Building the Energy Markets of Tomorrow . . . Today

Settlements Under SMD2

Agenda

- ✓ General Provisions of SMD2
- ✓ Transmission Service under SMD2
- ✓ Regulation Service under SMD2
- ✓ Operating Reserves Service under SMD2
- ✓ DAM Margin Preservation under SMD2
- ✓ Bid Production Cost Guarantee under SMD2
- ✓ Performance Tracking under SMD2
- ✓ Determinant & Settlement Reports under SMD2

General Provisions

- ✓ Three generator classifications
  - *On-dispatch (ISO Committed Flex)*
  - *Self-Scheduled*
  - *Self-Scheduled Flex*
- ✓ No real-time price chasing for off-dispatch units
  - *Anticipated benefits were not realized*
  - *May submit MW schedules as a self-scheduled unit*
    - Can vary schedule ever quarter-hour in anticipation of price changes
    - Schedule for HB xx must be submitted by HB xx – 60 min.
  - *Economic Payment Limit (EPL) calculation eliminated*
- ✓ Penalty for persistent under-generation remains

General Provisions – Transactions

- ✓ Accommodates new settlement rules for non-competitive external proxies
- ✓ No change for BPCG payments on imports
- ✓ RTC_{15} determines the price at an constrained external proxy bus
- ✓ External transactions cut by the NYISO will be protected relative to their day-ahead positions

General Provisions – Regulation

- ✓ Full two-settlement: regulation service will be scheduled and settled nominally on a 5-minute basis
- ✓ Marginal LOC incorporated into clearing price

General Provisions – Reserves

- ✓ Full two-settlement: reserve services will be scheduled and settled nominally on a 5-minute basis
- ✓ Marginal LOC incorporated into clearing price; therefore, separate LOC payment eliminated
- ✓ Reduction in availability payment based on daily performance will be removed
- ✓ Requirement to purchase replacement energy at LBMP for failure during a reserve pickup will be removed

General Provisions – Reserves (continued)

- ✓ Reserves during RTD-CAM
  - *Reserve requirements continue to be calculated during activation*
  - *Reserve prices will continue to be produced*
  - *Reserve demand curves continue to be applicable*
  - *Reserve Pickups:*
    - Units dispatched can set LBMP price
    - Units will buy out of their DAM obligation based on schedule
    - MWs produced paid at LBMP

General Provisions - BPCG

- ✓ On-Dispatch units continue to be eligible for real-time BPCG payments
- ✓ Self-Scheduled will not be eligible for BPCG payments
  - *If Self-Scheduled for any hour they will not be eligible the entire day*
  - *Self-Scheduled Flex will be eligible for incremental cost above min; this should never occur.*
- ✓ Units will not be eligible for BPCG payments if ramp rate constrained down *or up*
- ✓ *Incorporates Economic Operating Point*

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Imports, Exports, & Wheels-though Settlement Under SMD2

Proxy Bus Pricing

Competitive Bus?	Import Constrained?	Export Constrained?	NYISO Ramp Constrained?	Real-Time Price
Yes	No	No	No	RTD/RTD-CAM
Yes	Yes	No	No	RTC_{15}
Yes	Yes	No	Yes	RTC_{15}
Yes	No	Yes	No	RTC_{15}
Yes	No	Yes	Yes	RTC_{15}
No	No	No	No	RTD/RTD-CAM
No	Yes	No	No	Higher of 1) RTC_{15} or 2) lower of RTD/RTD-CAM or $0
No	Yes	No	Yes	RTC_{15}
No	No	Yes	No	Lower of 1) RTC_{15} or 2) higher of RTD/RTD-CAM or SCUC
No	No	Yes	Yes	RTC_{15}

Import Settlements

Scheduled Day Ahead?	Scheduled by RTC?	Flow in Real-time?	External Proxy Constrained in RTC?	Real-time Settlement
Y	Y	Y	N	None
Y	N	N	N	Buys back at RTD or RTD-CAM price.
N	Y	Y	N	Paid RTD or RTD-CAM price. If RTD price is less than the accepted bid a supplemental payment shall be made.
Y	Y	Y	Y	None
Y	N	N	Y	Buys back at RTC price.
N	Y	Y	Y	Paid RTC price.

Import Settlements Under Instances Of Non-competitive Proxy Bus

Scheduled Day Ahead?	Scheduled by RTC?	Flow in Real-time?	External Proxy Constrained in RTC?		Real-time Settlement
			Import Constrained	Export Constrained	
Y	Y	Y	N		None
Y	N	N	N		Buys back at RTD or RTD-CAM price.
N	Y	Y	N		Paid RTD or RTD-CAM price. If RTD price is less than the accepted bid a supplemental payment shall be made.
Y	Y	Y	Y		None
Y	N	N	Y	N	Buys back at the higher of 1) the RTC price or 2) the lower of the RTD/RTD-CAM price or $0.
N	Y	Y	Y	N	Paid the higher of 1) the RTC price or 2) the lower of the RTD/RTD-CAM price or $0.
Y	N	N	N	Y	Buys back at the lower of 1) the RTC price or 2) the higher of the RTD/RTD-CAM price or the SCUC price.
N	Y	Y	N	Y	Paid the lower of 1) the RTC price or 2) the higher of the RTD/RTD-CAM price or the SCUC price.

Export Settlements

Scheduled Day Ahead?	Scheduled by RTC?	Flow in Real-time?	External Proxy Constrained in RTC?	Real-time Settlement
Y	Y	Y	N	None
Y	N	N	N	Paid RTD or RTD-CAM price.
N	Y	Y	N	Pays RTD or RTD-CAM price.
Y	Y	Y	Y	None
Y	N	N	Y	Paid RTC price.
N	Y	Y	Y	Pays RTC price.

Export Settlements Under Instances Of Non-competitive Proxy Bus

Scheduled Day Ahead?	Scheduled by RTC?	Flow in Real-time?	External Proxy Constrained in RTC?		Real-time Settlement
			Import Constrained	Export Constrained	
Y	Y	Y	N		None
Y	N	N	N		Sells back at RTD or RTD-CAM price.
N	Y	Y	N		Pays RTD or RTD-CAM price.
Y	Y	Y	Y		None
Y	N	N	Y	N	Sells back at the higher of 1) the RTC price or 2) the lower of the RTD/RTD-CAM price or $0.
N	Y	Y	Y	N	Pays the higher of 1) the RTC price or 2) the lower of the RTD/RTD-CAM price or $0.
Y	N	N	N	Y	Sells back at the lower of 1) the RTC price or 2) the higher of the RTD/RTD-CAM price or the SCUC price.
N	Y	Y	N	Y	Pays the lower of 1) the RTC price or 2) the higher of the RTD/RTD-CAM price or the SCUC price.

Wheel-through Settlements

Scheduled Day Ahead?	Scheduled by RTC?	Flow in Real-time?	Both, Import or Export Proxy Constrained in RTC?	Real-time Settlement
Y	Y	Y	None	None.
Y	N	N	None	Paid RTD or RTD-CAM TUC.
N	Y	Y	None	Pays RTD or RTD-CAM TUC.
Y	Y	Y	Both	None.
Y	N	N	Both	Paid RTC TUC.
N	Y	Y	Both	Pays RTC TUC.
Y	Y	Y	Import	None.
Y	N	N	Import	Paid prevailing real-time TUC.
N	Y	Y	Import	Pays prevailing real-time TUC.
Y	Y	Y	Export	None.
Y	N	N	Export	Paid prevailing real-time TUC.
N	Y	Y	Export	Pays prevailing real-time TUC.

In-hour Curtailment

In-hour Transaction Cuts Made by the NYISO

Note: "Prevailing real-time price" is the price used in real-time based on the rules established in the tables above.

Transaction Type	Scheduled Day Ahead?	Scheduled by RTC?	Flow in Real-time?	Real-time Settlement
Import	Y	Y	N	Buys back at prevailing real-time price. An additional payment may be made if required to protect against high real-time prices.
Export	Y	Y	N	Sells back at prevailing real-time price.
Wheel	Y	Y	N	Paid prevailing real-time TUC.

In-hour Transaction Cuts Made by External Control Areas

Transaction Type	Scheduled Day Ahead?	Scheduled by RTC?	Flow in Real-time?	Real-time Settlement
Import	Y	Y	N	Buys back at prevailing real-time price.
Export	Y	Y	N	Sells back at prevailing real-time price.
Wheel	Y	Y	N	Paid prevailing real-time TUC

Penalties for Transactions Failing Checkout after RTC Evaluation

Note: Transactions not flowing in real time shall settle according to the rules described in the above table. The table below defines an additional charge so that the MP failing the transaction bears the cost of the financial impact caused by the failed transaction.

Transaction Type	Financial Impact Charge per MWh
Import	Max(RTD-RTC,0)
Export	Max(RTC-RTD,0)
Wheel	Charged as both a failed import and failed export.

Financial Impact Charge

- ✓ Intent is to restructure the settlement and charges for failed transactions to provide billing clarity
- ✓ The appropriate allocation of billing dollars will be assured
- ✓ Clarification of the original intent of ECA “A” and “B”

Intent of Original ECAs

- ✓ ECA "A"
  - *Imports curtailed as the result of MP action are charged the higher of the real-time LBMP less the BME calculated LBMP multiplied by the curtailed MWh, or $0.*
  - *Exports curtailed as the result of MP action are charged the higher of the BME calculated LBMP less the real-time LBMP multiplied by the curtailed MWh, or $0.*
  - *Failed wheels are treated as a failed import and a failed export*
- ✓ ECA "B"
  - *If the external proxy is constrained, the BME calculated LBMP is used*
  - *Therefore, the BME-calculated and real-time LBMPs may be the same.*

Failed Transactions

- ✓ A Market Participant shall be deemed to cause a transaction to fail if it is curtailed for reasons within the control of the MP, for example:
  - *Inconsistent scheduling between Control Areas*
  - *Incorrect OASIS registration*
  - *Request made to external Control Area to curtail a transaction after submitting the bid in the NYISO hour-ahead market*
- ✓ “Failure” does not distinguish between intentional or unintentional: unintentional scheduling mistakes can cause as much impact on the Market as intentional gaming.

Real-Time LBMPs at External Proxies

Depending on whether an External Proxy is constrained or unconstrained, competitive or non-competitive, the LBMP at the Proxy may be any one of the following:

- *As calculated by SCD*
- *As calculated by BME*
- *As calculated by SCUC*
- *As calculated by EDRP/SCR pricing rules*
- *$0*

Issues with Current Settlement

- ✓ BME and Real-Time prices may be the same.
- ✓ Any “penalty” for a transaction failure is included as part of the energy settlement and not easily identifiable.
- ✓ Settlement imbalances will occur
  - *Over collections from failed imports*
  - *Under payments to failed exports*
  - *These imbalances are not clearly discernable in Schedule 1*

SMD 2.0 Implementation

- ✓ Transactions that fail checkout after RTC_{15} will settle their energy contracts at prevailing real-time prices.
- ✓ In addition, the MP causing the failure will incur a Financial Impact Charge (FIC)
- ✓ For a failed import, the charge shall be:

$(Sched_{RTC} – Act_{RT})$ X $Max[(Price_{RTD} – Price_{RTC}),0]$

- ✓ For a failed export, the charge shall be:

$(Sched_{RTC} – Act_{RT})$ X $Max[(Price_{RTC} – Price_{RTD}),0]$

- ✓ Failed wheels are treated as a failed import and a failed export

Advantages

- ✓ MPs causing a transaction failure will pay a charge in relation to the impact they cause the NY Market, which is consistent with the intent of today's tariff
  - *A failed import causes RTD to commit additional resources, which may drive RTD prices above RTC prices.*
  - *A failed export causes RTC to commit unneeded resources, which may drive down RTD prices and increase uplift.*
- ✓ In Billing, energy settlements and FICs will be calculated and reported separately.
  - *Transactions will see the FIC as a charge separate from the energy settlement*
  - *Revenue from the charges will be reported as a credit to Schedule 1*

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Regulation Service Settlement Under SMD2

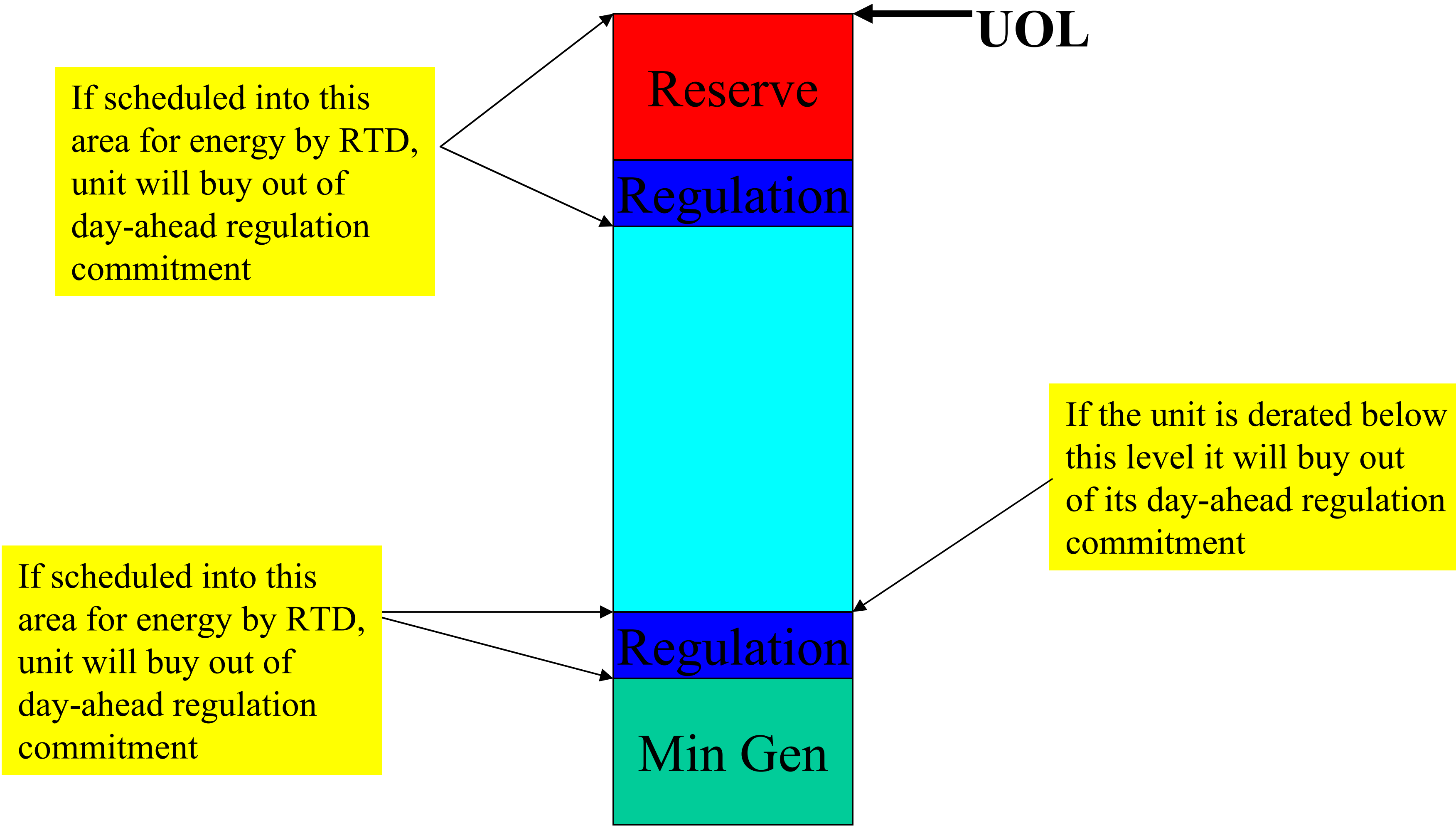
Regulation Settlements

- ✓ Refer to Rate Schedule 3 of the draft Services Tariff
- ✓ New billing parameters
  - *Real-time marginal clearing prices for Regulation Service*
  - *Real-time balancing MWh for Regulation Service*
  - *Regulation Revenue Adjustment (RRA) charges or payments for regulating units*
- ✓ Obsolete billing parameters (null fields)
  - *Supplemental regulation MWh*
  - *Supplemental marginal clearing price*
  - *Regulation replacement cost*

General Settlement Rules

- ✓ There will be a full two settlement. Regulation service will be scheduled and settled nominally on a 5-min. basis.
- ✓ A unit that is scheduled by RTD into an area bounded by the UOL and the UOL less the combined day-ahead reserve and regulation awards will buy out of its day-ahead regulation commitment.
- ✓ A unit that is scheduled by RTD into the area bounded by the minimum generation and the minimum generation plus the day-ahead regulation award will buy out of its day-ahead regulation commitment
- ✓ A unit can be de-scheduled for regulation and not be capacity constrained
- ✓ A unit changing status from on- to off- control will buy out of its day-ahead regulation commitment
- ✓ A de-rated unit may be required to buy out of its day-ahead regulation commitment

General Settlement Rules



Regulation Schedules

- ✓ BAS will use real-time regulation schedules from RTD
- ✓ RTD considers unit constraints when determining schedules
  - *Ramp rate*
  - *De-rates*
  - *On/off-control status*
- ✓ Settlement for regulation is based on schedule. Therefore, if a unit does not perform as required it still buys out of its day-ahead commitment

Balancing Regulation in Real-Time

- ✓ Settlement made for each RTD period.
- ✓ Scheduled by RTD
- ✓ If the regulation schedule from RTD is less than the DAM schedule the unit will buy out of its day-ahead commitment.
- ✓ For each RTD interval the unit shall pay the balancing regulation MWs multiplied by the real-time regulation clearing price.

