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Cost Performance Tradeoff Study of Low-Carbon System Concepts

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ABSTRACT

Achieving higher emission reductions on one hand and employing lower cost concepts on the other hand are desirable in designing future power generator systems. Hence, interdisciplinary studies in a form of system concept modeling should be employed to conceptualize and construct economic and efficient low-carbon system concepts. The concept modeling starts with simple idealized models that preserve the key structural features of a system and adds complex features in the following stages to elucidate principles, relationships, and interfaces. For wind systems, the essential features for concept modeling are wind and load variations, and the main goal is to obtain the cost of electricity delivered by the system as a function of wind penetration (emission reduction); more complex features (storage, photovoltaic, transmission, etc.) are added in the following stages. In this work, an interdisciplinary concept modeling is provided to estimate the magnitude of cost versus performance using the wind/load data from Pennsylvania New Jersey Maryland Interconnection (PJM) LLC, and cost estimations published by the Energy Information Agency. The results show that system total cost increases modestly at low penetration, and it increases more rapidly when wind curtailment becomes significant. Eventually storage becomes cheaper than curtailment. The key question that should be answered in this modeling is the magnitude of electricity cost for high penetration, low emission systems.

INTRODUCTION

In recent years, developing low-carbon systems that reduce the emission of greenhouse gases and at the same time reduce the dependency on conventional energy sources has moderate to strong support across the world. Wind power, abundant, globally available, and green, has been drawing more interest and has improved its market share more rapidly compared with other types of renewable energies [1].

Classic system concept development begins with concept models – keep it simple. Complexity is then gradually added in stages. This top-down approach allows for a clear understanding of functional performance (e.g. the relationship between wind curtailment and system costs), relationships between functions and interfaces. The art of system concept modeling is in choosing the appropriate level of detail. The model needs to include enough detail to grasp the structural essence of the problem. But too much detail too soon obscures the fundamental relationships. To correctly preserve intermittency, wind-system-concept models must be based on system level wind and load data. This phase presented in this paper is based on2012 data for PJM.

Since the purpose of concept modeling is to compare alternatives, unbiased consistency between concepts is more important than absolute precision. It is very important for the models to develop consistent component capacity performance and cost estimates. Cost estimates involve many assumptions and judgments; the most important of which are discount rates, equipment longevity and future fuel cost. To provide this consistency, cost analysis is based on cost estimates developed by the Energy Information Agency (EIA)[2].

The scope of this phase is to compare generation systems at the regional level. Cost includes the transmission hookup of a generator to a regional power grid, but not long distance transmission. Transmission upgrades could cost more than primary power production. Follow-on phases will address parameter sensitivity (e.g. fuel cost) start expanding into multiple years and multiple regions and more complex generator combinations.

The objective of this study is to illuminate the cost and performance (emission) relationships of wind systems and to compare them with low-carbon alternatives. Cost is measured in dollars per megawatt hour ($/MWh) at the system level. Emission performance is measured as *%*CO_2 emissions relative to an all-natural gas system. The final results are provided in a single chart illustrating the cost of wind and other low-carbon alternatives' penetration for achieving any arbitrary carbon emission ranging from a maximum 100% to a minimum 0% emission rate. This chart will be a basis for sensitivity analysis for cost performance studies of different low-carbon system concepts.

EIA COST COMPONENTS

The Study objective is a conceptual level comparison of the cost of alternative system configurations. The cost of any energy system has two main components:

Fixed cost – This is the annual cost that needs to be paid regardless of how much energy is or is not produced. The main component is the "mortgage payment", the interest and depreciation on capital equipment investments.

Variable cost – These costs vary in proportion to how much energy is produced by a generator. The main component is fuel cost.

This study adapts levelized cost estimates developed and published by the EIA at which the estimated levelized cost of new generation resources is tabulated. The numbers are calculated in 2011 $/megawatt hour, and it is assumed that these systems would be brought online in 2018 [2].

Table 1 summarizes the relevant EIA cost estimates. The various fixed cost components listed above are summed into a single number in the table. The EIA tabulated cost components for a variety of dispatchable and non-dispatchable technologies (wind) include:

- Capacity factor (CF)– Average energy production as a *%* of nameplate capacity;
- Levelized capital cost – Roughly, the mortgage payment;
- Fixed operations and maintenance – O&M that is independent of utilization rate;
- Variable operations and maintenance - mainly fuel cost;
- Transmission investment – cost of hookup to the grid; and
- Total system levelized cost – The cost that underlies generation utilities' wholesale price bids.

