Incentive Compatible Pricing Mechanisms for Meeting Expected Ramp Capability in Real-time Markets

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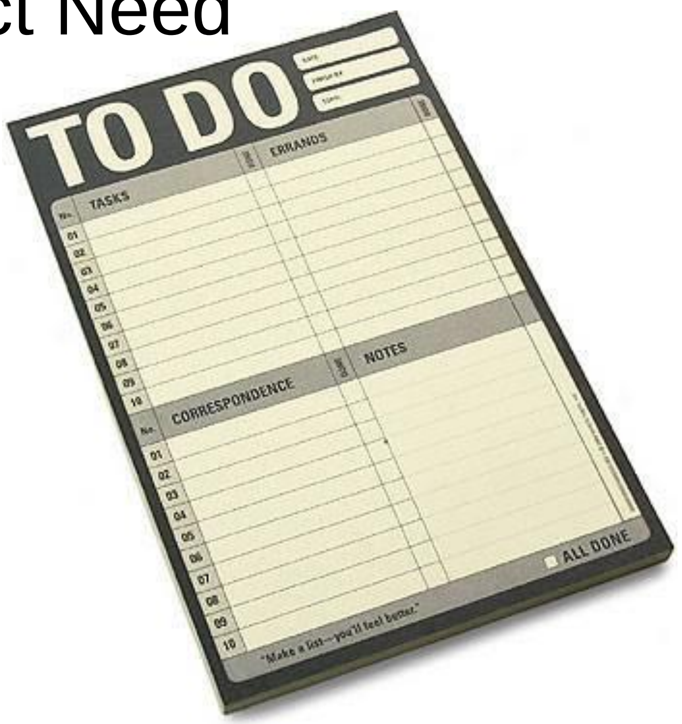
Agenda

- Current Ramp Product Design Overview
- Considerations of Ramp Product Need
- Numerical Examples
- New Market Designs
- Summary and Conclusions



Industry Relevance

- California ISO Shaping a Renewed Future **FlexiRamp**
  - Reserving flexible capacity for use in real time
  - Reduce price spikes
- MISO **Ramp Product & Look Ahead Dispatch**
  - Capability to ramp 10-minutes ahead
  - Further look-ahead for ramping needs assessment
-
- Xcel Energy® **Flex Reserve**
  - Reserve for long-term wind ramps that are not regulation or contingency
- ERCOT **Ancillary Service Redesign**
  - Wide scale reorganization of ancillary service products
  - Primary frequency response, fast frequency response, inertia service
  - Regulation requirements based on forecast error characteristics
- Performance-based regulation service (*FERC Order 755*)