Example: The DAM

Consider a unit with a UOL of 100 MW and a min gen of 20 MW and a response rate of 5 MW/min. A bid for HB xx is submitted in the DAM as follows:

•Energy: 100 MW @ $50/MW

•Regulation: 25 MW @ $5/MW

The DAM clears as follows:

•LBMP for energy: $55

•Clearing price for regulation: LOC + Availability = ($55-$50) + $5 = $10

The unit is accepted for 75 MW of energy and 25 MW of regulation for HB xx.

Example: Real Time, Scenario 1

The next day, the unit is scheduled for 100 MWs of energy and 0 MWs of regulation for the entire HB xx. The LBMP is $100 and the clearing price for regulation is $10. The unit performs as expected.

Settlement is as follows:

DAM:

•Energy: 75 MWs x $55 = $4,125

•Regulation: 25 MWs x $10 = $250

Real-time:

•Energy: 25 MWs x $100 = $2,500

•Regulation: -25 MWs x $10 = ($250)

Total settlement: $6,625

Example – Real Time, Scenario 2

In this scenario, the unit fails to move from 75 MW. Settlement will be as follows:

DAM:

- Energy: 75 MWs x $55 = $4,125
- Regulation: 25 MWs x $10 = $250

Real-time:

- Energy: 25 MWs x $100 = $0
- Regulation: -25 MWs x $10 = ($250)

Total settlement: $4,125

RTD will Adjust Regulation Schedules based on Unit Status

- ✓ If the unit goes off-control, RTD will pass a zero regulation schedule
- ✓ If a unit is derated, RTD will adjust the regulation schedule as required
- ✓ If unit response rate changes, RTD will adjust regulation schedules accordingly

Remove Explicit Reduction of DAM Availability Payment

- ✓ Currently, a unit's DAM availability payment can be reduced based on the amount of time a unit is on-control
- ✓ Since RTD will pass a zero regulation schedule when a unit is off-control, it will buy out of its day-ahead commitment
- ✓ Therefore, the explicit reduction of the availability payment can be removed

Energy Settlement on AGC Units

- Energy settlement is at lesser of AGC basepoint or actual output
- In addition, a Regulation Revenue Adjustment will be made:
  - *A payment will be made to the Generator if:*
    - AGC basepoint > RTD basepoint and the Energy bid > real-time LBMP
    - AGC basepoint < RTD basepoint and the Energy bid < real-time LBMP
  - *The Generator will pay a charge if:*
    - AGC basepoint > RTD basepoint and the Energy bid < real-time LBMP
    - AGC basepoint < RTD basepoint and the Energy bid > real-time LBMP
- RRA will be included in real-time BPCG revenue stream
- RRA will be charged to the load under the OATT RS# 3

Eligibility

- ✓ The unit must have bid in as Flexible (either ISO or Self Committed)
- ✓ The unit must have a real-time Energy schedule from RTD
- ✓ The unit must have Regulation schedule from RTD

Real-Time Energy Settlement for AGC Units

- ✓ A Generator providing Regulation Service will settle in real-time the lower of its AGC basepoint or actual output
- ✓ The real-time settlement for each RTD interval will be as follows:

$[Min(Act, BP_{AGC}) – Energy_{DAM} – Trans_{RT}]$ X $LBMP_{RT}$

Where:

Act = Average actual real-time energy output

BP_{AGC} = Average AGC basepoint

$Energy_{DAM}$ = DAM energy schedule

$Trans_{RT}$ = Real-time transactions scheduled at the Generator bus

$LBMP_{RT}$ = Real-time LBMP at the Generator bus

RRA when AGC Basepoint > RTD Basepoint

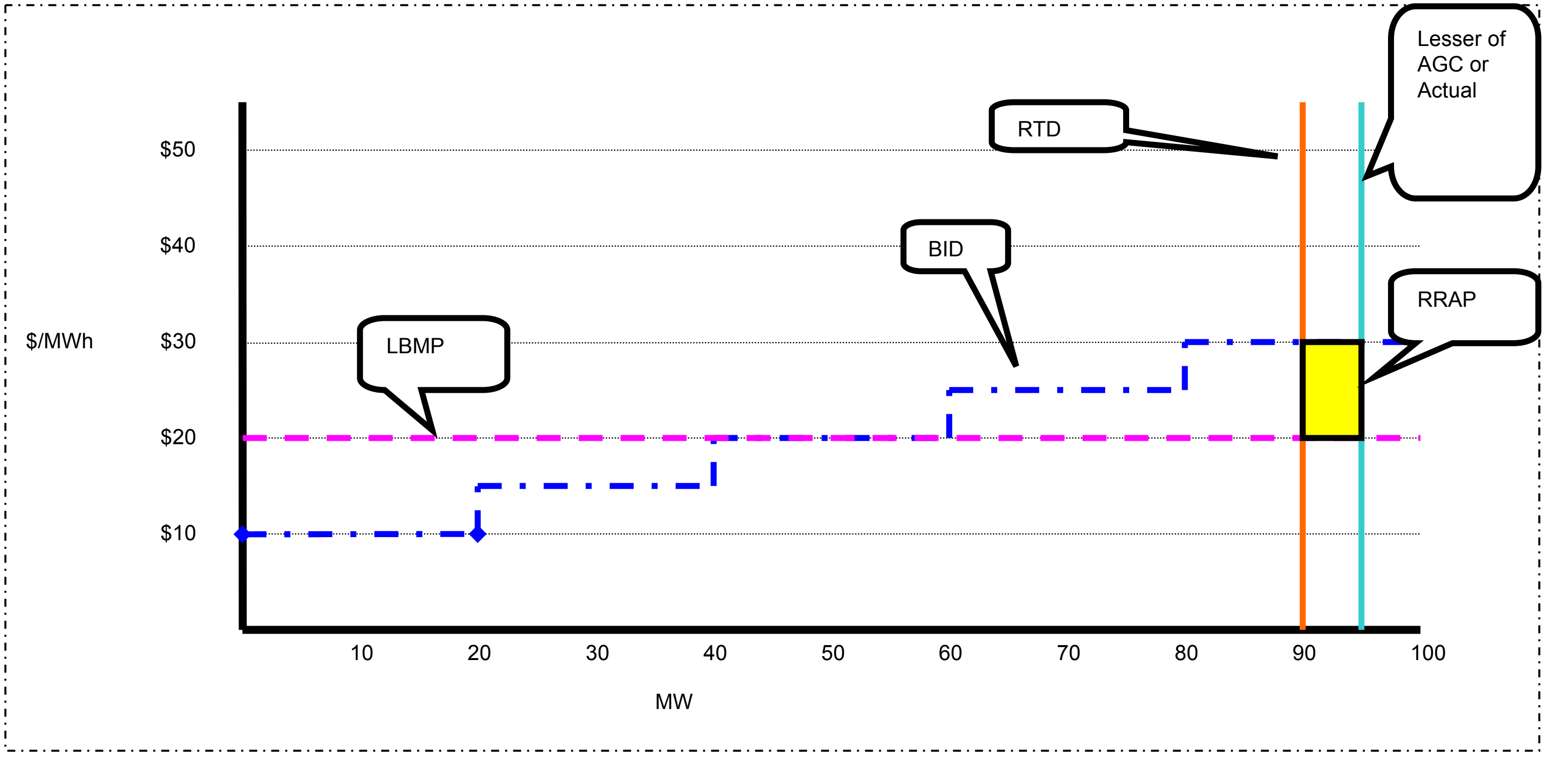
- ✓ If the bid cost > LBMP, a payment is made to the Generator
- ✓ If the bid cost < LBMP, the Generator is charged
- ✓ The calculation is as follows:

$$RRA = \int_{BP_{RTD}}^{Max\,[BP_{RTD},\,Min\,(BP_{AGC},\,Act)]} \left[Bid_{RT} - LBMP_{RT} \right] \times {}^{Int}\!/_{3600}$$

Example: AGC > RTD and LBMP < Bid

$$RRA = [Min(Act,\ BP_{AGC}) - BP_{RTD}] \times (Bid - LBMP_{RT}) =$$

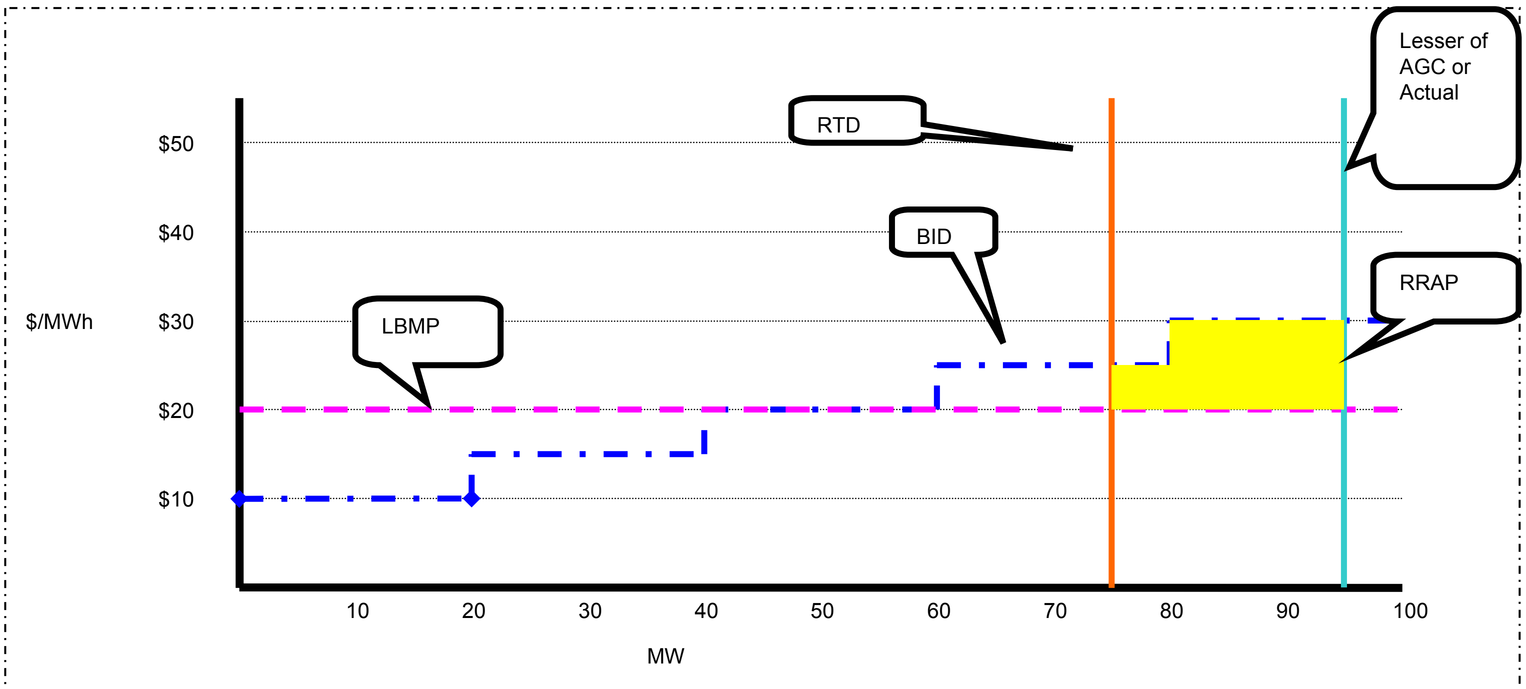
$$(95 - 90) * (\$30 - \$20) = \$50$$



Example: AGC > RTD and LBMP < Bid, Multiple Steps on Curve

$RRA = [(BidBrkPt - BP_{RTD}) \text{ X } (Bid_1 - LBMP_{RT})] + [Min(Act, BP_{AGC}) - BidBrkPt) \text{ X } (Bid_2 - LBMP_{RT})] =$

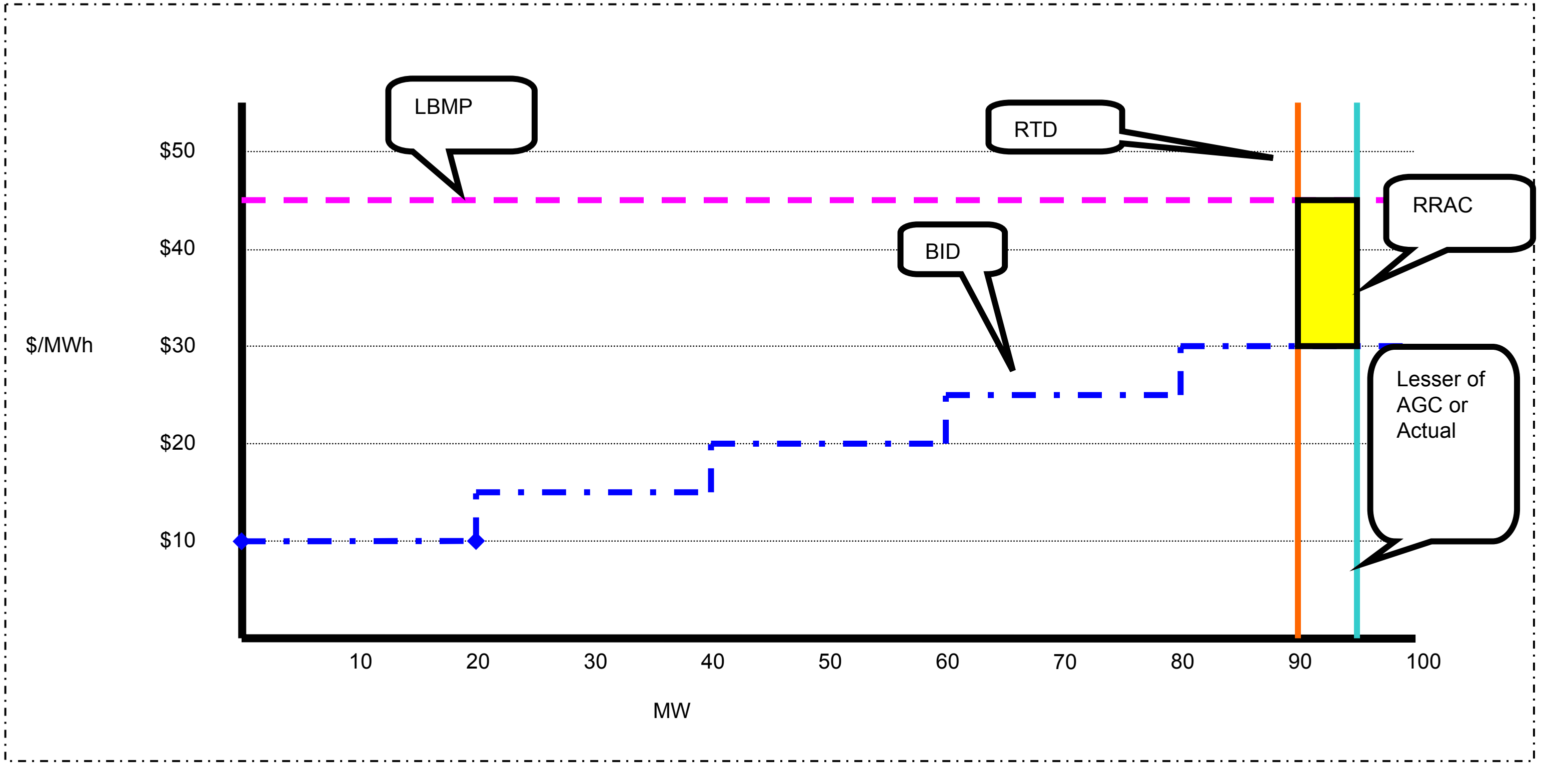
$[(80 - 75) * (\$25 - \$20)] + [(95 - 80) * (\$30 - \$20)] = \$175$



