STATE OF RHODE ISLAND
ENERGY EFFICIENCY & RESOURCE MANAGEMENT COUNCIL

MEETING AGENDA

Thursday, June 9, 2016
3:30 PM - 5:30 PM
Conference Room B, 2nd Floor, Department of Administration
One Capitol Hill, Providence, RI

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1. **Call to Order**

2. **Approval of May Meeting Minutes**

3. **Executive Director Report (10 min)**
   a) *Executive Director Transition*
   b) *New Member Appointments*

4. **Executive Committee Report (10 min)**
   a) *EM&V Presentation at July Meeting*
   b) *Finance Update*

5. **Policy and Planning Issues (35 min)**
   a) *Update on Synapse Contract for Demand Response Consulting Services (20 min)*

Doug Hurley of Synapse Consulting will present initial findings on demand response issues related to Rhode Island.

   b) *Savings Targets Process Update (15 min)*

The consultant team will update the Council on the savings targets development work including reviewing an updated schedule. The Council will be asked to support adjusting the schedule to align with the process of updating the Least Cost Procurement Standards.

6. **Updates on Energy Efficiency Programs and System Reliability Procurement (30 min)**
   a) *Presentation on Energy Codes Work (30 min)*

Eric Beaton of National Grid and Becca Trietch of the Office of Energy Resources will present on recent work related to energy codes in Rhode Island, including the Codes Compliance Enhancement Initiative and stretch code development.

7. **Council Business**
   a) *Vote on Allocating Funds for Council Member Education "Retreat"*

8. **Public Comment**

9. **Adjournment**

STATE OF RHODE ISLAND
ENERGY EFFICIENCY & RESOURCE MANAGEMENT COUNCIL

MEETING MINUTES

Thursday, June 9, 2016 | 3:30 PM - 5:30 PM

Conference Room B, 2nd Floor, Department of Administration, One Capitol Hill, Providence, RI

Members in Attendance: Abigail Anthony, Bob Bacon, Joe Cirillo, Roberta Fagan, Marion Gold, Jennifer Hutchinson, Michael McAteer, Shigeru Osada, Chris Powell, Betsy Stubblefield Loucks, Karen Verrengia, Diane Williamson

Others Present: Eric Beaton, Kat Burnham, Sandra Charves, Tim Faulkner, Mike Guerard, Rachel Henschel, Doug Hurley, Mark Kravatz, Courtney Lane, Dino Larson, Stefan Nagy, Jeremy Newberger, Scudder Parker, Paul Ryan, Rob Sherwood, Rachel Sholly, Becca Trietch, Nick Ucci, Belinda Wong, Chon Meng Wong, Muxi Yang

1. Call to Order

Chairman Chris Powell called the meeting to order at 3:30 PM.

2. Approval of May Meeting Minutes

Joe Cirillo made a motion to approve the May meeting minutes. Karen Verrengia seconded and all approved.

3. Executive Director Report

Commissioner Marion Gold reported that the Senate will not approve Kat Burnham as a Council member citing that People's Power and Light does not represent small non-profits. The Legislature is wrapping up and will not be able to appoint an alternative nominee this session, so the Council will be one member shy for the next six months.

4. Executive Committee Report

Chairman Powell reported that the Committee discussed the outline for the evaluation, measurement and verification (EM&V) presentation which will happen at the July meeting. The Committee also discussed the savings targets process, a finance update, and Council member retreat, which will be discussed today.

5. Policy and Planning Issues

a) Update on Synapse Contract for Demand Response Consulting Services

Scudder Parker of the consultant team introduced Doug Hurley of Synapse Energy Economics, who has been contracted by the EERMC to look more deeply at demand response issues in Rhode Island. Mr. Hurley presented initial findings *(see attached)*. Chairman Powell noted that the back-up generation market in the large commercial and industrial (C&I) sector is collapsing because of new regulations requiring zero emission controls. Will that impact capacity prices? Mr. Hurley said that back-up diesel generators that do not have air emissions controls will have a hard time running. At the same time, the cost of new power plants and also air emission controls are coming down. Abigail Anthony asked if Mr.

Hurley was suggesting that the state move forward with implementing DR and then think about how to use it strategically. He said that he is suggesting both, meaning that one of the key drivers should be to grow the demand response market. Ms. Verrengia asked what similar programs exist throughout the country. Mr. Hurley referenced the report in their packets – people have done time of use, home energy reports, in-home displays, direct load control, time of use pricing with and without peak time rebates, etc. Michael McAteer talked about recent relevant work by eSource and IDO and offered to send the link to Mr. Hurley. Mr. Parker added that traditionally, demand response has targeted transmission and distribution constraints. Now we are starting to realize that there are other things that could be used for a variety of purposes throughout the whole system. The challenge is how to get these things into the right hands. Mr. Osada asked what is the total peak load for each sector – what is the potential market. Mr. Hurley was not sure. Knowing this would help to develop a marketing strategy. Mr. Parker said that the key is to figure out how to get people participating and actively learning how to use the system which will result in lower costs, higher participation, and greater impacts down the road.

b) Savings Targets Process Update

The consultant team updated the Council on the savings targets development work including an updated schedule *(see attached)*. No real results yet, but within the next week or so quite a few of the key drivers will be organized in terms of data. The consultant team along with OER met with The Energy Council of Rhode Island (TEC-RI) last week and received some useful information from the large C&I sector. Mr. Parker explained that the consultant team proposes to file the savings targets later in the fall with the filing of the updating of the Least Cost Procurement Standards. Ms. Anthony felt that the adjustment was a good idea, but that the Council should let the Public Utilities Commission (PUC) know when to expect the submission. Jennifer Hutchinson agreed. Mr. Guerard said that a near final draft is expected by November for Council feedback and a final draft will be presented for a vote at the December meeting. The consultant team will draft language to the PUC for the Executive Committee to approve for submission by the Council's attorney.

6. Updates on Energy Efficiency Programs and System Reliability Procurement

a) Presentation on Energy Codes Work

Eric Beaton and Muxi Yang of National Grid and Becca Trietch of the Office of Energy Resources presented on recent work related to energy codes in Rhode Island, including the Codes Compliance Enhancement Initiative and stretch code development *(see attached)*. Chairman Powell pointed out that it is important to understand that with each iteration of new energy codes, stretch codes must be updated to continue to go above and beyond base code. Ms. Anthony asked if buildings that go through a gut renovation have to comply with the newest code. Ms. Trietch said that it depends on how big the renovation is. Ms. Anthony wondered how much new construction is happening and, thinking about savings targets, what slice of the pie is this addressing. Mr. Guerard said that the consultant team has been looking at this and the state is currently at a record low of residential construction in the last 20 years or so. They will try to estimate increases in housing stock and then layer in more progressive codes. Mr. Parker clarified that incentives only apply to those that go above code. Ms. Anthony asked for an update on building labeling. Ms. Trietch reported that OER did not receive the Department of Energy grant for the commercial pilot, but the working groups continue to meet. Additionally, the City of Providence is moving forward with a pilot and OER is looking forward to getting useful data from that. Mr. McAteer asked how the code community has responded to the idea of stretch codes. Ms. Trietch said that there is some push-back, including concerns about cost, which is why it will be voluntary. Chairman Powell shared that at Brown University, lifecycle cost analysis is required, which brings attention to total value versus first cost.

7. Council Business

a) Vote on Allocating Funds for Council Member Education "Retreat"

Mr. Cirillo made a motion to allocate up to $1,000 to fund the member retreat. Ms. Anthony seconded and all approved.

8. Public Comment

There was no public comment.

9. Adjournment

Mr. Cirillo made a motion to adjourn. Bob Bacon seconded and all were in favor. The meeting adjourned at 5:10 PM.

Synapse Energy Economics, Inc.

Memorandum

TO: RHODE ISLAND ENERGY EFFICIENCY AND RESOURCE MANAGEMENT COUNCIL

FROM: DOUG HURLEY AND SPENCER FIELDS

DATE: JUNE 6, 2016

RE: STATE OF DEMAND RESPONSE IN NEW ENGLAND

Demand Response in New England

In May 2013, on behalf of the Regulatory Assistance Project's European Programmes, Synapse published a lengthy paper assessing demand response (DR) in the United States. The Executive Summary of that report describes DR as "the intentional modification of electricity usage by end-use customers during system imbalances or in response to market prices."

While this is true in a broader sense, DR in New England in recent years is primarily the voluntary reduction of electrical usage at small and large commercial or industrial end-use customer facilities during peak load hours[1]. The reduction can happen to avoid charges imposed upon those customers for usage during monthly or annual coincident peak load hours, or as a response to a dispatch signal from an aggregator – or Demand Response Provider (DRP) – who has enrolled in our region's Forward Capacity Market (FCM). Although it feels as if we are forever on the cusp of other types of DR, as of yet we still see little of it a) from the residential sector; b) that increases load to absorb excess renewable generation; or c) for such services as frequency regulation or even real-time energy market prices.

There are a small number of large customers who participate in DR on their own – most notably paper mills and other large industrial facilities in Maine. The majority of end-use customers find it prudent to rely upon the technical expertise, market experience, and financial backing of DRPs to handle the mechanics and risks of DR. This is true when DR is used just to avoid costs, but doubly so when participating in ISO New England's wholesale markets as a capacity resource. In our region the DRPs have focused on customers such as hospitals, universities, and grocery-store chains and other large retail facilities. The DRPs have recognized that their customer's preference is to reduce their load only a few times per year, if possible. As such, aggregation of retail customers in a demand response resource in the wholesale markets is almost exclusively used as a capacity product. In other words, customers have little intention of watching daily energy market prices and responding for revenue on an opportunistic basis. Rather, they are happy to provide response a few times each year if necessary in

[1] This reduction in consumption from the grid is often met by starting small behind-the-meter generation units with air emissions equipment that allows them to meet state-level air permit requirements.

exchange for a known, steady, monthly capacity payment. The DRPs handle the mechanics of combining many retail customers into a single portfolio and managing the dispatch of the group of them to meet the required performance during any one event. This leaves the end-use customer to focus on their business, enjoy the additional electric usage information and management capabilities often provided as part of the service, and receive a monthly check from the DRP. The amount that they receive of that share of the DRP's capacity revenue is private commercial information between those entities, and can vary widely by customer and over time.

Amount of Demand Response

For the first section of this report, we refer to DR as either actual reduction in load on a customer site or on-site generation units that have air emission controls such that they meet relevant state and federal permits. Those who are familiar with ISO-NE terminology will know this as Real Time Demand Response (RTDR). In a separate section below, we discuss on-site backup generation from units that do not have such controls, and are therefore severely limited by their permits to run in a small number of hours.

In the early stages of ISO-NE's forward capacity auctions, the total cumulative amount of cleared DR in the region gradually increased over time, even as the capacity clearing price in each auction was the pre-determined floor price. This dynamic makes sense to some degree – naturally, as DRPs and their customers learned more about how the newly-formed capacity market would function, they became more comfortable with bidding in and ultimately procuring greater and greater amounts of DR capacity. As seen in Figure 1, even with the lowest possible capacity clearing prices in the first five forward capacity auctions (FCAs), DRPs were confident enough to nearly double DR capacity cleared in the market between FCAs 1 and 5, reaching 1,400 megawatts of capacity, or nearly 5 percent of overall system capacity needs by FCA 5.

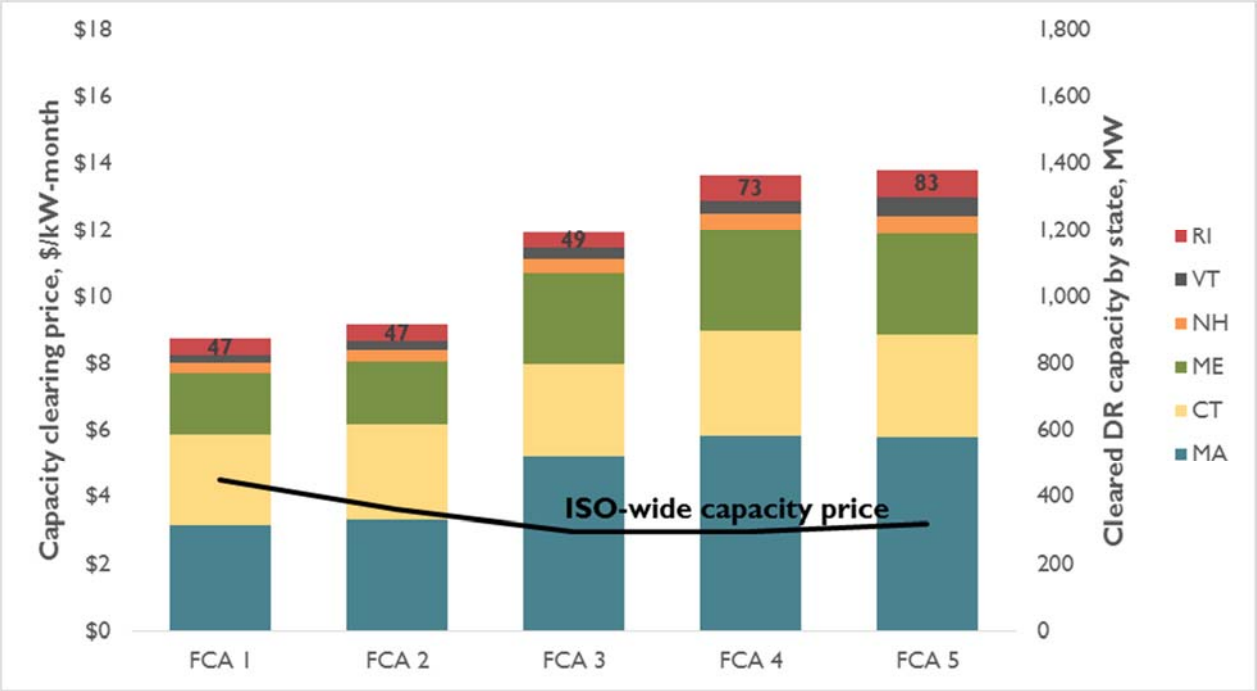
DR in the capacity market is either load reduction, or backup generation with air emission controls, that can response to ISO dispatch instructions when called upon. Under the current FCM rules, DR is dispatched only during ISO-NE's Operating Procedure 4 (OP-4), Action During a Capacity Deficiency. OP-4 is activated rarely, only a few times each year, and DR that has a capacity obligation is only dispatched during some OP-4 events.[2] Several years may pass without a need to implement Action 2 of OP-4, when DR is activated by the ISO-NE. The most recent three such events were in July 2011, July 2013, and December 2013. No such events have occurred since then. Events last a few hours on that day.

