Market Power Framework for the IESO-Administered Markets

Stakeholder Workshop:

Market Surveillance Panel's

Proposed Analytical Framework

February 15, 2007

ONTARIO ENERGY BOARD
COMMISSION DE L'ÉNERGIE DE L'ONTARIO

Overview

- MSP's market power framework
  - Activity to date
  - Exercise of market power
- Proposed implementation
  - Non-Energy Limited Generation (NELG)
  - Imports
  - Energy Limited Generation (ELG)
- Consultation and Next Steps
- Background Data

MSP’s Market Power Framework

Activity to date

- Proposed market power framework
  – described in December 2006 discussion paper
- Initial stakeholder meeting January 17, 2007
  – to introduce proposed framework
  – Stakeholders requested further illustrative scenarios

Exercise of Market Power

Necessary (and Sufficient) Conditions

- Offer exceeds/sets MCP & supply should be inframarginal

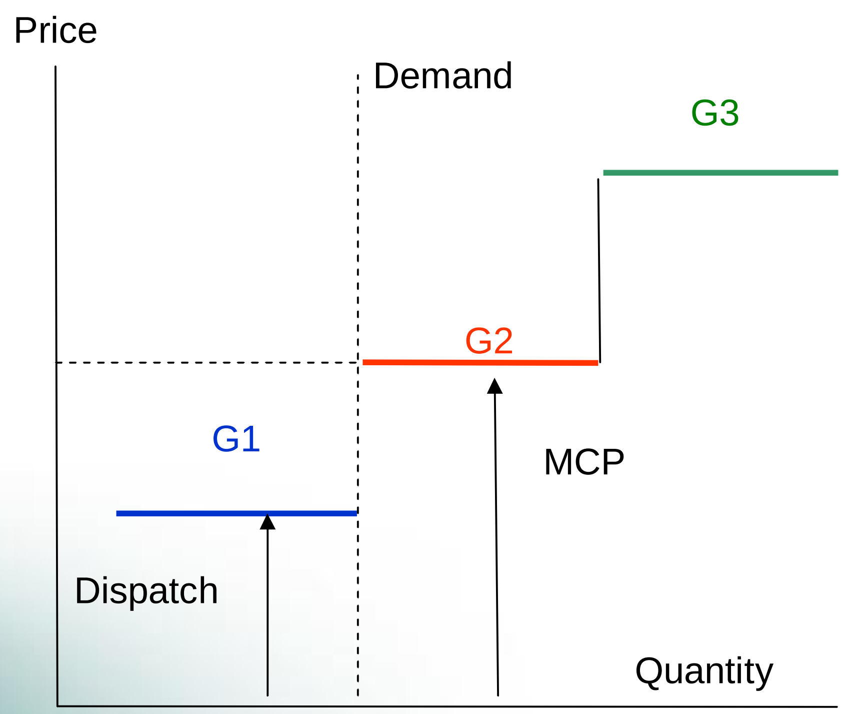
Offer Price(Q) ≥ MCP > Max [MC(Q), AIC(Q)]

- Market participant profit is higher as a result

$$\Pi(Q^A) > \Pi(Q^C)$$

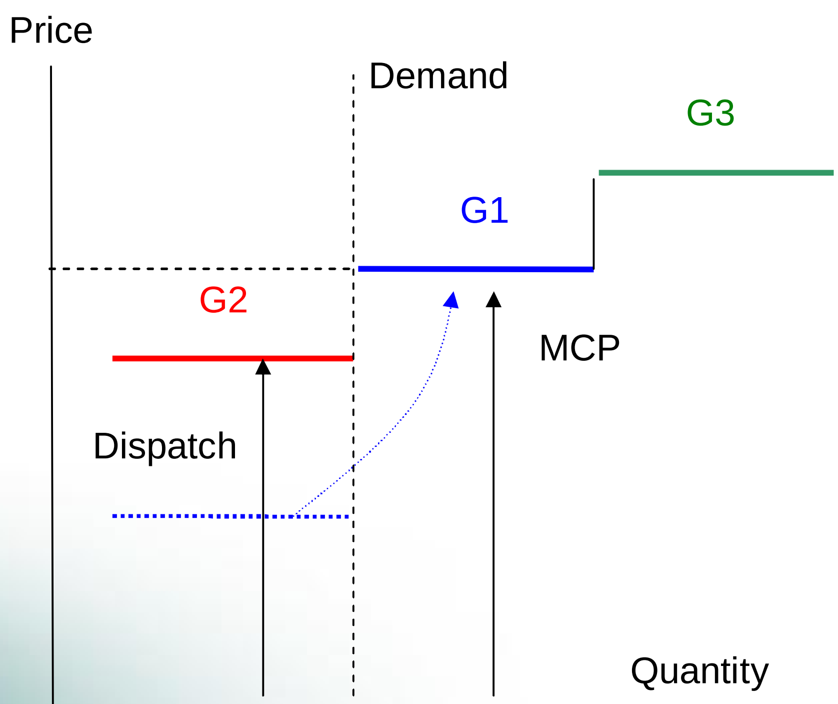
Presumption of an exercise of market power subject to explanation by market participant

Case A: Competitive Market



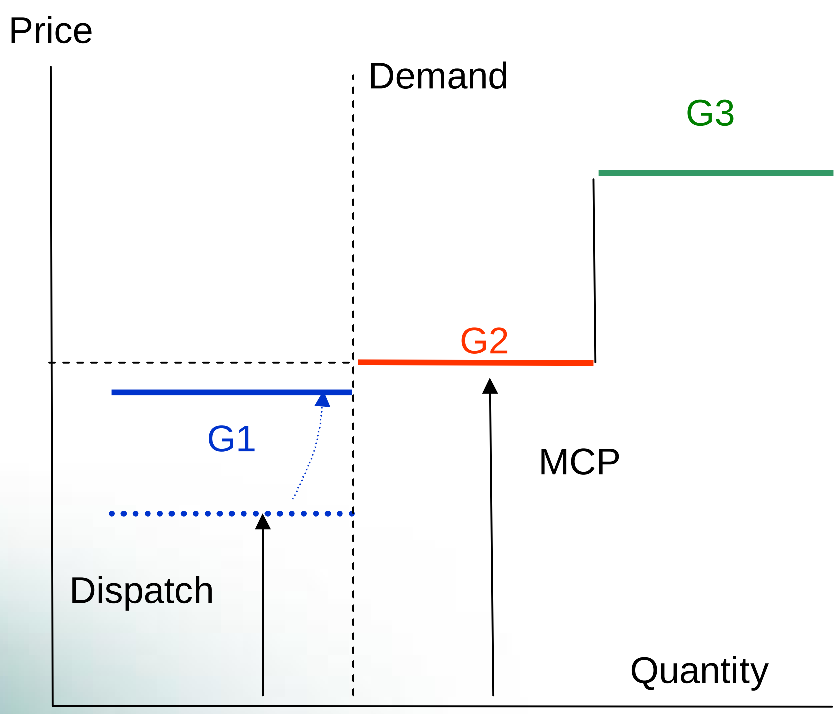
- Generators 1, 2 and 3 all bid their incremental cost.
  - All are the same size;
  - only one is needed to meet the demand.
- Generator 1, the lowest cost unit, is dispatched.
  - This is the efficient dispatch.
- Generator 2, the next MW of supply, sets the market clearing price.
  - This is the competitive price outcome.

Case B: Economic Withholding



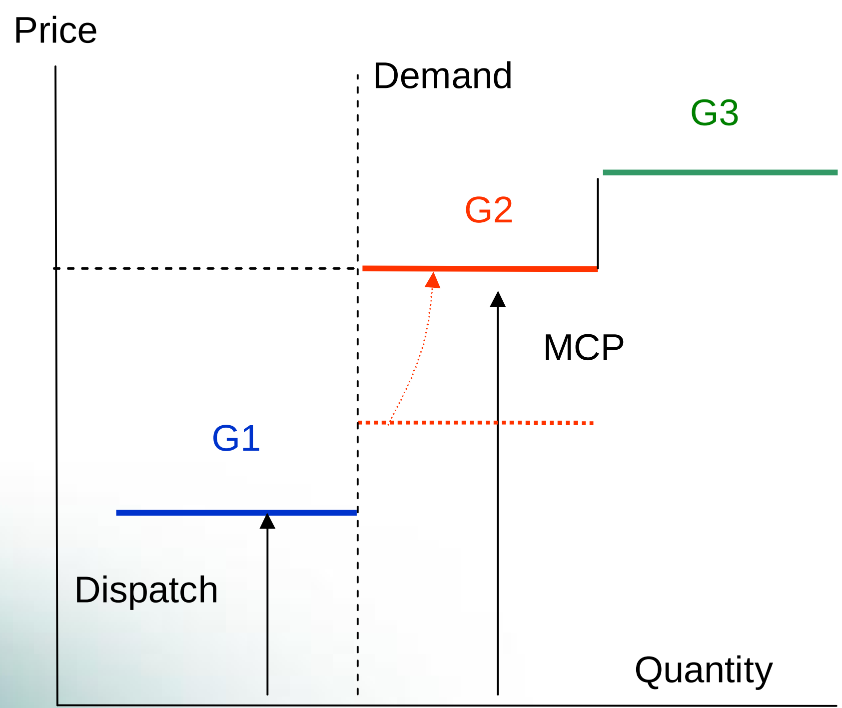
- Lowest cost G1 raises price above G2.
- Dispatch is inefficient,
  - using G2 instead of G1
- MCP is higher
  - set by price of G1 rather than price (cost) of G2
- If Generator 1 has other dispatched generators in its portfolio
  - and profits from the higher MCP
- **Likely an exercise of market power**

Case C: Price Increase Infra-Marginal Generator



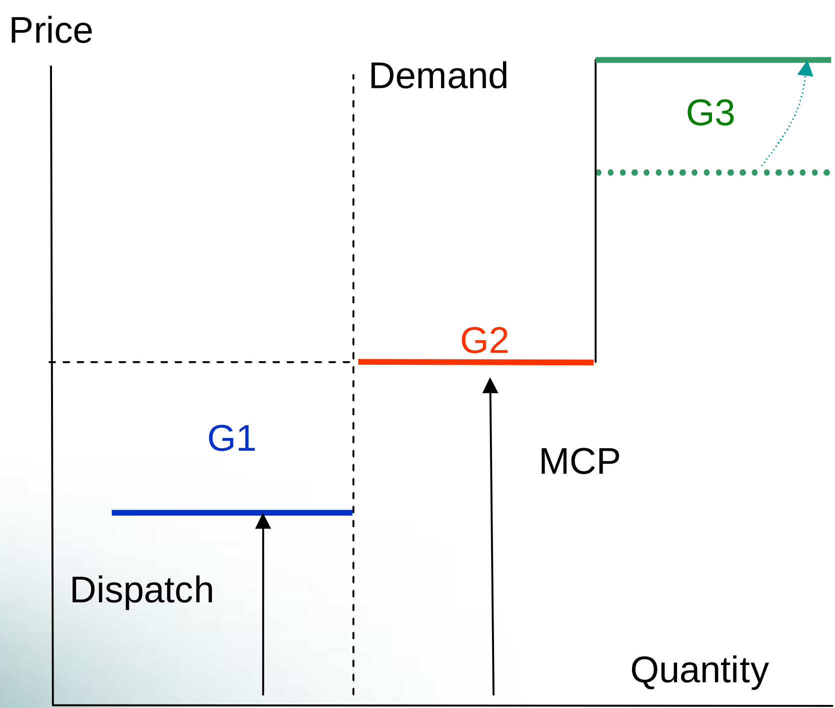
- Generator 1 increases its offer price
  - but remains below the incremental cost of G2.
- There is no change to the dispatch.
- There is no change to the MCP.
- **There is no exercise of market power.**

Case D: Pricing-Up
Price Setting Generator



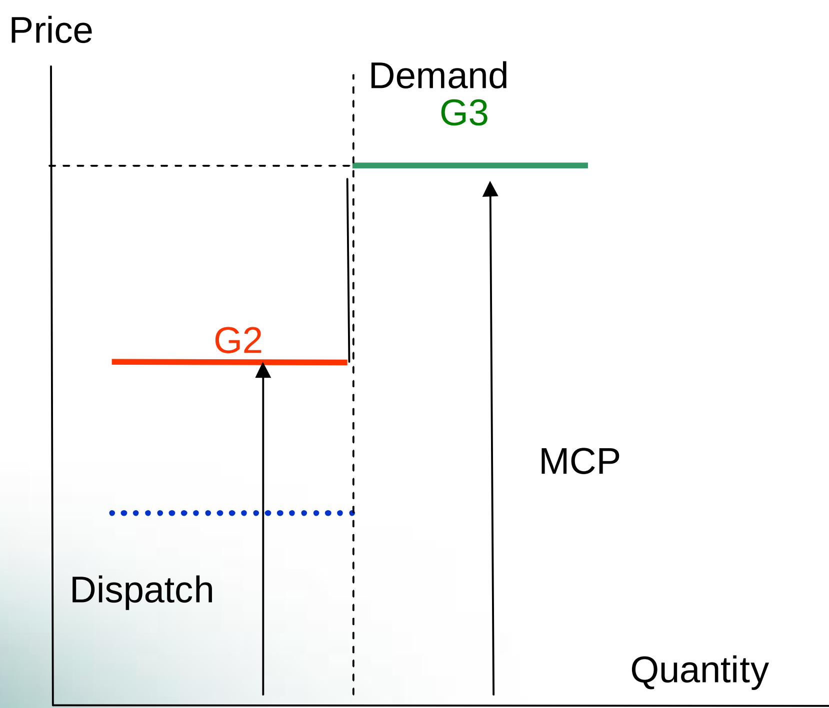
- Generator G2 increases its offer price.
- There is no change to the dispatch.
- There is an increase in the MCP.
- If Generator 2 has other dispatched generators in its portfolio
  - and profits from the higher MCP
- **Likely an exercise of market power**

