FINANCIAL IMPACTS OF CONGESTION RELIEF MEASURES UNDER ELECTRICITY DEREGULATION

Cherry Yuen
Corporate Research
ABB Switzerland Ltd
cherry.yuen@ch.abb.com

Jiuping Pan
Corporate Research
ABB (USA) Inc.
jiuping.pan@us.abb.com

Qianjin Liu
Corporate Research
ABB (China) Ltd.
qianjin.liu@cn.abb.com

Abstract – This paper aims at evaluating the financial benefits brought about by congestion relief measures under deregulated environment. The paper looks into the difference of economic impacts under different congestion charging mechanisms, using an example set on a province in China, which is undergoing electricity deregulation. Two representative congestion mechanisms will be investigated: one takes fully into account transmission constraints and one does not.

Keywords: congestion management, electricity deregulation, locational marginal pricing, congestion uplift, congestion relief

1 INTRODUCTION

Owing to new and uncertain business environment, deregulation has become an obstacle to the upgrade of power transmission facilities. The two questions that are often asked are: who will benefit and how much net profit there will be if transmission facilities are upgraded. This paper addresses these two issues and estimates the net benefits for the whole system and financial impacts on various categories of market participants.

This paper aims at evaluating the financial impacts brought about by congestion relief measures under deregulated environment. The paper looks into the difference of economic impacts on different players under different congestion charging mechanisms, using a network of a province in China. Two representative congestion mechanisms will be investigated: one taking fully into account transmission constraints and one not. A typical example of market settlement mechanism taking into account power transmission constraints is Locational Marginal Pricing (LMP), which is widely adopted by various regional markets in the USA[1]. A contrasting pricing mechanism is the one that employs a "congestion uplift" which accounts for the total congestion costs for the whole system. This uplift is an additional component to the system marginal price. A uniform final market price will then be applied to all parties in the market. This pricing mechanism is used in some European countries, e.g. England [1] and Spain [2].

The simulations for the Chinese provincial system study are done using an energy market simulation tool. The simulations are accomplished under different scenarios so that congestion costs are calculated for cases under different system security levels: no constraints respected, only fixed MW transmission constraints respected (thermal limits, voltage stability), and both transmission constraints and n-1 contingencies respected. The results of the different benefits and impacts arising from different types and levels of congestion relieves are then presented. It should be noted that the exact means of congestion relief are not specified, which is not the emphasis of this paper. Nevertheless, the focus is on the comparison of financial impacts when there are different degrees of relief under various scenarios. It should also be noted that for illustration purposes, active power losses are not modeled in the simulation cases.

The structure of this paper is as follows. This introductory part is followed by the description of the two congestion pricing mechanisms, illustrated with a simple network. Then comes the real case study and results presentation. The conclusions are at the end.

2 CONGESTION PRICING MECHANISMS

In this section the two congestion pricing mechanisms, namely LMP and "congestion uplift" will be explained, with the help of an example based on a simple network. These two mechanisms are chosen for this paper because they represent two extreme cases. In the LMP method, every single node in the network can have a different price due to congestion. On the other hand, the "congestion uplift" method has only one price zone in the whole market and therefore all consumers are charged with a uniform price [3]. In the energy markets worldwide, there also exist other forms of congestion management or pricing mechanisms that lie in between these two extremities because the whole market is divided into different price zones or areas. For example, zonal pricing is employed by CAISO [4] while area pricing is employed in the Nordic Spot Market [5].

2.1 Locational Marginal Pricing (LMP)

LMP is based on Optimal Spot Pricing [6]. Its main strength is its ability to give locational price signals that well address the short-term problems of the transmission network, i.e. constraints. However, the nodal price differences might not give the right

[1] Nodal pricing is employed by PJM, ISO New England and NYISO, while CAISO is adapting some kind of variant of nodal pricing.

incentives for transmission investments or expansion [7].

In general, nodal prices are found by the maximization of the social welfare while taking into account the various constraints imposed by energy balance and the transmission system. Social welfare is defined as the sum of the consumer surplus and supplier profit. Assuming inelastic demand and price-taking generation owners[2], the formulation can be simplified to the following:

$$\min \sum C(S) \tag{1}$$

s.t. $g(x, S) = 0$

& $h(x, S) \leq 0$

where

S = scheduled despatch of the generators

C = cost function of the generators

x = network parameters

g = various equality constraints

h = various inequality constraints

Under LMP, each node in the transmission system can have its own price and generators and loads are also paid and charged according to their locations. An implication that arises from this is the following:

$$\sum GeneratorCosts \leq \sum GeneratorRevenues \leq \sum LoadPayments \tag{2}$$

Here, the total generator costs represent the generator bids, and these two items would equal each other in real markets when generators are bidding at their marginal costs. This inequality relationship stated in (2) will be further illustrated in the example at the end of this section. In fact, the difference between total load payments and generator revenues is the so called "congestion surplus" and has been one of main issues resulting from the implementation of LMP [8].

