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Keeping the Lights On in Texas: Meeting ERCOT's 2007 and 2008's Needs

Emergency Interruptible Load Task Force, Texas PUC

October 31, 2006

Considerations

- **General observations:**
  1. **DR can provide immediate capacity shortfall relief**
  2. **DR can be reliable, cost effective and does not need long term contracts**

- **Specific suggestions:**
  1. **Procure enough DR to make a difference**
  2. **Require two way telemetry**
  3. **Establish earlier trigger in the EECP**
  4. **Set appropriate expectations – not 1 day in 10 year**
  5. **Included unannounced testing protocol**

Alternative Proposal

Qualifications & requirements

Capacity	ERCOT to determine capacity sufficient to avoid blackouts; Approximately 1000-3000 MW (more than the minimum 2200 MW which are estimated to have been needed to have avoided the April 17, 2006 blackout); Resources could be dispatched in blocks less than total program capacity
Target Load	All interval metered commercial, institutional and industrial customers; No minimum size requirement to participate
Certification	DR Aggregators must become certified to participate in EIL and abide by appropriate financial assurance protocols
Technology requirement	Telemetry, at least 15 minute interval data; Allows ERCOT to verify load response during dispatch; allows appropriate baseline determinations and simplifies settlement
Measurement and verification	Initially, test audit to determine capacity, then asset is “ready to respond,” then asset’s capacity is adjusted after each dispatch based on performance during that event, annual or biannual tests if no event called to assure reliable capacity is available
Baseline methodology	Weighted historical average of interval data of previous 10 business days, weather adjusted; event performance is the difference between consumption during a DR event and the baseline (ISO-NE)

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Alternative Proposal, Continued

Dispatch and recall	**Notification**.10-minute, 30-minute and 1-hour notification **Dispatch**. Dispatch via either hard line link to control room (*e.g.*, SCADA link to QSE) or internet based system to QSE. Key is not to require under frequency relays which have the unfortunate ability to swing the system dramatically from under frequency to over frequency situations **Recall.** Granular recall is possible.
Who pays?	Network load pays for EIL program; an emergency demand response program is a reliability product
Who gets paid?/ How are they paid?	QSE is paid; QSE pays responsive load
Compliance issues	Initial audit test to determine capacity and verify capability to respond; EIL must be dispatched or tested annually or semi-annually; Capacity adjusted after each dispatch to experienced performance.
Effect on clearing price	The relationship between EILP and scarcity pricing must be determined; EnerNOC has no position

Alternative Proposal, Continued

Coordination with other ancillary services	Load cannot participate simultaneously in EIL and LAARs (or any other ancillary service program)
Self-provision	Bilateral contracts possible
Contract duration	2 year program; Annual contract *Monthly contract would not work*: → Most likely EIL would not be procured in shoulder months, yet ERCOT emergencies have occurred very recently in shoulder months (April and October 2006) → Monthly procurement will not provide loads with enough revenue assurance to participate
Procurement contract v. auction	Auction is preferable – will show the true value of this product in the market; Given current time constraints, an expedited auction might not be possible; If contract, ERCOT should initiate contract on a first come, first served basis

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APPENDIX

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The Other ISO Emergency DR Programs Have Better Designs

Program Element	*New England*	*New York*	*PJM (non ASM)*	*PJM ASM*	*CA*	*Texas*
Real Time Monitor and Control	yes	no	no	yes	no	no
Reasonable Baseline	yes	½ yes	mixed	NA	mixed	no
Reasonable Event Trigger	yes	mostly	yes	yes	no	yes
Reasonable Availability Payment	yes (CT) no (other)	in part	no	yes	in part	in part
Clear authority/ roles/ guidance	yes	yes	mixed	yes	no	mixed
Aggregator role	yes	yes	yes	yes	in transition	yes
ASM access	pilot	no	NA	yes	no	yes
Timely settlements	yes	no	no	tbd	no	yes

ERCOT Program Not Consistent with Response Times and Payment Levels for Emergency Demand Response Programs in Other Markets

Program	Description	Response Time	Payment Required
CAISO: Base Interruptible Program	Demand response events initiated during a Stage 2 emergency (when operating reserves fall below 5%)	10 minutes	$84/kW-year
ISO-NE: GAP RFP	Specific to Southwest Connecticut (area of transmission constraint); demand response events initiated during OP4 Actions 9 and 12 (Action 9: Interrupts those resources that do not require a voltage reduction to be implemented; Action 12: when the ISO implements a voltage reduction of 5% of normal operating voltage requiring more than 10 minutes to implement)	30 minutes	$100/kW-year
NYISO: ICAP/ Special Cases Resources Program	Activated in response to a forecast or actual operating reserve deficiency	2 hours	Market based; zone dependent; payments from November 2005-October 2006: New York City=$116/kW-year; Long Island= $93/kW-year

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Existing ERCOT Projects With Small Incentive Levels Have Not Been Successful….

Program	Description	Payment Level	Participation
TXU	Emergency Load Management SOP, activated at ERCOT EECP Step 3, one hour notification	$22.5/kW-yr	23.75 MW (2006 plan)
AEP	Emergency Load Management SOP, activated at ERCOT EECP Step 3, one hour notification	$25.78/kW-yr	3.65 MW (2006 plan)

Current capacity in other ISO/RTO reliability based DR programs

- **NYISO ICAP/SCR**
  - All zones: 1265 MW
  - Zone J, NYC: 426 MW
  - Zone K, Long Island: 201 MW
- **ISO-NE 30 Minute Real-Time Demand Response**
  - All Zones: 522 MW
  - Connecticut: 395 MW (capacity constrained)
  - 54 Towns in Southwest Connecticut: 211 MW (capacity constrained)

In other ISO/RTO markets, DR aggregators must become certified to participate

- **PJM**: Curtailment Service Provider (CSP)
- **NYISO**: Responsible Interface Party (RIP) and Meter Data Service Provider (MDSP)
- **ISO-NE**: Enrollment Participant (EP) and Internet Based Control System Provider (IBCS Provider)
- **CAISO**: Demand Reserves Partnership Provider (DRP Provider)

Different markets have interval data requirements

- **PJM**:
  - 1-minute interval data: Synchronized Reserve Market
- **ISO-NE**:
  - 5-minute interval data: 30 minute Real-Time Demand Response

Different markets have different baseline protocols

- **ISO-NE**: Weighted historical average of 5 minute interval data, weather adjusted ← this is the most accurate
- **NYISO**: Average peak monthly demand

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Different markets have different notification requirements

Those DR programs around the country that require 10 minute response are relatively new or in pilot form

- **10 minutes**
  - PJM Synchronized Reserves Market (FYI—EnerNOC enabled the first DR asset in this market, August 2006)
  - ISO-NE Demand Response Reserves Pilot Program
- **30 minutes**
  - ISO-NE 30 Minute Real-Time Demand Response
  - SDG&E's Base Interruptible Program
- **2 hours**
  - NYISO ICAP/Special Case Resources (SCR)

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ISO-NE Experience on August 2, 2006