Case E: Price Increase
Extra-Marginal Generator



- Generator 3 increases its offer price
- There is no change to the dispatch.
- There is no change to the MCP.
- **There is no exercise of market power.**

Case F: Physical Withholding



- Generator 1 is available but does not submit an offer.
- Dispatch is inefficient,
  - using G2 instead of G1
- MCP is higher
  - set by price of G3 rather than price (cost) of G2
- If Generator 1 has other dispatched generators in its portfolio
  - and profits from the higher MCP
- **Likely an exercise of market power**
- Not Applicable to imports

Three Operational Tests

1. Participant Conduct Test
   - offered at ‘extraordinarily’ high prices or not offered
2. Market Price Impact Test
   - offer raised market price substantially
3. Profitability Test
   - participant profits (net revenues) are higher due to pricing strategy

Application and Exceptions

- Specific tests tailored to characteristics of 3 types of supply
  - Non-energy limited generation (thermal)
  - Imports
  - Energy limited generation (hydroelectric)
- Exceptions
  - MCP for hour below $50 per MWh
  - economic withholding for nuclear units
  - physical withholding for imports
  - NUGs or other generation with entire portfolio at fixed prices

Proposed Implementation
Non-Energy Limited Generation (NELG)

1. NELG Participant Conduct Test

Conduct Test to establish either

- Pricing up or economic withholding
  - Pricing is unusually high
    - based on offer history (reference price)
    - maximum production costs (MAXAIC)
- Physical withholding
  - Supply is not offered or is forced out
    - Unit and portfolio thresholds

NELG Participant Conduct Test Trigger

– Pricing up or economic withholding

- Pricing is unusually high if

Offer Price (Q) > max (Reference Price Threshold (Q), MAXAIC)

where

Reference Price Threshold (Q) = Reference Price (Q) + 2*std dev (Q)

MAXAIC is AIC at minimum production level

- for at least one 10 MW lamination Q and

Offer Price (Q) $\geq$ HOEP

HOEP > max (AIC(Q), MC(Q), Reference Price(Q))

Reference Price

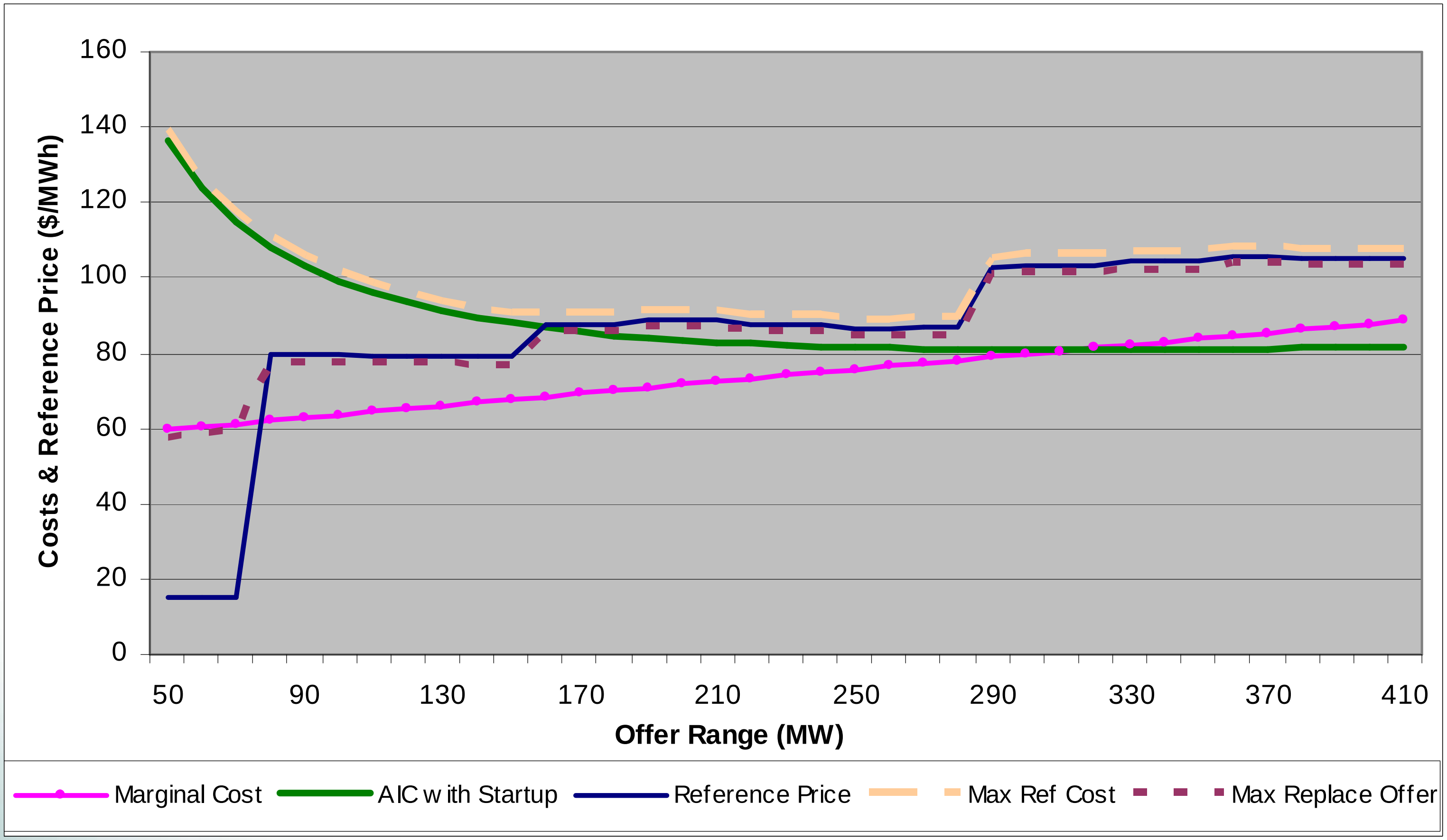
– Calculated for the entire output range of a generating unit between
  – reported minimum loading level, and
  – reported maximum capacity of the unit or maximum quantity offered from the unit.
  – Laminations are divided into 10 MW ranges
– Adjustment to account for fuel price changes

$$RP_q = 0.9P_q\left(\frac{f_T}{\sum_{t=T-1}^{T-90} f_t \Big/ 90}\right) + 0.1P_q$$

Fossil Fuel Production Costs

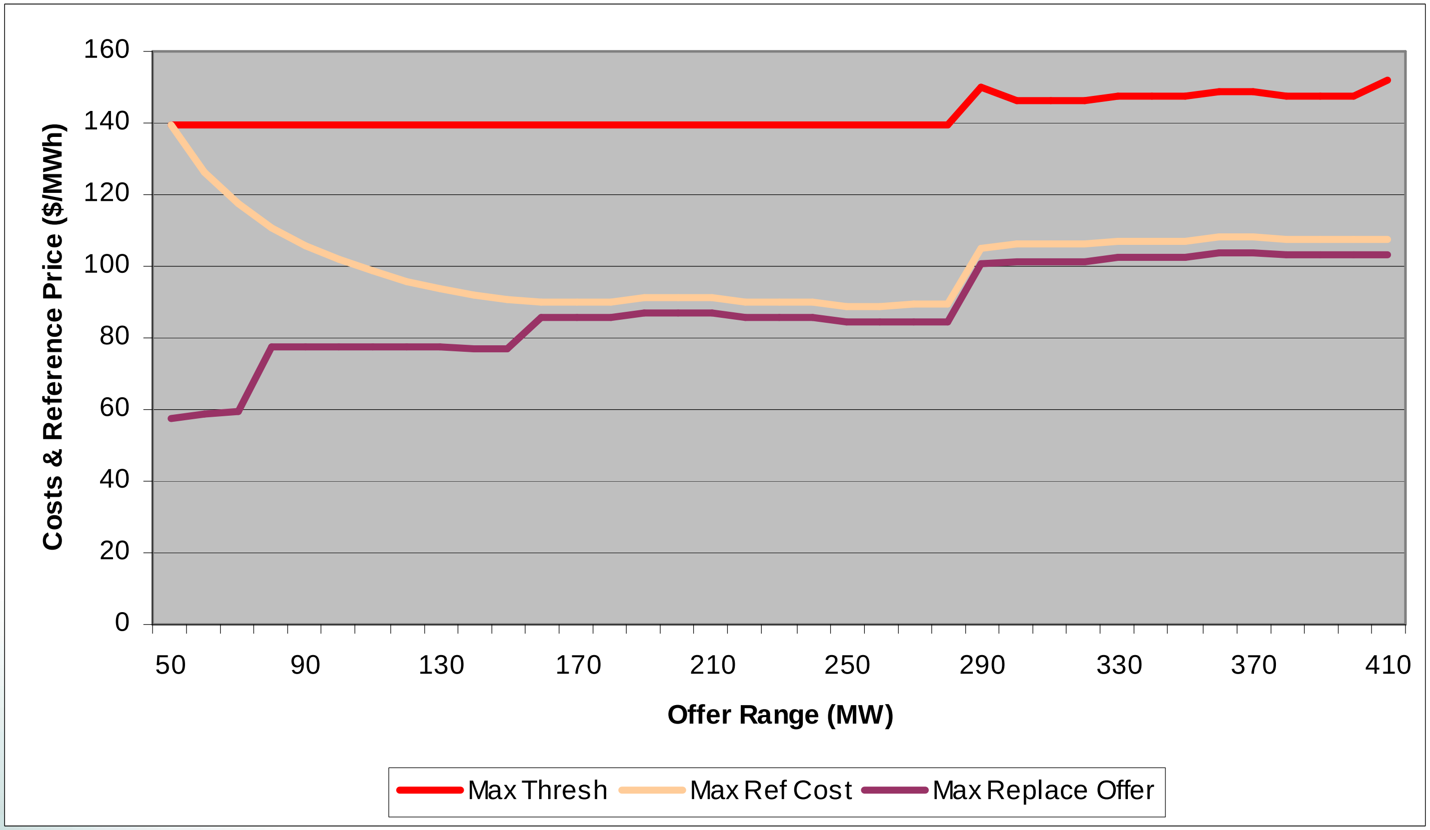
- Fuel Consumption Cost Curve
  - representing Total Production Cost each hour
  - production efficiency multiplied by the fuel price
    - a quadratic function of the production level
  - plus total variable operation and maintenance costs
- Marginal Cost (MC)
  - linear function multiplied by the fuel price
    - derivative of production efficiency
  - plus variable operation and maintenance costs per unit of production
- Average Incremental Cost (AIC)
  - cost per MW of production
  - including Total Production Cost and
  - the start-up costs apportioned to the hour
    - assuming the minimum run time
  - MAXAIC is AIC at minimum production level

Illustrative Costs



Max Ref Cost = max (AIC, MC, Reference Price)
Max Replace Offer = max (MC, Reference Price)

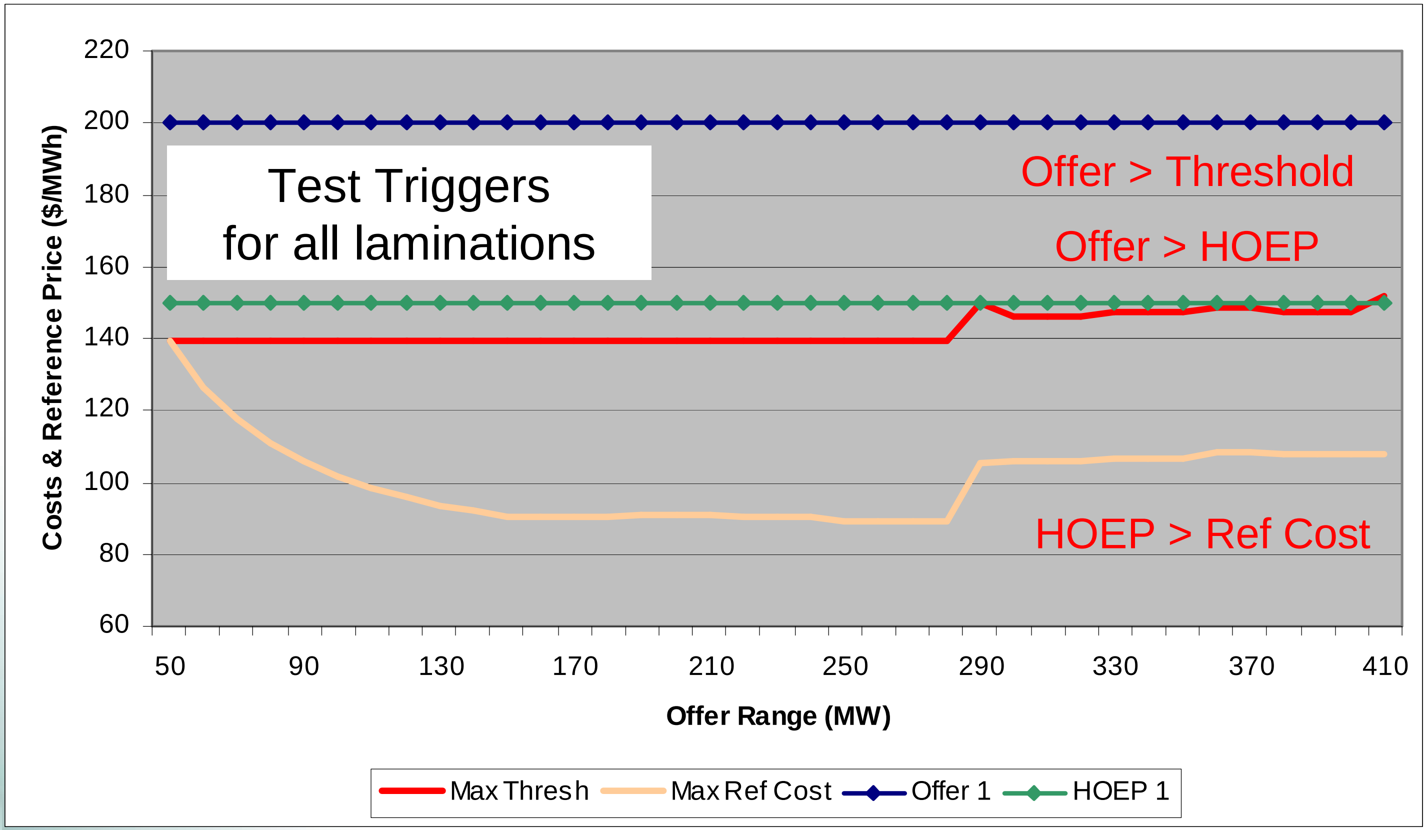
Illustrative Derived Thresholds & Costs



MaxThresh = max (Reference Price Threshold, MAXAIC)