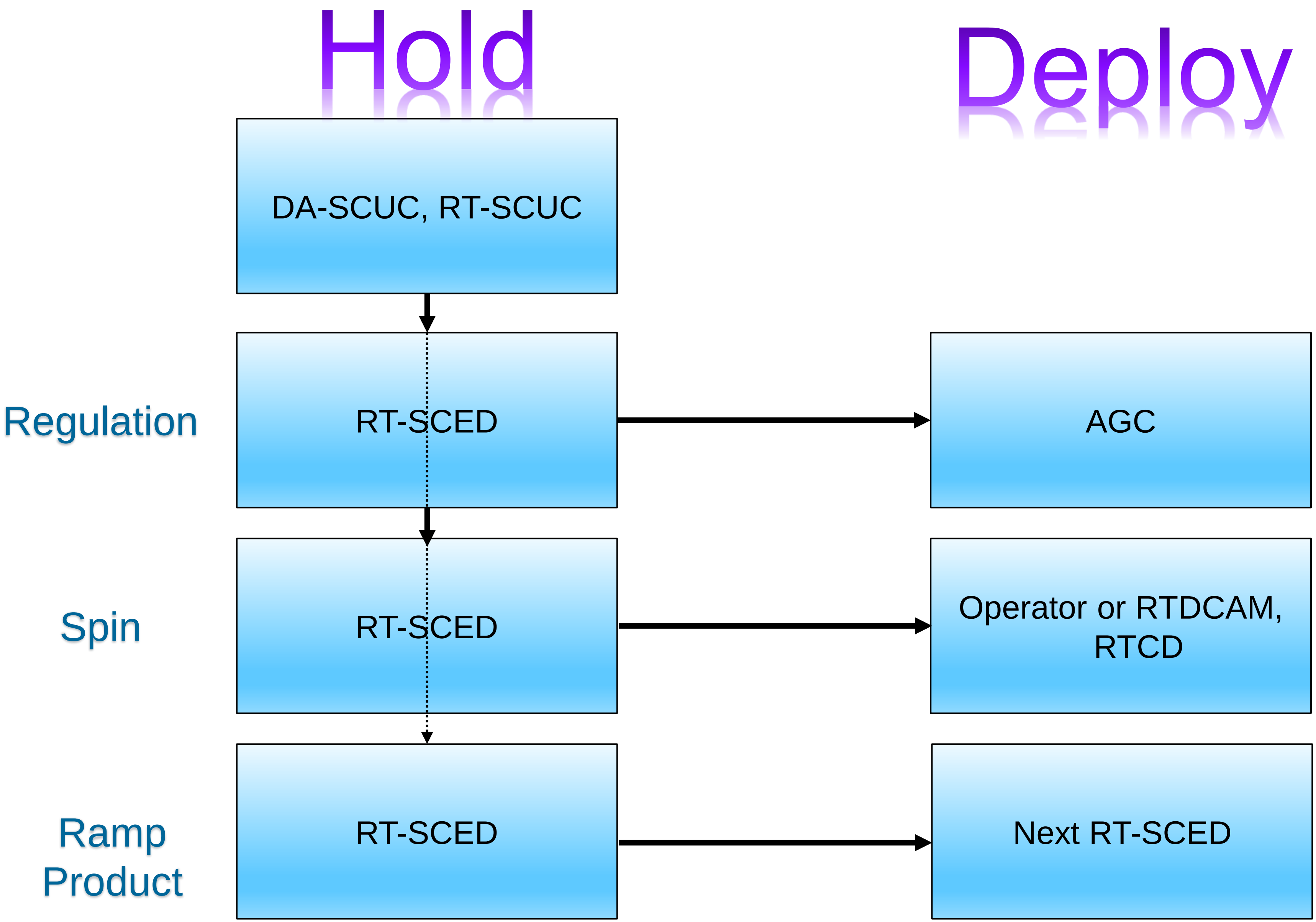
Flexi-ramp/ramp Capability Product Description & Motivation

- Essentially a constraint, similar to a reserve constraint in selected or all commitment and dispatch models used for scheduling and market clearing
- Main objective to reduce the number of price spikes due to ramp unavailability
  - Reliability benefits can also be observed
  - Reduction in costs may be present as well
- Mixed Integer Programming Solver too good! Leaves no residual headroom.
  - MIP vs. LR – get the (near) exact capability asked for
  - Transient price spikes set by reserve shortage prices when ramp capability is not sufficient
  - Typically not a true shortage event or in danger of actual load shedding event, offline resources available to be turned on, but not by dispatch model (may result in ACE in area)
- Ramp products accounts for variability and uncertainty
  - Multi-period dispatch also accounts for variability, but may not incentivize for ramp capability
- Pays resources for holding the capacity and ramp for this product
  - They will get paid energy price as well if used for energy with specific rules against double counting

Active Power Ancillary Service Comparisons

	Regulation	Spin and non-spin	Ramp product
What Guides Response	Automatic (AGC)	Operator-directed	SCED
Frequency of Use	Every interval	Rarely	often
What it is used for	Short-term changes in load and VER	Contingencies	Forecast errors and (several minutes timeframe) ramp events
Penalty Price	$80-$600 /MW-h (medium)	Typically >= $500 /MW-h (high)	Between $5 and $250 /MW-h (low)
Non-zero Bids Allowed	Yes: wear and tear and efficiency costs	Sometimes	No
When Deployed	After dispatch interval (in between RTSCEDs)	After dispatch interval (sometimes through new dispatch, e.g., RTD-CAM RPU, RTCD)	Part of dispatch interval

Active Power Ancillary Service Comparisons



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CAISO and MISO Approach Comparison

