ISSUE 13: Control Action Operating Reserve (CAOR)

Issue Description:

Control Action Operating Reserve (CAOR) is the implementation of standing offers in IESO reserve markets for certain out-of-market control actions that are available to the IESO and that can be considered as part of meeting the Ontario operating reserve (OR) requirement.

In July, 2003, the IESO Board approved market rule amendment (MR-00235-R00-R05) introducing CAOR in the market. This initiative authorized the IESO to include standing offers to represent 400 MW of control actions that were previously considered as meeting the OR requirement at $0 and deemed to be 'out-of-market' OR sources (i.e. voltage reductions and the ability to forego the acquisition of OR). The IESO initiated the market rule amendment in response to the adverse impacts resulting from the manual use of the out-of-market sources for OR. In November 2005, the IESO Board approved an additional 400 MW of standing offers for CAOR as well as a change in the IESO action in anticipation of an OR shortfall (insufficient offers to satisfy all energy and OR requirement)[1].

At present, there are two aspects of the current implementation of CAOR that represent market pricing issues. First, is the existing pricing principle and structure of the CAOR standing offers appropriate? Second, what is the market and pricing impact of the proposal to remove CAOR from pre-dispatch[2]? Each of these is discussed in more detail below.

Background:

History
Refer to Appendix A for CAOR history.

CAOR usage
Refer to Appendix B for update on CAOR usage for the period between Jan. 2005 – Jun. 2008.

CAOR structure

In 2003, the original CAOR structure consisted of two virtual generation resources created at the Richview bus, each with the capacity of 400 MW. One resource, RICHVIEW-230.G_3VR, was utilized for the original offer of ($30, $30.10) for both pre-dispatch and real time. The second

[1] The change was that the IESO would no longer manually reduce the operating reserve requirement under the conditions noted .

[2] IESO has proposed to remove CAOR from pre-dispatch. Refer to the document 'MPWG 51 Issue 13 - Proposal to Remove CAOR from Pre-dispatch'.

resource, RICHVIEW-230.G_5R, was created at the same time to allow for the future expansion of CAOR.

In 2005, the IESO Board approved an additional 400 MW of standing offers for CAOR. The additional MWs were incorporated only in the real time dispatch and pricing algorithm. The following table depicts the current CAOR pricing structure.

Current Control Action Operating Reserve in Market - Resource Offers						
Resource	Total Quantity (MW)	30 min OR Price ($/MW/Hr)	10 min Non Sync OR Price ($/MW/Hr)	Resource OR Scheduling Ramp Rate (MW/Min)	Energy Bid ($/MWh)	Resource Energy Ramp Rate (MW/Min)
RICHVIEW-230.G_3VR	400 PD & RT	30.00	30.10	999	2000.00	4 up, 999 down
RICHVIEW-230.G_5VR	200 RT	N/A	75.00	999	2000.00	4 up, 999 down
RICHVIEW-230.G_5VR	200 RT	N/A	100.00	999	2000.00	4 up, 999 down

CAOR Pricing Principle

During the first year after market opening, the IESO practice of manually reducing the OR requirement during shortage periods had counter-intuitive implications on energy and OR market clearing prices.

On July 3, 2003, 400 MW of CAOR offers were created in the market at $ 30.00 for 30 minute (30R) OR and $ 30.10 for 10 minute non-synchronized (10N) OR. The prices applied were based on an objective that CAOR would be scheduled at roughly the same frequency (around 7%) as the IESO manual reductions noted above. Also, about 95% of the time, the OR clearing price in constrained pre-dispatch sequence was below $30/MW. The basis for creating a different price for 10N and 30R resources was to ensure that CAOR was typically scheduled as 30-minute OR before 10N OR. Therefore, CAOR would be scheduled when economic rather than on ad hoc basis when shortage conditions arise.

On November 23, 2005, the IESO introduced an additional 400MW of standing offers for CAOR. The principle behind increasing the CAOR quantity in the market was to further reduce instances of counter intuitive pricing. The additional 400MW were only offered in the real time sequence. In 2004, simulations were conducted to establish the prices for an additional 400 MW of CAOR (Refer to Appendix C for simulation results). The prices were assigned on the basis of minimizing the impact on energy and OR market prices

Stakeholders have raised issues with respect to the existing implementation of CAOR. They have expressed concerns that the existing pricing structure may displace other market offers of OR, thereby affecting market prices. Over the past few years, the frequency of scheduling CAOR has increased beyond 7% (rationale for the pricing of the first 400 MW of CAOR - Refer to Appendix B). Therefore, it is necessary to determine if the current CAOR pricing structure is still appropriate.

It should be noted that the IESO believes that some OR offers are strategic in nature rather than representing the actual cost of providing OR. For example, during freshet hydro-electric facilities prefer to run for energy instead of spilling excess water to offer into the OR market. Also, MWs offered in OR are also offered for energy. The co-optimization of energy and operating reserve could result in MWs used for energy while the corresponding OR offer remains in the OR stack. However, these OR offers are not actually available to provide OR.

At present, the IESO has recommended removing CAOR from pre-dispatch for operational reasons (Refer to 'Proposal to remove CAOR from pre-dispatch'). The effects on the market of this proposed change require consideration.

Why a Pricing Issue?

As noted above, the existing CAOR pricing structure may result in displacing available market OR offers and affecting market prices.

Also, if CAOR is removed from pre-dispatch as proposed, what are the market and pricing impacts? Would it cause increased divergence between real time and pre-dispatch pricing sequences?

Scope of Study:

- *Other Markets:* Conducting studies on the price structure and procedures of other markets for CAOR like mechanisms. Refer to Appendix C for the preliminary information on NY, PJM markets.
- *Academia:* Research papers based on pricing of OR by Dr. William Hogan.
- *Examination of Ontario OR offer curve:* To evaluate available and non-strategic market OR offers being displaced by CAOR.
- *Reliability impacts*
- *Market efficiency impacts:* To determine market efficiency and market price impacts due to possible changes in pricing structure and/or procedures.

Appendix A

History:

Industry reliability standards authorities such as North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Council (NPCC) and the IESO establish reliability standards with respect to Operating Reserve (OR) requirements in Ontario. It is IESO's objective to have those requirements satisfied using market sources through IESO administered markets.

At times the market offers and bids are insufficient to fully satisfy all energy and OR requirements. Under such conditions, the IESO can, according to reliability standards[3] and the market rules, disregard the OR requirements and/or consider the MW relief that would result from a number of control actions for meeting the OR requirement. A subset of these out-of-market control actions include disregarding the ten and thirty minute OR requirement, voltage reductions of 3 % & 5 % and making exports recallable[4].

During the first year of market operations, the IESO integrated the out-of-market measures into the market through a manual process. In most circumstances these control actions were counted towards the operating reserve requirement in periods where there was not enough market based OR offers. When the IESO expected or identified a shortage in an upcoming interval due to insufficient OR market offers, the operating reserve requirements were manually reduced (in accordance with relevant NERC and NPCC reliability standards) by the amount of the estimated market shortfall. This manual reduction in an operating reserve requirement had the effect of allowing the market to clear with available OR offers. The reserve requirement was lowered knowing that if a real time contingency were to occur, and the full OR requirement was required (i.e. without OR reduction) to respond to the contingency, both market based OR and out-of-market OR would be employed to respond to such situation.

These actions had counterintuitive implications on the OR, and the energy market clearing price (Joint Optimization for calculating prices). The decrease in reserve requirement led to a fall in reserve prices as the amount of supply remained constant and the OR demand had decreased[5]. A decrease in demand with steady supply will almost always lead to drop in price. This price drop was not providing the market with intuitive price signal. When the OR requirement was lowered and/or when control actions were used to provide the MW relief in OR demand, increase in OR prices was expected. But as the demand was lowered while supply remained unchanged, the MCP fell, signalling sufficient market resources when in fact the opposite may be true.

[3] According to NERC and NPCC (Document A6 – Operating Reserve Criteria) standards.

[4] For a listing of all control actions available to the IESO control room operators please refer to Appendix E of Market Manual 7.4; Emergency Operating State Control Actions. http://www.ieso.ca/imoweb/pubs/systemOps/so_GridOpPolicies.pdf.

[5] Lowering the OR requirement is a drop in OR demand, and is equivalent to a total decrease in market demand.

Other than counter-intuitive price drops, the manual implementation of out-of-market control actions added divergence between Pre-dispatch and Real time prices. The policy of the day was to only reduce the OR requirement in real-time which contributed to RT vs. PD price divergence.