While reviewing the figures below, it may be helpful to remember that obligations taken in FCA-1 correspond to delivery in the 12-month period beginning June 1, 2010 and ending May 30, 2011. Each

[2] OP-4 contains several actions ranging from notification of a capacity deficiency by the ISO-NE (Action 1) to a 5% voltage reduction (Actions 6 and 8) and television and radio appeals by the New England Governors for voluntary load reduction (Action 11).

subsequent FCA corresponds to the following 12-month power year. FCA-2 for June 2011 – May 2012, FCA-3 for June 2012 – May 2013, and so on.

Figure 1. Total cleared demand response resources in ISO-NE versus capacity clearing price, FCAs 1-5

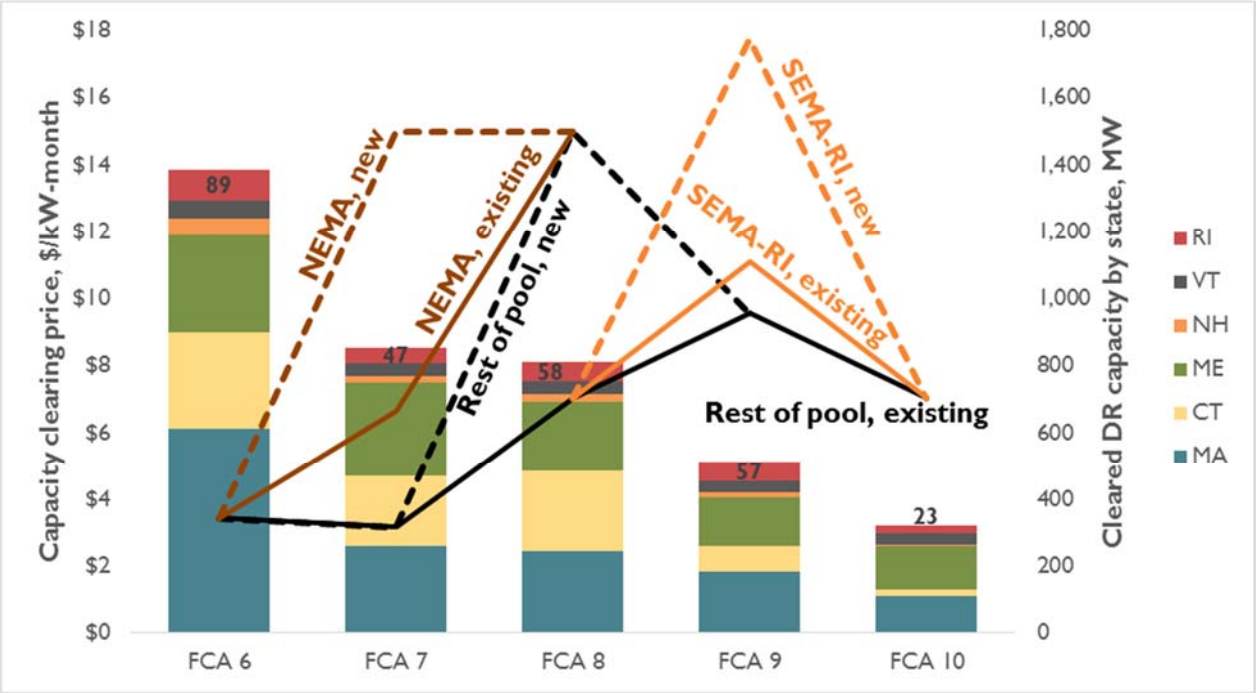


At that point, DR seemed to be ready to respond to any future increases in capacity clearing prices in ISO-NE by clearing even more DR capacity.

Between FCAs 6 and 7, however, this dynamic changed drastically. As seen in Figure 2, DR capacity in New England dropped by nearly 40 percent from FCA 6 to FCA 7 while capacity prices in some regions tripled for new resources and doubled for existing ones. This was largely the result of a combination of increased compliance costs and uncertainty about the future of DR due to court challenges to FERC Order 745, which we will describe in greater detail later. As a result, overall cleared DR capacity has dropped in every auction since FCA 6, with levels at the lowest point ever in FCA 10, a full gigawatt below the peak of cleared DR capacity just five auctions earlier.

The amount of DR we see in each state is roughly proportional to the ratio of peak load for that state, with two major exceptions. While we aren't surprised that Massachusetts has a large share of the DR, with nearly half of the region's peak load, Maine has a larger share than expected because the large paper mills in Maine participate in DR. Connecticut has a larger share than expected because that state had programs in place that had specific incentives for DR beyond those in the other New England states.

Figure 2. Total cleared demand response resources in ISO-NE versus capacity clearing price, FCAs 6-10



Note: Figures 1 and 2 use the same scale on the vertical axes in order to avoid distortion.

Further, it appears that this drop in cumulative installed capacity is primarily a result of the largest aggregator reducing its customer base in the ISO-NE market. Although these market participants have chosen to not explicitly use their names when clearing DR capacity, based on similar naming conventions throughout the auctions it is possible to group various DR capacity into groups by two main DRPs and one "Other" category. The two most active DRPs in New England, in order, have been Constellation[3] and EnerNOC. The "Other" category is comprised of the few large industrial customers that participate on their own, without a DRP, such as the paper mills and BOC Gas in Maine and the Deer Island water treatment plant east of Boston. As seen in Figure 3, the 500 megawatt drop in cumulative DR capacity in ISO-NE between FCAs 6 and 7 came entirely from the largest DRP in the region. This would appear to also be the case in Rhode Island, where the market is dominated by the same major DRP, as seen in Figure 4.

[3] Constellation's DR programs have, over the years, been owned by CPower, Constellation, Exelon, and most recently by a new company that took the CPower name.

Figure 3. Demand response cleared capacity by demand response provider in ISO-NE, FCAs 6-10

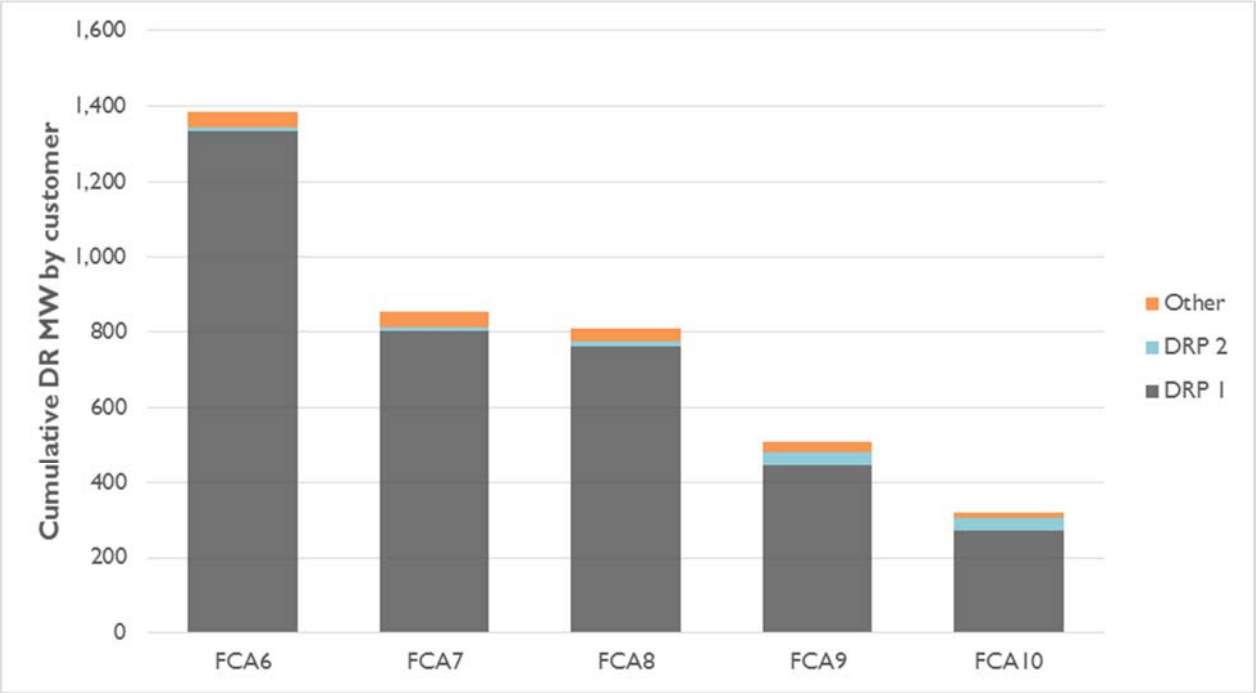
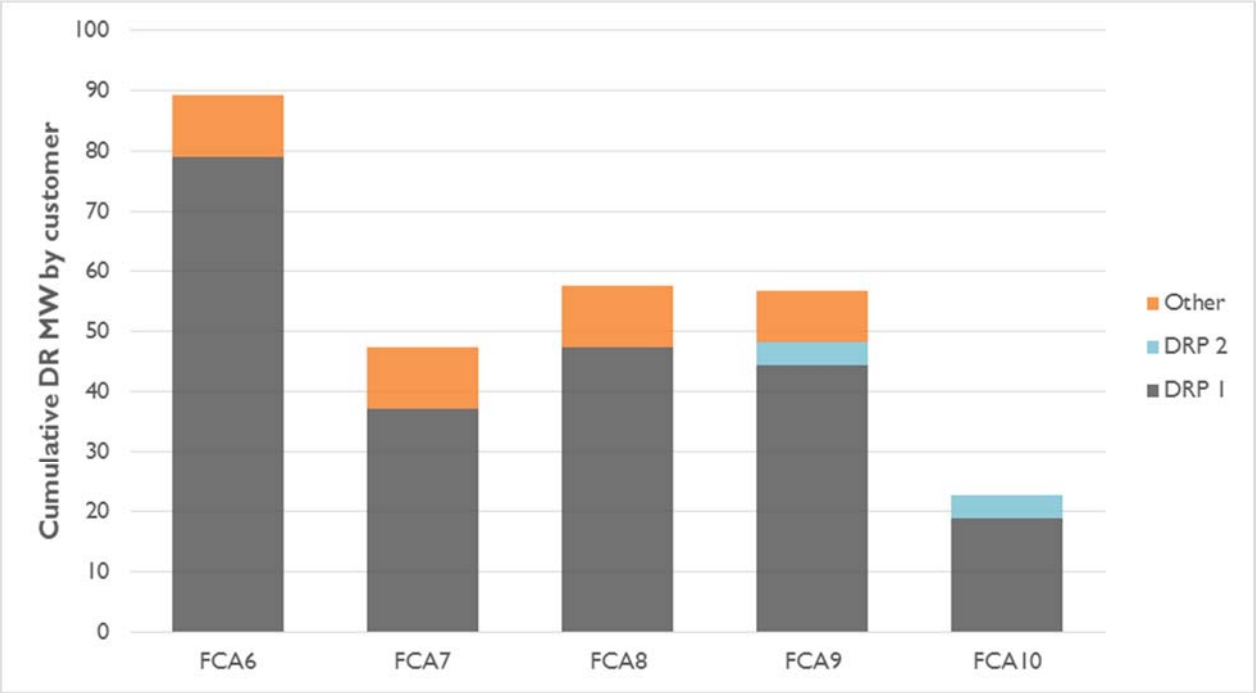


Figure 4. Demand response cleared capacity by demand response provider in Rhode Island, FCAs 6-10



Figures 1-4 show the amount of DR that cleared in each FCA. However, each DRP or individual customer has the opportunity to trade away the obligation that cleared in the FCA through any one of numerous

reconfiguration auctions. On average for commitment periods 1-7, 56% of the total amount of DR capacity that cleared in an FCA is still held by a DRP at the start of the associated commitment period.[4]

Baseline Methodology, Order 745, and Performance Incentives

There is a clear trend for DR in New England in Figures 1 and 2. There was a steady increase for the first four auctions, which covered delivery from June 1, 2010 through May 31, 2014. The amount offered into the FCAs then leveled off for FCA-5 and FCA-6 before dropping sharply in FCA-7 and continuing to decline steadily each year through the most recent auction, FCA-10, which was held in February of this year.

There are three primary reasons for the steady decline which seems counter to rising capacity prices in the same timeframe. The first reason is cost. All demand response, by its nature, is measured by determining the amount of electricity actually consumed during an event and comparing it to a "baseline", the amount of electricity we would have expected that customer to consume on that day, in those hours. Consumption on a hot, humid summer day is likely to be different than on a cool spring day. For certain facilities, normal consumption on a Wednesday might be very different from that on a Friday or Saturday. The methodology for setting and constantly refreshing baselines can be very complicated, and indeed it was. For several years, the major DRPs in New England complained that the baseline methodology required by ISO-NE was much more complicated – and much more expensive to implement – than anywhere else in the country. These additional costs drove them to participate more heavily in other areas of the country (and the world), instead of doing so here. Like any business, DRPs have a limited amount of capital to spend and must do so where it is most fruitful for them. Recently, negotiations have convinced the ISO-NE that the methodology can be changed to one that is more feasible for the DRPs, while still providing a reliable measure of actual response provided. With this change in place, one would expect the amount of DR to rise over the next few capacity auctions.

The second primary reason was a court challenge to FERC Order 745, which was recently decided by the United States Supreme Court.

In March 2011 the FERC issued their Order 745, which mandated that all ISOs and RTOs allow demand response to participate in their wholesale energy markets and that such participation would be paid at the same rate paid to generation participants – the Locational Marginal Price (LMP). Prior to this order's issuance, some regions in the country paid DR at a lower rate, subtracting either the generation portion (G) or the entire retail rate (G&T, for "generation and transmission") from the wholesale energy market payment rate. These alternative payment structures were often called "LMP minus G" or "LMP minus G&T". After a lengthy process, the FERC decided that participation by DR in the wholesale energy market performed the same service to balance load and supply as was being provided by a generator, thus

[4] The Commitment Periods for FCAs 8-10 have not yet begun, and thus we do not yet know the final obligations taken for those years.

warranting equal payment. During hours when the energy market price is high, and thus when DR would most likely participate, the full LMP could be 2-3 times greater than "LMP minus G".