For natural gas, the conceptual system costs are based on EIA's estimates for advanced combined cycle generators. Real systems would employ a mix of different types of natural gas generators, combined cycle and combustion turbines. However, after adjusting fixed cost for capacity factor, the differences are small and unimportant for concept tradeoffs.

Table 1 - Levelized cost components estimated by EIA ($/MWh)

Generator technology	CF %	Fixed cost	Variable cost	Levelized cost
Advanced nuclear	90	96.1	12.3	108.4
Natural gas advanced combined cycle	87	20.6	45.0	65.6
Geothermal electric	92	89.6	0.0	89.6
Wind – onshore	34	86.6	0.0	86.6

SYSTEM MODELING METHODOLOGY

The system modeling methodology is to calculate the proportional contribution for each of the different generator types, and then add them up. This is straight forward for variable cost: the EIA levelized variable cost from Table 1 is directly applied to each proportional component.

Calculating fixed cost in our levelized cost model is a bit more complicated, because it is necessary to back out the EIA assumed capacity factors and calculate actual capacities for each of our system scenarios. The EIA levelized fixed cost estimates (Table 1), first estimate total fixed cost per nameplate ($/MW), then level it using discounted cash flow analysis (equivalent mortgage payment). They then divide the levelized fixed cost per nameplate ($/MW) by the annual hours indicated by an assumed CF, to get the levelized fixed cost ($/MW) of electricity production.

Each of our system scenarios has a required capacity for each generation component. Hence, in order to compute the fixed cost for the required capacity we need to back out the CF assumed by EIA. That is, the wind-onshore fixed cost of 86.6$/MWh must be multiplied by 0.34 to get 29.44 $/MWh (This reverses the EIA calculation where EIA started with 29.44 and divided by the CF to get the fixed cost for that CF).

INSTALLED RESERVE MARGIN

The system needs sufficient reserve capacity to reliably operate during peak load. Consistent with the "keep it simple" philosophy of concept modeling, this paper uses an archaic deterministic method [3]. After a rather complex set of calculations, PJM uses an Installed Reserve Margin of about 15% [4].

A debated question is the contribution of wind to system reserves. Pavlak [5] argues that the contribution of wind to system capacity is negligible and presents empirical evidence that it is <4% of wind nameplate for the PJM region. The number is small and consistent with the "keep it simple" philosophy; the contribution of wind to system capacity is ignored.

ALL-NATURAL GAS SYSTEM SCENARIO

An all-natural gas (NG) advanced-combined-cycle system is the reference scenario. It is the lowest cost and highest carbon emission baseline system. On the system cost/performance chart, this configuration will be viewed as 100% CO_2emission.

Figure 1 presents the load time series for PJM in 2012 [6]. The time series is presented as hourly averages. Year 2012 was a leap year, so the number of data points is $24*366=8,784$. The average load data, peak load (annual maximum), and total capacity (peak load + 15% reserves) are illustrated as well. The cost numbers are normalized relative to the average load. Hence, the variable cost of natural gas is the variable cost from Table 1, times the average load, divided by the average load (to normalize it). For the all-natural gas scenario, the variable cost is simply the variable cost from Table 1.

The fixed cost of the all-natural gas scenario is the fixed cost from Table 1, times the capacity factor in table 1 (to back out the CF used by the EIA) times the ratio of total capacity to average capacity. These computations are summarized in Table 2 showing the cost of our conceptual all-natural-gas PJM system, 100% emissions, is 80.76 $/MWh.

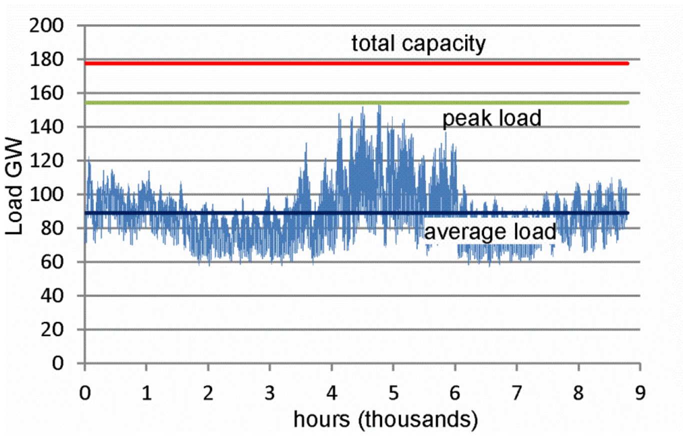

Figure 1 - PJM load in 2012

Table 2 - System cost for all natural gas

Average load 2012 (GW)		88.95
NG capacity (GW)	Annual peak + 15% reserves (154.34*1.15)	177.49
Avg. NG production (GW)	Average load	88.95
NG fixed cost ($/MWh)	= 20.6 * 0.87 * 177.49/88.95	35.76
NG variable cost ($/MWh)	= 45.00	45.00
Total system cost ($/MWh)		**80.76**

NATURAL GAS + WIND + IDEAL STORAGE SCENARIO

Storage is idealized for this scenario: zero cost, 100% efficiency, large (but finite) size. 100% of wind power is used to displace load. This is a good approximation for low wind penetration, before the onset of curtailment (high wind production exceeds low load). This scenario identifies system limits. System costs will exceed these limits due to the reality of curtailment, storage cost and storage inefficiencies.

