Pennsylvania Public Utility Commission
Act 129

Demand Response Stakeholders' Meeting

June 11, 2013

Presented by the Statewide Evaluation Team:

Nexant

GDS Associates, Inc.
Engineers and Consultants

MONDRE
ENERGY, INC.

Objectives of the DR Study

Overarching Objective: Provide the Commission with information that will inform their decision on whether or not to include DR programs in future phases of Act 129 by quantifying the ability of DR programs to reduce retail electric rates.

1. Evaluate alternatives to the Top 100 hours criteria
2. Conduct best practice comparison of programs offered by ISO's and utilities in other states
3. Quantify the incremental benefit of the Act 129 DR program above and beyond programs offered by PJM
4. Conduct benefit/cost assessment of the 2012 DR program with sensitivity analysis
5. Investigate the impact of Act 129 programs on reducing electric rates over and above existing PJM programs
6. Develop recommendations for DR program structures in future phases of Act 129.

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Final Report Content

- Overview of existing program structures and treatment of payments for TRC in other States
- Review of Top 100 hours structure and limitations
- Recommended/ Proposed structure for any future DR programs for the State
- Summary of Incremental Value survey results
- Incremental impact analysis to determine impact of Act 129 programs
- Economic analysis of Incremental Savings and effect on TRC

Incremental Savings from Act 129

Incremental Savings Analysis

- Expected to be a subset of customers participating in Act 129 load curtailment programs who are also active in the PJM DR markets.
- The 2011 TRC Final Order directed the EDCs to ignore any charges, penalties or payments from PJM in the calculation of the TRC ratio.
- How *should* benefits be attributed when a customer receives incentives from two revenue streams for the same action?
- Act 129 benefits were discounted because a portion of the load reductions observed in 2012 may have happened in the absence of the Act 129 programs.

Incremental Savings Analysis

- The EDC data request response tells us the frequency of dual participation.
- When a customer participates in both markets during the same hour, how should the energy and capacity benefits be allocated?
- Not an issue for Phase 1 of Act 129. All benefits are attributable to Act 129.
- Likely to vary from participant to participant.
- Can only be answered by contacting customers and understanding their motivations and decision making process.

Incremental Savings Analysis

- Standardized set of survey questions administered by EDC evaluators.
- Standardized scoring system.
- 90/10 confidence and precision at the statewide level.
- Survey responses were used to calculate an Incremental Benefits Ratio (IBR), or portion of benefits attributable to Act 129.

INCREMENTAL SAVINGS ANALYSIS

- IBR calculated separately for dual participation in the PJM Economic and Emergency programs.
- Equal to 1 for any hour during which a site participates in only an Act 129 event.
- When overlapping participation is observed:

Act 129 Benefits = (Total Energy and Capacity Benefits) * (Incremental Benefits Ratio)

PJM Benefits = (Total Energy and Capacity Benefits) * (1 – Incremental Benefits Ratio)

INCREMENTAL SAVINGS ANALYSIS- PARTICIPANT SURVEY

Participant Survey

- A sample of 86 customers provided estimates with precision of ±10% at the 90% confidence level
  - Sample included participants from each of the 7 EDCs
  - Sample was stratified by customer type and size
- 69% of participants were "PJM veterans" who had participated in either the PJM Economic or PJM Emergency program in or before 2011
- Participation in Act 129 programs was influenced primarily by a high incentive
  - Only 5% of customers indicated they would have participated had the incentive been lower

PARTICIPANT SURVEY

- Incremental Benefits Ratio
  - Scoring system designed to allocate the benefits of program impacts to Act 129 and PJM programs

Incremental Benefits Ratio	Score
Economic Incremental Benefits Ratio	0.77
Emergency Incremental Benefits Ratio	0.63

  - When Pennsylvania customers participate in both an Act 129 DR event and receive a PJM Economic DR settlement during the same hour, the Act 129 program receives 77% of the benefits

COST EFFECTIVENESS & SENSITIVITY ANALYSIS

METHODOLOGY

- Act 129 programs are evaluated using a Total Resource Cost (TRC) test.
- The TRC test accumulates the benefits and costs of a DR program and presents the results as a ratio (benefits/costs).

Benefits and Costs included in the SWE TRC Test

Benefits*	Costs
Avoided Cost of Generation Capacity	Equipment & Installation Costs
Avoided Cost of Transmission and Distribution Capacity	Program Administrative Costs
	Marketing Costs
	Evaluation Costs
	Incentives Paid to Participants

* Possible benefits from wholesale price suppression were not quantified in this analysis.