In July 2003, the IESO's Pricing Initiatives Team studied the implications of manual use of out-of-market control actions and proposed a solution 'Control Action Operating Reserve (CAOR)' to mitigate the issues mentioned above. CAOR is the implementation of standing offers in IESO reserve markets for certain out-of-market control actions. With standing offers assigned to some of the out-of-market control actions, there was reduction in counter-intuitive price effects during times of scarcity. Under market rule amendment MR-00235-R00-R005, 400 MW of CAOR offers were created in the market at $ 30.00 for 30 minute (30R) OR and $ 30.10 for 10 minute non-synchronized (10N) OR.

The prices applied to the CAOR were chosen so that CAOR would be scheduled in the future in roughly the same frequency in which the 'out of-market' sources of reserve were used via manual intervention during the first year of market operations. After some analysis and consultation with market participants, the $30.00/MW for 30 minute reserve was chosen. The $30.10/MW was chosen for 10-minute reserve to ensure that CAOR was typically used first as 30-minute reserve before being scheduled as 10 minute reserve.

This first 400 MW of CAOR offers were included in both the pre-dispatch and the real-time constrained and unconstrained sequences. Within each of the sequences, the CAOR will be scheduled automatically by the DSO (and in potentially different amounts in each sequence) based on its offer prices compared to the offer prices of other market sources. When CAOR is scheduled in pre-dispatch, it can result in fewer imports and more exports being scheduled. It may also mean that the start of a non-quick start generation facility is prevented. As a result, the scheduling of CAOR in pre-dispatch could mean an increase in the probability that a real-time contingency would require the actual implementation of the appropriate control action such as making exports recallable. If identified in the pre-dispatch, these exports will be available as reserve (the exports can be cut) in real-time in the event of contingency.

After CAOR was introduced in the market in July 2003, there was a number of concerns raised relating to its implementation. In particular whether the price set for CAOR is appropriate. If the price of CAOR is too low, it may be displacing other potential market resources. Also, the use of exports as CAOR can result in financial loss to the exporters. Exporters are mostly unaware while bidding that their export may be made recallable and hence get curtailed in real-time if the need arises. The other area of concern was the scheduling of CAOR in pre-dispatch, as it increases the probability of using CAOR in real time.

In November 2005, with MPWG consultation, the IESO board approved an additional 400 MW of standing offers for CAOR and significant changes were made to control room procedures to manage situations of OR shortage. The practice of manually reducing the OR requirement was eliminated except when OR is activated, as it was accepted as a direct cause for counter-intuitive pricing. The procedure now allows the Dispatch Scheduling Optimizer (DSO) to calculate shortage price in times when there is a shortage of OR offers.

At present, the IESO has proposed to remove CAOR from pre-dispatch. The IESO have identified operational and reliability concerns with CAOR in pre-dispatch (Refer to 'MPWG 51 Issue 13 - Proposal to remove CAOR from pre-dispatch' for details).

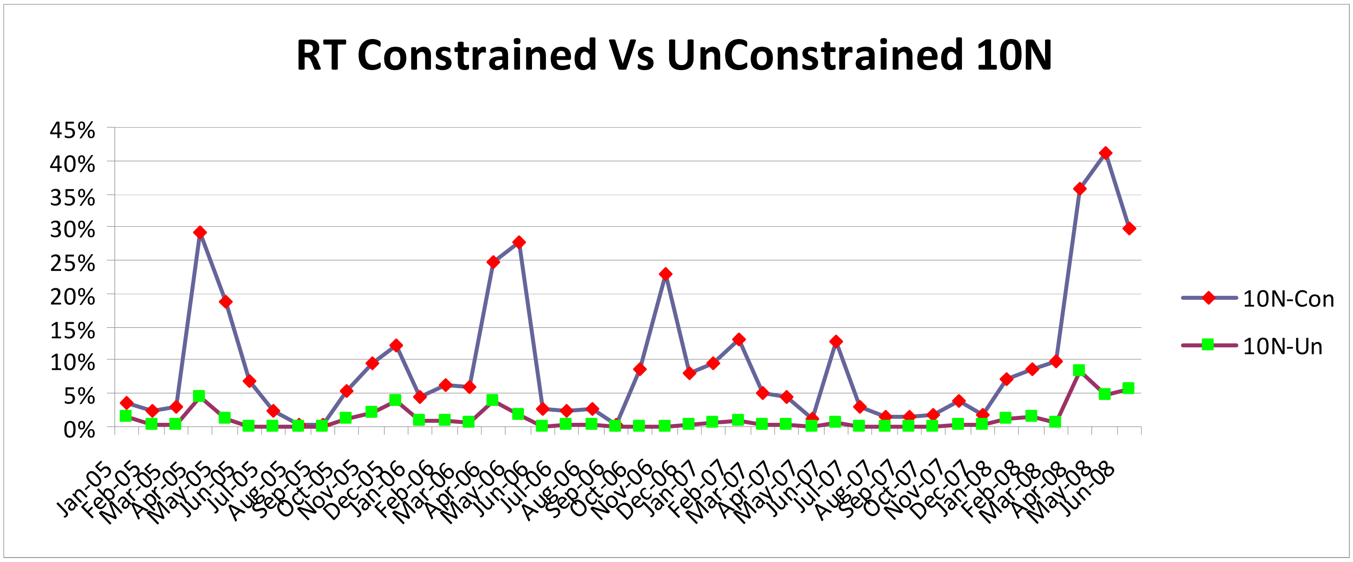
Appendix B

Frequency of CAOR Usage:

It was estimated that prior to the implementation of CAOR, the IESO used 'out-of-market' sources of reserve in roughly 7% of the 5-minute intervals (in constrained schedule but also affected unconstrained sequence). From the period between Jan. 2005 – Jun. 2008, CAOR has been scheduled in the real-time constrained sequence in 9.5% of the 5-minute intervals and in the real-time unconstrained sequence in 1.94% of the intervals. On other hand, the CAOR has been scheduled in roughly 10.3% of the constrained pre-dispatch sequences and 2.7% of the unconstrained pre-dispatch sequences. Scheduling the CAOR in pre-dispatch can lead to less actual energy such as imports or fossils generation being scheduled in pre-dispatch and hence being available in real-time; one of the factors contributing to the increased use of CAOR relative to the prior use of 'out of-market' sources of reserve.

It can be noticed from figures below, CAOR is scheduled more frequently in spring season relative to other seasons. There is a seasonal pattern to the scheduling of CAOR offers in the spring season due to high water levels. During spring, hydro-electric generating stations in the province are being run at or near full capacity as they cannot store high volume of running river water. It is clearly preferable for these stations to produce energy instead of spilling excess water and providing operating reserve. While these generators are running at almost full capacity, they have very limited excess capability to offer into the OR market. The hydro-electric generators start offering again in OR market as the runoff decreases while heading into summer months.

