From: William Johnston [wj3@comcast.net]
Sent: Tuesday, October 13, 2009 10:35 AM
To: Debra Moldover
Cc: Bruce Gordon; Peter Vogt; James Mason; Biggins, James; Quinn, Laura; Millie Kriemelmeyer; Wilson Parran; Tom Deming, Esq.
Subject: Fw: ML number for the article from the scoping meeting.
Attachments: Mason_Coupled Wind-CAES Power Plants_Comparative Base Load Power Plant Analysis__RERI_13 August 2009.pdf

Debra, here is a link (from James Mason further below) to Craig Severance's and Arjun Makhijani's presentation on CAES coupled with wind for San Antonio. James Mason is now preparing for a presentation to the Austin city council, as I understand. I attach hereto Mason's '09Aug13 paper submitted to *Energy* for peer review and publication. I understand he and Severance are planning a joint paper soon. Makhijani authored *Carbon-Free and Nuclear-Free--A Roadmap for US Energy Policy* ('07Aug). You may have to listen through the intro and the first speaker who is pronuke to get to the other two. I could only get the first video with all the speakers to work, but it was worth the hour.

http://texasvox.org/2009/09/18/watch-san-antonio-clean-tech-forum-the-great-nuclear-debate/

Looking forward to hearing from you soon on this available option, and of any help from Senator Mikulski on a fair eis by NRC. I will forward separately the hardball email from James Biggins, an NRC general counsel on our efforts there to date. They propose to proceed now with the eis without including this in the alternatives or recognizing it exists, as I understand. I did manage to get into the record at that '08March scoping meeting the Grand Solar Plan ('08Jan Scientific American) but that is now old hat. Mason was a coauthor on that, and now has coupled wind with CAES as the most cost effective alternative, which NRC would ignore!

Bill Johnston

----- Original Message -----
From: Solar Plan
To: William Johnston
Cc: Peter Vogt ; Bruce Gordon ; Millie Kriemelmeyer ; Tom Deming, Esq. ; Quinn, Laura ; James Biggins, Esq. ; Patrick Magnotta ; Marty Madden ; Jeff Newman ; Christie Goodman ; Chris Bush
Sent: Thursday, September 24, 2009 12:09 PM
Subject: Re: ML number for the article from the scoping meeting.

I'm glad you spent the time to sort through the presentations, I did not know how to convey directions on how to get to Craig's presentation. The key is get a comparative economic analysis of alternatives to nuke ("due diligence"). Progress is being made.

James

> ----- Original Message -----
> **From:** William Johnston
> **To:** Solar Plan
> **Cc:** Peter Vogt ; Bruce Gordon ; Millie Kriemelmeyer ; Tom Deming, Esq. ; Quinn, Laura ; James Biggins, Esq. ; Patrick Magnotta ; Marty Madden ; Jeff Newman ; Christie Goodman ; Chris Bush
> **Sent:** Thursday, September 24, 2009 11:22 AM
> **Subject:** Re: ML number for the article from the scoping meeting.
>
> James,
>
> Thanks for the link, though I could only get the top window to work, in which each of the 4 experts spoke 12 minutes each (the first one being the San Antonio local utility guy who really had nothing to say, the second being the pronuke guy

Brooke who was a Greenpeace founder but who seems to have no answers to the next two). Great to hear for the first time Craig Severance who you say is rewriting your paper with you now, and Arkijahni also for me the first time. It was a shot in the arm, reassurance that we are on the right track and should prevail here soon, if we have not already in fact, just need to wait for things to play out? Amazing how uninformed our decision makers here are. The local utility guy seemed to be proud of still requiring paper copies for his own purposes, i.e., shunning computers/internet, and boasting of his weekends golfing. Talk about your dinosaurs!

I should probably try to hunt down and respond to our county commissioners recent editorial comment to the Sun in Baltimore, which received no local coverage at all, mostly because they have sought from the start to make it a non-issue locally. No mention or coverage at all, except the canned info provided by the nukers and run automatically every time without any independent thought. Talk about your company town, here we have had company county and state. Keep the peasants ignorant, as ignorant as the leaders who are easily led with moderate campaign contributions. No independent coverage at all by the local media, nor even by the haughty Washington Post.

The key concept: compressed air energy storage (CAES) affordably (3 cents/kwh?) converts any kind of intermittent energy supply (say from truly clean alternatives, unlike nuke) to base load needs. That, with conservation and price differential for peak demand via smart meters, problem solved. Maybe it will not be necessary for you to come testify here, but in the meantime I will try to get request on record at the PSC.

Bill

fyi for any readers, compare 1.1 Gw of wind by 2020 for San Antonio, if not more, with 1.6 Gw from CCNPP3 in say 6 years after receiving the federal permit in maybe 3 years?

> ----- Original Message -----
> **From:** Solar Plan
> **To:** William Johnston
> **Cc:** Peter Vogt ; Bruce Gordon
> **Sent:** Thursday, September 24, 2009 1:00 AM
> **Subject:** Re: ML number for the article from the scoping meeting.
>
> San Antonio has a proposal to expand the South Texas Nuclear Project. A friend, Craig Severance, made a presentation at a community forum discussing the pros/cons of the proposal.
>
> http://texasvox.org/2009/09/18/watch-san-antonio-clean-tech-forum-the-great-nuclear-debate/
>
> The issue with wind at present is RPS (Renewable Portfolio Standards), which in the case of San Antonio is 1.1 GW of wind by 2020. As Craig states, why spend the money for wind and also for the nuke capacity, when you can get firm wind (with CAES) for less money.
>
> James
>
>> ----- Original Message -----
>> **From:** William Johnston
>> **To:** James Mason
>> **Cc:** Peter Vogt ; Bruce Gordon
>> **Sent:** Wednesday, September 23, 2009 5:13 PM
>> **Subject:** Fw: ML number for the article from the scoping meeting.
>>
>> James,
>>
>> They just put the '08JanSciam article on line? Got to check it out. Did you see the Sept. 11 Science on the potential for wind in China by McElroy (?) et al. at Harvard? Some great info.
>>
>> Maybe tomorrow or Friday morning I will find strength to get your report and offer to testify before the state PSC, as a new and specific item in our pending request for rehearing. Have a little work to do in the developing federal eis case

also, straightening out the record, presenting environmental effects due to the cooling tower and maybe others, and hopefully hearing something soon from NRC or CEQ on a new scoping meeting.

If there was a regional CAES, then any local wind or solar anywhere on the grid could supply instantaneous demand and any left over CAESd. Would the marginal rate for stimulating that supply, from business and residential, be a song compared to nuke? Of course, smart meters must be able to limit supply to priorities when pressure drops, if not enough backup? Or maybe that cannot be allowed to happen? But the issue is how much of a peak/worst-time surcharge, to assure available supply meets instantaneous demand? Gets us into what smart meters might do. Scary in many ways. Guess they could always turn on an old fossil unit standing by, if nothing better.

Bill

----- Original Message -----
From: Quinn, Laura
To: William Johnston
Sent: Tuesday, September 22, 2009 10:36 AM
Subject: ML number for the article from the scoping meeting.

Mr. Johnston,
The magazine article that you submitted to the NRC can be found in ML081130650.

Thanks
Laura

Laura Quinn
Environmental Project Manager
Office of New Reactors
Nuclear Regulatory Commission
301-415-2220
Laura.Quinn@nrc.gov

Hearing Identifier: CalvertCliffs_Unit3Cola_Public_EX
Email Number: 1025

Mail Envelope Properties (623D1A94ADF7483FABE675099B534827)

Subject: Fw: ML number for the article from the scoping meeting.
Sent Date: 10/13/2009 10:34:51 AM
Received Date: 10/13/2009 10:35:06 AM
From: William Johnston

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MESSAGE	8955	10/13/2009 10:35:06 AM
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A Coupled Wind-CAES Base Load Power Plant Model: Comparative Economic Analysis of Base Load Power Plant Options

Prepared by James Mason, Ph.D.
Renewable Energy Research Institute

Article Submitted to the Journal *Energy*

13 August 2009

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Abstract

This study evaluates the economic feasibility of deploying coupled wind and CAES (compressed air energy storage) power plants for base load capacity. Due to inherent variation in wind speeds, wind plants even with geographic dispersion cannot be assigned full load capacity credit and must be supported by thermal power plants to balance and firm variable wind electricity supply in order to maintain grid reliability, which is the purpose of coupling wind and CAES power plants. A coupled wind-CAES plant model is compared to other types of base load capacity power plants: wind with backup natural gas plants; natural gas combined-cycle (NGCC) plants with and without carbon capture and storage (CCS) systems; a pulverized steam coal plant without a CCS system; a coal integrated gasification combined cycle (IGCC) plant with a CCS system; and a nuclear plant. The coupled wind-CAES plant model has the lowest retail electricity price estimate of the wind plant options. Coupled wind-CAES plants achieve a breakeven electricity price with NGCC plants without CCS systems when the price of natural gas is \$9.10/MMBtu. The low fuel consumption rate of coupled wind-CAES plants insulates electricity price from future increases in natural gas prices, which will provide significant long-term economic benefits. The cost of CO_2 emissions reduction for coupled wind-CAES plants compared with conventional pulverized coal plants without CCS systems is \$33/tonne or a \$0.024/kWh (26%) increase in retail electricity price. In conclusion, this study finds that coupled wind-CAES plants are an economically viable option for base load capacity.

Table 5. Results: Comparative Analysis of Base Load Power Plants (Per Unit of Load Capacity Credit).