This decision was heavily challenged by many parties, led by the Electric Power Supply Association (EPSA), an industry group of generation owners. EPSA initially prevailed when the court of appeals for the District of Columbia circuit vacated Order 745 in its entirety in May 2014. The FERC chose to challenge this decision to the U.S. Supreme Court. The case was heard in October 2015, and in late January 2016 the highest court overturned the lower court ruling, ending nearly five years of uncertainty over the fate of DR's ability to participate in wholesale markets in the U.S. While Order 745 was specific to energy markets, prohibition from the energy market would have eventually meant prohibition from all wholesale markets. The vast majority of wholesale market revenues for DRPs come from the capacity market.

Over that five-year period the uncertainty had a chilling effect not only on the DRPs, but also on their customers. End-use customers focus on how to run their own business, and are often reluctant to participate in DR programs, and even then are cautious at the outset. If the value of that program varies widely, or is gone entirely, they are unlikely to participate again anytime soon. As a result, although Order 745 is now resolved and baseline costs in New England are now on par with those in other regions, Synapse expects to see a slow, modest rise until participation levels reach those previously achieved.

Concurrent with the first two primary challenges for DR, ISO-NE added a further layer of uncertainty to DR participation in the region. Responding to their own lack of confidence that generation stations – particularly those fired by natural gas that could not procure enough fuel during gas-constrained winter months – the ISO-NE proposed FCM Performance Incentives (FCM PI, also known as "Pay for Performance"). Under FCM PI, all capacity resources face either large financial payments or severe financial penalties based on their ability to provide energy or reserves during shortage conditions. Any amount of payment or penalty is assessed based upon their performance relative to their capacity obligation.[5] While energy efficiency resources are only subject to these payments or penalties during their specific On Peak Demand Resource hours, all other types of capacity resources are subject during any hour of the year. Whether FCM PI is deemed an opportunity for extra revenue or a risk of penalties entirely depends upon that resource's ability to meet their obligation during a shortage condition.

While this was a heavily debated package of changes for all resources, DR stands to feel the impact of the new program more than most. Coincident with the implementation of the FCM PI rules, DR would be subject to a "must offer" rule requiring them to offer the full amount of any capacity supply obligation into the day ahead energy market every day of the year. This change takes effect June 2018, corresponding with FCA-9. Until that time, participation in the energy market is voluntary.

[5] Expected performance is a percentage of capacity supply obligation, as adjusted by several factors including actual load on the system during the shortage conditions.

In order to receive FCM PI payments, and therefore avoid penalties, a capacity resource must be providing either energy or reserves during shortage conditions. So far, DR has been prohibited from participating in the reserves market in New England, though this will change coincident with FCM PI in June 2018. Theoretically DR is a good fit as a reserves resource: DR can respond very quickly (within the 10 minute or 30 minute deadlines) and is usually only asked to respond for short durations. However, the implementation of DR for reserves is untested, and our region's DRPs are understandably unsure that all will go well. This challenge also represents the opportunity to earn reserve payments for those DRPs that participate and perform in those few hours each year when reserves are activated.

Over time Synapse expects DRPs to gradually become more comfortable with the FCM PI rules, the energy market "must offer" rule, and the reserves market, leading to increased participation. Until such a time, however, DR is likely to grow slowly. Given that FCM PI implementation begins June 2018, Synapse expects that, at best, the region will begin to see sharp increases in the amount of DR clearing in FCA-13, to be held in February 2019.

Demand Response in Planning

Aggregators and customers are not the only ones interested in the amount of DR operating in New England. Our regional grid operator, the ISO-NE, has been consistent in their view of DR as a reliable system resource. Our report on Demand Response as a Power System Resource concludes that demand response performs reliably when called upon. The ISO-NE performs several levels of system planning, and here we describe how DR is included in each of three broad categories.

Short Term Planning

The ISO-NE forecasting and planning teams are constantly updating expected system load and available resources on a daily, hourly, and even sub-hourly basis. In this context, the ISO begins forecasting loads for the upcoming season, the upcoming week, on a day-ahead basis, and continually within each operating day. These forecasts can and do rely upon two sets of DR. The first set is any amount of DR that has an obligation to reduce their load based upon participation in the Day Ahead or Real Time energy markets. At present, participation by DR in the energy markets is entirely voluntary, and only a small amount of the DR on the system chooses to do so. However, any amounts that do clear are expected to reduce load according to their dispatch schedule. This planning procedure will not change with the implementation of FCM PI and the "must offer" rule for DR: any amount that clears in the energy markets will be expected to deliver. Any amount that did not clear – their offer price was higher than the clearing price – will not be included in ISO planning.

Additionally, any and all DR that has cleared in the capacity market (Figures 1-2, above) is expected to respond should emergency conditions arise. The specific conditions under which the ISO-NE is permitted to activate DR are written in "Operating Procedure 4 (OP-4), Action During a Capacity Deficiency". Although DR has seldom been activated under OP-4, these amounts are included in daily planning by the ISO.

Capacity Planning

The ISO-NE's capacity market is well-labeled as the Forward Capacity Market, as the procurement for capacity is performed more than three years in advance of the delivery period. For example, FCA-10 was held in February 2016 for a commitment period of June 2019 – May 2020. The forecast of needed capacity in that auction was performed throughout the summer and fall of 2015. As part of that calculation of capacity requirement, the ISO not only forecasts expected peak load in the relevant future year, but also forecasts the expected performance from those capacity resources – including DR – that are already on the system. In the fall of each year, the ISO-NE presents to NEPOOL their assumptions for the capacity procurement amount, including an expected performance rate for existing DR resources. This is analogous to a forced outage rate for generation stations. The assumed performance rate published by the ISO for demand response over the past four auctions is shown in Table 1, below. These values are based upon seasonal audits and/or actual dispatch events during the summer prior to the relevant auction.

Table 1. DR Performance Rates

Auction	Assumed DR Performance Rate	Month of Publication
FCA-10	89%	Sept 2015
FCA-9	88%	Sept 2014
FCA-8	89%	Sept 2013
FCA-7	86%	Aug 2012
FCA-6	83%	Oct 2011

Transmission Planning

On an annual basis the ISO-NE transmission planners look forward ten years to estimate needs for additional transmission projects throughout the region. More detailed studies are performed on certain local areas on a round-robin or as-needed basis, as they are not deemed to be required every year. As it typically takes between five and eight years to design, construct, and begin operation on any major new transmission project, the focus is on the outer years, beyond the 4-year timeframe of FCM planning.

Over this horizon, the ISO-NE has recently begun to include a forecast of future installation of energy efficiency and behind-the-meter solar photovoltaic projects, as both of these will reduce peak load and thus the need for transmission projects to deliver energy from generation stations to end-use customers. However, no such forecast is performed for DR. The ISO-NE assumes that the end-use customers who are the basis for DR resources are free to exit the market, or their contracts with DRPs, at any time. As such, they are not confident that they can rely upon a specific amount of DR for a summer that is five or ten years into the future. To date, they have not been challenged on this assumption, and thus DR is not included in transmission planning procedures.

Distributed Generation

So far we have focused upon the type of Demand Response that is provided by actual reduction in usage by end-use customers, or by on-site backup generation units that have installed emission controls, allowing them to meet air permit requirements.

The capacity market in New England also allows for the participation of Real Time Emergency Generation (RTEG) resources, which are on-site backup generation units whose run hours are limited by their air permits to annual testing and any hour in which the ISO-NE implements a voltage reduction on the system as part of their OP-4 emergency procedures. Figure 5 shows the total amount of RTEG resources that have cleared in each of the ten capacity auctions held so far. In the first few FCAs, RTEG resources started out very strong, with greater participation than DR. Starting with FCA-7, we see a similar trend to the one in Figure 2 for DR, above. The amount of RTEG has dropped off precipitously.

Figure 5. Total cleared RTEG resources in ISO-NE, FCAs 1-10

RTEG resources are almost exclusively provided to the market in the same manner as DR – by DRPs who have the technical expertise and financial resources to help end-use customers. Thus, as one might expect, when we sort out the RTEG amounts by DRP, the pattern across New England and within Rhode Island is similar to what we saw in Figures 3 and 4, above.

Figure 6. RTEG cleared capacity by demand response provider in ISO-NE, FCAs 6-10

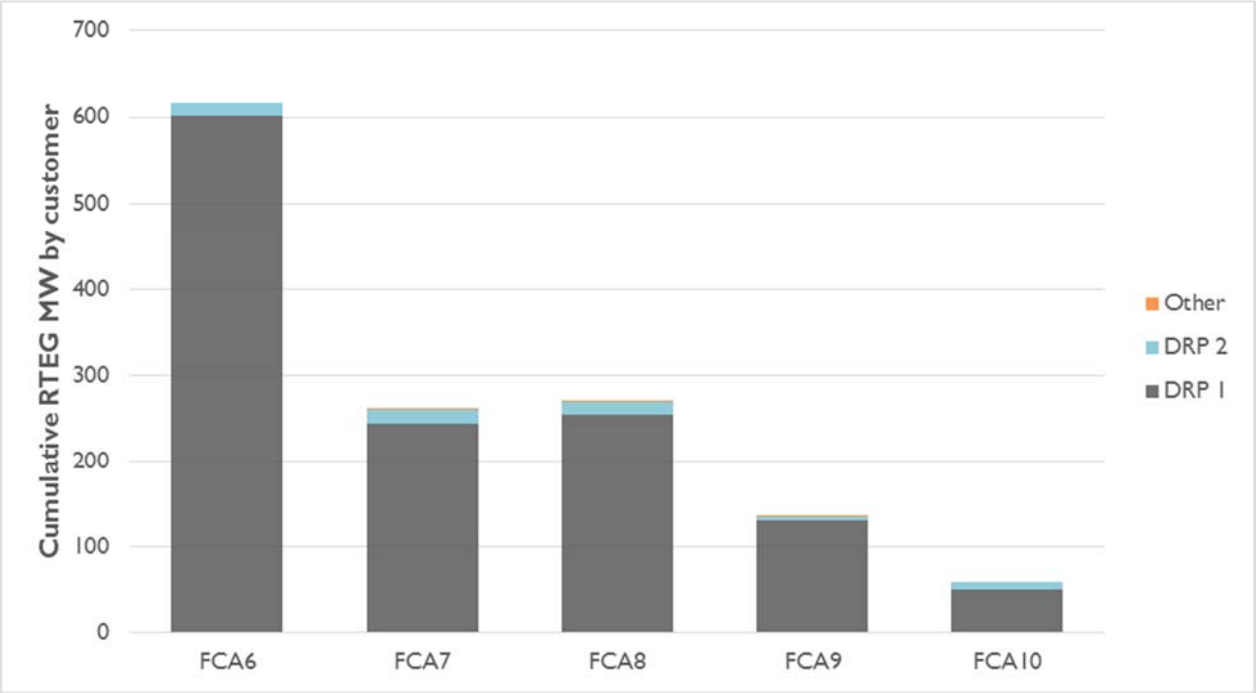
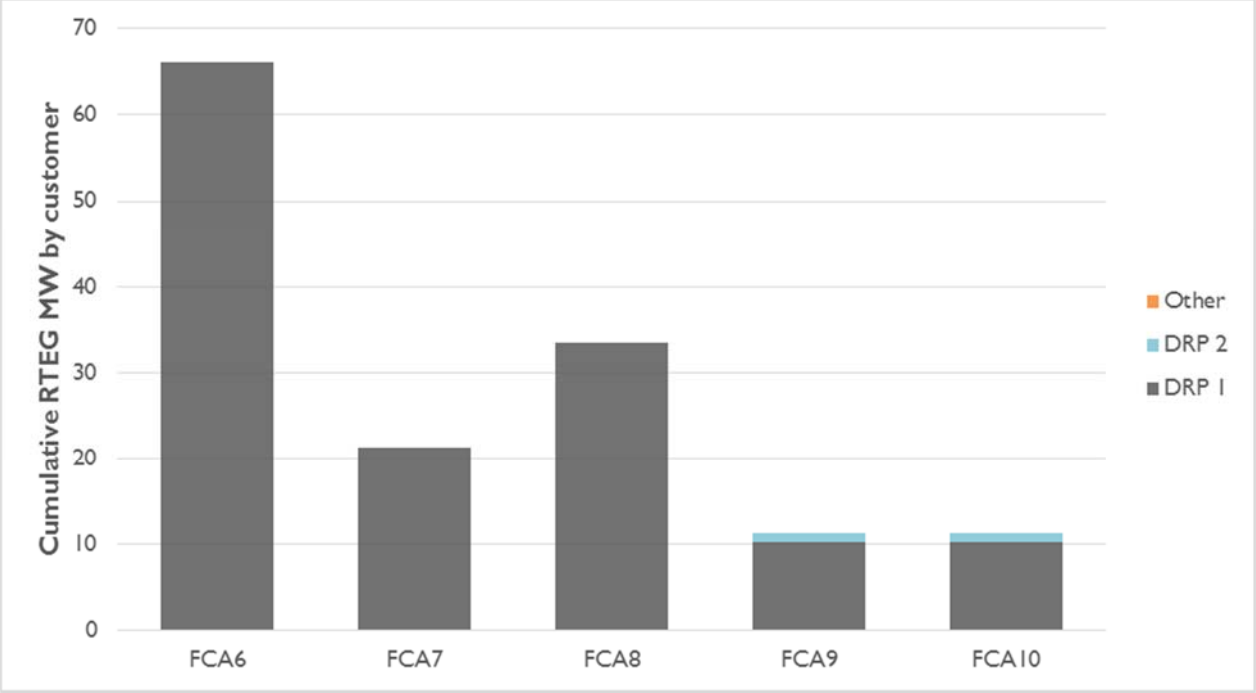


Figure 7. RTEG cleared capacity by demand response provider in Rhode Island, FCAs 6-10



The explanation for the overall pattern of decline in recent years is the same as it was for DR, with a few twists. Whereas the affirmation of Order 745 by the U.S. Supreme Court was a resolution for DR, the coincident changes to FCM PI have effectively eliminated RTEG from this market. Recent rulings and

guidance by the EPA on their Reciprocating Internal Combustion Engine National Emissions Standards for Hazardous Air Pollutants (RICE NESHAPS) provide still further difficulties.