2.2 Congestion Uplift

An uplift or an additional premium that is added to the system marginal cost to account for the additional costs the system operator has to pay to generators to ensure system security, very often related to constraints due to operating limits of the transmission lines. In this paper we only focus on "Congestion Uplift".

The characteristic of this congestion management mechanism is that everybody is charged the same despite of their variation of contributions to the congestion. Therefore it gives no locational signals to the network users regarding which part or where of the transmission system should be strengthened.

In principle, the "Uplift" is calculated based on the total costs required to remove congestions by turning up/on and turning down/off the generators available in the balancing market. These costs that have been paid by the system operator to ensure system security have to be recovered from the final market price, and therefore, at each market settlement:

$$FinalMarketPrice = SystemMarginalPrice + Uplift$$

and

$$FinalMarketPrice = \frac{\sum (GeneratorPayments + Compensations)}{\sum Demands}$$

$$Uplift = FinalMarketPrice - SystemMarginalPrice \tag{3}$$

2.3 Illustrating Example

The example with a simple network topology serves to illustrate the two aforementioned congestion management mechanisms in terms of real figures and also financial impacts on individual players in the market. Active power losses are neglected. Figure 1 shows the 2-bus network that is a typical scenario in which congestion arises: the load is separated from the cheap generator by a constrained transmission corridor, which can consist of several high voltage transmission lines. Note that in practice the actual transmission capacity might not be just restricted by thermal limit, but also by transient and voltage security constraints.

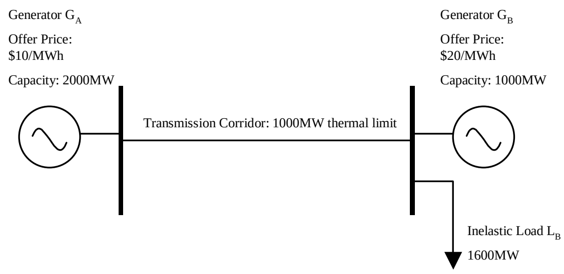
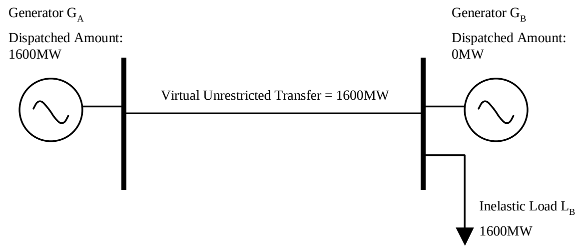
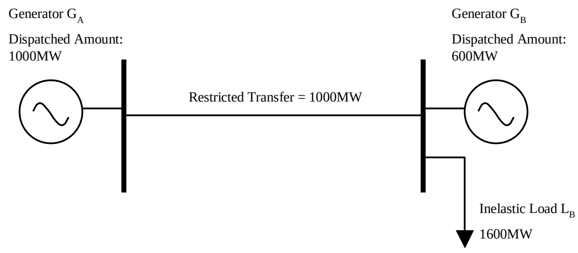


Figure 1 **2-bus network for illustration**

Figure 2 shows the different dispatch patterns. Figure 2a shows a virtual dispatch in which no transmission constraints are taken into account while Figure 2b shows the final allowed dispatch when transmission constraints are considered.



(a) Unrestricted Dispatch



(b) Constrained Dispatch

Figure 2 **Dispatch Patterns without and with Transmission Constraints**

---

2 Note that these assumptions do not alter the conclusions of our studies on the comparison of different congestion management mechanisms.

2.3.1 LMP

The settlement for the generators and the load is according to the nodal prices of the system. In this case, the nodal prices at bus A and bus B are 10$/MWh and 20$/MWh respectively. The revenues and payments for different parties are listed in Table 1.

		k$/h
Generator G_A	1000MW x 10$/MWh	10
Generator G_B	600MW x 20$/MWh	12
Total Revenue		**22**
Load L_B	1600MW x 20$/MWh	32
Total Payment		**32**
Congestion Surplus	**32k – 22k**	**10**

Table 1 LMP Settlement Figures for Different Parties

As observed from the table, congestion surplus is resulted when the total revenue of generators is smaller than the total payment of the load. This is because of the fact that only a portion of the demand (600MW) is provided by the more expensive generator, but nevertheless the whole quantity of demand is charged at the price of the expensive node. This illustrates the second part of the inequality stated in (2). For the other part of the inequality, i.e. the total generator revenue being larger than the total generator operating costs, it is not explicitly illustrated. But it would become obvious if there was another additional generator at bus B which has a capacity less than 600MW and is cheaper than G_B but more expensive than G_A. In this case since this additional generator would be paid the nodal price which is set by G_B, it would be paid more than its costs/bids. This will be more clearly manifested in the real case studies.