	Wind with NGCT (Optimized)[a]	Wind with NGCC (Optimized)	Wind with CAES (Optimized)	NGCC	NGCC w/CCS	Steam Coal without CCS	Coal IGCC with CCS	Nuclear
Retail Electricity Price (\$/kWh)	0.133	0.126	0.116	0.104	0.134	0.092	0.142	0.145
Capital Cost (\$/kW)	2,579	2,800	3,833	857	1,683	1,833	3,031	5,000
CO_2 Emissions (g/kWh)	355	282	78	392	132	806	70	0
Fuel Consumption (Btu/kWh)	6,837	5,010	1,439	7,196	8,613	8,844	9,713	0
CO_2 Reduction Cost (\$/t)	91	65	33	29	63		67	66

Notes:

a. Abbreviations: NGCT = natural gas combustion turbine; NGCC = natural gas combined-cycle; CAES = compressed air energy storage power plant; CCS = carbon capture and storage system; IGCC = coal integrated gasification combined-cycle.

I. Introduction: Base Load Capacity Power Plants.

This study evaluates the economic efficacy of deploying coupled wind and compressed air energy storage (CAES) power plants for base load capacity. By 2030, the U.S. will need to build approximately one hundred gigawatts (GW) of base load capacity to retire aging plants and to accommodate demand growth [1]. Base load power plants supply electricity to meet the daily minimum load, which means they operate at full power output, 24/7. In addition, the U.S. Department of Energy (DOE) agencies, Office of Energy Efficiency and Renewable Energy (EERE) and the National Renewable Energy Laboratory (NREL), are developing plans for wind power plants to supply 20-30% of total U.S. electricity generation by 2030, which is 800-1200 TWh (terawatt-hours) of electricity produced by approximately 300 GW of wind power plants [2, 3].

The Midwest plains states from the Canadian border to the Texas Panhandle and the Atlantic Ocean are the two largest and highest quality sources of wind energy in the U.S. This study investigates the economics of building coupled wind-CAES plants in the Midwest and then transporting the electricity to markets throughout the U.S. via long distance transmission lines (refer to Fig. 1). The purpose of this study is to establish a baseline model for coupled wind-CAES plants located at sites in the Midwest with a minimum Class 4 wind regime and to compare the results with other sources of base load power. The evaluation of offshore Atlantic Ocean wind plants is beyond the scope of this study.

At present, the conventional types of base load power plants are pulverized coal plants, nuclear plants, and natural gas combined-cycle (NGCC) plants. This study extends the analysis of base load capacity power plants to include wind power plants that are combined with backup natural gas combustion turbine and combined-cycle power plants and CAES air turbine power plants. Due to inherent variation in wind speeds, studies indicate that the effective load carrying capacity (ELCC) of wind power plants ranges from 5% to 30%, which means that wind power plants by themselves are not able to replace conventional base load capacity power plants [2]. The ELCC estimates hold even in the case of aggregate electricity production by geographically dispersed wind plants. In other words, wind plants are primarily an energy source that reduces the operational time and fuel consumption of fossil fuel plants and are assigned only marginal capacity credit.

If wind plants are to be assigned full base load capacity credit, then they must be able to reliably supply a pre-determined quantity of electricity on demand. Because of wind's variability, the only way to assign full load capacity credit to wind plants is at the system level, which consists of combining wind plant capacity with supporting thermal power plant capacity to balance and firm variable wind electricity supply. This study evaluates two wind base load capacity models: 1) a wind plant with supporting natural gas plant model; and 2) a wind plant with supporting CAES plant model. In the wind with natural gas plant model, the wind plants are assigned a 15% ELCC, which is a realistic expectation for a Class 4 wind resource regime [3]. Two types of backup natural gas power plants models are specified; a natural gas combustion turbine (NGCT) plant model and a natural gas combined-cycle (NGCC) plant model.

The wind plant with supporting NGCT plant model is the conventional backup power plant model to balance and firm variable wind electricity supply. In addition, this study includes the application of NGCC power plants to balance and firm variable wind electricity supply. The task is to maximize wind electricity supply and to minimize operation of supporting natural gas plants through the use of wind forecasts. Another issue that needs to be taken into account with the wind and natural gas plant model is the amount of time that the supporting natural gas plants must operate in spinning reserve mode in lieu of wind forecasting uncertainty about wind electricity production levels.

The third wind model and the focal point of this study is a coupled wind-CAES plant model. Several studies have been published in recent years documenting CAES power plants as a viable means to resolve the intermittency problem of wind and solar energy [4, 5, 6, 7, 8]. The basic idea is to transport a portion of wind electricity production to a CAES plant where it is used to power compressors and compress air. The compressed air is then stored in large underground reservoirs such as aquifers, depleted gas wells, or salt domes. The compressed air is released on demand from the storage reservoir to power the plant's turbine/generator unit. A CAES plant schematic is presented in Fig. 2. The volume of the air storage reservoir is selected to insure that an adequate supply of compressed air is available for the CAES plant to maintain a constant supply of electricity to the grid under all wind plant electricity production conditions. The turnaround wind energy storage efficiency is approximately 70%, which is comparable to the turnaround energy storage efficiency of other types of electricity storage systems [9].

For coupled wind-CAES plants, the objective is to maximize the grid distribution of wind electricity and to minimize CAES electricity production. In the coupled wind-CAES model, wind plant capacity is over-sized at a level to enable the assignment of a predetermined portion of peak wind electricity production to grid distribution and the remaining portion of wind electricity to the CAES plant. The size of the CAES plant and the volume of the air storage reservoir are designed to insure that the coupled wind-CAES plants are able to deliver a constant, pre-determined quantity of electricity to the grid.

A CAES combustion turbine power plant is similar to a conventional combustion turbine power plant but consumes about 58% less fuel. The difference in the CAES plant design is the separation of the air compressors from the turbine's air expansion unit. A conventional combustion turbine power plant consumes more energy to power the air compressors than the energy it uses for air expansion. In fact, two-thirds of the energy consumed by a conventional combustion turbine power plant is used to power the air compressors to create the air density and velocity to power the turbines and generate electricity. In contrast, the CAES power plant design separates the air compressors from the turbine/generator unit, which reduces fuel consumption by 58% since wind or some other external energy source is used to power the air compressors.

CAES is a proven technology with a 290-MW CAES plant operating in Germany since 1978 and a 110-MW CAES plant operating in Alabama since 1991 (refer to Fig. 3). The Alabama CAES plant was the only Gulf Coast power plant in operation during Hurricane Katrina in 2005. The McIntosh, Alabama CAES plant stores compressed air in an underground salt dome. The volume of stored compressed air is sufficient to generate electricity for twenty-six hours without recharging the air storage reservoir.

The geologic formations suitable for air storage reservoirs are porous rock formations such as deep saline aquifers, depleted natural gas fields, and salt formations. The distribution of favorable geologic formations for CAES suggests that there is ample air storage capacity for CAES plants in areas of the U.S. with Class 4 and higher wind resources (refer to Fig. 4) [9]. According to EPRI (Electric Power Research Institute) energy storage cost estimates, which are presented in Table 1, CAES is the lowest form of large-scale energy storage [10].

For CAES plants located in the Midwest, deep saline aquifers are the likely choice for air storage reservoirs. The air storage volume potential of aquifers is large compared with other types of storage reservoirs. It may be possible for a single aquifer to store a volume of compressed air to support gigawatts (GW) of CAES plant capacity, which would significantly reduce air storage cost.

One of the central questions of this study is whether the application of CAES power plants to shape and firm variable wind power results in a lower retail electricity price compared with the current method of using backup natural gas power plants. Then, the results of the wind models are compared with the results for the other base load power plant options. Also, a sensitivity analysis is performed to evaluate the effect of natural gas price increases on the retail prices of electricity produced by natural gas fired power plants.

II. Specification of Base Load Power Plant Models.

The specifications of wind and supporting thermal power plant models used in this study are informed by a review of studies conducted in recent years that are laying the groundwork for the large-scale production of wind electricity in the U.S. In 2007, the Office of Energy Efficiency and Renewable Energy (EERE) released the "20% Wind Energy by 2030" report [2]. The EERE study is being followed by the DOE/NREL sponsored Eastern Wind Integration and Transmission Study (EWITS) for the Eastern Interconnect region, which is studying 20-30% wind penetration levels. In December 2008, the initial EWITS report, JSCP'08 Economic Assessment, was released by the Joint Coordinated System Plan (JCSP) [3]. JCSP is composed of regional Independent Service Organizations (ISO) and electric utilities that manage and coordinate the nation's regional electricity transmission systems.

The largest source of high quality inland wind resources, Class 4 and higher, are located in the Midwest states from the Canadian border to the Texas Panhandle. Obviously, the cost of wind electricity is dependent on the quality of the wind resource, but long-distance transmission costs need to be factored into the cost assessment. The 2008 JCSP'08-EWITS study states that there may be economic benefits from the transmission of Midwest wind electricity to northeastern and southeastern states, but more research is required. The JCSP'08-EWITS report is the first step in planning the development of a national electricity transmission system for the U.S.

At present the EWITS program does not include a coupled wind-CAES plant scenario. While the JCSP'08 report acknowledges the issue of energy storage for wind power, the need for energy storage is rejected with assertions about possible solutions without providing supporting data.[1] This study extends the JCSP'08-EWITS report by specifying and evaluating the economic merits of an optimized wind-CAES model that is derived from a review of Succar and Williams 2008 wind CAES study [9].

The JCSP'08-EWITS study has two wind plant scenarios for 2024 power plant capacity allocations: 1) wind producing 5% of total U.S. electricity generation, i.e., 200 TWh of electricity; and 2) wind producing 20% of total U.S. electricity generation, i.e., 800 TWh of electricity. The JCSP'08-EWITS power plant capacity allocations are presented in Tables 2 and 3.

