Estimating the Cost of Wind Power in a Restructured Power System Based on Locational Marginal Prices

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ABSTRACT

This paper focuses in the economics of wind power markets by finding the supply and demand costs in the presence of transmission congestion and line losses. Wind producers are affected by the variable and stochastic nature of wind mills. In the Vertically integrated monopoly markets, conventional and non-conventional resources are correlated together so that it can result in the declared supply cost and demand cost to be equal. It is expected that after some decades, the installation of solar and tidal will decrease the inelastic wind power supplied to the consumers. This situation can be avoided by the proper selection of sites, implementation of exact costs, and calculation of perfect Locational Marginal Pricings (LMPs) based on congested and un-congested cases. This paper demonstrates the solutions by three sections. Firstly, the estimation for economics of wind power generation based on all the basic parameters needed for a wind power plant. Secondly, the analysis of supply (producers) and demand (consumers) in a two area networks for un-congested and congested systems. Finally, the identification of LMPs and line losses are intended with and without economic constraints. The MATLAB programs are simulated on the basis of demand and supply curves.

General Terms

The general terms used throughout in this paper are stated below for quick reference:

LMP_i	Nodal price(LMPs) at bus
LMP_{ref}	Nodal price at the reference bus
LMP_{Lossi}	Marginal cost of losses from reference bus to busi.
$LMP_{congestioni}$	LMP in transmission congestion.
$D(G)^{cong}$	Dispatch paid to Generator (congested)
$R(L)^{cong}$	Revenues from load (congested)
$D(G)^{ucon}$	Dispatch paid in Uncongested case
$R(L)^{ucon}$	Revenue Load in Uncongested case
Pi^{cong}	Congested case supply in producer *i*
Pj^{cong}	Congested case supply in producer *j*
Dm^{cong}	Congested case Demand in producer *m*
Dn^{cong}	Congested case Demand in producer *n*
Pi^{ucon}	Uncongested case supply in producer *i*
Pj^{ucon}	Uncongested case supply in producer *j*
Dm^{ucon}	Uncongested Demand in consumer *m*
Dn^{ucon}	Uncongested Demand in consumer *j*
Si^{cong}	Congested case Price in producer *i*
Sj^{cong}	Congested case Price in producer *j*
Sm^{cong}	Congested case Price in consumer *m*
Sn^{cong}	Congested case Price in consumer *n*
Si^{ucon}	Uncongested case Price in producer *i*
Sj^{ucon}	Uncongested case Price in producer *j*
Sm^{ucon}	Uncongested case Price in demand *m*
Sn^{ucon}	Uncongested case Price in demand *n*
Tl^{cong}	Congested Supply in transmission limit
Skj^{con}	Congested equalized Price (producer *j)*
Sl^{ucon}	Congested Price in transmission limit
C (*Ll*)	Cost with line losses
Ll	Line losses
SRP	Systems Redispatch Payments
CR	Congestion Revenue
UC	Uplift Charges
C(S)	Change in Consumer Surplus
P(S)	Change in Producer Surplus
C_T	Total annual cost of energy
*Ad*c	Annual depreciation charge
*F*c	Annual fixed cost
*SF*c	Annual semi fixed cost
*R*c	Running cost multiplied by KWh
*T*d	Total depreciation
*U*l	Useful life of the equipment
*A*KWh	Annual energy production, kWh/yr
AEP	Annual Energy Production, kWh
*L*f	Load factor
*C*f	Capacity factor
*T*a	Turbine availability
*G*s	Generator size (rated power), kW
*C*in	Initial value or capital cost
*L*f	Load factor
S_V	Scrap value after useful life
n	Useful life of the equipment in years
r	Annual rate of interest
*M*d	Maximum demand
*A*rc	Annual running charge
*A*d	Average demand
*I*c	Installed capacity
x	Annual unit depreciation
q	Amount of depreciation every year
CAISO	California Independent System Operators
RSPs	Restructured Power Systems
MCPs	Marginal Clearing Prices

Keywords

Locational Marginal Prices (LMPs), Wind power market, Restructured power systems, integrated power grids.