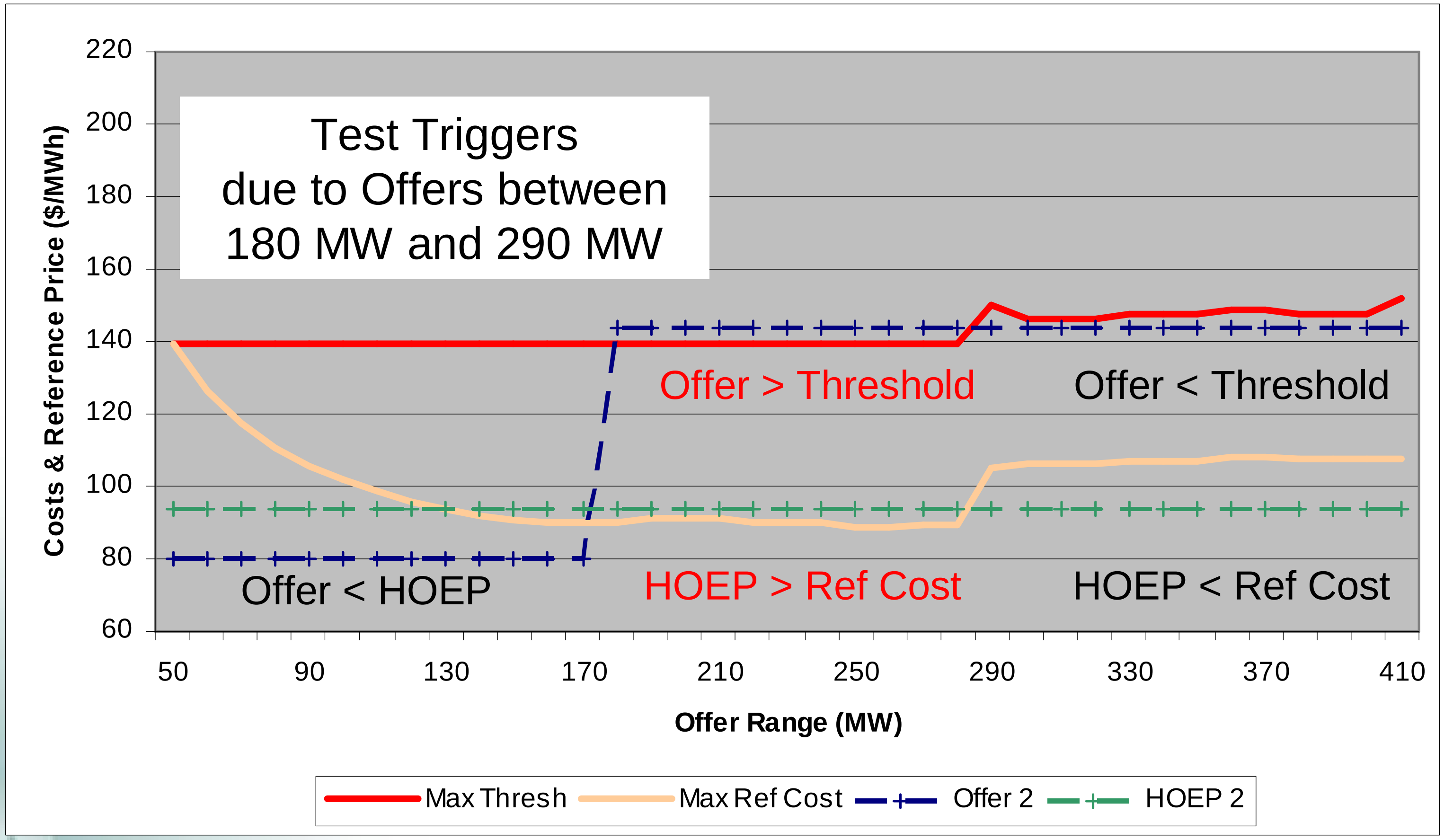
Scenario N-1: Conduct Test Triggers

Scenario N-1: 2 identical 410 MW fossil units
Offered at $200/MWh for all production quantities
HOEP = $150/MWh



Scenario N-2: Conduct Test Triggers

Scenario N-2: Offer rises from \$80 to \$145 above 180 MW
HOEP = \$95



2. NELG Market Price Impact Test

Market Price Test is used if Conduct Test triggers for one of participant's units

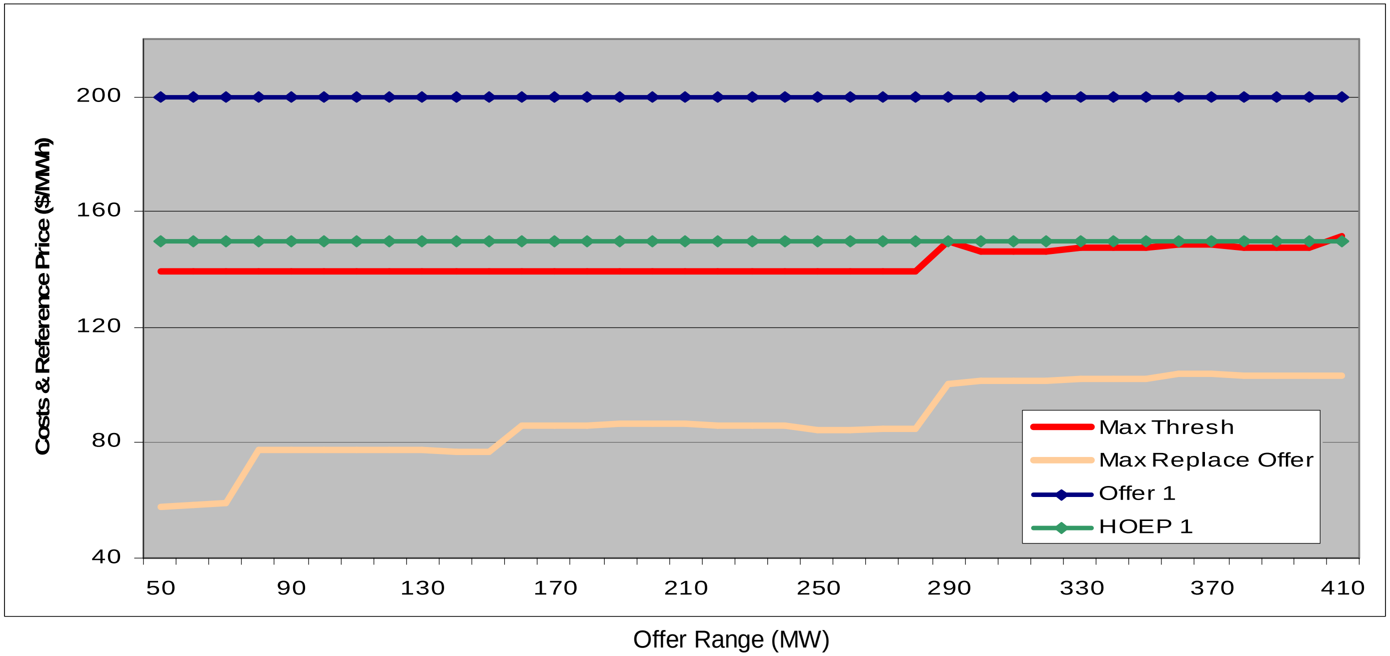
- Replace offers using higher of fuel-price adjusted reference prices or marginal cost
  - Simulate pre-dispatch and real-time
  - Adjusting imports & exports in real-time
- Triggers Market Price Test if
  - real-time simulated price (the competitive price) is substantially below HOEP

$$HOEP - PE^c > \$50MWh \qquad \frac{HOEP - PE^c}{PE^c} > 100\%$$

Example – NELG Price Test Scenario N-1

Actual

- HOEP = $150/MWh, pre-dispatch price = $120
- No imports in the market schedule
- Generator has 2 identical 410 MW units offered at $200
- Both units trigger the Conduct Test (Scenario N-1 above)



Price Test Triggers – Scenario N-1

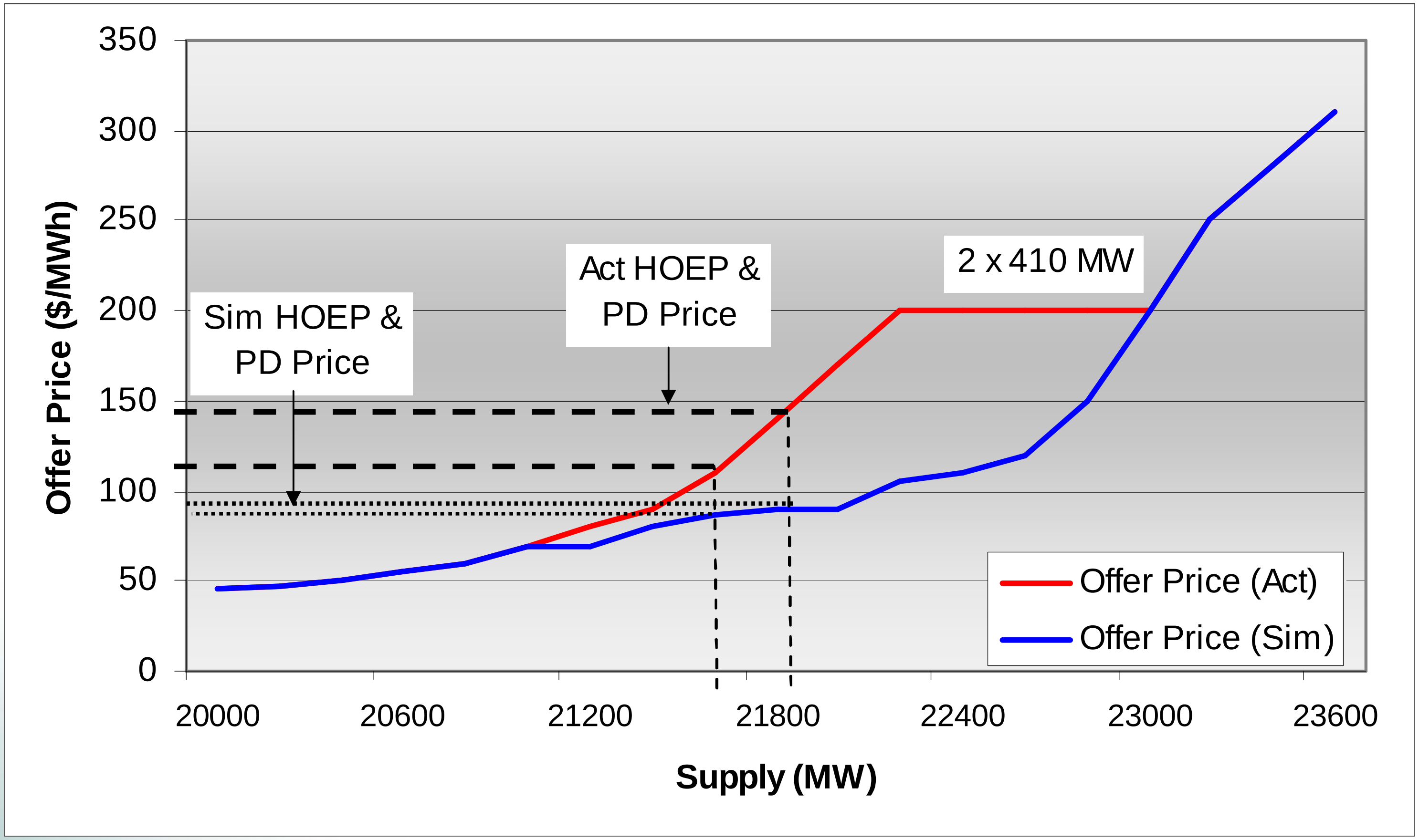
Simulation

- Replace offers for each unit: range from $58 - $105
  - Max Replace Offer in previous figure
- PD Simulation
  - PD price of $89, with 280 MW scheduled for each unit
  - 560 MW of other generation offset but no change to net imports
- RT Simulation leads to
  - RT price of $95, with 280 MW scheduled for each unit

RT Price change triggers Price Test

- HOEP - PE^C = $150 - $95 = $55
- $55 > $50 threshold = trigger

Supply Curves – Scenario N-1



Price Test Does Not Trigger - Scenario N-3

Actual

- Same as Scenario N-1 except
  - **pre-dispatch price is $180 / MWh**
  - **400 MW of imports in the market schedule, priced just below $180**
- As for Scenario N-1, with HOEP $150 and the 2 identical 410 MW units offered at $200, the Conduct Test triggers