Another seasonal characteristic of the spring season is the small difference between the on peak and off peak energy. Whereas during other seasons, relatively higher off peak demand requires more fossil unit to be online during most hours of the day. This results in the likelihood that there will be capacity available to OR market during peak hours. But in spring as the demand is lower, fewer fossil units are operating to satisfy the demand and hence less fossil units are available to offer OR. Therefore, it can be noticed that CAOR is mostly being scheduled during peak hours during spring as in other seasons both fossil generators, and excess hydro capacity would have been offering sufficient reserves to eliminate the need to schedule CAOR.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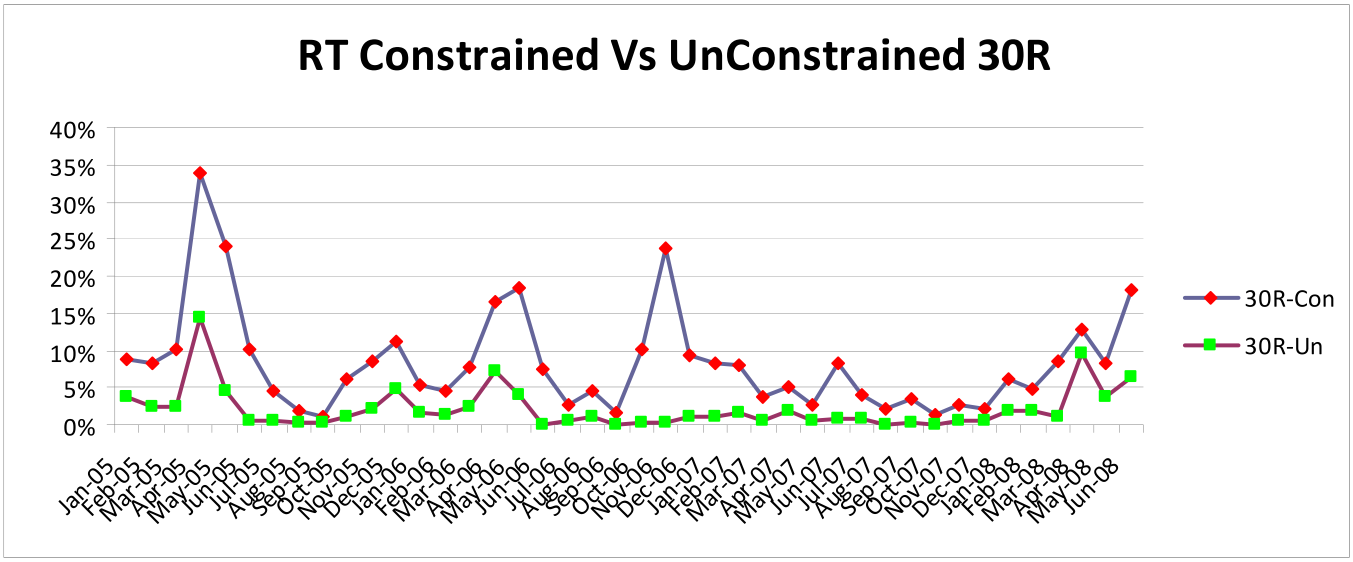
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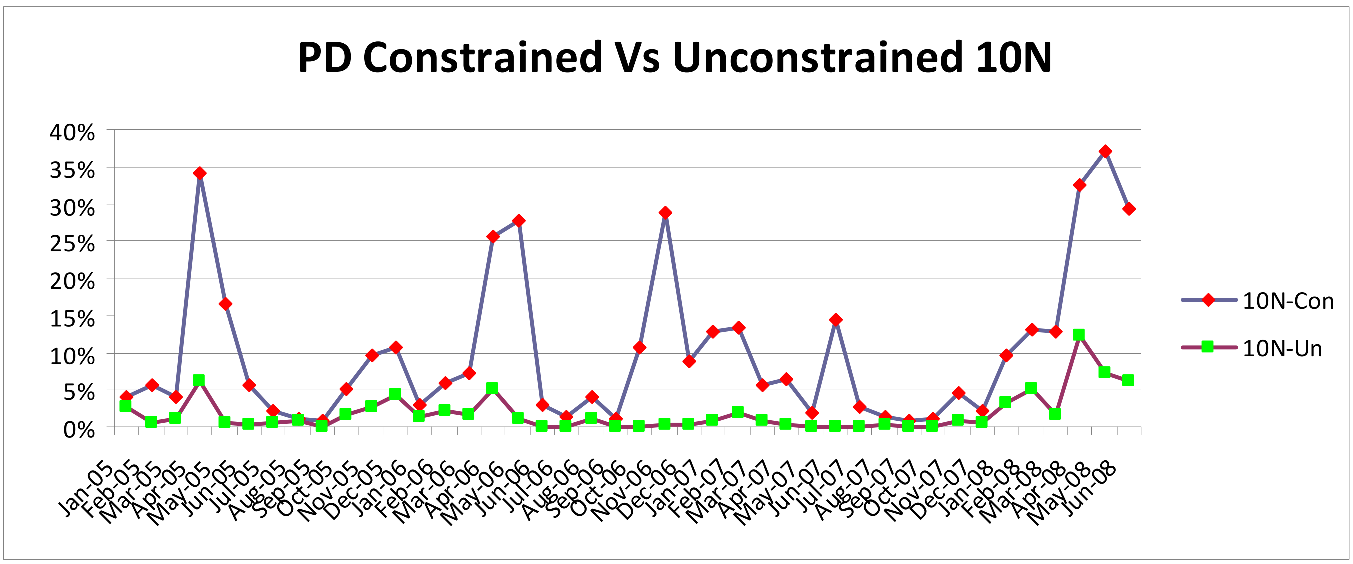
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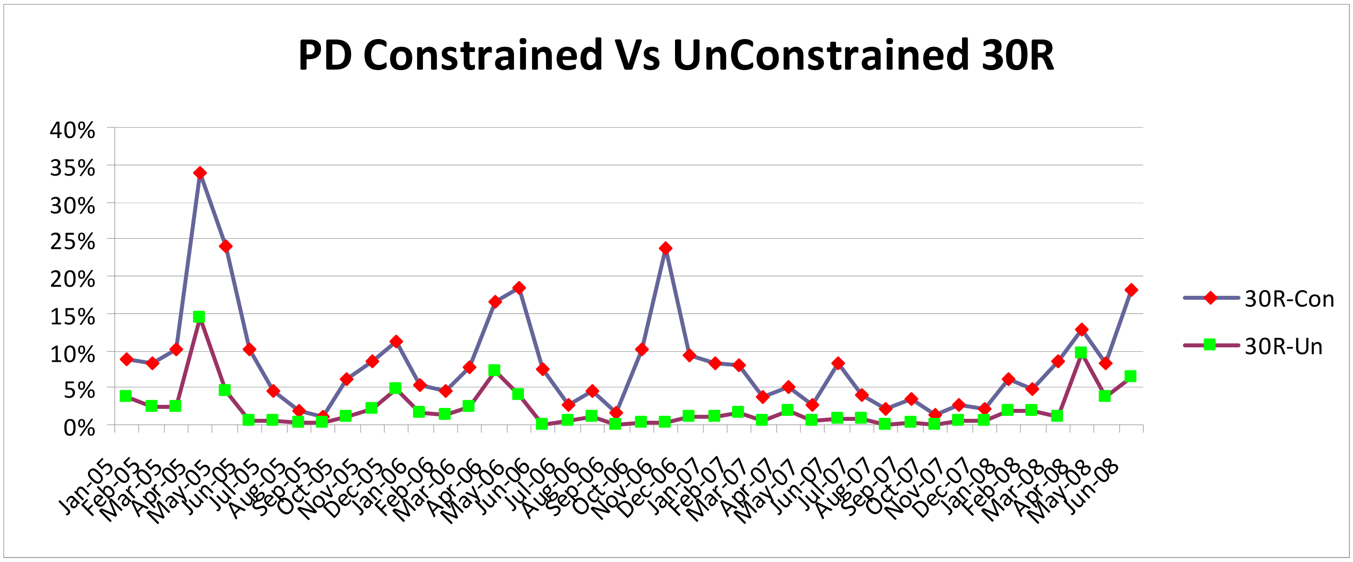
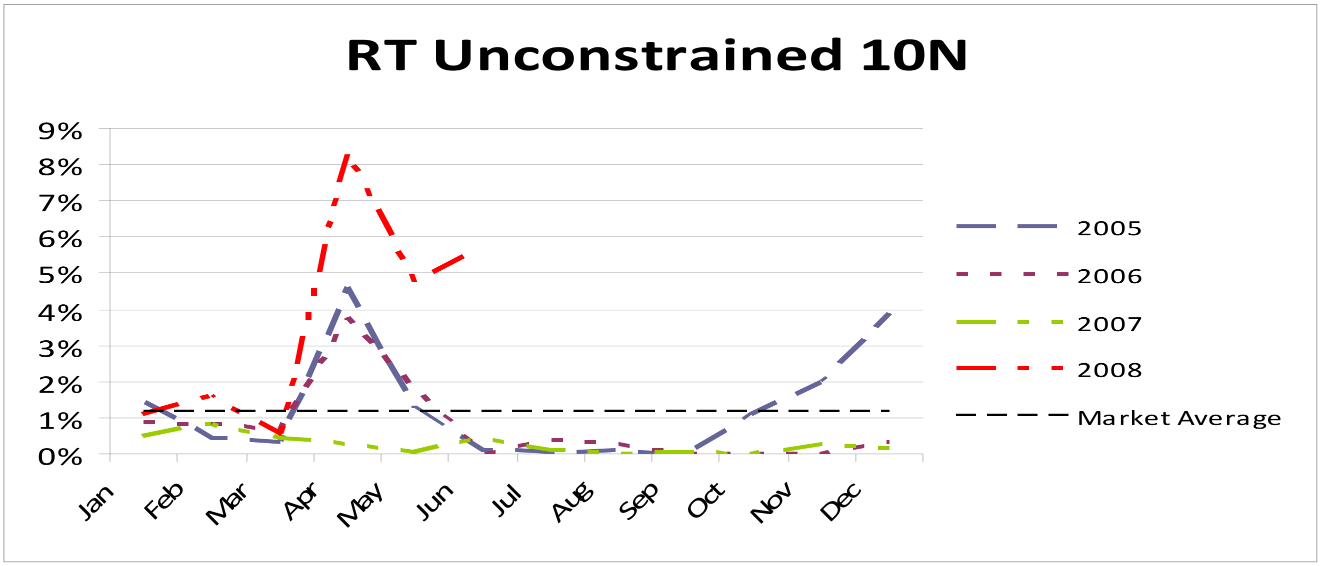


The CAOR is typically scheduled first in the real-time constrained schedule rather than in the real-time unconstrained schedule. This is a result of transmission constraints that 'bottle' energy or operating reserve capacity, making it unavailable for delivery to the load in other parts of the IESO grid. It may also be an effect of other factors such as the use of the actual ramping capabilities in the constrained sequence rather than the 3-times[6] ramp rate assumption used in the unconstrained sequence, or other input differences resulting from the timing differences between the two sequences.

