Approved: 03/18/08
Date

MINUTES OF THE SELECT COMMITTEE ON ENERGY & ENVIRONMENT FOR THE FUTURE

The meeting was called to order by Chairman Don Myers at 1:30 PM on March 12, 2008, in Room 784 of the Docking State Office Building.

All members were present except:
Representative Robert Olson, Excused
Representative Jason Watkins, Excused
Representative Richard Proehl, Excused
Representative Oletha Faust-Goudeau, Excused

Committee staff present:
Mike Corrigan, Revisor of Statutes Office
Mary K. Galligan, Kansas Legislative Research Department
Ryan Hoffman, Kansas Legislative Research Department
Barbara Lewerenz, Committee Assistant

Conferees appearing before the committee:
Wes Ashton, Manager of Government Affairs, Aquila
and Representative of Kansas Gas Service, a Division of Oneok
Colin Hansen, Executive Director, Kansas Municipal Utilities
Larry Berg, Vice President, Corporate Relations, Midwest Energy, Inc.
Whitney Damron, Lobbyist, The Empire District Electric Company
Tom Thompson, Lobbyist, Kansas Chapter of the Sierra Club
Joe Spease, President, Pristine Power
Raymond H. Dean, Prof. Emeritus, EECS, University of Kansas
Reid Nelson, Private Citizen

Others attending:
See attached list:

Chairman Myers announced continuing hearing on **HB-2949- Kansas energy plan act**,

**Proponent**

Chairman Myers recognized Wes Ashton, representing Aquila and Kansas Gas Service, a division of Oneok (Attachment 1). Mr. Ashton spoke in favor of the bill, but requested that Section 5 of the bill be rewritten to strike the word "negligible" when referring to the future of natural gas and leave appropriate proportions of natural gas and coal up to the individual utilities.

**Neutral**

Chairman Myers recognized Colin Hansen, Kansas City Board of Public Utilities (Attachment 2). Mr Hansen said the need for base-load power both now and in the future is real. Municipal utilities rely on purchase power agreements, yet are transmission dependent and capital constrained. He recommended that fuel mix standards set forth in the bill be considered goals rather than mandates.

Chairman Myers recognized Larry Berg, Midwest Energy, Inc. (Attachment 3). Mr Berg stated that Midwest Energy produces a larger proportion of renewable energy than any other utility in Kansas. They have been unable to obtain any commitment from any electric generation utility in Kansas to provide base-load resources. If it is necessary to purchase base-load energy under short-term agreements, it most likely will increase cost to the consumer. He recommended that the percentages of generation targets in the bill be approximate.

MINUTES OF THE Select Committee on Energy & Environment for the Future at 1:30 PM on March 12, 2008 in Room 784 of the Docking State Office Building.

Chairman Myers recognized Whitney Damron, The Empire District Electric Company (Attachment 4). Mr Damron said that Empire will continue to monitor the future of base-load generation in the region to include nuclear, pulverized coal and new technologies as they emerge. The company's objectives are to provide cost-effective, safe and reliable electric service to customers.

**Opponents**

Chairman Myers recognized Tom Thompson, Kansas Chapter of the Sierra Club (Attachment 5). The Sierra Club is in opposition to HB-2949, but appreciates the committee's attempt to begin work on an energy plan for Kansas. They would like to see a plan that considers sustainability, pollution control and other environmental issues.

Chairman Myers recognized Joe Spease, Pristine Power (Attachment 6). Mr. Spease urged committee members to vote against **HB-2949** and instead develop programs to support the wind and solar projects.

Chairman Myers recognized Raymond H. Dean, Professor Emeritus, EECS, University of Kansas (Attachment 7). Professor Dean requested that the bill's definition of base-load generation include wind, gas, compression storage and adiabatic energy storage.

Chairman Myers recognized Reid Nelson, a private citizen (Attachment 8). Mr. Nelson stressed energy efficiency and asked that it be included in the bill. He sited Vermont and Texas as states with aggressive efficiency policies that have limited growth in energy usage.

Conferees agreed to furnish statistics requested by committee members on residential and commercial facilities heated by gas and information on coal-fire plants of Iatan 2, Plum Point and Pueblo.

Being no further conferees, the Chairman closed the public hearing. The meeting was adjourned at 2:55 p.m.

# House Select Committee on
# Energy and Environment for the Future

**GUEST LIST**

**DATE** March 12, 2008

| Your Name | Representing |
|---|---|
| Maril Hazlett | CEP |
| Isaac Ferguson | Kansas Chamber of Commerce |
| Joe Dick | KCBPU |
| Whitney Damron | Empire Electric Co. |
| Wes Ashton | Aquila |
| Tom Day | KCC |
| Shari Albrecht | KONE |
| Joe Spease | Pristine Power |
| Tom Thompson | Sierra Club |
| | |
| | |
| | |
| | |
| | |
| | |
| | |
| | |
| | |
| | |
| | |
| | |
| | |
| | |
| | |
| | |
| | |
| | |
| | |
| | |
| | |

Aquila

Legislative Testimony before the House Select Committee on Energy & Environment for the Future
Regarding HB 2949
March 12, 2008

Submitted by Wes Ashton, Manager of Government Affairs

Chairman Myers and members of the Select committee, thank you for the opportunity to testify today on HB 2949, the Kansas Energy Plan Act. My name is Wes Ashton and I am the Manager of Government Affairs for Aquila. This testimony is also submitted on behalf of Kansas Gas Service, a division of Oneok.

I want to start out by acknowledging the tremendous undertaking this Committee is attempting to establish state policy for electric generation for Kansas for the next twenty years and beyond. The concept of working toward the establishment of a long-term comprehensive plan is certainly a direction we believe our state should pursue. While this bill contains a strong foundation for a state policy, there is one specific section we would like to discuss.

Section 5 of HB 2949 details specific percentages of generation starting with the 2006 fuel mix for current standards and establishing electric generation targets for 2020, 2025 and 2028. Section 5 acknowledges that natural gas makes up approximately 4% of current base load electric generation and is expected to go up to 5% by 2020 according to the bill. However, the section goes on to encourage "negligible" use of natural gas by 2028 on lines 15-16.

As a number of conferees have already stated, this policy may end up posing additional challenges for the state and specific utilities in future years. As a comprehensive policy for our state is developed, experts have repeatedly told us there is not one solution or quick fix to our future demand and generation needs. Natural gas can and should be considered as part of a larger policy as it has been for decades. If it isn't the best option at the time, assuredly another option will be selected.

As prices stand today, natural gas does cost more to create electricity than coal. Predicting the future price of coal or natural gas for electric generation would be difficult or impossible and a dip in prices could improve the positioning of gas-fired plants. For future Legislative sessions section 5 could be used as direction for future Legislative sessions to support or oppose specific proposals, and this bill could conceptually remove one of the options from the table for consideration.

As this Committee determines the direction for this legislation, we should not limit our options so quickly into the process of establishing a long-term policy. In future years, our Legislature, our state's utilities, citizens and the KCC will work together to determine the appropriate mix for base load and peak generation. That mix will likely be determined by weighing the cost, availability, reliability and safety. Some factors may favor natural gas, and others may not. However, that decision will best be determined at that time with the information available. As we look ahead at setting policy for the next 20 years, it is worthwhile to also look back 20 years to 1988 and how much has changed in the energy field since that time. For this legislation to remain relevant, it needs flexibility.

As this committee works on the language of Section 5, consider striking the word "negligible" on line 16. If the goal of the legislation is to promote nuclear energy, that concept can still be achieved by rewriting sub-section (3) to read "By the year 2028, coal and natural gas, 60%; nuclear, 40%. That would leave the appropriate proportions of natural gas and coal up to the individual utilities.

Thank you Mr. Chairman and members of the committee for the opportunity to testify today on HB 2949 and I will stand for questions when appropriate.