1. INTRODUCTION

1.1 Motivation and Procedure:

Now a day's, Wind energy is termed as Price Taker due to the issues like transmission congestions, line losses and marginal costs. The main problems in a wind power market are variability in the wind speed and un-predictability of supply. Even though there is no transmission congestion, the presence of line losses in the transmission lines can make the entire systems to be useless. Hence, the impromptu selection of site and investments can make the wind power to be in higher unit costs. These problems cause difficulty for producers to predict their annual production and depreciation charge [1]. Today India has the fifth largest installed capacity of wind power in the world. Recently, the survey from Global Wind Energy Council showed that the global warming which is resulted in the reduction of rainfall, destruction of ozone layer and rising of the sea level should be reduced only by encouraging the green power markets.

Eventually, in the developing country like India more potential of wind energy is available but most of the people are confused that, if wind power plants are termed as a price taker then what is the benefit for using it. After some decades, the loss of annual production of wind plants will result in the increased usage of hydro, biomass and solar power plants which will affect the green environment. Along with new regulations to reduce carbon emissions and achieve energy security, many governments are turning to tax relief to promote renewable energy sources for power generation. The International Energy Agency (IEA) and the World Health Organizations (WHO) support for renewable energy investment in a wide variety of tax incentives like Credits, Grants, Tax holidays, Accelerated depreciation and Non-tax incentives.

Obviously, based on the different locations the marginal prices are varying but these problems can be rectified by Locational Marginal Prices which is used for the calculations for the next incremental costs and defined as the marginal cost to serve one more megawatt (MW) of load at a certain location. When the generator at a specific location is causing economic harm to the entire system, adding one more MW of load may have somewhat counterintuitive effects. It is often assumed that because wind farms have a high capital cost, wind energy will push up electricity prices. Hence, electricity that is offered will be in a higher price and discourage the spot electricity prices.

In early decades, Wind Producers are affected seriously by the Locational Marginal Pricings (*LMPs*) so that they could not able to send the approximate report of their annual power production to the Independent System Operators (ISO) [2]. They are forced to submit some of the transmission buses as permanent congestion areas which cause problems to schedule the supply and demand prices. In the last decade, Federal Energy Regulatory Commission (FERC) in United States projected an advanced market design for common implementation to the wholesale power markets. The two-settlement system provided by FERC consisted of firstly, day-ahead market which is supported with the Market Clearing Prices for demand and supply curve secondly, Locational Marginal Pricings (*LMPs*) explain the congestion management but they are criticized by the market participants due to lack of information for *LMPs* and uncertainties among market participants under local regions.

1.2 Literature Review and Contribution:

Most of the references have been described the wind power production as a money taking power plant after Solar power plant. Thus the lack of solution in the variability, unpredictability and correlated behaviour of wind farms resulted in the increased usage of Solar Panels and Hydro power plants. It is proved that Wind Turbines are securing more land for constructions other than Wind Plants. The work presented by Jónsson *et al.* proved that wind power behaves as a price maker in electricity markets. El-Fouly *et al.* develop the wind production on market prices and total generation costs [3]. The main contribution of this paper is to equate the supply and demand of producers and consumers in an electrical power market with the detailed explanation for LMPs.

1.3 Paper Organization:

The problems affecting the wind power markets, like transmission congestion Pricing can be solved only by the detailed derivation of *LMPs* and the economic limitations for the operation of wholesale power markets. This will result in the impromptu situation for wind producers due to the misjudging of MWh prices. In this paper, the detailed explanation of restructured power markets is solved on the presence of transmission limits. Section II the concept, calculation and practical application of LMPs, Section III presents, Economics of power generation of restructured power system for the consumer demand and production supply. Section IV the calculations for Transmission Congestion Costs based on the Uplift Charges, System Redispatch Payments and Congestion Revenues examines the calculation for LMPs as an example of 3-bus system when one bus is subjected to a load obligation. Section V concludes the paper.

2. CONCEPTS OF LMPs

2.1 Over view:

The definition and calculations of LMPs are depends upon economic theory and power system when the transmission Congestion affects the cost of generations and lowering the market benefits [4]. The word LMP is used for the price of a load aggregation point. Based on the marginal cost, the total system cost is similar to social surplus (total surplus) that is defined by social welfare using cost functions.

Locational Marginal Price (LMP) is the marginal cost of supplying, at least cost, the next increment of electric demand at a specific location market price of generation in the constrained area. In the electric power network, taking into account both supply (generation/import) bids and demand offers and the physical aspects of the transmission system including transmission and other operational constraints.