2.3.2 Congestion Uplift

To find out the congestion uplift, it is necessary to work out first the redispatch costs. Here it is assumed that for both generators they are paid or compensated at their offer prices. The settlement is shown in Table 2.

System Marginal Price	10$/MWh	
Generator G_A Unconstrained Payment	1600MW x 10$/MWh	16 k$/h
Generator G_A Constrained Payment	1000MW x 10$/MWh	10 k$/h
Generator G_A Constrained-off Compensation	16k – 10k	6 k$/h
Generator G_A Total Revenue	6k +10k	16 k$/h
Generator G_B Unconstrained Payment	0MW x 20$/MWh	0
Generator G_B Constrained-on Payment	600MW x 20$/MWh	12 k$/h
Total Revenue		**28** k$/h
Total Redispatch Cost (Constrained – Unconstrained Payment)	28k – 16k	12 k$/h
Final Market Price	28k$/h / 1600MW	17.5 $/MWh
Congestion Uplift	(17.5 – 10) $/MWh	7.5 $/MWh
Load L_B	1600MW x 17.5$/MWh	28 k$/h
Total Payment		**28** k$/h

Table 2 Uplift Settlement Figures for Different Parties

As shown from the table, the aim of the uplift is to compensate the additional costs for constrained-on and constrained-off payments. The constrained-off compensation is to compensate the “loss-of-opportunity” of generator G_A. In some markets this is not implemented and if applied in this example, it means that only generator G_B would be compensated and that the total redispatch cost would be 12+10-16 = 6 k$ instead of 12 k$ (light-shaded cells). In this case, the total generators’ revenue would be equal to 22 k$/h, the same as in the LMP case.

It should be noted that under this congestion management mechanism, the total revenue for generators is higher than that from LMP while the total load payment is less than that from LMP. Also, there is no net congestion surplus. Table 3 shows the differences between LMP and Congestion Uplift settlements.

	LMP	Congestion Uplift	Difference (Uplift-LMP)
Generator G_A	10	16	+6
Generator G_B	12	12	0
Load L_B	32	28	-4
Congestion Surplus	10	0	-10

Table 3 Comparison of LMP and Congestion Uplift (k$/h)

3 REAL CASE STUDIES

3.1 Introduction

The financial impact analysis is done in this section with the use of simulations based on a real network topology. A province from China is chosen which can represent the general situation of the Chinese power system: heavy demand in the East is linked via the transmission system to the abundant power stations in the West. The simulations are done with data based on year 2003. The summer peak and annual energy consumption of the system are 17,373 MW and 106,097 GWh respectively, approximating an annual load factor of 70%. The installed generation capacity is 23,150 MW. The network has 433 buses and the highest transmission voltage level is 525 kV. The simplified representation of the network which shows only the high voltage lines is shown in Figure 3. It also shows the location of the coal mines and the generators which use imported coal.

The financial results presented are accumulations of the market settlement outcomes over one year period assuming that the market settles every hour of the day, i.e. total number of settlements is 8760. The simulations are done using an energy market simulation tool that takes into account the full model of the transmission network [9]. This tool, GridView, is a software developed by ABB Inc. to simulate the operation of competitive electric power markets, based on fundamental costs, market protocols and contractual arrangements subject to realistic transmission constraints. The core of the program is security-constrained optimal unit commitment and economic dispatch based on the costs/bid information of each generator.