Example: AGC > RTD and LBMP > Bid

$$RRA = [Min(Act, BP_{AGC}) - BP_{RTD}] \text{ X } (Bid - LBMP_{RT}) =$$

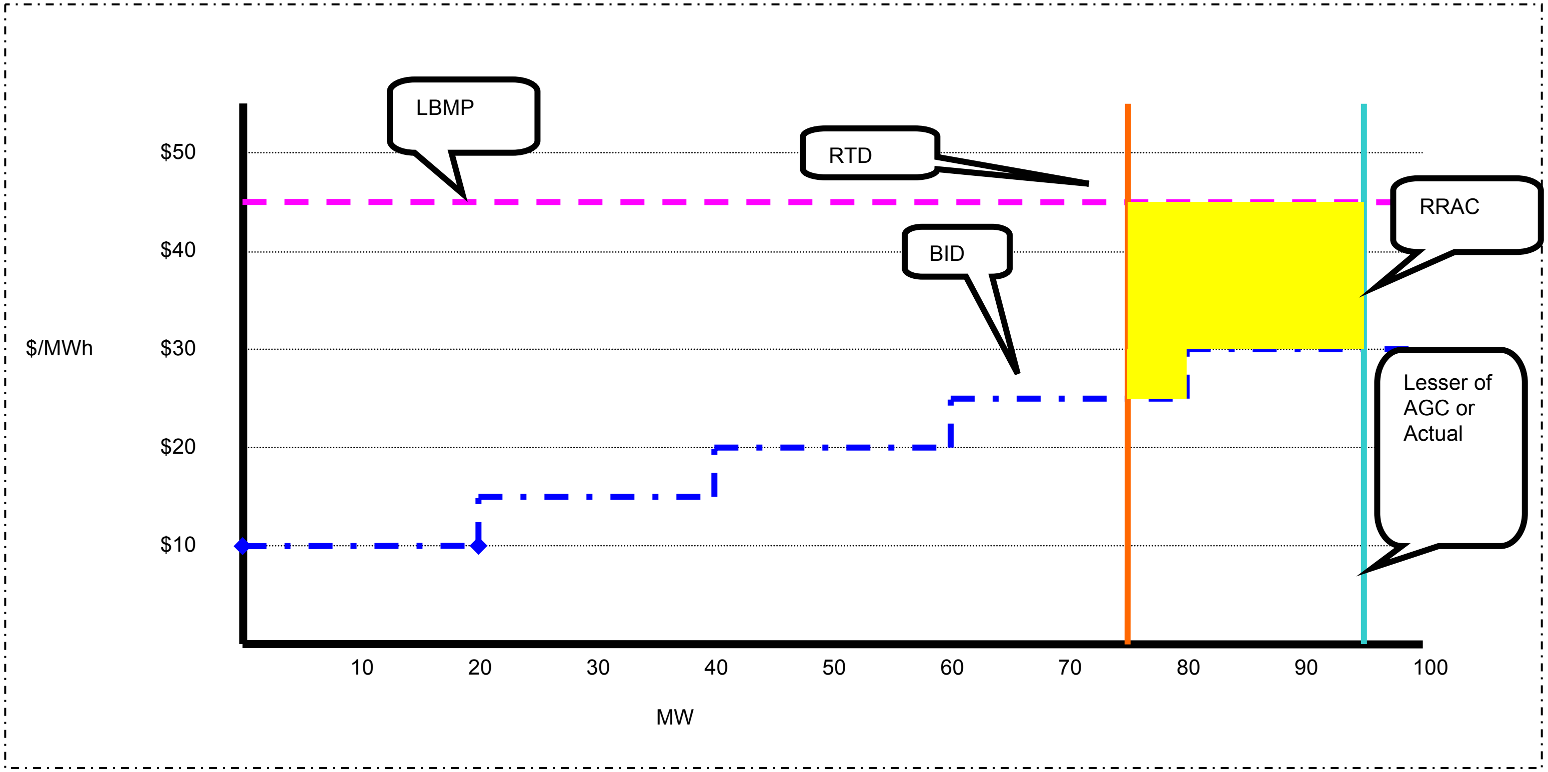
$$(95 - 90) * (\$30 - \$45) = (\$75)$$



Example: AGC > RTD and LBMP > Bid, Multiple Steps on Curve

$RRA = [(Bid\ BrkPt - BP_{RTD}) \times (Bid_1 - LBMP_{RT})] + [(Min(Act, BP_{AGC}) - BidBrkPt) \times (Bid_2 - LBMP_{RT})] =$

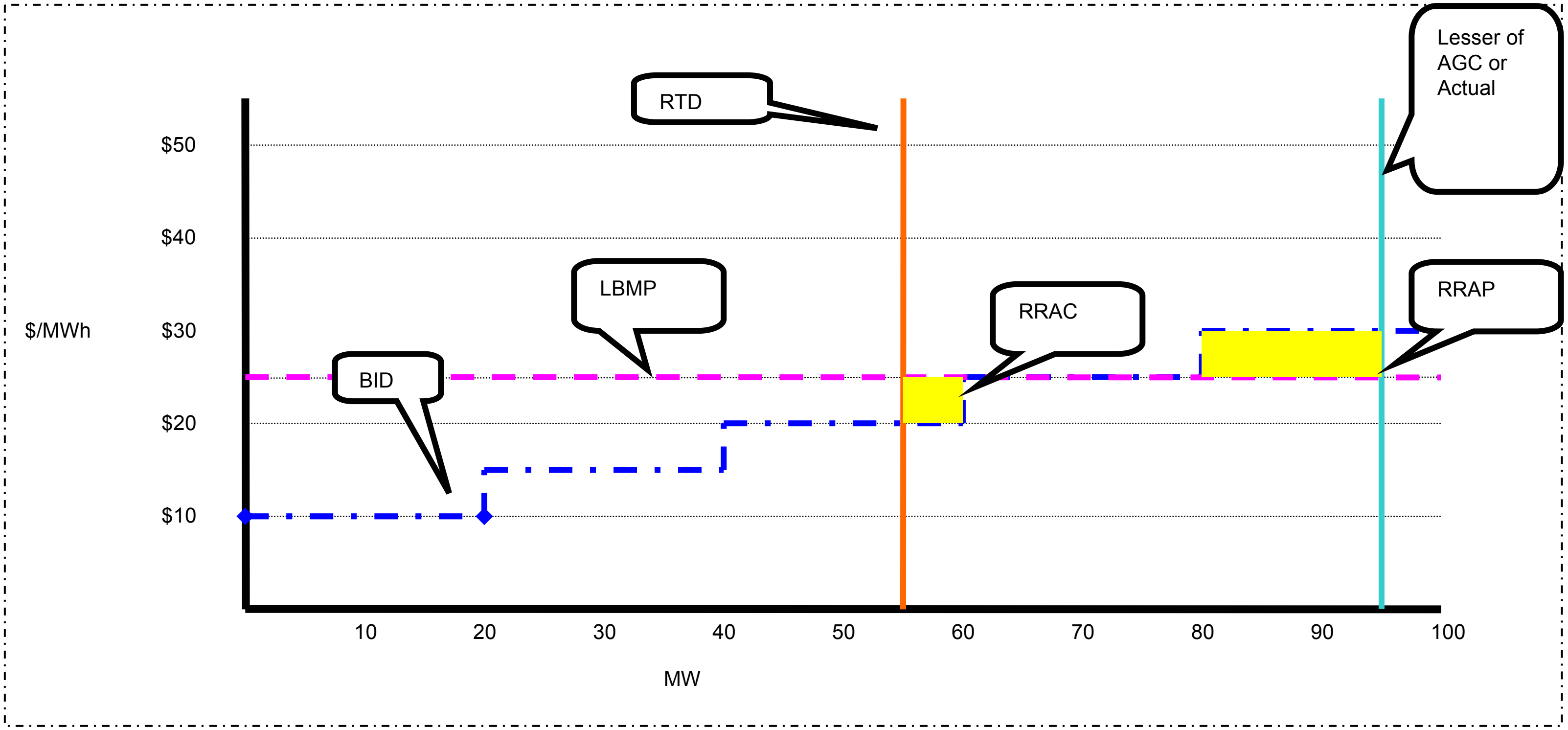
[(80 – 75) * (\$25 - \$45)] + [(95 – 80) * (\$30 - \$45) = (\$375)



Example: AGC > RTD, Multiple Steps on Curve

$RRA = [(BidBrkPt_1 – BP_{RTD}) \text{ X } (Bid_1 – LBMP_{RT})] + [(Min(Act, BP_{AGC}) – BidBrkPt_2) \text{ X } (Bid_2 – LBMP_{RT})] =$

[(60 – 55) * ($20 - $25)] + [(95 – 80) * ($30 - $25)] = $50



RRA when AGC Basepoint < RTD Basepoint

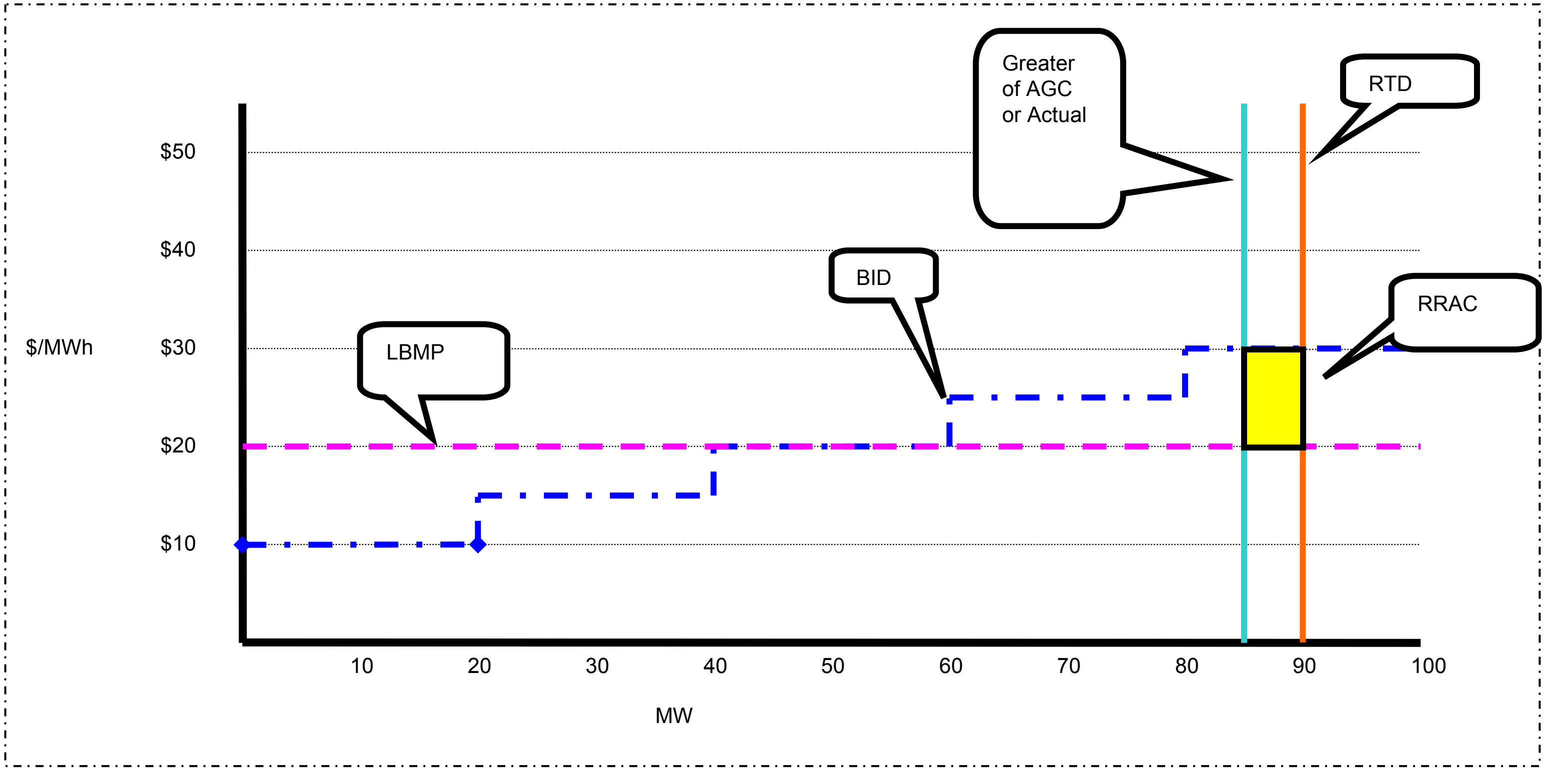
- ✓ If the bid cost < LBMP, a payment is made to the Generator
- ✓ If the bid cost > LBMP, the Generator is charged
- ✓ The calculation is as follows:

$$RRA = \int_{Min[BP_{RTD}, Max(BP_{AGC}, Act)]}^{BP_{RTD}} - [Bid_{RT} - LBMP_{RT}] \times {}^{Int}/_{3600}$$