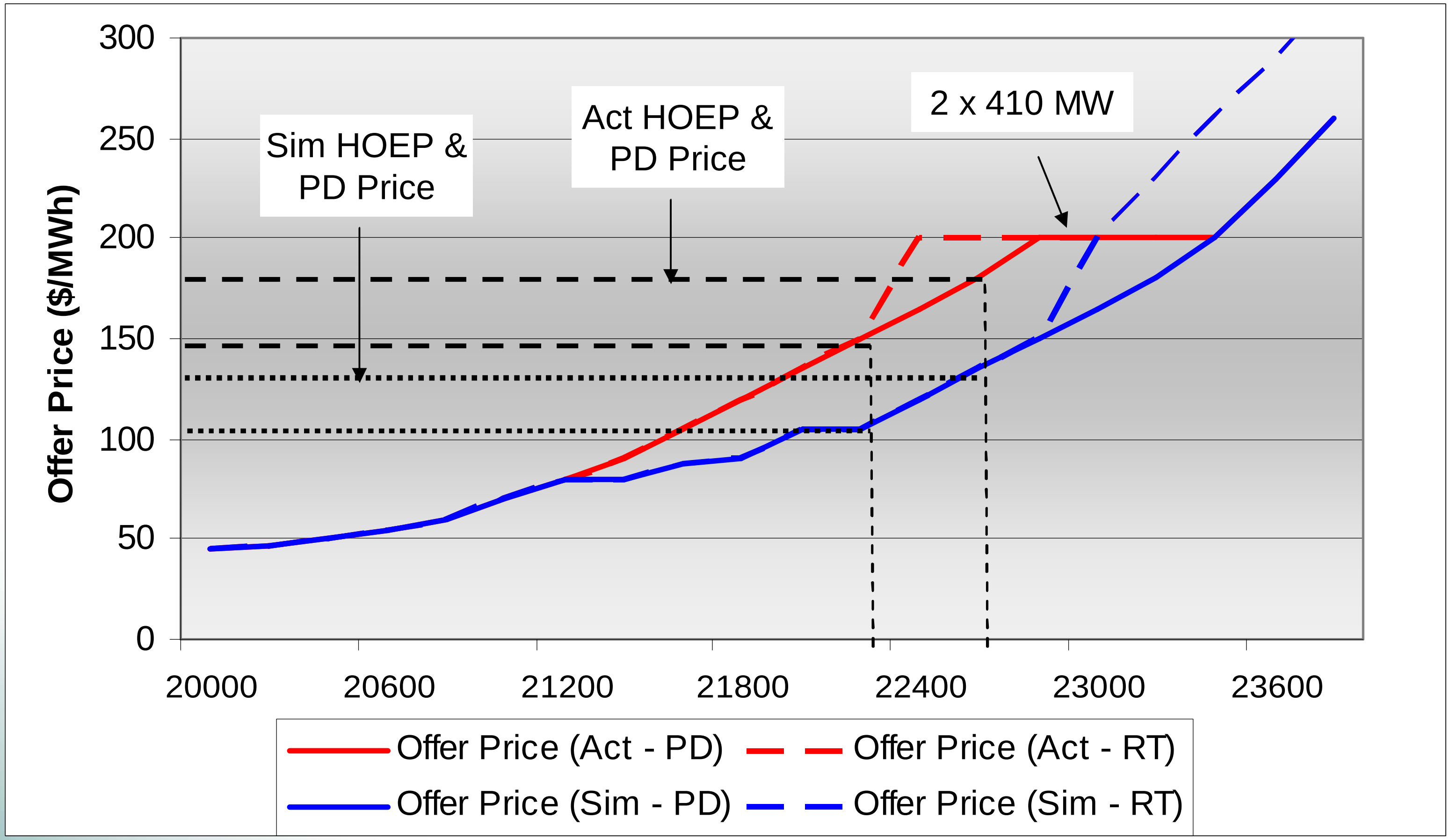
Simulation

- PD Simulation
  - PD price of $135, with 410 MW scheduled for each unit (total 820 MW)
  - 420 MW of other generation offset as well as 400 MW of import
- RT Simulation
  - Uses replacement offers and 400 MW less import
  - simulated RT price is $110

RT Price change does not trigger price test

- HOEP - PE^C = $150 - $110 = $40 < $50 = no trigger

Supply Curves – Scenario N-3



3. NLG Profitability Test

- Profitability Test triggers if
  - actual profit is higher than simulated profit
  - Net revenue used in profit test

    = energy price or payment less production cost
  - for actual vs. simulated competitive price and schedules

- Accounting for participant's entire portfolio
  - Consider supply schedules unchanged, supply not scheduled and new supply scheduled
  - recognizing supply with fixed prices

Profitability Test: No Portfolio - Scenario N-1

- Generator owns only the 2x410 MW units, offered at $200 with HOEP $150 (previous Scenario N-1)
- Simulation schedules 2x280 MW
  - Simulated competitive price is $95
- Profit (net revenue) comparison
  - With no generation scheduled, actual market schedule net revenue is zero.
  - At 280 MW, AIC for the units is $80/MWh.
  - Assuming no contract, simulated net revenue

    = 2 * 280 * ($95- $80) = $8,400
- Since actual net revenue < simulated net revenue Profitability Test does not trigger.

Profitability Test: Portfolio Effect - Scenario N-4

- Like Scenario N-1 except
  - **Participant has additional 500 MW of scheduled generation**
  - **with AIC of $50/MWh**
- Simulation schedules 2x280 MW **& initial 500 MW**
  - Simulated competitive price is $95
- Profit comparison
  - 500 MW actual schedule at $150 HOEP yields net revenue
    = 500 * ($150 - $50) = $50,000
  - Simulated schedule net revenue at $95 price (with no contract)
    = 500 * ($95 - $50) + 2 * 280 * ($95 – $80)
    = $22,500 + $8,400 = $30,900
- Since actual net revenue > simulated net revenue Profitability Test triggers

Proposed Implementation
Imports

1. Import Conduct Test

Conduct Test

- to establish if offer is unusually high
  - Thresholds based on 1 year history at an intertie
  - using hourly ratios of all participant offers to the highest price in neighbouring markets (IBA)
    - Assumes stable relationship, for each 50 MW lamination

Offer Price > Threshold

= (Reference Offer Index + 2 SD) * IBA

- Reference Offer Index (ROI) is historical average ratio
- SD is historical standard deviation of ratios
- IBA is current hour's highest price

Offer Price ≥ Pre-Dispatch Price

> Reference Offer Price (ROP) = ROI * IBA

Sample ROIs & Thresholds

Table B-1: Threshold factors for Five Interfaces in Ontario

Dec 2004 to Nov 2005										
	Michigan		Manitoba		Minnesota		New York		Quebec	
Interval (MW)	Threshold	ROI	Threshold	ROI	Threshold	ROI	Threshold	ROI	Threshold	ROI
0 - 49	1.20	0.70	1.12	0.38	1.02	0.45	1.56	0.97	1.60	0.76
50 - 99	1.29	0.72	0.51	0.15	0.92	0.51	1.62	0.88	1.58	0.89
100 - 149	1.42	0.80	0.41	0.11			1.69	0.96	2.87	0.94
150 - 199	1.26	0.73	0.73	0.25			1.63	1.01	2.01	1.04
200 - 249	1.39	0.77	0.77	0.28			1.59	0.98	1.65	1.00
250 - 299	1.35	0.72	0.93	0.44			1.47	1.00		
300 - 349							1.56	1.05	1.55	0.98
350 - 399									1.56	0.97
400 - 449							1.67	1.14	1.48	0.96

- For example, for a 250 import from New York
  - the historical average (ROI) is 1.00
  - the threshold (average + 2 SD) is 1.47

2. Import Market Price Impact Test

Market Price Test

- For any participant offers triggering the Conduct Test
  - at any intertie for a given hour
  - replace offers and simulate new <u>pre-dispatch</u> market price
  - Revised Offer = Reference Offer Price = ROI * IBA
- Market Price Test checks whether competitive PD price is substantially lower than actual PD price

3. Import Profitability Test

Profitability Test

- Has profit (net revenue) increased for actual vs. “competitive” conditions
  - Recognizing importer is paid the higher of HOEP or offer
  - Many cases may be inferred from PD conditions and changes
- Propose this be based on participant’s imports only
  - unless generation also triggered Conduct Tests

Import with No Market Schedule Scenario I-1

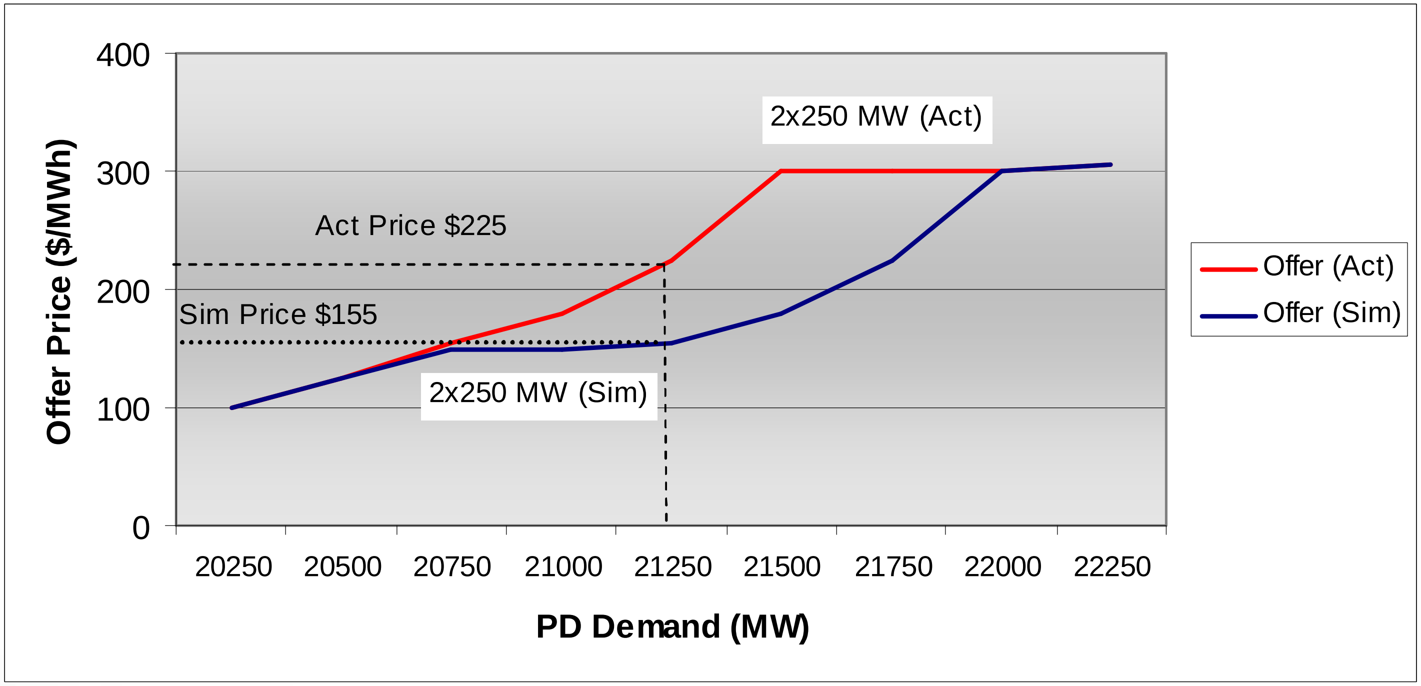
Scenario I-1:

- 2x250 MW import at NY offered at $300/MWh
- PD price is $225/MWh; HOEP = $150/MWh
- Offers not accepted in the market schedule
- IBA price is $150/MWh; NYISO price is $135/MWh

Conduct Test:

- Threshold = 1.47 * $150 = $220.5 < Offer Price = $300
- ROP = ROI * IBA = 1.00*$150 = $150 < PD Price = $225
- Since Offer Price > Threshold and PD Price > ROP
- 2x250 MW trigger Conduct Test

Price Test Simulation – Scenario I-1



Price Test:

- Replacement offers use ROP = $150, for 2x250 MW
- Simulation leads to new PD price $155, with 2x250 MW scheduled
- Since $225-$155 = $70 > $50, Market Price Test triggers

Profitability Test – Scenario I-1

Profitability Test:

- In this case simulated import would receive \$150/MWh
  - since both Offer Price and HOEP = \$150
- Cost is assumed to be
  - price of energy from the source market
    + a small Transmission charge

  = \$135 + \$5 = \$140/MWh

- Actual net revenue = 0 since Market schedule = 0 MW
- Simulated net revenue = Simulated Quantity * (Price Paid – Cost)

  = 2x250MW x (\$150 - \$140) = \$5,000

- Since actual net revenue < simulated net revenue, Profitability Test does not trigger

Import at Margin - Scenario I-2

Scenario I-2:

- Like scenario I-1 except **PD price is $300 and 100 MW import scheduled**
- 2x250 MW import at NY offered at $300
- HOEP = $150; IBA = $150; NYISO price = $135

Conduct Test:

- Threshold is 1.47 * $150 = $220.50 < $300; ROP = 1.00 * $150 = $150
- 2x250 MW trigger Conduct Test

Price Test:

- Replacement offers are $150 for 2x250 MW;
- Simulation leads to new PD price $200, with 500 MW scheduled
- Since $300-$200 = $100 > $50, Price Test triggers

Profitability Test:

- Actual net revenue = 100 * ($300 – $140) = $16,000
- Simulated net revenue = 500 * ($150 - $140)= $5,000
- Since Actual net revenue > simulated net revenue, Profitability Test triggers

Proposed Implementation
Energy Limited Generation

1. ELG Participant Conduct Test

Conduct Test to establish if

- water has been inefficiently allocated into low-priced hours
  - recognizing there are many restrictions on hydro production
- Create ratio of actual revenue for water to ideal revenue for each day
  - assuming perfect foresight and no production restrictions
- Test compares current day's ratio with historical daily ratios
- Checks for other factors which explain unusual results

ELG Participant Conduct Test Ratios & Thresholds

- Daily Water Allocation Efficiency Ratio (WAER)
  - Ratio of imputed actual revenue to ideal revenue
  - for Pre-dispatch and Real-time results
- Current day's WAERs compared with thresholds based on 90-day history
- Threshold is the lesser of
  - 2 percentile WAER over 90 days (near low-end)
  - 85% * 90-day average WAER
- Conduct Test triggers if for <u>both PD and RT</u>