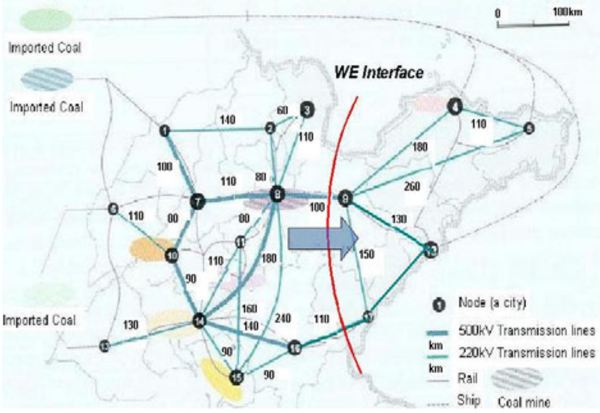


Figure 3 **Simplified Representation of the Chinese Provincial Network**

The assumptions of the simulations are stated as follows. In this province, thermal power dominates and the negligible amount of hydro power is not modeled. The difference of costs among the thermal generators is due to their different distances from the locations of the coal mines or resources (Figure 3). Most of the coal mines are located in the west, as a result the transportation costs for the eastern generators are higher [10]. Moreover, the generators are assumed to bid using their correspondingly production costs. For the demand curve, the system demand curve for year 2003 was used, and is distributed proportionally to the load buses throughout the system.

3.2 Transmission Congestion Analysis

In this subsection, three different scenarios are simulated: the first one considers no transmission constraints at all, the second considers only fixed MW transmission constraints, such as those set by thermal limits, transient or voltage-security limits, the third one considers both the fixed MW constraints as well as respecting n-1 contingencies.

The first scenario with no consideration of transmission limits will show the unconstrained schedules of generation and will give the minimum total system production cost. In this scenario, the power flow on the monitored transmission corridor can be used as an indication of desired transfer capability. The transmission corridor, which consists of several major transmission lines connecting the west and the east regions, has in fact a limit of transfer of about 2200MW because of voltage security issues. This corridor will be called WE- Interface from now on and is marked on Figure 3. In the second and third scenarios, this limit together with those of other transmission lines will be respected.

3.2.1 Scenario 1: No Transmission Constraints

In this case all the transmission constraints are ignored and it results in an unconstrained dispatch. The yearly averaged simulations results are shown in Table 4 while Figure 4 and Figure 5 show the power flow on the WE-Interface and SMP for each hour of 2003.

System Marginal Price (SMP)	12.39 $/MWh
Total System Production Cost	1200.13 M$
Averaged Total Flow on WE-Interface	2819.40MW

Table 4 **Annual Averaged Results for Scenario 1**

From Figure 4 one can also see that even though the flow can be as high as 4000MW but most of the times it does not get more than 3500MW. Moreover, owing to the constraints of other transmission lines, the actual unrestricted flow on the interface is even less. Taking this into consideration, 3000MW will be used as the target of maximum desired transfer capacity for congestion relief.

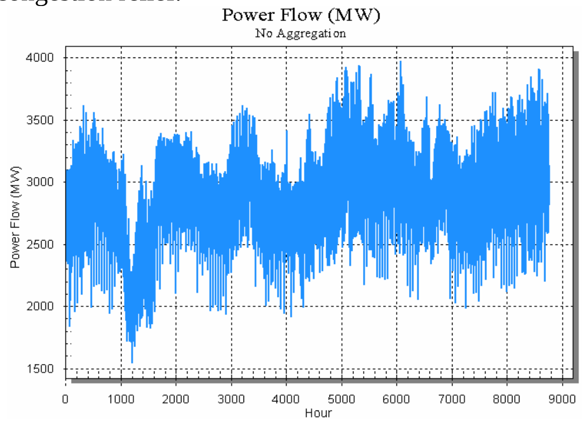


Figure 4 **Unrestricted Power Flow on WE-Interface**

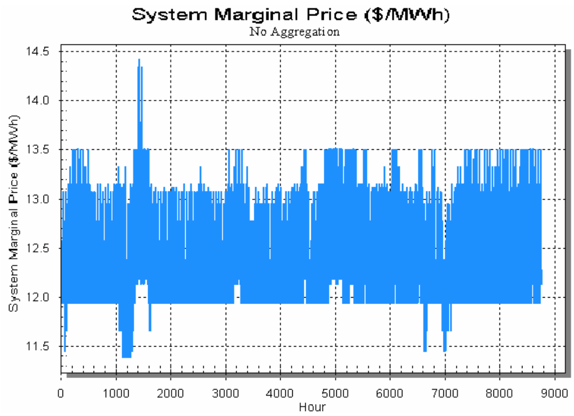


Figure 5 **System Marginal Price**

3.2.2 Scenario 2: Fixed MW Transmission Constraints

In this scenario, the WE-Interface limit of 2200MW set by voltage security constraint and the constraints on all the other transmission lines are respected during the simulations. The effect is that the heavy loads on the east side of the province will not be able to profit as much from the cheap generation on the west side as before. Congestion takes place and the more expensive generators in the east side will be dispatched. This will result in a higher averaged price on the east side than its west counterpart. Table 5 shows the simulation results. In addition to the averaged system results, two regions, namely Western and Eastern regions separated by the WE-Interface, are also defined for better result presentation and analysis.