Select Committee on Energy & Environment for the Future
3/12/08
Attachment # 1

**kansas**municipal**utilities**

*Submitted Testimony Provided the*

**House Select Committee on Energy and the Environment for the Future**
March 12, 2008

*Colin Hansen, Executive Director*
*Kansas Municipal Utilities*

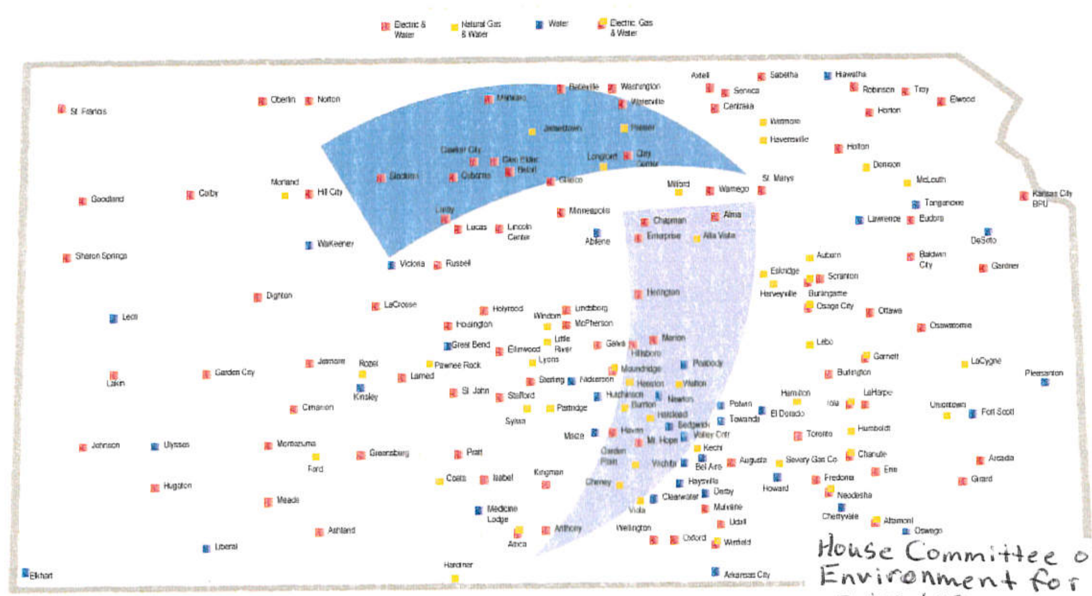
## House Bill 2949

Chairman Myers and Members of the Committee:

On behalf of Kansas Municipal Utilities (KMU), I appreciate the opportunity to provide testimony to the committee regarding House Bill 2949, legislation to enact the Kansas energy plan act.

Formed in 1928, Kansas Municipal Utilities (KMU) is the statewide association that represents the interests of 170 municipal electric, natural gas, water and wastewater utilities. In addition, KMU also assists in representing Kansas Municipal Energy Agency (KMEA) and Kansas Power Pool (KPP), the state's two not-for-profit joint action agencies providing energy and transmission procurement services for member cities.

A municipal utility is owned by the city it serves. Service, rather than profit, is the utility's mission. Decisions about the operation of a municipal utility are made locally, by members of the community. As such, a municipal utility is uniquely able to respond to the community's needs, build on the community's strengths, and reflect and advance the community's values.




House Committee on Energy + Environment for the Future
3/12/08
Attachment # 2

Municipal electric utilities operating in Kansas are very diverse in size and location. In total, we serve over 235,000 customers or approximately 17% of Kansas citizens. We have electric utilities serving as many as 65,000 meters and as few as 23. The median size of a municipal electric utility in Kansas is 882 customers. Our members, as the figure on the previous page illustrates, stretch to the far corners of Kansas and everywhere in between.

Only the largest of the state's 119 municipal electric utilities, Kansas City Board of Public of Utilities (KCBPU), currently owns and operates baseload facilities. The rest of the state's public power systems operate as wholesale consumers, purchasing their electricity needs on the open market through wholesale contracts. As such, municipal electric utilities are extremely sensitive to the availability of baseload energy. With many of our members' wholesale contracts expiring, we have had to become much more attuned to wholesale and baseload markets. Because of the difficulty in obtaining baseload energy, municipal systems have joined forces through state-authorized joint action agencies to amass loads of sufficient size to gain the attention of generators with baseload supplies.

In addition, 63 municipal electric utilities own and operate local generating plants. The vast majority of these power plants operate small diesel or natural gas fired units that only operate during peak times or when transmission service is lost. Their function is to reduce the cost of capacity and in turn the overall cost of electricity to the citizens of the community. They also play a critical role in bolstering the reliability of the grid locally, regionally, and in several instances, statewide. Ice storms this past winter illustrated well the value of these locally-owned and operated power plants.

KMU member cities applaud the state's effort to begin discussions on the development of a comprehensive energy plan and we support efforts to further needed investment in transmission infrastructure, energy efficiency, conservation and renewable energy as well as economic baseload power. Through various city and joint action agency efforts, municipal transmission investments are being studied and pursued in order to continue improving system reliability and ensure that these cities have access to much-needed power supplies.

Investments in renewable energy are being made by the municipal utility community. The Kansas City Board of Public Utilities is purchasing 25 megawatts (MW) of power from the Smoky Hills wind farm in central Kansas. Other smaller systems, such as the City of Winfield's electric utility, are contracting for wind power as well. A significant portion of the KMU membership's generation portfolio is comprised of hydropower flowing from the

Western Area Power Administration (WAPA), Southwestern Area Power Administration (SWPA) and the Grand River Dam Authority (GRDA).

The need for baseload power both now and in the future is real. Municipal utilities rely on purchase power agreements, yet are transmission dependent and capital constrained. What does this mean? It means that the majority of our power is provided to customers via purchase power contracts with utilities such as Westar, Kansas City Power & Light (KCP&L) and Sunflower Electric Power Corporation. Power delivered to those of our members that own local generation can be curtailed if demand spikes. It also means that municipal utilities have very limited power supply options due to transmission constraints and in order to construct new generation or transmission our cities have to go to the capital markets to procure financing. Few cities in Kansas have the financial capability to back the tremendous amount of investment needed to help fund baseload generation. As such, municipal customers will largely need to continue purchasing power at wholesale, hopefully at a just and reasonable rate.

As the Committee works through this complex legislation, we would ask that the interests of the municipal systems be considered, particularly the many smaller systems that we represent and how they may be impacted by compliance with this measure. Specifically, we would recommend that the fuel mix standards set forth in this measure be considered as goals rather than mandated in statute. While those in the utility industry need certainty from a business operations standpoint, the reality is that we are operating in very uncertain times. With uncertainty stemming from rapidly rising construction costs for power and transmission infrastructure, questions about climate change legislation, overall cost of power, utilities need to retain flexibility in decision-making so as to ensure a reliable, affordable product our customers.

In conclusion, the KMU membership recognizes that energy conservation and renewable energy need to be a key component in any utility's energy strategy. However, the need for low-cost and reliable baseload power remains a necessary reality. All of these components, as well as the reliability and peaking capacity provided by local municipally-owned power plants, need to be incorporated into a diversified and balanced electricity generation portfolio for the State of Kansas.

**Larry Berg Consulting**

**Neutral Testimony Submitted by Larry Berg**
**On Behalf of Midwest Energy, Inc.**
**To the House Select Committee on Energy & Environment for the Future**
**HB 2949**
**March 12, 2008**

Chairman Myers and members of the committee, thank you for the opportunity to testify on HB 2949, the Kansas Energy Plan Act. My name is Larry Berg and I represent Midwest Energy, a member-owned electric and natural gas distribution cooperative, headquartered in Hays. Midwest Energy serves 90,000 customers in 41 central and western Kansas counties.

First, I would like to inform this committee of the lack of new baseload energy alternatives available to Midwest Energy. Second, I will touch on Midwest's commitment to a diversified energy portfolio. And finally, I would like to offer a couple of comments regarding HB 2949.