2.2 Settlements:

The Objective function of LMPs is calculated by maximizing the demand offer and supply bid [5]. This is subject to the constraints by the presence of transmission limits and line losses. The *LMP*s or nodal prices are the combination of three components: marginal cost at a reference bus, marginal cost of transmission losses, and marginal cost of transmission system congestion.

$$LMP_i = LMP_{ref} + LMP_{lossi} + LMP_{congestioni} \qquad (1)$$

The prices under the integrated model are called Locational Marginal Pricing or Nodal Pricing (calculated at each node).

The charge for selling 1 MW at A and buying 1 MW at B are (neglecting losses) exactly the same as the charge for transmission from A to B.

$LMP_A = LMP_{Ref} + LMP_{lossA} + LMP_{CongestionA}$ (2)

$LMP_B = LMP_{Ref} + LMP_{lossB} + \lambda LMP_{CongestionB}$ (3)

$LMP_{lossA} = LMP_{lossB} = 0$ (4)

The rate for transmission from A to B is the congestion rate and is priced at:

$LMP_B - LMP_A = LMP_{CongestionB} - LMP_{CongestionA}$ (5)

Transmission service for bilateral transactions is shown on the case study which explaining the load and supply based on economic dispatch.

2.3 Determining transmission Congestion in a two bus systems:

Objective function is to maximize the total consumer benefit (area under the demand offer) minus the total cost to supply (the area under the supply bid) which is Subject to the Constraints by equalizing total supply quantity and total demand quantity. Each nodal price can be decomposed into three components: marginal cost at a reference bus, marginal cost of transmission losses, and marginal cost of transmission system congestion due to binding constraints [6]. Firstly the objective function is to minimize the dispatch paid to generator, D (G) and Revenue from loads, R(L) by combining the supply and loads under congested case:

Minimize, D (G) ^{cong} =

$$\sum_{i=1}^{N} Pi^{cong} Si^{cong} + \sum_{j=1}^{N} Pj^{cong} Sj^{cong} \quad (6)$$

Minimize, R (L) ^{cong} =

$$\sum_{m=1}^{N} Dm^{cong} Sm^{cong} + \sum_{n=1}^{N} Dn^{cong}\, Sn^{cong} \quad (7)$$

In the un-congested case dispatch from generator is equal to the revenues from load,

$$D(G)^{ucon} - R(L)^{ucon} = 0 \quad (8)$$

$$\sum_{i=1}^{N} (PiSi)^{ucon} + \sum_{j=1}^{N} (Pj\, Sj)^{ucon} - \sum_{m=1}^{N} (DmSm)^{ucon} + \sum_{n=1}^{N} (Dn\, Sn)^{ucon} = 0$$

where,

D (G) ^{ucon} =

$$\sum_{i=1}^{N} (PiSi)^{ucon} + \sum_{j=1}^{N} (PjSj)^{ucon} \quad (9)$$

R (L) ^{ucon} =

$$\sum_{m=1}^{N} (DmSm)^{ucon} + \sum_{n=1}^{N} (DnSn)^{ucon} \quad (10)$$

Subject to
$0 \le Ll \le Ll^{max}$
$0 \le Tl \le Tl^{max}$
$P^{min} \le P \le P^{max}$
$S^{min} \le S \le S^{max}$

System Redispatch Payyments (SRP) =

$SRP = D(G)^{cong} - D(G)^{ucon}$ (11)

Congestion Revenue (CR)=

$CR = R(L)^{cong} - D(G)^{ucon}$ (12)

Uplift Charge,UC =

$Pi^{cong} Si^{ucon} + Pj^{cong} Si^{ucon} + Tl^{cong} Sl^{ucon}$ (13)

Consumer Surplus, C(S) =

$Dm\,(Si^{cong} Si^{ucon} + Dn^{cong} * (Sk^{con} - Sn^{ucon})$ (14)

Producer Surplus, P(S) =

$Pi^{cong} * (Si^{ucon} - Si^{cong}) + 0.5 * Tl^{cong} * (Si^{ucon} - Si^{cong}) + Pj^{cong} (Sj^{ucon} - Sk^{con}) + 0.5 * Tl^{cong} * (Si^{con} - Sk^{cong})$ (15)

Cost calculation with line losses,

$C(Ll) = Pi^{cong*} Si^{cong} / Pj^{cong}$ (16)

where,

$Pi^{cong} = Pj^{cong} - Ll$ (17)

3. ECONOMICS OF RESTRUCTURED MARKETS BASED ON DEMANDS AND SUPPLY

3.1 Production and Consumption based on the Restructured Power Markets:

For many decades, vertically integrated electric utilities monopolized the way they controlled, sold and distributed electricity to customers in their service territories. In this monopoly, each utility managed three main components of the system: generation, transmission and distribution [7]. A competition is guaranteed by establishing a restructured environment in which customers could buy from different suppliers and change suppliers as they wish in order to pay market-based rates.

