Energy
Market
Company

Notice of Market Rules Modification

Paper No.:	EMC/RCP/30/2007/263
Rule reference:	Chapter 6, Appendix 6D
Proposer:	Market Operations, EMC
Date received by EMC:	22 September 2006
Category allocated:	2
Status:	Approved by EMA
Effective Date:	To be advised

Summary of proposed rule modification:

This modification is to implement Mixed Integer Program-based regulation constraints to prevent generating units that are not scheduled to provide regulation from being "trapped" at their RegulatioMin or RegulationMax level.

Date considered by Rules Change Panel:	9 January 2007
Date considered by EMC Board:	31 January 2007
Date considered by Energy Market Authority:	13 March 2007

Proposed rule modification:

See attached paper.

Reasons for rejection/referral back to Rules Change Panel (if applicable):

PAPER NO.	:	**EMC/BD/01/2007/07(b)**
RCP PAPER NO.	:	**EMC/RCP/30/2007/263**
SUBJECT	:	**MIXED INTEGER PROGRAM BASED MODELING OF REGULATION CONSTRAINTS**
FOR	:	**DECISION**
PREPARED BY	:	**WANG JING** **ANALYST**
REVIEWED BY	:	**PAUL POH LEE KONG** **SVP, MARKET ADMINISTRATION**
DATE OF MEETING	:	**31 JANUARY 2007**

Executive Summary

Regulation anomaly is an issue identified in the RCP work plan. This paper presents the solution proposed by EMC to mitigate the regulation anomaly. The suggested solution would ensure that no generator would be unnecessarily constrained to be scheduled at their RegulationMin or RegulationMax levels when not scheduled to provide regulation because of the current regulation constraints. This is achieved by applying a set of new constraints using Mixed Integer Programming on all qualified regulation providers.

The RCP recommends that the EMC Board **adopt** this proposal.

1. Introduction

This paper presents EMC's proposal to modify the regulation constraints in the market clearing engine. The new constraints would eliminate the occurrence of "trapped" generators, where some generators qualified as regulation providers are unnecessarily constrained for energy dispatch at their regulation minimum or regulation maximum level because of regulation constraints. The proposed approach would allow for more economic dispatch schedules.

2. Background

Regulation is the frequent adjustment to a generating unit's output so that any power system frequency variation due to the imbalance between load and generation can be corrected. Currently, regulation can only be provided by generation registered facilities (GRFs).

The PSO prompts GRFs to provide regulation through the Automatic Generation Control (AGC) subsystem. For the AGC to be able to control a GRF, the GRF's output must be within a certain range. This range is defined by the RegulationMin and RegulationMax of the GRF, i.e., the GRF's output should not be less than the RegulationMin or greater than RegulationMax.

To determine if a GRF with a valid regulation offer is qualified to provide regulation, the following conditions are checked:

Conditions	Reason
1 Regulation offered >0	The GRF must have offered regulation into the market.
2 Sum of energy offered >= RegulationMin	The GRF must have a valid energy offer into market and the energy it offered is sufficient to allow it to provide regulation
3 StartGeneration[1] > RegulationMin 4 StartGeneration <= RegulationMax	The GRF must be able to provide regulation at the beginning of the dispatch period

If a GRF satisfies all the conditions, it qualifies as a regulation provider and the following regulation constraints will be applied to it in running the MCE.

Regulation Max constraint:

$$\text{Generation} + \text{Regulation} - \text{ExcessRegGen} \leq \text{RegulationMax}$$

Regulation Min constraint:

$$\text{Generation} - \text{Regulation} + \text{DeficitRegGen} \geq \text{RegulationMin}$$

These constraints ensure that the output of the regulation provider when providing both scheduled energy and scheduled regulation is within the range of RegulationMin and RegulationMax, thus allowing it to respond readily to AGC to provide regulation. The Regulation Min/Max constraints, together with the regulation offer constraints, define the feasible solution space for any qualified regulation provider.

[1] StartGeneration refer to output of a GRF expected at the start of a dispatch period. Please refer to the definition of StartGeneration in 6D.3 of Appendix 6D of the market rules.

Figure 1 below illustrates how the regulation constraints are currently applied in the MCE. The RegulationMin/Max constraints and the regulation offer constraints define the border of the solution space. The blue trapezium area indicates the feasible solution space of all the possible regulation and energy dispatch combination for a qualified regulation provider.

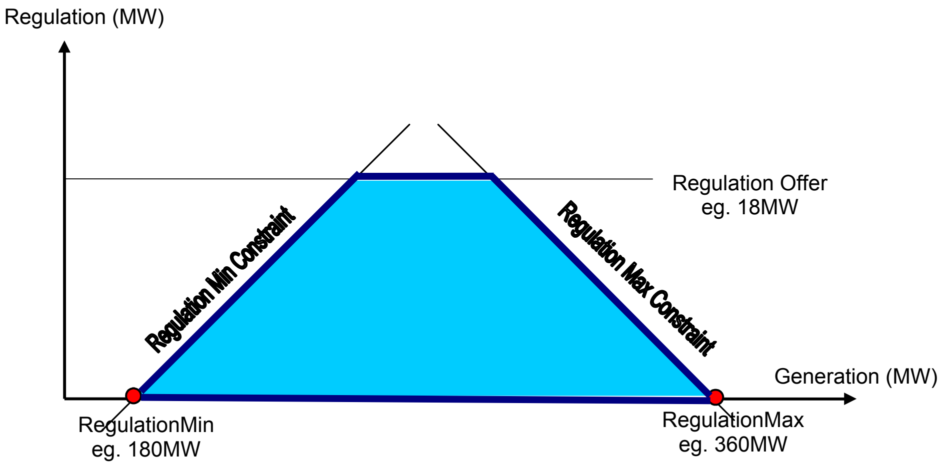


Figure 1 Current MCE modeling of regulation constraints

The existing regulation constraints may result in a situation where a qualified regulation provider, despite not being scheduled for regulation, is "trapped" at its RegulationMin and RegulationMax. These two scenarios are depicted by the two red dots at the bottom of Figure 1.

For example, if the RegulationMin constraint is binding and the market clearing price is lower than the qualified regulation providers energy offer price, it would still be forced to generate at RegulationMin level. This is despite other cheaper energy offers being available. If the RegulationMax constraint is binding on the other hand, the qualified regulation provider would not be scheduled above RegulationMax even if it is offering cheaper (below market clearing price) energy into the market.