FCM Performance Incentives

Under the package of changes generally known as FCM PI, all capacity resources will be either paid additional amounts or penalized based upon their delivery of either energy or reserves whenever a shortage condition occurs. The payment/penalty rate is steep, initially $2,500/MWh but rising to over $5,000/MWh, and thus provides a very keen incentive. RTEG resources are not allowed to participate in the reserves market, and are restricted by their air permits from providing energy until the ISO declares OP-4 Action 6, a 5% reduction of the nominal voltage on the system. It is unlikely that any shortage condition will actually reach this step. Indeed, RTEG resources have never been dispatched during the FCM era, with the last dispatch occurring on August 2, 2006. If not dispatched, RTEG will face the penalties that are too steep to risk for most providers. FCM PI is an obligation that RTEG resources are essentially prohibited from meeting.

RICE NESHAPS Ruling[6]

Although generally outside the scope of this effort, we will offer a brief overview of this issue. The US EPA recently issued a ruling that would allow certain categories of backup generation units to operate up to 100 hours per year for the purpose of participating in wholesale markets, such as the capacity market in New England. That ruling was challenged by the state of Delaware, and the pertinent sections of the rule were vacated by the U.S. Court of Appeals for the District of Columbia Circuit in May 2015. In a guidance letter issue on April 15, 2016[7] the EPA states that "It is the EPA's view that this change will mean that an engine may not operate in circumstances described in the vacated provisions for any number of hours per year unless it is in compliance with the emission standards … for a non-emergency engine." It is our understanding from initial conversations with ISO-NE staff and DRPs that this ruling effectively eliminates the ability of most RTEGs to meet any obligation they have taken in the FCM.

At this point, DRPs are actively looking to either retrofit customer-sited backup generation so that it can participate as part of a DR resource or trade away the capacity obligations they have taken for RTEG resources. It is unclear how much longer the RTEG category will exist within the FCM rules.

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[6] Reciprocating Internal Combustion Engines National Emissions Standards for Hazardous Air Pollutants

[7] Available at https://www3.epa.gov/ttn/atw/icengines/

Demand Response: Scoping the Opportunity for Rhode Island

June 9, 2016

Providence, RI

Doug Hurley

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Background

- Synapse Energy Economics is a research and consulting firm specializing in energy, economic, and environmental topics.
- Energy Efficiency plan work in several states and Canadian provinces
- Demand Response, Energy Efficiency, and Distributed Generation in wholesale markets since 2006
- Previous career in high-technology industry

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Purpose

- Provide background on current status of DR in Rhode Island
  - Existing Demand Response providers focus on larger customers: chain supermarkets, schools, hospitals, industrial facilities, etc.
  - Wholesale market opportunities are returning with lower costs and higher prices
  - Backup generation will need air emission controls
  - This market sector has a known, proven solution for load reduction.
    - Because customers are known and active, should respond to new types of DR: storage, load shifting, consumption to absorb renewable energy
    - Is there a role to assist Larger C&I customers in finding those partners?
  - Opportunities to explore are the Residential and Small C&I sectors
- Assist EERMC in framing the discussion around DR as part of LCP
  - No clear existing model for success
  - Key drivers
  - Grow the market, anticipate technology adoption rates
  - Making decisions under uncertainty for multi-year planning

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Barriers to EE also apply to DR

- Bounded Rationality
- Lack of Awareness
- Lack of Information and Training
- Lack of Capital or Financing
- Uncertainty and Risk Avoidance
- High Transaction Cost
- Split Incentives

Also apply to Demand Response

- Some barriers greater or lesser depending on customer (size, market, etc.)

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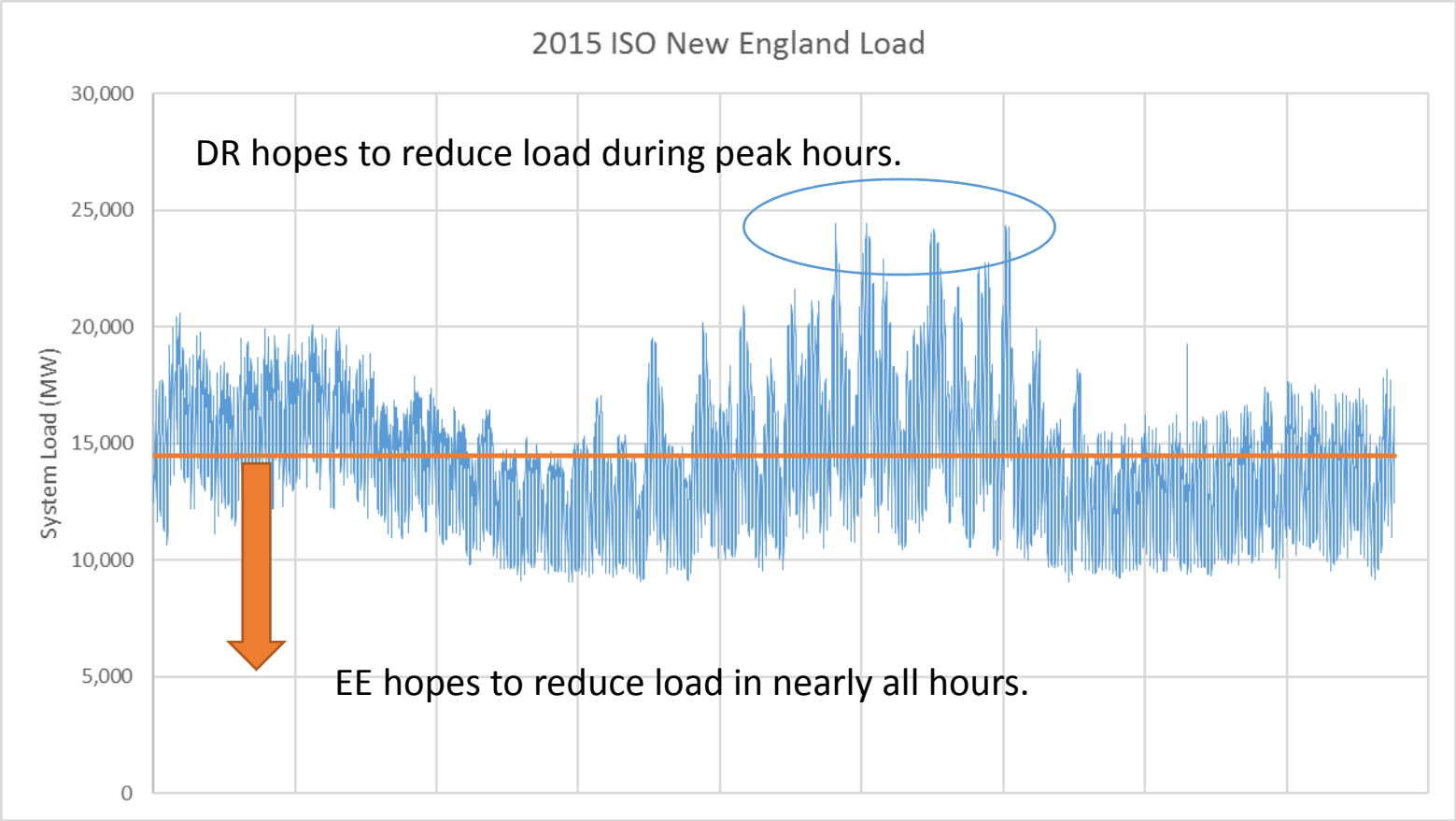
Roles of DR and EE



"Peak hours" can mean many different things, such as New England system coincident peak load, local coincident peak load, high price hours, or something else.

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Lots of Acronyms, No Clear Path

- AMI, TOU, CPP, PTR, DLC – an acronym soup of related activities, all of which are applicable and aimed at mass-market peak load reduction
- This is HARD. Many, many pilots of all of these (and more) around the country. Nobody has figured this out, yet. Pilots emerge, evolve, and find either mixed results or moderate success.
- From Rocky Mountain Institute, May 2016
  - "4%: Just 5 million out of 128 million residential utility customers in the country are enrolled in time-based rates." (p.18)
  - While enabling technology clearly helps, "There is conflicting evidence on the impact of passive technology, but active technology has proven to consistently and significantly improve peak load reduction" (p.42)
  - "Peak Load Reduction: This has been heavily studied. Results show a wide range of impacts, depending on the design of the [time-based] rate."

- James Sherwood, et al. A Review of Alternative Rate Designs: Industry experience with time-based and demand charge rates for mass-market customers. (Rocky Mountain Institute, May 2016), http://www.rmi.org/alternative_rate_designs.

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Drivers

- There can be a long list of drivers for DR at smaller customer sites, including (but not limited to):
  - Reducing peak-related costs for that customer, and for all customers
    - Demand charges, transmission and distribution infrastructure, capacity, peak energy through improved load shape
  - Happy Customers! (a.k.a. Customer Satisfaction)
  - Simplicity and understandability for mass-market customers
  - Reduced emissions
  - Operational benefits (reliability)
  - Context considerations
- Group effort to decide upon the key drivers, minimize the number of them as much as possible, and weight the importance of each

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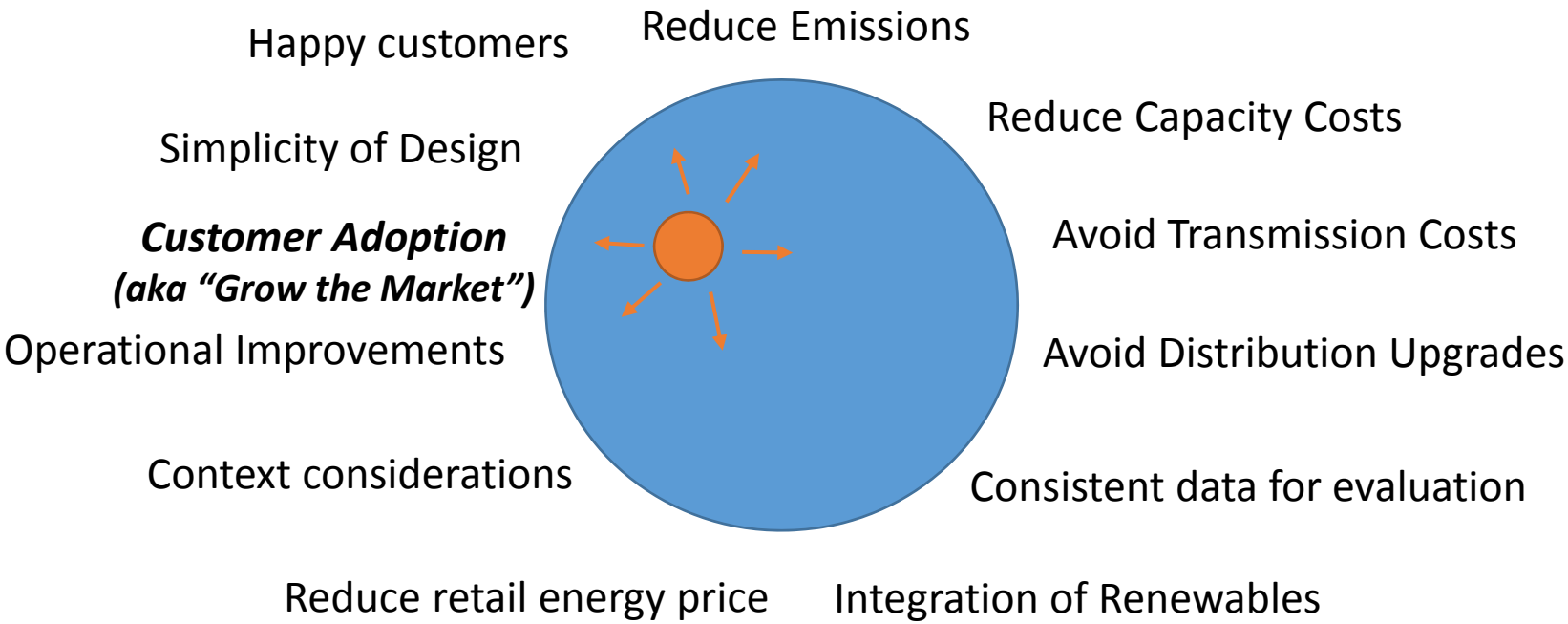
Weighing Key Drivers

Add, adjust, and reorganize drivers as a group.
Then consider the strength of each versus the others.