The current baseload contracts that Midwest Energy has enjoyed for the last 20 years will expire between May, 2008 and 2010. To that end, Midwest conducted two RFP processes in early 2006. One RFP was issued to replace expiring contracts under which Westar Energy supplies most of Midwest's needs. The other RFP was issued to secure renewable energy. The latter RFP was successful. Midwest currently has 25 MWs of wind resources, which is equivalent to about 8% of its peak load. By the end of this year, Midwest will have an additional 25 MWs of wind energy. 50 MWs of wind energy will represent 16% of Midwest Energy's peak load. That's a larger proportion of renewable energy than any other utility in Kansas. Additionally, Midwest Energy also holds a small allocation of federal hydro-power from the Western Area Power Administration.

Midwest Energy is in the process of adding 75 MWs of gas-fired, peaking generation to its current fleet of 25 MWs of gas-fired peaking units, for a total of 100 MWs.

Midwest Energy has been far less successful in securing baseload energy resources needed to serve their customers "around the clock." Except for a letter of intent with Sunflower Electric Power Corp. to purchase 75 MWs from one of the new Holcomb units, Midwest has been unable to obtain any commitment from any electric generation utility in Kansas to provide any baseload resources. Midwest Energy may be forced to purchase baseload energy under short-term agreements that expose their customers to possibly higher rates.

Select Committee on Energy & Enviroment for the Future
3/12/08
Attachment # 3

**Kansas City Office** • 10904 Delavan Ct., Kansas City, KS 66109 • **Topeka Office** • 83:
Phone 913.940.2454 • Fax 913.357.4732
lbconsult@att.net

As you can see, Midwest has and will continue to have a very diversified portfolio, which is what HB 2949 is attempting to accomplish between now and 2028

Finally, I would like to offer a couple of observations for your consideration. First, on page 2, lines 23-24, states "promotion of market driven solutions to electric generation needs of the State" and then states on page 3, lines 13-16, specifies a preferred fuel mix. This seems somewhat contradictory. Regarding sec. 3(a), recognition should be given to the interaction between electric generation fuel choices and the affordability of home heating fuels. The rush to gas, whether as a backup to wind or as a primary fuel source, will compound the problem that wellhead gas prices have already tripled or perhaps quadrupled since the late 1990s. Finally, I would recommend that the percentages of generation targets be approximate.

Midwest Energy applauds this committee for its vision of a statewide energy plan. Thank you again Mr. Chairman and committee for the opportunity to testify today on HB 2949 and I will stand for questions when appropriate.

SERVICES YOU COUNT ON

**The Empire District Electric Company (Empire)**

Empire, a Kansas Corporation, is an operating public utility, based in Joplin, Missouri, engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. Empire's electric service territory includes an area of about 10,000 square miles with a population of over 450,000, including nearly 168,000 electric customers. Approximately 10,250 of these customers are in Kansas.

The electric service territory is located principally in southwestern Missouri and also includes smaller areas in southeastern Kansas, northeastern Oklahoma and northwestern Arkansas. The principal activities of these areas include light industry, agriculture and tourism. Empire's system had a Net System Input (NSI) of 5,485,658 MWh and a system peak of 1,173 MW in calendar year 2007.

Empire also provides natural gas (through its wholly-owned subsidiary, The Empire District Gas Company), water service, and fiber optics.

**Existing Generation Resources**

Empire's current portfolio of generating resources include 380 MW of owned coal units, 859 MW of natural gas or natural gas and fuel oil units and a 16 MW hydro unit. Additionally, Empire currently has power purchase agreements for 150 MW of wind generation and 162 MW of coal-fired generation. Empire also participates in the energy market for economy power purchases on a continuous basis. The following table shows the percent of energy expected from each resource type for 2008.

| Resource Type | Energy Pct |
|---|---|
| Owned Coal | 41.2% |
| Natural Gas | 18.6% |
| Hydro | 1.1% |
| Coal Purchase | 19.1% |
| Wind Purchase | 9.4% |
| Non-contract Purchases | 10.6% |
| Total Net System Input | 100.0% |

Select Committee on Energy + Environment for the Future
3/12/08
Attachment # 4

### Supply-Side and Demand-Side Resources Through 2010

Currently, construction is progressing on 200 MW (Empire's approximate share) of new jointly-owned coal-fired capacity (100 MW at Iatan 2 and 100 MW at Plum Point). Each of these units is scheduled to come on line in 2010. In addition, a power purchase agreement (PPA) has been signed for 105 MW of new wind energy (Meridian Way Wind Farm) scheduled to begin operation in 2009. A 162 MW coal-fired PPA from Westar will expire in 2010.

The demand-side management (DSM) programs currently being implemented include : Low Income Efficiency Program, Low Income – New Home Program, Home Performance with ENERGY STAR® Program, ENERGY STAR® Change a Light, Residential High Efficiency Central Air Conditioning (CAC), ENERGY STAR® Homes, Commercial and Industrial (C&I) Rebate, and Building Operator Certification Program.

### Kansas Wind Projects

It is anticipated that in 2009, Empire will source about 15% of its electric energy from the Elk River and Meridian Way wind projects, both of which are located in Kansas.

Empire currently has a 20-year contract to purchase wind energy from the 150 MW Elk River Windfarm located in Butler County Kansas near the town of Beaumont. This resource began commercial operation in December 2005. In 2006, Empire purchased approximately 515,970 MWh of energy from this resource, which accounted for about 9.7% of net system input. In 2007, Empire purchased about 8.9% of its net system input from this wind resource.

In June 2007, Empire announced that it had signed a 20-year purchased power agreement with a second wind energy project. This project, known as the Meridian Way Wind Farm, will be located in Cloud County Kansas, near Concordia. This 105 MW Wind Farm (approximate Empire share) is expected to be operational in late 2008.

Empire will continue to monitor state and federal legislative and regulatory requirements for renewable portfolio standards (RPS). With the current wind projects described above, Empire believes that it will be well-positioned to meet the percentages of renewable energy that might be required by a state or federal RPS.

### Beyond 2010: Twenty-Year Resource Planning

Empire has conducted an analysis of future loads, resources, and risks in a study known as an Integrated Resource Plan (IRP). This study covers a 20-year planning horizon. This periodic IRP analysis, in conjunction with Empire's normal planning process, assists Empire in making decisions concerning the timing and type of system expansion that should ultimately occur. The results of the IRP analysis reflect only current and projected conditions as they are known at the time of the study. Empire will reexamine its decisions for future system expansions as the need for additional resources, driven by load growth, and the influence of external factors, primarily environmental, become more evident. Empire developed a preferred plan and implementation plan during the IRP process, but it is subject to the ongoing need to reevaluate modeling assumptions based on changing conditions.

Integrated resource planning for electric utilities has evolved considerably over the past twenty years and can no longer solely identify the least cost resources; such a plan must explicitly consider risks and uncertainties. Empire's objectives in preparing its 2007 IRP reflect its commitment to provide cost-effective, safe, and reliable electric service to its customers:

- to generate and provide reliable electricity service while complying with all environmental requirements
- to minimize rate impacts for customers
- to achieve and/or maintain investment grade ratings on its debt; thus providing for corporate financial stability and minimizing the financing costs included in the rates paid by Empire's customers
- to accommodate and manage cost, environmental, and load growth uncertainties

Today, there are many uncertainties related to base load resources over the next 20 years. Key uncertainties include environmental, load growth, capital and transmission costs and market and fuel prices. Empire developed 12 alternate plans during the IRP process, and subjected the plans to rigorous risk analysis. Some level of future carbon tax was assumed in all future plans. Only in the lowest carbon tax scenario were new coal units chosen beyond 2010 as possible resources. Nuclear was considered in all plans except for the base case. Thus, new nuclear is not in Empire's preferred plan for the next 20 years. There is still too much uncertainty about nuclear costs and waste disposal. New designs and licensing procedures for nuclear units are being discussed, but they are still unproven at this time. Also, Empire could only participate as a joint owner in such a large project and plans associated with such a unit in the area have not advanced to such a point that it could be realistically considered by Empire in the preferred plan over the twenty-year planning horizon.