Methodology

- Two different program types were offered to meet demand reduction requirements.
- Direct Load Control (DLC)
  - Installation of controllable thermostat allows utility to remotely control temperature
  - Installation of control switch allows utility to remotely cycle air conditioners
- Load Curtailment (LC)
  - Price initiatives for customers to respond to control events by reducing loads

Assumptions – Load Reduction

- Peak demand reduction was estimated from information provided by EDCs
- Peak demand reduction is the average kW reduction across the EDC's top 100 peak hours in 2012
- For any of the top 100 hours in which an EDC did not call a control event, a load reduction of 0 kW is averaged into the program savings estimate

Assumptions – Load Reductions

Per Unit Impacts from Act 129 DLC Programs at the Meter Level

EDC Program	Per Unit Impact During Events (kW)	Average Per Unit Impact During the Top 100 Hours (kW)
PECO Residential Smart Saver	0.84	0.48
PECO Commercial Smart Saver	0.69	0.35
PPL Direct Load Control	0.59	0.41
Duquesne Direct Load Control	0.76	0.29
Met Ed IDER	0.73	0.40
Penelec Direct Load Control	0.60	0.44
Penn Power Direct Load Control	0.68	0.39

Assumptions – Attribution Survey

- Residential programs
  - PJM DR programs require >50 kW reduction for participation
  - Individual customers do not participate
  - SWE unaware of aggregators delivering residential kW under the Act 129 programs
  - Assume 100% of residential load reductions attributable to Act 129
- Commercial programs
  - Use of attribution study to adjust loads
  - kW savings reduced by factor of 0.77 if curtailment coincides with PJM Economic Event
  - kW savings reduced by factor of 0.63 if curtailment coincides with PJM Emergency Event
  - Otherwise, 100% of commercial kW savings attributed to Act 129

Assumptions – Attribution Survey

- Impact of attribution factors
  - Overall kW savings were reduced by an average of 8.2%
  - Range of 0% to 23% across EDCs

- If EDCs had limited curtailment events to a smaller number of critical peak hours, then more overlap with PJM event hours would be expected and the percent reduction in benefits from load reduction would likely increase.

Assumptions – Attribution Survey

- Over half of the potential load reduction capacity in EDC load curtailment programs was also enrolled in the PJM ELRP in 2012.

Proportion of Act 129 Load Reduction Commitments in PJM ELRP

EDC	MW in PJM ELRP	MW not in PJM ELRP	Proportion of Act 129 MW in PJM ELRP
Duquesne	19.2	17.3	0.53
Met-Ed	53.7	53.5	0.50
Penelec	56.0	77.9	0.42
Penn Power	26.4	15.1	0.64
West Penn Power	134.2	63.1	0.68
PECO	98.9	91.0	0.52
PPL	78.2	64.8	0.55
Total	**466.5**	**382.6**	**0.55**

Assumptions – Avoided Capacity Costs

Avoided Cost of Generation Capacity – 2012 PJM Zonal Prices

EDC	Avoided Cost ($/kW-Year)
Duquesne	$6.11
West Penn	$6.11
Met Ed	$48.69
Penelec	$48.69
Penn Power	$48.69
PECO	$52.21
PPL	$48.69

Assumptions – Avoided T&D Costs

- Avoided T&D costs are hard to quantify
  - Very specific to each utility
  - Information not as readily available as the PJM Capacity Market
  - Some utilities will use zero benefit from avoided T&D as a conservative approach to the TRC test
- SWE elected to evaluate a range of avoided costs
  - Range of $0 to $50 per kW-year provides reasonable range
  - Base case assumption is $25 per kW-year

Cost Effectiveness Direct Load Control Programs

- Seven direct load control programs
  - Six residential
  - One commercial
- Over 165,000 participants were enrolled
- Delivered an average load reduction of 88 MW during the top 100 hours of 2012.

Cost Effectiveness Direct Load Control Programs

- Single-year TRC analysis – all programs

Line Item	Value ($thousands)
Avoided Generation Benefits	4,445
Avoided T&D Benefits	2,197
Total Benefits	**6,642**
Equipment, Admin, and Program Costs	42,434
Incentives Paid	14,716
Total Costs	**57,150**
TRC Benefit/Cost Ratio	**0.12**

- Individual program TRC ranged from 0.04 to 0.14

Cost Effectiveness Load Curtailment Programs

- Nine load curtailment programs
  - One residential (Critical Peak Rebate Program)
  - Eight commercial

- Delivered an average load reduction of 518 MW during the top 100 hours of 2012.