Also, frequent scheduling of CAOR in pre-dispatch is another area of concern as it adds risk to the reliability. By including CAOR in the pre-dispatch, viable imports are not being scheduled, thereby reducing the real time supply. Increasing imports and domestic generation in real time will provide more flexibility to the IESO in contingency situations. If an import or the start-up of a fossil generator was scheduled instead of CAOR in any interval, it would have relieved domestic generation and resulted in positive impact on the reliability.

[6] Noting that the 12X impact would influence most of the study period.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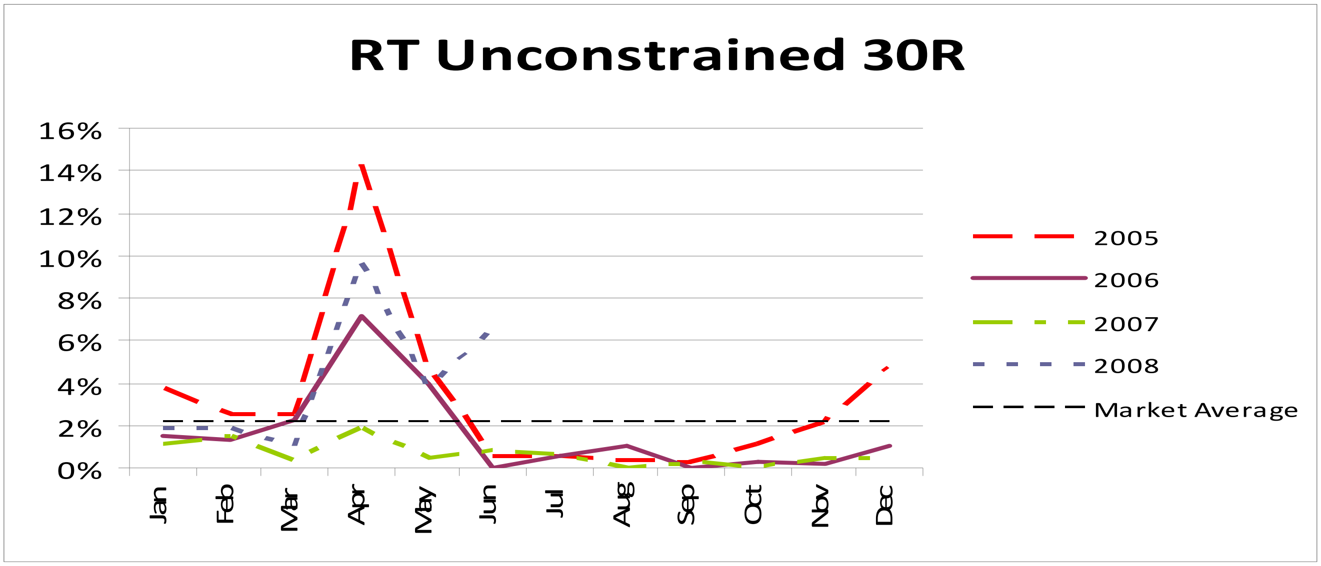