Any finite storage can eventually be overwhelmed by too many sequential low wind days. This means that NG needs the capacity to satisfy full peak load with reserves even with a large amount of wind.

With no wind we have the all NG system as cost in the preceding section at 80.76 $/MWh. EIA assumed a wind CF of 0.34 as sort of an overall national average. The actual CF for PJM was 0.30 in 2012, hence the wind fixed cost needs to be corrected by this ratio. Table 3 presents the cost for 100% wind with ideal storage.

A cost-performance chart, a graph of system cost of electricity as a function of emissions is presented in Fig. 2. The red square is the system cost for all natural gas calculated in Table 2. The blue dashed line is system cost as a function of system emissions as reduced by wind assuming ideal storage. Cost at the right hand end of the line, 0.0% emissions, was calculated in Table 3.

Table 3 - System cost for wind + ideal storage

Average load 2012 (GW)		88.95
NG capacity (GW)	Annual peak + 15% reserves (154.34*1.15)	177.49
Avg. NG production (GW)	88.95 * 0	0
Avg. wind production (GW)	88.95	88.95
NG fixed cost ($/MWh)	= 20.6 * .87 * 177.49/88.95	35.76
NG variable cost ($/MWh)	= 45.00*0.0	0.00
Wind fixed cost ($/MWh)	= 86.6*0.34/0.30	98.15
Total system cost ($/MWh)		**133.90**

The blue dashed line would be horizontal if the system cost with wind were equal to the system cost without wind. That is if the cost of wind equaled the cost of fossil fuel saved:

$$\$NG_{fixed} + \$NG_{variable@100\%} = \$NG_{fixed} + \$Wind$$
$$\$Wind = \$NG_{variable@100\%}$$

Using EIA estimates, the levelized cost of wind is $86.6/MWh, which is more expensive than the levelized cost of natural gas @ $45/MWh, and the system cost increases with wind penetration; hence, the blue dashed-line slopes up.

If the cost of natural gas increases the red square and the left hand side of the blue dashed-line would move up as well. However, the right hand-side of the line, the cost of an all wind system would not change. Conversely if the cost of wind turbines decreased, the right hand-side of the line would move down and the left hand-side would not change.

A wind + NG system scenario follows the ideal storage curve out to the point where curtailment begins. PJM 2012 wind contributed 1.6% to the total load. The wind-time series is scaled up (assuming the same footprint of deployed wind farms) until wind just begins to overlap the load curve. As illustrated in Fig. 3, curtailment begins when average wind equals approximately to 26.4% of average load.