Additionally, applying RegulationMin/Max constraints to GRFs that are not scheduled to provide regulation, which is currently the case, is inappropriate. Since such GRFs would not be required to provide regulation, they should not be subject to any regulation constraint.

The above two situations where the scheduled generation of a GRF is unnecessarily constrained to its RegulationMin/Max are described as a GRF being "trapped" or a "regulation anomaly". When any GRF is "trapped", the MCE's dispatch schedules could be uneconomical, thus undermining market efficiency.

3. Proposed Solution

The cause of the problem of a "trapped" GRF is imperfect definition of the solution space. If a GRF is not scheduled for regulation, then it should be allowed to provide energy at any output level and not subject to the RegulationMin/Max Constraints. Thus the solution space for a qualified regulation provider should be expanded to outside the blue trapezium area if no regulation is cleared for this GRF. Its scheduled energy range is illustrated by the red line in Figure 2.

It can be seen that the modified solution space is non-convex. Because the MCE employs Linear Programming (LP) that only solve convex problems, PSC has recommended introducing Mixed Integer Programming (MIP) to the current MCE to solve this optimization problem.

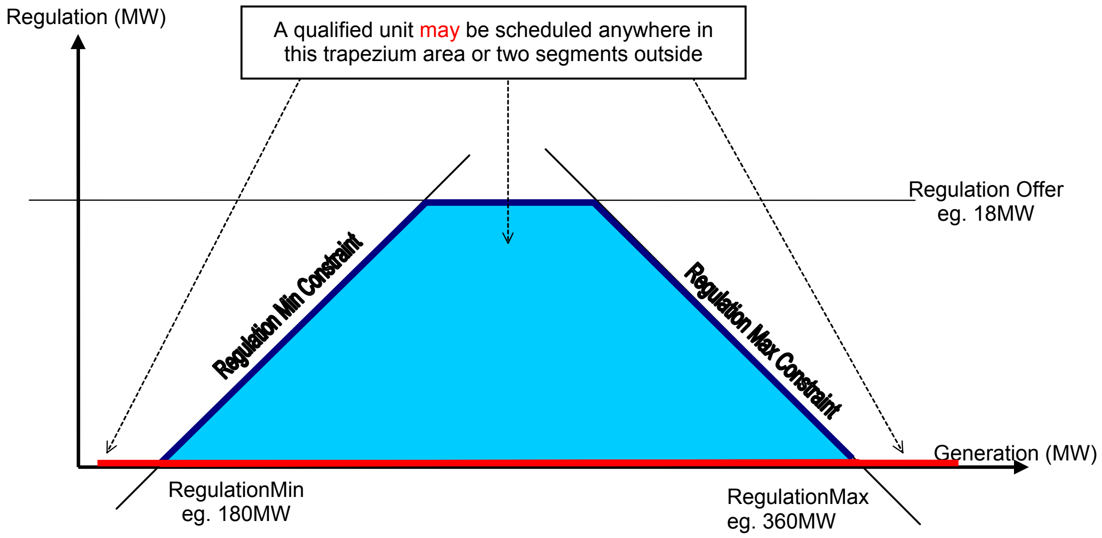


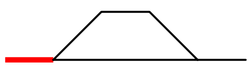
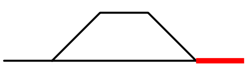
Figure 2 Proposed Modeling of Regulation Constraints

3.1 MIP-based Regulation Constraints

To model the new regulation constraints as shown in Figure 2, a set of MIP based regulation constraints as in Annex 1 are introduced.

The basic idea behind these constraints is to divide the whole solution space (the blue trapezium area plus the red line in Figure 2) into three segments (as shown in the table below) and apply different regulation constraints to each of them. For each segment, the applicable regulation-generation constraints can be described as follows.

Table 1 Decomposition of regulation constraints

The sector of solution space modeled	Applicable Regulation Constraint
	$\text{Regulation} = 0$ $\text{Generation} \leq \text{RegulationMin}$
	$\text{Generation} - \text{Regulation} + \text{DeficitRegGen} \geq \text{RegulationMin}$ $\text{Generation} + \text{Regulation} - \text{ExcessRegGen} \leq \text{RegulationMax}$
	$\text{Regulation} = 0$ $\text{Generation} \geq \text{RegulationMax}$

The following 7 MIP-based constraints are used to arrive at modeling each of the 3 segments. (Annex 1 explains in details how these constraints correctly reflects the desired modeling of the solution space shown in Figure 2 and Table 1.)

MIP1 Regulation Min

$$\text{Generation} - \text{Regulation} + \text{DeficitRegGen} + E * z \geq \text{RegulationMin}$$

MIP2 Regulation Max

$$\text{Generation} + \text{Regulation} - \text{ExcessRegGen} - E * z \leq \text{RegulationMax}$$

MIP3 Regulation Availability Switch at Regulation Min

$$\text{Regulation} - E * y_{\text{RegMin}} \leq 0$$

MIP4 Generation Switch at Regulation Min

$$\text{Generation} - E * y_{\text{RegMin}} \leq \text{RegulationMin}$$

MIP5 Regulation Availability Switch at Regulation Max

$$\text{Regulation} - E * y_{\text{RegMax}} \leq 0$$

MIP6 Generation Switch at Regulation Max

$$\text{Generation} + E * y_{\text{RegMax}} \geq \text{RegulationMax}$$

MIP7 Binary Restrictions

$$z + y_{\text{RegMin}} + y_{\text{RegMax}} = 2$$

where E: a big positive constant number

z, y_{RegMax}, y_{RegMin}: binary integer variables of value 0 or 1.

As MIP based constraints allow the RegulationMin/Max constraints on qualified regulation providers to be “relaxed” if it is not dispatched for any regulation, applying these new constraints on all qualified regulation providers, will eliminate the occurrence of “trapped” generators.

3.2 MIP-based Approach

As MIP-based solution increases the time needed to solve the optimization problem, MIP-based approaches will be applied only to cases where “trapped” generators are discovered.

The following steps are used to determine if MIP-based regulation constraints should be applied to solve the optimization function:

a) Apply normal regulation qualification checks before the initial solve and identify the generators that qualify to provide regulation.

b) After the first solve, apply a check to determine if any generator is cleared for a quantity of energy equal to their RegulationMin/Max.

c) If at least one generator is cleared at either of these points, then formulate and apply the MIP-based regulation constraints on all qualified regulation providers and re-solve.