Empire will continue to monitor the future of baseload generation in the region. This could include nuclear, pulverized coal or new technologies as they emerge. As previously mentioned, for the base case Empire has assumed that no nuclear units in which it can participate will be built during the planning horizon. However, Empire will keep current on publicly released plans in the region for new nuclear units. Similarly, Empire will monitor and evaluate opportunities for participation in coal-fired units, integrated gasification combined cycle units (IGCC), or other emerging technologies planned in the region. Empire will be cognizant of and striving for resources that incorporate methods for carbon capture and carbon sequestration, as appropriate, in compliance with any global climate change legislation that might be enacted. Again, environmental risk was a key uncertainty in the IRP study.

For more information on Empire, please contact:

David Martin
Director of Governmental Affairs
P. O. Box127
Joplin, MO 64801
(417) 625-6107 (O)
(417) 850-0862 (M)

Whitney Damron
919 South Kansas Avenue
Topeka, KS 66612
(785) 354-1354 (O)
(785) 224-6666 (M)

The Empire District Electric Company
NYSE: EDE

**Testimony before the House Select Committee on Energy and Environment for the Future, March 12, 2008**
**Opposing H.B. 2949**

Chairperson Myers and Honorable Members of the Committee:

My name is Tom Thompson and I represent the Kansas Chapter of the Sierra Club. I have come today to speak in opposition to H.B.2949.

The Sierra Club is in opposition to 2949 but appreciates the Committees attempt to start work on a Kansas Energy Plan. Kansas needs a far-reaching, comprehensive plan that works to meet the energy needs of Kansans in a reliable, sustainable and environmentally appropriate fashion. This bill primarily deals with what it calls base load. It also presents many unanswered questions.

The Sierra Club is concerned that this bill primarily deals with base load, particularly with proportion of nuclear power being increased to meet base load needs. This is being done without first considering the effects of an aggressive conservation and efficiency program to decrease the need for additional base load. The Kansas Energy Council has hired Summit Blue from Boulder, Colorado to study the energy efficiency potential for Kansas. They are to report to the commission at their June 10th meeting. Conservation needs to be part of any program dealing with future base load.

The Sierra Club is also concerned that this bill, though it encourages development of renewable sources of energy, does not allow for new advancements in renewable technology that might be used in meeting base load needs. The targets in the bill need some allowances for these technologies so that they might be included should they become available.

It is also of concern that in the fuel mix cited on page 3 line 8 includes wind at 2% in the balloon. The Sierra Club applauds the inclusion of wind in Section 5. Then the bill does not consider it part of the fuel mix in coming years apparently because it is not considered to be what is called dispatchable. From that point in the bill, development of wind does not appear to be encouraged because it is not dispatchable.

The Sierra Club hopes that the state of Kansas continues its pursuit of a viable energy plan. The Sierra Club would like to see a plan that considers sustainability, pollution potential including carbon dioxide and other greenhouse gases, future carbon fees, waste disposal issues, life-time costs, impact on health and energy independence. It also hopes that the general public is given ample opportunity for input.

The Sierra Club recommends that 2949 not be passed favorably.

Thank you for this opportunity and your time.

Sincerely

Tom Thompson
Sierra Club

House Select Committee on Energy
+ Environment for the Future
3/12/08
Attachment # 5

Mr. Chairman and members of the committee,

Thank you for this opportunity to comment on HB 2949. I feel strongly that it is wrong for Kansas.

At a time when most of the world is looking for ways to develop wind power, solar power, geothermal, hydrogen, or hydro power, this bill encourages what other parts of our country and the world are trying to avoid: more fossil fuels and nuclear power.

When most of the world is calling for stricter regulations on coal power and nuclear power, this bill seeks to loosen restrictions on those sources. Where other states are creating innovative energy conservation programs, this bill does nothing for conservation.

When Wall Street and other major financial centers around the world have made it clear that they want to fund renewable energy projects and reduce or stop funding on new fossil fuel projects, Kansas should read those signs carefully and place our support behind the same areas of power generation favored by Wall Street. Instead of supporting the failed "clean coal" technologies that have been abandoned by the Bush administration, we should seek ways to use hydrogen or compressed air energy storage to firm the wind in western Kansas, which would create thousands of jobs here at home.

I urge you to vote against HB 2949 and work instead to develop programs to support the wind and solar projects that have greater potential for the Kansas economy in job creation and in supplying clean, low-cost electricity.

Joe Spease
President, Pristine Power
9934 Goddard
Overland Park, KS 66214
913-492-2862
jspease@pristine-power.com

House Select Committee on Energy
+ Environment for the Future
3/12/08
Attachment # 6

**House Select Committee for Energy and Environment Future**
**Representative Don Meyers, Chair**

# Kansas Energy Plan Act
# H. B. 2949

**12 March, 2008**
**Room 784, Docking State Office Building**
**Topeka, Kansas**

## Wind & Natural Gas, Wind & NG with Storage, Wind & Storage without NG (Adiabatic) — as BASELOAD

**Raymond H. Dean, Prof. Emeritus, EECS, University of Kansas**
**(private citizen)**

**Thank you for this opportunity to comment on the Kansas Energy Plan Act.**

**The first item in Section 3's list of policies says:**

**"Encouragement of continued development of alternative and renewable energy."**

**But Sections 4 and 5 propose that most future fuels be coal and nuclear, which are not renewable. There seems to be a faulty assumption that fossil and nuclear fuels will last forever, and that the only way to do things in the future is the way we did them in the past.**

**Here's a suggestion for fixing the problem: Instead of associating "base-load" generation with particular technologies or particular "capacity factors," associate it with the desired functionality – *continuous production of reliable power at low marginal cost*.**

**For example, 25 years ago, many considered the gas-combined-cycle to be a good "base-load" technology, because gas was inexpensive and the gas-combined-cycle got extra value from the gas turbine's free exhaust heat. Using that free exhaust heat to drive a steam turbine increased the electric power per unit of gas to about 150%. But recently rising gas prices have motivated re-assignment of this gas-combined-cycle to "intermediate-load" generation.**

Select Committee on Energy
& Environment for the Future
3/12/08
Attachment # 7

**Fortunately, there is another way to obtain *continuous production of reliable power at low marginal cost.* Couple gas turbines with wind turbines - using two parts wind energy with one part gas energy. This *renewable-combined-cycle* increases the electric power per unit of gas to about 300%. This is twice as good as the gas-combined-cycle.**

**If gas prices continue to rise, enhance the wind-and-gas combination by adding underground compressed-air energy storage (CAES).[1] This cuts gas consumption by another factor of two. It increases the electric power per unit of gas to about 600%.**

**By also storing heat, it's possible to completely eliminate gas and make the process "adiabatic" (no net heat added). No matter what happens to the price of gas, this 100% renewable system has lower marginal cost than either coal or nuclear.**

**Associating gas and/or compressed-air storage with wind eliminates wind's intermittency. This makes wind as reliable and dispatchable as coal or nuclear. Geographical distribution makes wind more reliable. The associated gas or compressed-air turbines make wind more rapidly dispatchable.**

**In this bill's definition of "base-load" generation, please do not exclude the renewable combinations: (1) Wind and gas.[2] (2) Wind, gas, and compression storage. (3) Wind and adiabatic energy storage. In appropriate combination, wind is excellent "base-load" generation. It is:**