Cost Effectiveness Load Curtailment Programs

- Single-year TRC analysis – all programs

Line Item	Value ($thousands)
Avoided Generation Benefits	19,268
Avoided T&D Benefits	12,957
Total Benefits	**32,225**
Equipment, Admin, and Program Costs	7,013
Incentives Paid	44,227
Total Costs	**51,240**
TRC Benefit/Cost Ratio	**0.63**

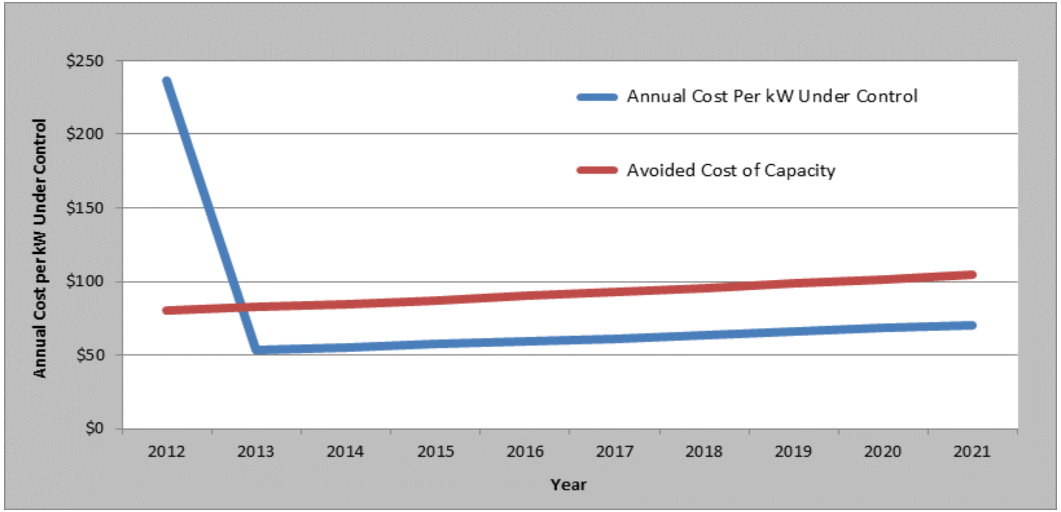
- Range: 0.22 to 1.06 (two programs above 1.00)

Sensitivity Analysis

- A single, historical benefit cost ratio from the 2012 DR season has limited value for making a decision about whether to continue DR.
- The SWE conducted sensitivity analyses to demonstrate how TRC results can change based on a variety of conditions and assumptions.
- The analysis involved variables such as:
  - Generation Cost
  - T&D Cost
  - Reduced Incentive Cost
  - Line Loss Values
  - Full Load Reduction
  - Dual Enrollment

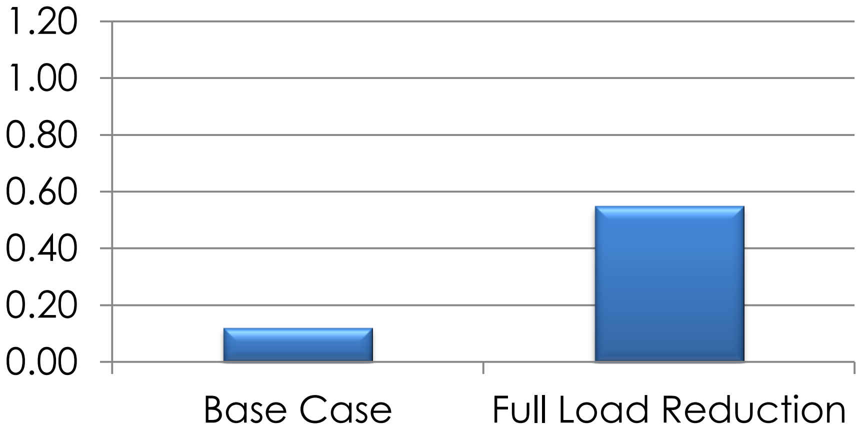
Multi-Year Analysis of DLC

- Program investments in a DLC program are typically front-loaded because of cost of equipment
- Equipment costs are recovered over useful lives of 8 to 10 years
- SWE performed DLC sensitivities using a 10-year life