This process can be described by the following flowchart. An additional check and re-solve step is added to the existing flowchart. This process ensures that there would be no non-physical losses or trapped generators in the solution.

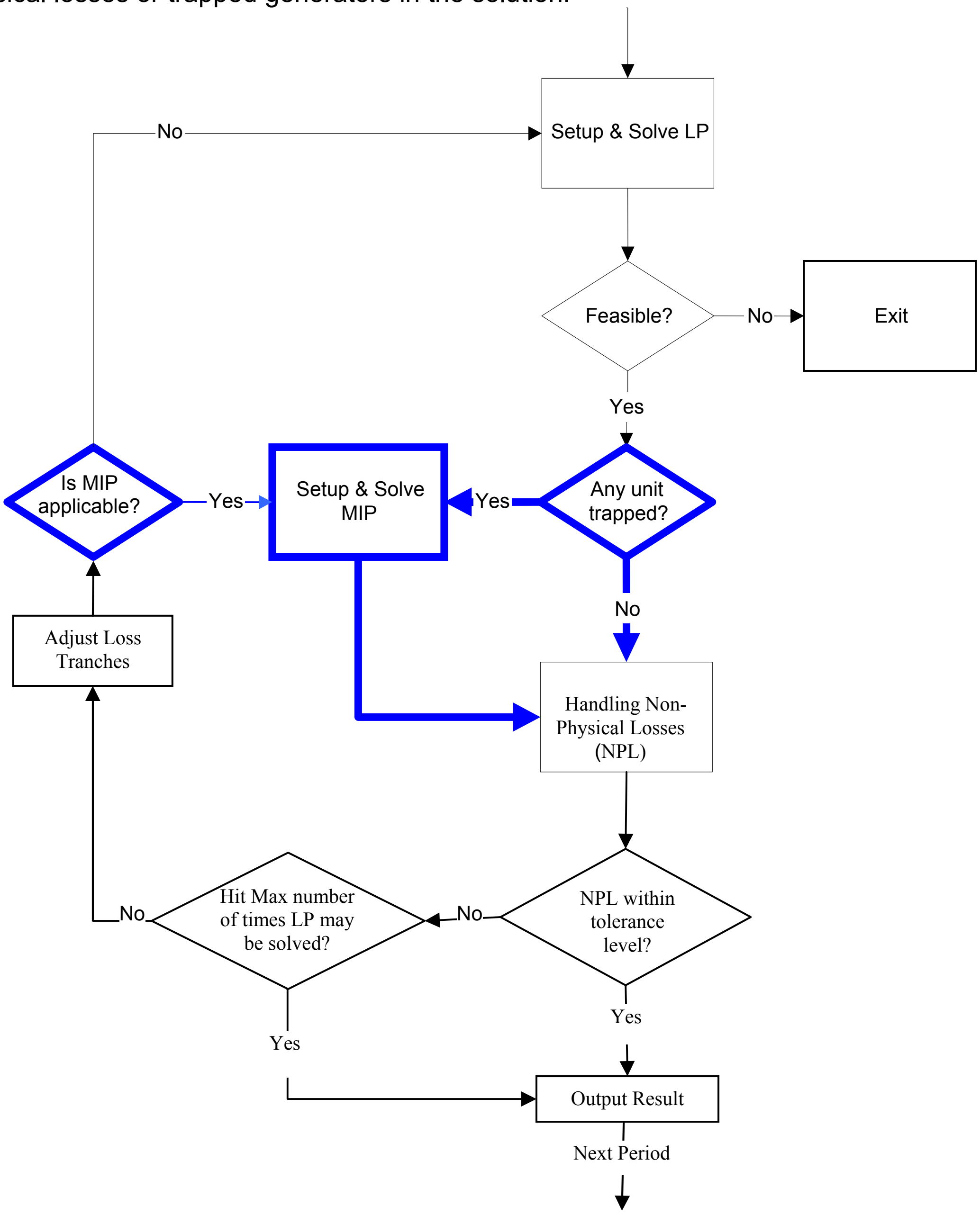


Figure 3 Process flow in MCE clear procedure after being modified for MIP

3.3 Required Rule Changes

To implement the MIP-based approach as described in section 3.2, the following changes to the market clearing formulation (appendix 6D of the Market Rules) are required.

Section	Rule changes	Reasons for change
6D.3 & 6D.4	Add new parameters and variables.	To define new parameters and variables to be used in the MIP regulation constraints
6D.18	Add new MIP-based regulation constraints to the MCE formulation.	To implement the proposed modelling of regulation constraints.
6D. 21A	New section. To add a regulation anomaly correction process in the MCE formulation.	To implement a check for any "trapped" generator following each MCE solve. This acts as a trigger mechanism for the use of MIP-based regulation constraints.
6D.22	Modification to the sequence of events.	To modify loss calculation correction procedures to reflect the changes in the flow chart.

3.3.1 Associated Changes

EMC also proposes two other changes to the present pre-check conditions for regulation providers.

1 The current rules require a GRF's total energy offer to be greater than <u>or equal to</u> its RegulationMin in order for its regulation offer to be considered. However, if the total energy offer of a GRF is only equal to its RegulationMin, then because of the Generation Block Constraint, this GRF would be scheduled for energy to at most its RegulationMin level. With its energy scheduled below or equal to its RegulationMin, this GRF would in fact not be scheduled to provide any regulation. Thus, such a GRF's regulation offer should not be considered in the first place.

2 Currently, GRFs with StartGeneration equal to its RegulationMin would be disqualified from providing regulation. This is to allow GRFs that are trapped in one period to be scheduled below its RegulationMin in the next period.

With the implementation of MIP-based regulation constraints, occurrence of regulation anomaly can be completely eliminated. Hence, there is no reason to keep this arrangement because a GRF with StartGeneration equal to its RegulationMin is able to provide regulation and should not be disqualified as a regulation provider.