Example: AGC < RTD and LBMP < Bid

$RRA = -[BP_{RTD} – Max(Act, BP_{AGC})] \text{ X } (Bid – LBMP_{RT}) =$

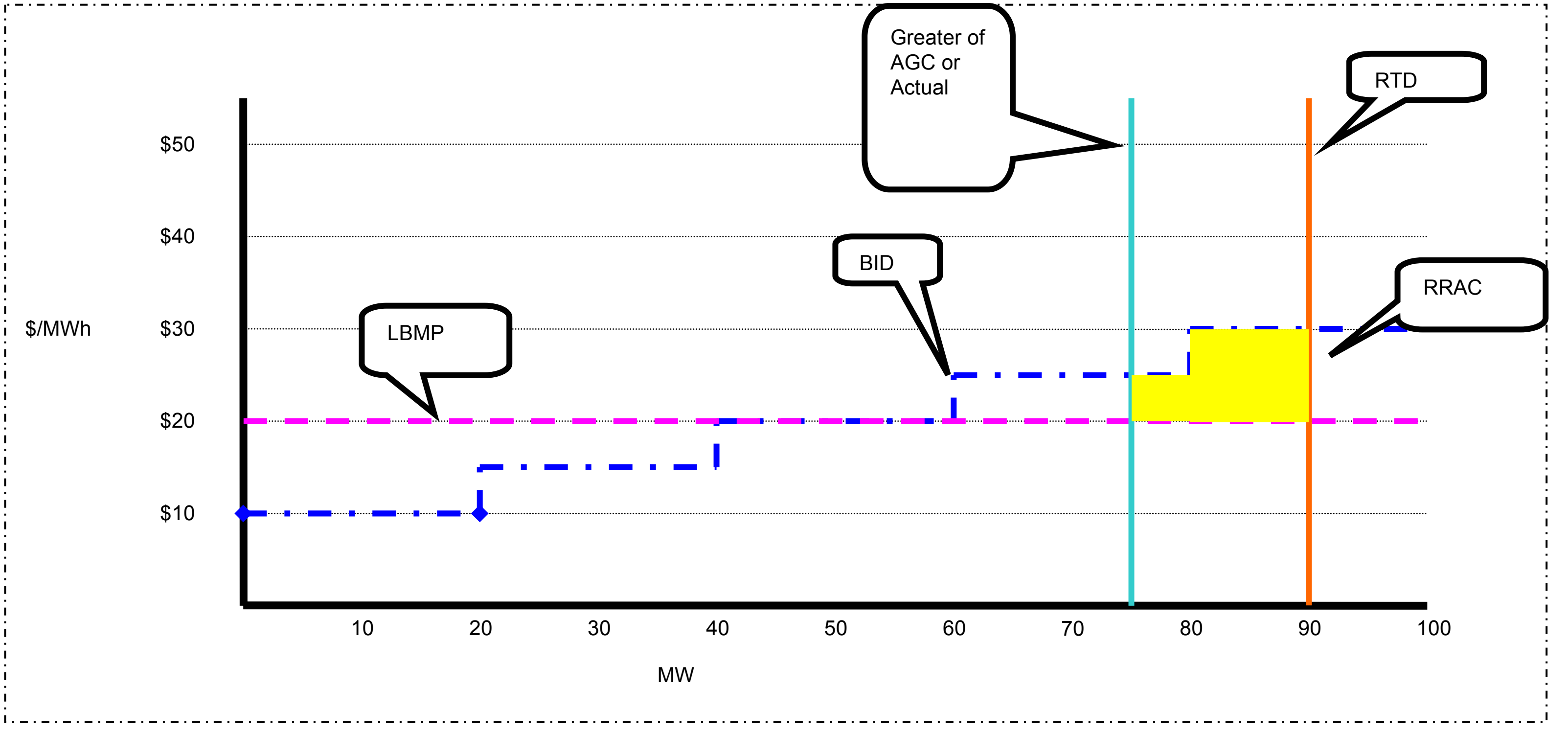
-(90 – 85) * ($30 - $20) = ($50)



Example: AGC < RTD and LBMP < Bid, Multiple Steps on Curve

$RRA = -[((BidBrkPt - Max(Act, BP_{AGC})) \times (Bid_1 - LBMP_{RT})] - [(BP_{RTD} - BidBrkPt) \times (Bid_2 - LBMP_{RT})] =$

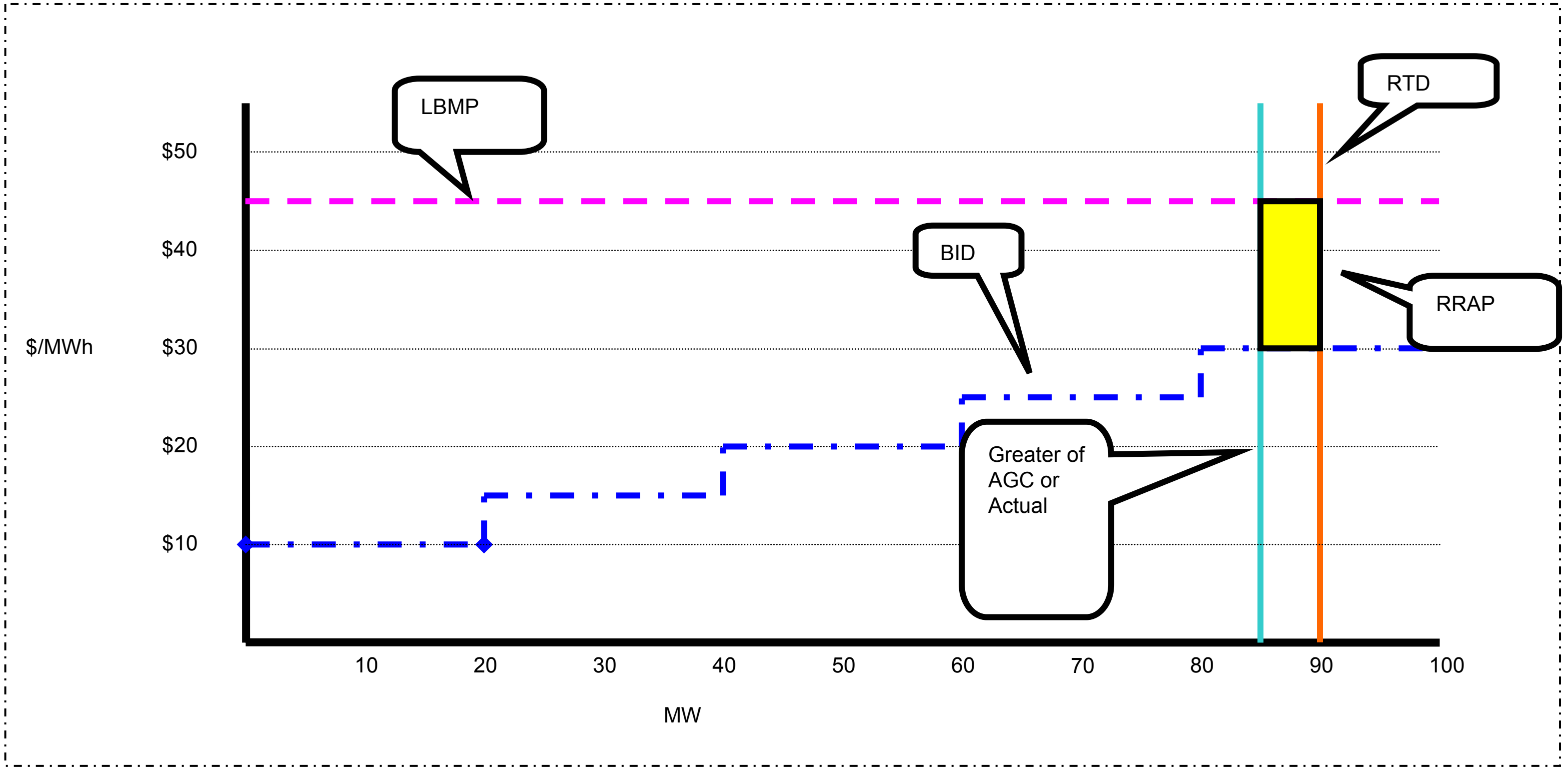
- [(80 – 75) * ($25 - $20)] – [(90 – 80) * ($30 - $20)] = ($125)



Example: AGC < RTD and LBMP > Bid

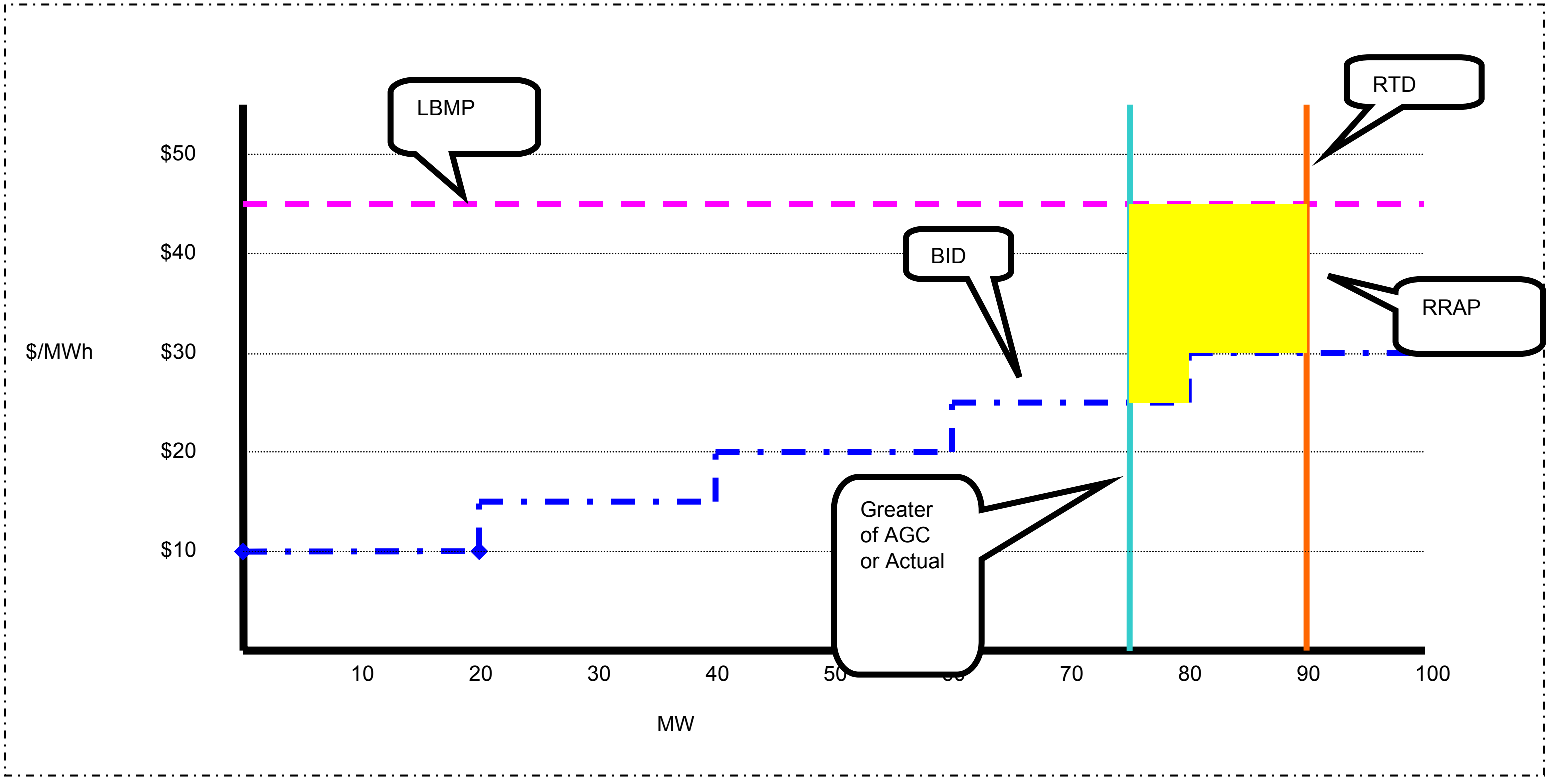
$RRA = -[BP_{RTD} - Max(Act, BP_{AGC})] \times (Bid - LBMP_{RT}) =$

$- (90 - 85) * (\$30 - \$45) = \$75$



Example: AGC < RTD and LBMP > Bid, Multiple Steps on Curve

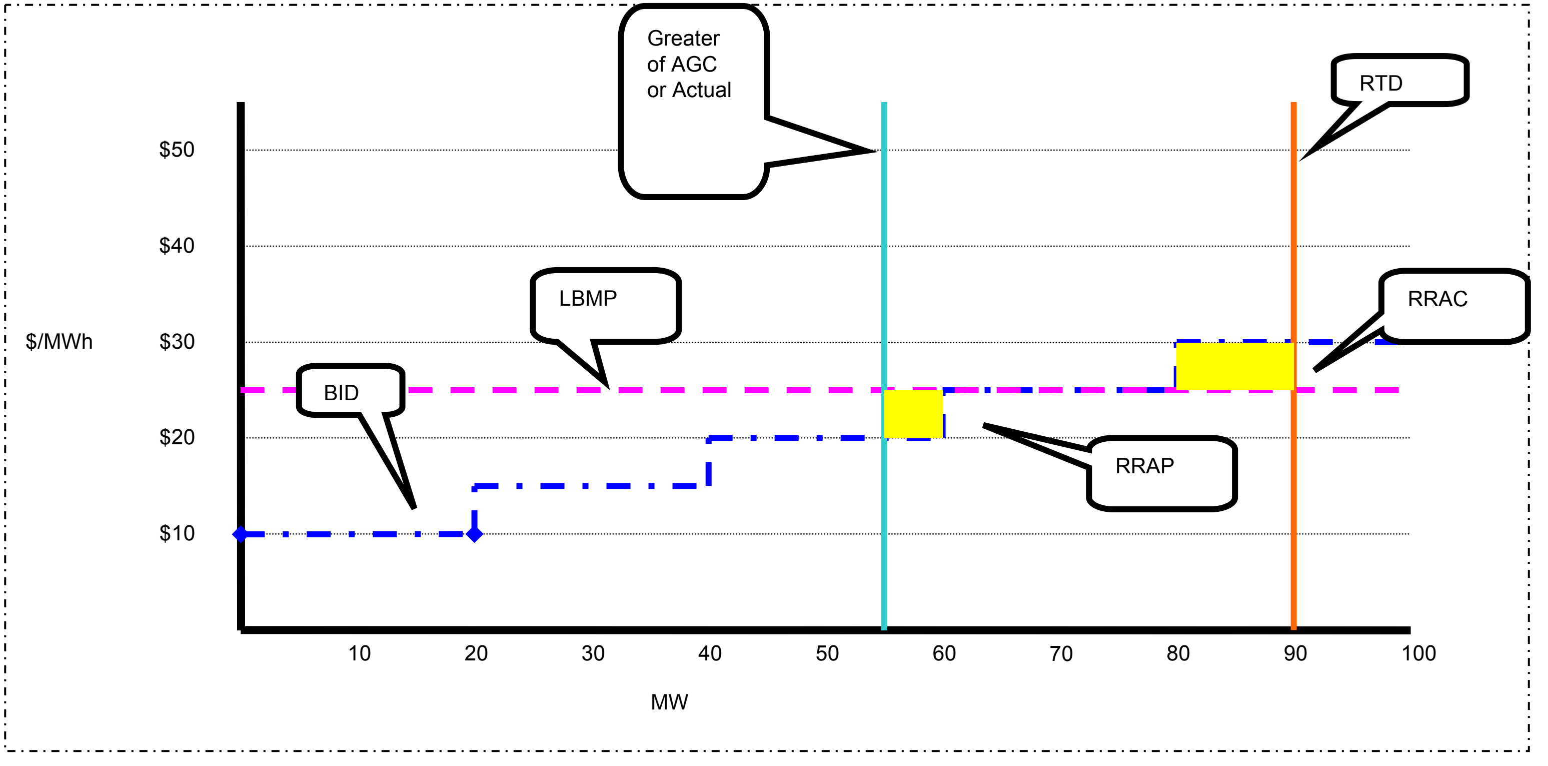
RRA = - [((*BidBrkPt* – *Max*(*Act*, BP_{AGC})) X (*Bid*$_1$ – $LBMP_{RT}$)] – [(BP_{RTD} – *BidBrkPt*0 X (*Bid*$_2$ - $LBMP_{RT}$)] =
-[(80 -75) * ($25 - $45)] – [(90 – 80) * ($30 - $45)] = $250



Example: AGC < RTD, Multiple Steps on Curve

$RRA = -[((BidBrkPt_1 - Max(Act, BP_{AGC})) \times (Bid_1 - LBMP_{RT})] - [(BP_{RTD} - BidBrkPt_2) \times (Bid_2 - LBMP_{RT})] =$

-[(60 -55) * ($20 – 25)] – [(90 – 80) * ($30 - $25)] = ($25)



