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Preliminary Estimate of Cost Savings in NPCC System with Wind Generation

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Contents

Abstract

This paper shows potential generation cost savings caused by integrating incremental MW capacity of wind power to Northeastern Power Coordinating Council (NPCC) US electric power system. The approach begins by applying the Basic Economic Dispatch (ED) to the existing grid. Preliminary potential decisions for the utilities and the market side for integrating and investing in wind energy market can be captured from the calculation that is shown in later section to calculate the breakeven installed MW wind capacity so that the total revenues cover the total fixed and variable costs for each incremental percentage levels mentioned above.

This analysis takes into account the effective capacity of wind generation. The calculations are based on the average month's capacity factors for each % wind level. The results show significant total generation cost reductions at 5%, 10% and 15% incremental wind power levels.

Introduction

The intent of this paper is to develop a preliminary cost savings estimates by integrating wind power into NPCC bulk power grid. In our analysis, we use a system representation of [1]. The economic dispatch problem is formulated based on an estimated average installed cost of $1500/200MW and an operation and maintenance cost of 10$/MWh as in [2]. We address the effect of increasing wind MW capacities in the total generation cost savings. Also we calculate a preliminary wind plant Break-Even size in which the total estimated revenues equals the total estimated costs to help for potential planning and expansion decisions to take place.

Problem Statement

The problem of minimizing the total generation cost is posed here as a basic economic dispatch optimization problem as follows:

- Given the total system load P_L in MW.
- Given the available generated power P_{Gi} in MW from power plants that are already ON where:

$$PG_{iMIN} \le PG_i \le PG_{iMAX}$$

- Given an approximated linear cost function for each participating generator as:

$$C_i(PG_i) = A_i\, PG_i + B_i$$

Where A_i is the marginal cost for generator i , and i = 1,2,., N

The basic ED is performed to decide how to schedule P_{Gi} so that:

$$\underset{PG_i}{MIN} \sum_{t=1}^{t=4380} \sum_{i=1}^{NG} C_i(PG_i)$$

Subject to:

$$\sum_{i}^{NG} PG_i = P_L$$

Electrical Model Example

We used the electrical model derived in [1], which models the anticipated electric power system conditions at peak load during the summer of 2007. The electrical model is a greatly reduced model of the Northeastern US bulk electric power system by equivalencing process. Figure 1 represents a one line diagram of the equivalenced 36 bus model used in our analysis.

Cost Savings

In this section we discuss the effect of increasing wind power MW capacities in the NPCC Bulk power grid. Table 1 below shows the generation and load data of the 6 areas and their corresponding Marginal costs. Note that in [1] each of the 6 generation areas is separated into market zones, for example NY area has 19 marker zones, and each zone has its own marginal cost.

The way the area marginal costs are used here for NY is the average marginal costs of its 19 market zones. Same are done for all other areas. The market clearing price is the average marginal costs for all areas.
The existing power grid has already a 1.6% wind power capacity installed all in NY area, which contributes 20% power generation for NY.

Table 1 NPCC area data

	Original power [MW]		Equivalenced power [MW]		
Area	**Generation MW**	**Load MW**	**Generation MW**	**Load MW**	**MC $/MWh**
NY	**31150**	**31875**	**37294**	**37976**	**54.43**
New England	**23460**	**25017**	**23157**	**23847**	**54.96**
Ontario	**25285**	**24254**	**21051**	**21158**	**38.14**
PJM	**58974**	**56783**	**52028**	**51588**	**51.33**
Quebec	**-**	**-**	**800**	**0**	**49.55**
Maritimes	**4273**	**3453**	**4273**	**3546**	**54.96**
Total	**143142**	**141382**	**138603**	**138115**	**-**