- **clean energy**
- **reliable energy**
- **low marginal cost energy**

**Thank you for your consideration.**

---

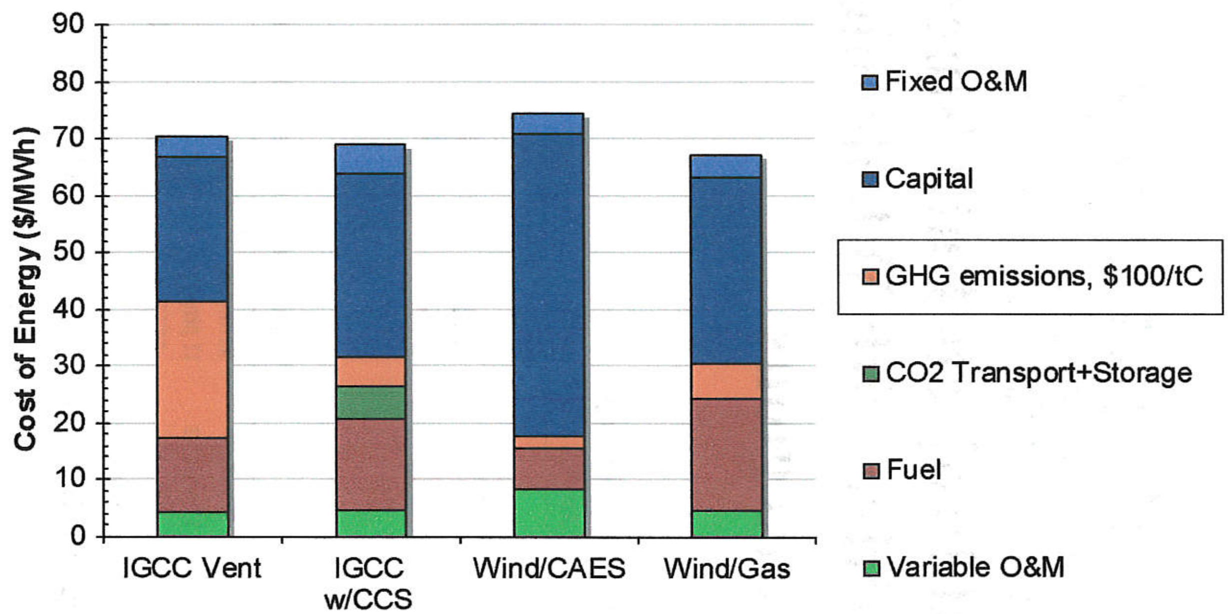
[1] http://www.princeton.edu/~ssuccar/recent/Succar_NETLPaper_May06.pdf
http://www.princeton.edu/~ssuccar/recent/Greenblatt_EP_2007.pdf
**These papers show how wind-power combinations compete in the "base-load" market. Notice the first paper's carbon-sequestration (coal-oriented) audience and the word "Baseload" in both titles. The outside world accepts wind-power as part of "base-load".**
[2] **when the current "base-load" includes gas.**

**Samir Succar, "Comparing Coal IGCC with CCS and Wind-CVAES Baseload Power Options in a Carbon-Constrained World", National Renewable Energy Lab, Jan. 4, 2007**

**http://www.nrel.gov/analysis/seminar/docs/2007/ea_seminar_jan_4_succar.ppt**

**slide #10 (assumed natural gas price of approximately $5.00 / MCF):**

# Generation Costs for Baseload Options

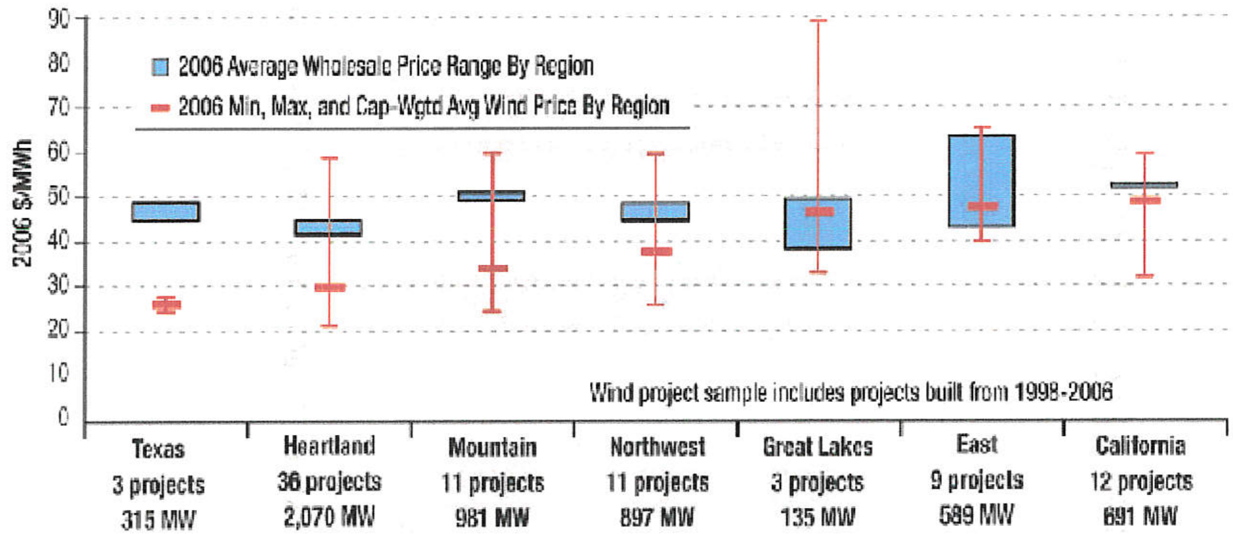



**237 gC/kWh 53 gC/kWh 23 gC/kWh 62 gC/kWh**

7-3

U.S. Department of Energy
Energy Efficiency and Renewable Energy
Bringing you a prosperous future where energy is clean, abundant, reliable, and affordable

# In 2006, Wind Projects Built Since 1997 Were Competitive with Wholesale Power Prices in Most Regions




*Source: FERC 2006 "State of the Market" report, Berkeley Lab database.*

Note: Even within a region there are a range of wholesale power prices because multiple wholesale price hubs exist in each area (see previous map)



Ryan Wiser and Mark Bolinger, "Annual Report on U. S. Wind Power Installation, Cost, and Performance Trends: 2006", May 30, 2007
http://eetd.lbl.gov/ea/EMS/reports/ann-rpt-wind-06.pdf

7-4

ELSEVIER

Energy Policy 35 (2007) 1474–1492

ENERGY POLICY

www.elsevier.com/locate/enpol

# Baseload wind energy: modeling the competition between gas turbines and compressed air energy storage for supplemental generation

Jeffery B. Greenblatt[a,*], Samir Succar[b], David C. Denkenberger[c], Robert H. Williams[b], Robert H. Socolow[d]

[a]*Environmental Defense, Oakland, CA, USA*
[b]*Princeton Environmental Institute, Princeton University, Princeton, NJ, USA*
[c]*Department of Civil, Environmental and Architectural Engineering, University of Colorado, Boulder, CO, USA*
[d]*Department of Mechanical and Aerospace Engineering, Princeton University, Princeton, NJ, USA*

Available online 9 June 2006

**Abstract**

The economic viability of producing baseload wind energy was explored using a cost-optimization model to simulate two competing systems: wind energy supplemented by simple- and combined cycle natural gas turbines ("wind + gas"), and wind energy supplemented by compressed air energy storage ("wind + CAES"). Pure combined cycle natural gas turbines ("gas") were used as a proxy for conventional baseload generation. Long-distance electric transmission was integral to the analysis. Given the future uncertainty in both natural gas price and greenhouse gas (GHG) emissions price, we introduced an effective fuel price, $p_{\mathrm{NGeff}}$, being the sum of the real natural gas price and the GHG price. Under the assumption of $p_{\mathrm{NGeff}} = \$5/\mathrm{GJ}$ (lower heating value), 650 W/m$^2$ wind resource, 750 km transmission line, and a fixed 90% capacity factor, wind + CAES was the most expensive system at ¢6.0/kWh, and did not break even with the next most expensive wind + gas system until $p_{\mathrm{NGeff}} = \$9.0/\mathrm{GJ}$. However, under real market conditions, the system with the least dispatch cost (short-run marginal cost) is dispatched first, attaining the highest capacity factor and diminishing the capacity factors of competitors, raising their total cost. We estimate that the wind + CAES system, with a greenhouse gas (GHG) emission rate that is one-fourth of that for natural gas combined cycle plants and about one-tenth of that for pulverized coal plants, has the lowest dispatch cost of the alternatives considered (lower even than for coal power plants) above a GHG emissions price of \$35/tC$_{\mathrm{equiv.}}$, with good prospects for realizing a higher capacity factor and a lower total cost of energy than all the competing technologies over a wide range of effective fuel costs. This ability to compete in economic dispatch greatly boosts the market penetration potential of wind energy and suggests a substantial growth opportunity for natural gas in providing baseload power via wind + CAES, even at high natural gas prices.