Inclusion of RRA in Real-Time BPCG

RRA will be included in the revenue stream in the real-time BPCG calculation

$$\sum_{g \in G} Max\left\{ \sum_{i=1}^{N} \left(\begin{array}{l} \left(\begin{array}{l} \int_{EI_{gi}^{DA}}^{EI_{gi}^{RT}} C_{gi}^{RT} + MGC_{gi}^{RT} \times \left(MGI_{gi}^{RT} - MGI_{gi}^{DA} \right) \\ + SUC_{gi}^{RT} \times \left(NSUI_{gi}^{RT} - NSUI_{gi}^{DA} \right) - LBMP_{gi}^{RT} \times \left(EI_{gi}^{RT} - EI_{gi}^{DA} \right) \end{array} \right) \times {}^{s_i}\!/_{3600} \\ \\ - \left(NASR_{gi}^{TOT} - NASR_{gi}^{DA} \right) - RRA_{gi} \end{array} \right), 0 \right\}$$

Recovery of RRA under OATT Rate Schedule 3

The RRAP will be part of the Supplier Payment and the RRAC will be part of the Supplier Charge as defined in Section 2.0 of Rate Schedule 3 of the OATT

$$\text{Rate}_{\text{RFR}} = \frac{\text{(Supplier Payment – Supplier Charge – Generator Charge)}}{\text{Load}_{\text{NYCA}}}$$

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Reserves Service Settlement Under SMD2

Reserve Settlements

✓ General Settlement Rules

- **There will be a full two settlement. Reserve services will be scheduled and settled nominally on a 5-min. basis.**
- **Units are not required to purchase energy at LBMP for failure to perform in a reserve pickup.**
- **Units will be paid LBMP for overgeneration during a reserve pickup.**
- **Units dispatched by RTD-CAM have the ability to set LBMP**
- **Units may need to buy out of their DAM reserve commitment in the event of a de-rate**
- **LOC will be incorporated into clearing prices**

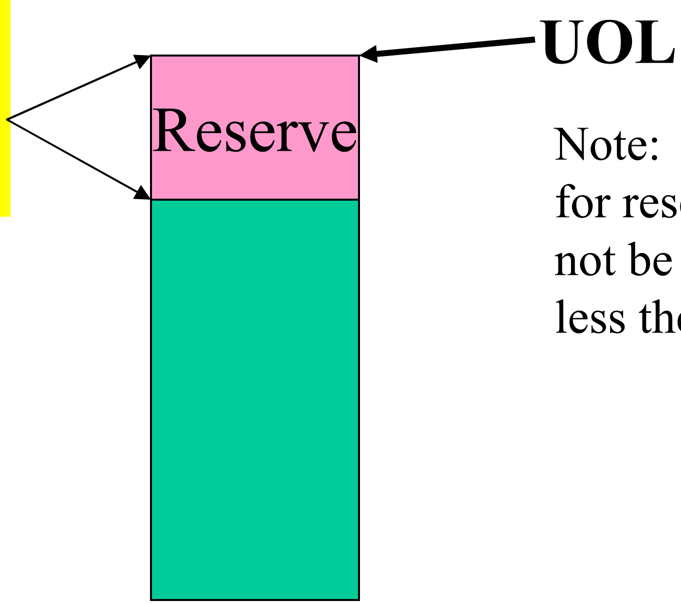
Reserve Settlements

- ✓ Refer to Rate Schedule 4 of the RTS Services Tariff
- ✓ New billing parameters
  - *Real-time marginal clearing prices for 10-minute synchronized, 10-minute non-synchronized and 30-minute*
  - *Real-time balancing MWh for 10-minute synchronized, 10-minute non-synchronized and 30-minute*
  - *Supplemental payments (BPCG) to units during Large Event Reserve Pick-ups*
- ✓ Obsolete billing parameters (null fields)
  - *Supplemental marginal clearing prices*
  - *Supplemental reserve MWh*
  - *LOC payments for reserve*
  - *Reserve reduction MWh*
  - *Reserve penalty and Supply Ratios*

Overall Settlement Rule

If a unit is scheduled by RTD for energy into the area bounded by UOL less the DAM reserve award and the UOL, the unit shall buy out of its day-ahead reserve commitment.

If scheduled by RTD into this Area for Energy, the unit shall buy out of its day-ahead Reserve commitment.



Note: A unit can be de-scheduled for reserve due to economics and not be dispatched higher than UOL less the DAM reserve award.

Reserve Schedules

- BAS will use real-time reserve schedules from RTD or RTD-CAM
  - *Advisory 30-minute reserve schedules are computed by RTC_{30} to insure sufficient capacity*
  - *Advisory reserve schedules for 10-minute start units are computed by RTC_{45} to insure sufficient capacity*
  - *All actual reserve schedules, including 10-minute synchronized reserve, are computed by RTD*
  - *RTS considers unit constraints when determining schedules; i.e. ramp rates, de-rates, etc.*
- **Important point:** Settlement for reserve is based on schedule.

30-Minute Start Units

- ✓ Scheduled and committed by RTC_{xx} for xx+30
  - *RTC_{00} will schedule for :30*
  - *RTC_{15} will schedule for :45, etc.*
- ✓ Scheduling by SCUC does not guarantee the unit will run in real-time
- ✓ Units will buy out of their DAM commitment based on their schedule when called upon to start; the clearing price will be the real-time 30-minute reserve price
- ✓ Units will receive real-time LBMP at their bus for energy produced

10-Minute Start Units

- Scheduled and committed by RTC_{xx} for xx+15 or RTD-CAM, e.g.:
  - *RTC_{45} will commit for RTC_{00}*
  - *RTD-CAM will commit for a corrective action*
- Units will buy out of their DAM commitment based on their schedule when called upon to start; the clearing price will be the real-time 10-minute non-synchronized reserve price
- Units will receive real-time LBMP at their bus for energy produced

Synchronized Units

- ✓ Scheduled by RTD or RTD-CAM
- ✓ Units may buy out of their DAM commitment based on their 10-minute synchronized reserve schedule from RTD
  - *Schedule based on economics*
  - *Schedule from RTD-CAM for a reserve pickup (also based on economics)*
- ✓ Units will receive real-time LBMP at their bus for energy produced

Reserve Settlement Rules

- ✓ Settlement made for each RTD period.
- ✓ If the reserve schedule from RTD is less than the DAM schedule the unit will buy out of its day-ahead commitment.
- ✓ For each RTD interval the unit shall pay the balancing reserve MWs multiplied by the real-time applicable reserve clearing price.

Example – The DAM

Consider a 40 MW unit capable of starting and coming up to full load within 10 minutes. A bid for HB xx is submitted in the DAM as follows:

•Energy: 40 MW @ $200/MWh

•Reserve: 40 MW @ $3/MW

The DAM clears as follows:

•LBMP for energy: $50

•Clearing price for 10-minute non-synchronized reserve: $4

Therefore, the unit is accepted for 0 MW of energy and 40 MW of 10-minute non-synchronized reserve for HB xx.

Example – Real Time, Scenario 1

The next day, RTC_{45} calculates an LBMP of $300 for HB xx. RTC_{45} therefore schedules the unit to produce 40 MW of energy and provide 0 MW of reserve for HB xx. The unit performs as expected. RTS calculates a $10 clearing price for 10-minute non-synchronized reserve.

Settlement is as follows:

DAM:

•Energy: 0 MW x $50 = $0

•Reserve: 40 MW x $4 = $160

Real-time:

•Energy: 40 MW x $300 = $12,000

•Reserve: -40 MW x $10 = ($400)

Total settlement: $11,760

Example – Real Time, Scenario 2

In this scenario, the unit fails to start. Settlement will be as follows:

DAM:

•Energy: 0 MW x $50 = $0

•Reserve: 40 MW x $4 = $160

Real-time:

•Energy: 0 MW x $300 = $0

•Reserve: -40 MW x $10 = ($400)

Total settlement: ($240)

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Day-Ahead Margin Preservation Settlement Under SMD2

Introduction

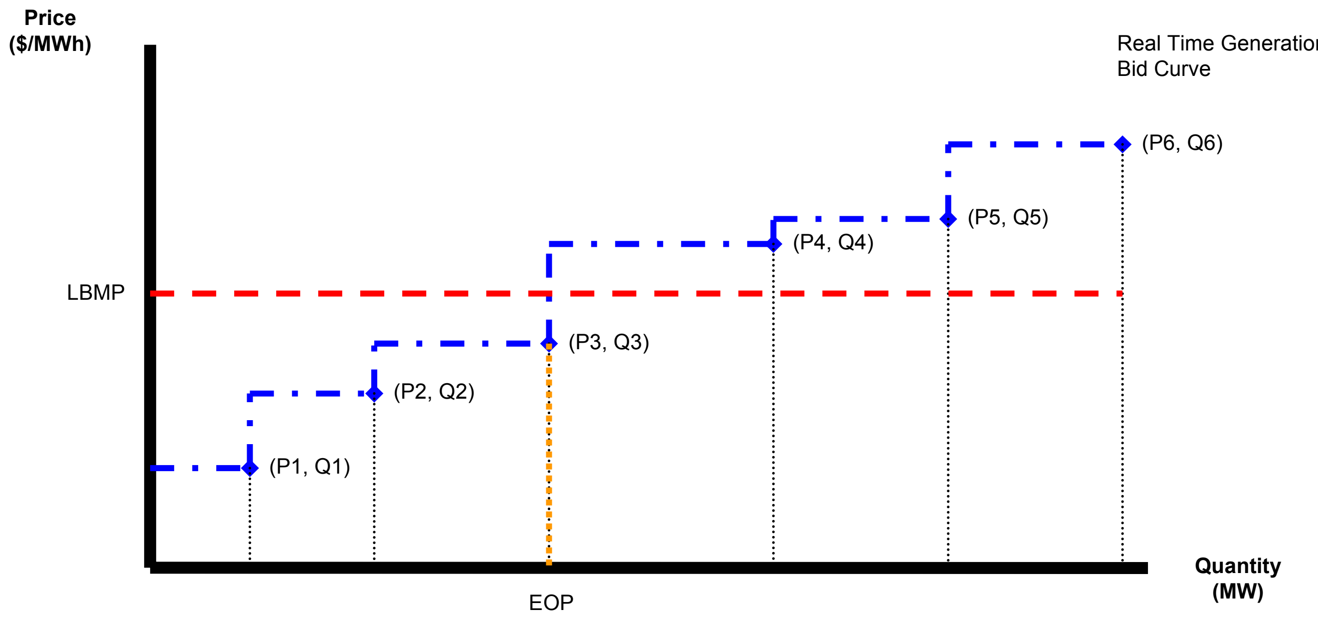
- ✓ Current DAMAP calculation will be modified to include Reserve and Regulation, as well as Energy
- ✓ Calculation includes the concept of an Economic Operating Point (EOP)
- ✓ Unit de-rates will need to account for modifications to the DAM Energy, Reserve and Regulation schedules

Eligibility for DAMAP

- ✓ Units bid as the following shall be eligible for DAMAP:
  - *ISO Committed Flexible*
  - *Self Committed Flexible*
  - *All current DAMAP eligibility rules that apply to today's On-Dispatch units shall apply*
- ✓ Self and ISO Committed Fixed units are not eligible for DAMAP unless scheduled by the ISO or TO out of economic order in response to a system security need.

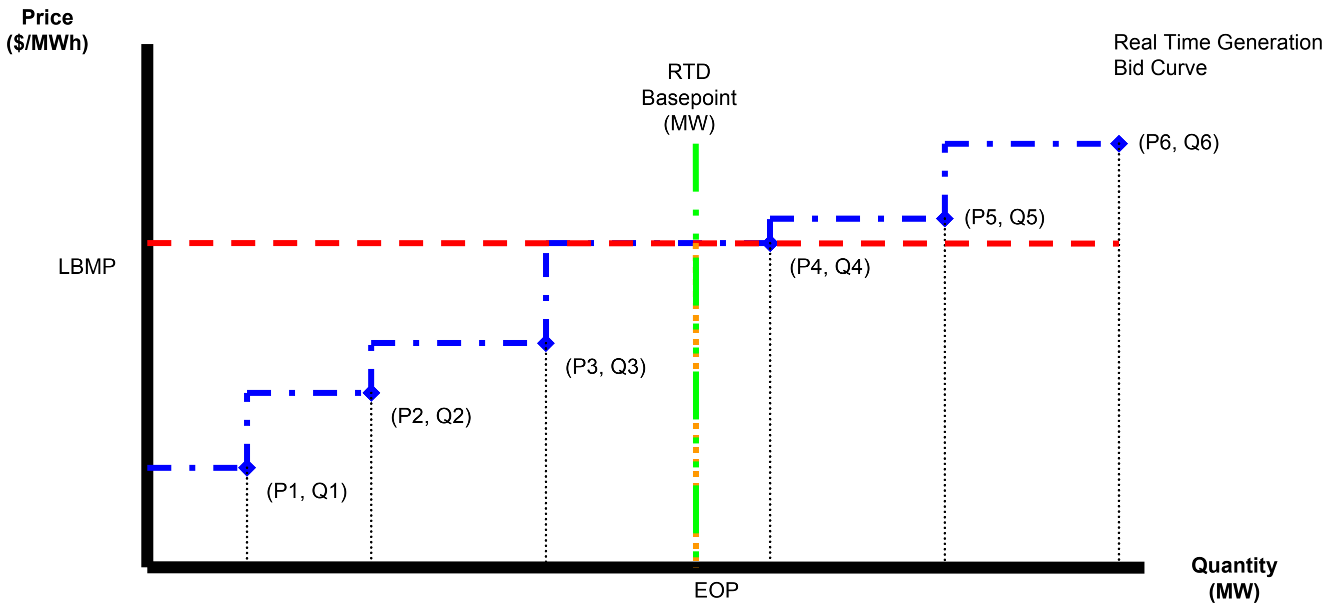
Economic Operating Point (EOP)

Definition: The point on the real-time bid curve intersected by the LBMP.