  WAER < Threshold
  - Subject to identifying other explanatory factors

Revenue & WAER Calculation – Scenario E-1

Real-Time

Delivery Hour	HOEP	Actual Schedule	Ideal Allocation
1	33.6	103	
2	32.1	102	
3	27.4	90	
4	16.2	90	
5	11.3	90	
6	8.6	91	
7	24.0	48	
8	34.6	40	
9	44.0	84	
10	116.7	84	185.8
11	152.1	84	185.8
12	138.2	89	185.8
13	185.7	89	185.8
14	186.9	77	185.8
15	92.9	54	185.8
16	69.2	98	185.8
17	74.4	126	185.8
18	92.6	164	185.8
19	76.3	164	185.8
20	101.2	164	185.8
21	96.7	164	185.8
22	59.1	163	185.8
23	40.7	164	
24	56.3	122	128.5
Total MWh		2,544	2,544
Revenue		188996	275149
Actual WAER		68.7%	

Pre-Dispatch

Delivery Hour	PD MCP	Actual Schedule	Ideal Allocation
1	34.73	117	
2	32.46	103	
3	31.48	90	
4	27.71	90	
5	27.07	90	
6	27.16	137	
7	32.09	48	
8	39	0	
9	50.06	84	53.9
10	53.49	84	185.8
11	68.41	84	185.8
12	96.24	84	185.8
13	110	84	185.8
14	70.99	77	185.8
15	77.03	48	185.8
16	95	166	185.8
17	86.03	166	185.8
18	80.03	164	185.8
19	55.92	164	185.8
20	53.87	164	185.8
21	54.83	164	185.8
22	48.57	163	
23	98.37	164	185.8
24	94.01	120	185.8
Total MWh		2,655	2,655
Revenue		166868	206003
Actual WAER		81.0%	

Comparison of WAER with Threshold – Scenario E-1

- For Scenario E-1
  - Real-time: WAER = 68.7 % (as above)
    - From 90-day history: Average WAER = 90.8%; 2 percentile = 76.1%
    - Threshold = min (2 Percentile, 85%*Average WAER)
      = min(0.761, 0.771) = 76.1%
  - Pre-dispatch: WAER = 81.0 % (as above)
    - From 90-day history: Average WAER = 91.6%; 2 percentile = 80.1%
    - Threshold = min(0.801, 0.779) = 77.9%

- Comparison of WAER with Thresholds:
  - Real-time: Since 68.7% < 76.1%, RT WAER < RT Threshold
  - Pre-dispatch: Since 81.0% > 77.9%, PD WAER > PD Threshold

- Since WAER is not < Threshold for both PD and RT
  - Conduct Test does not trigger

ELG Conduct Test: Other Factors – Scenario E-2

- Scenario-2
  - Like Scenario-E1 except PD WAER = 60% < PD Threshold
  - For both RT and PD WAER < Threshold

- Before Conduct Test is triggered, consider other factors
  - Based on data available to MAU
  - Could include:
    - i) Unusual instability of earlier PD prices
    - ii) Atypical minimum flow restrictions
    - iii) Unexpected water release by other plant
    - iv) Unusually low daily energy (water)
    - v) Trends in WAER due to seasonal etc. factors

- If these do not "explain" low WAER, conduct test is triggered.

2. ELG Market Price Impact Test

Market Price Test

- Create revised allocations for all ELG triggering Conduct Test
  - Revised schedules "consistent" with history
  - Target Revenue = Day's Ideal Revenue * Average WAER
  - Minimize hourly changes for the Revised Schedules

- Simulation with revised schedules in PD & real-time

- Market Price Test looks at price impact in all hours of the day
  - netting price increases and decreases weighted by hourly market demand

$$\sum_h w_h.(HOEP_h - PE_h{}^c) > n.\$50 / MWh$$

  - Where threshold factor n has not yet been set.
  - Could be in range n = 2 to 3

ELG Market Price Test: Revised Allocation

- The revised allocation is based on minimizing the schedule change in each hour, while improving the daily revenue

Min: $\sum_h (E_h^{r} - E_h^{a})^2$ Objective Function (simplified)

subject to constraints

$E_h^{min} < E_h^{r} < E_h^{max}$ (1)

$\sum_h E_h^{r} = \sum_h E_h^{a}$ (2)

$V^{r} \geq RWAER_T \cdot V^*$ (3)

- The objective is to minimize the difference function representing the sum of squares of the differences between actual and revised hourly schedules

- There are 3 groups of constraints
  - (1) hourly limits on production between some minimum and maximum amount
  - (2) total energy for the revised schedules must equal the total actual energy
  - (3) the target daily revenue ($V^{r} = \sum$ hourly energy * HOEP) must be at least a set amount equal to the 90-day average WAER times the ideal revenue possible

Simple Revised Allocation – Scenario E-3

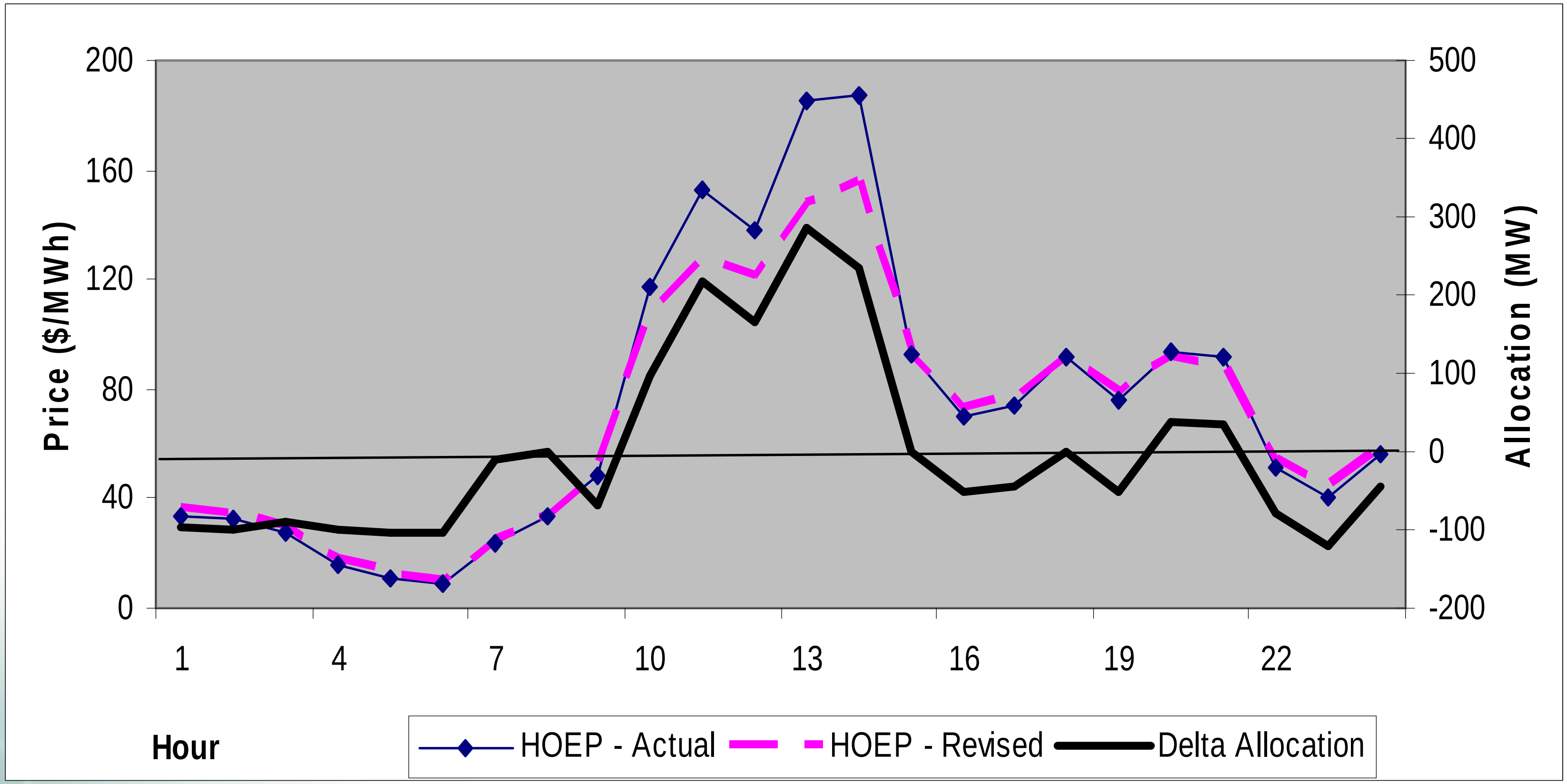
		Actual		Revised	
Hour	HOEP	Output	Revenue	Output	Revenue
	($/MWh)	(MWh)	($)	(MWh)	($)
1	80	1	80	0.5	40
2	100	0	0	0.25	25
3	100	0	0	0.25	25
Total		1	80	1	90

- For Scenario E-3 actual revenue is $80, ideal revenue is $100
- Assuming 90-day Average WAER = 0.90,
  - target revenue for the revised allocation
    = Average WAER * Ideal Revenue
    = 0.90 *$100 = $90

ELG Market Price Test: Multiple Plants – Scenario E-4

- Scenario E-4
  - Assumes several ELG plant have triggered the Conduct Test
- Revised allocations are determined for each plant
  - The total actual schedules and revised schedules are shown in the graph (following)
- Simulations are run using the revised schedules
  - PD is simulated first, but results in no changes to imports
  - RT is then simulated with the revised schedules
  - Revised HOEPs are calculated for all hours (see graph)

Revised Allocations & Revised HOEP – Scenario E-4



ELG Market Price Trigger – Scenario E-4

- Market Price Test compares
  - the weighted sum of hourly price impacts
  - with a threshold value

$$\sum_h w_h.(HOEP_h - PE_h{}^c) > n.\$50 / MWh$$

- Based on simulated results the sum $ 102.16
- The Market Price Test will trigger in this scenario, <u>depending on the value of n</u>
  - For n=2, the threshold is n*$50 = $100
  - For n=3, the threshold is n*$50 = $150
- The Market Price Test
  - triggers if is n=2,
  - does not trigger if n=3

3. ELG Profitability Test

- The ELG Profitability Test is triggered if the actual net revenue is greater than net revenue for the simulated results representing competitive conditions
  - calculated across all hours of the day and
  - accounting for all resources scheduled by the generator

ELG Profitability Test – Scenario E-4

- Scenario E-4: Generator has only hydro plant scheduled
  - All of which triggered the Conduct Test and Market Price Test (see earlier slides)
- Based on Actual schedules and prices, and $10 incremental running cost
  - Actual net revenue for the day: $393 k
- Based on Revised schedules
  - Revised net revenue for the day: $479 k
- Since Actual net revenue < Revised net revenue this is not an exercise of market power

ELG Profitability Test – Scenario E-5

- Scenario E-5: Like Scenario E-4 except
  - Generator also has 500 MW fossil plant and 500 MW import scheduled
  - Fossil plant has an average incremental cost of $60/MWh;
    - scheduled HE 10-21 for energy prices > $60/MWh
  - Imports have cost $70/MWh;
    - also scheduled HE10-21 and receive HOEP
- With hydroelectric plant, 500 MW fossil & 500 MW import
  - Actual net revenue for the day: $983 k
  - Revised net revenue for the day: $953 k
- Since Actual net revenue > Revised net revenue
  Profitability Test triggers