For the above reasons, EMC proposes the following changes to the pre-check conditions:

Section	Current Pre-check Conditions imposed on a GRF's regulation offer	Proposed Pre-check Conditions imposed on a GRF's regulation offer
6D.13A.1.1	Sum of energy offered >= RegulationMin	Sum of energy offered > RegulationMin
6D.13A.1.2	StartGeneration > RegulationMin	StartGeneration >= RegulationMin

4. Impact Analysis

In order to effectively perform an impact analysis of the MIP-based approach, a MIP-based MCE prototype was built. The MIP-based MCE was run in parallel with the existing MCE from June 23rd to July 20th, 2006. Their results were then compared to evaluate the impact of the proposed MIP-based solution.

4.1 Objective Value (Net Benefit) and Price Impacts

From comparison of the dispatch results, both objective values and USEPs were observed to have been affected in the MIP-based solution. The changes can be graphically explained with Figure 4. It illustrates how energy is cleared in the LP approach (top) where generator A is "trapped" at its RegulationMin. Whereas given the same conditions in the MIP-based approach (bottom), energy is scheduled in merit order.

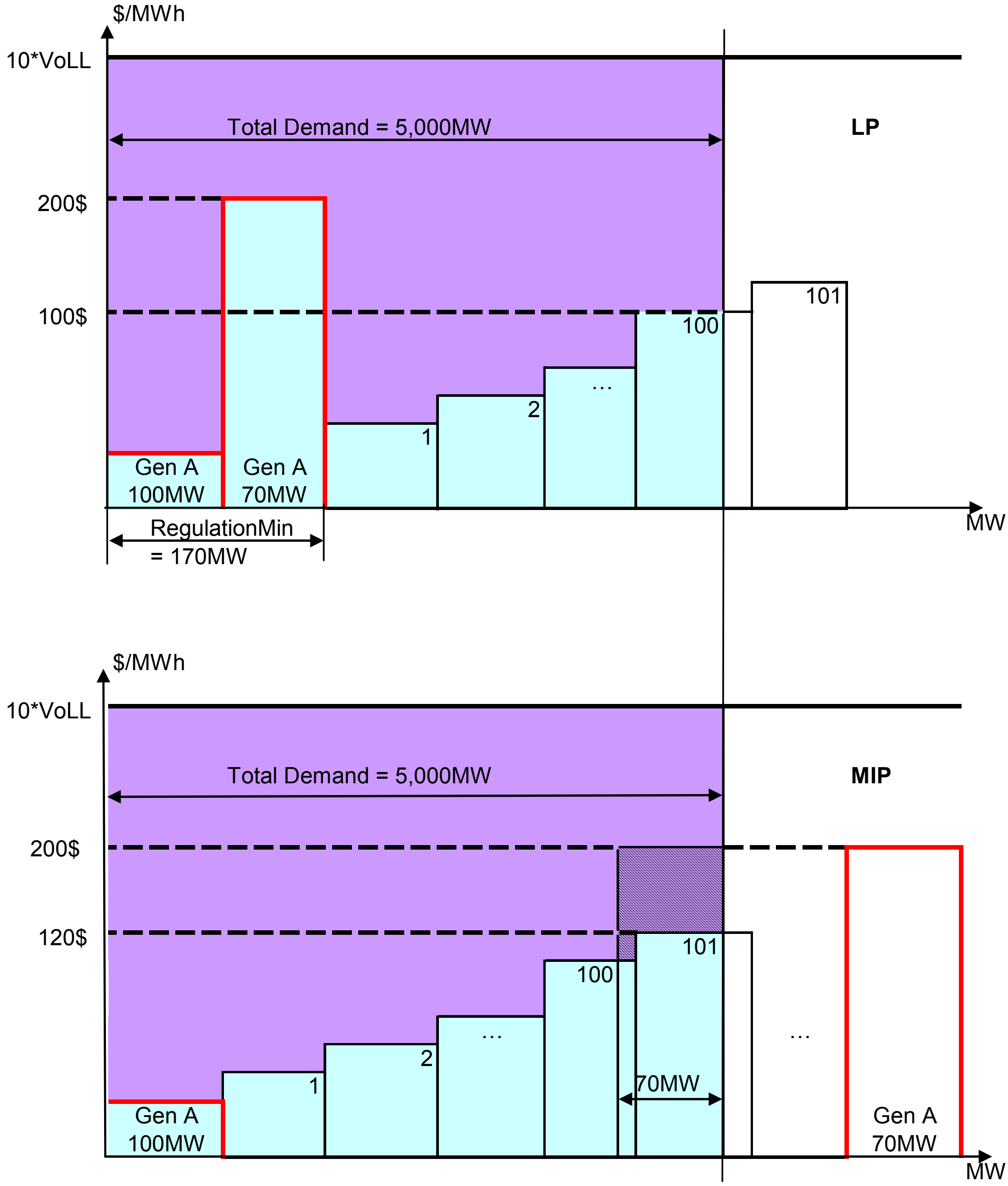


Figure 4 Illustration of market energy clearing process and net benefit with LP and MIP approaches

Generator A is a qualified regulation provider but not scheduled for any regulation. Its RegulationMin is equal to 170MW.

In the LP approach, the existing regulation constraints require each qualified regulation provider to generate between RegulationMin and Max. Hence, despite Generator A's offers being higher priced, it is forced to generate at its RegulationMin of 170MW. Other generators' offers (stack 1 to 100) are cleared in merit order to meet the rest of the demand (which is the total demand of 5,000MW minus the forced generation of 170MW). The market clearing price is set at the 100th stack's offer price, i.e. $100.

In the MIP-based approach, the RegulationMin/Max constraints on Generator A are relaxed. It can then be dispatched below its RegulationMin. In this case, all 5,000MW of load would be cleared based on all generators' offers in merit order. It can be seen from the diagram that generator A's second offer stack is not cleared because the offer price is too high. Instead, the 70 MW of next least expensive stack (the rest of the 100th stack and part of the 101st stack) is cleared in place of generator A's second offer band. The clearing price is thus determined by the 101st stack's offer price of $120, which is higher than the original $100. Consequently, the USEP would also be higher.

However, with some less expensive generation (the 101st stack compared with the 2nd stack of Generator A) dispatched, the total cost of generation (as indicated by the blue shaded area) is reduced and the net benefit value (indicated by the purple shaded area) increased. The increased net benefit[2] is the difference of the generation costs between the originally "trapped" generation and its substitute (as indicated by the shadowed area).

In the same vein, if a GRF is "trapped" at RegulationMax at the beginning, the MIP-based solution would have a higher net benefit value and a lower USEP because less expensive energy would be cleared in the market.