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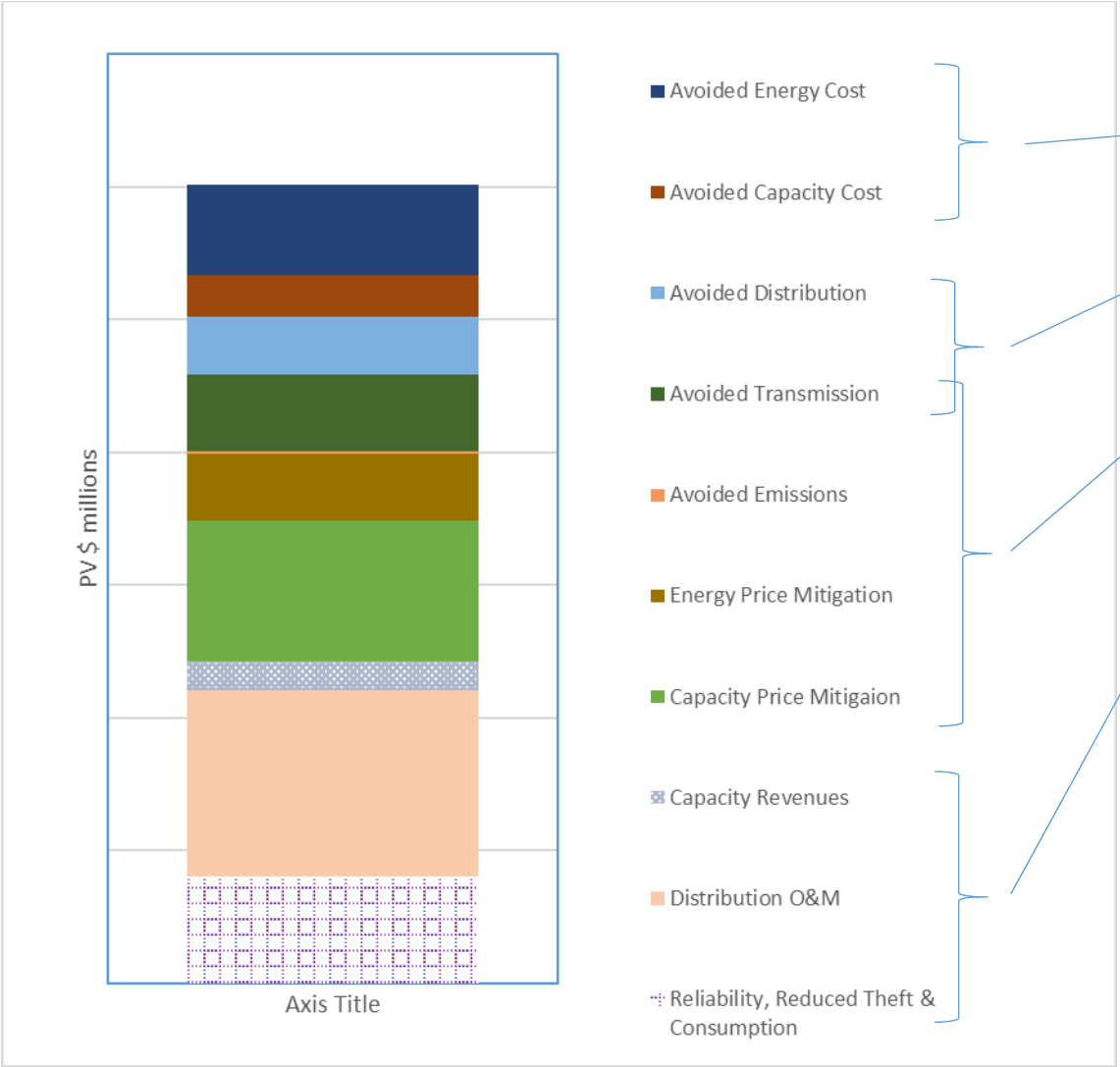
Relative Size of Potential Benefits of DR



- *Benefits to*
  - *Participants*
  - *All Rhode Islanders*
  - *All New England customers*
  - *To the utility, ultimately passed on to customers.*

(Shown are Illustrative relative benefits, as described by BG&E in a recent case.)

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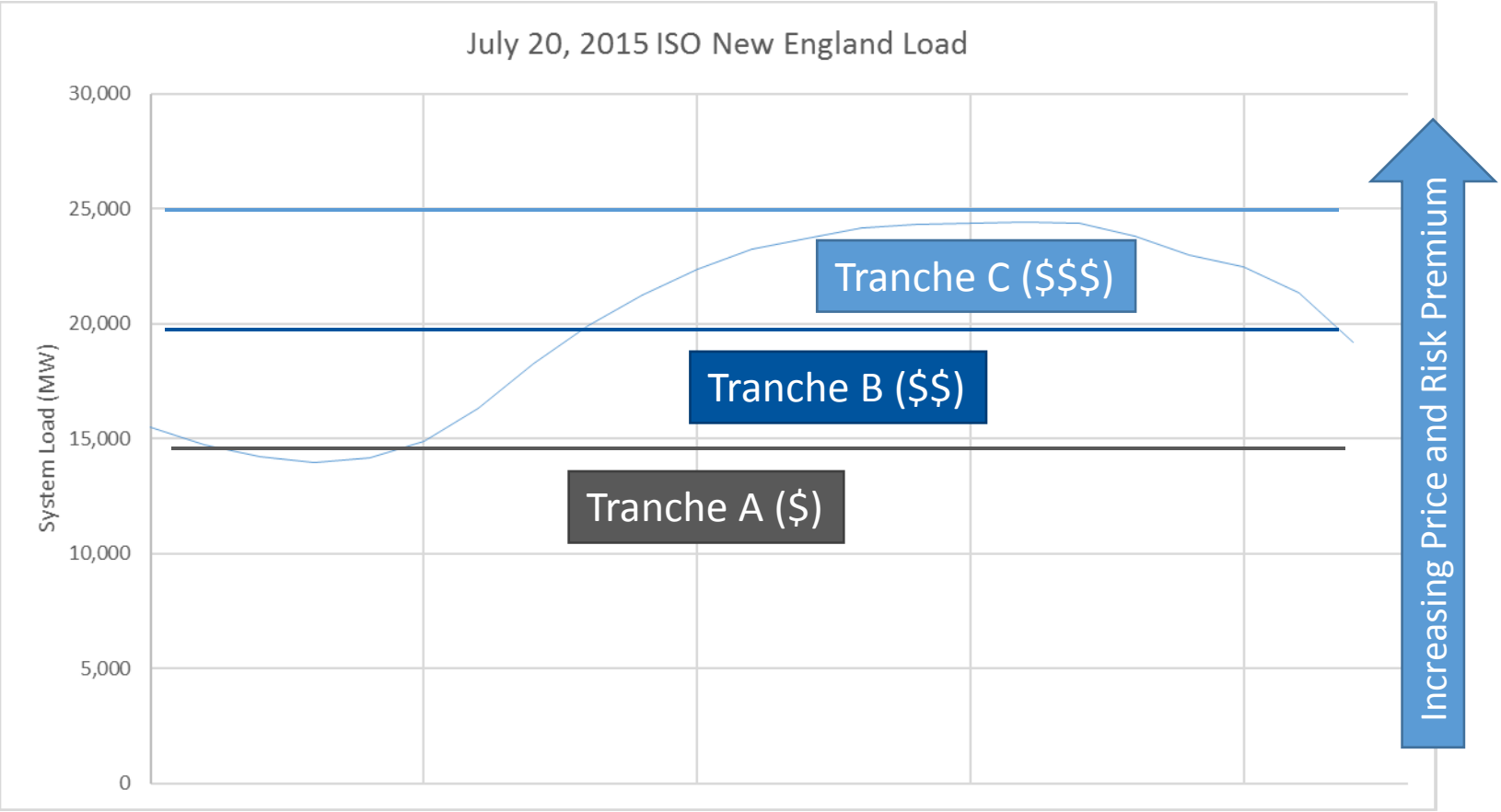
Impact on Power Supply Price



If customers continue to see year-round flat prices, that price can be reduced by reducing load during most expensive hours.

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Simplicity and Understandability

~50% of residential customers do not have a good understanding of the terms *kW* and *kWh*

Results from E Source Survey

"When we introduced common utility terms such as *demand* and *load shape*, **customers were flummoxed**."

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Simplicity and Understandability

Gandalf Group 2013 Ontario Focus Groups

Widespread concern that customers do not have the **tools** to manage demand.

"There is no template for measuring maximum use that people are used to in the way they understand TOU."

Customers also expressed concerns regarding **fairness**, specifically that "that small lapses in their conservation efforts will mean they will have to pay a high price".

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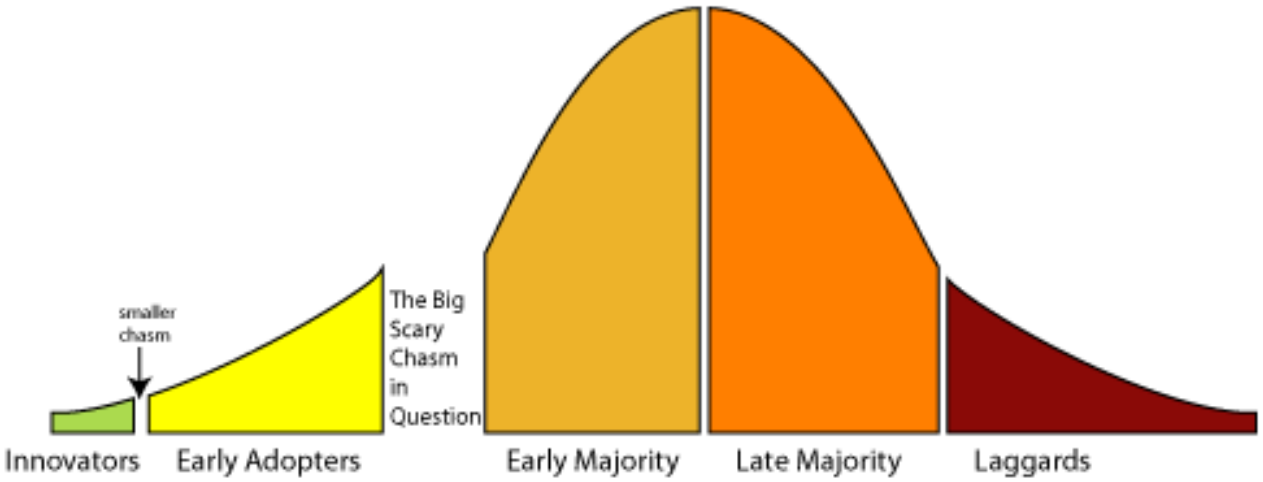
Technology Adoption Rate

Technology Adoption Cycle

Geoffrey Moore's 'Crossing the Chasm' diagram
circa 1991

(Adapted from Diffusion of Innovations, by Everett Rogers in 1962)



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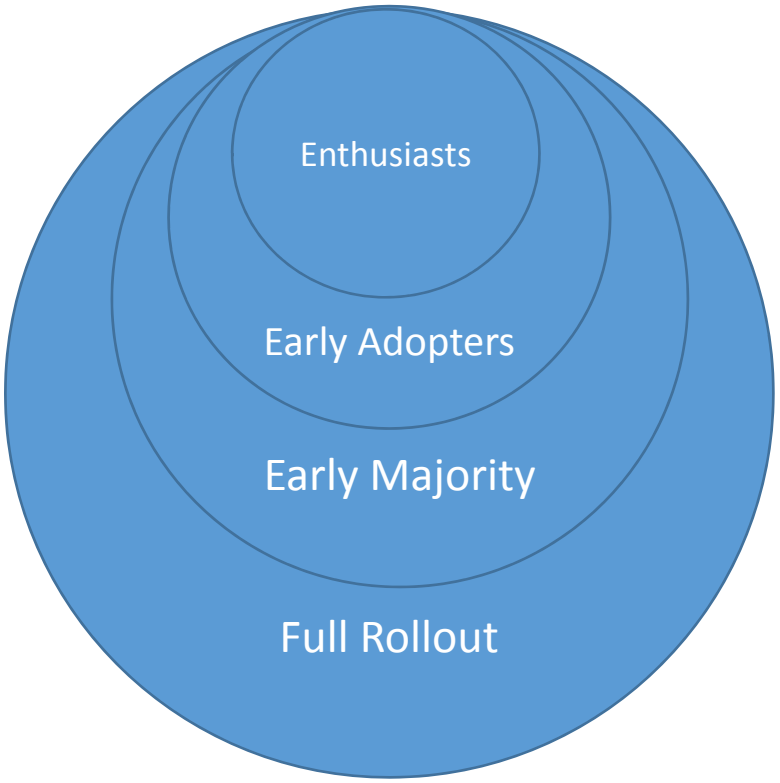
Technology Adoption Circles Model

Loosely translated and then adapted …



A Tiered Rollout anticipates Technology Adoption Rate

- Enthusiasts
  - Excited about energy tech for its own sake
  - Willing to pay
  - Great source for early feedback (will be engaged) and free marketing
- Early Adopters
  - Want to put energy tech to use
  - Will pay some, but less. Want savings.
  - Hints at needs of Early Majority
- Early Majority
  - Hearing from multiple sources.
  - Need product with good user experience
  - Will be convinced by savings
  - *A different market. Tech must change.*
- Full Rollout

Goal is to grow the market for demand response.

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Decisions Under Uncertainty

Can we do better than this guy?

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Solution from a Decision Model

- A multi-year plan that is not static. Designed from the beginning to be altered over time.
- The best decision?

  Not quite…. Hindsight will always have been better.
- A **Decision Rule**

  Includes best decision "now" (Stage 1)

  PLUS

  Conditional rules for what to do later

  If we see A, do X, if we see B, do Y, etc.

  Set a plan now to handle future changes in landscape, learning, etc.
- Often suggests additional alternatives to consider

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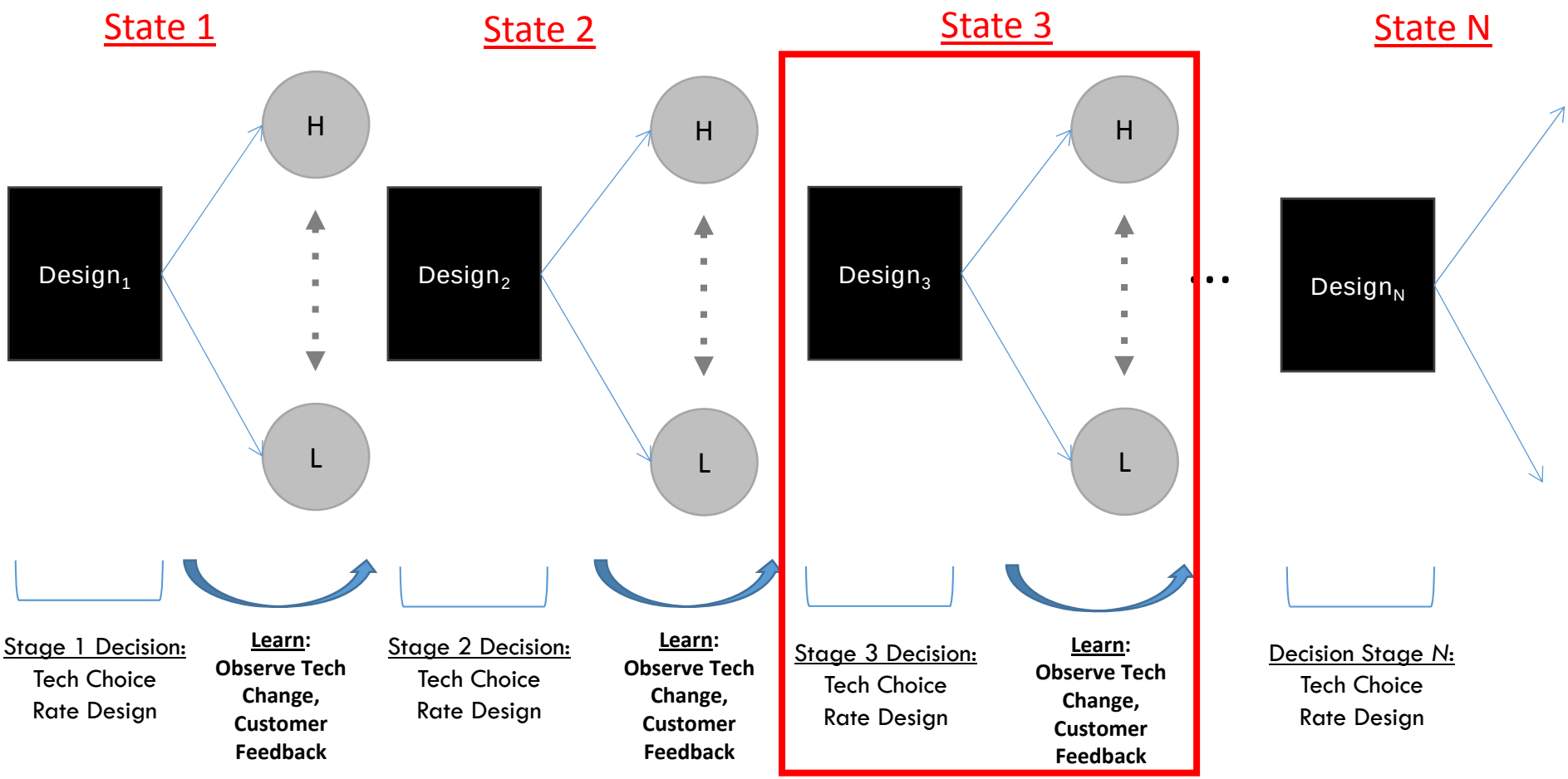
Example Problem