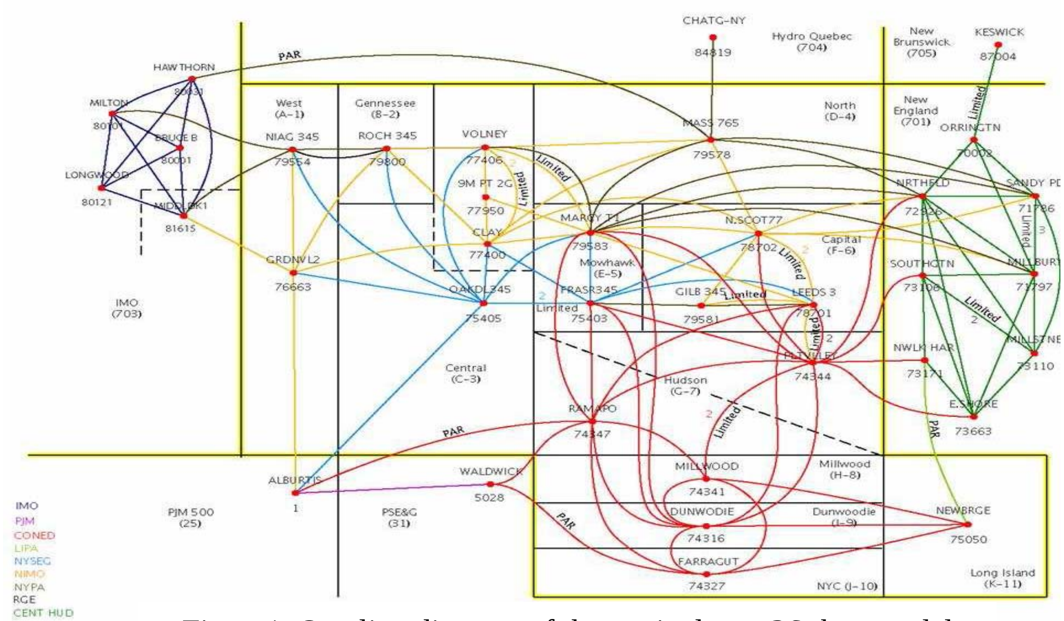

Figure1. One line diagram of the equivalence 36- bus model

Figure 2 shows the average monthly capacity factor examined for the years 2001 through 2003 [3]. As expected, the highest capacity factors occur in December, January, and February months, with minimum and maximum of 34% and 50%, respectively. While the lowest ones are in summer months (June, July and August) with minimum and maximum capacity factors of %10 and 37.5%, respectively. The range of capacity factors for the remaining months are in between these two extremes. The average capacity factors of 43.9%, 38%, 24%, and 34% for each season are used here in the analysis.

The ED is performed using GIPSYS software package. Generation cost reductions result for 5%, 10%, and 15% increase in wind power for the NPCC power grid, respectively with their corresponding average cost savings are depicted for the four seasons. The economic dispatch results are presented in tables 2 through 5 in the next section.

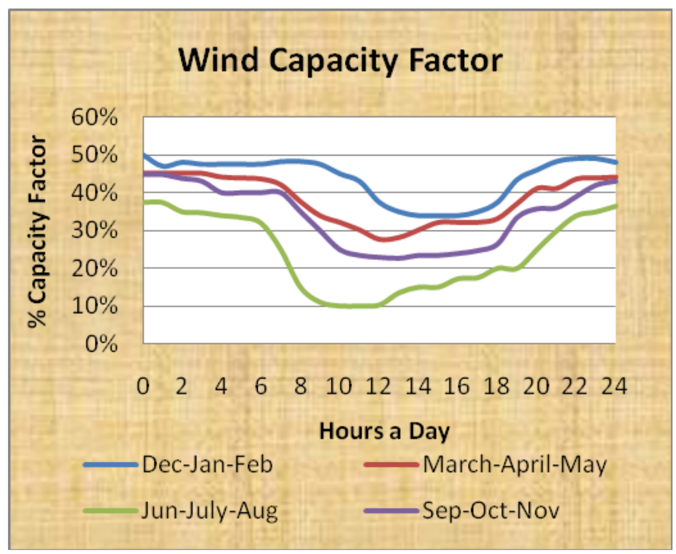

Figure 2. Average Seasonal Wind Shape NYIOS 2002

Potential Decisions

This section discusses potential future investment decisions to integrate additional MW wind power in the NPCC bulk power system. The potential locations are in NY area [3]. Figure 3 along with Table 2 depict future MW capacities with corresponding future zones.