In both cases, regardless of whether the GRF is trapped at its RegulationMin or RegulationMax, the MIP-based solution could reduce the total generation cost and increase the value of the MCE's objective function. Thus, the MIP-based solution increases economic efficiency.

Results from the one-month test have also proven that the MIP-based solution is superior. Annex 2 compares the objective function value and USEP between the two approaches. In all cases where "trapping" occurred, higher objective function values are observed in the MIP-based approach. Where no "trapping" occurred, the objective function values were equal for both methods. The total increase in objective function value during the one month test period amounted to $380,539. In terms of USEP, the biggest increase of $188.28 in USEP (change from $220.85 to $409.13) was found in the real-time dispatch run of period 4, 5th of July. The largest decline of $4.46 in USEP (change from $131.48 to $127.02) was observed in the real-time dispatch run of period 19, 19th of July. PSC and EMC have checked the prices and schedules and consider them to be the correct outcomes. Please refer to Annex 3 for more detailed analyses.

4.2 Performance Impacts

Longer solve time is expected of this new approach. Because the MCE is required to produce schedules of each type within specified time limits, we must ensure that the proposal would not have a significant impact on system performance.

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[2] In maximizing Net benefit, the MCE also takes into account reserve cost, regulation cost and violation penalties. For ease of understanding these cost has been excluded in the illustration and presumed to be similar in both the LP based approach and the MIP based approach.

Table 2 compares the solve times under the MIP based approach and the existing LP approach during the one month test period.

Table 2 MCE performance comparison

Run Type	Max Solve Time available*	MAX solve time under existing MCE during testing period	MAX solve time under MIP based MCE during testing period
Real-Time Dispatch	270s	61s	65s
Short-Term Schedule	540s	269s	290s
Pre-Dispatch Schedule	7,200s	1,140s	1,509s
Market Outlook Scenario	43,200s	3,624s	6,163s

* Max solve time available is the interval between the time that computation of the schedules begins and the time that the schedules are required to be released or published, as specified in Appendix 6A of Chapter 6 of market rules.

It can be seen that the performance of the MIP-based MCE is well within the time frame specified in the market rules. Further, because the hardware specifications of the testing server are lower, the above performance figures are a conservative estimate of the level of future MCE performance. In conclusion, the application of MIP will not have any significant negative impact on the MCE performance.

5. Conclusion

We conclude that integrating MIP into MCE would enable it to produce more optimal market outcomes that increase economic efficiency. These more optimal outcomes would be the result of reduction in generation costs. Test results have also shown that the MIP-based MCE can continue to generate schedules for each type of runs within the time frame required by the market rules.

6. Impact on Market Systems

Some changes to the EMC's IT system are required. There is no impact on any other market participant's systems.

7. Implementation process

EMC estimates that the implementation process would require approximately 8 weeks, which consists of 2 weeks for user acceptance testing, 3 weeks for parallel run of current and modified MCEs and 3 weeks for audit.

EMC's IT system will have "code freeze" from 1 November 2006 to 31 March 2007, during which there will be no code changes to the NEMS systems. The above test and audit can only be carried out after the code freeze is lifted. Hence, we suggest that the proposed rule change take effect 2 months after the code freeze.

The cost of the implementation is covered by the EMC's maintenance contract, which is already catered for in EMC's budget.

8. Consultation

We have published the rule modification proposal on the EMC website for comments. No comments have been received for consideration.

9. Legal sign-off

EMC's legal counsel has indicated that because of the technical nature of the rule modification proposal he is not able to provide a legal signoff.

10. Technical Working Group Deliberation

The TWG met to deliberate on this proposal on 10 October 2006. All TWG members unanimously agreed with the conclusion of this paper and endorsed the rule modification proposal as set out in Annex 4.

11. Recommendation

The RCP unanimously recommends that the EMC Board:

a) **adopt** the rule modification proposal as set out in Annex 4;

b. **seek** the Authority's approval for the rule modification proposal; and

c) **recommend** that the rule modification proposal come into force **five months** after the date on which the approval of the Authority is published by the EMC.

Annex 1 MIP-based Regulation Constraints

MIP1 Regulation Min $Generation - Regulation + DeficitRegGen + E * z \geq RegulationMin$
MIP2 Regulation Max $Generation + Regulation - ExcessRegGen - E * z \leq RegulationMax$
MIP3 Regulation Availability Switch at Regulation Min $Regulation - E * y_{RegMin} \leq 0$
MIP4 Generation Switch at Regulation Min $Generation - E * y_{RegMin} \leq RegulationMin$
MIP5 Regulation Availability Switch at Regulation Max $Regulation - E * y_{RegMax} \leq 0$
MIP6 Generation Switch at Regulation Max $Generation + E * y_{RegMax} \geq RegulationMax$
MIP7 Binary Restrictions $z + y_{RegMin} + y_{RegMax} = 2$

where,
E: a big positive constant number
z, y_{RegMax}, y_{RegMin}: binary integer variables of value 0 or 1.

MIP 7 constraint is an equation constraint. It ensures that at any given time only two out of these three binary variables have values of 1. This means that in total three combinations are possible:

$z = 0$, $y_{RegMax} = 1$, $y_{RegMin} = 1$	(Trapezium Area)
$z = 1$, $y_{RegMax} = 1$, $y_{RegMin} = 0$	(Segment Below Regulation Min)
$z = 1$, $y_{RegMax} = 0$, $y_{RegMin} = 1$	(Segment Above Regulation Max)

The following subsections illustrate how each of these combinations represents the different sector of the solution space as indicated in Figure 2 and Table 1.

A1.1 Trapezium Area

$z = 0, \ y_{RegMax} = 1, \ y_{RegMin} = 1$

Substitute these values into the MIP constraints we have:

$Generation - Regulation + DeficitRegGen \geq RegulationMin$	(a)
$Generation + Regulation - ExcessRegGen \leq RegulationMax$	(b)
$Regulation - E \leq 0$	(c)
$Generation - E \leq RegulationMin$	(d)
$Regulation - E \leq 0$	(e)
$Generation + E \geq RegulationMax$	(f)

Since E is a big number, constraints (c) (d) (e) and (f) are redundant, so we have:

$Generation - Regulation + DeficitRegGen \geq RegulationMin$	(a)
$Generation + Regulation - ExcessRegGen \leq RegulationMax$	(b)

It can be seen that constraints (a) and (b) are the same as the original Regulation Min/Max constraints which form the trapezium together with regulation offer limit constraint.