FERC Order 888 required transmission owners to provide a comparable service to other customers who did not own any transmission facilities and ISO developed eleven principles for restructuring electrical industry. Power Exchange (PX) accepts supply and demand bids to determine a MCP for each of the 24 periods in the training day. MCP is the balance price at the market equilibrium for the aggregated supply and demand graphs.

In the day-ahead market and for each hour of the 24-hour scheduling day, sellers bid a schedule of supply at various prices, buyers bid a schedule of demand at various prices and MCP is determined for each hour. The hour-ahead market is similar to day-ahead, except trades are for 1 hour. An inelastic market does not provide sufficient signals or incentives to a consumer to adjust its demand in response to the price [8]. Customers use the concept of elastic demand when they are exposed to and aware of the price of energy.

3.2 Transmission Congestion and Electrical Volatility:

The generators which are affected by congestion can cause the transmission limit so it is difficult to dispatch additional power from it. This could be caused for various reasons, such as transmission line outages, generator outages, changes in energy demand and also due to uncoordinated transactions [9]. Congestion can be corrected by adding phase shifters, tap transformers, reactive power control, redispatch of generation, curtailment of loads and may be possible by removing congested lines to prevent severe damage.

Congestion could prevent system operators from dispatching additional power from a specific generator and could be caused for various reasons, such as transmission line outages, generator outages, changes in energy demand and uncoordinated transactions. Congestion can be corrected by applying control such as phase shifters, tap transformers, reactive power control, redispatch of generation, curtailment of loads and may be possible by removing congested lines to prevent severe damages by reservations, rights and congestion pricing[10].

Electricity is a non-storable commodity and its supply and demand must be matched at all the times. Price Fuel price is a main factor in volatility of prices including weather conditions, overloaded lines but in wind mills the wind speed and outputs are the result for volatility. Volatility is directly proportional to standard deviation (measure of the volatility of a random variable such as spot price).

3.3 Economics of Power Generation:

A power generation is required to deliver power to a large number of consumers to meet their requirements. Therefore, a careful study with different steps are founded in this section with various parts including depreciation charge, capacity factor, load factor, interests and annual cost production calculations [11]. The total annual cost of electrical energy generated can be divided into three parts and two parts systems,

For three part systems: $C_T = Rs\,(Fc+SFc+Rc)$ or

For two part systems: $C_T = Rs\,(AKW+BKW)$ (18)

Constant which when multiplied by maximum KW demand on the station gives the annual cost (A) and when multiplied by the annual KWh generated gives the annual running cost (B).

In the Straight line method, Annual depreciation charge (Adc) is the ratio of Total depreciation (Td) and Useful time (Ul).

$$Adc = Td/Ul=(Cin - Sv)/n \quad (19)$$

In the Diminishing value method:

Value of the equipment after 'n'year = Cin $(1-x)^n$

Value of the equipment after n years is the difference between the diminished value and annual depreciation.

$$x=1-(S_V/Cin)^{1/n} \quad (20)$$

Depreciation of the first year (annual depreciation is 15% than annual unit depreciation (x) is 0.15 = x (Cin)

In the Sinking fund method:

Cost of replacement = Cin - S_V (21)

Amount q deposited at the end of first year becomes:

$$q(1+r)^{n-1}$$

Annual deposit in the sinking fund is,

$$q = (Cin - Sv)\,[r/\,((1+r)^{n}-1)] \quad (22)$$

Sinking fund at the end of n years:

$$(q\,(1+r)^n-1)\,/\,r$$

The load factor plays a vital role in determining the cosy of energy and is calculated by average load over maximum demand. Some importance advantages of high load factor are the reduction of unit generated and variable load problems.

$$\text{Average load} = \frac{\text{Area (in KWh) under daily load curve}}{\text{24 hours}}$$

Unit generated per annum:

$$AKWh = Md*Lf*8760 \quad (23)$$

Annual running charge (Arc) for a power plant is the combination of annual cost of fuel and taxes, wages but for wind (Arc is without the cost of fuel and oil). Annual fixed cost is the percentage of interest and depreciation with respect to the capital cost, life time, interest and loans.