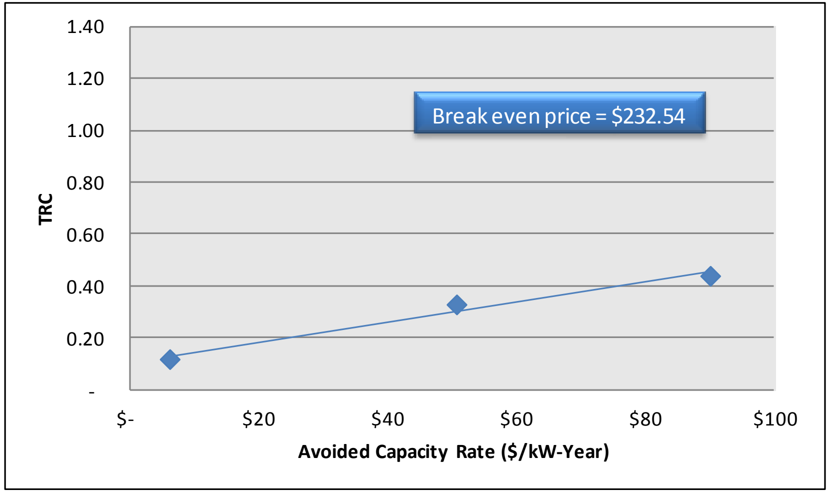
Full Load Reduction for DLC

- Use number of devices times kW reduction per device – do not average in zeros for non-control Top 100 hours
- SWE believes this approach is appropriate because the EDC makes the investment and pays the incentive to have the load under control *if necessary* to reduce peaking conditions

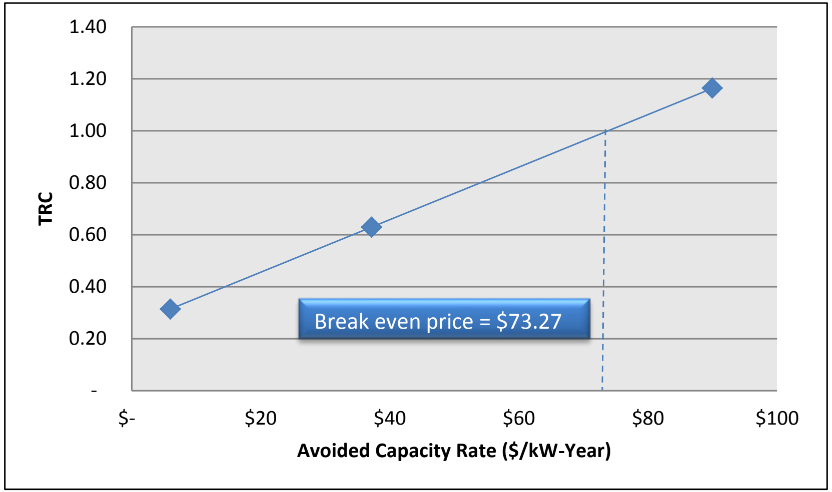


Avoided Generation Capacity Costs

Combined DLC Programs



Combined Curtailment Programs



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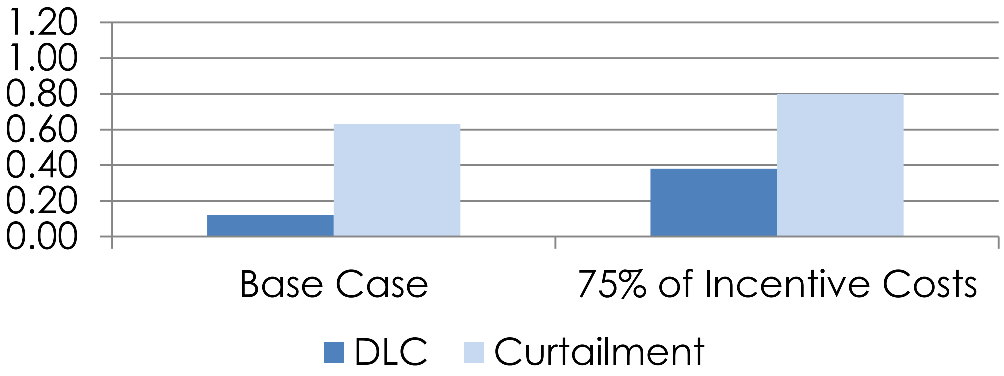
INCENTIVES