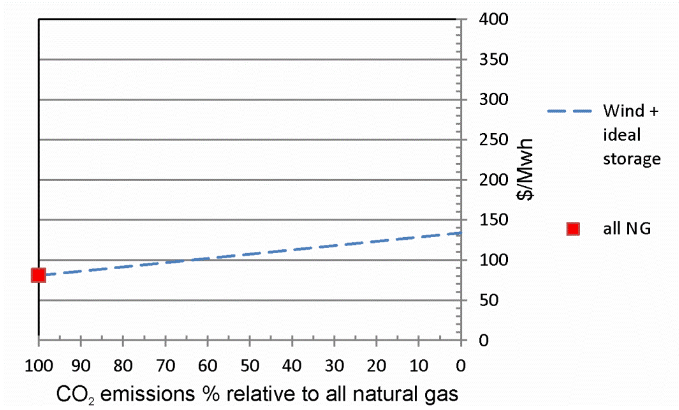

Figure 2 - Wind + NG + ideal storage

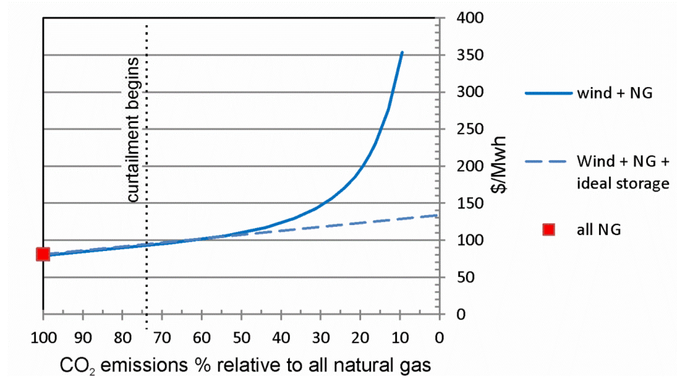

Figure 4 - Wind + NG with curtailment

WIND + NG SYSTEM SCENARIO

The cost-performance chart for the wind + NG system scenario is presented in Fig.4. Curtailment (shutting down some wind turbines so hourly average wind power never exceeds hourly average load) begins at 26% wind penetration (74% emissions). But curtailment does not have a noticeable effect on system cost until about 50% penetration. The solid blue curve in Fig. 4 is calculated by curtailing wind when wind power exceeds load; that is, when the hourly average wind spikes in Fig 3 exceed hourly average load in Fig. 3. The dashed line in Fig. 4 is calculated by assuming ideal storage, there is no curtailment; all of the wind energy produced is used. The fact that the two curves do not diverge until 50% penetration indicatesthat the high power wind spikes in Fig. 3 do not persist long enough to contain much energy relative to average power New technologies in wind turbine drivetrain configurations such as multiple-generator drivetrain [7], High-temperature-superconductive generators [1] in commercial and residential [8] scalesprovide higher CF values that can provide higher emission reduction at lower cost. The large wind power spikes in Fig.3 apparently do not have much energy associated with them

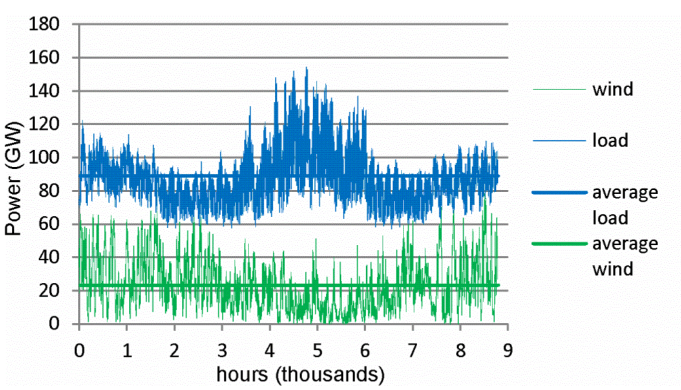

Figure 3 - PJM 2012 load and scaled wind at the beginning of curtailment

WIND + NG + BULK STORAGE SCENARIO

This scenario considers the impact of grid scale storage on system cost vs. performance. The size of the storage is assumed to be one day of average load or 2,135 GWh. Cost/performance of bulk storage is developed in Appendix A. It is modeled after Bath County pumped hydro storage facility [9]. The upper Bath County reservoir is 0.4 square miles and the reservoir rises and falls 105 feet during operation. The cost of pumped storage is 197 \$/kWh and PJM would need 68 such facilities to provide 2,135 GWh of storage capacity.

The system logic is to charge storage whenever there is any excess wind power and to discharge whenever there is available charge and wind cannot meet load. NG provides power whenever load cannot be satisfied by either wind or storage.

Figure 5 shows the state of charge of the pumped hydro storage for wind penetration equal to average load. It is apparent from this figure that the system challenge is July, about 5,000 hours into the year. There is insufficient wind to keep the storage charged.

The cost-performance chart for the wind + NG + one day of pumped storage system is illustrated in Fig. 6. As the storage size is reduced to zero the two curves will merge. The overall impact of grid scale storage is marginal. This is consistent with Budischack's conclusion [10] that it is cheaper to overbuild wind.