System Marginal Price (SMP)	12.51 $/MWh
Total System Production Cost	1205.09 M$
Averaged LMP Western Region	12.27 $/MWh
Averaged LMP Eastern Region	13.25 $/MWh
Averaged Total Flow on WE-Interface	2192.84 MW
Total Generator Revenue	1322.79 M$
Total Load Payment	1344.97 M$

Table 5 Annual Averaged Results for Scenario 2

The comparison results between LMP and Congestion Uplift are shown in Table 6. With the implementation of LMP methodology, the total generator revenue is less than the total load payment, exhibiting again the inequality relationship as stated in (2). The congestion surplus would be equal to load payment - generator revenue = 22.18 M$. With the implementation of Uplift methodology and the assumptions that all generators are bidding at their production cost and that constrained-off compensation is not implemented (section 2.3.2), the revenue is equal to the total production cost. In this case, the total system redispatch cost is 1205.09-1200.13 = 4.96 M$ (Table 4 and Table 6).

(All in unit M$)	LMP	Congestion Uplift	Difference (Uplift-LMP)
Generator Revenue	1322.79	1205.09	-117.7
Load Payment	1344.97	1205.09	-139.88
Congestion Surplus	22.18	0	-22.18

Table 6 Results Comparison for Different Methodologies

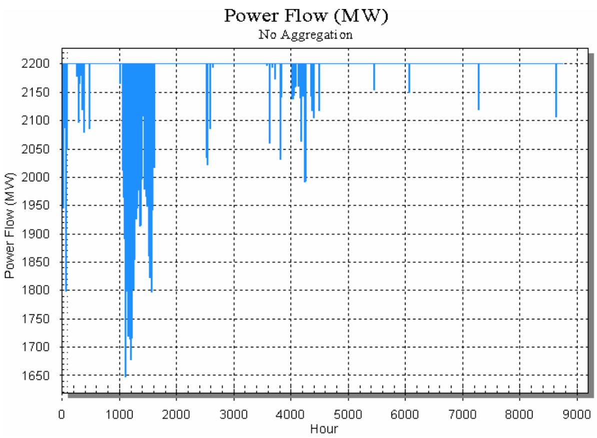


Figure 6 Restricted Power Flow on WE-Interface

Figure 6 shows the restricted flow on the WE-Interface. It also shows the severity of congestion when no relief measures are implemented. Figure 7 shows the averaged LMPs of the Western and Eastern regions. As mentioned in section 3.1, the prices in the Western region are lower than those of Eastern region because of the cheaper coal in that region.

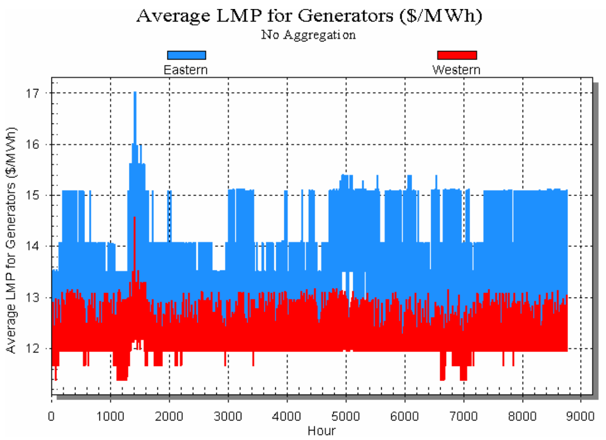


Figure 7 Averaged LMPs for both Regions

3.2.3 Scenario 3: Both Transmission Constraints and n-1 Contingencies

In this scenario, in addition to the constraints in scenario 2, n-1 contingency is also respected. Two critical 525kV transmission lines chosen for contingency analysis are two that run almost parallel to each other, located in the west region and are not part of the WE-Interface. It poses the additional constraint since the optimal dispatch cannot result in overload of the monitored line when the other line is out in contingency, and vice versa.

System Marginal Price (SMP)	12.53 $/MWh
Total System Production Cost	1205.29 M$
Averaged LMP Western Region	12.29 $/MWh
Averaged LMP Eastern Region	13.27 $/MWh
Averaged Total Flow on WE-Interface	2192.69 MW

Table 7 Annual Averaged Results for Scenario 3

Comparing the values in Table 5 and Table 7, it can be observed that there is a slight increase of prices for both Western and Eastern regions when n-1 contingency constraints are respected. It should be noted that there would be more increases in prices when more lines are included in the n-1 contingency analysis. Figure 8 shows the flow on the monitored lines during the two contingencies.