Capacity factor is the ratio of actual output (Average demand) and total expected output (Installed capacity),

$$Cf = Ad/Ic \quad (24)$$

Total annual operating cost of station A and B:

$$C=C_A+C_B \quad (25)$$

Using above equations, economics of a wind power plant can be calculated easily.

4. CASE STUDY

4.1 Transmission Congestion Costs in a Vertically Integrated Monopoly Market:

This section gives the detailed calculation for examines the calculation for LMPs in a two area networks as an example based on a constrained system and un-constrained system. In this example, the real time price for wind power in Tamilnadu state (largest wind power potential state in India) ($0.066/kWh) is taken as an example and it will be of $66/MWh.

Table1: Dispatch, dispatch costs, and revenues for the unconstrained and constrained systems

Unconstrained System			**Constrained System**		
MW	**D(G)**	**R(L)**	**MW**	**D(G)**	**R(L)**
700 MW	$46,200 /h	$33000 /h	600 MW	$36,432 /h	$30,360 /h
300 MW	$19,800 /h	$33000 /h	400 MW	$31,680 /h	$39,600 /h
1000 MW	$66,000 /h	$66000 /h	1,000 MW	$68,112 /h	$69,960 /h
					Congestion Costs
System Redispatch Payments					$2,112 /h
Congestion Revenues					$18,48 /h
Total costs to loads compared to an uncongested case (Method 1 + Method 2)					$3,960 /h

Firstly, system redispatch payments can be calculated by taking the difference of un-congested case (product of supply and cost per MWh) and congested case (product of supply and cost per MWh). Here, congestion cost is equal to change in dispatch order. Secondly, congestion revenue can be calculated by finding the difference of congested case (product of fixed load and changed cost) and congested case (product of supply and cost) [12]. In the above table first column represents the Area A, second Area B and third Total respectively an MW is Mega Watts.

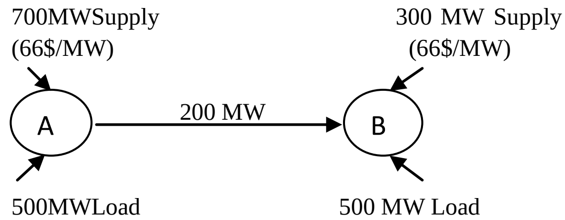


Figure (1) Two Area Network (Un-Congested Case)

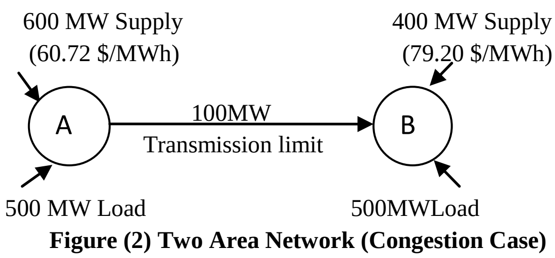


Figure (2) Two Area Network (Congestion Case)

Uplift Charge can be found by finding the product of congested supplies with uncongested cost and transmission limit supply with increased transmission cost [13]. In the restructured market, the Uplift charge can be calculated by, (600*66) + (300*66) + (100*72.6) = $66660/h

The combined energy and Uplift cost price to the load can be calculated by,

66660/1000=$66.66/MWh

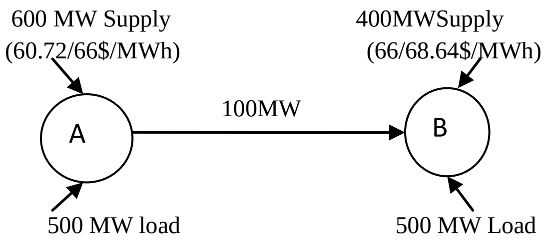


Figure (3) congested/uncongested

The additional transmission capacity results in an LMP change in Area A from $60.72/ MWh (congested) to $66 /MWh (uncongested) and from $68.64 /MWh (congested) to $66 /MWh (uncongested) in Area B. Thus the change in consumer surplus is:

500MW ($60.72- 66/MWh) + 500MW ($68.64-66/MWh) = $-1320/h

With an increase in transmission capacity, production in Area A increases from 600 MW to 700 MW, and the price increases linearly from $60.72 /MWh to $66 /MWh. In Area B, production is decreased from 400 MW to 300 MW, and the price decreases linearly from $68.64/MWh to $66 /MWh. The change in producer surplus is given by:

(600 MW)*($66 – 60.72 /MWh) + 0.5*(100MW)* ($66-60.72 /MWh) + (300 MW)*($66 – 68.64 /MWh) + 0.5*(100 MW)*($66-68.64 /MWh) = $2508 /h.

4.2 Calculation of LMPs with and without losses:

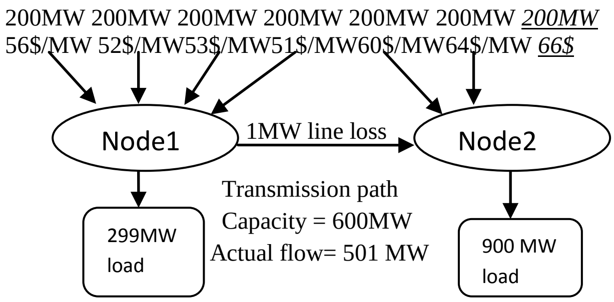


Figure (4) Two Nodes System (No transmission constraints)

In the above network in the figure it is no transmission limit and hence the flow is uniform (only needed supply is taken). Underlined supplies are excluded from the supply.

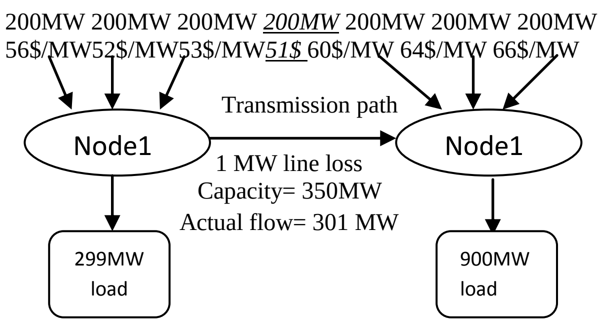


Figure (5) Two Nodes Network (transmission constraints)

In the above network in the figure, there is a transmission limit (the system must be dispatched).

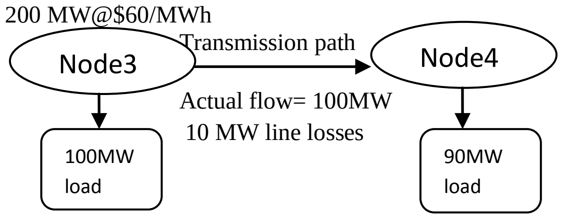


Figure (6) Two Nodes Network (with line losses)

Hence, node 4 price can be calculated by,

(Price in node3 ($) * actual flow (MW)) / node 4 = ($60/MWh*100MW)/90 MW= $66.66/MW.

In the above figure line losses are included and it causes the increase in price without Congestion.

4.3 Economic Curtailment of Wind Power:

In the case without load obligations G1 can supply the entire load. When the system is under transmission limits (load obligation in G2), the contingency analysis is used to ensure security [14]. .

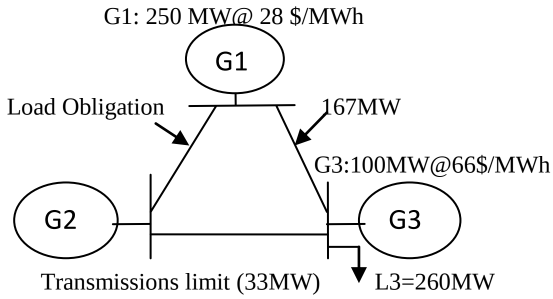


Figure (7): 3-bus system with Transmission limit

Firstly, adding one MW of load to bus 1, this can easily be supplied by G1 which causes no change. Secondly, adding one MW of load to bus3, the transmission system is congested and no more power is from G1. Finally, adding one MW of load to bus2 counter flows can be achieve by reducing 1MW in the bus 3 and flows from bus1-2 and bus 3-2.