*Keywords:* Wind energy; Compressed air energy storage (CAES); Greenhouse gas emissions

## 1. Introduction

Wind energy has enjoyed robust growth in recent years, averaging 30% per year increase in installed capacity since 1992 (EWEA, 2004). Driving this growth has been a combination of factors: a twofold drop in capital costs between 1992 and 2001 (Junginger and Faaij, 2003), and a number of government initiatives designed to encourage wind energy. Global installed wind capacity stood at 59 GW at the end of 2005 (GWEC, 2006; WWEA, 2006), generating about 1.0% of global electricity consumption. Projections indicate that capacity may rise to nearly 200 GW by 2013 (BTM Consult ApS, 2004), with the potential to grow much larger (e.g., Archer and Jacobson, 2005).

Fueling much of the government support for wind energy are environmental concerns. While it is widely recognized that the impact of wind energy on the environment is not zero, the significant impacts of air pollution, water consumption and the depletion of natural resources are much lower than those of current fossil fuel technologies (European Commission, 2003). Moreover, its

*Corresponding author. Tel.: +1 510 4572210; fax: +1 510 6580630.
*E-mail address:* jgreenblatt@environmentaldefense.org (J.B. Greenblatt).

0301-4215/\$ - see front matter 
doi:10.1016/j.enpol.2006.03.023

7-5

potential to provide large amounts of electricity without direct GHG emissions[1] has now become perhaps the major driving force for wind energy. Numerous energy analysts predict that the inevitable limitation of GHG emissions, whether via an emissions trading system, emissions taxes, or some other mechanism, will further encourage the growth of wind energy by making it economically competitive with fossil fuels, without direct subsidy.

However, wind is an intermittent resource. When wind power output falls, grid operators must be able to provide sufficient power from other sources to satisfy demand. At small market penetrations, such shortfalls can be met by existing voltage regulation, load following, and spinning reserve resources, with negligible additional system cost (Kelly and Weinberg, 1993). But at larger penetrations (e.g., 20%), this incremental cost per unit wind energy produced becomes significant, of the order of 1–1.5¢/kWh (ILEX Energy Consulting, 2002), due to the need for supplemental generating capacity.[2] This "intermittency penalty" does not include the higher cost of wind energy itself. Wind energy penetration levels of >20% are already a reality in Denmark and several Spanish and German provinces (BTM Consult ApS, 2004; Holttinen 2005). Moreover, many European countries and at least one US state (California) have set goals of 20% or more electrical energy from renewables in the next two decades (Goswami, 2004; Hinrichs-Rahlwes, 2004; Parent, 2004; Timms, 2004; Steineger, 2005), and much of this energy would be supplied by wind (BTM Consult ApS, 2004).

Another important consideration at high levels of wind energy deployment is the distance between wind resource and demand. In the US, much of the high-quality wind resource is located in the sparsely populated Great Plains (Elliott et al., 1991),[3] while in Asia, there are vast resources in Mongolia (Elliott et al., 2001) and remote parts of northern and western China, as well as offshore (Lew et al., 1998; CREIA, 2004). As the EU exhausts its onshore potential, it is looking both offshore and at sites in Russia, northwestern Africa, and Kazakhstan (Czisch, 2004). Many of these locations require long transmission distances (up to 4500 km) to bring the electricity to market, making transmission capital an important additional cost for wind energy.

The full cost of wind energy, including proper treatment of the issues of intermittency and remoteness of wind resources, must be carried out in order to understand the true potential of wind in meeting future electricity needs, giving attention to the need for supplemental generation to guarantee system reliability (ILEX Energy Consulting, 2002; DeCarolis and Keith, 2006) and strengthened or expanded transmission capacity needed to exploit remote wind resources.

This paper explores the economic viability of two alternative strategies for transforming wind energy from an intermittent resource into a baseload electricity source. We have simulated the three-way economic competition among combined cycle (CC) natural gas turbines, wind with a combination of simple cycle (SC) and CC gas plants, and wind partnered with compressed air energy storage (CAES). Long-distance transmission was modeled for the wind and CAES systems; however, it was assumed that the gas plants (SC and CC) would be located nearby to demand because they are generally unconstrained by the location of physical resources.[4]

Natural gas turbines are well-suited for addressing wind intermittency issues because of their fast ramping rates and low capital costs. Other supply technologies, such as hydroelectric and coal plants, can also be used, though coal's slower ramping rates generally limit its ability to supplement wind energy. Complementary intermittent generation, such as solar PV, and demand-side management, such as interruptible loads, are also important possibilities.

Energy storage presents still another strategy for providing baseload electricity from wind. A number of storage technologies exist which are economical on various timescales (EPRI-DOE, 2003), but only two technologies—pumped hydroelectric storage and compressed air energy storage (CAES)—are cost-effective at the large temporal scales (several hours to days) needed to complement wind energy that we investigate here. Conversion of wind electricity into another storable energy carrier, such as hydrogen or thermal energy, is also a possibility. In this paper, we consider only CAES.

CAES is commercially available storage technology that is currently used primarily to store low-cost off-peak power for sale during periods when the electricity is more valuable. To date, three CAES plants have been built and operated in the world: a 290 MW facility in Germany (Huntorf, which became operational in 1978), a 110 MW facility in the United States (McIntosh, which went into operation in 1991), and a 25 MW R&D facility in Italy (Sesta, which ran for a few years in the early 1990s) (R. Schainker, pers. commun., 2006). Several more plants

[1]Total life cycle GHG emissions from wind energy are not zero (see, e.g., Denholm et al., 2005). However, compared with electricity plants that burn fossil fuels, the GHG emissions from wind turbines are extremely low.

[2]One way of explaining the growth of this incremental cost is that the "capacity credit" for intermittent wind capacity has its maximum economic value at very small grid penetration. This credit, estimated to be the wind capacity times it capacity factor (~1/3) times the economic value of the dispatchable (usually fossil) capacity displaced ($/kW), diminishes monotonically with increasing grid penetration.

[3]There may also be significant offshore resources in shallow waters of the eastern and western US coasts (Musial and Butterfield, 2004).

[4]The availability of adequate natural gas supply does represent a physical constraint that could affect how many gas plants are built. However, it should be relatively easy to site such plants near load centers because they require little space and have relatively low air pollutant emission levels. Placing a gas plant at the remote site confers no economic advantage to the system, unless siting or operation and maintenance (O&M) costs are lower, because transmission losses are incurred. By contrast, locating a CAES plant near the wind park allows the use of a smaller transmission line, imparting a significant economic advantage.

7-6

are under development, including a 260 MW facility in Iowa, and a 2700 MW facility in Ohio (EPRI-DOE, 2003; K.Holst, private commun., 2006). Although no CAES facility has yet been built with the explicit purpose of enabling baseload wind power generation, the Huntorf plant is used for leveling the variable power from numerous wind turbines in Germany (EPRI-DOE, 2003), and the Iowa facility is a proposed wind CAES system for delivering power during peak periods (Wind, 2002).

CAES units couple turbomachinery to energy storage in the form of compressed air. The compressed air can be stored underground in a solution-mined salt cavity, in a mined hard rock cavity, or in an aquifer; aboveground storage in tanks is also possible but is much more costly. The turbomachinery is basically a gas turbine in which the air compression and expansion steps are separated temporally. Commercially available CAES involves inter-cooling the air during compression and storing it at close to ambient temperature. The compressed air recovered from storage is heated[5] by burning a fuel such as natural gas[6] in it, and the combustion products are expanded in the turbine to produce electricity.

A typical CAES unit might consume 0.67 kWh of electricity to compress air for storage and later burn ~4200 kJ of natural gas in compressed air recovered from storage to generate each kWh of electricity. For such a unit the estimated electrical round-trip efficiency would be in the range 77–89%.[7] The underground storage volume required would typically be $\sim 2.4 \times 10^7\,m^3$ for each week of storage required per GW of CAES capacity.[8] Hard caverns can be excavated to volumes of $\sim 10^7\,m^3$ (roughly $250\,m^3$ diameter), so that GW-scale CAES units would require multiple caverns. For aquifer storage, assuming a layer thickness of 10 m and effective porosity[9] of 0.2, a 1 GW CAES unit with a week's storage capacity would occupy an area of $\sim 12\,km^2$.