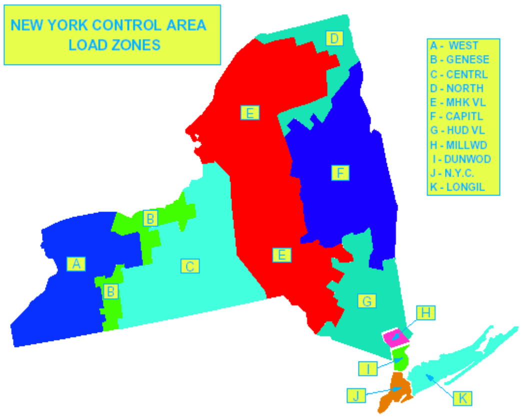

Figure3. NY control area load zones

Table 2 Potential Locations

Potential Wind Generation by Zone	
Zone A	4016 MW
Zone B	515 MW
Zone C	922 MW
Zone D	433 MW
Zone E	2683 MW
Zone F	703 MW
Zone G	154 MW
Zone H	0 MW
Zone I	0 MW
Zone J	0 MW
Zone K	600 MW
Total	10026 MW

Tables 3 through 6 provide estimates for fixed capital and operation and maintenance costs to each level of incremental MW wind power for each season. The average fixed costs are on the basis of \$1500/200MWh, which means \$7.5/MWh. Also estimated marginal costs (O&M) equal \$10/MWh [2].

Note that column 2 in each of the following tables, has fixed, and variable costs although it has 0% wind capacity installed, this is because the grid has already 1.6% installed wind power, and we mean by the **% wind installed** in the first row of all the tables; the **future % wind installed** as we consider here in this section the potential investments decisions for additional installed MW wind power.

We define:

ACC = the fixed average capital costs \$/hour.
Pw = Wind capacity (MW).
Thus, 5th row in the following tables;

$$ACC = 7.5 * Pw \ \$/Hour \qquad (1)$$

Where 7.5\$/MWh is the estimated fixed costs.

AVC = estimated average variable costs \$/hour (this is the wind generation costs, 6th row in all following tables).
MC = Estimated Marginal Cost \$/MWh
= 10\$/MWh as in [2].
Thus;

$$AVC = MC * Pw \ \$/Hour \qquad (2)$$

Note that the wind generation costs are NOT the results of running the basic ED program for each % wind level, it is part of it, but GYPSIS software package calculates the generation costs for the entire system that includes all generation data.

The total costs equal the sum of the fixed and variable costs:

$$Total\ Cost = ACC + AVC \qquad (3)$$

The profit is calculated as the difference between the marginal cost MC and the market clearing price MCP multiplied by the installed capacity Pw:

$$Profit = (MCP - MC) * Pw \ \$/hour \qquad (4)$$

Where, MCP = 50 \$/MWh, this price is the average MC for all market zones in the MPCC power grid [1].

Table 3. December, January, and February estimated 44% capacity factor

% wind	0%	5%	10%	15%
MW wind	1030.08168	3219.00525	6438.0105	9657.01575
Generation Costs ($/Hour)	$6,871,982.79	$6,773,568.79	$6,628,842.31	$6,484,115.84
Costs Savings ($/Hour)	$0.00	$98,414.00	$243,140.48	$387,866.95
ACC ($/Hour)	$17,595.00	$54,984.38	$109,968.75	$164,953.13
Wind gen costs ($/Hour)	$10,300.82	$32,190.05	$64,380.11	$96,570.16
Revenues ($/Hour)	$51,504.08	$160,950.26	$321,900.53	$482,850.79
Total Costs TC ($/Hour)	$27,895.82	$87,174.43	$174,348.86	$261,523.28
Profits ($/Hour)	$41,203.27	$128,760.21	$257,520.42	$386,280.63
Breakeven MW wind covers AVC	439.88	1,374.61	2,749.22	4,123.83
Breakeven MW wind covers TC	1191.232953	3722.602978	7445.205956	11167.80893