With all 3 test triggering, this may be an exercise of market power

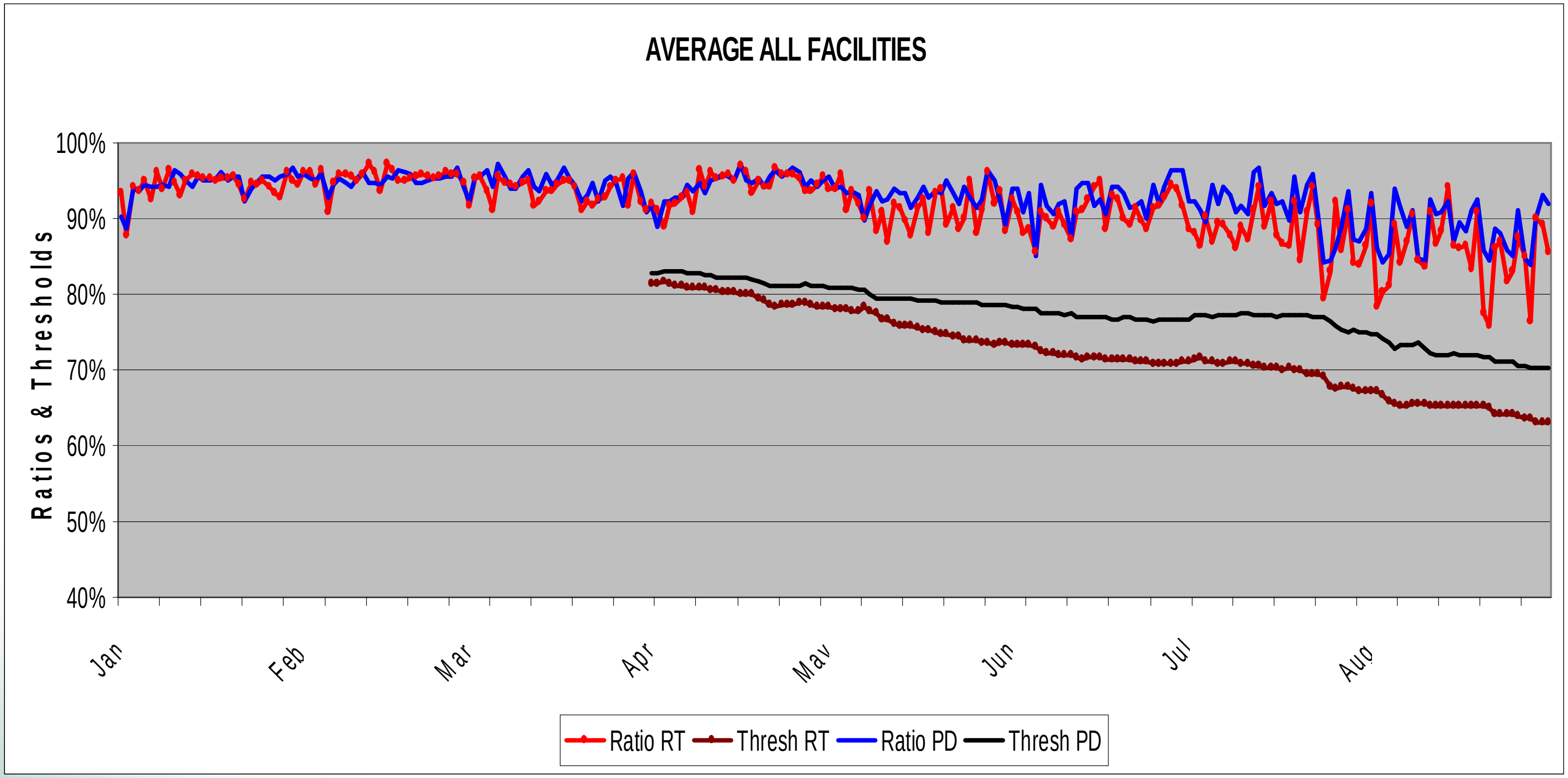
Consultation and Next Steps

Next Steps

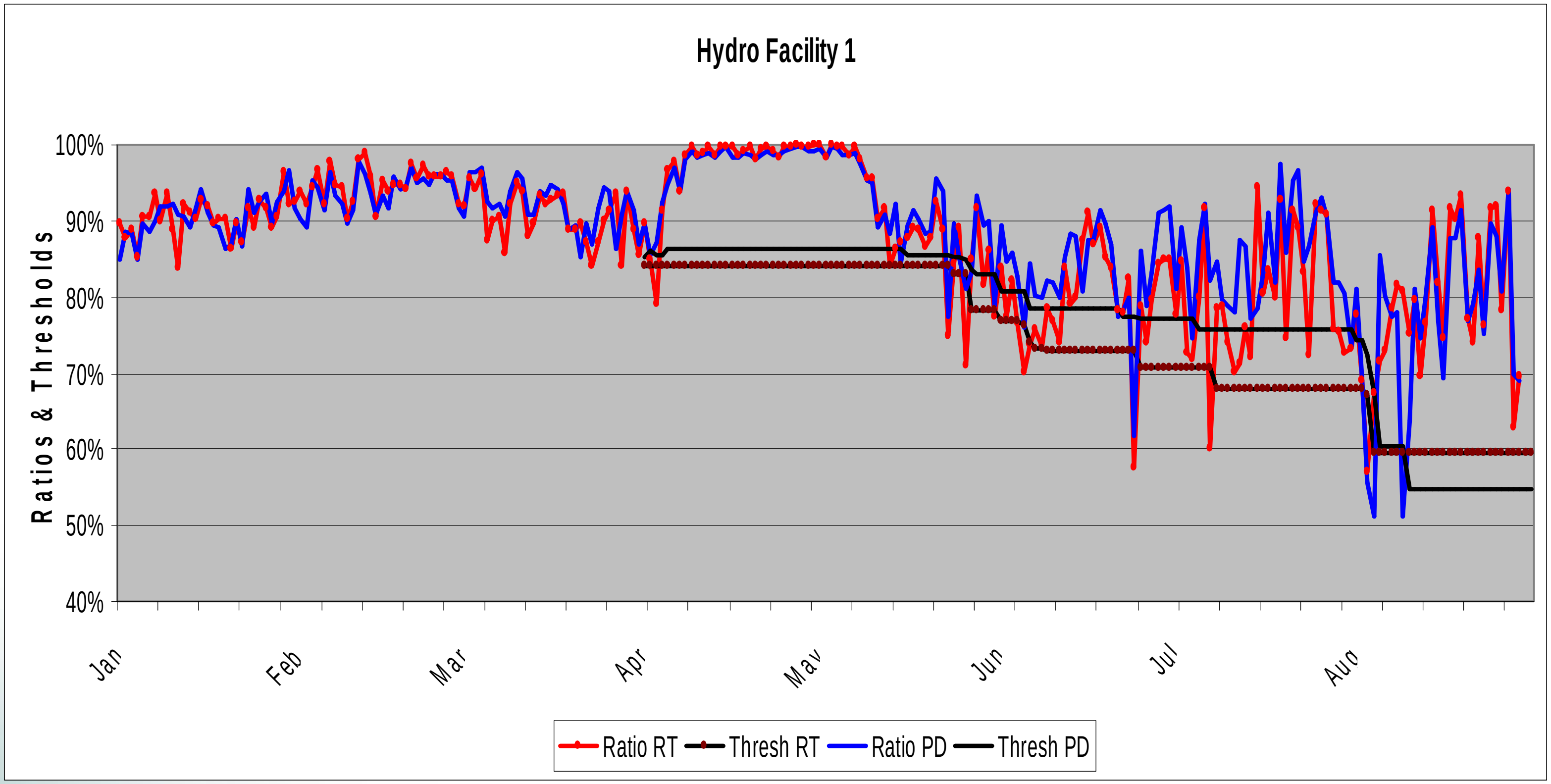
- Written stakeholder comments, due Feb 28, 2007
  – Including response to questions posed
- MSP review of comments and initial response
- Development of options and possible further consultation
- Finalize and publish Framework
- Begin the process to modify Data Catalogue

Background Data
Partial Response to Questions

ELG Daily WAER & Thresholds - Averages Across All Facilities



ELG Daily WAER & Thresholds – Sample Facility



Monthly ROI & Threshold by Intertie - 2005 for Lamination 0-49 MW

Monthly ROI Data by Intertie
2005

		MB		MI		MN		NY		PQ	
Annual Threshold		0.83		1.02		0.88		1.29		1.45	
Annual ROI		0.26		0.58		0.42		0.80		0.68	
Month	Interval (MW)	Mthly Threshold	Mthly ROI	Mthly Threshold	Mthly ROI	Mthly Threshold	Mthly ROI	Mthly Threshold	Mthly ROI	Mthly Threshold	Mthly ROI
Jan	0 - 49	0.81	0.53	1.03	0.58	0.84	0.45	1.24	0.76	1.53	0.76
Feb	0 - 49	0.98	0.60	0.96	0.59	0.92	0.61	1.13	0.79	1.15	0.61
Mar	0 - 49	1.22	0.56	1.08	0.62	0.97	0.53	1.28	0.83	1.26	0.83
Apr	0 - 49	0.58	0.13	1.17	0.69	0.91	0.34	1.41	0.88	1.38	0.70
May	0 - 49	0.74	0.48	0.99	0.59	0.63	0.23	0.99	0.68	1.30	0.67
Jun	0 - 49	0.06	0.06	0.99	0.59	0.76	0.29	1.43	0.81	1.19	0.45
Jul	0 - 49	0.08	0.05	1.59	0.77	0.80	0.43	1.40	0.86	1.89	0.78
Aug	0 - 49	0.05	0.05	1.63	0.73	0.80	0.41	1.35	0.81	1.47	0.75
Sep	0 - 49	0.09	0.05	0.96	0.46	0.62	0.33	1.28	0.85	1.41	0.71
Oct	0 - 49	0.11	0.06	0.85	0.39	0.78	0.41	1.18	0.73	1.19	0.49
Nov	0 - 49	0.19	0.11	1.01	0.53	0.91	0.49	1.23	0.74	1.26	0.80
Dec	0 - 49	0.63	0.33	0.92	0.48	0.95	0.54	1.19	0.77	1.38	0.78

Note, values do not correspond to earlier results shown because of a broadening of the markets included in the IBA calculation, the resulting Increase in IBA values and the reduction in calculated IOR and ROI.

Monthly ROI & Threshold by Intertie - 2006 for Lamination 0-49 MW

Monthly ROI Data by Intertie
2006

		MB		MI		MN		NY		PQ	
Annual Threshold		0.33		1.05		0.97		1.26		1.19	
Annual Mean		0.11		0.63		0.59		0.73		0.54	
Month	Interval (MW)	Mthly Threshold	Mthly ROI	Mthly Threshold	Mthly ROI	Mthly Threshold	Mthly ROI	Mthly Threshold	Mthly ROI	Mthly Threshold	Mthly ROI
Jan	0 - 49	0.12	0.05	1.01	0.57	0.96	0.58	1.29	0.79	1.27	0.70
Feb	0 - 49	0.34	0.09	0.94	0.62	0.87	0.57	1.20	0.71	1.18	0.69
Mar	0 - 49	0.07	0.05	0.93	0.58	0.92	0.58	1.42	0.68	1.10	0.40
Apr	0 - 49	0.08	0.05	1.00	0.66	0.93	0.62	1.17	0.78	1.21	0.78
May	0 - 49	0.09	0.06	1.13	0.63	1.02	0.66	1.24	0.62	1.28	0.70
Jun	0 - 49	0.20	0.10	1.02	0.52	0.94	0.53	1.33	0.80	1.31	0.68
Jul	0 - 49	0.27	0.12	1.00	0.64	0.98	0.62	1.22	0.70	1.03	0.50
Aug	0 - 49	0.34	0.14	1.04	0.61	0.99	0.60	1.34	0.67	1.22	0.65
Sep	0 - 49	0.56	0.34	1.03	0.70	1.00	0.65	1.29	0.91	1.60	0.95
Oct	0 - 49	0.96	0.82	0.94	0.61	1.02	0.63	1.13	0.70	1.11	0.49

Monthly ROI & Threshold by Intertie - 2005 for Lamination 100-149 MW

Monthly ROI Data by Intertie
2005

		MB		MI		NY		PQ	
Annual Threshold		0.34		1.18		1.43		2.35	
Annual ROI		0.09		0.64		0.82		0.80	
Month	Interval (MW)	Mthly Threshold	Mthly ROI	Mthly Threshold	Mthly ROI	Mthly Threshold	Mthly ROI	Mthly Threshold	Mthly ROI
Jan	100 - 149	0.75	0.41	1.17	0.68	1.25	0.72	1.20	0.65
Feb	100 - 149	0.60	0.43	1.14	0.71	1.34	0.91	1.43	0.86
Mar	100 - 149	0.51	0.33	1.23	0.74	1.38	0.75	1.17	0.82
Apr	100 - 149	0.18	0.12	1.14	0.70	1.44	0.90	1.45	0.71
May	100 - 149	0.50	0.15	0.91	0.57	1.57	0.85	1.26	0.87
Jun	100 - 149	0.15	0.09	1.16	0.69	1.42	0.92	1.10	0.72
Jul	100 - 149	0.39	0.09	1.30	0.72	1.34	0.75	1.25	0.79
Aug	100 - 149	0.29	0.07	1.50	0.72	1.60	0.82	6.55	1.34
Sep	100 - 149	0.15	0.06	1.09	0.58	1.24	0.83	1.28	0.82
Oct	100 - 149	0.08	0.04	0.96	0.47	1.43	0.83	1.02	0.69
Nov	100 - 149	0.25	0.08	1.17	0.66	1.48	0.85	1.65	1.07
Dec	100 - 149	0.59	0.23	1.11	0.64	1.33	0.77	1.36	0.95

* Insufficient Data for MN Intertie

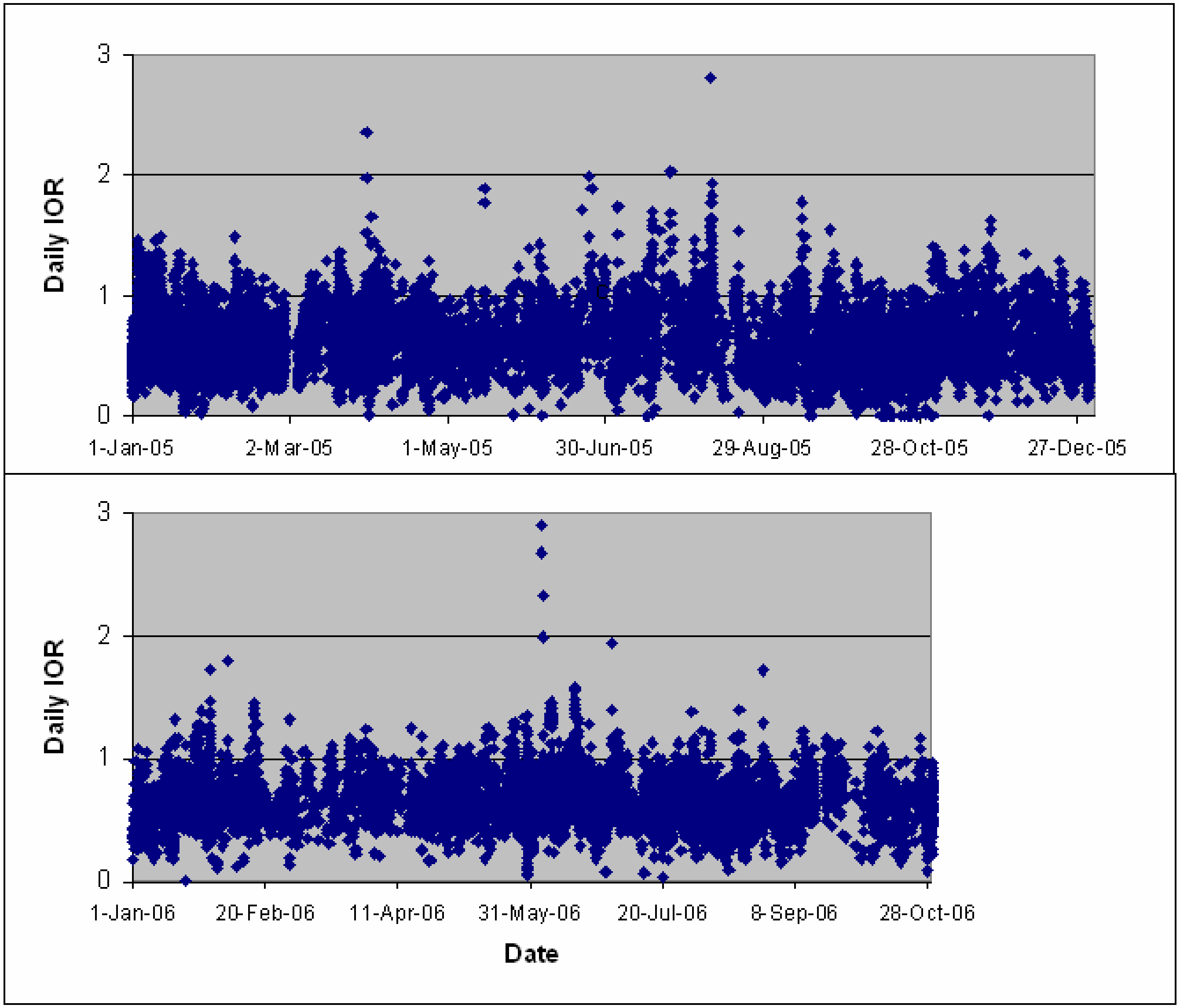
Monthly ROI & Threshold by Intertie - 2006 for Lamination 100-149 MW