In the 5% wind scenario, there is 58 GW of wind power plant capacity and 77 GW of base load steam generating capacity. In contrast, the 20% wind scenario calls for 229 GW of wind power plant capacity and 37 GW of base load steam generating power plant capacity. Also, the 20% wind scenario calls for a 21 GW increase in natural gas combustion turbine plant capacity compared with the 5% wind scenario. The 21 GW increase in natural gas power plant capacity balances, shapes, and firms the variable wind electricity produced by the 171 GW increase in wind plant capacity.

From the JCSP'08-EWITS capacity allocations, it possible to deduce the wind and backup natural gas power plant allocation that results in a unit reduction in base load steam generating plant capacity. The objective is to estimate the allocation of wind and natural gas power plant capacity that is required to supply a unit of base load capacity with the same reliability standards of fossil fuel plants. Power plant

[1] One of the energy storage solutions mentioned in the JCSP'08 study is the use of pluggable hybrid electric vehicles. While this is an intriguing idea, there are many unanswered questions such as the quantity of energy available in the batteries of fleet vehicles at the end of the day, which corresponds with summer and winter peak demand periods. Also, the large number of vehicles in use during the afternoon drive period also corresponds with the winter and summer peak demand period. While research is needed to rigorously evaluate this form of energy storage, it is beyond the scope of this study.

capacity that meets load capacity standards, meaning it supplies electricity on demand, is the relevant definition of power plant capacity.

Since the 171 GW increase in wind power plant capacity results in a 40 GW reduction in base load steam generating plant capacity, it follows that 4.32 units of wind capacity, which is to be combined with a yet to be determined backup natural gas plant capacity, is equivalent to a unit of base load steam generating plant capacity (171 GW divided by 40 GW). To determine the backup natural gas plant capacity, there is a 21 GW increase in natural gas combustion turbine plant capacity along with the 40 GW reduction in base load steam generating plant capacity, which is a ratio of 0.52 units of combustion turbine plant capacity per unit of base load steam generating plant capacity (21 GW divided by 40 GW). The conclusion derived from this capacity allocation is that 4.32 units of wind plant capacity combined with 0.52 units of backup combustion turbine plant capacity provides one unit of base load capacity credit.

Prior research suggests that the JCSP'08-EWITS allocation of wind and backup natural gas power plant capacity to replace base load steam generating plant capacity stated above is not an optimum allocation [9]. This conclusion is based on the capacity specifications of an optimized wind with natural gas plant model and an optimized wind with CAES plant model from the Succar and Williams wind CAES study, which are presented in Table 3 [9]. The Succar-Williams capacity specification for an optimized base load wind with natural gas plant model is a load capacity ratio of 1.0 units of wind plant capacity to 0.85 units of natural gas plant capacity and 0.12 units of reserve natural gas plant capacity. The optimized wind with backup natural gas plant model has a 15% effective load carrying capacity (ELCC) for wind power and a reserve capacity of 15%, which are consistent with the JCSP'08-EWITS' ELCC and reserve capacity assumptions. The electricity supply mix of the optimized wind with natural gas plant model is 50% from the wind plants, 49% from the natural gas power plants, and 1% from the reserve natural gas simple combustion turbine plants. This specification is used for a NGCT model and a NGCC model.

The capacity specification for Succar-Williams optimized base load wind with CAES plant model is 1.57 units of wind plant capacity to 0.64 units of CAES plant capacity. The electricity supply mix of the optimized wind with CAES plant model is 69% from the wind plants and 31% from the CAES plants. The volume of compressed air in the storage reservoir supports 88 hours of CAES power plant operation without reservoir recharging, which is sufficient to maintain a firm 85% capacity factor rating for annual electricity production by the coupled wind-CAES plant.

III. Financial Assumptions.

All findings are reported in metrics that are scaled to a unit of base load capacity credit. Power plant cost, performance, and modeling parameters are presented in Table 4. Levelized retail electricity prices are estimated by the net present value, cash flow method. A levelized price is the price that generates a constant revenue stream to recover all capital investments and expenses over the capital recovery period. The net present value, cash flow method is characterized by the formula

$$NPV = \sum_{t=1}^{N} \frac{NCF_t}{(1+k)^t} - I_0 . \tag{1}$$

where: NPV = net present value of the investment project; NCF_t = net cash flows per year for the project; k = cost of capital, which is a weighted average cost of capital (WACC); $(1 + k)^t$ = the discount rate to convert annual net cash flows to their present value; N = number of years for capital recovery; and I_0 = shareholder investment in the project. The levelized electricity price is \$/kWh of electricity that creates a revenue stream generating a sum of annual discounted cash flows equaling a zero NPV over the specified construction and capital recovery period.

The financial assumptions, which are consistent with JCPS'08-EWITS, are as follows. The real discount rate is a weighted average cost of capital and is based on the following: a capital structure of 55% debt and 45% equity; rates of return on capital of 9% for debt and 12% for equity; a 39% tax rate; and a 3% average annual inflation rate. The capital recovery periods are: 25 years for wind plants, 30 years for thermal power plants, HVDC transmission lines and DC-to-AC converter stations. The construction period is three years for natural gas and CAES plants, six years for coal plants, and seven years for nuclear plants. Depreciation is a fifteen year MACRS. A simplifying assumption is that base load power plants have an 85% annual capacity factor. Fuel costs are \$7/MMBtu for natural gas, \$1.94/MMBtu for coal, and \$0.70/MMBtu for uranium.[2]

The wind, natural gas, and coal power plant capital costs, fixed and variable O&M costs, and plant performance parameters are from the JSCP'08 study [3]. The wind capital cost estimate of \$2,000/kW is the JCSP'08 estimate of actual 2008 wind plant capital cost. Nuclear plant fixed and variable O&M cost and plant performance estimates are also from JCSP'08 study. But the projected nuclear plant capital cost for Nth plant of \$5,000/kW is original to this study and is approximately 30% less than the projected next plant capital cost of more than \$7,000/kW, which are the reported bids recently submitted for proposed Ontario, Canada nuclear power plants [11]. The reported Canadian nuclear power plant capital cost estimates are consistent with the reported capital costs for a Finnish nuclear power plant that is under construction by the French company Areva [12]. CAES capital cost estimates are original to this study, but the fixed and variable O&M costs and performance parameters are from Succar-Williams wind CAES study [9]. A simplifying assumption is that base load power plants have an 85% annual capacity factor.

The coupled wind-CAES plant model assumes that both wind and CAES plants are located in the Midwest and that the electricity is transported to local markets nationwide via high voltage DC (HVDC) transmission lines at an average distance of 1,600 kilometers and one DC-AC converter station. HVDC and DC-AC converter station costs are from DLR and converted to 2009 U.S. \$ [13]. The cost of transmission lines for natural gas, coal, and nuclear plants are included in the retail electricity price estimates as a local electric company cost component since the conventional base load power plants are generally located within the transmission network of the local electric company.

The local electric company cost component in the end-user retail electricity price, which includes expenses such as local electricity transmission and billing, is assumed to be \$0.035/kWh. The local electric company cost is a ballpark estimate derived from analyses of EIA reported average retail electricity prices for 2008, levelized electricity price estimates for new generation, and a report on the revenues and expenses for a EIA sample of investor owned electric companies [1, 14]. While the retail electricity price estimates reported in this study are not definitive since they are sensitive to the underlying assumptions, they are appropriate to make comparative inferences since the assumptions are applied consistently to all the power plant models evaluated in this study.

The CO_2 emissions reduction cost estimates are in reference to the CO_2 emissions of a pulverized coal plant, which is assumed to emit 806 g CO_2/kWh of electricity generated [3]. The CO_2 emissions reduction cost estimates are calculated by subtracting the retail electricity price of the power plant with lower CO_2 emissions from the retail electricity price of the pulverized coal plant; then the retail electricity price difference is divided by the quantity that CO_2 emissions are reduced per kWh of electricity. For the natural gas and coal plants with carbon capture and storage systems (CCS), the estimated CO_2 transport and storage cost is \$0.004/kWh [9, 15].

[2] The fuel price estimates are for 2015, which is the earliest date for plants to come online if construction were to begin today.

For the wind with natural gas plant models, it is assumed that the supporting natural gas plants are in spinning reserve mode at a rate equivalent to 20% of total wind electricity production [3, 16]. The time spent in spinning reserve mode is in addition to the time spent in electricity generation mode. When a natural gas combustion turbine plant is in spinning reserve mode, the fuel consumption rate is 16% greater than when in electricity generating mode [17]. When plants operate in spinning reserve mode, they receive revenues in the amount of the variable O&M and fuel expenses incurred.

IV. Findings: Comparison of Wind Plant Models with Natural Gas, Coal, and Nuclear Plants.

Capital costs, retail electricity prices, retail electricity price sensitivity to increases in fuel price, fuel consumption rates, CO_2 emissions rates, and CO_2 emissions reduction cost estimates are presented in Table 5 and Figs. 5-10. The capital cost of the JCSP'08-EWITS wind with natural gas model is \$8,944/kW of base load capacity. The corresponding levelized retail electricity price is \$0.164/kWh. In contrast, the capital cost of the optimized wind with backup NGCT and NGCC plant models are \$2,579 and \$2,800/kW of base load capacity respectively, and the retail electricity prices are \$0.133/kWh and \$0.126/kWh respectively. These findings support the contention that the JCSP'08-EWITS' wind plant capacity allocation is sub-optimum in terms of both capital cost and retail electricity price.

The capital cost of the wind with CAES plant model is \$3,833/kW of load capacity, and the retail electricity price estimate is \$0.116/kWh. While the capital cost of wind-CAES base load capacity is greater than the optimized wind with natural gas plant models, the retail electricity price is less. The capital cost differential between the wind-CAES model and the wind-NGCT model is recovered in ten years from the electricity price savings, and for the wind-NGCC model the capital cost differential is recovered in fourteen years. At a 20% wind penetration level, which is 800 TWh of annual electricity production, the wind-CAES electricity price savings over the forty-year operating life of the power plants are approximately \$400 billion, which covers the total investment cost of a 100 GW wind-CAES base load power plant system.