Table 4. March, April, and May estimated 38% capacity factor

% wind	0%	5%	10%	15%
MW wind	892.653	2789.540625	5579.08125	8368.621875
Generation Costs ($/Hour)	$ 6,878,161.5	$ 6,792,877.5	$ 6,667,459.7	$ 6,542,042.0
Costs Savings ($/Hour)	0	85284.0657	210701.8095	336119.5533
ACC ($/Hour)	$17,595.00	$54,984.38	$109,968.75	$164,953.13
Wind gen costs ($/Hour)	$8,926.53	$27,895.41	$55,790.81	$83,686.22
Revenues ($/Hour)	$44,632.65	$139,477.03	$278,954.06	$418,431.09
Total Costs TC ($/Hour)	$26,521.53	$82,879.78	$165,759.56	$248,639.34
Profits ($/Hour)	$35,706.12	$111,581.63	$223,163.25	$334,744.88
Breakeven MW wind covers AVC	$439.88	$1,374.61	$2,749.22	$4,123.83
Breakeven MW wind covers TC	$1,306.91	$4,084.09	$8,168.18	$12,252.27

Table 5. June, July, and August estimated 24% capacity factor

% wind	0%	5%	10%	15%
MW wind	567.0282	1771.963125	3543.92625	5315.889375
Generation Costs ($/Hour)	$6,892,801.68	$6,838,627.94	$6,758,960.17	$6,679,292.85
Costs Savings ($/Hour)	0	54173.74167	133841.511	213508.8317
ACC ($/Hour)	$17,595.00	$54,984.38	$109,968.75	$164,953.13
Wind gen costs ($/Hour)	$5,670.28	$17,719.63	$35,439.26	$53,158.89
Revenues ($/Hour)	$28,351.41	$88,598.16	$177,196.31	$265,794.47
Total Costs TC ($/Hour)	$23,265.28	$72,704.01	$145,408.01	$218,112.02
Profits ($/Hour)	22681.128	70878.525	141757.05	212635.575
Breakeven MW wind covers AVC	$439.88	$1,374.61	$2,749.22	$4,123.83
Breakeven MW wind covers TC	$1,804.82	$5,640.05	$11,280.10	$16,920.15

Table 6. September, October, and Nov. estimated 34% capacity factor

% wind	0%	5%	10%	15%
MW wind	794.8248	2483.8275	4967.655	7451.4825
Generation Costs ($/Hour)	$6,882,559.93	$6,806,622.38	$6,694,949.50	$6,583,276.61
Costs Savings ($/Hour)	0	75937.55	187610.432	299283.314
ACC ($/Hour)	$17,595.00	$54,984.38	$109,968.75	$164,953.13
Wind gen costs ($/Hour)	$7,948.25	$24,838.28	$49,676.55	$74,514.83
Revenues ($/Hour)	$39,741.24	$124,191.38	$248,382.75	$372,574.13
Total Costs TC ($/Hour)	$25,543.25	$79,822.65	$159,645.30	$239,467.95
Profits ($/Hour)	$31,792.99	$99,353.10	$198,706.20	$298,059.30
Breakeven MW wind covers AVC	439.88	1,374.61	2,749.22	4,123.83
Breakeven MW wind covers TC	1,413.62	4,417.58	8,835.15	13,252.73

As shown from the above tables, that the maximum cost reductions and maximum revenues from wind occur at the highest wind capacities as depicted in table 3. Figures 4 and 5 show the highest total cost reductions and the wind revenues occur for December, January, and February season.

We are also interested in calculating the break even MW wind power where the profit equals zero. This breakeven capacity is basically the critical size or the critical running capacities of wind farms at which the fixed and variable costs are covered.