	MISO	CAISO
Ramp horizon time	10 minutes (2 RTSCED intervals)	5 minutes (1 RTSCED interval)
Insufficiency cost (scarcity price for ramp product)	$5/MW-h	Stepped demand curve ($11 to $250/MW-h for upwards)
Requirement	Expected Variability + 2.5σ (uncertainty)	Expected variability + 95th percentile (uncertainty)
Markets	DAM, LAC, and RTM	FMM and RTM (not DAM)
Deliverability	Post-deployment deliverability constraints	

Considerations for ramp product need

<u>Things that may impact whether there is a need</u>

- Regulation service with a small penalty price for small shortages
- Off-line CT and relaxed min-gen pricing
- Longer horizon real-time markets, e.g., 15-mins
- Non-spin reserves that vary with time and can meet net load ramp and forecast error
- Reserve ramp constraints that are not shared with energy ramp constraints
- 5-minute settlements
- Persistence VER forecasts vs. improved VER forecasts
- Lack of price spikes
- Lack of VER
- Lack of self scheduling
- Significant ramp capability already present

Market Design for Ramp Capability Based on Expected Ramp Capability

Market Models for Ramp Capability

Expected Variability

- Current ramp product designs can reduce short-term price spikes by pre-positioning and committing above expected real-time net load
- Look-ahead dispatch, assuming good look-ahead forecasts, can more efficiently prepare the system compared to ramp products for variability
- Look-ahead dispatch, however, can lose the incentive for pre-positioning units (no lost opportunity cost), especially if the ramp is less than expected
- Current ramp products may not respect network constraints for expected variability (exception MISO post-deployment flow constraints)

Uncertainty

- Current ramp products do not model the deployment costs ramping, which may be higher than the capacity costs
- It is possible for look-ahead dispatch to also prepare for uncertainty; however, constraint relaxations (penalty prices) across become important
- Multi-scenario models (e.g., stochastic programming) can prepare for uncertainty more efficiently than current ramp products and model deployment costs [Wang & Hobbs 2014]
- Ramp products for uncertainty may be duplicating regulation reserve, unless regulating reserve can be reduced
- Because of the interplay between regulation reserve and ramp products, ramp products may not have a substantial reliability improvement
- Unless focused in the day-ahead commitment with day-ahead uncertainty, ramp products are unlikely to have a significant impact on production costs

Single Period (SP)

	Cost	Ramp	Capacity
G1	20$/MWh	2 MW/min	100 MW
G2	30$/MWh	2 MW/min	100 MW
G3	80$/MWh	2 MW/min	100 MW

Load	I1	I2
Scenario 1	200	219
Scenario 2	100	119

Single Period No Flex constraint

Scenario 1	I1	I2
G1	100	100
G2	100	100
G3	0	10
LMP ($/MWh)	30	1000
Flexi price ($/MWh)	N/A	N/A

Penalty

Scenario 2	I1	I2
G1	100	100
G2	0	10
G3	0	9
LMP ($/MWh)	20	80
Flexi price ($/MWh)	N/A	N/A

Time-Coupled Multi-Period (TCMP) Market Model

	Cost	Ramp	Capacity
G1	20$/MWh	2 MW/min	100 MW
G2	30$/MWh	2 MW/min	100 MW
G3	80$/MWh	2 MW/min	100 MW

Load	I1	I2
Scenario 1	200	219
Scenario 2	100	119

Time Coupled Multi-Period No Flex constraint

Scenario 1	I1	I2 (adv.)
G1	100	100
G2	91	100
G3	9	19
LMP ($/MWh)	30	(130)80
Flexi price ($/MWh)	N/A	N/A

Scenario 2	I1	I2 (adv.)
G1	91	100
G2	9	19
G3	0	0
LMP ($/MWh)	20	(40)30
Flexi price ($/MWh)	N/A	N/A

Single Period Ramp Capability Product (SPRC)

	Cost	Ramp	Capacity
G1	20$/MWh	2 MW/min	100 MW
G2	30$/MWh	2 MW/min	100 MW
G3	80$/MWh	2 MW/min	100 MW