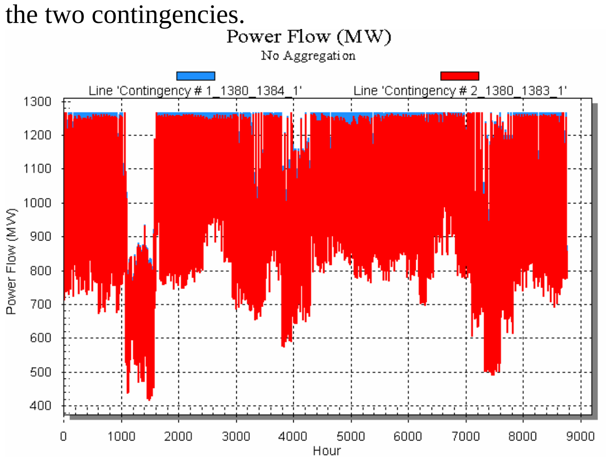


Figure 8 Power Flow on Monitored Lines during Contingencies

3.3 *Congestion Relief Analysis*

In this last subsection, in order to see the financial impacts on different market players arising from various degrees of congestion relief, this corridor transmission limit will be increased stepwise of 100MW from 2200MW until 3000MW. Practically, the transmission system operator can increase transfer capacity incrementally through the use of reactive power compensation devices. For example, installing adequate SVCs in some selected locations in the eastern region would effectively mitigate the voltage security problems and thus enables increased west to east power transfer (up to a few hundreds MWs) through the transmission corridor. An obvious alternative would be adding a new high-voltage transmission line.

The analysis is done based on scenario 2 as mentioned in section 3.2.2. In fact the results from scenarios 2 and 3 would be similar, because the 2 lines considered in the contingency analysis are not part of the WE-Interface. Because of the numerous individuals in this market (122 generators and 410 loads), the impact analysis is done at the aggregated level of generators and loads located at the eastern region and the western region. The third player is the Independent System Operator who is more concerned with the overall congestion cost savings estimated by the reduced system production cost from improved network transfer capability.

Table 8 shows the impact of congestion relief on system dispatch where the congestion cost savings are calculated as the difference of the total system production costs without any congestion relief and with a certain degree of congestion relief. Obviously, improved WE-Interface transfer capability reduces the number of congestion hours and the total system production cost. The annual congestion cost savings at the target of desired transfer capability (i.e., 3000MW) are estimated as 3.5 M$. Note that the congestion cost savings are significant up to a capacity level of 2700MW , as shown in Figure 9. Beyond that capacity level, the economic value of congestion relief becomes less significant. This suggests that the effective target of transfer capacity for congestion relief might be set at 2700MW instead of 3000MW. At this capacity level, a system wide production cost savings of 3.24 M$ can be achieved and the number of congestion hours can be reduced by more than 3000 hours.

WE-Interface Limit (MW)	Congestion Hours (Hrs)	Total System Production Cost (M$)	Congestion Cost Savings (M$)
2200	8438	1205.09	---
2300	8264	1204.18	0.91
2400	7965	1203.38	1.71
2500	7253	1202.74	2.35
2600	6210	1202.23	2.86
2700	5085	1201.86	3.24
2800	2938	1201.72	3.37
2900	1253	1201.62	3.47
3000	320	1201.59	3.50

Table 8 **Impact of Congestion Relief on System Dispatch**

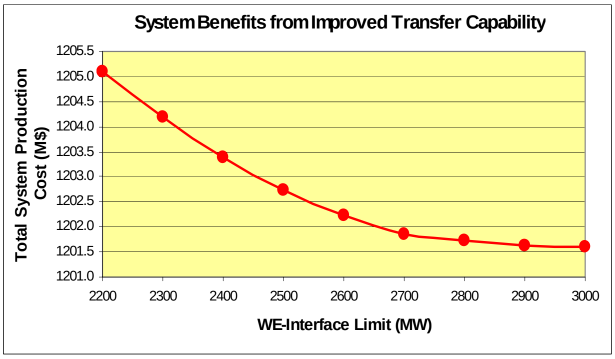


Figure 9 **Impact of Congestion Relief on Total System Production Cost**

In addition to the congestion relief of the concerned WE-Interface, further system benefits can be achieved if appropriate expansion options are implemented for the other congested transmission lines throughout the system. Congestion relief analysis concerning these individual lines will not be discussed in this paper.