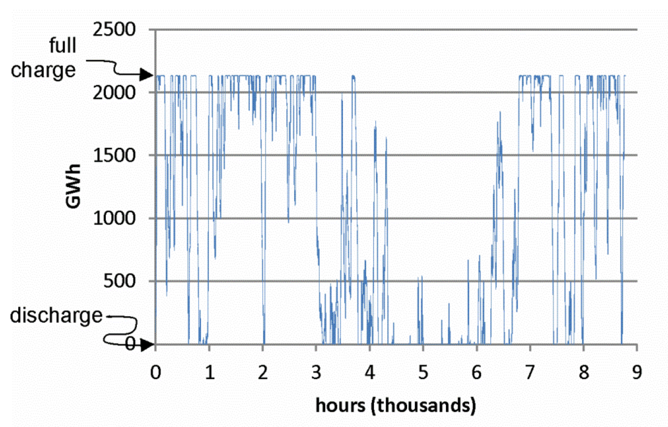

Figure 5 - State of charge 2.1 TWh storage @ average wind = average load

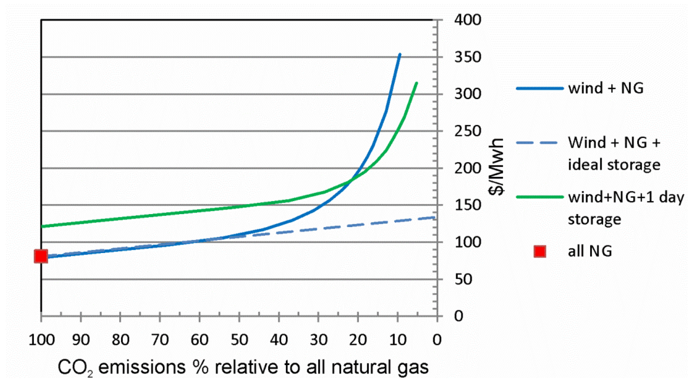

Figure 6 - Wind + NG + one day pumped storage

NUCLEAR + NG SCENARIO

Nuclear power is a zero carbon option that needs to be compared with renewables. In the US today, commercial nuclear power plants are base load power plants producing constant power on a daily timeframe. Nuclear plants schedule maintenance during low load seasons so nuclear follows seasonal load variations as illustrated in Fig. 7 [11]. During peak demand commercial nuclear has an availability of 0.97.

Through design and operational improvements, France has developed their reactors to have modest load following capability on 24 hour time scales. Our system concept model follows the French concept. The nuclear plants are assumed to follow the diurnal minimum load and natural gas is used for both diurnal variations and for system reserves. This concept is illustrated in Fig. 8. Subtracting the modified base load from total load results in NG provides 19.8% of total system power.

Based on this model, assuming that natural gas has the capacity to provide the 15% system reserves, the system cost for nuclear + NG is derived in Table 4. The nuclear + NG scenario has system emissions of 19.8% and a system cost of 128.8 $/MWh. This data point is added to our system cost-performance chart as illustrated in Fig. 9.

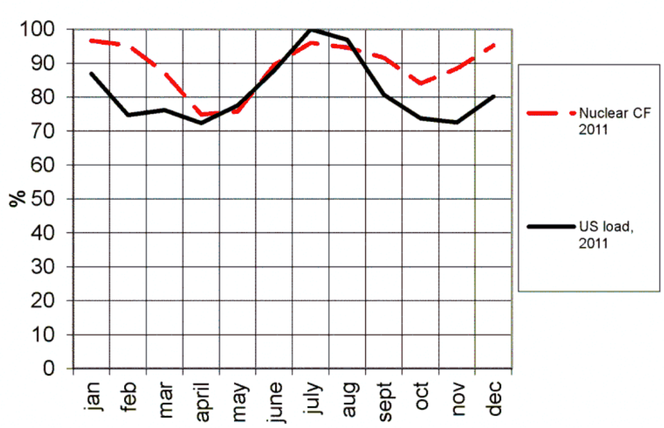

Figure 7 - Nuclear power plant capacity factor

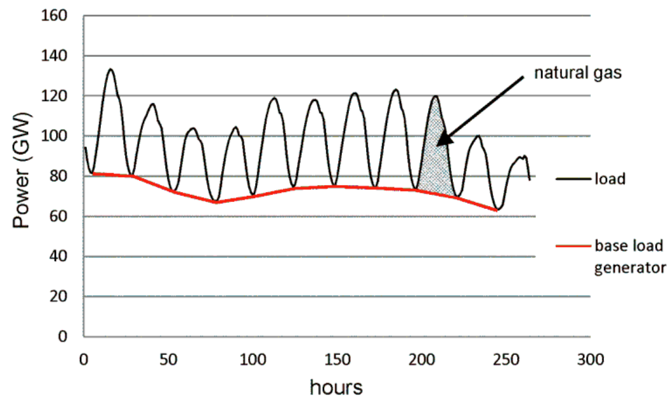

Figure 8 - Nuclear + NG system model

Table 4 - Nuclear + NG system costs

Average load 2012 (GW)		88.95
Nuclear capacity (GW)	Maximum of diurnal minimums	96.80
Nuclear production (GW)	Average of diurnal minimums	71.30
NG capacity (GW)	Annual peak load + 15% reserves – nuclear capacity (154.34*1.15-96.8)	78.89
NG production (GW)	Average load – nuclear production (88.95 – 71.30)	17.65
NG fixed cost ($/MWh)	= 20.6 * .87 * 78.89/88.95	15.89
NG variable cost ($/MWh)	= 45.00 * 17.65/88.95	8.93
Nuclear fixed cost ($/MWh)	= 96.1* .9 * 96.8/88.95	94.12
Nuclear variable cost ($/MWh)	= 12.3 * 71.3/88.95	9.86
System cost ($/MWh)		**128.80**