A1.2 Segment Below Regulation Min

$z = 1, \ y_{RegMax} = 1, \ y_{RegMin} = 0$

Substitute these values into the MIP constraints we have:

$Generation - Regulation + DeficitRegGen + E \geq RegulationMin$	(a)
$Generation + Regulation - ExcessRegGen - E \leq RegulationMax$	(b)
$Regulation \leq 0$	(c)
$Generation \leq RegulationMin$	(d)
$Regulation - E \leq 0$	(e)
$Generation + E \geq RegulationMax$	(f)

Similarly since E is a big number, constraints (a) (b) (e) and (f) are redundant, so we have:

$\text{Regulation} \leq 0$	(c)
$\text{Generation} \leq \text{RegulationMin}$	(d)

These constraints represent the regulation segment below the Regulation Min where the GRF ramps below Regulation Min and providing no regulation.

A1.3 Segment Above Regulation Max

$z = 1,\ y_{RegMax} = 0,\ y_{RegMin} = 1$

Substitute these values into the MIP constraints we have:

$\text{Generation} - \text{Regulation} + \text{DeficitRegGen} + E \geq \text{RegulationMin}$	(a)
$\text{Generation} + \text{Regulation} - \text{ExcessRegGen} - E \leq \text{RegulationMax}$	(b)
$\text{Regulation} - E \leq 0$	(c)
$\text{Generation} - E \leq \text{RegulationMin}$	(d)
$\text{Regulation} \leq 0$	(e)
$\text{Generation} \geq \text{RegulationMax}$	(f)

Similarly since E is a big number, constraints (a) (b) (c) and (d) are redundant, so we have:

$\text{Regulation} \leq 0$	(e)
$\text{Generation} \geq \text{RegulationMax}$	(f)

These constraints represent the regulation segment above the Regulation Max where the GRF ramps above Regulation Max and also providing no regulation.

For both cases in A1.2 and A1.3 where the GRF is not scheduled for regulation, the new constraints allow the generation to be scheduled below RegulationMin and above RegulationMax. This way, the generating GRF would not be trapped any more.

Annex 2 Net Benefit and USEP Difference between Testing and Production

A2.1 Net Benefit Difference Summary
(Test minus Production)

RUN_DATE	Min Diff	Avg Diff	Max Diff	Total Diff
6/27/2006	$305.17	$3,895.60	$9,237.35	$38,955.99
6/28/2006	$0.00	$1,320.60	$3,191.78	$7,923.60
6/29/2006	$0.00	$432.68	$908.45	$3,894.08
6/30/2006	$0.00	$1,092.60	$3,011.63	$3,277.79
7/1/2006	$0.00	$180.44	$657.56	$902.18
7/2/2006	$0.00	$629.41	$1,300.84	$3,776.43
7/3/2006	$0.00	$976.05	$2,495.32	$7,808.43
7/4/2006	$0.00	$3,408.42	$12,453.05	$47,717.81
7/5/2006	$0.00	$1,988.97	$4,965.07	$11,933.81
7/6/2006	$0.00	$6,807.51	$17,412.24	$142,957.74
7/7/2006	$0.00	$655.66	$2,330.17	$15,080.28
7/8/2006	$0.00	$82.95	$181.45	$1,244.25
7/9/2006	$0.00	$1,115.67	$7,014.61	$29,007.50
7/10/2006	$0.00	$583.98	$1,538.49	$10,511.59
7/11/2006	$0.00	$70.64	$571.22	$1,130.20
7/12/2006	$0.00	$577.42	$2,928.16	$5,196.79
7/14/2006	$0.00	$947.67	$2,126.30	$3,790.66
7/15/2006	$0.00	$449.38	$784.98	$1,797.53
7/16/2006	$0.00	$1,530.30	$4,316.61	$27,545.39
7/17/2006	$0.00	$448.00	$907.04	$5,376.05
7/18/2006	$0.00	$282.67	$904.66	$1,696.03
7/19/2006	$0.00	$141.75	$886.95	$1,133.99
7/20/2006	$0.00	$716.45	$2,992.26	$7,880.91
Grand Total	$0.00	$1,474.96	$17,412.24	$380,539.03

A2.2 USEP Difference Summary
(Test minus Production)

RUN_DATE	Min Diff	Avg Diff	Max Diff
6/27/2006	-$0.04	$7.17	$35.59
6/28/2006	$0.00	$0.50	$1.58
6/29/2006	$0.00	$1.59	$5.12
6/30/2006	$0.00	$62.07	$121.71
7/1/2006	$0.00	$0.00	$0.00
7/2/2006	$0.00	$0.58	$1.79
7/3/2006	$0.00	$0.87	$4.47
7/4/2006	$0.00	$0.80	$3.91
7/5/2006	$0.00	$34.32	$188.28
7/6/2006	$0.00	$5.30	$24.89
7/7/2006	$0.00	$3.57	$19.54
7/8/2006	-$0.27	$2.23	$11.98
7/9/2006	$0.00	$7.59	$134.05
7/10/2006	$0.00	$0.47	$3.02
7/11/2006	$0.00	$0.32	$5.15
7/12/2006	$0.00	$0.04	$0.39
7/14/2006	$0.00	$0.66	$1.61
7/15/2006	$0.00	$0.12	$0.49
7/16/2006	$0.00	$3.70	$35.17

7/17/2006	-$0.80	$0.57	$5.84
7/18/2006	$0.00	$0.30	$1.73
7/19/2006	-$4.46	-$0.23	$2.60
7/20/2006	$0.00	$0.92	$7.46
Grand Total	-$4.46	$3.98	$188.28

Annex 3: Case Studies into USEP Changes

Case 1: Increase in USEP (GRF "trapped" at RegulationMin)

The largest difference of $188.28 in USEP was observed in the real time dispatch schedule of P04 05 Jul 2006. In this period, USEP rose from $220.85 using the current MCE to $409.13 using the MIP-based MCE.

The following are the differences in generation schedules between the test (MIP-based MCE) and production (LP-based MCE).