Monthly ROI Data by Intertie
2006

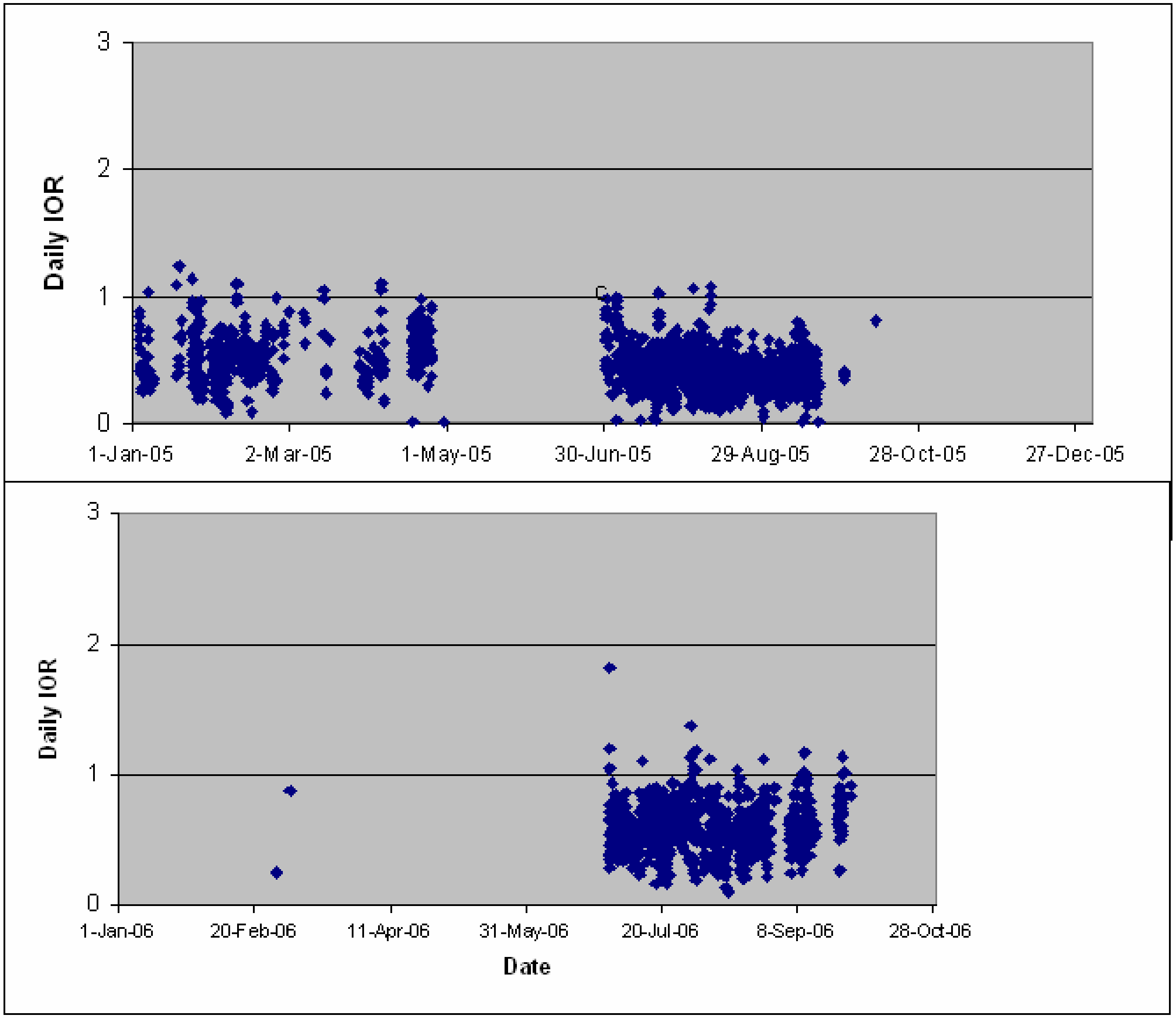
		MB		MI		NY		PQ	
Annual Threshold		0.37		1.08		1.31		1.17	
Annual ROI		0.13		0.64		0.70		0.49	
Month	Interval (MW)	Mthly Threshold	Mthly ROI	Mthly Threshold	Mthly ROI	Mthly Threshold	Mthly ROI	Mthly Threshold	Mthly ROI
Jan	100 - 149	0.50	0.26	1.04	0.59	1.27	0.68	1.28	0.82
Feb	100 - 149	0.34	0.19	0.99	0.62	1.11	0.73	1.12	0.72
Mar	100 - 149	0.12	0.08	1.02	0.62	1.26	0.86	1.11	0.75
Apr	100 - 149	0.17	0.10	1.04	0.66	1.17	0.68	0.94	0.50
May	100 - 149	0.20	0.11	1.13	0.71	1.32	0.66	1.26	0.75
Jun	100 - 149	0.24	0.12	1.16	0.70	1.40	0.88	1.61	0.68
Jul	100 - 149	0.44	0.18	1.22	0.69	1.10	0.61	1.04	0.42
Aug	100 - 149	0.45	0.10	1.02	0.58	1.36	0.74	1.28	0.48
Sep	100 - 149	0.54	0.16	1.09	0.69	1.64	0.98	1.48	1.07
Oct	100 - 149	0.77	0.29	1.02	0.62	1.20	0.73	1.23	0.83

* Insufficient Data for MN Intertie

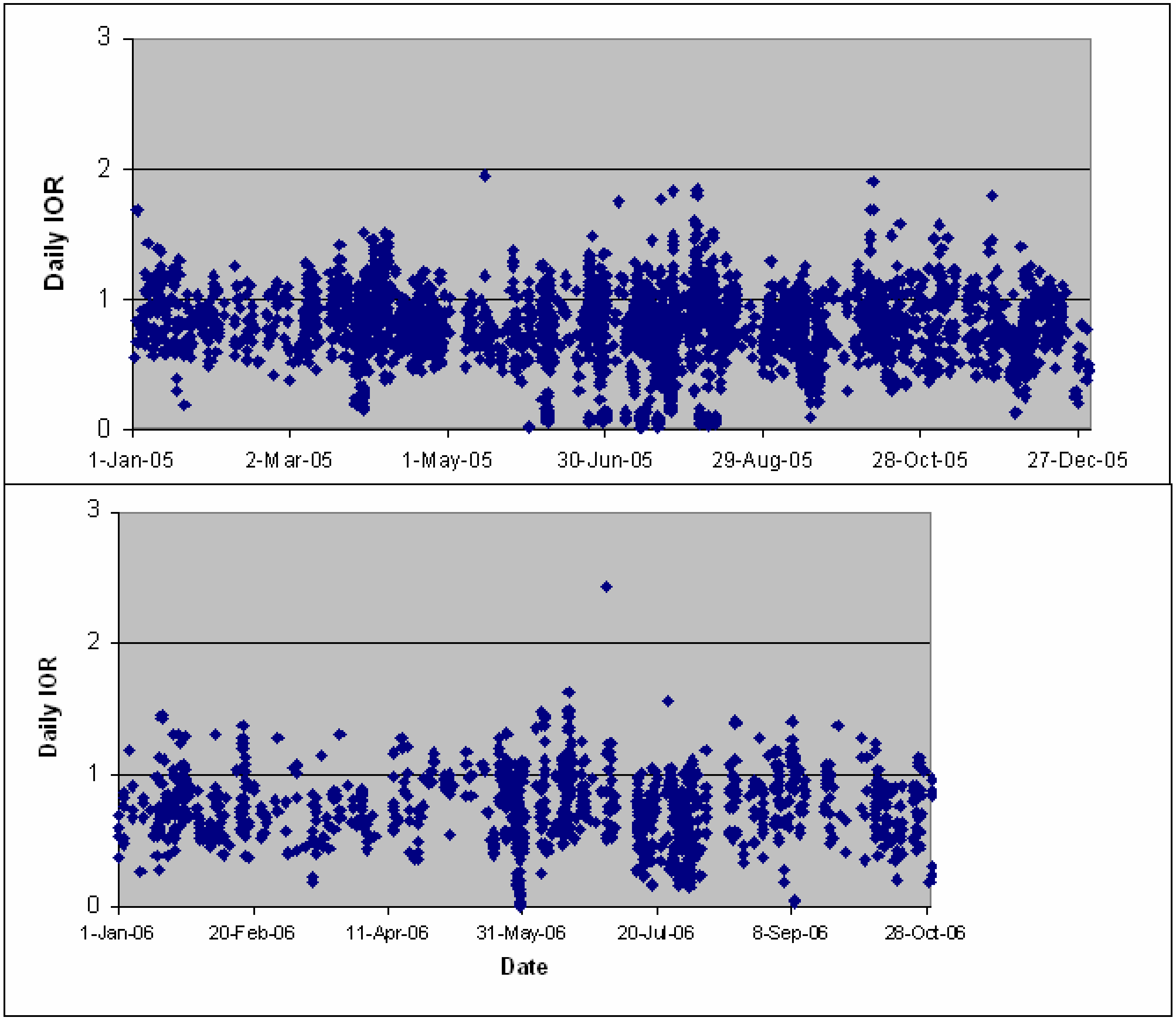
Daily IOR 2005-2006 for Michigan Intertie Lamination 50-99 MW



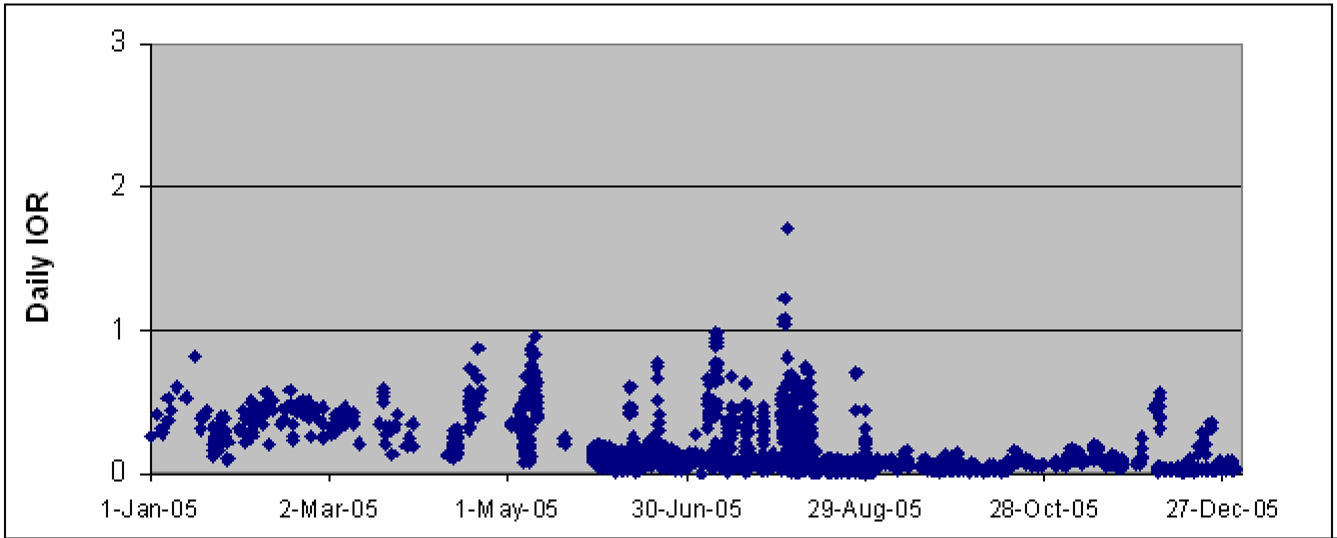
Daily IOR 2005-2006 for Minnesota Intertie Lamination 50-99 MW