The Breakeven MW wind that covers the AVC occurs when: TC (total cost) = Revenues:

$$ACC + AVC = MCP*Pw \qquad (5)$$

$$AVC = MC*Pw \qquad (6)$$

Therefore;

$$ACC+MC*Pw = MCP*Pw \qquad (7)$$

$$Pw = ACC / (MCP - MC) \qquad (8)$$

Wind capacity, Pw in (8), is the breakeven MW wind capacity for zero profit. Same steps are done for covering the total costs.

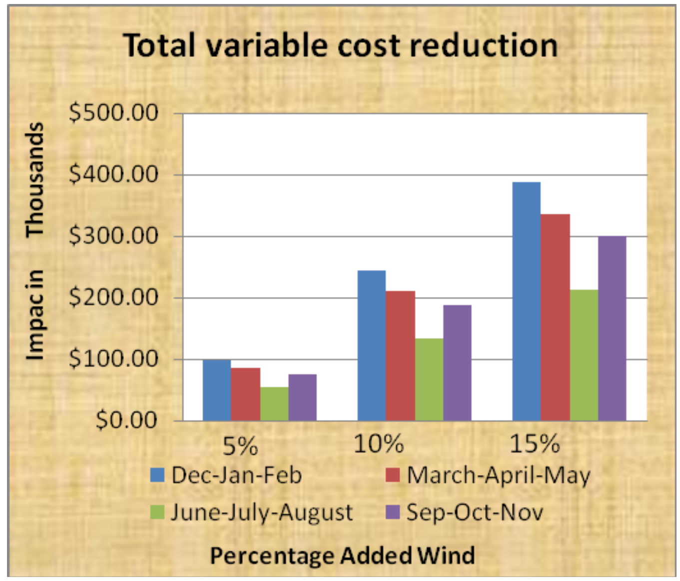

Figure 4. Total variable cost reductions for 5%, 10%, and 15% wind level for each season.

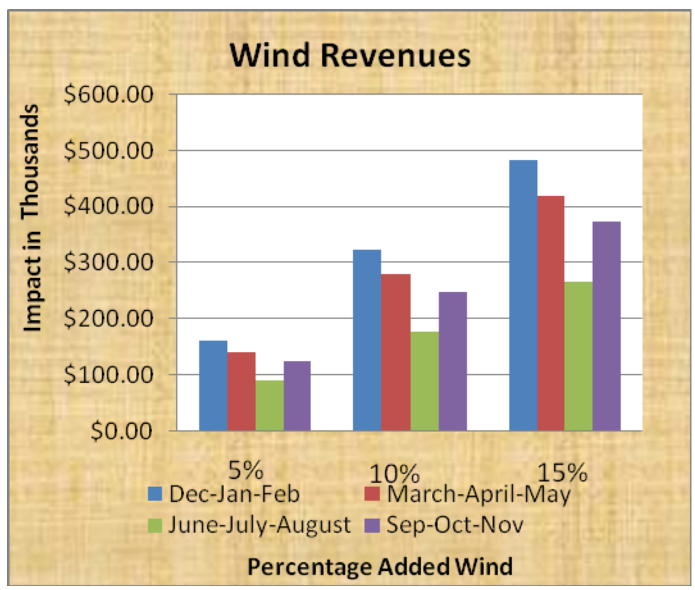

Figure 5. Wind Revenues at 5%, 10%, and 15% wind level for each season.

Conclusion and suggestions for future work.

This work shows the effect of increasing wind power capacity of the NPCC bulk power grid with a focus on New York area. The results present major generation cost reductions and a potential for more planning and expansion decisions. Suggestions for future work will carry the effect of wind intermittency effect with great effort in accurate and reliable wind forecasting methodologies. Also the effect of grid frequency control by means of AGC will be carried out.

References

[1] Eric H. Allen, Jeffrey H. Lang, and Marija D. Ili´c, “A Combined Equivalenced - Electric, Economic & Market Representation of the Northeastern Power Coordinating Council US Electric Power System,” *IEEE Power System transaction, 2008*.

[2]http://www.eere.energy.gov/windandhydro/windpoweringamerica/pdfs/2006_annual_wind_market_report.pdf

[3]http://www.nyserda.org/publications/wind_integration_report.pdf