State Variables: e.g., Capital Costs, Installed Capacity, Cumulative Peak-Related Costs, …



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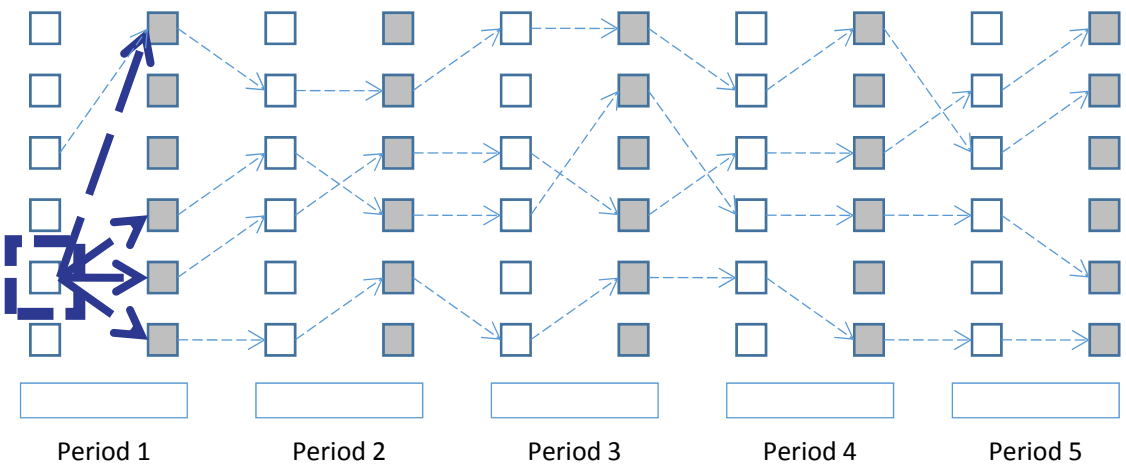
Mapping Extent of Planning Period

- Appropriate and desirable to plan, even with lack of information about the future
- Majority of uncertainties can be anticipated, weighed, and incorporated into a decision tree plan
- Some drivers can be eliminated straight away – either inconsequential or constant over time, in all states
- Plans can be sequenced. For example, one plan for pilot period, followed by another for the implementation period



Selectively sampling through most promising decisions and uncertainties

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Takeaways

Summary

- Nobody has this figured out yet
- Focus on Residential and Small C&I Sectors
- Decide upon key drivers
- Grow the Market with attention to technology adoption rate
- Use methods from Decision Making Under Uncertainty to guide multi-year plan for pilots and implementation
- Suggested starting point:
  - Some form of time varying rate available on opt-in basis
  - Technology to provide information and control usage
    - Direct load control if assurance of load reduction is a key driver
  - Offered as opt-in to Enthusiasts and then Early Adopters
  - Adapt and expand year by year as technology improves and adoption broadens

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Additional Considerations

- Combined with peak-focused EE
  - Incentives or measures above and beyond what is already part of LCP
- Build and offer a capacity resource. Offer at price required to recover costs. May or may not clear, but if it does, go build it! Small additional cost to customers (just planning costs).
- Preparation for system need such as LNG availability issues (Yemen pipelines, Spring 2014)

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Additional Background

Principles of Rate Design

Revenue Adequacy & Stability	Opportunity to recover allowed revenues; stability in revenues from year to year.
Efficient Price Signals	Send appropriate price signals to ensure efficient resource usage • *Don't create the need for more capacity unless the value of it exceeds the cost of adding it.*
Fairness	Rates should apportion costs fairly; avoidance of undue discrimination
Stability of Rates	Changes should be gradual
Practical Considerations	Simplicity, understandability, acceptability

These must be balanced, as they may be in tension.

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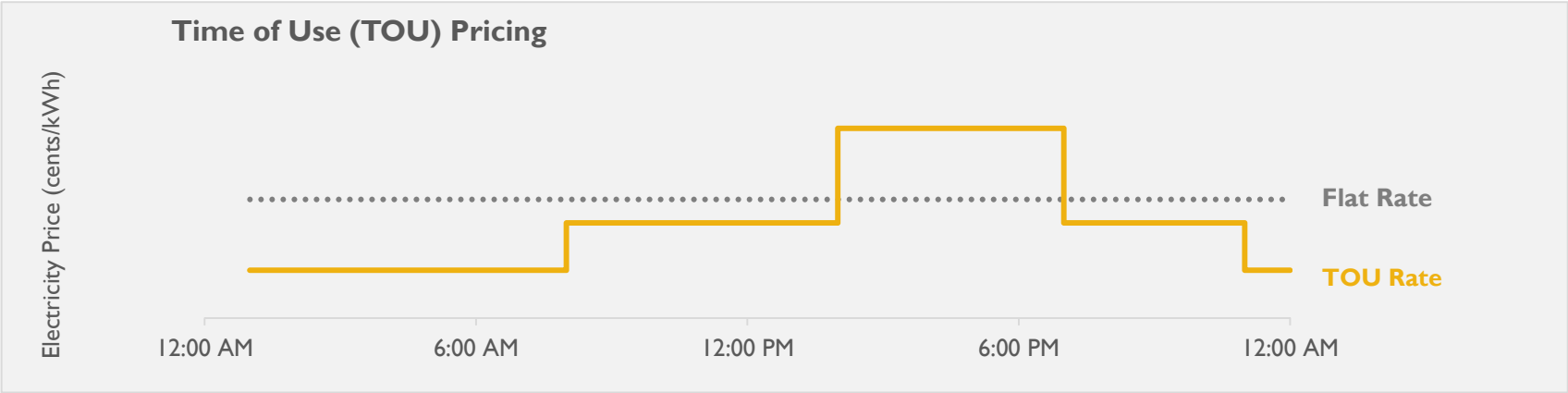
Rate Alternatives: TOU Pricing; CPP



CPP pricing is in effect only for “critical event” days when the system is most stressed.

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Ability to Monitor & Respond

- Technologies that allow customers to monitor their demand and automatically respond are not yet widespread.
- Without automatic technology, a customer has little ability to know whether they are close to setting a new peak, and little ability to easily manage that demand.
- Will low income, elderly, non-English speaking customers purchase and install such tools?

9312A Residential Demand Controller.
Pricing information is not readily available.

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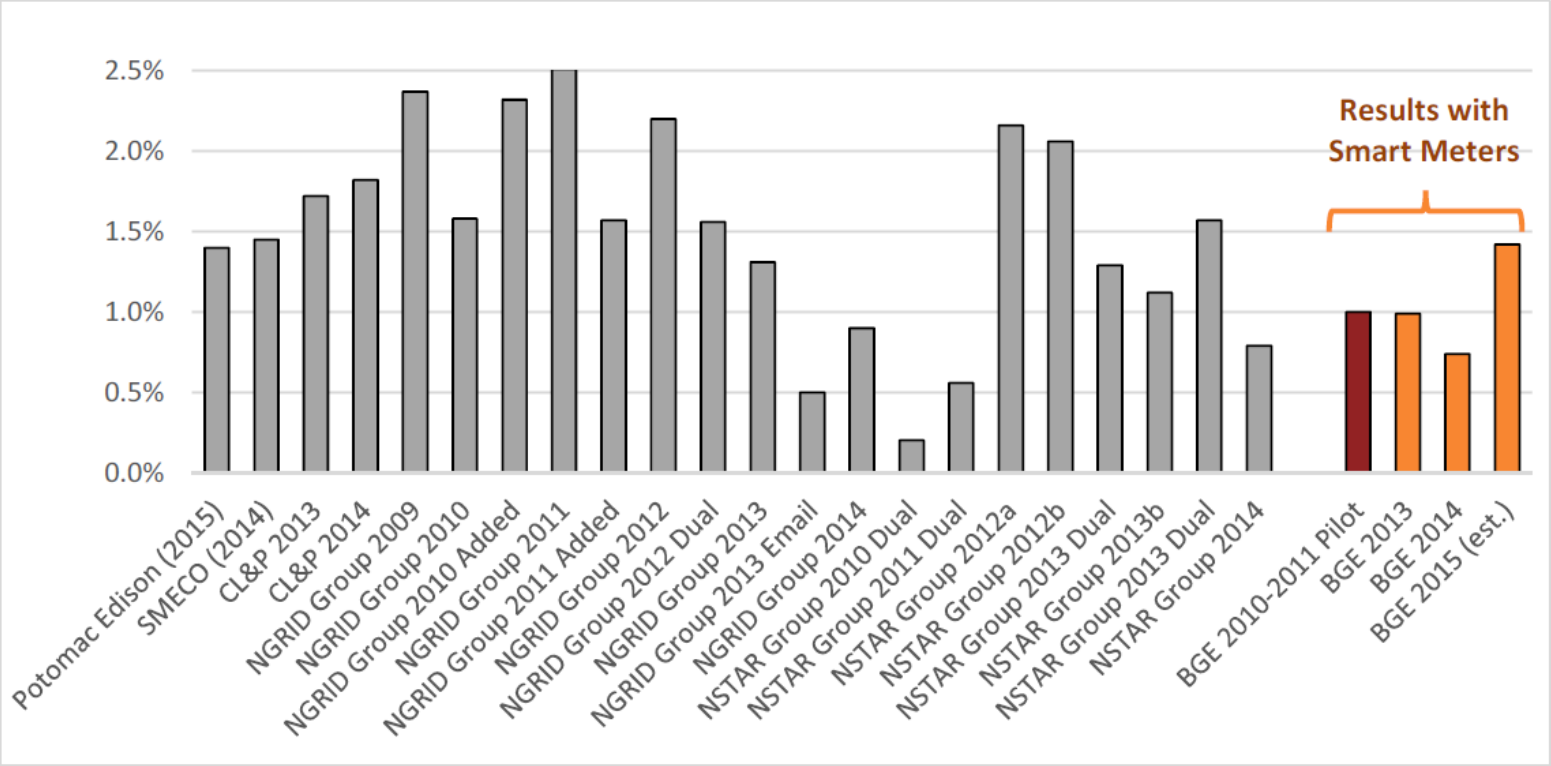
BGE Home Energy Reports (HER)

Figure MPC 4. Comparison of BGE Savings with Savings of Utilities without Smart Grid Initiatives



Source: Testimony of Max P. Chang. Figure MPC 4. Case 9406. 8 Feb 2016.

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Do demand charges work?

- According to a recent report, only **3** studies have quantified peak reduction from a demand charge, but they are limited in their usefulness, because:
  - Two of the studies are nearly ***40*** years old, and the other one is from Norway (with a very different climate)
  - All three studies had very small sample sizes (ranging from 40 to 443 participants)

In short, we don't really know!

Source: Rocky Mountain Institute (2016) A Review of Alternative Rate Designs

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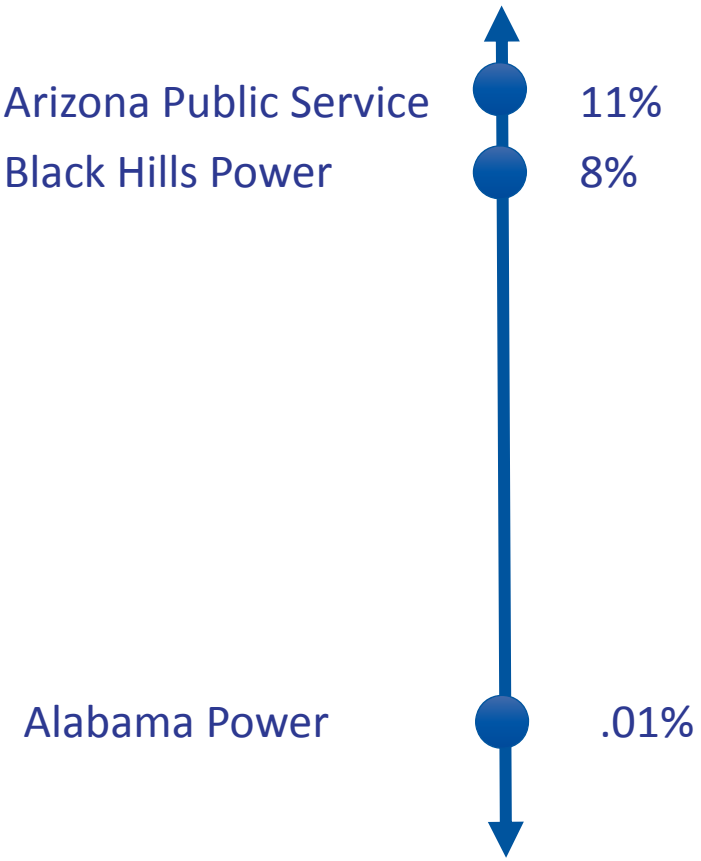
Acceptability of Demand Charges

- Only 25 utilities currently offer demand charges.
- For most of those utilities, enrollment is quite low (<1%).
- Where offered, energy-only time-of-use rates are generally preferred to demand rates.
- Demand charges may appeal to a small subset of customers (e.g., large residential customers with ability to control key end-uses).