Using only two supplemental generation technologies for backing up wind greatly simplified the model. We believe this approach captures most of the important contrasts between the fill-in generation and energy storage approaches to dealing with intermittency. However, our choice of the natural gas CC as the baseload power technology displaced might not adequately capture the implications of the full range of baseload options that wind systems might displace, which also include coal, nuclear and hydroelectric plants—an issue that we return to later in the paper.

In real electricity markets, a significant part of the intermittent wind energy production might be absorbed by existing ancillary services in a more economical way than by utilizing dedicated fill-in power or energy storage as modeled here.[10] However, this is not the case when long-distance transmission is involved, because of the need to maximize the use of expensive transmission capital. Moreover, at the high wind energy penetration levels posited in this model, ancillary services would probably be insufficient to absorb intermittent wind generation. Under these conditions, our model is likely to be a good approximation of the way wind intermittency will be handled in the future, and its simplicity and transparency are key advantages.

An advantage of considering only SC, CC and CAES is that they all burn the same fuel, so the effects of changing fuel prices and GHG prices are folded into one variable, the effective fuel price ($p_{NGeff}$), which we define as

$$p_{NGeff}(\$/GJ) = p_{NG}(\$/GJ) + p_{GHG}(\$/tC_{equiv.}) \cdot C_{NG}(tC_{equiv.}/GJ), \quad (1)$$

where $p_{NG}$ is the actual market price of natural gas, $p_{GHG}$ is the price of emitting GHGs ($CO_2$ plus equivalent amounts of other gases), and $C_{NG}$ is the total GHG content of natural gas, equal to $18.0\,kgC_{equiv}/GJ$, including typical upstream emissions[11]—so that each $\$100/tC_{equiv.}$ of GHG price contributes \$1.8/GJ to the effective fuel price.

This work builds upon several previous studies, beginning with the groundbreaking work of Cavallo and colleagues (Cavallo, 1995–1997; Cavallo and Keck, 1995) who first explored wind parks coupled with CAES and connected via transmission lines to distant demand

[5]If an attempt were made to expand the air in the turbine without heating, system components would freeze.

[6]Therefore, the $CO_2$ emissions from a CAES plant are not zero. However, the use of carbon-neutral fuels may be feasible (Denholm, 2006). In principle, it is also possible to store the heat of compression separately from the air, avoiding the need for fuel altogether (Bullough et al., 2004).

[7]The CAES electrical round-trip efficiency is difficult to specify precisely. We estimate a range of efficiencies for a unit consuming 4220 kJ of natural gas for each kWh of electricity recovered from storage based on assigning to the natural gas consumed an equivalent electricity value. If one assumes that the equivalent electricity from natural gas is based on simple cycle efficiency ($HR_{SC} = 9400$ kJ/kWh), then the total equivalent electricity input is 1.12 kWh, resulting in a CAES electrical round-trip efficiency of 89%. Alternatively, if one assumes combined cycle efficiency ($HR_{CC} = 6700$ kJ/kWh), then total electricity input is 1.30 kWh, and the CAES electrical round-trip efficiency is 77%.

[8]This estimate is based on the McIntosh CAES unit in the United States, which stores air in a salt cavern at pressures ranging between 45 and 72 atm. The McIntosh plant, which has a discharge capacity of 110 MW (5.05 kg of air per kWh) that can be sustained for up to 26 h, requires $0.14\,m^3$ of storage volume per kWh of electricity discharged.

[9]Effective porosity is the product of actual porosity and "saturation" (fraction of pores that can be displaced by air); in the above example, we have assumed a porosity of 0.3 and a saturation of 2/3 (C. Christopher, pers. commun., 2006).

[10]There are two possible complementary applications of CAES to wind systems: short-term power regulation (up to several hours) and long-term storage (several days). We model only the latter application in this paper, because we focus exclusively on baseload energy. A fuller analysis that includes the first application should increase the attractiveness of CAES.

[11]The $CO_2$ content of natural gas is approximately 13.64 kgC/GJ (higher heating value, HHV) or 15.16 kgC/GJ (lower heating value, LHV) (EIA, 2005). Upstream greenhouse emissions add an additional 2.84 kg $C_{equiv.}$/GJ (LHV) (Wang, 1999). The GHG emissions associated with manufacturing of capital components were not included. Energy units are heretofore expressed using the LHV convention, unless otherwise specified.

7-7

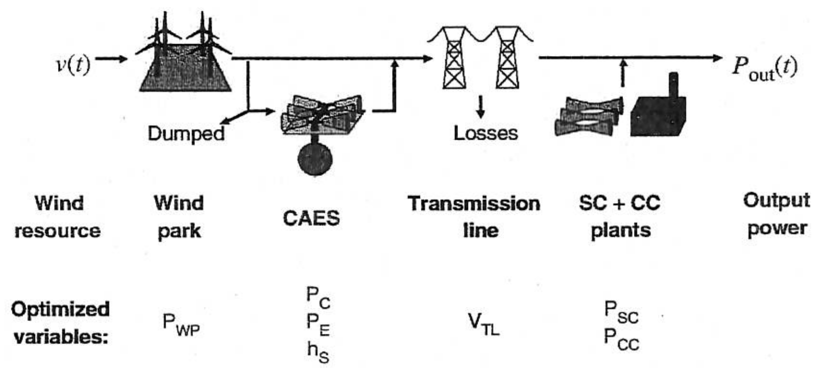



Fig. 1. Schematic diagram of model. Variable definitions are given in Table 3.

centers.[12] More recently, ILEX Energy Consultants (2002) calculated the intermittency penalty for various future levels of wind energy penetration on the UK electric grid. Keith and Leighty (2002) analyzed the comparative economics of transporting wind energy from North Dakota to Chicago via electric transmission versus hydrogen pipeline. The Iowa Association of Municipal Utilities analyzed the economics of a wind park coupled with CAES in Iowa (Wind, 2002), and Ridge Energy Storage, LLC (Desai and Pemberton, 2003; Lower Colorado River Authority, 2003) analyzed the economics of wind parks with CAES in West Texas. Denholm et al. (2005) analyzed costs and total lifecycle GHG emissions of generic baseload wind/CAES systems with long-distance transmission. DeCarolis and Keith (2006) modeled the competition among wind parks, SC, CC and CAES for multiple wind sites in the US Great Plains, transmitting electricity to Chicago.

## 2. Model description

We model the system shown schematically in Fig. 1, which delivers 2.0 GW of baseload power at the end of a long, high-voltage transmission line.[13] Base case model parameters are listed in Table 1, and equations are given in Table 2.

Modeling begins with an hourly time series of synthetic wind speeds $v(t)$, (see below) and from these calculates the hourly wind park power, which is split among directly transmitted power, power sent to the CAES compressor (if present), and "dumped" (curtailed) power. The CAES unit compresses air into a storage volume up to a specified reservoir capacity. The CAES expander utilizes this compressed air, along with natural gas, to generate electricity whenever the wind park power falls below the (constant) demand level. Transmitted electricity undergoes power-dependent losses. SC and CC gas turbine plants (if present) are then dispatched to make up any shortfall, up to the required capacity factor.

The wind + CAES system is designed to be a baseload power unit with sufficient storage capacity to deliver power at the transmission line output capacity while not allowing system output to fall below this level during more than 10% of the recorded hours. This design criterion both determines the amount of storage and dictates that the CAES expander capacity $P_E$ equals $P_{TL}$, the transmission line capacity. Alternative approaches for designing a wind + CAES system are also feasible—such as requiring 100% availability of power from the system (DeCarolis and Keith, 2006). The rationale for our design choice was twofold: (1) except for unscheduled outages, the system would have the capability to satisfy demand even during times of insufficient wind power output (as long as the CAES cavern is not depleted); and (2) the system has considerable operational flexibility—to the extent that, given a modest capability to forecast fluctuations in wind speed and electricity demand, the 10% downtime could be mostly scheduled during times of lowest demand. This approach both addresses grid stability concerns and exploits the flexible dispatch capability of CAES. Thus, it is possible to hold the system to a standard consistent with baseload operation and still allow the model to exploit the unique attributes of energy storage.