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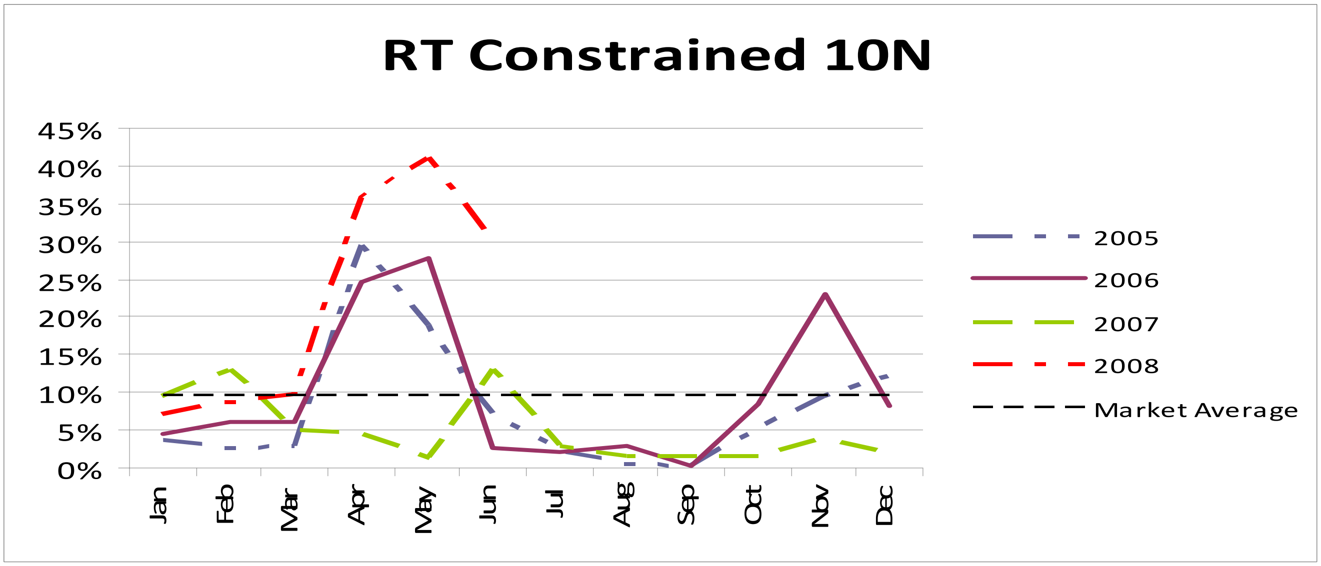
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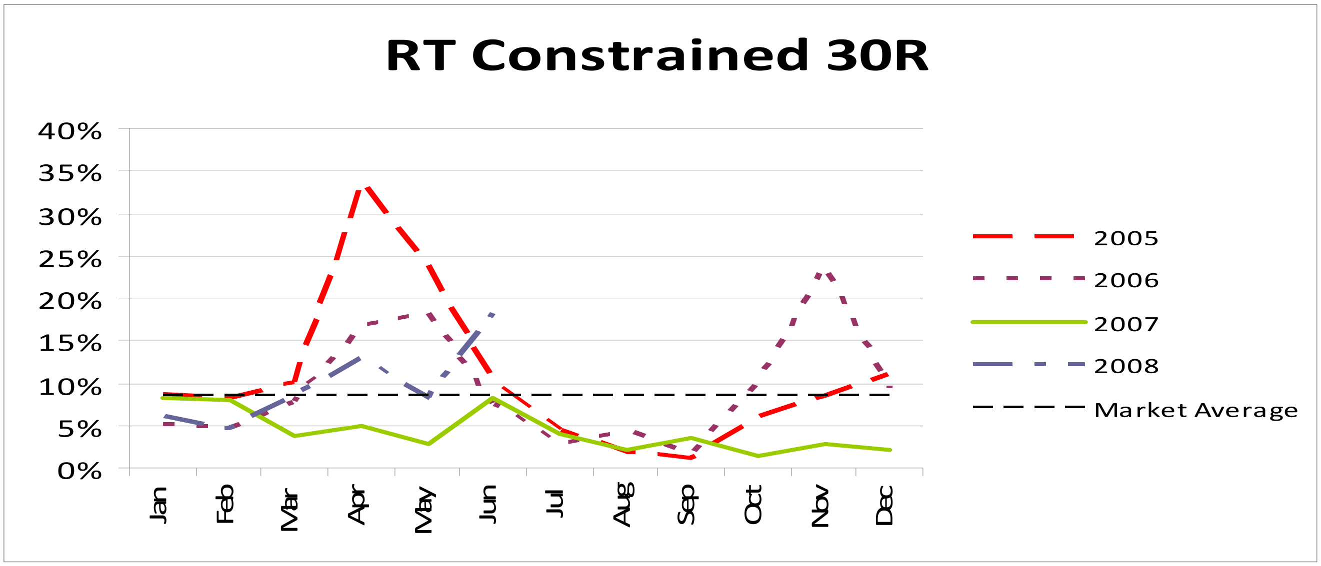
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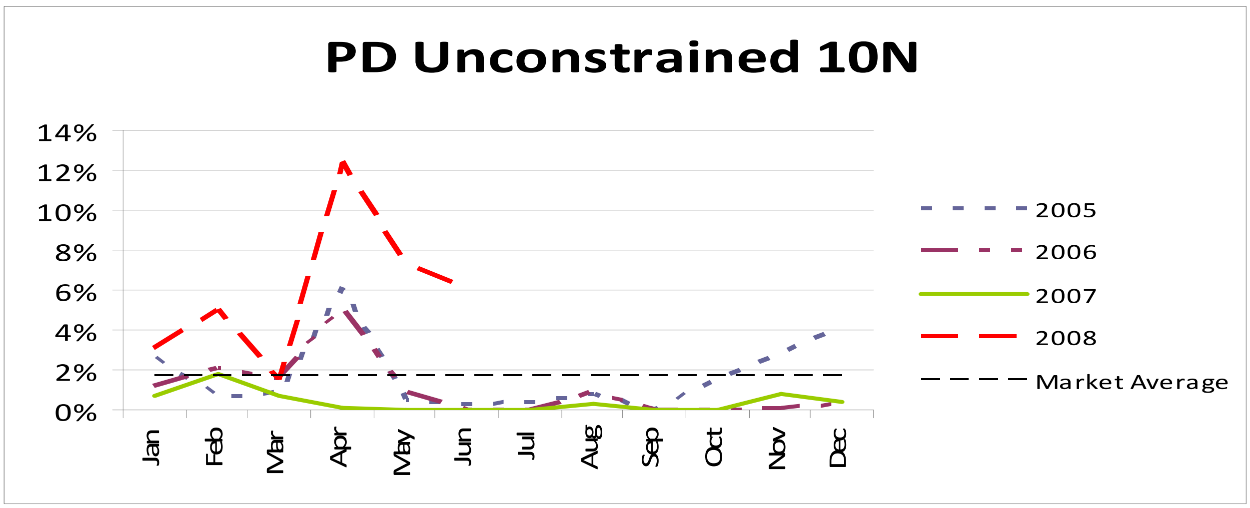
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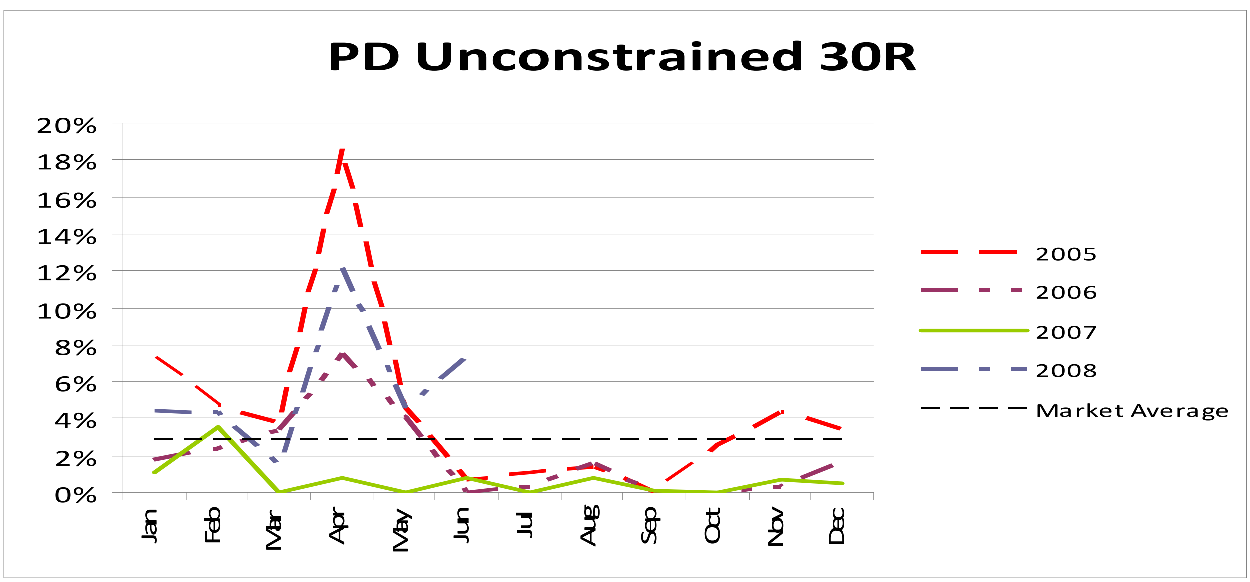
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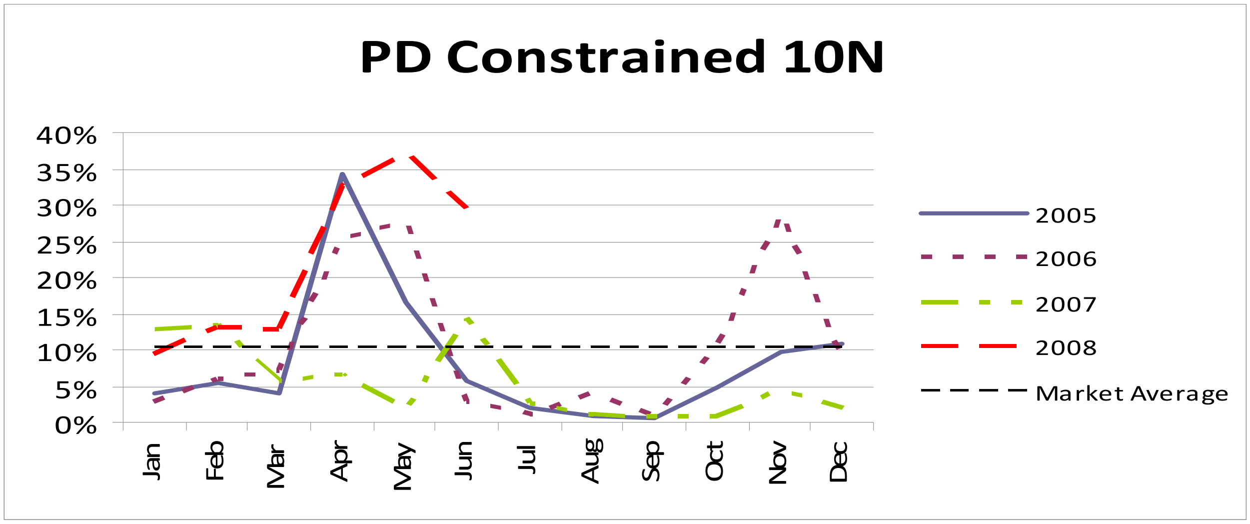
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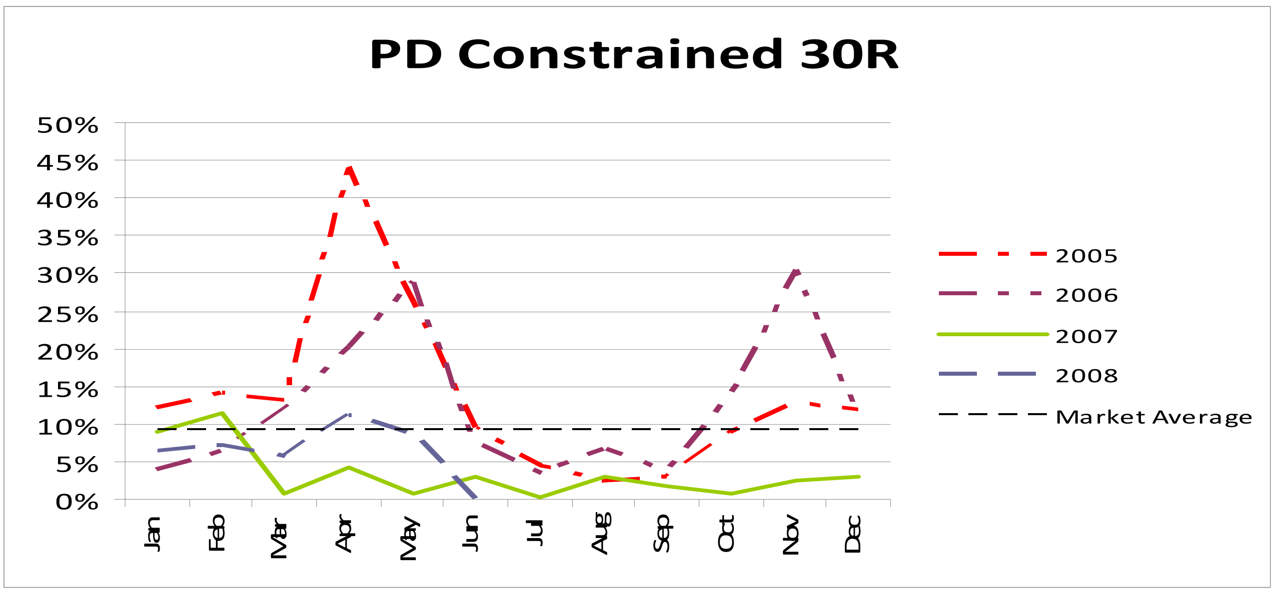