Table3: Costs and Prices without Economic Curtailment

G1 MW	**G1 Cost**	**G3 MW**	**G3 Cost**	Total	LMP
200	$28/ MWh	60	$66/ MWh	9560	
201	$28/ MWh	60	$66/ MWh	9588	$28
200	$28/ MWh	61	$66/ MWh	9626	$76
202	$28/ MWh	59	$66/ MWh	9550	$-10

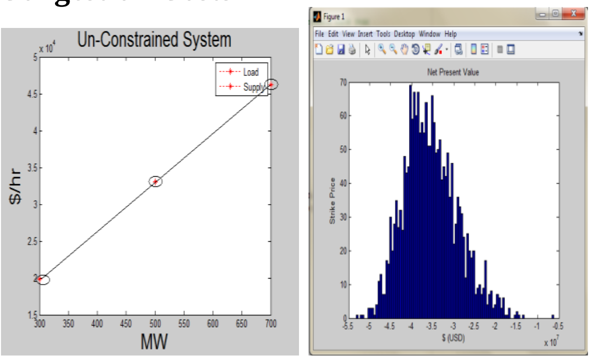
In the above table the columns shows the base case, adding 1MW to bus1, bus3, bus 2 respectively. In the next table G3MW is assumed to be zero. Hence, G3MW*G3 Cost is assumed to be zero [15].

Table 4: Costs and Prices with Economic Curtailment

Wind Gen MW	**G 1 MW**	**G 1 Cost**	**Total**	**LMP**
60	200	$28/ MWh	5600$	
60	201	$28/ MWh	5628$	$28
59	202	$28/ MWh	5656$	$56
61	200	$28/ MWh	5600$	$0

Above table shows the economic Curtailment in which, the high cost wind supply is turned off [16].

4.4 Simulation for the Transmission Congestion Costs



(a) (b)

Figure (8): (a) Un-congested System (supply and load are linear) and (b) Congested system (non-linear).

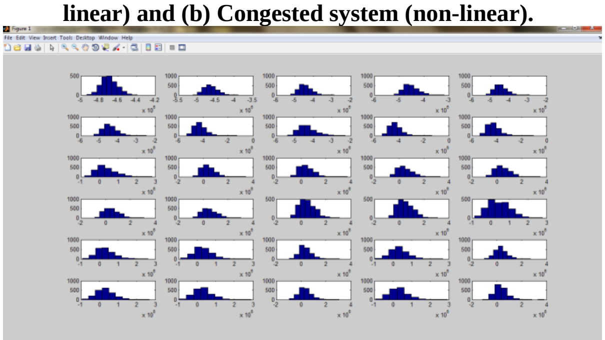
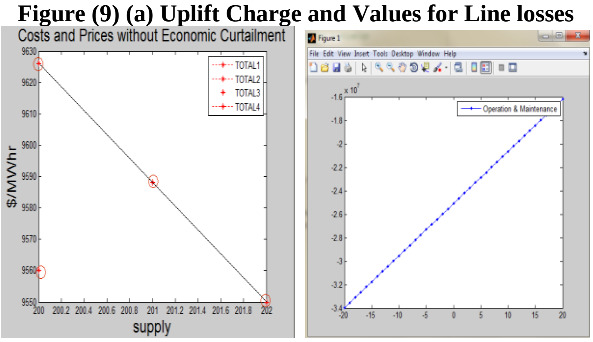


Figure (9) (a) Uplift Charge and Values for Line losses



(a) (b)

Figure (10) (a) With Economic Curtailment (b) Without economic Curtailment (curves are different on both conditions)

In fig (8), the simulation for congested and un-congested case simulated with the change in R(L) and D(G) and in fig(9) the uplift charges and line losses are simulated based on the increase of charge in congested case. Finally, in fig (10) with and without economic curtailments are simulated.

5. CONCLUSIONS

This paper provides a detailed explanation for the economics calculations and an easy methodology for the overall cost calculations for the wind mills. In the above sections, we calculated producer and consumer surplus in a restructuring market and line losses which can affect the entire systems. For maximizing the Social Welfare, the *LMPs* for different locations with line losses, congestions and economic curtailment are calculated. Most of the problems regarding wind power markets are solved with the help of two area networks and three bus systems. In the final MATLAB result, it is shown that without transmission limits, curves are linear and otherwise non-linear.

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