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EERMC CONSULTANT TEAM

Vermont Energy Investment Corporation || Optimal Energy Integrated Energy Resources

Memorandum

To: RI Energy Efficiency & Resource Management Council (EERMC)
From: EERMC Consultant Team
Date: June 7, 2016
Subject: Savings Targets and Standards for Energy Efficiency – Proposed revised timeline for development and submittal to PUC

Based on recent discussions with the Saving Targets subgroup and the EERMC Executive Committee, the Consultant Team recommends to the EERMC a modification to the schedule for submittal of electric and natural gas energy efficiency savings targets (Targets) for National Grid's efficiency procurement plan for 2018-2020.

The primary reason for the proposed delay from the initial plan of a September, 2016 filing is to align the Targets filing with the review and filing of Least Cost Procurements Standards (Standards) which were initially developed in 2008 and updated in 2011 and 2014. Given that both of these items serve critical functions in the development of 3-Year Plans (Plan), the Consultant Team is proposing that these activities are very closely aligned in this cycle.

In previous planning cycles the process was first to develop and file Targets and then review and file Standards. We recommend that both be filed before the end of 2016, with the Targets and Standards both presented to the EERMC at the December 8 council meeting.

We believe that this approach provides an opportunity for the System Integration Rhode Island (SIRI) process to keep advancing its work (which currently includes proposed revisions to the System Reliability Planning portion of the Standards). We also believe that Docket 4600 process that has been initiated by the PUC will provide a context in which a number of topics that could affect both the Targets and the Standards will be allowed to inform a combined Target and Standards process.

The table below illustrates the staggered nature of the process in the past.

Plan Cycle	Targets filed	Standards filed	Targets/Stds approved	3-Year Plan filed	Plan approved
2009 – 2011 *(All in Docket 3931)*	7/18/08 (Opportunities Report, Ph. 1)	2/29/08	9/2/08	9/2/08	3/31/09
2012 – 2014	9/1/10 *(Docket 4202)*	2/24/11 *(Docket 4202)*	6/7/2011	9/7/11 *(Docket 4284)*	12/21/11
2015 - 2017	9/1/13 *(Docket 4443)*	3/18/14 *(Docket 4443)*	3/27/14 (Targets) 5/27/14 (Stds)	9/2/14 *(Docket 4522)*	10/30/14

The initial timeframe proposed for 2016 for the EERMC to develop and propose Targets to the PUC sought to remain consistent with a September filing date in the year prior to the development of 3-Year Energy Efficiency Procurement Plans (in 2010 and 2013). The original objective was to have the Targets approved by the PUC before commencing development of the 3-Year Plan by National Grid and stakeholders, so the Plan would have direction on depth of savings to achieve. Similarly, filing of updates to the Standards was undertaken as a subsequent step once the Targets were submitted so that they could be presented to the PUC early in the ensuing year, and approved in sufficient time to inform the Plan.

Since the Targets and Standards both provide context to the Plan development, and have historically been combined in the same docket, the proposal is to present both to the PUC at the same time to streamline the process, with approvals for both expected in time to serve the key purpose of contributing to the Plan development. This would also allow any potential modifications to the Standards that may impact Targets to be fully factored into the Target setting. And, as has been noted previously, the setting of Targets for the 2018-2020 period provides unique challenges and opportunities given the increasing pace of evolution in the marketplace, so the additional months will allow for some more clarity in proposing changes to the standards and better understanding emerging trends before finalizing the Targets.

As part of the EERMC's consideration of this request, there would be potential budget impacts as it relates to the acceleration of the update of the Standards. It may also be that as Docket #4600 becomes more active, additional effort will be required to participate in that proceeding. We believe that both efforts will complement each other. The initial assumption is that the majority of the work on this Standards task would be undertaken in 2017, and now much of that work would move to being a 2016 activity, requiring supplemental budget for the Consultant Team and possibly other expert services. Upon approval of this recommendation, the Consultant Team would develop a proposed adjustment to the current scope of work.

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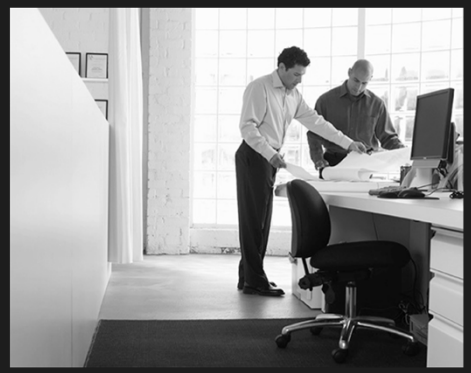
Rhode Island Code Compliance Enhancement Initiative (CCEI)



Presented to the RI EERMC

June 9, 2016

The Importance of Energy Codes

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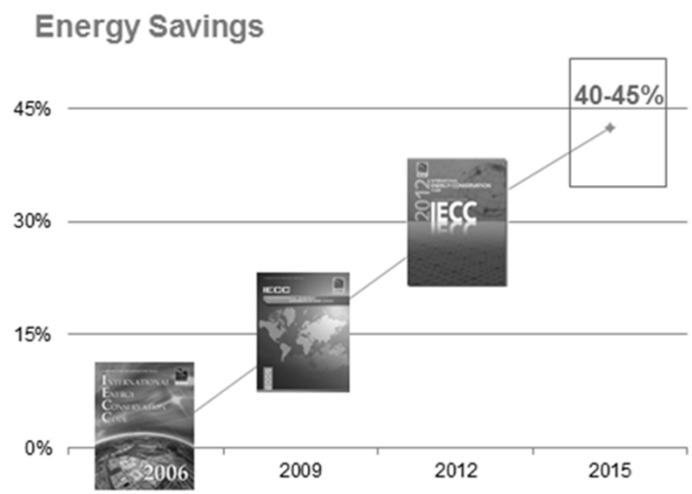
- According to the U.S. Dept. of Energy:
  - Energy codes are saving more than 40%-45% compared to the codes of a decade ago.



Why is the Utility Involved?

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- Less than ideal statewide energy code compliance rates in Rhode Island
  - Residential / 57%
  - Commercial / 70%
- New strategy for future portfolio savings
  - Energy codes today are saving more BTUs and kWhs compared to the codes of a decade ago
- Utility is the enabler and NOT the enforcer

Classroom Training

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Audience	Topics
Commercial: ■ Code Officials ■ Design & Construction Professionals ■ Energy Specialists	■ Commercial Energy Code: Overview ■ Envelope and Building Science ■ Lighting, Controls, and Electrical ■ HVAC / Mechanical Provisions
Residential: ■ Code Officials ■ Design & Construction Professionals ■ HERS Raters / Energy Specialists	■ Residential Energy Code: Overview ■ Envelope and Building Science ■ HVAC and Indoor Air Quality

Classroom Training Attendance Breakdown (Oct 2013-April 2016)

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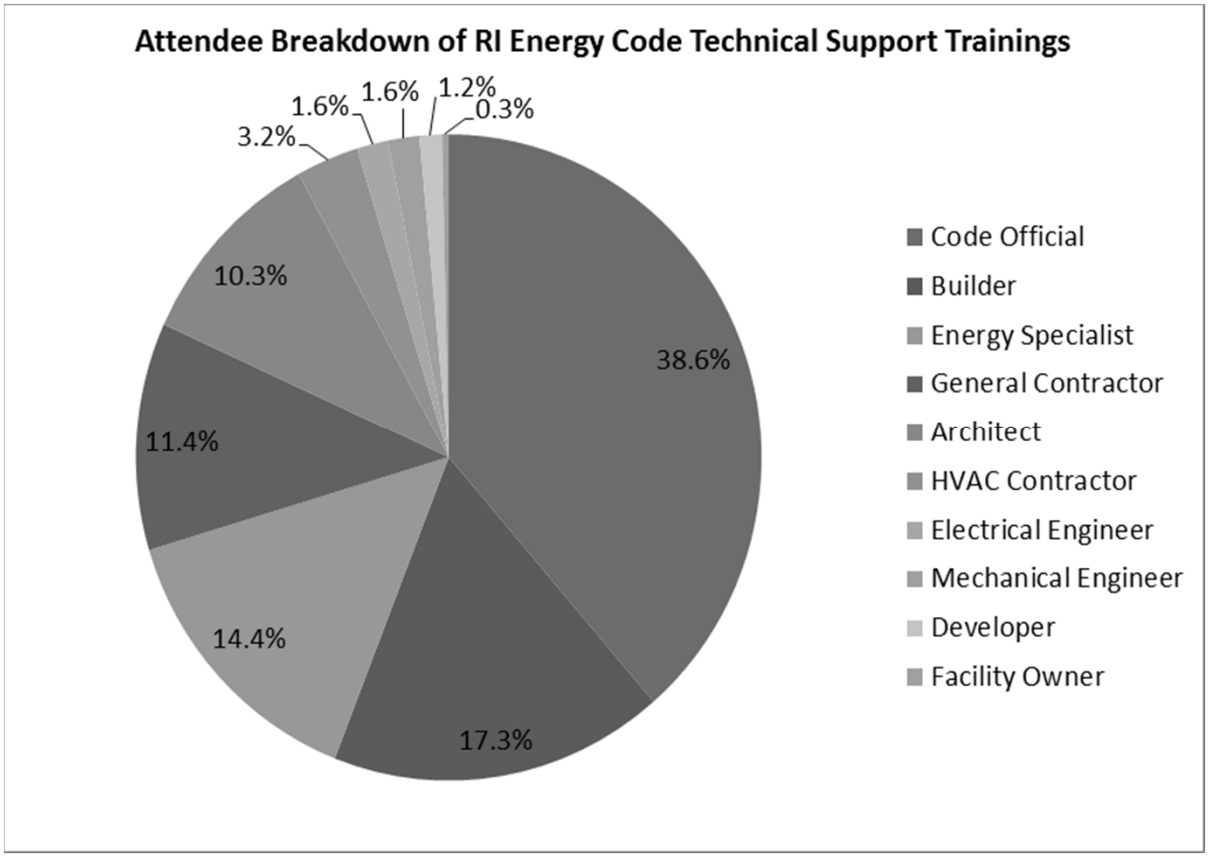

Webinars

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Audience	Topics
Commercial: ■ Code Officials ■ Design & Construction Professionals ■ Energy Specialists	■ Controlling air & moisture in the building enclosure ■ Daylighting requirements
Residential: ■ Code Officials ■ Design & Construction Professionals ■ HERS Raters / Energy Specialists	■ TBD

In-Field Trainings

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- Typically limited to 10-15 participants.
- Blower door and duct blaster hands-on set up and training.
- Discussion of code requirements for tests.
- Hands-on duct testing.
- Tours of commercial buildings that meet or exceed code
  - Tiverton Library
  - Brown University Applied Math Building
  - William Davies Career & Technical High School

In-Field Trainings

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CCEI Training Numbers (October 2013-April 2016)

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- 43 residential classroom trainings
- 29 commercial classroom trainings
- 30 residential in-field trainings
- 7 commercial in-field trainings
- 6 commercial webinars

- 931 attendees trained at residential classroom sessions
- 361 attendees trained at commercial classroom sessions
- 339 participants trained at residential in-field sessions
- 87 participants trained at commercial in-field sessions
- 34 commercial webinar attendees

- Total participants: 1,752

RI CCEI Training Feedback

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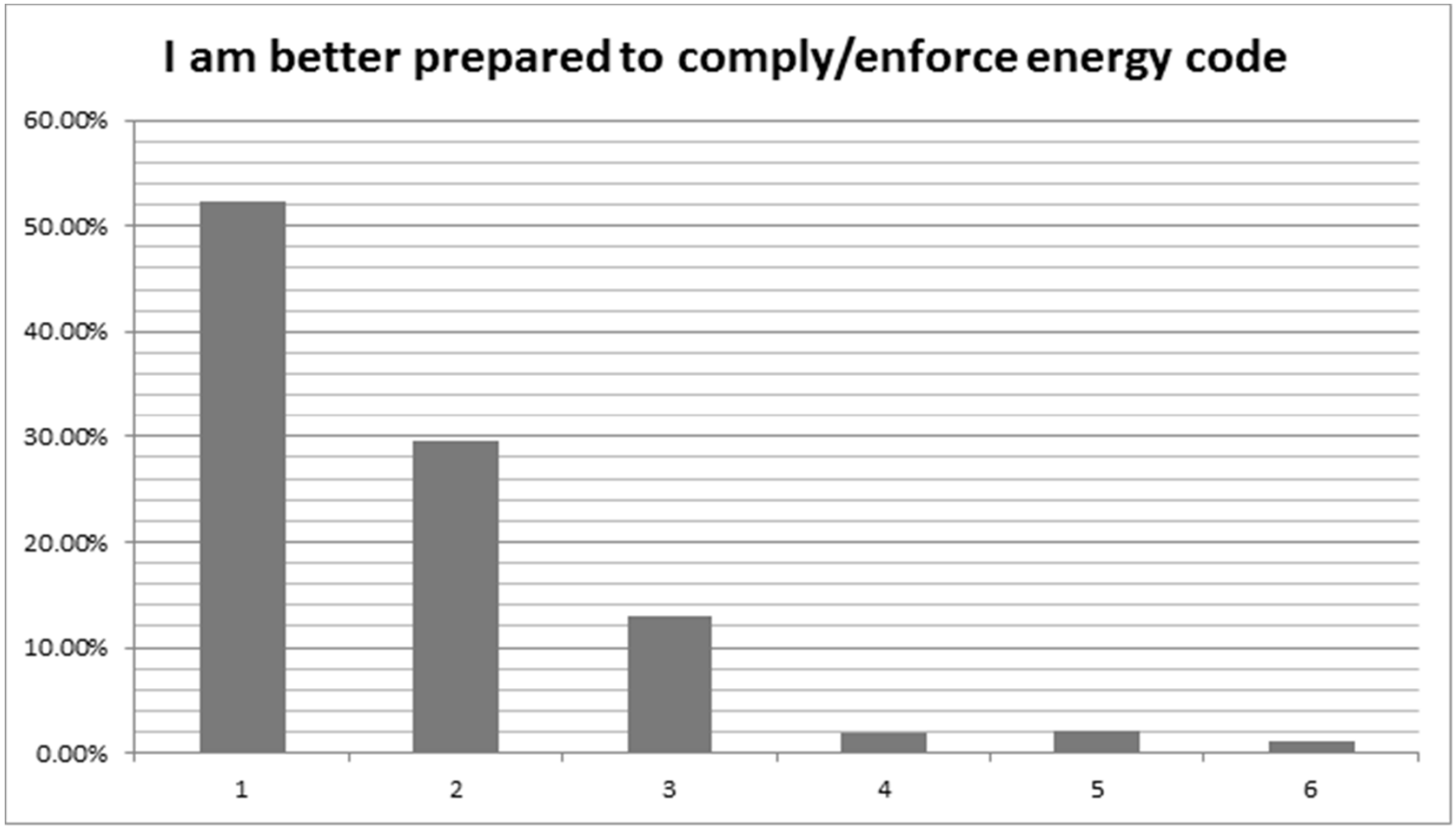