Load	I1	I2
Scenario 1	200	219
Scenario 2	100	119

Single Period With Flex ramping constraint

Scenario 1	I1	I2
G1 (Sched/Flex)	100/0	100
G2 (Sched/Flex)	91/9	100
G3 (Sched/Flex)	9/10	19
LMP ($/MWh)	80	80
Flexi price ($/MWh)	50	---

Scenario 2	I1	I2
G1 (Sched/Flex)	100/0	100
G2 (Sched/Flex)	0/10	10
G3 (Sched/Flex)	0/10	9
LMP ($/MWh)	20	80
Flexi price ($/MWh)	0	---

Cost and Reliability Results

	Cost	Ramp	Capacity
G1	20$/MWh	2 MW/min	100 MW
G2	30$/MWh	2 MW/min	100 MW
G3	80$/MWh	2 MW/min	100 MW

Load	I1	I2
Scenario 1	200	219
Scenario 2	100	119

Scenario 1	cost	penalty
Single period	$19,800	9
Multi-period	$11.970	---
Flex ramp product	$11,970	---

Scenario 2	cost	penalty
Single period	$5,020	---
Multi-period	$4,660	---
Flex ramp product	$5,020	---

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Incentive Compatibility

Scenario 1 (Same Costs, Same Schedules)	Time-coupled multi-period	Flex ramping capability product
G1 cost	$4,000	$4,000
G1 revenue	$11,000	$16,000
G1 profit (rev – cost)	$7,000	$12,000
G2 cost	$5,730	$5,730
G2 revenue	$10,730	$15,730
G2 profit (rev – cost)	$5,000	$10,000
G3 cost	$2,240	$2,240
G3 revenue	$1,790	$2,740
G3 profit (rev – cost)	$-450	$500

Negative Pricing

	Cost	Ramp	Capacity
G1	20$/MWh	2 MW/min	100 MW
G2	30$/MWh	2 MW/min	100 MW
G3	80$/MWh	2 MW/min	100 MW

Load	I1	I2
Scenario 3	100	129

Time Coupled Multi-Period No Flex constraint

Scenario 1	I1	I2
G1	91	100
G2	10	20
G3	0	9
LMP ($/MWh)	-20	80

Importance of Look-Ahead

	Cost	Ramp	Capacity
G1	20$/MWh	2 MW/min	100 MW
G2	30$/MWh	2 MW/min	100 MW
G3	80$/MWh	2 MW/min	100 MW

Load	I1	I2	I3
Scenario 3	100	129	-
Scenario 3A	100	129	129
Scenario 3B	100	129	139
Scenario 3C	100	129	149

Time Coupled Multi-Period No Flex constraint

LMP ($/MWh)	I1	I2	I3
3	-20	80	-
3A	-20	80	30
3B	-40	80	50
3C	-70	80	80

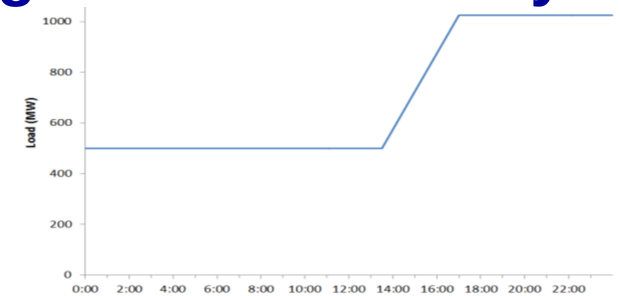
Summary

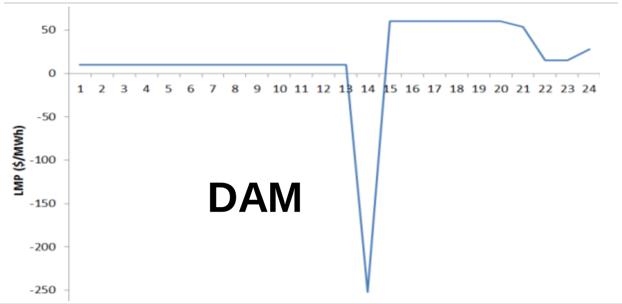
- TCMP and SPRC improve reliability (ACE) and reduce price spikes compared to SP
- TCMP performs better than SPRC in terms of production cost efficiency
- SPRC better incentivizes resources (and reduces negative profits/uplift) compared to TCMP
  - **KEY: When advisory intervals are wiped out, units providing a reserve for future advisory intervals, are not getting paid for that reserve**
- Negative prices can occur due to ramp constraints
- The length of look-ahead horizon can have an influence over the binding (first) interval price