GRF	RegMin	Prod Schedule MW	Prod Last Cleared Blk Price	Prod MEP	Test Schedule MW	Test Last Cleared Blk Price	Diff MW
G1	190	190	$404.50	$219.74	173.194	$404.50	-16.806
G2	190	170	$139	$219.77	175	$404.50	5
G3	120	167.789	$177	$218.76	172.62	$187	4.831
G4	140	212.237	$135	$218.87	220.536	$138	8.299
G5	232	320.15	$134	$219.74	318.868	$134	-1.282
						Total Diff (due to losses)	0.042

From the above table, GRF G1 was constrained on and forced to be dispatched at 190 MW in production, although its offer price at 190MW level is $404.50, which is much higher than the market clearing price. Other generators are cleared as normal, with market clearing price higher than their offer prices

In the MIP-based approach, G1 was successfully ramped down and scheduled 16MW less (173.194 MW which is below its RegulationMin). Other GRFs' schedules are adjusted accordingly to balance out the difference. The total generation remains almost unchanged. The slight difference of 0.042MW is the difference in the transmission losses due to redistribution of load flows.

The reduced generation from G1 was picked up by G2, G3 and G4 at costs ranging from $135 to $404.5. Please note that, although G1 has been ramped below the RegulationMin, the highest offer price cleared for it is still $404.5. And G2 was also cleared some energy at $404.5. This means that both G1 and G2 are cleared as the marginal unit and became price setters. Thus, USEP of 409.13 correctly reflects of the value of the marginal unit.

The reduction in the generation of G1 by 1.282MW is the result of co-optimization of reserve and energy dispatch, which is also normal.

The following table shows the differences in generation cost between the current MCE solution and the MIP-based MCE solution. Total generation cost is reduced by $2944.06 in the latter.

GRF	MW Diff	MW Diff breakdown wrt Block Prices		Cost Diff
G1	-16.806	16.806	$404.50	-$6798.027
G2	5	5	$404.50	$2022.50
G3	4.831	2.62	$187	$881.287
		2.211	$177	
G4	8.299	0.536	$138	$1121.973
		7.763	$135	
G5	-1.282	1.282	$134	-$171.788
			Total Cost Diff	-2,944.06

Case 2: Decrease in USEP (GRF "Trapped" at RegulationMax)

The largest reduction of $4.46 in USEP was observed in the real time dispatch schedule for P04 05 Jul 2006. In this period, USEP fell from $131.48 using the current MCE to $127.02 using the MIP-based MCE.

The following are the differences in generation schedules between the test (MIP-based MCE) and production (LP-based MCE).

Generation Unit	RegMax	Prod Schedule MW	Prod Last Cleared Blk Price	Test Schedule MW	Test Last Cleared Blk Price	Diff MW
G6	340	340	$101.50	350	$114.50	10
G7	250	210	$126	204	$126	-6
G8	350	279.101	$130	275	$125	-4.101
					Total Diff (due to losses)	-0.101

From the above table, GRF G6 was constrained by its RegulationMax and forced to be dispatched at 340 MW under the current MCE. In this case, GRF G8 was the marginal unit and set the price at around $130. In fact, GRF G6 can also provide another 10MW at the price of $114.5, which is lower than the market clearing price. However, because the RegulationMax constraint prevents G6 from generating more, some energy from more expensive GRFs (G7 at price of $126 and G8 at price of $130) had to be cleared to meet the demand.

In the MIP-based approach, the RegulationMax constraint on G6 was relaxed, G6 was successfully ramped up and was scheduled 10MW more. Other expensive GRFs were scheduled less accordingly to balance out the difference. As shown in the above table, in the MIP-based solution, G7 became the marginal unit and set the price at around $126, which was lower than the original market clearing price of $130.

The following table shows the differences in generation cost between the current MCE solution and the MIP-based MCE solution. Total generation cost was reduced by $261.13 in the latter.

GRF	MW Diff	MW Diff breakdown wrt Block Prices		Cost Diff
G6	10	9	$101.50	$1028
		1	$114.50	
G7	-6	-6	$126	-$756
G8	-4.101	-4.101	$130	-$533.13
			Total Generation Cost Diff	- $261.13

Annex 4 Proposed Modification to the Market Rules

Existing Rule/Comments	**Proposed Rules** (Deletion represented by strikethrough text and addition underlined.)	**Reasons for Modification**
	CHAPTER 6 **APPENDIX D MARKET CLEARING FORMULATION** **SECTION A: DEFINITIONS**	
	D.3 PARAMETERS InfinitePositiveValue: A relatively large positive value applied in section D.18.3 as a slack value. **D.4 VARIABLES** RegulationSegmentSelector1$_l$, RegulationSegmentSelector2$_l$, RegulationSegmentSelector3$_l$: Binary integer variables associated with *regulation offer l*, used for modeling of regulation-generation constraints in section D.18.3,	To define the new parameter and variables that are to be used in 6D. 18.3.
D.13A REGULATION RANGE CONSTRAINTS D.13A.1 A valid *regulation offer* shall only be used in the linear program if: D.13A.1.1 a valid *energy offer* exists for the *generation registered facility* for that period and the sum of the quantities in that *energy offer* is greater than or equal to RegulationMin$_g$ for the relevant *generation registered facility*; D.13A.1.2 the StartGeneration$_g$ of the relevant *generation registered facility* is greater than RegulationMin$_g$ for the relevant *generation registered facility*; and D.13A.1.3 the StartGeneration$_g$ of the relevant *generation registered facility* is less than or equal to RegulationMax$_g$ for the relevant *generation registered facility*.	**D.13A REGULATION RANGE CONSTRAINTS** D.13A.1 A valid *regulation offer* shall only be used in the linear program if: D.13A.1.1 a valid *energy offer* exists for the *generation registered facility* for that *dispatch period* and the sum of the quantities in that *energy offer* is greater than ~~or equal to~~ RegulationMin$_g$ for the relevant *generation registered facility*; D.13A.1.2 the StartGeneration$_g$ of the relevant *generation registered facility* is greater than or equal to RegulationMin$_g$ for the relevant *generation registered facility*; and D.13A.1.3 the StartGeneration$_g$ of the relevant *generation registered facility* is less than or equal to RegulationMax$_g$ for the relevant *generation registered facility*.	Due to regulation constraints, a *generation registered facility* whose total *energy offer* quantity is equal to RegulationMin would effectively not be dispatched to provide any *regulation*. Thus, it should not be pre-qualified to provide *regulation*. *Generation registered facility* with *StartGeneration* equal to *RegulationMin* is able to provide *regulation* and thus should be qualified as *regulation* provider.
Explanatory Note: Alternative tests could have been StartGeneration$_g$ + UpRampRate$_g$ x RemainingTime > RegulationMin$_g$, and StartGeneration$_g$ - DownRampRate$_g$ x RemainingTime < RegulationMax$_g$ which would ensure that the facility could provide the regulation at the end of the dispatch period. However, the current rules are more conservative, and are designed so that regulation can be provided throughout the dispatch period.	**Explanatory Note: Alternative tests could have been StartGeneration$_g$ + UpRampRate$_g$ x RemainingTime > RegulationMin$_g$, and StartGeneration$_g$ - DownRampRate$_g$ x RemainingTime < RegulationMax$_g$ which would ensure that the facility could provide the regulation at the end of the dispatch period. However, the current rules are more conservative, and are designed so that regulation can be provided throughout the dispatch period.**	