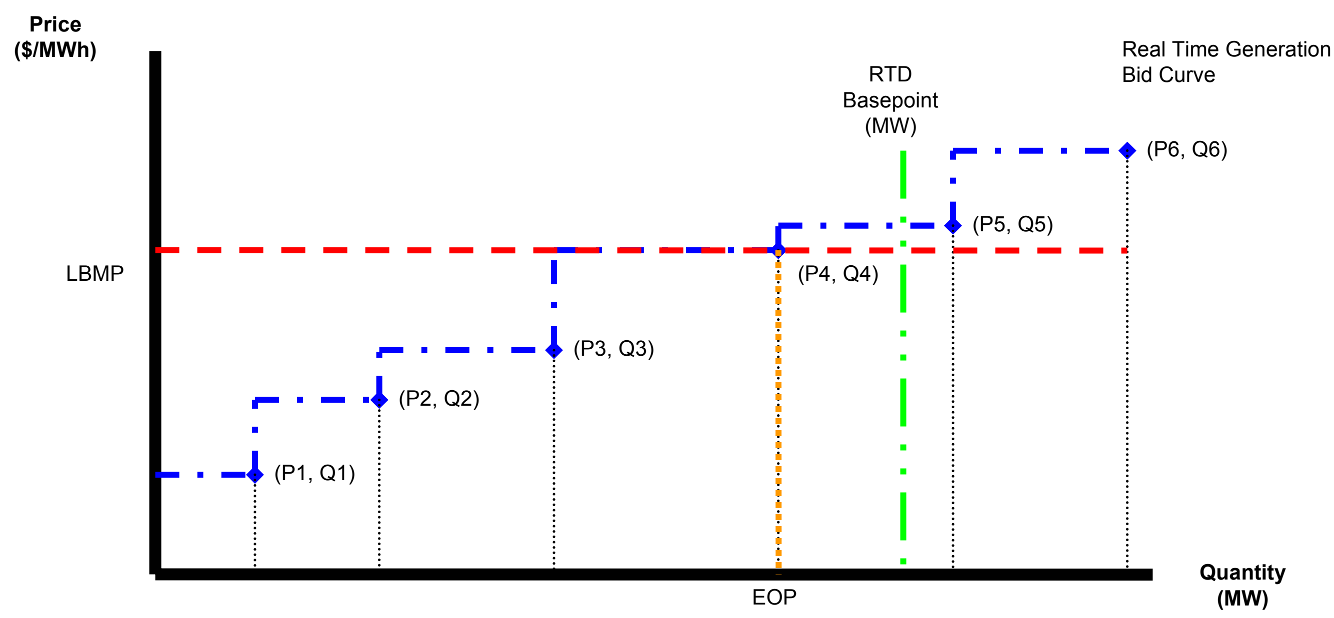
Economic Operating Point (EOP)

If the LBMP intersects the bid curve at a horizontal point of a step on the curve and the RTD BP intersects the curve at LBMP, EOP = RTD BP:



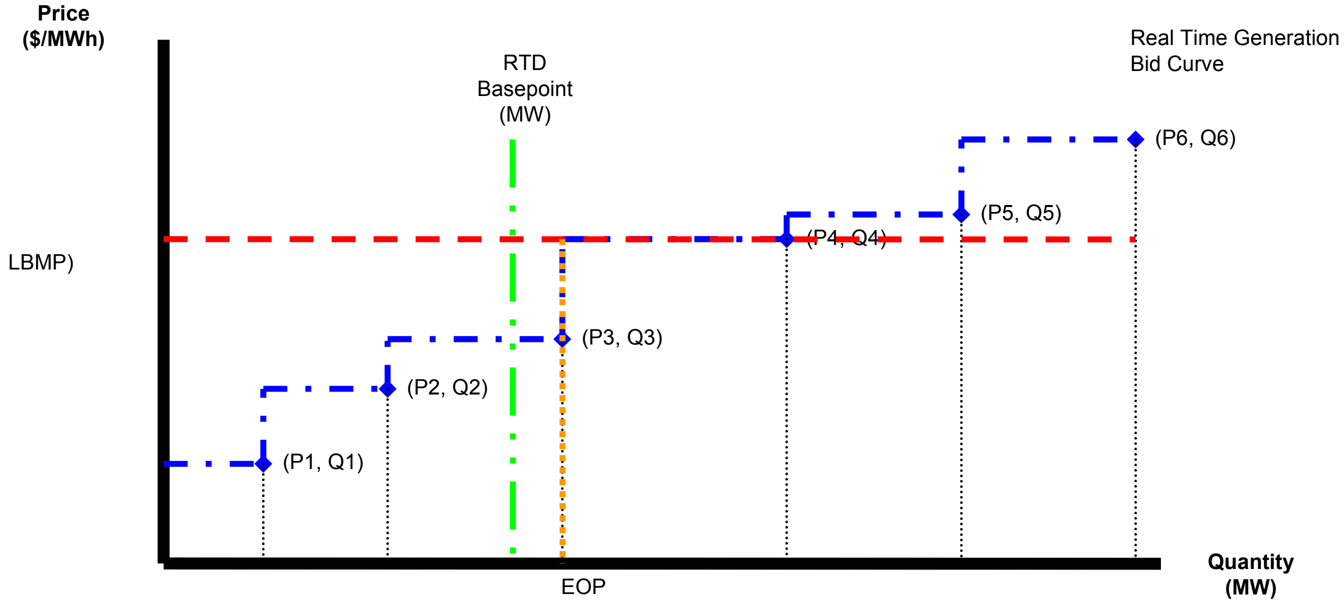
Economic Operating Point (EOP)

If the RTD basepoint intersects the curve at a point higher than the intersection of the LBMP:



Economic Operating Point (EOP)

If the RTD basepoint intersects the bid curve at a point below the intersection of the LBMP:

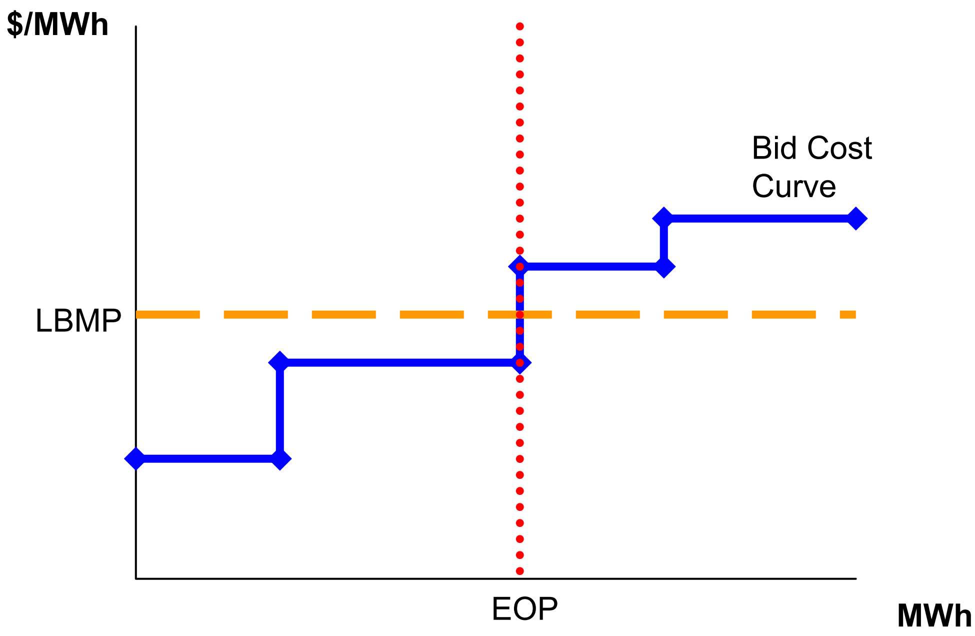


Calculation Procedure

- ✓ Step 1: Determine the EOP
- ✓ Step 2: Calculate the DAM schedule reductions in the event of a de-rate
- ✓ Step 3: Calculate adjusted DAM schedules
- ✓ Step 4: Determine the lower and upper limits used in the Energy contribution calculation
- ✓ Step 5: Calculate the Energy contribution to DAMAP
- ✓ Step 6: Calculate the Reserve products contribution to DAMAP
- ✓ Step 7: Calculate the Regulation contribution to DAMAP
- ✓ Step 8: Calculate the contribution to DAMAP from interval *i* to hour *h*
- ✓ Step 9: Calculate the DAMAP for hour *h*

Step 1: Determine the EOP

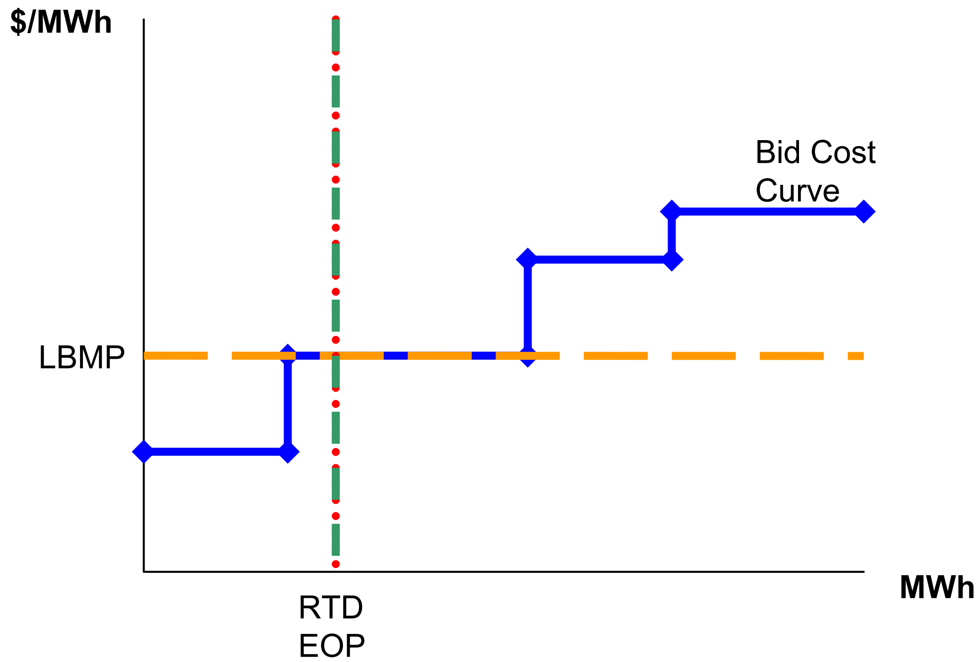
Definition: The EOP is defined as the point where the LBMP intersects the Supplier's bid cost curve.



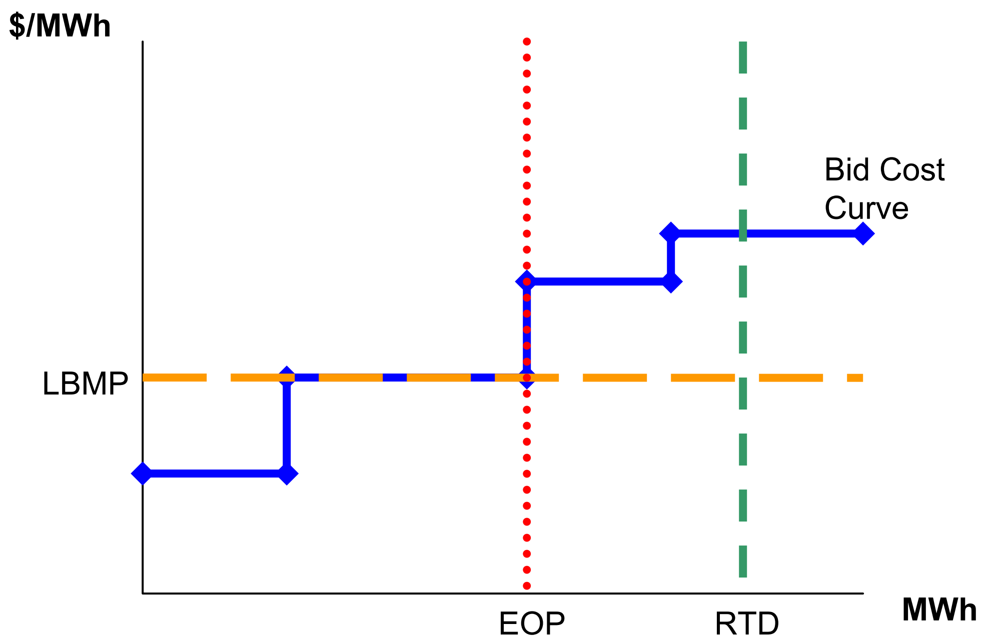
What if….

- ✓ The LBMP intersects at a horizontal portion of the curve?
- ✓ The rule is as follows:
  - *If the RTD basepoint is at a point on the curve that is equal to the LBMP intersect, the EOP shall be the same as the RTD basepoint.*
  - *If the RTD basepoint is at a point on the curve that is higher than the LBMP intersect, the EOP shall be at the maximum of the horizontal step.*
  - *If the RTD basepoint is at a point on the curve that is lower than the LBMP intersect, the EOP shall be at the minimum of the horizontal step.*

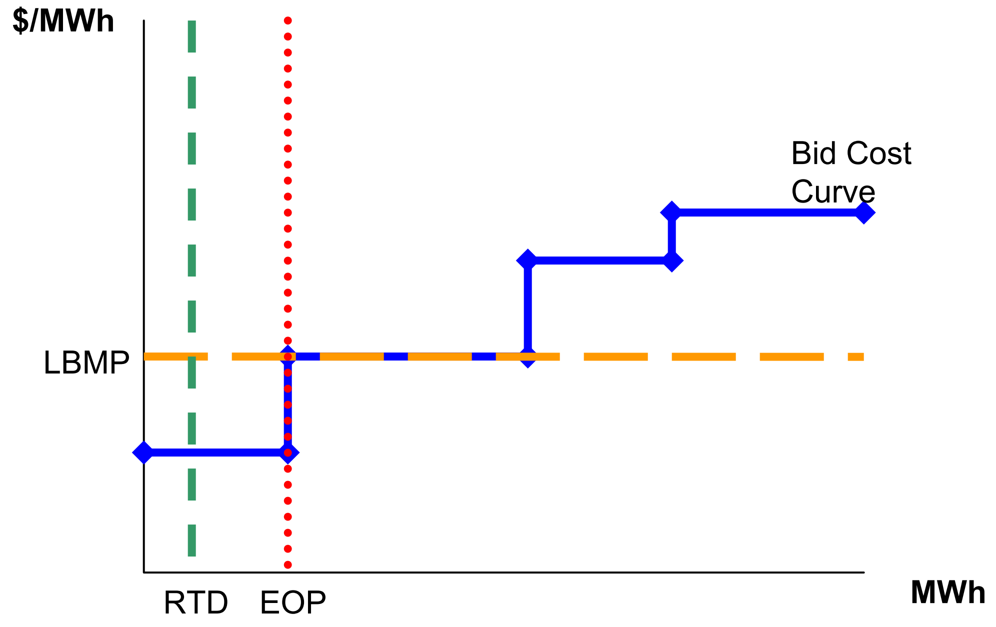
RTD Basepoint = LBMP Intersect



RTD Basepoint > LBMP Intersect



RTD Basepoint < LBMP Intersect



Step 2: Calculate DAM Schedule Reductions in the Event of a De-rate

- ✓ 2A: Calculate the **total** DAM schedule reduction for RTD interval *i.*
- ✓ *2B: Calculate the **potential** reduction for **each product** for RTD interval i.*
- ✓ *2C: Calculate the **actual** reduction for **each product** for RTD interval i*.

Step 2A: Total Reduction

$REDtot_i = Max(DASen_h + DASreg_h + \sum_p DASres_{hp} - RTuol_i\ ,\ 0)$

Where:

$REDtot_i$ = Total MW reduction of DAM schedules for interval *i.*

$DASen_h$ = DAM schedule for Energy for hour *h* containing interval *i*

$DASreg_h$ = DAM schedule for Regulation for hour *h* containing interval *i.*

$DASres_{hp}$ = *DAM schedule for Reserve product p for hour* h *containing interval* i

Step 2B: Calculate Potential Product Reduction

$$POTREDen_i = Max(DASen_h – RTSen_i\ , 0)$$

$$POTREDreg_i = Max(DASreg_h – RTSreg_i\ , 0)$$

$$POTREDres_{ip} = Max(DASres_{hp} – RTSres_{ip}\ , 0)$$

Where:

- $POTREDen_i$ = Potential reduction in the DAM Energy schedule for interval *i*.
- $RTSen_i$ = Real time schedule for Energy for interval *i*.
- $POTREDreg_i$ = Potential reduction in the DAM Regulation schedule for interval *i*.
- $RTSreg_i$ = Real time schedule for Regulation for interval *i*.
- $POTREDres_{ip}$ = Potential reduction in the DAM Reserve, product *p* schedule for interval *i.*
- $RTSres_{ip}$ = Real time schedule for Reserve, product *p*, for interval *i*.

Step 2C: Calculate Actual Reductions

If: $REDtot = 0$

$REDen_i = 0$

Where $REDen_i$ = Actual reduction in the DAM Energy schedule for interval *i.*

$REDreg_i = 0$

Where $REDreg_i$ = Potential reduction in the DAM Regulation schedule for interval *i*.

$REDres_{ip} = 0$

Where $REDres_{ip}$ = Potential reduction in the DAM Reserve, product p schedule for interval *i*.

Step 2C, Cont.