New Solutions

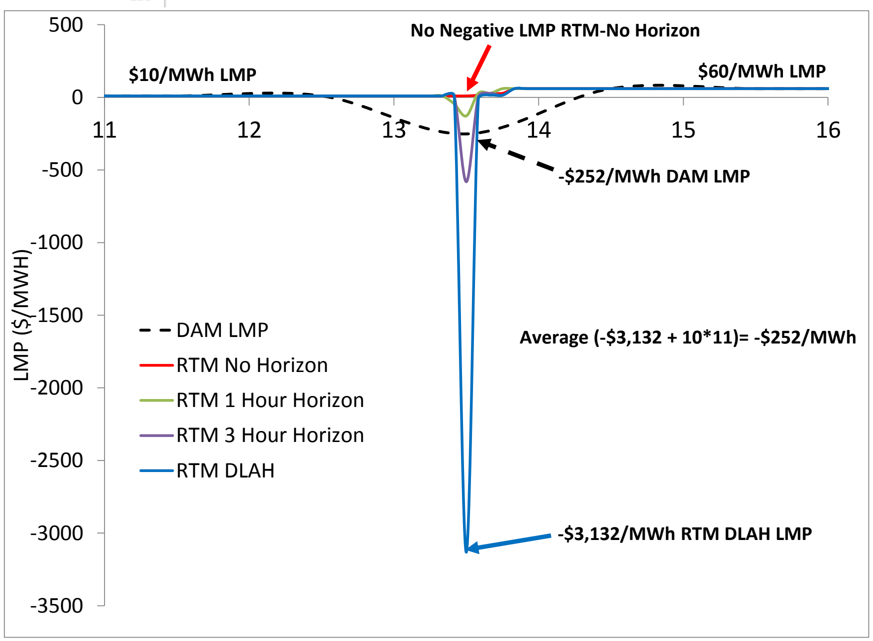
- Cross Interval Marginal Price (CIMP) prices based on marginal cost of binding interval due to increment demand in future intervals
  - Incentivizes resources to start their ramp when the binding interval LMP is below their costs
  - $CIMP_t = \frac{\partial \mathcal{L}(P_{i,1})}{\partial L_T},\ T \neq 1$
  - $CIMPRev_t = \left(P_{i,T}^{RT-ADV}\right) * CIMP_t$
  - **Key**: Since the first interval decision is binding, incentive must be commensurate with cost
  - Locational CIMP: Can be calculated similarly to LMP based on number of marginal units
- Dynamic Look-ahead Horizon (DLAH) where the look-ahead can guarantee it has information to create prices based on true marginal costs
  - $I_{END} = time(now) + \max_{i \in NG} \frac{(P_i^{max} - P_{i,act})}{RR_i}, \frac{(P_{i,act} - P_i^{min})}{RR_i}$

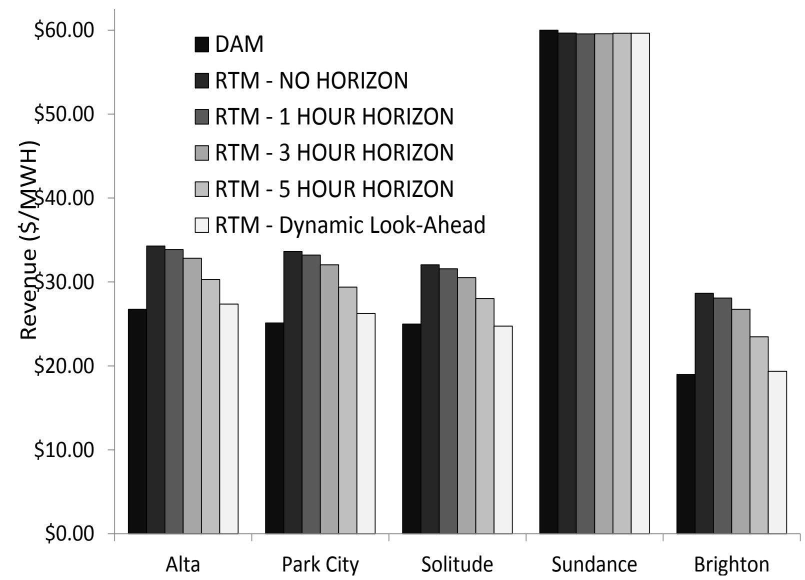
Negative LMP and Dynamic Look-ahead Dispatch