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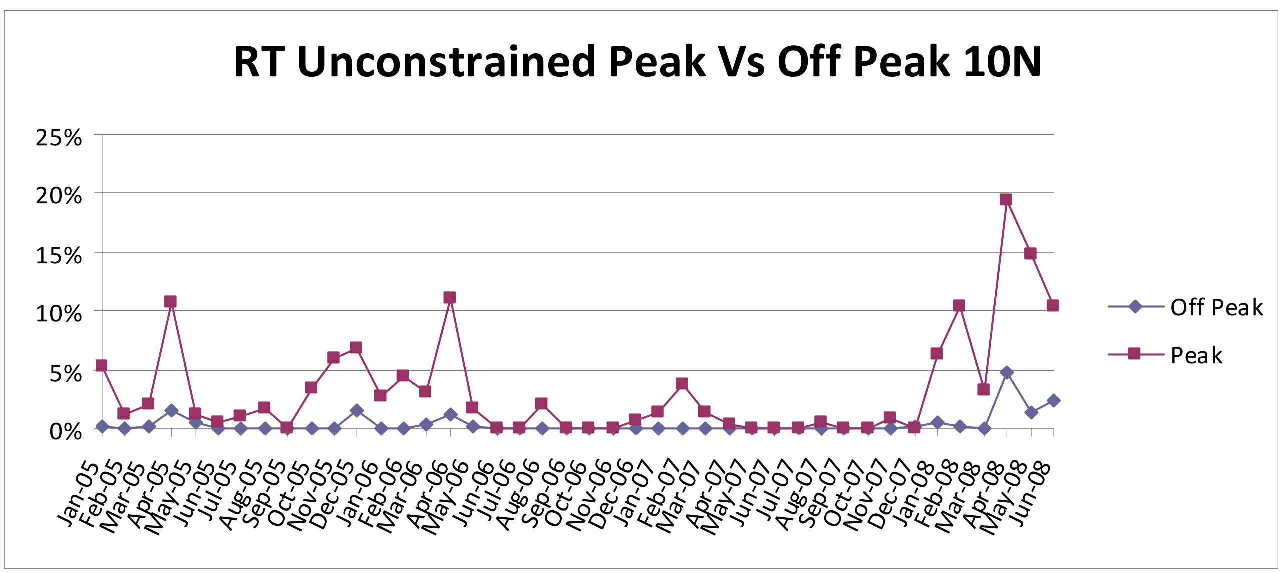
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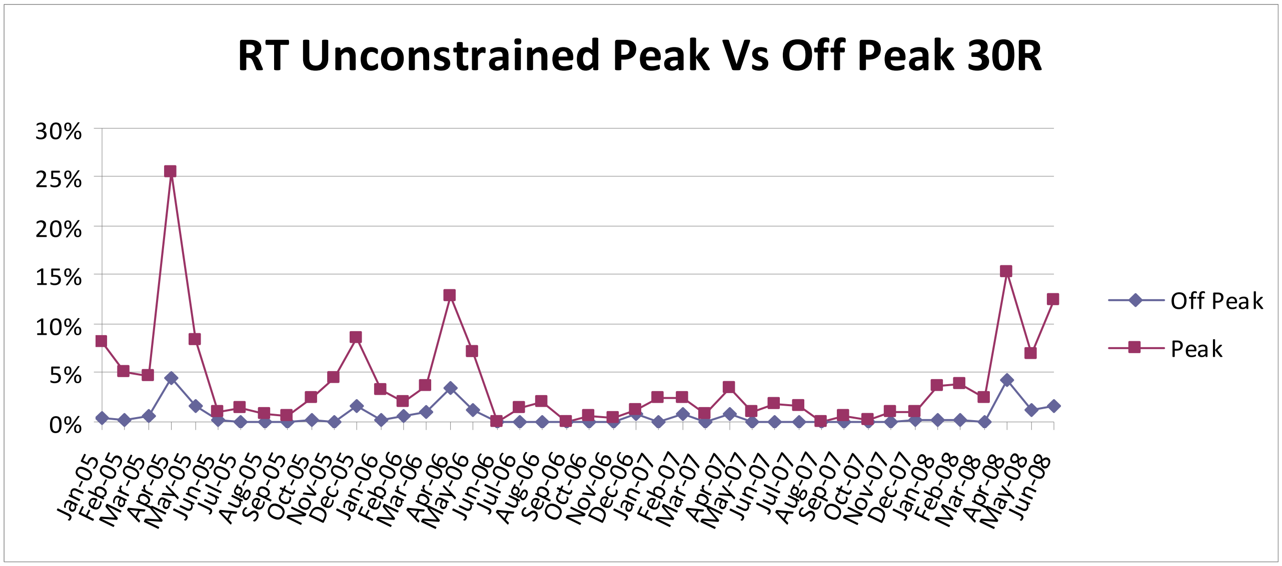
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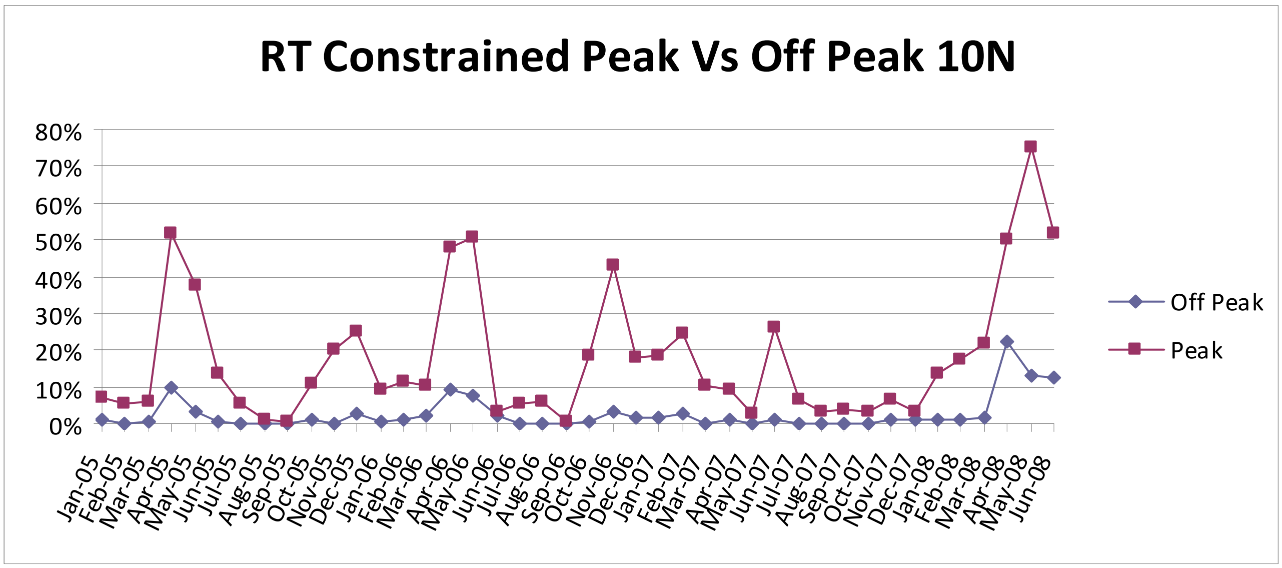
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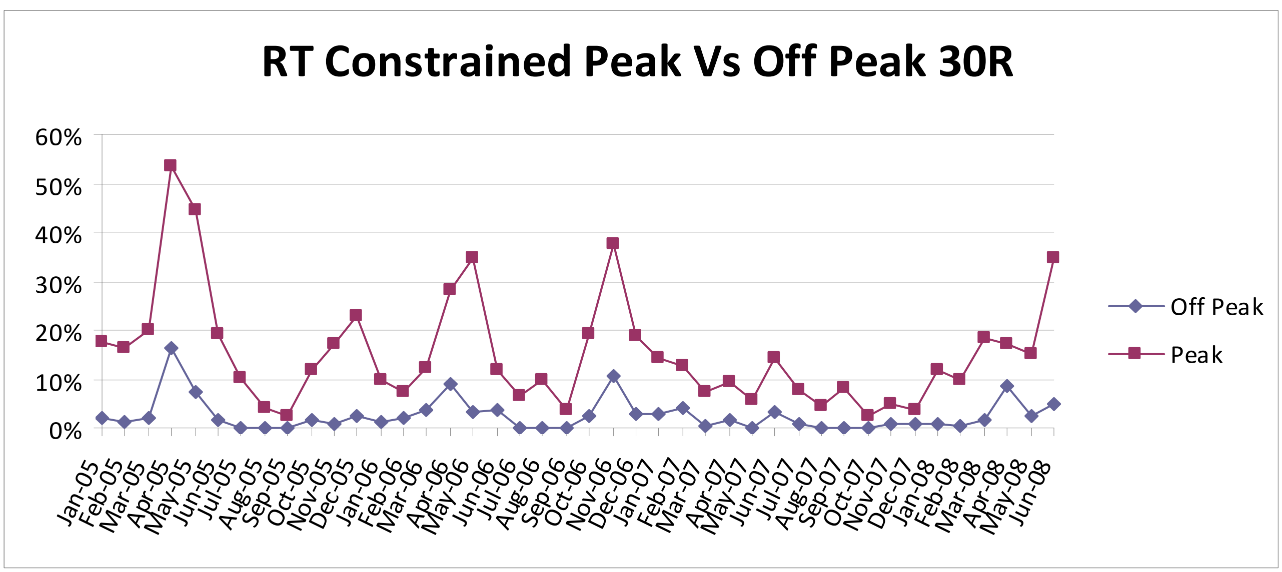
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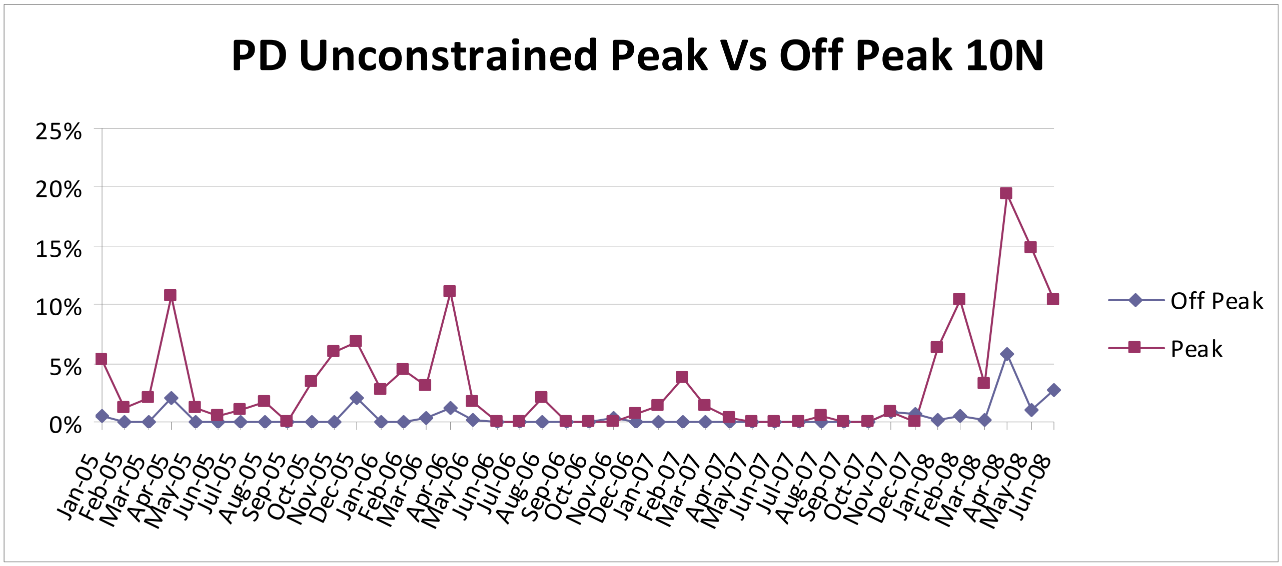
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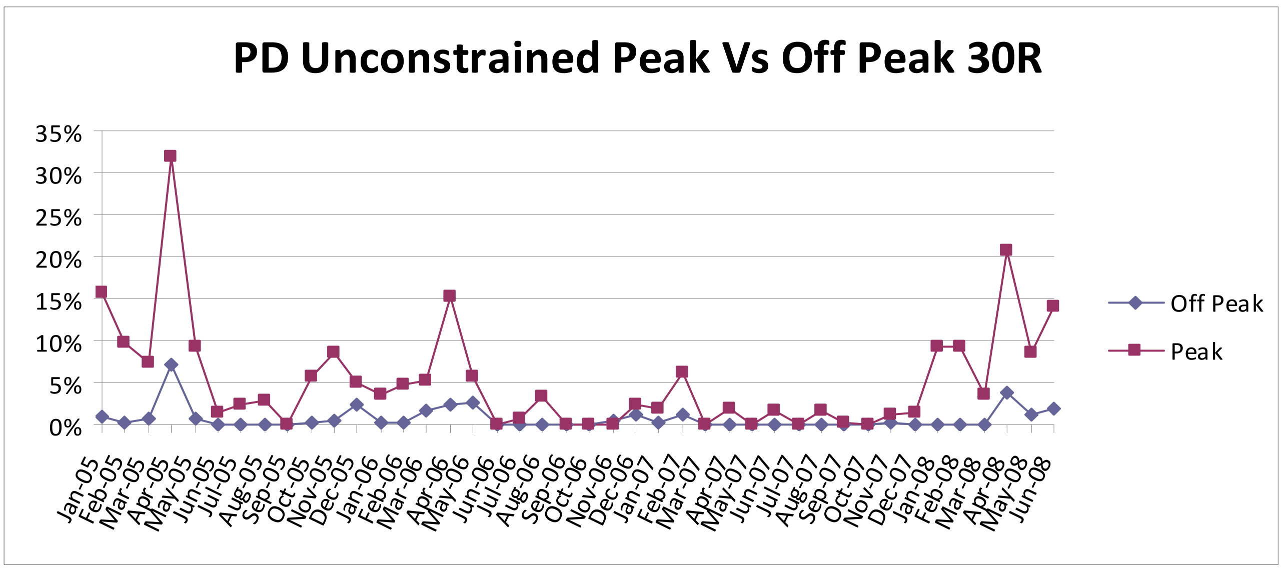
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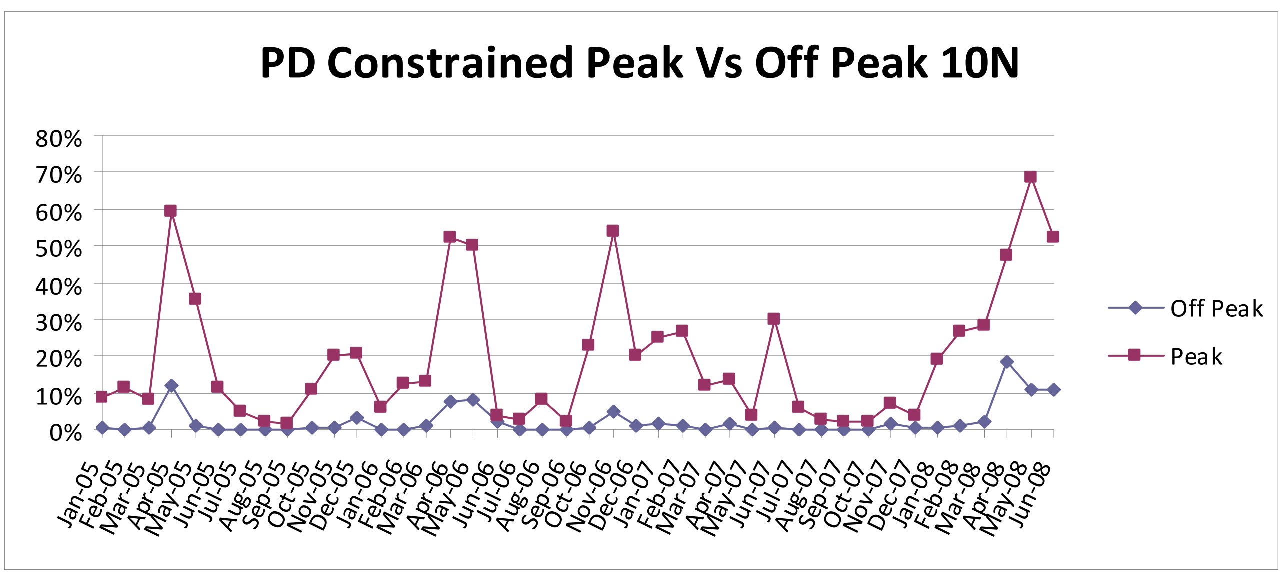
Jun-08
Off Peak
Peak