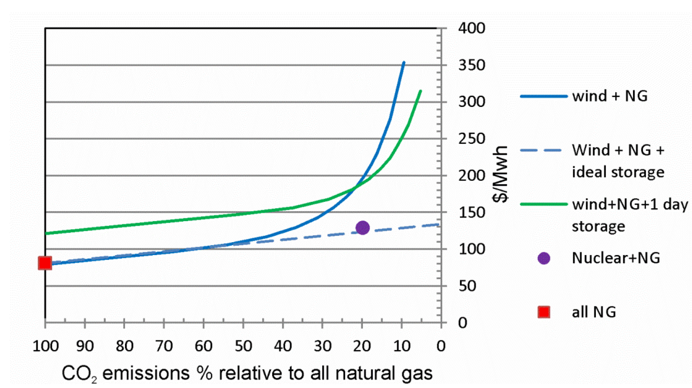

Figure 9 - Nuclear + NG scenario

NUCLEAR + NG + DIURNAL HOT WATER STORAGE SCENARIO

The previous section identified a modified base-load concept whereby base-load power plants are adapted to slowly follow load variations on 24-hour time scales. Within this concept, diurnal hot water storage can be used to reduce system emissions.

Figure 10 presents the hourly load for 2012 plus a 24 hour moving average (MA). The weekend dips every seven days are apparent. The MA shows the potential smoothing that can be achieved by load leveling.

The amount of diurnal storage required to level load can be calculated by summing the total energy above the MA for each day. As can be seen from Fig. 10, there is considerable variation from day to day. The cumulative distribution function for 366 daily storage opportunities is presented in Fig. 11. From this chart 150 GWh storage covers all except 23% of the days. On those 23% of days, storage covers most but not the entire requirement. The total energy not covered by storage, calculated by subtracting 150 GWh from daily storage requirement, must be covered by NG. This is quite small, 3799 GWh or 0.49% of total energy delivered. System emissions from this scenario are 0.5%.

System storage cost is the unit cost in \$/kWh times the total storage required, divided by the annual electricity consumption in MWh. Table 5 summarizes the system costs for this scenario with hot water storage (Appendix B). Figure 12 presents system cost-performance chart with the nuclear power scenarios. Nuclear power is a low cost approach to achieve big emission reductions.

Table 5 - Nuclear + NG + domestic hot water storage

Average load 2012 (GW)		88.95
Nuclear capacity (GW)	Maximum of moving average	130.06
Nuclear production (GW)	Average of moving averages	88.96
NG capacity (GW)	15% of peak load	23.10
NG production (GW)	3799 GWh / 8784; (0.49%)	0.43
NG fixed cost (\$/MWh)	= 20.6 * 0.87*23.1/88.95	4.65
NG variable cost (\$/MWh)	= 45.00 * 3977GWh/8784h/88.95GW	0.23
Nuclear fixed cost (\$/MWh)	= 96.1* .9 * 130.6/88.95	126.99
Nuclear variable cost (\$/MWh)	= 12.3 * 88.96/88.95	12.30
Storage cost (\$/MWh)	= \$12.32/kWh *150 x 10^6 kWh / 781.3 x 10^6MWh	2.36
System cost (\$/MWh)		**146.53**