	Cost ($/MWh)	Capacity (MW)	Ramp Rate (MW/Minute)	Start-up time
Alta	14	110	0.5	3 hours
Park City	15	100	0.5	3 hours
Solitude	28	520	0.5	3 hours
Sundance	60	200	10	10 minutes
Brighton	10	600	0.5	6 hours





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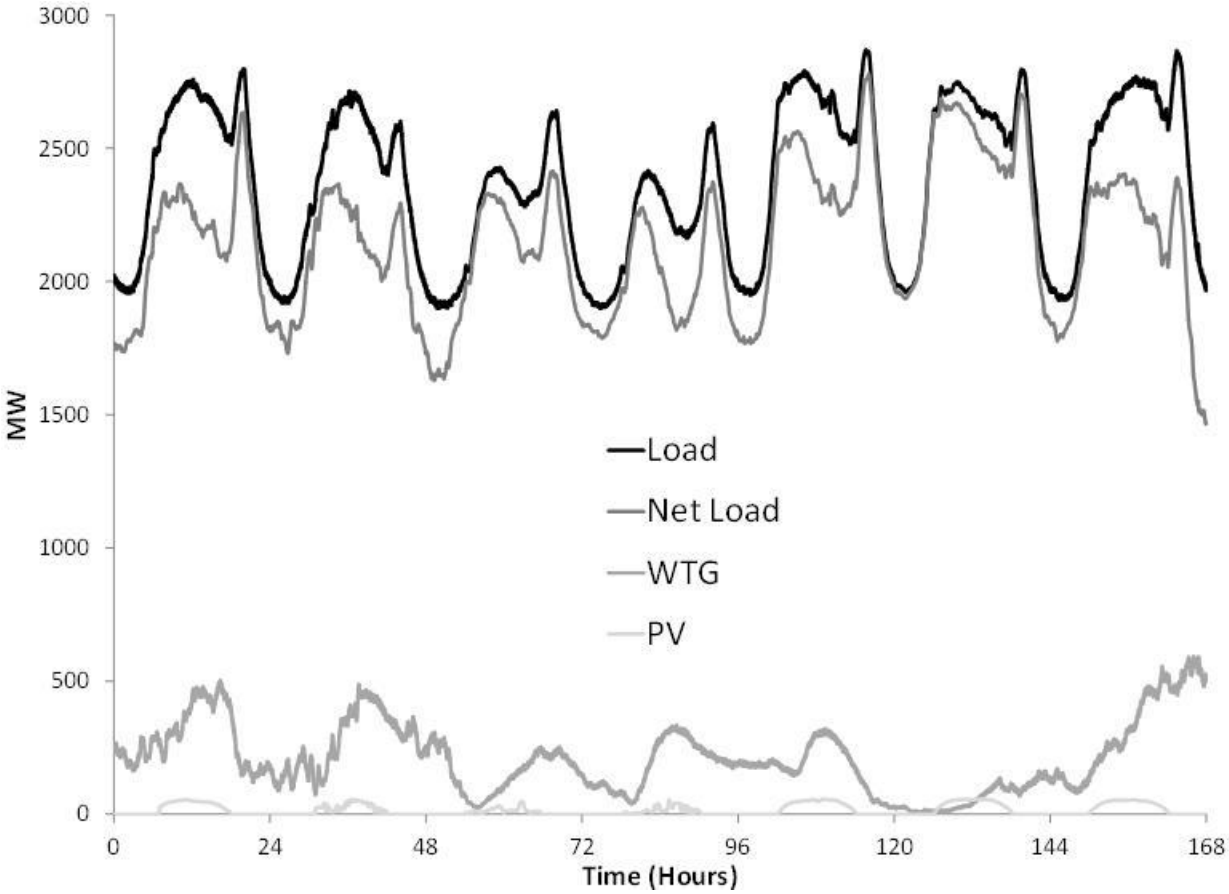
Case Study - CIMP