PD Constrained Peak Vs Off Peak 10N
80%
70%
60%
50%
40%
30%
20%
10%
0%
Jan-05
Feb-05
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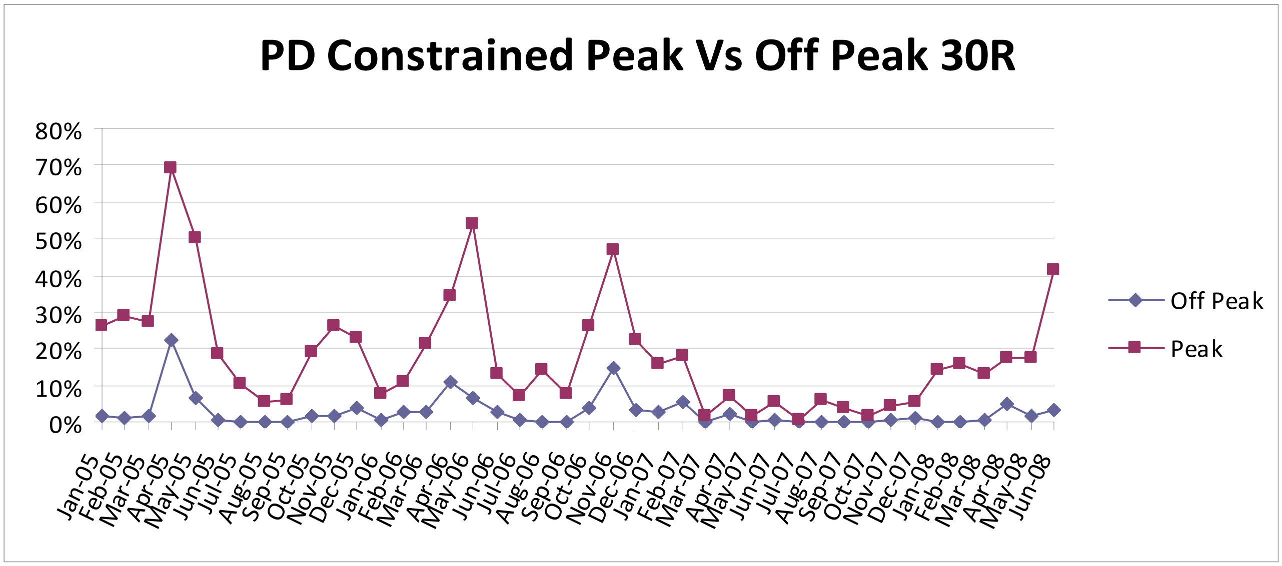
Jun-08
Off Peak
Peak


