate in the regulation market, but can provide energy and other types of ancillary services.

♦ DRR offers may include: (a) hourly curtailment price; (b) shut-down price; (c) offer price for each product (e.g. energy, spinning reserves, etc.). DRR offers are treated in the same manner as generator offers. Cleared DRR energy offers receive the same compensation as generators: day-ahead or real-time LMP for energy, or the A/S market clearing price. DRR offers are eligible for make-whole (Revenue Sufficiency Guarantee) payments.

♦ Currently third-party aggregators are not allowed to participate as DRR; in order to submit DRR offers, offeror must have baseline load, which restricts participants to LSEs and direct wholesale customers. In October 2009, MISO submitted a proposal to FERC that would allow third-party aggregators, establish an M&V and compensation methodology. MISO proposed to pay DRR LMP reduced by the customers retail rate (Marginal Forgone Retail Rate; MFRR). FERC has not yet responded to MISO's proposal.

♦ Participation in the energy and A/S market has been modest. Most DRR participates as DRR Type I. Uniquely among RTOs, MISO has a DRR Type II resource that provides regulation (approx. 20 MW)

References: MISO Demand Response Primer and Training Guide; https://www.midwestiso.org/Library/Repository/Project%20Material/Project%20Documentation/Demand%20Response%20Training%20Guide_April2010.pdf

List of Acronyms

A/S	ancillary service
AESO	Alberta Electric System Operator
ARC	aggregator of retail customers
ATC	available transfer capacity
BC	British Columbia
CAISO	California Independent System Operator
CBL	customer baseline load
CLR	Controllable Load Resource
CPP	critical peak pricing
DA	day-ahead
DADRP	Day-Ahead Demand Response Program
DALRP	Day-Ahead Load Response Program
DDS	Dispatch Down Service
DLC	direct load control
DOE	Department of Energy
DOS	Demand Opportunity Service
DR	demand response
DRR	Demand Response Resource
EDR	Emergency Demand Response
EDRP	Emergency Demand Response Program
EILS	Emergency Interruptible Load Service
ERCOT	Electric Reliability Council of Texas
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FEOC	Fair, Efficient and Openly Competitive
FERC	Federal Energy Regulatory Commission
GW	gigawatt
ILC	indirect load control
ILR	Interruptible Load for Reliability
ILRAS	Import Load Remedial Action Scheme
ISO	independent system operator
ISO-NE	ISO New England
LBMP	Locational Based Marginal Price
LMP	locational marginal price
LMR	Load Modifying Resource
LSE	load serving entity
LSS	Load Shed Service
LSSi	Load Shed Service for Imports
M&V	measurement and verification
MISO	Midwest ISO
MMBTU	million British Thermal Units
MW	megawatt
MWh	megawatt-hour
Non-CLR	Non-Controllable Resource
NYISO	New York ISO
OPP	Operating Policies and Procedures

List of Acronyms (cont.)

PES	Provincial Energy Strategy
PG&E	Pacific Gas and Electric Company
PRD	price responsive demand
PRL	Price Responsive Load
PTR	peak time rebate
RAA	Reserve Adequacy Analysis
RFP	request for proposals
RPM	Reliability Pricing Model
RT	real-time
RTDR	Real-Time Demand Response
RTEG	Real-Time Emergency Generation Resource
RTO	Regional Transmission Organization
RTP	real-time pricing
RTPRP	Real-Time Price Response Program
SCR	Special Case Resources
TDRP	Targeted Demand Response Program
TMR	Transmission Must Run
UFLS	Under-Frequency Load Shedding Scheme
UFR	Under Frequency Relay
VDI	verbal dispatch instruction
VLCP	Voluntary Load Curtailment Program
WECC	Western Electricity Coordinating Council

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