An important factor to take into account is the impact of expected increases in future natural gas prices. The reason this is important is because the aggregate fuel consumption rate of electricity produced by coupled wind-CAES plants is much less than that for the electricity produced by wind with natural gas plants. A sensitivity analysis of the effect of natural gas price increases on retail electricity prices is performed, and the results are presented in Fig. 7. An increase in natural gas price from \$7/MMBtu to \$14/MMBtu increases the electricity price difference between the coupled wind-CAES plant model and the wind with NGCC plant model from \$0.010/kWh to \$0.023/kWh, which increases the annual savings in spending on electricity from \$8 billion to \$18 billion at the 20% wind penetration level.

In conclusion, the coupled wind-CAES plant model has a lower retail electricity price and lower CO_2 emissions compared with the optimized wind with backup natural gas plant model. Also, the low fuel consumption rate of the coupled wind-CAES plant model is important in insulating electricity prices from expected increases in future natural gas prices. While the capital cost of the coupled wind-CAES plant model is greater than that of optimized wind with natural gas plant model, the discounted annual cash flow balances result in lower retail electricity price, due largely to the lower fuel consumption rate.

Next, the coupled wind-CAES plant model is compared with the NGCC, NGCC with CCS, steam coal; coal IGCC with CCS, and nuclear plants. The retail electricity price estimates for the NGCC, NGCC with CCS, coal IGCC with CCS, and nuclear plants are \$0.104/kWh, \$0.134/kWh, \$0.092/kWh, \$0.142/kWh, and \$0.145/kWh respectively. The CO_2 emissions reduction cost estimates for the NGCC, NGCC with CCS, coal IGCC with CCS, and nuclear plants are \$29/tonne, \$63/tonne, \$67/tonne, and \$66/

tonne respectively. In comparison, retail electricity price estimate for the coupled wind-CAES plant model is \$0.116/kWh, and the CO_2 emissions reduction cost is \$33/tonne.

Once again, the coupled wind-CAES plant model compares favorably with the conventional base load power plant options. While the retail electricity price estimate for NGCC is \$0.012/kWh less than that for the coupled wind-CAES plant model, the fuel consumption rate of NGCC plants leads to greater electricity price exposure to future increases in natural gas price; refer to the sensitivity findings presented in Fig. 7. The breakeven electricity price between the coupled wind-CAES plant model and the NGCC without CCS plant model occurs when natural gas price increases to \$9.10/MMBtu, which was surpassed in 2008.

While the retail electricity price for steam coal without CCS is the lowest of all base load power plant options, the CO_2 emissions rate of type of power plant is unacceptable in a carbon constrained world. For coal plants with CCS systems, conventional pulverized steam coal plants are replaced by coal IGCC plants with CCS systems. For the coal IGCC with CCS plant model, the electricity price is \$0.026/kWh greater than the wind-CAES electricity price. At the 100 GW capacity level, the annual electricity price differential between the electricity prices of the wind-CAES and coal IGCC with CCS models is about \$20 billion. Future increases in coal prices increase the economic disparity. Hence, the coupled wind-CAES model is economically competitive with the coal IGCC with CCS model. On a final note, the findings indicate that the wind-CAES model is economically competitive with the nuclear plant model.

V. Conclusion.

The findings of this study support the conclusion that coupled wind-CAES plants are an economically viable base load power plant option. An important finding is the lower electricity price and low CO_2 emissions reduction cost of the coupled wind-CAES plant model compared with those for wind with natural gas plants, the coal IGCC with CCS plant, and the nuclear plant models. Since wind is free, the low fuel consumption rate of CAES plants will insulate wind-CAES electricity prices from future increases in natural gas and coal prices.

It is noteworthy that the findings of this study call into question the economic feasibility of supporting the variable power production of wind plants with electricity produced by backup natural gas plants. Coupling wind plants to CAES plants is a less complex, more reliable, and more efficient electricity production and distribution system. In addition, coupled wind-CAES plants reduce CO_2 emissions by 90% compared with the CO_2 emissions rate of pulverized coal plants, whereas the wind with natural gas model reduces CO_2 emissions by only 69%. The 90% CO_2 emissions reduction rate of coupled wind-CAES plants is needed if the U.S. is to actually achieve an 80% reduction in CO_2 emissions by 2050. For CO_2 emissions reduction, it is important to realize that plants built today will still be in operation in 2050.

The DOE sponsored planning for wind to provide 20% of U.S. electricity generation in 2030 translates to 300 GW of wind plant capacity and 800 TWh of electricity generation. If the 300 GW of wind plants are coupled to CAES plants for base load capacity, then 190 GW of coupled wind-CAES base load capacity can be built by 2030. This base load capacity is sufficient to replace the deployment of all other plants.

For 100 GW of base load wind-CAES capacity, only 157 GW of wind plants and 64 GW of CAES plants are required. The total capital cost of a 100 GW base load wind-CAES system is \$416 billion, which includes \$32 billion for twenty-three 5-GW HVDC transmission lines and DC-AC converter stations. For this scale of coupled wind-CAES deployment, a national program will be required to develop air storage reservoirs on an ongoing basis similar to the national natural gas underground storage program.

One final issue is the concern in those areas of the country supplied by inexpensive coal power about electricity price increases that will result from CO_2 emissions reduction schemes. The retail electricity price estimate for a new pulverized coal plant without CCS is $0.092/kWh. The $0.116/kWh retail electricity price for coupled wind-CAES plants represents a $0.024/kWh increase in retail electricity price, which is a 26% increase or $24/month/1000 kWh of electricity. However, people fail to take into account the external health and global warming costs associated with coal power plant emissions. The health and global warming costs are at least $0.06/kWh, which is readily derived from recent studies on the health and global warming costs related to coal power plant emissions [18, 19]. The external costs are considerably greater than the increase in electric bills caused by coupled wind-CAES plants. Therefore, the increase in electricity prices caused by coupled wind-CAES plants actually represents a significant savings in terms of aggregate economic costs. In conclusion, the argument that CO_2 emissions reduction costs will lead to financial hardship is without merit.

Summary of Wind-CAES Benefits and Reasons to Build Wind-CAES Plants Today

1) Intermittent wind electricity creates greater variability in electricity supply for the local grid, which increases the complexity and costs of electricity supply regulation. Also, only a small fraction of intermittent wind electricity can be assigned load capacity credit, which means that wind power plants cannot replace fossil fuel plants to meet load capacity requirements. And, the addition of intermittent wind capacity increases reserve capacity requirements. Therefore, intermittent wind capacity increases system operational complexity and costs, which results in higher end-user electricity prices. In conclusion, the coupling of wind plants to CAES plants resolves wind's intermittency problems, improves system reliability, lowers system costs, and maximizes CO_2 emissions reduction by enabling replacement of fossil fuel power plants.

2) CAES gas turbine plants will achieve capital cost reductions. To date, only two CAES plants have been built, which means that next plant costs are artificially high due to the high cost of manufacturing one-of-a-kind components. Nth plant and learning curve cost reductions will occur with a moderate CAES plant adoption rate, and the trajectory of the Nth plant and learning curve cost reductions should be steep. At present, next plant costs are comparable to natural gas combined-cycle power plants, which are 50% greater than the costs of a natural gas simple cycle power plant. Since CAES plants are modifications of simple cycle gas turbine, Nth CAES plant costs should be about 30% lower than current next plant cost.

3) The low dispatch cost, i.e., variable operating costs including fuel cost, of wind-CAES plants gives them a bid-in advantage over fossil fuel and nuclear plants in de-regulated electricity markets. In de-regulated electricity markets, electricity with the lowest dispatch cost is sold first. Since the dispatch cost of wind-CAES plants is lower than fossil fuel and nuclear power plants, wind-CAES plants will be able to realize full capacity utilization. At present, the lowest dispatch cost providers for base load electricity are coal and nuclear plants. Hence, the adoption of wind-CAES plants can alter the mix of base load electricity supply.

4) If wind in the Midwest is to supply over a hundred gigawatts of power, which is well within its potential, then the coupling of wind and CAES plants is important since it will require only half the number of transmission lines required to transport the Midwest wind electricity to eastern seaboard markets, which also reduces transmission costs.

5) Wind-CAES plants utilizing aquifer and depleted gas field storage reservoirs should be built as soon as possible in order to gain experience with this air storage medium before installation of Midwest wind capacity is fully scaled up.

6) It is important for the U.S. be a leader in wind-CAES technology. With the development of wind-CAES technology, the technology can be exported to countries with natural gas and/or coal supply constraints such as Europe, China, and India.

7) In conclusion, there is an immediate need to create State and Federal legislation and regulatory rules to define CAES as an enabling technology for wind and PV electricity production and to include CAES in renewable energy incentive programs.

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Table 1. Energy Storage Cost Estimates [11].