PD Constrained Peak Vs Off Peak 30R
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70%
60%
50%
40%
30%
20%
10%
0%
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Peak

Appendix C

CAOR Simulation results:

In 2004, simulations were performed to determine the price of an additional 400 MW of CAOR introduced in the market.
The table below shows the impacts on both energy and OR prices for the two CAOR change options.

Table 1 – Energy and Operating Reserve Price Impacts

CAOR Change Option	Energy Price Impacts		OR Price ($/MW)						
			10 Spin		10 NS		30		Total
	Simulated ($/MWh)	Diff. ($/MWh)	Simul-ated	Diff.	Simul-ated	Diff.	Simul-ated	Diff.	OR Uplift ($/MWh)
$30X400 Mw $75X200 Mw $100X200Mw	50.15	**0.24**	6.06	0.29	4.02	0.29	3.86	0.36	**0.03**
$30X200Mw $50X200Mw $75X200Mw $100X200Mw	50.21	**0.30**	6.12	0.35	4.09	0.36	3.92	0.42	**0.04**

- Base case energy price is 49.91/MWh.

- Base case operating reserve prices are as follows:
    1. 10 minute synchronized - $5.77/MW
    2. 10 minute non-synchronized - $3.73/MW
    3. 30 minute non-synchronized - $3.50/MW

From above results, CAOR change option 1 was selected.

Appendix D

Other OR Markets and Theory:

NYISO OR Market:

The NYISO operates Operating Reserve (OR) markets in conjunction with day-ahead and real-time energy markets. Under the current structure, the NYISO market model co-optimizes energy and operating reserve every five minutes in the real-time market and utilizes demand curves for real-time OR procurement under shortage conditions. Since OR markets are co-optimized with energy markets, clearing prices reflect the costs to the system for diverting resources to provide OR that would otherwise provide energy. When the system is short of operating reserves, the reserve price is based on the economic value of the reserve demand curve and this value is reflected in the energy price.

Therefore, the key elements of NY OR markets can be summarized as follows:

- Co-optimization of operating reserve with energy in both the day-ahead and real-time markets.
- Use of demand curves in price determination of operating reserves to reflect the value of OR and energy in shortage conditions (in real time).
- Operating reserve prices are based on the marginal cost of providing the service to the system, which equals the sum of the marginal OR provider's:
  (i) Availability offer price
  (ii) Opportunity cost of not providing another product, such as energy
- In real-time, all dispatchable generators' availability bid is set to zero.
- A two-settlement system for OR, whereby day-ahead schedules must either be provided in real-time or purchased back from the RT market at RT clearing prices.

The NYISO requires all flexible resources to participate in the reserve market. Reserves must be available from units within specific regions of the NYCA, and OR units receive both Day-ahead and Real time schedule. The NYISO procures three types of operating reserves: 10 min spinning, 10 min total, and 30 minute reserve.

The procurement of reserves is subject to locational requirements to ensure that the reserves are available to respond to possible system contingencies. Because the Central-East Interface is often constrained, maintaining reliability requires that a substantial portion of the reserves be procured in Eastern New York. Likewise, transfer limits on the interface between Long Island and the rest of New York dictate that some operating reserves be purchased from within Long Island.

Further, OR markets employ a location based pricing mechanism to pay the suppliers. The locational reserve clearing prices are calculated as sum of shadow prices of all applicable nested reserve constraints. The shadow prices reflect the lost opportunity cost (LOC) that is incurred based on the marginal sale of energy that a unit foregoes to provide OR. Clearing prices reflect the marginal cost of energy and OR to the system, given the level of supply, demand, and transmission constraints. The sum total of payments to the suppliers is then socialized to loads through a load ratio share allocation.

In shortage situations, the real-time market uses demand curves to limit the costs of procuring OR and allows market to clear with 'rational prices'. Without these demand curves, the OR requirements place an infinite value on the marginal unit of OR that violates the reliability limit. Therefore, the demand curves enable the market to produce rational prices for reserves even if not enough reserves are available at any price to meet NYISO's reserve target. The demand curves provide the model with an effective basis for prioritizing high-value reserves over lower-value reserves under shortage conditions and setting prices accordingly. The demand curve values are set high enough to capture all the available market reserves with certainty. It should be noted that the implementation of Demand curves does not impede operator's ability to manually procure reserve necessary to meet requirements.

The current market design consists of nine demand curves, one for each category and location of reserve. Individual curves are applied for each reserve constraint and during reserve shortages these values establish reserve clearing prices. The demand curves impacts the Locational Based Marginal Prices (LBMP) of energy only when NYCA is capacity constrained i.e. when serving next MW of load creates or increases the shortage of reserve.

	New York CA	Eastern New York	Long Island
10 min spin reserve	500	25	25
10 min total reserve	150	500	25
30 min total	200MW @ $50 200MW @ $100 200MW @ $200	25	300

These demand curve values are cascading and value of each constraint violated is added to LBMP of energy. The demand curves trigger rising energy and OR prices during shortage situations and when activated must be converted to energy in order to meet the demand. During activation they set the clearing prices in the energy market.

PJM OR Market:

PJM operates a 2 tiered reserve market. Their reserve market exists in both the real time and day-ahead timeframes. Tier 1 OR is excess capacity of generators currently online, and is priced higher than $0.00 only in the case of reserve pickup. Tier 2 resources offer in to the OR market with an offer cap of $7.50 over their cost, and are only scheduled into the OR market if the reserve requirement is not satisfied by the supply of Tier 1 OR. This price cap remains active unless scarcity pricing is called into effect. PJM only calls in scarcity pricing at the point at which emergency actions are taken to remedy a reserve shortage. The PJM rules for scarcity pricing are as follows:

Scarcity Pricing Rules

- Triggers: Emergency energy request events; maximum emergency generation events; manual load dump events; and voltage reduction events. Based on the implementation of one or more of these emergency actions over an area consisting of two or more contiguous zones with 5 percent or greater positive distribution factor ("dfax") relative to concurrently binding 500 kV or greater transmission constraints.
- Effect: Price goes to the highest offer of a unit running for PJM within the zone.

PJM market participants have very limited exposure to price signals in the OR market due to the offer cap. This is an issue that PJM is in the process of evaluating. The emergency actions that PJM undertakes in shortages in the OR markets are not priced into the market. They operate under a discretionary policy for control actions as opposed to our rule based policy.