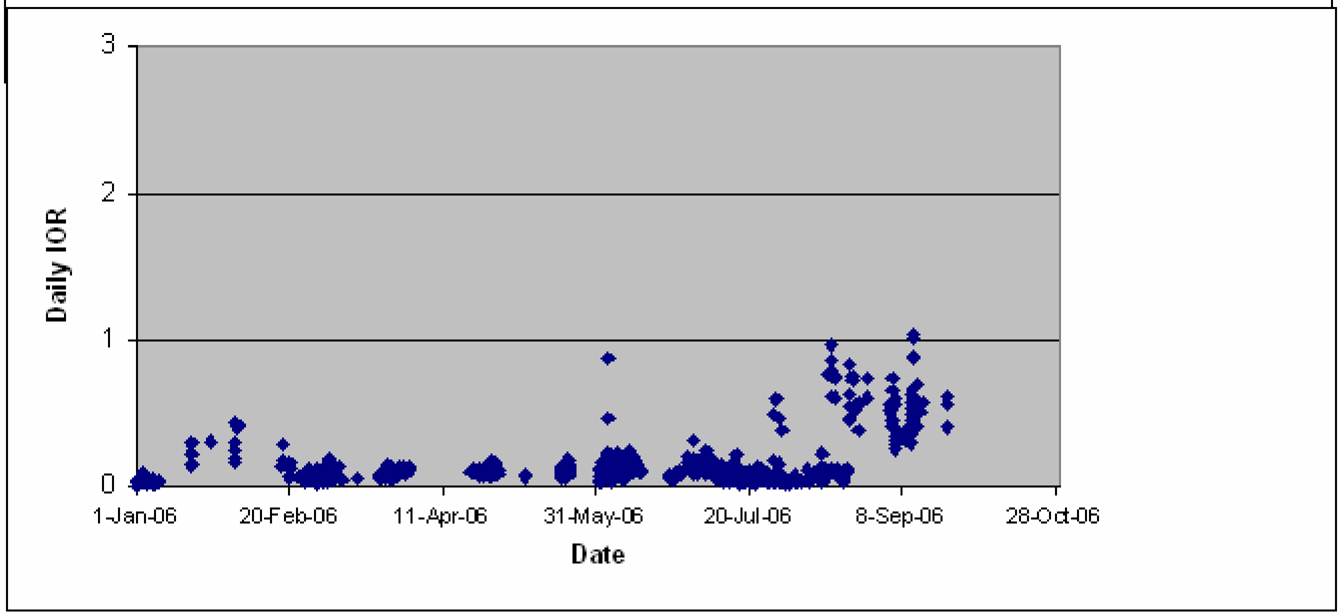


Daily IOR 2005-2006 for New York Intertie Lamination 50-99 MW

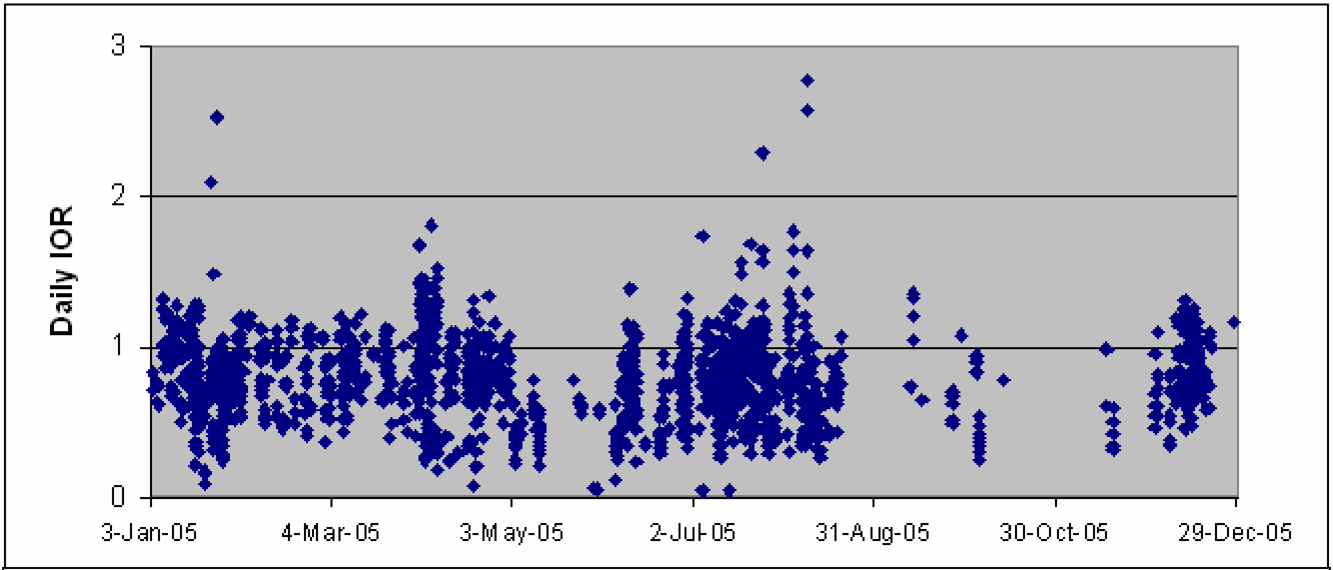


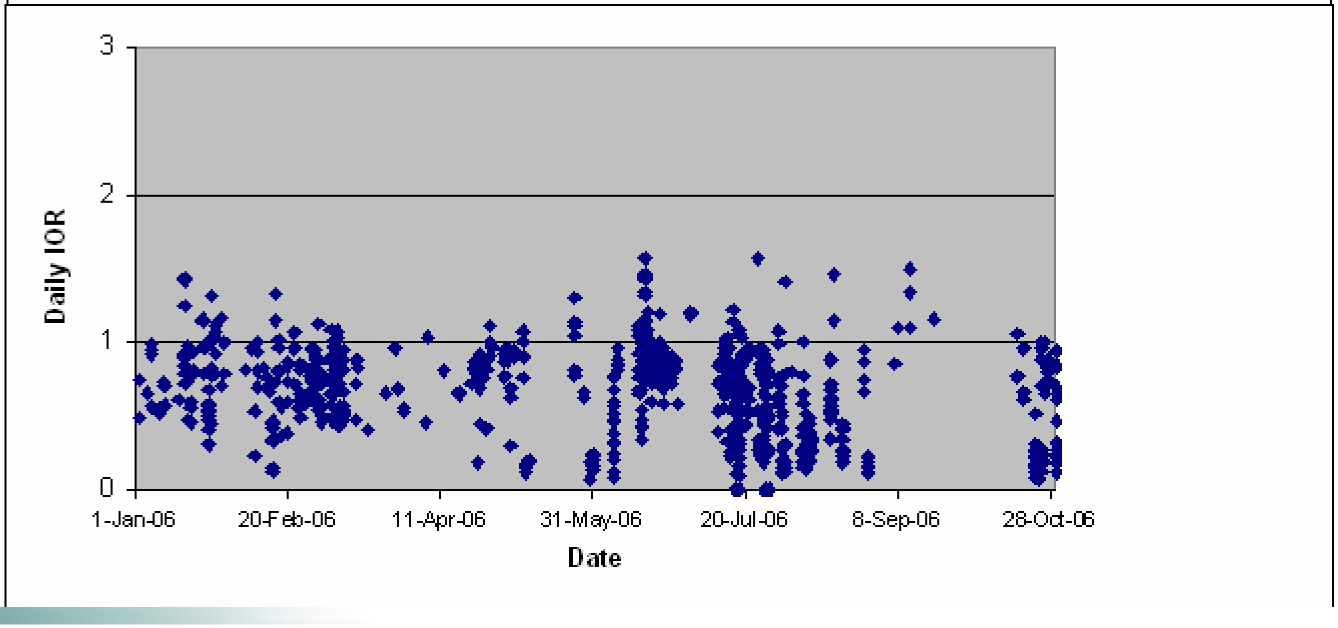
Daily IOR 2005-2006 for Manitoba Intertie Lamination 50-99 MW





Daily IOR 2005-2006 for Quebec Intertie Lamination 50-99 MW





Additional Examples & Supporting Data

Illustrative Reference Prices and Thresholds – NELG Scenario 1

MaxThresh = max (Reference Price Threshold, MAXAIC)

Multiple Import Offers – Profit Gain Scenario I-3

Scenario I-3:

- Like scenario I-1 **with additional 2x250 MW offered at $200**.
- HOEP = $150; IBA = $150; NYISO price = $135
- PD price is $225 and the lower priced 2nd 2x250 MW are scheduled

Conduct Test:

- Threshold is $220.50 and ROP is $150, for all
- Since $300 >$220.5, offer price > threshold for 1st 2x250 MW, which triggers Conduct Test for these.
- Since $200 <$220.5, offer price < threshold for 2nd 2x250 MW, which does not trigger Conduct Test for these.

Price Test:

- Replacement offers are $150, applied only for 1st 2x250 MW.
- Simulation leads to new PD price $155; 1st 500 MW replace 2nd 500 MW
- Since $225-$155 = $70 > $50, Price Test triggers

Profitability Test:

- Actual net revenue = 500 * ($200 – $140) = $30,000
- Simulated net revenue = 500 * ($150 - $140)= $5,000
- Since actual net revenue > simulated net revenue, Profitability Test triggers

Multiple Import Offers – No Profit Gain Scenario I-4

Scenario I-4:

- Same as previous (scenario I-3) **except HOEP = $250**
- 2x250 MW import at NY offered at $300, and 2x250 MW offered at $200.
- IBA = $150; NYISO price = $135; PD price is $225

Conduct Test: (same as I-3)

- 1st 2x250 MW, triggers conduct test
- 2nd 2x250 MW, does not trigger

Price Test: (same as I-3)

- Replacement offers are $150, applied only for 1st 2x250 MW.
- Simulation leads to new PD price $155; 1st 500 MW replace 2nd 500 MW
- Since $225-$155 = $70 > $50 , Price Test triggers

Profitability Test:

- Actual HOEP = $250 remains unchanged in simulation, no change in exports
  - Actual and simulated exports receive HOEP = $250 since this exceeds offer prices
- Actual net revenue = 500 * ($250 – $140) = $55,000
- Simulated net revenue = 500 * ($250 - $140) = $55,000
- Since actual net revenue < simulated net revenue, Profitability Test does not trigger

SUMMARY OF IMPORT SCENARIOS

	I-1: Offers Above PD	**I-2: Offers At PD**	**I-3: Offers Above and Below PD**	**I-4: Offers Above and Below PD**
PD/ HOEP	$225 / $150	**$300** / $150	$225 / $150	$225 / **$250**
Offers (MW @ Price)	2 x 250 MW @ $300	2 x 250 MW @ $300	2 x 250 MW @ $300 **+ 2 x 250 MW @ $200**	2 x 250 MW @ $300 + 2 x 250 MW @ $200
Imports Scheduled	**None**	**100 MW**	**2 x 250 MW**	**2 x 250 MW**
Conduct Test	Triggered	Triggered	Triggered for 1^{st} 2 x 250MW	Triggered for 1^{st} 2 x 250MW
Price Test	Triggered	Triggered	Triggered	Triggered
Profitability Test	Not Triggered	Triggered	Triggered	Not Triggered
Outcome	No Action	Talk to Participant	Talk to Participant	No Action

Simulated Schedules & Prices – ELG Scenario E-4

Hour	Actual HOEP ($/MWh)	Actual Hydro (MW)	Revised HOEP ($/MWh)	Revised Hydro (MW)
1	33.63	206.0	36.31	109.8
2	32.07	204.0	34.78	105.1
3	27.36	180.0	29.54	88.9
4	16.22	180.0	17.73	79.0
5	11.33	180.0	12.43	77.0
6	9.00	182.0	9.90	77.0
7	23.97	88.0	24.21	77.0
8	33.64	77.0	33.64	77.0
9	48.05	168.0	50.73	97.7
10	117.09	172.0	108.58	269.0
11	152.29	168.0	127.89	386.5
12	138.16	178.0	121.35	344.8
13	185.70	182.0	147.50	468.0
14	186.89	236.0	155.58	468.8
15	92.93	293.0	92.82	294.6
16	70.01	314.0	72.63	260.6
17	74.35	354.0	76.58	310.4
18	91.87	432.0	91.97	430.4
19	76.25	412.0	79.04	361.3
20	94.04	386.0	91.55	423.6
21	91.22	382.0	89.05	415.6
22	51.47	391.0	54.50	310.5
23	40.33	369.0	44.10	247.5
24	55.92	244.0	57.94	198.1
Revenue		452417		538518.3
Incr Cost	$10	59780	$10	59780
Profit		392637		478738.3

Data for Net Market Price Impact – ELG Scenario E-4

- Data in table show
  - Total hourly schedule change (Delta Allocation)
  - Hourly changes to HOEP (Delta HOEP)
  - Hourly weightings = hourly demand / daily average demand

Hour	1	2	3	4	5	6	7	8	
Delta Allocation (MW)	-96	-99	-91	-101	-103	-105	-11	0	
Delta HOEP ($/MWh)	-2.67	-2.71	-2.18	-1.51	-1.11	-0.90	-0.24	0.00	
Demand Weighting	0.935	0.904	0.885	0.839	0.816	0.816	0.855	0.925	
Hour	9	10	11	12	13	14	15	16	
Delta Allocation (MW)	-70	97	219	167	286	233	2	-53	
Delta HOEP ($/MWh)	-2.68	8.51	24.40	16.81	38.19	31.32	0.10	-2.62	
Demand Weighting	0.975	1.032	1.054	1.060	1.075	1.074	1.095	1.105	
Hour	17	18	19	20	21	22	23	24	**Total / Wtd**
Delta Allocation (MW)	-44	-2	-51	38	34	-81	-122	-46	**0**
Delta HOEP ($/MWh)	-2.23	-0.10	-2.79	2.49	2.17	-3.03	-3.76	-2.03	**93.45**
Demand Weighting	1.125	1.122	1.074	1.098	1.091	1.059	1.007	0.979	**102.16**

Data for Profitability Test – ELG Scenario E-5

Hour	Actual HOEP ($/MWh)	Actual Hydro (MW)	Actual Foss+Imp (MW)	Revised HOEP ($/MWh)	Revised Hydro (MW)	Revised Foss+Imp (MW)
1	33.63	206.0		36.31	109.8	
2	32.07	204.0		34.78	105.1	
3	27.36	180.0		29.54	88.9	
4	16.22	180.0		17.73	79.0	
5	11.33	180.0		12.43	77.0	
6	9.00	182.0		9.90	77.0	
7	23.97	88.0		24.21	77.0	
8	33.64	77.0		33.64	77.0	
9	48.05	168.0		50.73	97.7	
10	117.09	172.0	1000	108.58	269.0	1000
11	152.29	168.0	1000	127.89	386.5	1000
12	138.16	178.0	1000	121.35	344.8	1000
13	185.70	182.0	1000	147.50	468.0	1000
14	186.89	236.0	1000	155.58	468.8	1000
15	92.93	293.0	1000	92.82	294.6	1000
16	70.01	314.0	1000	72.63	260.6	1000
17	74.35	354.0	1000	76.58	310.4	1000
18	91.87	432.0	1000	91.97	430.4	1000
19	76.25	412.0	1000	79.04	361.3	1000
20	94.04	386.0	1000	91.55	423.6	1000
21	91.22	382.0	1000	89.05	415.6	1000
22	51.47	391.0		54.50	310.5	
23	40.33	369.0		44.10	247.5	
24	55.92	244.0		57.94	198.1	
Revenue		1823219			1793066	
Incr Cost		839780			839780	
Profit		983439			953286	