	$/kW +	[$/kWh[a] x	Hours] =	Total Capital ($/kW)
Compressed Air:				
- Large (100 MW plus)[b]	924	2	88	1,100
- Small (20 MW minus)	700-800	200-250	4	1,500-1,800
Pumped Hydro (100 MW plus)	1,500-2,000	100-200	10	2,500-4,000
Battery (10 MW):				
- Lead Acid	420-660	330-480	4	1,740-2,580
- Advanced (Target)	450-550	350-400	4	1,850-2,150
- Flow (Target)	425-1,300	280-450	4	1,545-3,100
Flywheel (100 MW Target)	3,360-3,920	1,340-1,570	0.25	3,695-4,315
Super-Conducting Magnetic Storage (1 MW)	200-250	650,000-860,000	1/3600	380-490
Super-Capacitors (Target)	250-350	20,000-30,000	1/360	310-435

Notes:

a. This capital cost is for the storage "reservoir," expressed in $/kW for each hour of storage. For battery plants, costs do not include expected cell replacements. The cost data are in 2008 $ and are updated periodically by EPRI (updated August 20, 2008). Costs do not include permits, contingencies, interest during construction, and the substation.

b. The large compressed air energy storage cost estimate is original to this study and is in 2008 $. It should be noted that the large compressed air storage cost estimates are 47% greater than EPRI high cost estimate. The CAES cost estimate is a next plant estimate, and Nth plant cost should be about 30% less since the turbo-train is very similar to a conventional combustion turbine plant.

Table 2. JCSP'08 Data from Executive Summary, p. 6, Table 1-1.

New Generation Capacity (GW)	5% Wind	20% Wind	% Change
Wind	58.0	229.0	295%
Base Load Steam	76.8	37.2	-52%
Gas CT	49.2	69.6	41%
Gas CC	4.8	4.8	0%
Other Fossil	1.2	1.2	0%
Total	190.0	341.8	80%

Electricity Production (TWh)	5% Wind	20% Wind	% Change
Wind	242	764	216%
Base Load Steam	2,160	1,741	-19%
Gas	210	301	43%
Other	1,356	1,371	1%
Total	3,968	4,177	5%

Table 3. Specification of Wind Models to Provide Load Capacity Credit.[a]

	Capacity (W/W Load Capacity)	Capacity Factor (%)	Electricity to Grid (kWh/yr)	Fuel Consumption (Btu/kWh)	CO_2 Emissions (g/kWh)	Capital Cost ($/W Load Capacity)
JCSP'08 Wind-NG Model[b]						
Wind	4.32	40%	5.88		11	8.64
NG CT	0.52	35%	1.57	4,335	246	0.31
Totals			7.45	4,335	256	8.94
Optimized Wind-NG Model[b]						
Wind	1.00	42%	3.70		3	2.00
NG CC	0.85	49%	3.63	4,796	238	0.73
Reserve NG CT	0.12	11%	0.12	173	9	0.07
Totals			7.45	4,969	250	2.80
Optimized Wind-CAES Model[b]						
Wind	1.57	37%	5.14		5	3.13
CAES	0.64	41%	2.31	1,411	77	0.70
Totals			7.45	1,411	82	3.83

Notes:

a. Abbreviations: W = Watt; kWh = Kilowatt-Hour; CO_2 = Carbon Dioxide; g = Grams; NG = Natural Gas; CT = Combustion Turbine; CC = Combined-Cycle.

b. The JCSP'08 wind with natural gas model is derived from the JCSP'08 study [3], and the optimized wind with natural gas and wind with CAES models are derived from the Succar and Williams wind CAES study [9].

Table 4. Power Plant Cost and Performance Parameters.[a]

	Capital Cost ($/kW)	Heat Rate (Btu/kWh HHV)	Cost of Fuel Use ($/kWh)	Fixed O&M ($/kW)	Variable O&M ($/kWh)	CO_2 Emissions (g/kWh)
NG Combustion Turbine	597	10,842	0.076	17.72	0.00366	570
* NG CT Spinning Reserve		12,637	0.088			664
NG Combined-Cycle	857	7,196	0.050	34.01	0.00211	392
NG Combined-Cycle with CCS	1,683	8,613	0.060	41.61	0.00301	70
Pulverized Coal	1,833	8,844	0.017	28.22	0.00470	806
Pulverized Coal with CCS	3,800	13,724	0.027	37.38	0.00936	86
Coal IGCC	2,118	8,309	0.016	39.62	0.00298	735
Coal IGCC with CCS	3,031	9,713	0.019	46.64	0.00455	132
Nuclear	5,000	10,400	0.013	69.57	0.00051	0
Wind	2,000	0		15.91	0.00500	7
CAES Gas Turbine	1,100	4,550	0.032	4.00	0.00600	248

HVDC Transmission	Capital Cost (million $)	Electricity Loss Rate	O&M (% of Capital)	Gross Unit Capacity (GW)	Net Unit Capacity (GW)	Voltage
HVDC Lines (per 1000 km)	550	2.5%	1.0%	5.0	4.5	± 800 kV
DC-AC Converter Station	550	0.9%	1.0%			

Notes:

a. Power plants consume some of the electricity that they produce, which is commonly referred to as parasitic power losses. In the estimation of retail electricity prices, NETL [15] parasitic power loss estimates are taken into account. Also, it is assumed that the maximum capacity of HVDC power lines is 90% of rated capacity.

Table 5. Results: Comparative Analysis of Base Load Power Plants (Per Unit of Load Capacity Credit).

	Wind with NGCT (Optimized)[a]	Wind with NGCC (Optimized)	Wind with CAES (Optimized)	NGCC	NGCC w/CCS	Steam Coal without CCS	Coal IGCC with CCS	Nuclear
Retail Electricity Price ($/kWh)	0.133	0.126	0.116	0.104	0.134	0.092	0.142	0.145
Capital Cost ($/kW)	2,579	2,800	3,833	857	1,683	1,833	3,031	5,000
CO_2 Emissions (g/kWh)	355	282	78	392	132	806	70	0
Fuel Consumption (Btu/kWh)	6,837	5,010	1,439	7,196	8,613	8,844	9,713	0
CO_2 Reduction Cost ($/t)	91	65	33	29	63		67	66

Notes:

a. Abbreviations: NGCT = natural gas combustion turbine; NGCC = natural gas combined-cycle; CAES = compressed air energy storage power plant; CCS = carbon capture and storage system; IGCC = coal integrated gasification combined-cycle.

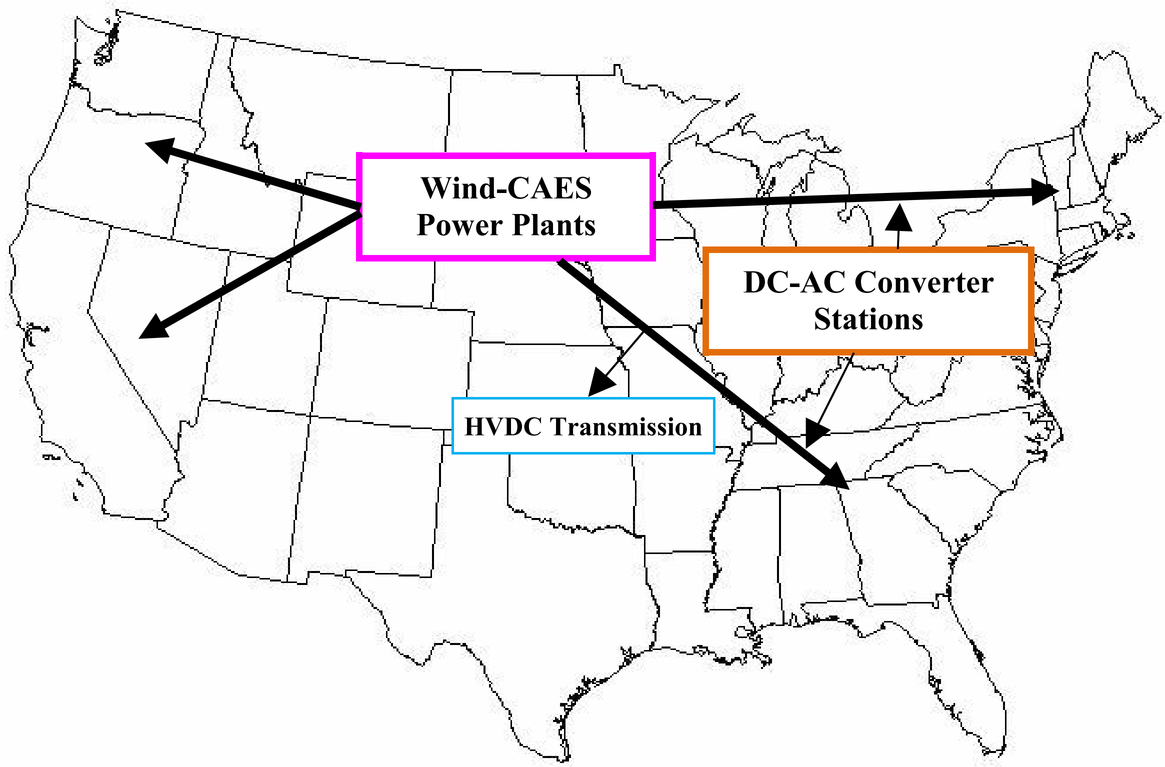

Figure 1. A national wind-CAES electricity production and distribution system.