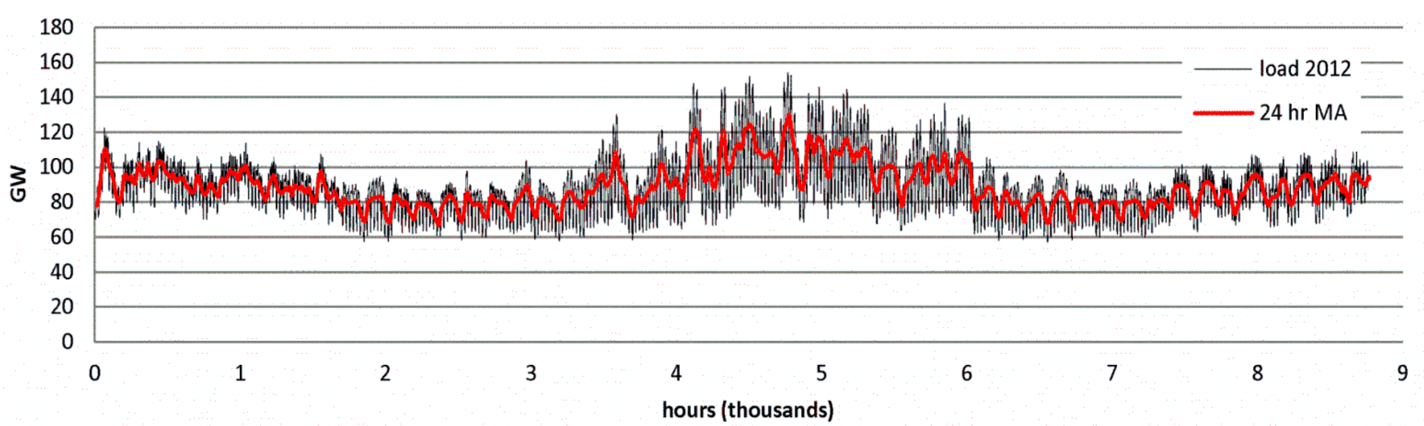

Figure 10 - Load and 24 hour moving average 2012

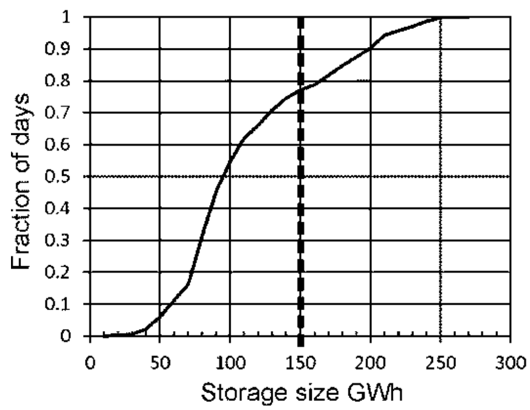

Figure 11 - Diurnal hot water storage size GWh

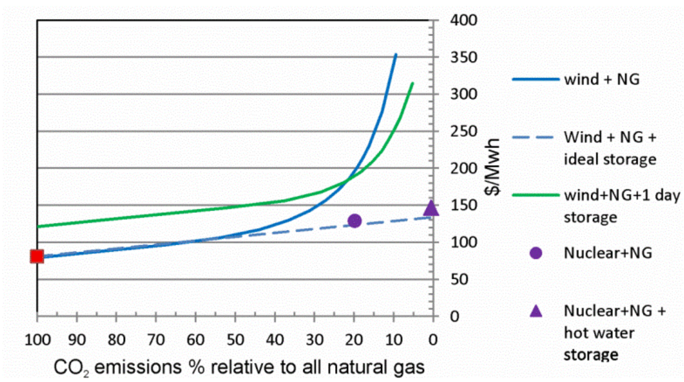

Figure 12 - System cost vs. performance with nuclear power scenarios

FUTURE WORK

Based on the results obtained in this work, the following high priority tasks for system concept development can be identified for the future work:

- Multiple years - This paper used wind and load time series data published by PJM in 2012. To more fully characterize cost/performance for PJM, this needs to be expanded to:
  1. Be consistent with technical methods published by PJM in PJM Generation Adequacy Analysis[12]. For example designed peak-load employs five years of load data adjusted for growth.
  2. Adjust wind power for wind nameplate growth.
  3. Look for year to year variation in the curtailment curve. Is the curtailment curve stable? Is averaging multiple years useful?
- Multiple regions - How much variation in the curtailment curve exist between different regions? Single wind farms would exhibit much higher curtailment. What does the data say about EirGrid, MISO, Bonneville, ERCOT, and Hawaii? Different regions are likely to result in different conclusions.
- Storage parameter variation - At the conceptual level, storage cost is fully characterized by capacity, capacity cost and efficiency. Keeping the latter two constant (quantified for Bath County pumped hydro storage), how does capacity change the curtailment curve? Varying, the latter two parameters, can we identify requirements for storage that would make a difference?
- Add transmission - This modeling considers a "copper sheet" transmission, no bottlenecks or losses or additional costs. In real systems, there will be a tradeoff between transmission costs and curtailment which could be very significant..
- Solar PV - In PJM, July and August correspond to peak load and low wind. This is a time when Solar PV, suitably positioned, performs well. Using solar PV time series and EIA costs, how does the addition of varying amounts of solar affect the cost-performance curve.
- Geothermal Electric (GTE) Scenario - Geothermal electric is another base-load technology, similar to nuclear power. GTE has the potential to be adapted to a modified base-load generator with cost/performance characteristics very similar to that of nuclear power.
- EIA cost limitations - Systems configured here push the assumptions behind EIA cost projections. For example, with a wind + NG system at very low emissions, the system needs full peak NG capacity. The NG generators are needed at high power for only a few days per year. The assumptions behind EIA's variable cost estimates would not apply. How does variable cost change with wind penetration?
- Curtailment - Preliminary analysis of PJM/MISO data shows that the long distance connection of PJM and MISO does not provide system capacity at the level of one-day-in-ten-years [13] However, such connection should improve curtailment. To what extent is this true?
- Parameter variation – The model provides the basis for exploring future scenarios such as different future fuel prices.
- Prior data comparisons - There have been other cost/performance studies such as Budischak [10]. The present concept modeling results need to be compared with the prior studies and differences explained.
- Formalize and detail the modeling – Concept definition starts with very simple system models and gradually adds complexity in stages. This paper is the first step. It is now necessary to selectively increase depth, add features and formality to the modeling. The purpose is to identify system component requirements, point to risk areas and the need for component development and critical item tests.