Table 9 shows the economic impact analysis for transmission customers under the implementation of LMP methodology. The following observations and conclusions can be obtained:

- Congestion relief measures decrease the LMP difference between the two regions, resulting from decreased LMP in the eastern region and increased LMP in the western region.
- Improved WE-Interface transfer capability allows more power to be delivered from the low-cost western region to the high-cost eastern region, resulting in reduced generation in the eastern region and increased generation in the western region.
- Generators in the western region will see increased revenue as a combined result of increased generation and increased energy prices. On the other hand, generators in the eastern region will see reduced revenue as a combined result of reduced generation and decreased energy prices.
- Loads in the eastern region will see reduced payment as a result of reduced energy prices. On the other hand, loads in the western region will see increased payment as a result of increased energy prices. For example, when the WE-Interface limit is improved from 2200MW to 2700MW, the reduced load payment for the eastern region is about 17 M$ while the increased load payment for the western region is about 7 M$.

Interface Limit (MW)	Average LMP ($/MWh)	Total Generation (GWh)	Generation Revenue (M$)	Load Payment (M$)
	Eastern Region			
2200	13.25	14481	195.6	450.3
2300	13.15	13641	182.8	446.6
2400	13.04	12820	170.4	442.7
2500	12.93	12049	158.9	439.0
2600	12.83	11363	148.8	435.5
2700	12.77	10779	140.6	433.3
2800	12.72	10414	135.3	431.6
2900	12.69	10195	132.2	430.7
3000	12.68	10113	131.1	430.4
	Western Region			
2200	12.29	91616	1127.2	894.7
2300	12.31	92455	1139.7	896.2
2400	12.33	93277	1151.8	897.5
2500	12.36	94048	1163.7	899.3
2600	12.37	94733	1173.9	900.6
2700	12.38	95318	1182.5	901.6
2800	12.41	95683	1189.2	903.3
2900	12.41	95902	1192.9	903.9
3000	12.41	95983	1193.8	903.8

Table 9 **Impact Analysis under LMP Methodology**

Table 10 shows the economic impact analysis with the implementation of Uplift methodology and the assumptions stated in Section 3.2.2. Under this congestion management mechanism, the total revenue for generators or the total payment by loads is equal to the total system production cost. Improved transfer capability allows for more generation from less expensive power plants in the western region being dispatched and therefore reduces the total system production cost as well as the system redispatch cost. It should be noted that the total system redispatch cost is found by the difference of the generator revenue (total production cost) for the respective restricted case and that from non-restricted case (Table 4).

WE-Interface Limit (MW)	Generator Revenue (M$)	Load Payment (M$)	System Redispatch Cost (M$)
2200	1205.09	1205.09	4.96
2300	1204.18	1204.18	4.05
2400	1203.38	1203.38	3.25
2500	1202.74	1202.74	2.61
2600	1202.23	1202.23	2.10
2700	1201.86	1201.86	1.73
2800	1201.72	1201.72	1.59
2900	1201.62	1201.62	1.49
3000	1201.59	1201.59	1.46

Table 10 **Impact Analysis under Uplift Methodology**

While the impacts on loads and generators arising from the two congestion management mechanisms can be compared and studied by referring to Table 9 and Table 10, the impact comparison on the ISO is shown in Figure 10. Even without considering how the congestion surplus arising from LMP is dealt with, the ISO should be given an incentive to reduce congestion costs. Therefore, congestion surplus and redispatch cost are selected as an indicator because they are peculiar to the LMP and Uplift mechanisms respectively. In this study scenario, it can be observed that congestion surplus is always larger than redispatch cost. Moreover, congestion surplus is decreasing more rapidly than the latter with the increase of transfer capacity, but does not get as small even with the biggest relief.

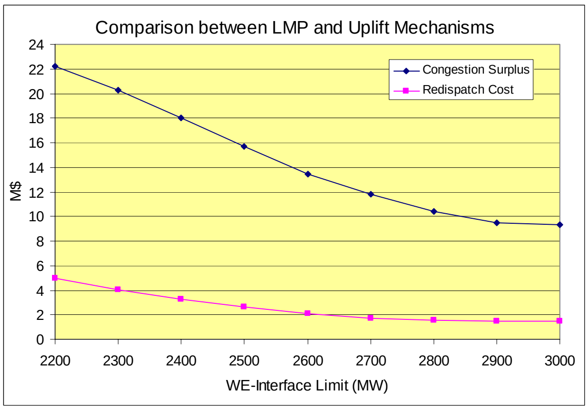


Figure 10 **ISO Perspective of Financial Impact under LMP and Uplift Mechanisms**

In general, the redispatch costs arising from the Uplift mechanism can hardly be used as an instrument to provide incentives for transmission investment, because of the lack of consideration of locational signals during the cost calculation process. On the other hand, the use of the differences of nodal prices (LMP mechanism) has also been criticized for not giving the appropriate incentives for transmission rights pricing and transmission expansion [7], even though the LMP mechanism takes into account the location of congested lines with respect to different generation facilities.