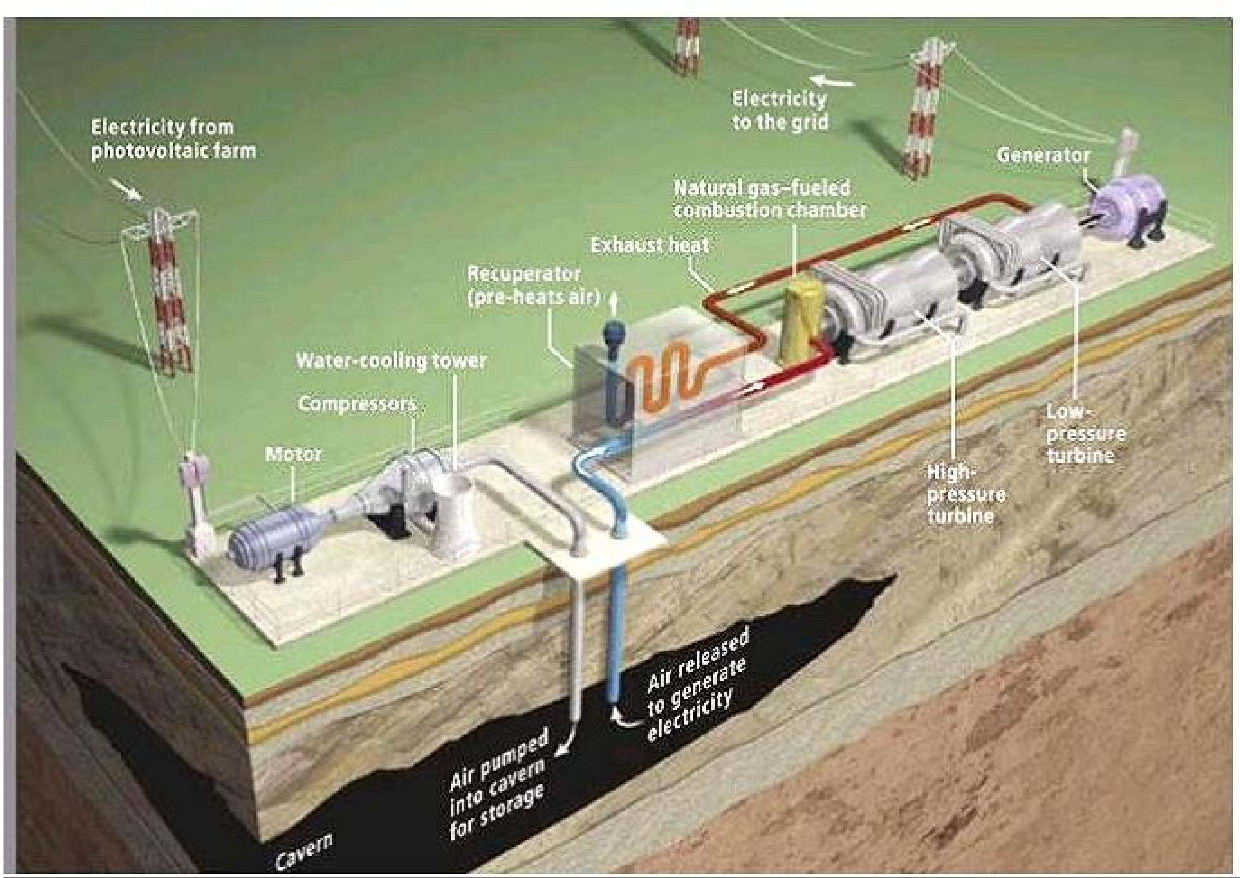

Figure 2. Schematic of a CAES air turbine power plant.

Figure 3. The Alabama Electric Cooperatives' McIntosh, Alabama 110-MW CAES power plant with compressed air well-head on the right. The power plant has been in continuous operation since 1991.

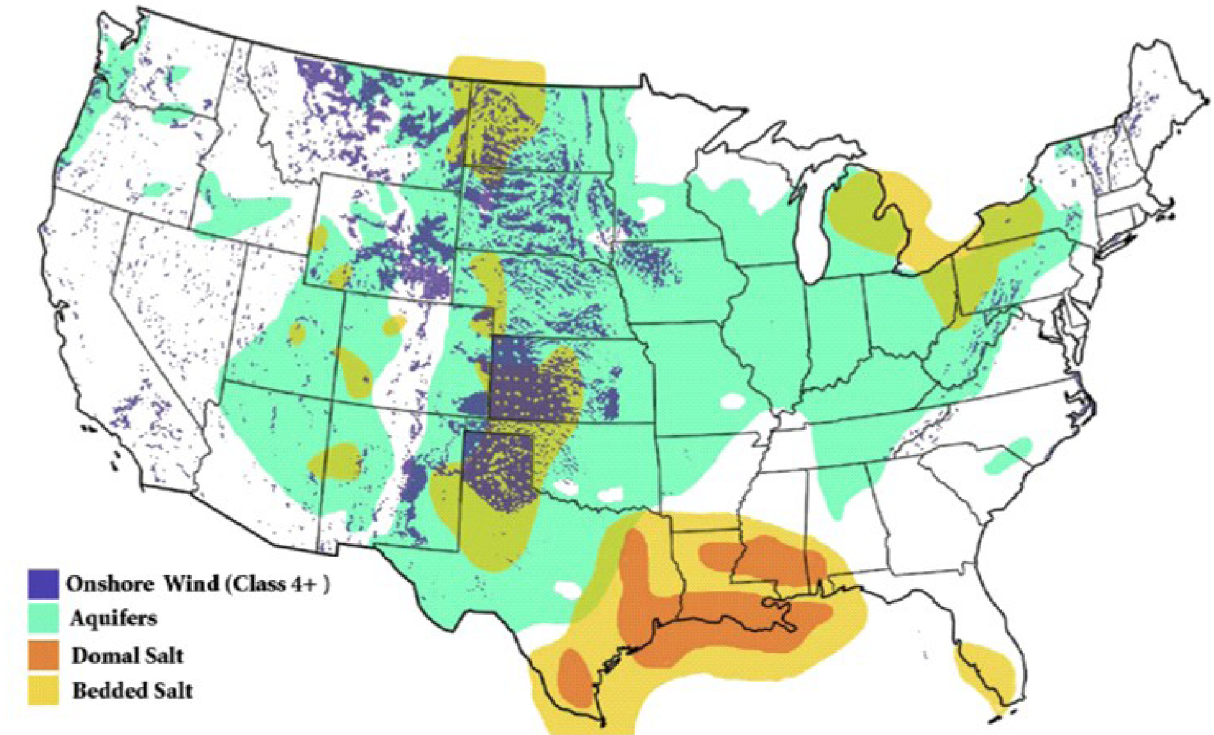

Figure 4. Map of U.S. showing areas with Class 4 or higher wind resources and areas with geology suitable for underground air storage reservoirs.

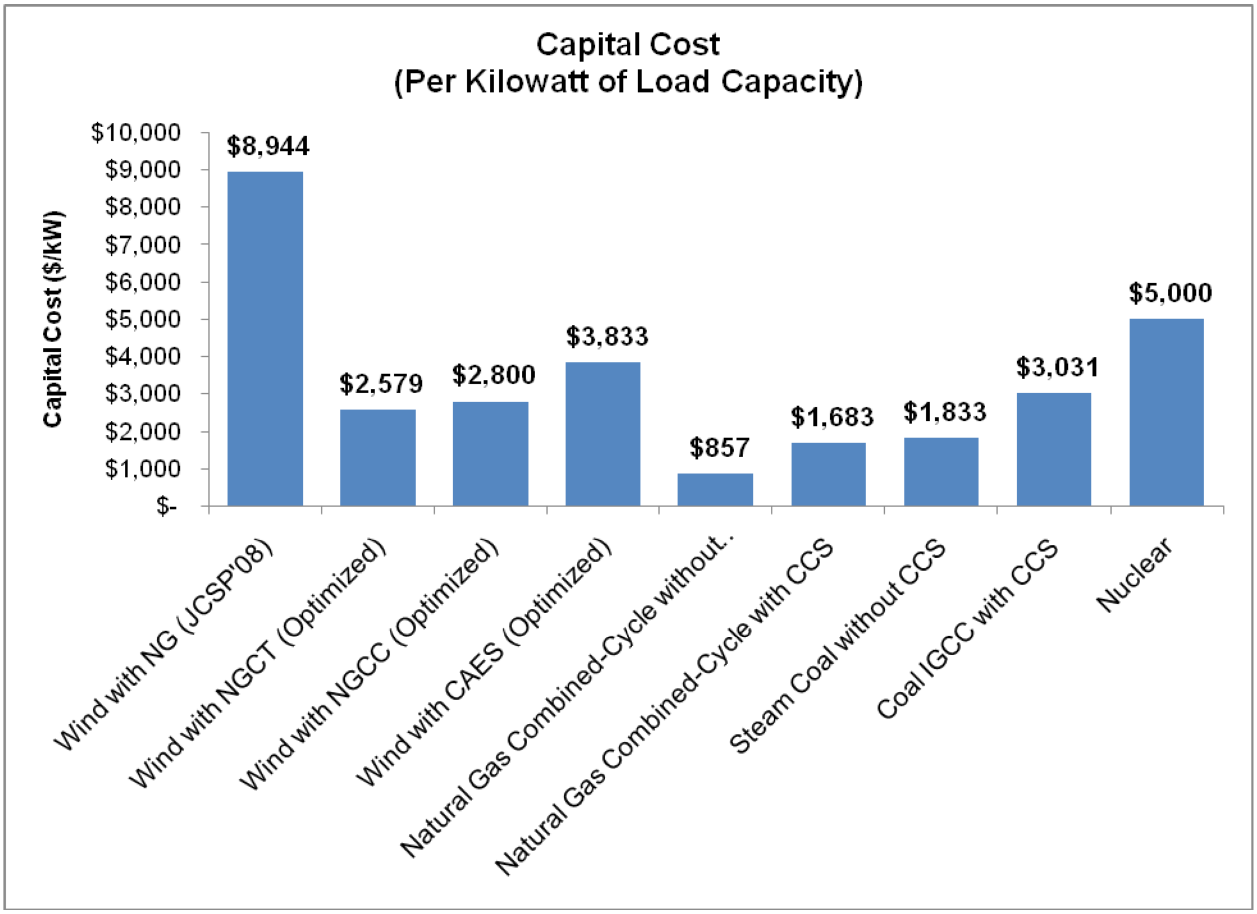

Figure 5. Capital cost per kilowatt of load capacity.