Existing Rule/Comments	**Proposed Rules** (Deletion represented by strikethrough text and addition underlined.)	**Reasons for Modification**
	D.18 REGULATION D.18.3 Mixed Integer Program Based Regulation Constraints The provisions of this section shall apply only to a re-solve of the linear program under section D.21A.2 or section D.22.7 where applicable. In such a re-solve, sections D.18.3.1 to D.18.3.7 shall replace sections D.18.1.3 and D.18.1.4. D.18.3.1 Mixed Integer Program Based Regulation Max Constraint $\text{Generation}_{g(l)} + \text{Regulation}_l - \text{ExcessRegGen}_l - \text{InfinitePositiveValue} \times \text{RegulationSegmentSelector2}_l \le \text{RegulationMax}_{g(l)}$ $\{l \in \text{REGULATIONOFFERS}\}$ D.18.3.2 Mixed Integer Program Based Regulation Min Constraint $\text{Generation}_{g(l)} - \text{Regulation}_l + \text{DeficitRegGen}_l + \text{InfinitePositiveValue} \times \text{RegulationSegmentSelector2}_l \ge \text{RegulationMin}_{g(l)}$ $\{l \in \text{REGULATIONOFFERS}\}$ D.18.3.3 Regulation Availability Determination at Regulation Max $\text{Regulation}_l - \text{InfinitePositiveValue} \times \text{RegulationSegmentSelector3}_l \le 0$ $\{l \in \text{REGULATION OFFERS}\}$ D.18.3.4 Regulation Availability Determination at Regulation Min $\text{Regulation}_l - \text{InfinitePositiveValue} \times \text{RegulationSegmentSelector1}_l \le 0$ $\{l \in \text{REGULATIONOFFERS}\}$ D.18.3.5 Generation Switch at Regulation Max $\text{Generation}_{g(l)} + \text{InfinitePositiveValue} \times \text{RegulationSegmentSelector3}_l \ge \text{RegulationMax}_{g(l)}$ $\{l \in \text{REGULATIONOFFERS}\}$ D.18.3.6 Generation Switch at Regulation Min $\text{Generation}_{g(l)} + \text{InfinitePositiveValue} \times \text{RegulationSegmentSelector1}_l \le \text{RegulationMin}_{g(l)}$ $\{l \in \text{REGULATIONOFFERS}\}$ D.18.3.7 Regulation Segment Selectors Restrictions $\text{RegulationSegmentSelector1}_l + \text{RegulationSegmentSelector2}_l + \text{RegulationSegmentSelector3}_l = 2$ $\{l \in \text{REGULATIONOFFERS}\}$	To add the proposed Mixed Integer Program based regulation constraints into the MCE formulation.

Existing Rule/Comments	**Proposed Rules** (Deletion represented by strikethrough text and addition underlined.)	REASONS FOR MODIFICATION
	SECTION D: POST-PROCESSING **D.21A REGULATION ANOMALY CORRECTION** D.21A.1 After each solution of the linear program which did not involve the use of the constraints set out in sections D.18.3.1 to D.18.3.7, the *EMC* shall carry out the procedures in section D.21A.2 to the extent provided in this section D.21A. D.21A.2 If the following condition: $Generation_{g(l)} = RegulationMin_{g(l)}$ or $Generation_{g(l)} = RegulationMax_{g(l)}$ $\{ l \in REGULATIONOFFERS \}$ is true for any *generation registered facility*, then the linear program shall be re-solved with the constraints set out in sections D.18.3.1 to D.18.3.7 in lieu of the constraints set out in sections D.18.1.3 and D.18.1.4.	To create a regulation anomaly correction process.
D.22 LOSS CALCULATION CORRECTION D.22.2 After each solution of the linear program, the *EMC* shall carry out the procedures in sections D.22.3 to D.22.7 to the extent provided in those sections. However, the *EMC* shall not do so if any of the line violation variables, $ExcessLineFlowForward_k$, $ExcessLineFlowReverse_k$, $DeficitWLineFlow_k$ or $ExcessWLineFlow_k$, for any *dispatch network line k* is greater than zero.	**D.22 LOSS CALCULATION CORRECTION** D22.2 ~~After each solution of the linear program~~ After complying with the procedures in section D.21A, the *EMC* shall carry out the procedures in sections D.22.3 to D.22.7 to the extent provided in those sections. However, the *EMC* shall not do so if any of the line violation variables, $ExcessLineFlowForward_k$, $ExcessLineFlowReverse_k$, $DeficitWLineFlow_k$ or $ExcessWLineFlow_k$, for any *dispatch network line k* is greater than zero.	To reflect changes to the market clearing procedure required for regulation anomaly correction. Please refer to Figure 3 of for the market clearing procedure.
D.22.7 The re-defined set of line flow/line loss points determined in section D.22.6 for each *dispatch network line* shall be used to re-solve the linear program.	D.22.7 The re-defined set of line flow/line loss points determined in section D.22.6 for each *dispatch network line* shall be used to re-solve the linear program for the given *dispatch period* in the given run of the *market clearing engine*. In so re-solving the linear program under this section D.22.7, if the constraints set out in sections D.18.3.1 to D.18.3.7 had earlier been used in re-solving the linear program for that given *dispatch period* in the given run of the *market clearing engine*, then the constraints set out in sections D.18.3.1 to D.18.3.7 shall be used again in re-solving the linear program (in lieu of the constraints set out in sections D.18.1.3 and D.18.1.4).	