TEMPLATES

An Excel template of the simulations is available from the first author so that others could extend and expand the modeling efforts.

CONCLUSION

Classical system concept development starts with very simple concept models, and then gradually adds complexity to produce more complex formal models that more closely approximate real world nuances. This paper opens the way to develop more formalized system concept modeling and prioritizes system development. Several tentative conclusions can be drawn:

- For the PJM region in 2012, a wind + natural gas system can reduce emission as much as 50% below that of an all-natural gas system with only a modest increase in system generation cost. This analysis ignores transmission costs which could be very significant.
- Further emission reduction becomes increasingly expensive and nuclear and geothermal electric systems appear to be less costly solutions for low emissions.
- Modified base-load generators (nuclear and geothermal electric) that follow load on 24-hour time scales along with domestic hot water storage can achieve nearly zero emission electric power systems at modest cost.
- Grid-scale storage at the level of one day at average load does not reduce system costs except at higher emission levels.
- Evolving systems - How could these systems evolve with time. Start with simple concept models of the existing grid mix (emissions are only 25% greater than all NG.) A primary set of scenarios could be minimum cost, what happens as the cost of NG increases? A second set of scenarios could involve policy decisions such as carbon tax or emission regulations (coal).

APPENDIX A – BULK STORAGE

Pumped storage is proven technology. The main difficulty is that it is limited by geography, two large reservoirs in close proximity with ~ 1,000 ft of vertical separation. For the purpose of concept trades we identify the cost and performance of pumped storage and assume that some technology will become available to provide large scale storage at similar cost and performance.

The reference is Bath County pumped storage in Virginia. This facility was licensed in 1977. Round trip efficiency is typically 80%.

Table A1 presents the cost and performance characteristics for Bath County pumped storage. Note that the capacity cost is $197 $/kWh vs the $100 for domestic hot water storage. Also the PJM region would require 68.4 storage facilities of similar size to store one day of electric power.

Table A1 - Bath County pumped storage cost

Rated power kW			3,030,000
Duration at rated power (hr) =			10.3
Capacity kWh			3.12E+07
Capex $	1977		1.60E+09
	2014	3.85	6.16E+09
Capacity cost $/kWh			$197
30 year annuity $/kWh/yr			$15.27
PJM one day capacity kWh			2.13E+09
# Bath sized storage units			68.4

APPENDIX B – HOT WATER STORAGE COST

France has demonstrated that oversized electric hot water heaters under the control of the utility are effective for diurnal load leveling. The concept is for the utility to heat the water at night for daytime use.

The total size of such a system is limited by the quantity of energy used for residential hot water heating. EIA estimates that residential use amounts to 37% of total electricity consumption [14] and 18% of residential energy use is for domestic hot water [15]. This means that about 7% of electricity consumption can be shifted from day to night time use. This amounts to total storage of 150 GWh for the PJM RTO (average load 88.95GW/h). The cost of such a system is estimated as the cost of installing new hot water systems.

Table B1 - Hot water storage cost

Item	Cost ($)
80 gal tall hot water heater	539
Mixing valve	80
Controller	100
Installation	500
Total	1219

The energy stored assuming 80 gal cycled 50^{o}F (160-210^{o}F) is 10 kWh and the capacity cost of residential hot water storage is $122/kWh. Since people require hot water storage anyway we assume the additional cost of storage to be $100/kWh, ½ that of pumped hydro. System tradeoffs require a levelized cost or equivalent annuity. Using the same 6.6% discount factor as the EIA and assuming a 12 year life, the annuity factor is 0.1232 and the levelized cost $12.32/kWh.

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