For an investment analysis, one must go through comprehensive expansion and improvement options, evaluated at a long time horizon, e.g. ten years. Therefore, based on our studies presented in this article, one cannot conclude if the congestion costs arising from either of the two mechanisms are enough to justify the improvement proposed at the beginning of section 3.3. The authors would therefore recommend such investment analysis as possible further study considering a range of future supply and demand growth scenarios. In order to provide adequate incentives, such investment analysis should also address the value of transmission capacity expansion on system reliability improvement. Since increased congestion is frequently associated with lowered reliability of transmission constrained areas, the market simulations should incorporate both economic and reliability considerations [11].

4 CONCLUSIONS

This paper has illustrated congestion relief impacts on different market players in energy markets under two extremely different congestion management methodologies. They are namely LMP and Congestion Uplift mechanisms. The principles of the mechanisms have first been explained using a simple network. Congestion relief comparison analysis under different degree of relief is conducted by market simulations based on a real network of a province in China. The results have shown that the impacts on generators, loads as well as ISO can show large differences between these two congestion methodologies. For future studies, one could consider doing a thorough analysis on different investment options based on the congestion costs arising from different congestion charging mechanisms.

5 REFERENCES

[1] F. A. Wolak and R. H. Patrick, “The impact of market rules and market structure on the price determination process in the England and Wales electricity market”, Univ. California Energy Inst., Berkley, POWER Rep., PWP-047, Apr. 1997

[2] “OMEL electricity market 2003”, annual report from OMEL, Operador del Mercado Iberico de Energia, 2003, available at www.omel.es

[3] E. Bompard, P. Correia, G. Gross and M. Amelin, ”Congestion-Management Schemes: A Comparative Analysis Under a Unified Framework”, IEEE Transactions on Power Systems, Vol 18, No. 1, Feb. 2003

[4] S. Raikar, M. Ilic, “Assessment of transmission congestion for major electricity markets in the US”, conference proceedings, IEEE Power Engineering Society Summer Meeting, 2001.

[5] “Nord Pool Spot AS – The Nordic Spot Market”, Product Report, Jan. 2003, available at www.nordic.com

[6] M.W. Caramanis, R.E. Bohn, F.C. Schweppe, “Optimal Spot Pricing: Practice and Theory”, IEEE Transactions on Power Apparatus and Systems, Vol. PAS-101, No. 9 Sep. 1982

[7] S.S. Oren, P.T. Spiller, P. Varaiya and F. Wu, “Nodal Prices and Transmission Rights: a Critical Appraisal”, Electricity Journal, Apr. 1995

[8] J. W. Bialek, “Elimination of merchandise surplus due to spot pricing of electricity”, IEE Proc.- Gener. Transm. Distrib., Vol. 144, No. 5, Sep. 1997

[9] X. Feng, L. Tang, Z. Wang, J. Yang, W. Wong, H. Chao, and R. Mukerji, “An Integrated Electrical Power System and Market Analysis Tool for Asset Utilization Assessment”, IEEE PES Summer Meeting, Chicago, Jul. 2002

[10] B. Eliasson, Y.Y Lee, “Integrated Assessment of Sustainable Energy Systems in China”, Kluwer Academic Publishers, 2003

[11] H. Chao, F. Li, L.H. Trinh, J. Pan, M. Gopinathan, and D.J. Pillo, “Market Based Transmission Planning Considering Reliability and Economic Performances”, International Conference on Probabilistic Methods Applied to Power Systems (PMAPS), Ames, Iowa, USA, Sep. 2004.

6 BIOGRAPHIES

Cherry Yuen received her PhD at the University of Strathclyde in Glasgow, Scotland in 2001. Since 2001 she joined ABB and is currently a research scientist at Corporate Research, ABB Switzerland Ltd. Her main research areas include energy deregulation, congestion management, asset management as well as computer applications for power systems.

Jiuping Pan is currently a principal consulting R&D engineer with ABB Corporate Research in USA. His expertise includes generation and transmission planning, power system reliability, T&D asset management, energy market modeling and simulation studies.

Qianjin Liu joined ABB (China) Corporate Research as a senior engineer in 2003. His main research interests are FACTS and wide area control.