- High incentives paid for program participation appear to be a major component of costs
- The mandated Act 129 demand reduction requirements likely necessitated higher-than-typical incentives
  - Penalty-avoidance
  - Require control for *at least* 100 hours



INCENTIVES

EDC	Incentive Structure	Effective 1-Year Incentive
PPL, Duquesne	$32 per year	$32
Penelec, Penn Power	$40 initial payment; $20 per year.	$60
Met-Ed	$50 initial payment; $40 per year.	$90
PECO	$30 per month for each summer month.	$120

Utility	Incentive Structure	Effective 1-Year Incentive
Atlantic City Electric Co.	$50 1-time payment; not recurring	$50
Baltimore Gas & Electric	$50 upfront, $50/year for 5 years	$100
Delmarva Power & Light	$40 per year	$40
Dominion Virginia Power	$40 per year	$40
Duke Energy Ohio	$5 minimum, plus incentive/ control hour based on market price	Cannot Estimate
Jersey Central Power & Light	$50 1-time payment; not recurring	$50
Commonwealth Edison	50% Cycling - $5 per month	$20
	100% Cycling - $10 per month	$40
Public Service E&G Co.	Option 1 - $50 1-time payment	$50
	Option 2 - $11 plus $4/month	$27

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Worst/Best Case Scenarios

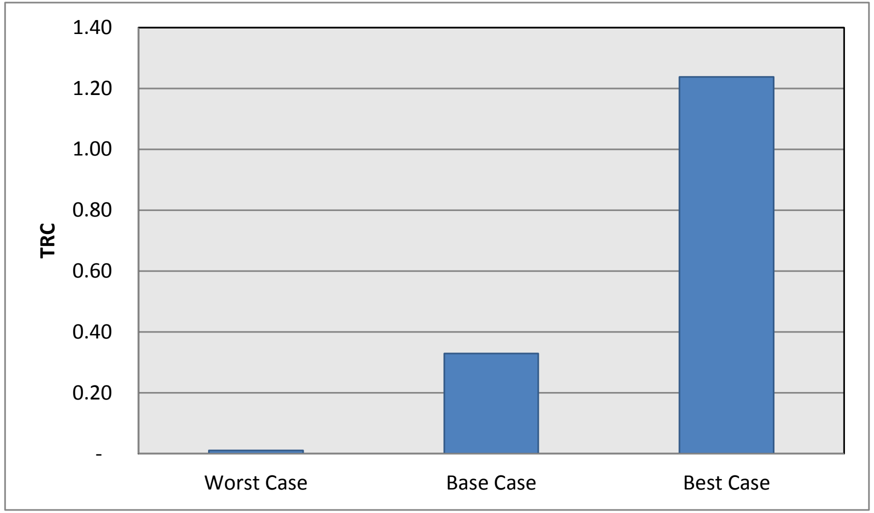
- **Worst case scenario**
  - Low avoided generation capacity cost ($6 per kW-Year)
  - No avoided T&D costs
  - Highest program costs on a per-kW basis
  - Highest incentives

- **Best case scenario**
  - High avoided generation capacity cost ($90 per kW-Year)
  - High avoided T&D costs ($50 per kW-Year)
  - Lowest program costs on a per-kW basis
  - Lowest incentives