Statewide Circuit Riders

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Audience	Type	Content
Commercial & Residential: ■ Code Officials ■ Architects / Designers ■ Engineers ■ Construction Managers ■ Builders / Contractors ■ Material Suppliers ■ Building Owner	■ Phone call support ■ 1-855-343-0105 ■ Office consultation ■ On-site consultation	■ Answers to general energy code questions / interpretations ■ Project specific code compliance consulting (conceptual plan and specification review) ■ Project specific code compliance verification (on-site physical observation / consultation)

Statewide Documentation Tools

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Audience		Content

Commercial & Residential:
■ Code officials
■ Architects / Designers
■ Engineers
■ Construction Managers
■ Builders / Contractors
■ Material Suppliers
		■ Frequently Asked Questions guide
		■ Residential new construction field guide
		■ Technical bulletins:
		  ■ Air sealing for savings
		  ■ Build tight & ventilate right
		  ■ Blower door testing required
		■ REScheck and COMcheck compliance checklist
		■ Statewide permit checklist

RI Energy Codes

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- Residential energy code:
  - 2012 IECC with RI amendments
- Commercial energy code:
  - ASHRAE 90.1-2010 with RI amendments
- Both effective July 1, 2013
- Energy codes are updated every 3 years
- Next code version is 2015 IECC / ASHRAE 90.1-2013 to likely be adopted on August 1, 2016; enforceable November 1, 2016.

Stretch Energy Code

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- Currently, no formal “stretch code” in RI.
- Governor Raimondo’s Executive Order in December 2015:
  - RI-OER to coordinate with EERMC, National Grid, and GBAC to establish voluntary stretch code based on IGCC or equivalent
- Commercial stretch code targeted for development by December 31, 2016; adopted no later than July 1, 2017.
- Residential stretch code targeted for development by July 1, 2017; adopted no later than December 31, 2017.

Third Party Energy Specialists

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- Third party specialists (i.e. HERS Raters, energy engineers, etc.)
- Possible inclusion in RI in 2016.
- Third party specialists will take the burden off the code officials since they are energy-specific experts.
- Code officials could use them individually or in tandem with code officials.

Energy Code Trends

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- Increased building testing requirements
- Energy Rating Index (ERI)
- Outcome-based codes
  - Focus after building occupied
  - Commissioning
- Increased focus on renewables

Evaluation

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Achieve savings based on promoting compliance to RI commercial and residential energy code

Code technical savings potential

- NBI Commercial Energy Modeling
- ICF Residential Energy Modeling

Baseline code compliance rate

- 2012 RI Commercial Energy Code Compliance Baseline Study
- 2011 Baseline Study of Single-Family Residential New Construction

Post CCEI code compliance rate

- Ongoing Commercial Energy Code Compliance Study
- In 2017, Residential Code Compliance Study

Attribution to CCEI

- 2013 RI Code Compliance Enhancement Initiative Savings and Attribution Logic Evaluation

Savings Illustration

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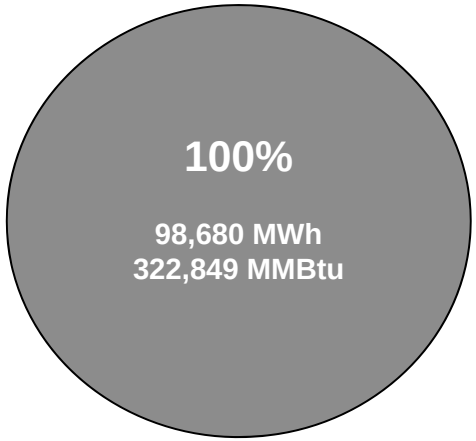

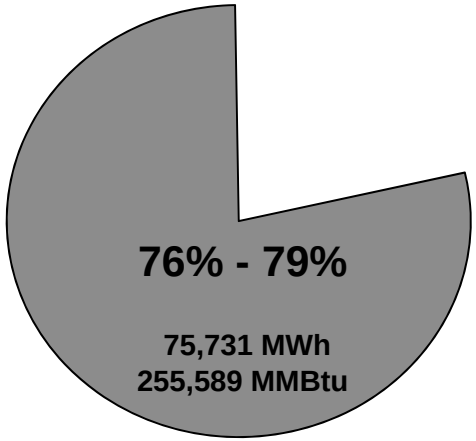

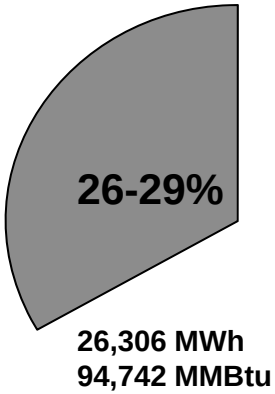

2014-2017
Gross Technical Potential
Difference between average homes/commercial buildings and modeled code homes/buildings

2014-2017
Estimated Gross Savings
Including the influence of market natural adoption, other entities' code enhancement efforts, and other NGrid EE programs

2014-2017
Estimated CCEI Net Savings
Net savings claimed by the program

Current and Planned Evaluation Efforts

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- Commercial code compliance study underway
  - Part 1: quantitatively assess state-wide compliance to the RI Energy Conservation Code
  - Part 2: qualitatively understand compliance patterns and the impact of the CCEI initiative
- Residential code compliance study planned in 2017
- Updated attribution methodology study planned in 2017

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Questions?

To learn more, contact:

Eric Beaton
781-907-3780
Eric.beaton@nationalgrid.com

Muxi Yang
781-907-1458
Muxi.yang@nationalgrid.com

www.ngrid.com/rienergycode

Rooftop Solar Zoning

Stretch Codes

Becca Trietch

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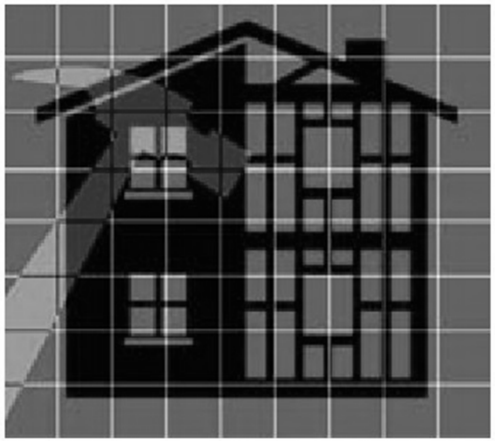
What is a Stretch Code?

- A local code or alternative compliance pathway that is more aggressive than base code
- Also known as Reach Codes, Stretch Codes help buildings to achieve higher energy savings & implement advanced practices
- Can be voluntary or mandated



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What are the benefits?

Spurring & Directing the Market

- Train the building and development communities in advanced practices before base code is improved
- Accelerate market acceptance and adoption of more stringent energy efficiency codes
- Opportunity to work in tandem with utility incentive programs
- Improve code compliance – education & practice implementing more advanced requirements before it is required by base code

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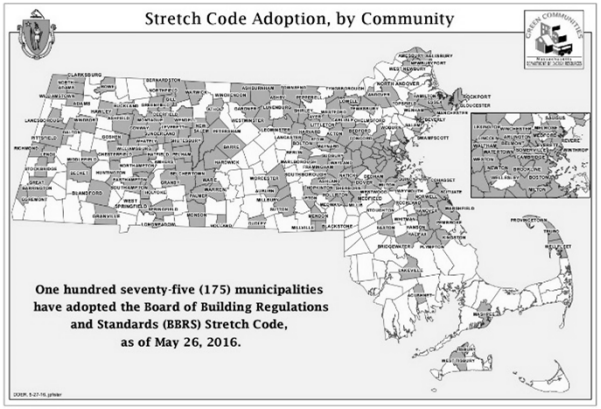
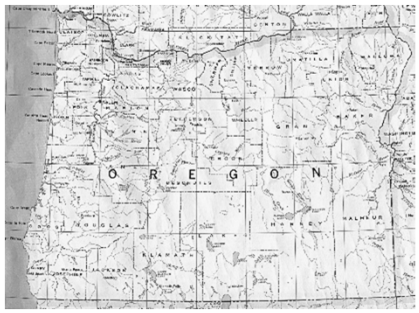
What are others doing?

- **MA:** state-approved stretch code in 2009
  - optional path for municipalities to adopt
  - has been approved as a mandatory base code in 175 MA communities.
- **CA:** CALGreen Tier 1 & Tier 2
  - optional tiers above required code
  - tiers are a part of CALGreen
- **OR:** Created the Oregon Reach Code (ORC) in 2011
  - optional building standard
  - based on IGCC
  - Updated every 3 years





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RI Current Status- Green Buildings Act

- Signed into law in 2009
- **All new construction projects over 5,000 gsf, and all renovation projects over 10,000 gsf, constructed by a "public agency" be designed and constructed to the LEED Certified or equivalent high performance green building**
- In general, pertains to all "Public Properties"
- In 2010 the Green Buildings Advisory Committee (GBAC) was formed
- **International Green Construction Code (IGCC) is an equivalent high performance standard**

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Lead By Example Executive Order

- **EO 15-17 requires OER, EERMC, National Grid, and GBAC to:**
  - "…establish a voluntary aspirational or stretch building code based on the IGCC or equivalent by 2017."
  - "…code shall be available for use in all State construction and renovation projects as well as those in the private sector."

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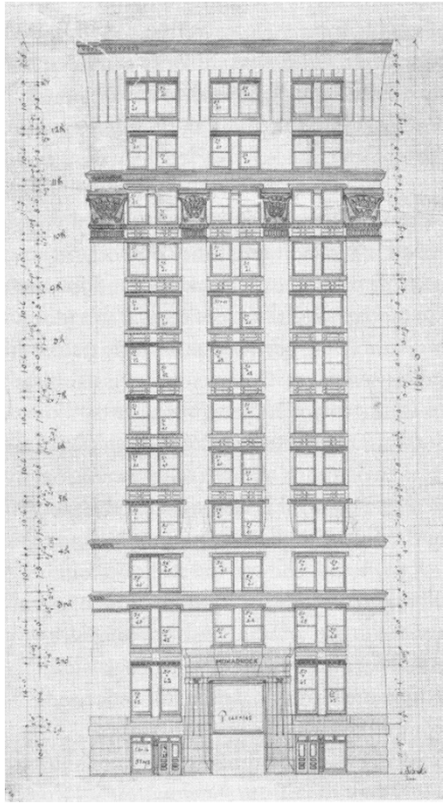
RI's Stretch Code Goals



- **Conduct monthly meetings with OER, EERMC, National Grid, GBAC**
- **Create a stretch code that:**
  - Can be used by state agencies or any other public or private entity
  - Will reduce energy usage below RI's energy conservation code
  - Will help applicable entities comply with the Green Buildings Act
  - Help entities qualify for utility incentive programs
  - Will spur advanced green building techniques

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Stretch Code Goals: Timeline

Dec 31, 2016	July 1, 2017	Dec 31, 2017
• Completed Draft of Commercial Stretch Code • Identify funding source for the next stretch code update	• Formally adopt Commercial Stretch Code • Completed Draft of Residential Stretch Code	• Formally adopt Residential Stretch Code

- Both stretch codes will consider sustainability in a holistic fashion, but will contain separate chapters/sections focused solely on energy
- Both will provide prescriptive and model-based performance pathways for compliance
- The group will establish a process, timeline, and future funding source for updating and perpetuating the stretch code going forward

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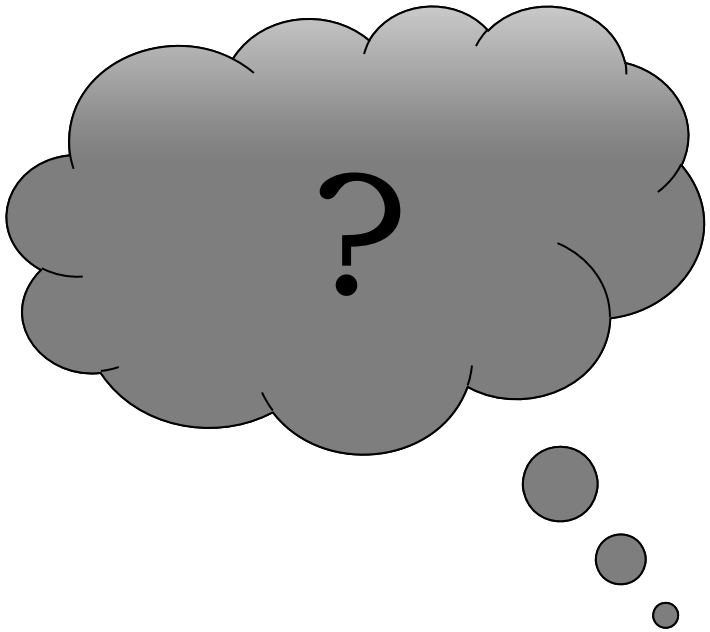
Questions?



Becca Trietch

Office of Energy Resources

Becca.Trietch@energy.ri.gov

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