Else:

$REDen_i = [POTREDen_i / (POTREDen_i + POTREDreg_i + \sum_p POTREDres_{ip})] \text{ X } REDtot_i$

$REDreg_i = [POTREDreg_i / (POTREDen_i + POTREDreg_i + \sum_p POTREDres_{ip})] \text{ X } REDtot_i$

$REDres_{ip} = [\mathrm{POTREDres}_{\mathrm{ip}} / (POTREDen_i + POTREDreg_i + \sum_p POTREDres_{ip})] \text{ X } REDtot_i$

Step 3: Calculate Adjusted DAM Schedules

$AdjDASen_i = DASen_h - REDen_i$

Where $AdjDASen_i$ = Adjusted DAM Energy schedule for interval i.

$AdjDASreg_i = DASreg_h - REDreg_i$

Where $AdjDASreg_i$ = Adjusted DAM Regulation schedule for interval i.

$AdjDASres_{ip} = DASres_{hp} - REDres_{ip}$

Where $AdjDASres_{ip}$ = Adjusted DAM Reserve, product p, schedule for interval i.

Step 4A: Determine Lower Limits used in the Energy Contribution Calculation

If: $RTSen_i < EOP_i$,

$LL_i = Max[RTSen_i , Min(Act_i , EOP_i)]$, but not more than $AdjDASen_h$

Else:

$LL_i = Min[RTSen_i , Max(Act_i , EOP_i)]$, but not more than $AdjDASen_h$

Where:

LL_i = Lower Limit to be used in the Energy contribution calculation for interval *i*.

EOP_i = The EOP for interval *i*.

Step 4B: Determine Upper Limits used in the Energy Contribution Calculation

If: $RTSen_i \geq EOP_i \geq AdjDASen_h$,

$UL_i = Min[RTSen_i , Max(Act_i , EOP_i)]$, but not less than $AdjDASen_h$

Else:

$UL_i = Max[RTSen_i , Min(Act_i , EOP_i)]$, but not less than $AdjDASen_h$

Where:

UL_i = Upper Limit to be used used in the Energy contribution calculation for interval *i*.

Step 5: Calculate the Energy Contribution to DAMAP

If: $RTSen_i < AdjDASen_h$

$$CDMAPen_i = \left\{ \left(AdjDASen_h - Max\left[RTSen_i, Min\left(Act_i, LL_i \right) \right] \right) \times LBMP_{RT_i} - \int_{Max\{RTSen_i, Min(Act_i, LL_i)\}}^{AdjDASen_h} DABen_h \right\}$$

Else:

$$CDMAPen_i = Min\left\{ \left[AdjDASen_h - UL_i \right] \times LBMP_{RT_i} + \int_{AdjDASen_h}^{UL_i} RTBen_h, 0 \right\}$$

Where:

$LBMP_{RTi}$ = Real-time LBMP at the generator bus for interval *i*.

$RTBen_h$ = Real-Time bid for Energy for hour *h* containing interval *i*.

$CDMAPen_i$ = Energy contribution to DAMAP for interval *i*.

Step 6: Calculate the Reserve Products Contribution to DAMAP

If: $RTSres_{ip} < AdjDASres_{hp}$

$CDMAPres_{ip} = (AdjDASres_{hp} – RTSres_{ip})\ X\ (RTPres_{ip} – DABres_{hp})$

Else:

$CDMAPres_{ip} = (AdjDASres_{hp} – RTSres_{ip})\ X\ RTPres_{ip}$

Where:

$RTPres_{ip}$ = Real-time price for Reserve product *p* for interval *i*.

$CDMAPres_{ip}$ = Reserve product *p* contribution to DAMAP for interval *i*.

Step 7: Calculate the Regulation Contribution to DAMAP

If: $RTSres_{ip} < AdjDASres_{hp}$

$CDMAPreg_i = (AdjDASreg_h – RTSreg_i) X (RTPreg_i – DABreg_h)$

Else:

$CDMAPreg_i = (AdjDASreg_h – RTSreg_i) X Max[(RTPreg_i – RTBreg_h),0]$

Where:

$RTPreg_i$ = Real-time price for Regulation for interval *i*.

$RTBreg_h$ = Real-time bid for Regualtion for hour *h* containing interval *i*.

$CDMAPreg_i$ = Regulation contribution to DAMAP for interval *i*.

Step 8: Calculate the Contribution to DAMAP from Interval *i to Hour* h

$$CDMAP_i = (CDMAPen_i + \sum CDMAPres_{ip} + CDMAPreg_i) \times (Int_i/3600)$$

Where:

Int = Length of RTD interval *i* in seconds

$CDMAP_i$ = RTD interval *i* contribution to DAMAP for hour *h*

Step 9: Calculate the DAMAP for Hour *h*

Finally,

$$\mathbf{DMAP_h = Max(0, \sum CDMAP_i)}$$

Note, that as today, the DAMAP has a floor of zero.

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BPCG Settlement Under SMD2

BPCG Eligibility

- ✓ Units designated as ISO-Committed Flexible (IC-Flex) are eligible for DAM BPCG and RT BPCG.
- ✓ Units designated as ISO-Committed Fixed (IC-Fixed) are eligible for DAM BPCG payments, but are not eligible for real-time BPCG payments or DAMAP.
  - *DAMAP may be warranted if a unit is scheduled by the ISO or TO out of economic order in response to a system security need.*
- ✓ Units designated as Self-Committed Flexible (SC-Flex) not eligible for DAM but are eligible for real-time BPCG payments and DAMAP.
  - *SC-Flex unit not eligible for a real-time BPCG if its self-committed minimum generation level is less than its DAM schedule at any point during the Dispatch Day.*
- ✓ Units designated as Self-Committed Fixed (SC-Fixed) not eligible for DAM or real-time BPCG payments or DAMAP
  - *same treatment as for fixed units today*
  - *DAMAP may be warranted if a unit is scheduled by the ISO or TO out of economic order in response to a system security need.*

BPCG Modifications

- ✓ DAM BPCG calculation will include revenues from 30-minute synchronized reserve
- ✓ Regulation Revenue Adjustment [RRA] added to the Net Ancillary Services Margin [NASR] calculation
- ✓ With the adoption of a full two settlement Regulation & Reserves Markets, SRE-related data is removed in lieu of accommodating the buy-out of DAM positions for Regulation & Reserves
- ✓ With the inclusion of LOC in Market Clearing Price calculations, NASR calcs exclude LOC
- ✓ NASR for spinning reserves to address mandatory $0 real-time availability bid
- ✓ BPCG zero during Large event RPU & following 3 dispatch intervals
- ✓ Introduces a new term, Economic Operating Point [EOP]

Real-Time BPCG Calculation

- ✓ Other than adding the Regulation Revenue Adjustment and revenue for 30-minute Synchronized Reserve to the revenue stream, the real-time BPCG equation has not changed under RTS
- ✓ Changes have been made to the definition of several of the terms

Real-Time BPCG =

The terms used in the following formula are defined in RT BPCG handout.

$$\sum_{g \in G} Max\left\{ \sum_{i=1}^{N} \left(\begin{array}{l} \left(\int_{EI_{gi}^{DA}}^{EI_{gi}^{RT}} C_{gi}^{RT} + MGC_{gi}^{RT} \times \left(MGI_{gi}^{RT} - MGI_{gi}^{DA} \right) + SUC_{gi}^{RT} \times \left(NSUI_{gi}^{RT} - NSUI_{gi}^{DA} \right) - LBMP_{gi}^{RT} \times \left(EI_{gi}^{RT} - EI_{gi}^{DA} \right) \right) \times {s_i}/{3600} \\ - \left(NASR_{gi}^{TOT} - NASR_{gi}^{DA} \right) - RRA_{gi} \end{array} \right), 0 \right\}$$

Changes and Additions to Terms

- ✓ SUC_{gi}^{RT} shall be zero for Self-Committed Generators
- ✓ The value used for EI_{gi}^{RT} shall be dependent on the relationship of AEI_{gi} to the EOP_{gi}
- ✓ Changes to $NASR_{gi}^{TOT}$ components as follows:
  - *Addition of revenue from 30-minute synchronized reserve*
  - *Modification of Regulation Service revenue to account for real-time settlement*
  - *Modification of Spinning Reserve revenue to account for real-time settlement*
- ✓ Addition of the RRA to the revenue stream

Eligibility for Real-Time BPCG

- ✓ Units bid as the following shall be eligible for a RT BPCG payment:
  - *ISO Committed Flexible units will be treated the same as On-Dispatch units are today*
  - *Self Committed Flexible, subject to the following: if a SC-Flex unit's real-time self-commit schedule is less than its DAM schedule at any point in the Dispatch Day, it shall not be eligible for real-time BPCG payments*
- ✓ ISO or Self Committed Fixed units are not eligible for RT BPCG; if a unit is Fixed at any point during the Dispatch Day, it is ineligible for the entire day.

Zero Start-up Bids for Self Committed Units

- ✓ Units that bid as Self Committed are indicating that they want to run and be price takers up to some self committed point
- ✓ Therefore, a zero-dollar start-up cost is used in the BPCG calculation
- ✓ MIS passes a $0 start-up cost to BAS for Self-Committed units
- ✓ Therefore, no further processing in BAS shall be required

Exclusion of Reserve Pickup and Max Gen Intervals

- ✓ RTD intervals that include large event reserve pickups and max gen pickups and the three intervals following shall be excluded from this BPCG calculation
- ✓ For these excluded intervals, a separate BPCG calculation is performed
- ✓ The calculation is identical to the RT BPCG calculation **but**:
  - *Each event is calculated independent of each other*
  - *Payments are independent of and do not affect RT BPCG*

Generator Output is Dependent on the Relation of the Actual Energy Injection to the EOP

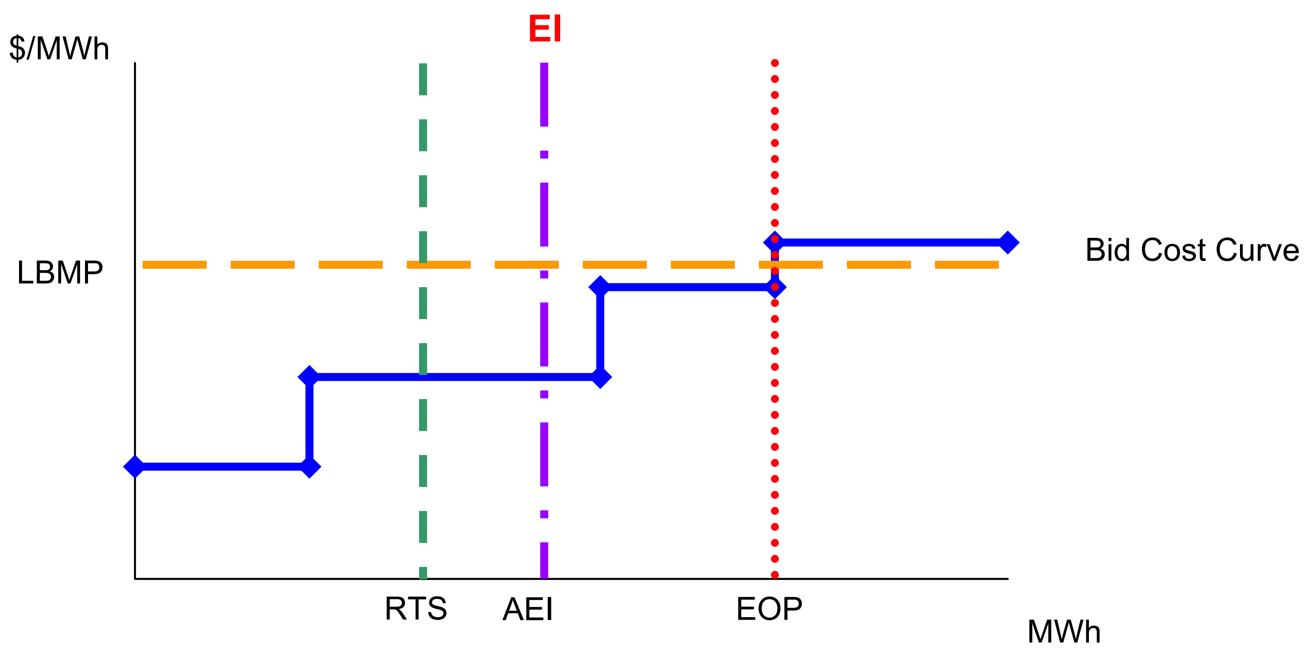
If $EOP_{gi} > AEI_{gi}$:

$$EI_{gi}^{RT} = Min[Max(AEI_{gi}, RTSen_{gi}), EOP_{gi}]$$

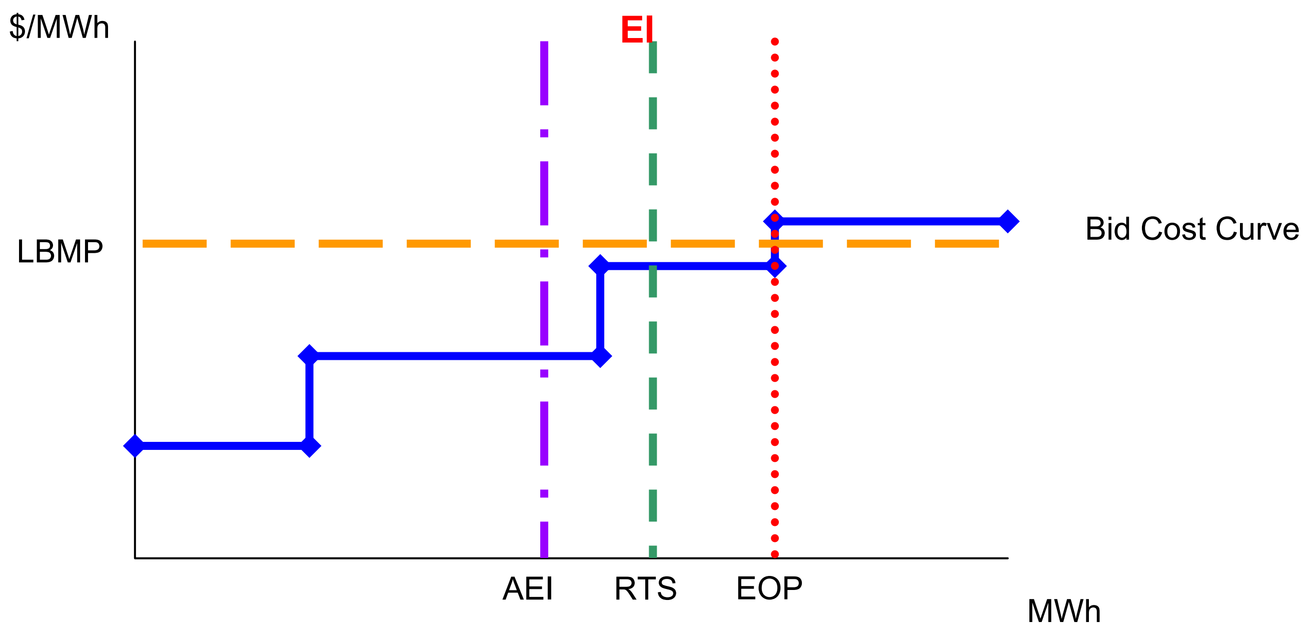
Else if $EOP_{gi} \leq AEI_{gi}$:

$$EI_{gi}^{RT} = Max[Min(AEI_{gi}, RTSen_{gi}), EOP_{gi}]$$

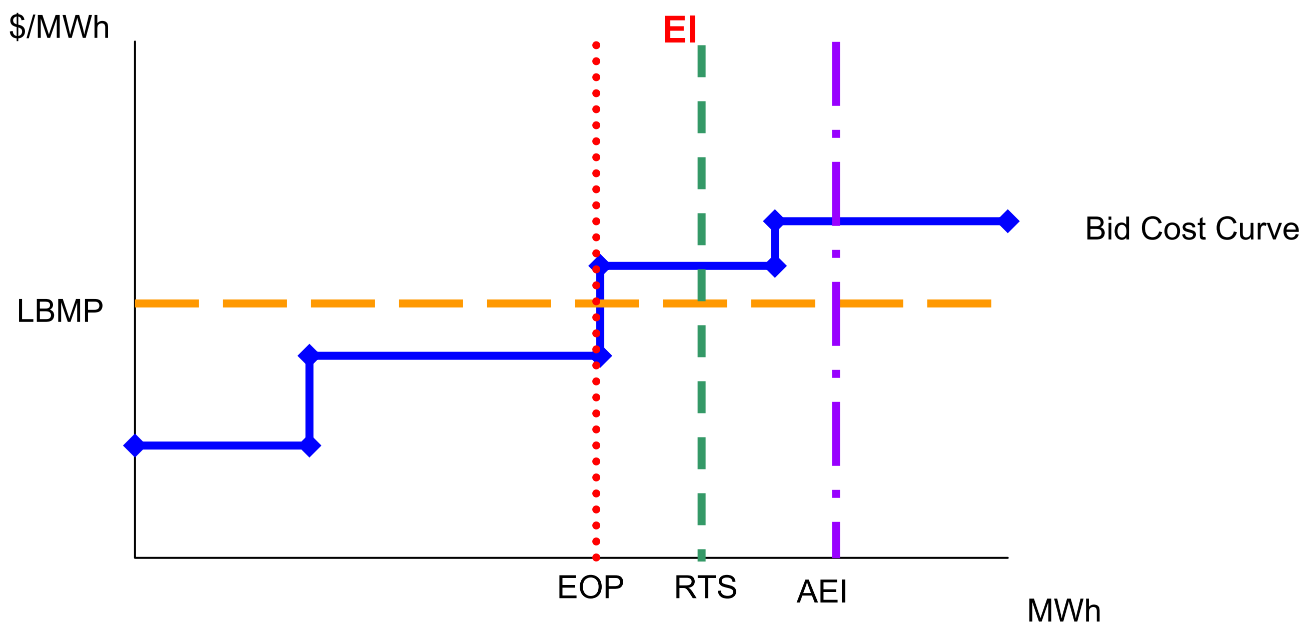
Example 1: $EOP_{gi} > AEI_{gi}$



Example 2: $EOP_{gi} > AEI_{gi}$



Example 3: $EOP_{gi} \leq AEI_{gi}$



Include 30-Minute Synchronized Reserve Revenue in $NASR_{gi}^{TOT}$

Revenue from 30-minute Synchronized Reserve is computed as follows:

$DASres_{hg30}$ X ($DCPres_{hg30} – DABres_{hg30}$) + $ResBal_{gi30}$ X $RTPres_{gi30}$

Where:

$DASres_{hg30}$ = Day-ahead schedule for 30-minute synchronized Reserve for hour *h* Generator *g*

$DCPres_{hg30}$ = Day-ahead price for 30-minute synchronized Reserve for hour *h* Generator *g*

$DABres_{hg30}$ = Day-ahead bid for 30-minute synchronized Reserve for hour *h* Generator *g*

$ResBal_{gi30}$ = Balancing 30-minute synchronized Reserve for Generator *g* interval *i*

$RTPres_{gi30}$ = Real-time price for 30-minute synchronized Reserve for Generator *g* interval *i*

Modify Spinning Reserve Revenue Calculation

- ✓ Generators will not supply availability bids but will settle in real-time for Spinning Reserve
- ✓ The revenue calculation will be as follows:

$$DASres_{hg10s} \times (DCPres_{hg10s} - DABres_{hg10s}) + ResBal_{gi10s} \times RTPres_{gi10s}$$

Where:

$DASres_{hg10s}$ = Day-ahead schedule for Spinning Reserve for hour *h* Generator *g*

$DCPres_{hg10s}$ = Day-ahead price for Spinning Reserve for hour *h* Generator *g*

$DABres_{hg10s}$ = Day-ahead bid for Spinning Reserve for hour *h* Generator *g*

$ResBal_{gi10s}$ = Balancing Spinning Reserve for Generator *g* interval *i*

$RTPres_{gi10s}$ = Real-time price for Spinning Reserve for Generator *g* interval *i*

Modify Regulation Revenue Calculation

- ✓ Generators will settle in real-time for Regulation Service
- ✓ The revenue calculation will be as follows:

$DASreg_{hg}$ X $(DCPreg_{hg} – DABreg_{hg})$ + $Max\{[RegBal_{gi}$ X $(RTPreg_{gi} – RTBreg_{gi})], 0\}$

Where:

$DASreg_{hg}$ = Day-ahead schedule for Regulation for hour *h* Generator *g*

$DCPreg_{hg}$ = Day-ahead price for Regulation for hour *h* Generator *g*

$DABreg_{hg}$ = Day-ahead bid for Regulation for hour *h* Generator *g*

$RegBal_{gi}$ = Balancing Regulation for Generator *g* interval *i*

$RTPreg_{gi}$ = Real-time price for Regulation for Generator *g* interval *i*

$RTBreg_{gi}$ = Real-time bid for Regulation for Generator *g* interval *i*

Addition of Regulation Revenue Adjustment to Revenue Stream

- ✓ The RRA_{gi} must be added to the real-time BPCG calculation for Generator *g*, interval *I.*

BPCG for Large Event RPUs

- ✓ During a Large Event RPU, basepoints are sent to units which do not allow them to back down, even if a transmission overload occurs. As a result, units may be held at a level which is not economically feasible.
- ✓ To prevent units from backing down to avoid financial harm, a supplemental payment (BPCG) shall be made.
- ✓ These BPCG payments are made and accounted for independently from all other BPCG payments.

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Performance Tracking Under SMD2

Overview

- ✓ Performance Tracking System (PTS) consists of 2 major functions:
  1. *RTD Energy Report*
  2. *Hourly History and Availability Report*
- ✓ PTS inputs comprised of
  - *six-second data*
  - *five-minute data*
  - *exception data [e.g. In-service flag, on-control flags, on-dispatch flags, etc.]*
- ✓ All input data will be read from a PI database.
- ✓ This data is processed and the results are sent to MIS to be used by BAS and MMU.
- ✓ Using PI provides visibility to Staff for 6-second data anomalies
- ✓ New design provides for subsequent re-calculation to accommodate data corrections or processing interruptions

RTD Energy Report

- ✓ Generates results for generating units and tie lines for a RTD interval (normally every 5 minutes) and RTD-CAM interval (on demand).
- ✓ Collects 6-second base points after each RTD execution and computes averages for a RTD run interval.
- ✓ Computes generator control error and error tolerance, performance index and other performance statistics used by BAS to fairly penalize units for poor performance, as well as by MMU for reserve pickup information, which is run during an RTD-CAM execution.

Hourly Availability & History Reports

- ✓ Generates hourly generator statuses
- ✓ Statuses consist of the number of seconds in the hour each generating unit was available, in-service, on-dispatch and on-control.
- ✓ Generates the operating capacity for each generating unit during the hour.
- ✓ Executes at the top of each hour for the previous hour.

Unit Average Output per RTD Interval

PTS averages the actual unit MW output sampled at a six-secon

$$\textbf{Units Average Actual Gen (UAAG[g])} = \frac{\sum_{i=1}^{n} \mathrm{ACTGEN[g]}}{n}$$

g = 1 to the number of generators

n = number of six-second samples in the RTD interval

Average Tie-flow per RTD Interval

PTS averages the tie flow MW, sampled at a six-second rate.

$$\textbf{Average Tie Flow, AvgTie[t]} = \frac{\sum_{i=1}^{n} \text{TIEFLW[t]}}{n}$$

t = 1 to the number of tie flows
n = number of six-second samples in the RTD interval

Average Desired AGC Basepoint per RTD Interval

PTS calculates the average Desired 6-second AGC setpoints for a RTD interval.

For non-regulating units the desired and ramped 6-second setpoint values will be the same.

For regulating units, **AVG Desired Generation (ADG[u])** $= \dfrac{\sum_{i=1}^{n} \mathrm{DESGEN}[u]}{n}$

For non-regulating units, **AVG Desired Generation (ADG[u])** $= \dfrac{\sum_{i=1}^{n} \mathrm{RAMPBP}[u]}{n}$

u = 1 to the number of regulating or non-regulating units
n = number of six-second samples in the RTD interval

Average Ramped AGC Basepoint per RTD Interval

PTS calculates the average Ramped 6-second AGC setpoints for a RTD interval.

For regulating and non-regulating units, **AVG Ramped Generation (ARG[u])** = $\dfrac{\sum_{i=1}^{n} \mathrm{RAMPBP}[u]}{n}$

u = 1 to the number of regulating or non-regulating units
n = number of six-second samples in the RTD interval

Control Error Tolerance per RTD Interval

The unit error deviation tolerance is calculated for non-regulating units and is derived at by taking the minimum value of:

- Fixed percentage of the units operating capacity (OpCap). The fixed rate is set by NYISO and is currently set at 3%.
- 3 * the response rate of the generating unit.

Control Error Tolerance (CET) = MIN(OpCap * .03, ResponseRate * 3)

For example, a generating unit has an operating capacity of 1000 MW and the response rate is 5 MW, the control error tolerance would be calculated as follows:

CET = MIN (1000 * .03, 3 * 5) = MIN (30, 15) = 15 MW

Positive Control Error per RTD Interval

The unit's positive control error is the MW value by which the unit over generated for a RTD interval. Every 6-seconds the unit is checked for over generation. If the unit's actual MW value exceeds the units desired generation plus the control error tolerance then the unit has over generated. The amount of over generation is accumulated over the RTD interval to arrive at the positive control error for the RTD interval.

Logic:

```
PCE = 0
for (i=1 to n)
{  if (ACTGEN > DESGEN + CET)  { PCE = PCE + ACTGEN – DESGEN + CET  }}
```

Where:
n = number of 6-second samples in the RTD interval

Positive Control Error for Regulating Units

- ✓ Unit positive control error is the MW value by which the unit violates the 30-second maximum value of the rate limited desired generation of the unit by over generating while providing regulation.
- ✓ For regulating units the positive control error is calculated every 30-second within a RTD execution.
  - *Every 30-seconds a units actual MW output is compared to its highest desired generation over the past 30-seconds.*
  - *If the actual generation exceeds the highest desired generation then a positive control error has occurred.*
  - *The positive control error for that 30-second interval is calculated by subtracting the actual MW output from the highest desired generation.*
  - *The positive control errors that occur in a RTD interval are accumulated to give us the units positive control error over a RTD interval.*
- ✓ PTS will not modify the units desired generation setpoint based on the units response rate limit.

Negative Control Error per RTD Interval

The unit's negative control error is the MW value by which the unit under generated for a RTD interval. Every 6-seconds the unit is checked for under generation. If the unit's actual MW value is less than the units desired generation minus the control error tolerance then the unit has under generated. The amount of under generation is accumulated over the RTD interval to arrive at the negative control error for the RTD interval.

Logic:

```
NCE = 0
for (i=1 to n)
{ if (ACTGEN < DESGEN - CET) { NCE = NCE + DESGEN – ACTGEN - CET } }
```

Where:
n = number of 6-second samples in the RTD interval

Negative Control Error for Regulating Units

- ✓ Unit negative control error is the MW value by which the unit violates the 30-second minimum value of the rate limited desired generation of the unit by under generating while providing regulation.
- ✓ For regulating units the negative control error is calculated every 30-second within a RTD execution.
  - *Every 30-seconds a units actual MW output is compared to its lowest desired generation over the past 30-seconds.*
  - *If the actual generation falls below the lowest desired generation then a negative control error has occurred.*
  - *The negative control error for that 30-second interval is calculated by subtracting the units lowest desired generation from the actual MW output.*
  - *The negative control errors that occur in a RTD interval are accumulated to give us the units negative control error over a RTD interval.*
- ✓ PTS will not modify the units desired generation setpoint based on the units response rate limit.

Unit Control Error during Reserve Pick-ups

- ✓ Unit control errors are calculated differently when a reserve pickup occurs.
- ✓ A reserve pickup is deemed to have failed if the basepoint that is set at the start of the reserve pickup is not met after 10 minutes.
- ✓ If a reserve pickup passes, unit control errors both negative and positive will be set to 0.
- ✓ Units not penalized for over generating during a reserve pickup.
- ✓ If a reserve pickup fails, the positive control error (PCE) is set to zero.
  - *The negative control error (NCE) is calculated by the subtracting the actual generation at 10 minutes past the start of the reserve pickup, from the basepoint set at the start of the reserve pickup minus the control error tolerance (CET).*
  - *The CET is calculated the same as when we are not in a reserve pickup mode. See section above, which describes the CET calculation.*
  - *PCE = 0*
  - *NCE = $RAMPBP_{t=0}$ – $ACTGEN_{t=10}$ – CET (t = time in minutes from the start of the reserve pickup)*

Performance Index

- ✓ A performance index Pi_{REG} for each Regulating unit assigned to track units' ability to follow regulation control signals, on a RTD interval basis.
  - *Performance index is used in determining each regulation units' regulation availability payment.*
  - *On-control status of the unit at the beginning of the RTD interval is the assumed on-control status for the entire RTD interval*
    - This means that for units which are on-control for the first 6-second period of the RTD interval they will be assigned a grace value of 100% for the entire interval.
    - For availability, the percent of the RTD interval that the unit was on-control is used in determining the final PI.
    - Units that begin the interval off-control will be assigned a Pi_{REG} of zero (including a grace value of zero) for the entire interval.

Unit Regulation Margin (**URM**) = Regulation Response Rate (MW/min) * RTD Interval (min)

Unit Regulation Performance Index **(PiREG) =** ((URM – (PCEr + NCEr))/URM + 0.10) * (RegPeriod / RTD Interval (sec))

RegPeriod is the number of seconds in on-control status.

Unit Statuses

- In-Service
  - *Status at the beginning of the RTD interval assumed for the entire RTD interval.*
- On-Control
  - *Status at the beginning of the RTD interval assumed for the entire RTD interval.*
- On-Dispatch
  - *Status at the beginning of the RTD interval assumed for the entire RTD interval.*

Building the Energy Markets of Tomorrow . . . Today

Determinant Data & Settlement Reporting Under SMD2

Reporting of Determinant & Settlement Data

- ✓ Legacy posting of advisory settlement statements to MP websites as static comma separated variable [csv] formatted files migrated to DSS application.
- ✓ Settlements datamart to incorporate SMD2 billing determinants and results in corporate reports
  - *affects settlement rules pertaining to:*
    - Real-time balancing of Reserve and Regulation
    - Large Event Reserve Pick-up supplemental payments
    - RRA payments and charges
    - Day-Ahead Margin Assurance Payments (DAMAP)
    - Real-time Bid Production Cost Guarantee (BPCG) payments

Nature of Reserves & Regulation Specific Data

- ✓ Reserve Settlement
  - *RTD level schedules for all Operating Reserve products*
  - *Marginal clearing prices for all Operating Reserve products at the Generator bus for each RTD interval*
  - *Reserve settlement $ for all Operating Reserve products for each RTD interval*
  - *Large Event Reserve Pick-up Flag*
- ✓ Regulation Settlement
  - *RTD level schedules for Regulation Service*
  - *Marginal clearing price for Regulation Service for each RTD interval*
  - *Regulation settlement $ for each RTD interval*

Nature of DAMAP & BPCG Specific Data

- ✓ Refer to Attachments C and J of the draft Services Tariff
- ✓ Economic Operating Point (EOP)
  - *Point where the LBMP intersects the bid curve*
  - *May be greater than, less than or equal to the RTD basepoint*
- ✓ Upper Operating Limit (UOL) for each RTD interval
- ✓ The following results of intermediate calculations for each RTD interval:
  - *Potential schedule reductions for Energy, Operating Reserve products and Regulation Service*
  - *Total schedule reductions for Energy, Operating Reserve products and Regulation Service*
  - *Upper and lower limits on the bid curve used in the DAMAP calculation*
- ✓ The Energy, Operating Reserve product and Regulation Service contribution to DAMAP for each RTD interval
- ✓ The calculated DAMAP for each RTD interval