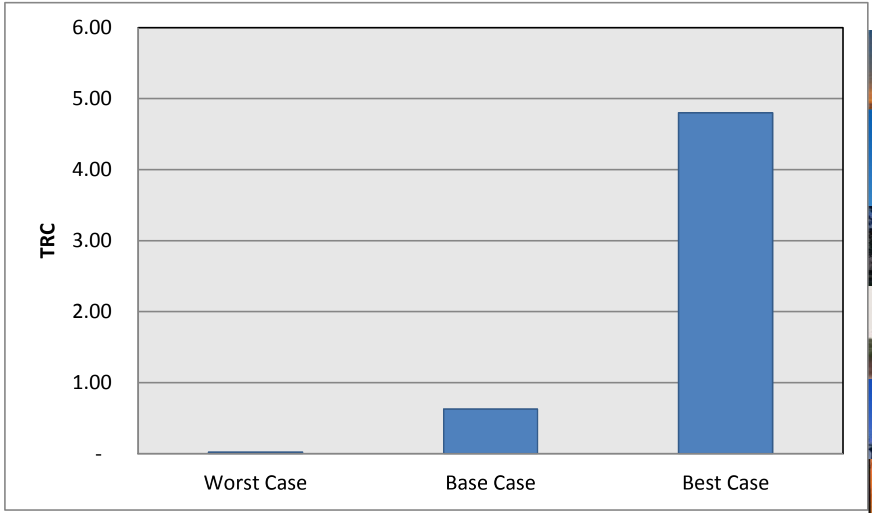
Worst/Best Case Scenarios

- EDC DR programs could likely achieve TRC ratios greater than 1.0 given some changes to program design and favorable market conditions.

Combined DLC Programs



Combined Curtailment Programs



Findings and Recommendations

Key Findings

- The Act 129 DR programs <u>may</u> not be cost-effective as offered in 2012
- The SWE doesn't believe this finding automatically means that DR should not be included in future phases of Act 129
- Market conditions and the legislative requirements of Act 129 contributed to the high acquisition costs and low benefits of the PY4 DR programs

Key Findings

- Factors that contributed to low TRC ratios
  - Low market price for generation capacity
  - Top 100 hours protocol
  - Aggressive targets
  - High program startup costs
- Exclusions
  - Wholesale Price Suppression
  - T&D Benefits

Market Price of Generation Capacity

- Primary benefit for DR programs
- Market prices were low in the 2012, particularly for the western EDCs
- Final Report recommended careful consideration of the BRA results for the 2016/2017 delivery year
- Capacity prices are down from previous years
  - $43.48/kW-year in the MAAC zone

Top 100 Hours Protocol

- Number of dispatch hours drove the acquisition price up for DR resources
- Low LMPs, near-zero probability of a 5-CP hour
- Predictive difficulties
  - EDCs paid for load reductions that didn't "count"
  - Abnormally cool August led to EDCs saving resources for hot days that never came

Aggressive Targets

- Most EDCs needed to achieve 2.0-2.5% demand reduction target through DR programs to meet the 4.5% target
- 2.0-2.5% demand reduction from DR in a single summer is aggressive compared to other states (assuming the rest is achieved through energy efficiency)
- Penalties for non-compliance force EDCs to pay DR resources at elevated incentives to secure participation.
- Penalties also discourage non-dispatchable DR programs because the savings are less certain.

Program Startup Costs

- Equipment and installation are the two largest costs for a DLC program and must occur upfront
- C&I programs also experience startup costs that increase first-year acquisition costs to a lesser extent

Load Curtailment Programs

- SWE estimates that 55% of the MW enrolled in the Act 129 Load Curtailment programs were also enrolled in PJM ELRP
- Only a fraction of customers enrolled in the PJM Economic program are actively participating indicating LMPs aren't high enough to engage customers.
- EDC intervention is not needed to bring these customers to market
- Any Act 129 DR programs for the non-residential sector should focus on adding incremental value to the PJM programs

Direct Load Control

- 2012 TRC ratios were low (< 0.1)
- Lifetime program TRC ratios are marginal
- Measure life and annual incentive amount are the key factors
- *Continuing* an existing DLC program is likely cost-effective if the Phase I equipment and installation costs are considered to be "sunk"

RECOMMENDATIONS

- Additional research is needed in two areas
  - Wholesale price suppression
  - T&D benefits
- Top 100 hours compliance period should be revised
- The number of hours DR should be called will vary
  - By EDC
  - From year to year

Recommendations

- DR impacts should be measured over a subset of hours when certain conditions are met
- Real-time LMPs can serve as the "trigger" for DR. SWE recommends a threshold of $200 or $250 per MWh.
  - Responds to both high demand and reduced supply
  - Requires rapid dispatch
  - Could cause challenges for weather dependent resources
- Use the day-ahead forecast as a trigger
  - Safer for the EDCs
  - Doesn't respond well to generation shortfalls

Recommendations

- Optimal number of MW to dispatch should be identified through a DR potential study
- 2% budget ceiling means that spending should be allocated between DR and EE where it will be most beneficial
- SWE Potential Assessment will consider a limited number of funding splits and make recommendations
  - 1% EE, 1% DR
  - 1.5% EE, 0.5% DR
  - 2% EE, 0% DR

QUESTIONS?