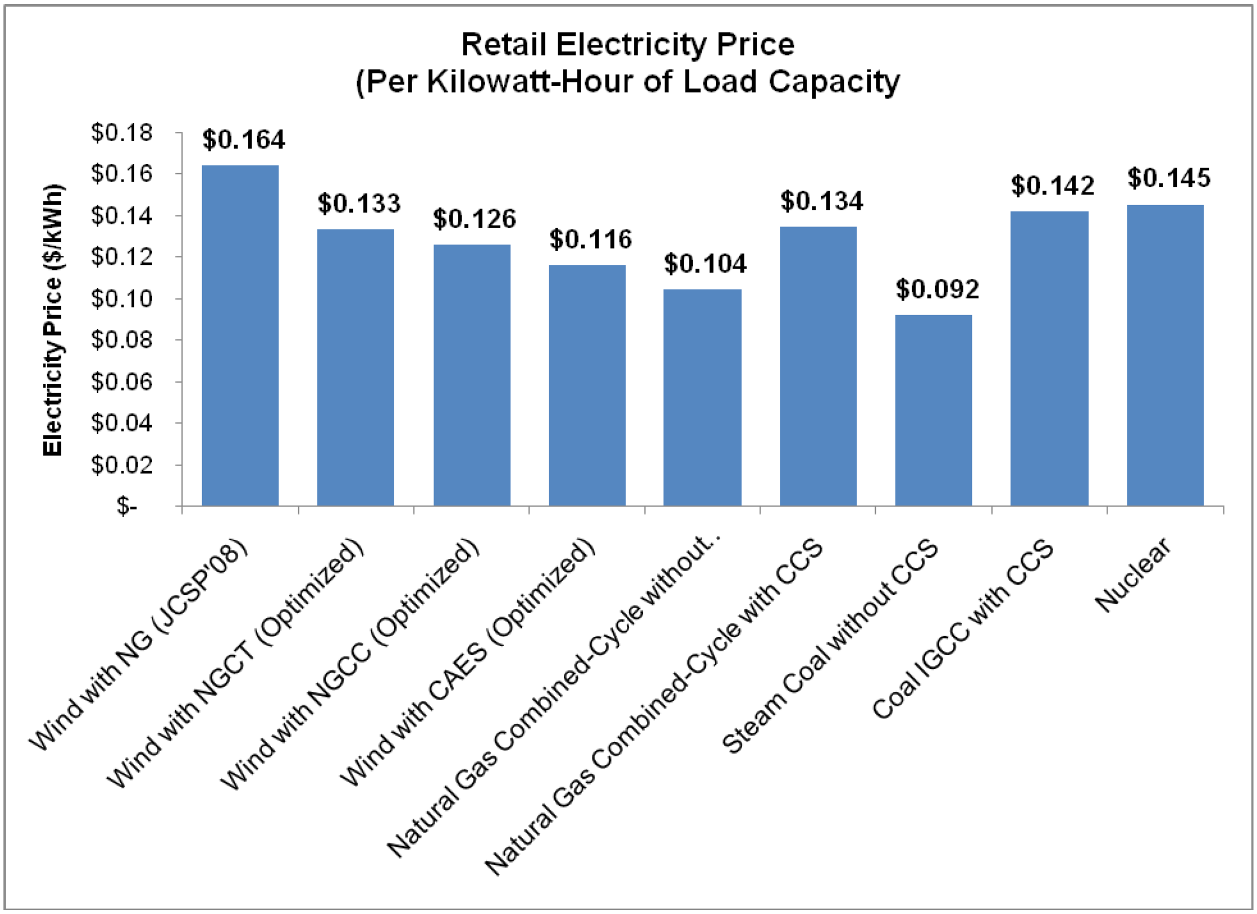

Figure 6. Levelized retail electricity price estimates.

Notes:

a. Financial assumptions for the levelized retail electricity price estimates are: capital structure of wind plants, thermal plants, and HVDC transmission lines = 55% debt capital and 45% equity capital; rates of return on capital = 9% on debt capital and 12% on equity capital; book life of assets: wind plants = 25 years, thermal power plants = 30 years, and HVDC transmission lines = 30 years; composite tax rate = 39%; average annual inflation rate = 3%; and fuel prices: natural gas = $7/MMBtu; coal = $1.94/MMBtu ($40/short ton); uranium = $0.70/MMBtu. Nuclear costs include: fuel processing = $0.006/kWh; spent fuel disposal = $0.0015/kWh; and plant decomissioning = $0.0015/kWh.

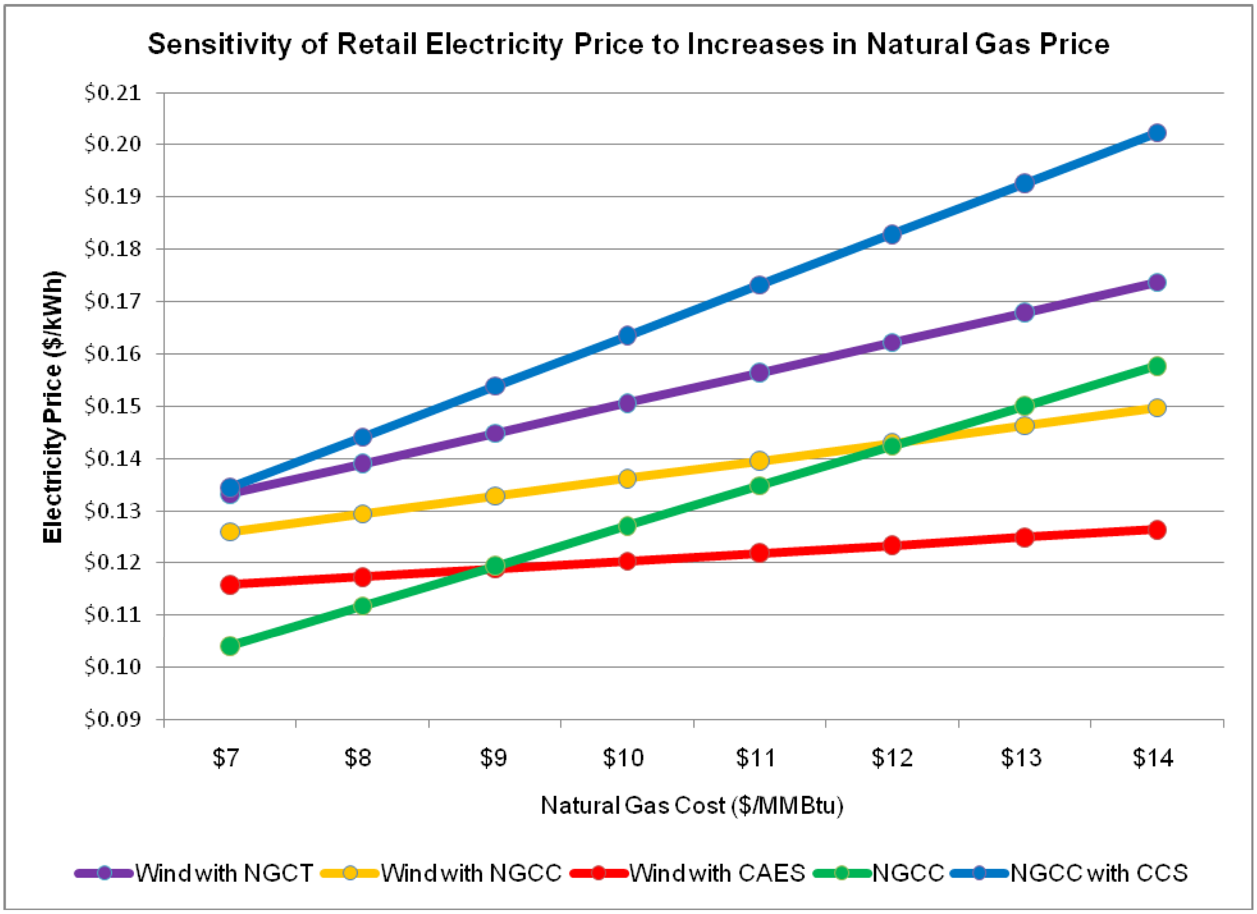

Figure 7. Sensitivity of retail electricity price to increases in natural gas prices to electricity producers.