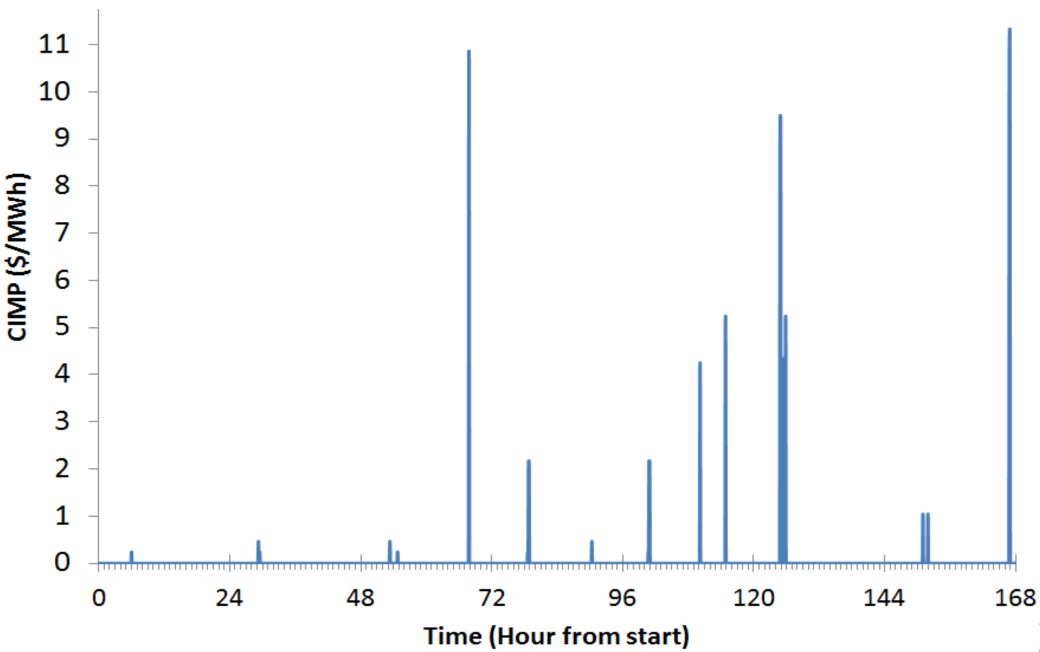
IEEE Reliability Test System: 1 week, with VG, daily DASCUC, 15-minute RTSCUC, 5-minute RTSCED, 4-sec AGC

Reliability Test System Task Force, "The IEEE reliability test system—1996," *IEEE Trans. Power Syst.*, vol. 14, no. 3, pp. 1010-1020, Aug. 1999.

CIMP

Unit-intervals with negative profit	Without CIMP	With CIMP	% reduction
Overall	9160	9038	1.3%
Eliminate no-load cost from total costs	3372	2979	11.6%
Eliminate no-load cost from total costs and all unit-intervals where unit is at P_{min}	560	280	50%

	Cost ($M)	Price Spikes	σ_{ACE} (MW)	AACEE (MWh)
SP	$3.164	121 (6%)	8.42	675
SPRC	$3.158	79 (3.9%)	6.59	594
TCMP	$3.147	57 (2.8%)	6.05	559



Summary and Conclusions

- Ramp products provide benefits for price spike reduction
- Many different potential reasons for whether a ramp product is needed or not (devil is in the details)
- There may be some further evolution in providing for a more efficient, reliable, incentive compatible product for providing ramp in energy markets
- Ramp products may provide better incentives, Time-coupled dispatch provide more efficient solutions.
- New slight modifications to the current market design may provide efficient solutions that meet multiple objectives
- Designs may need to be evaluated in the case of uncertainty and based on the various different market designs in practice (again, devil is in the details)

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