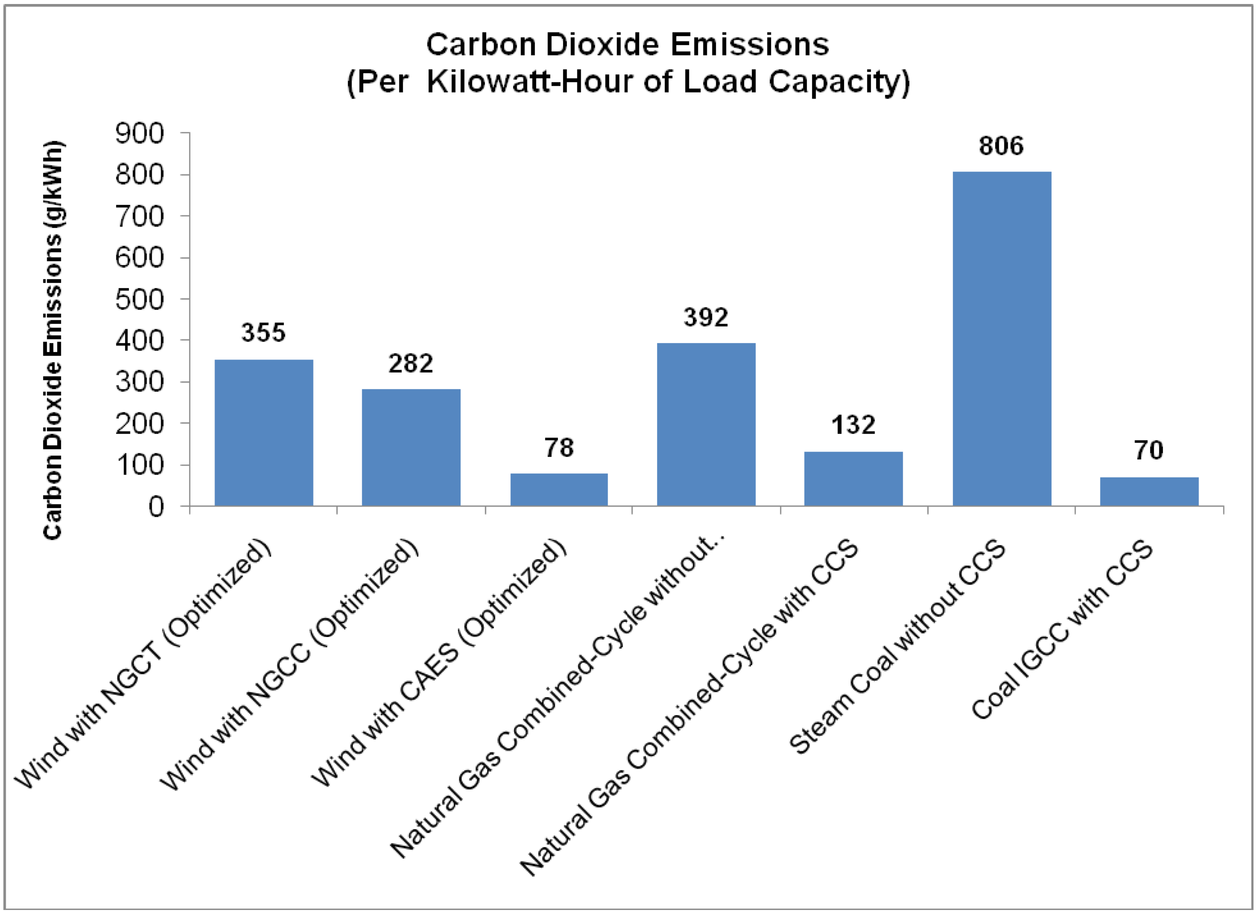

Figure 8. Carbon dioxide emissions.

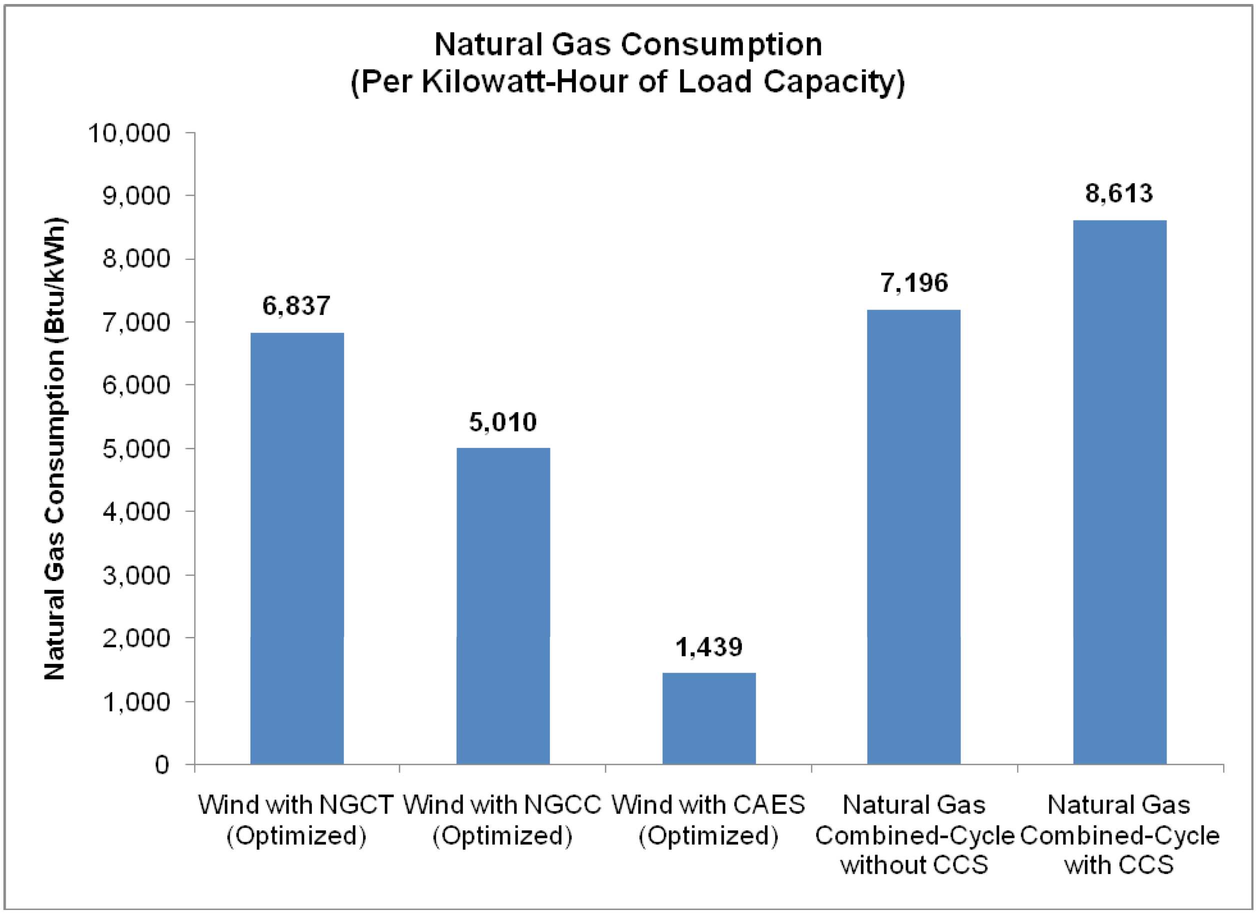

Figure 9. Natural gas consumption rates for power plants using natural gas.

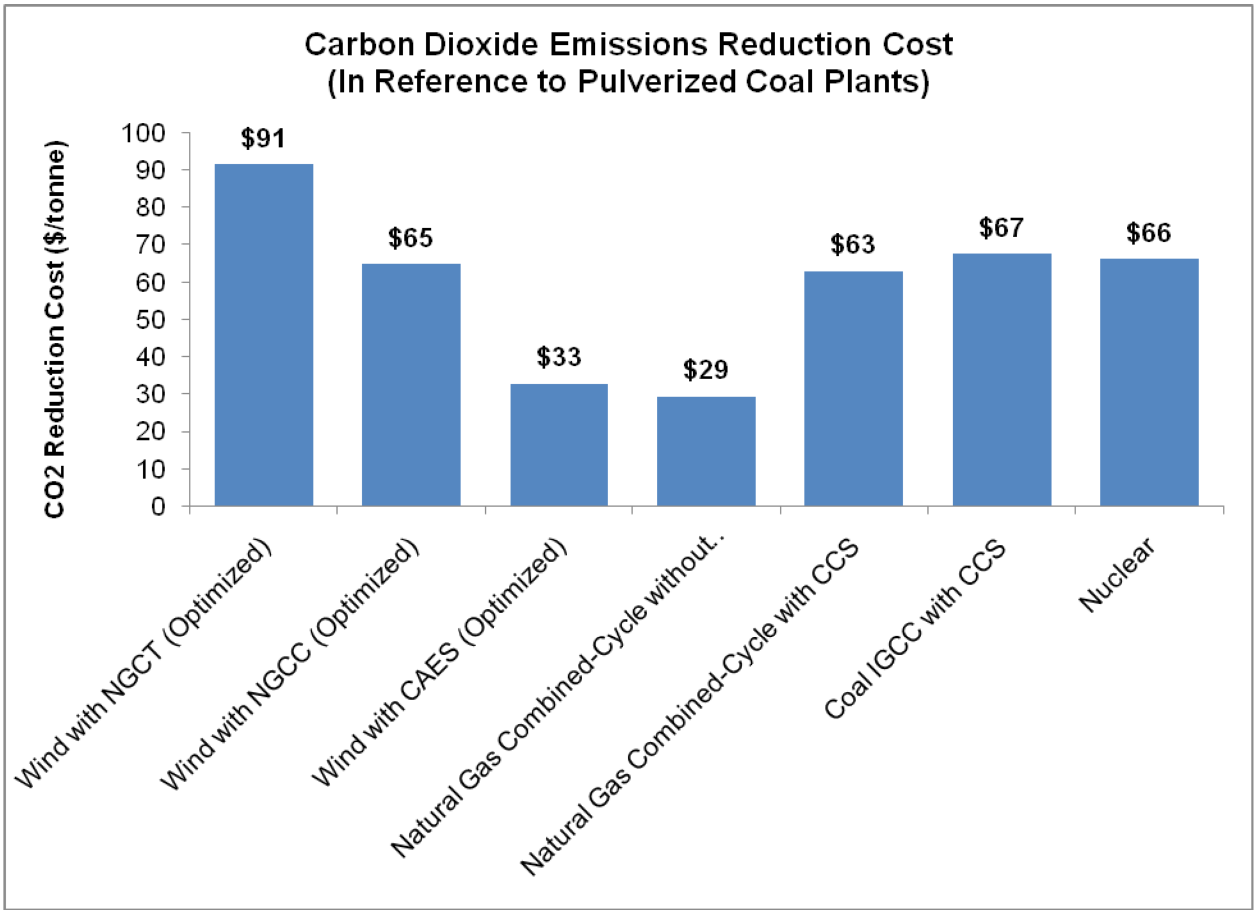

Figure 10. Cost of carbon dioxide emissions reduction in reference to a base load pulverized steam coal plant.