The wind speed time series was constructed with an autoregressive algorithm (McFarlane et al., 1994) producing a Weibull distribution of frequencies, and a time series autocorrelation function that decayed exponentially with time constant $\theta/2$, where $\theta$ was an input parameter set to 30 h in the base case.[14] We assumed a wind park of sufficient size ($\geqslant$2 GW) that intra-hour variations in power can be averaged, and an hourly time series can be used. This time step is also compatible with the ramping capabilities of SC, CC and CAES plants. No diurnal or seasonal variations in average wind speed were modeled. The wind park is assumed to be made up of pitch-regulated

[12] Several studies of wind parks coupled with CAES significantly predate the Cavallo work (e.g., Zlokovic, 1969) but they did not consider long-distance transmission.

[13] Such high-capacity transmission lines are needed to make long-distance transmission cost-effective.

[14] This choice of $\theta$ represents a typical midrange value from the 51 data sets we examined.

7-8

Table 1
Base case parameters of the model

| Parameter | Symbol | Base value | Units | Reference |
|---|---|---|---|---|
| *Major parameters* | | | | |
| Demand (constant) | $P_d$ | 2 | GW | |
| Capital charge rate[a] | $CCR$ | 11 | %/yr | |
| System capacity factor | $CF$ | 90 | % | |
| Transmission distance | $D_{TL}$ | 750 | km | |
| Base effective fuel price[b] | $p_{NGeff}$ | 5 | \$/GJ | |
| Average wind speed (class 4)[c] | $v_{avg}$ | 8.22 | m/s | Malcolm and Hansen (2002) |
| Autocorrelation time[d] | $\theta$ | 30 | h | |
| Wind park base cost[e] | $C_{WP,0}$ | 700 | \$/kW | Neij, 1999; Junginger and Faaij, 2003 |
| CAES compressor cost[f,g] | $C_C$ | 170 | \$/kW | EPRI-DOE (2003) |
| CAES expander cost[f,g] | $C_E$ | 185 | \$/kW | EPRI-DOE (2003) |
| CAES storage cost[g,h] | $C_S$ | 1 | \$/kWh | EPRI-DOE (2003) |
| SC capital cost[i] | $C_{SC}$ | 240 | \$/kW | Gas Turbine World (2003) |
| CC capital cost[i] | $C_{CC}$ | 580 | \$/kW | Dillon et al. (2004) |
| TL converter cost | $c_{conv}$ | 50 | \$/kW | Hauth et al. (1997) |
| TL tower+cable (line) cost | $c_{line}$ | 491 | \$/kV km | Empirical fit to Hauth et al. (1997) |
| TL right-of-way cost[j] | $c_{ROW}$ | 988 | \$/m km | Empirical fit to Hauth et al. (1997) |
| *Minor parameters* | | | | |
| Hours per year | $HY$ | 8760 | h/yr | |
| Time step | $\Delta t$ | 1 | h | |
| Simulation period | $T$ | 50,000 | h | |
| GHG intensity of natural gas[b,k] | $C_{NG}$ | 18.0 (55.6) | kgC$_{equiv.}$/GJ (GJ/tC$_{equiv.}$) | |
| Air density | $\rho_{air}$ | 1.225 | kg/m$^3$ | Malcolm and Hansen (2002) |
| Weibull shape factor | $K$ | 2 | | Malcolm and Hansen (2002) |
| Wind turbine rotor diameter | $D$ | 100 | m | Malcolm and Hansen (2002) |
| Wind turbine hub height | $h$ | 120 | m | Malcolm and Hansen (2002) |
| Wind turbine base rated power | $P_{rate,0}$ | 3.50 | MW | Malcolm and Hansen (2002) |
| Wind turbine cut-in speed | $v_{in}$ | 3.0 | m/s | Malcolm and Hansen (2002) |
| Wind turbine rated speed (at $v_{avg}$) | $v_{rate,0}$ | 12.33 | m/s | Malcolm and Hansen (2002) |
| Wind turbine rated speed ratio | $r_{rate}$ | 1.5 | | Malcolm and Hansen (2002) |
| Wind turbine efficiency[l] | $C_p$ | 39 | % | Malcolm and Hansen (2002) |
| Array efficiency below rating | $\alpha_0$ | 86 | % | Denkenberger (2005) |
| Wind turbine fixed block coefficient[m] | $f_{fix}$ | 29 | % | Denkenberger (2005) |
| Wind turbine thrust block coefficient[m] | $f_{thr}$ | 32 | % | Denkenberger (2005) |
| Wind turbine torque block coefficient[m] | $f_{tor}$ | 9 | % | Denkenberger (2005) |
| Wind turbine power block coefficient[m] | $f_{pow}$ | 30 | % | Denkenberger (2005) |
| Wind turbine thrust block exponent[m] | $e_{thr}$ | 0.7 | | Denkenberger (2005) |
| Wind turbine torque block exponent[m] | $e_{tor}$ | 1.4 | | Denkenberger (2005) |
| Wind turbine power block exponent[m] | $e_{pow}$ | 3 | | Denkenberger (2005) |
| CAES minimum power ratio | $r_{min}$ | 5 | % | |
| CAES energy output/input ratio | $E_o/E_i$ | 1.50 | | EPRI-DOE (2003) |
| CAES balance of plant cost ratio[f] | $R_{BOP}$ | 63 | % | EPRI-DOE (2003) |
| CAES heat rate[b] | $HR_{CAES}$ | 4220 | kJ/kWh | EPRI-DOE (2003) |
| SC heat rate[b] | $HR_{SC}$ | 9400 | kJ/kWh | |
| CC heat rate[b] | $HR_{CC}$ | 6700 | kJ/kWh | EPRI-DOE (2000) |
| SC maximum derating[n] | $R_{SC}$ | 20 | % | Nakhamkin et al. (2004) |
| CC maximum derating[n] | $R_{CC}$ | 13 | % | |
| Wind park fixed O&M (levelized replacement cost) | $C_{WP,F}$ | 15 | \$/kW yr | Malcolm and Hansen (2002) |
| Wind park variable O&M cost | $C_{WP,V}$ | 0.8 | ¢/kWh | Malcolm and Hansen (2002) |
| CAES fixed O&M | $C_{CAES,F}$ | 4 | \$/kW yr | EPRI-DOE (2003) |
| CAES variable O&M | $C_{CAES,V}$ | 0.3 | ¢/kWh | EPRI-DOE (2003) |
| SC fixed O&M | $C_{SC,F}$ | 10.8 | \$/kW yr | Dillon et al. (2004) |
| SC variable O&M | $C_{SC,V}$ | 0.13 | ¢/kWh | Dillon et al. (2004) |
| CC fixed O&M | $C_{CC,F}$ | 10.8 | \$/kW yr | Dillon et al. (2004) |
| CC variable O&M | $C_{CC,V}$ | 0.13 | ¢/kWh | Dillon et al. (2004) |
| TL number of circuits | $N_C$ | 1 | | Hauth et al. (1997) |
| TL number of poles | $N_P$ | 2 | | Hauth et al. (1997) |
| TL number of converters | $N_{conv}$ | 2 | | Hauth et al. (1997) |
| TL converter loss (per station) | $l_{conv}$ | 1 | % | Hauth et al. (1997) |
| TL thermal power coefficient | $p_{th}$ | 6.030 | kW/kV$^2$ | Empirical fit to Hauth et al. (1997) |
| TL line loss coefficient | $l_{line}$ | 1.029 | % kV$^3$/kW km | Empirical fit to Hauth et al. (1997) |
| TL right-of-way width coefficient | $w_{ROW}$ | 10.79 | M MW$^{-1/6}$ | Empirical fit to Hauth et al. (1997) |

D-9

Table 1 (*continued*)

| Parameter | Symbol | Base value | Units | Reference |
|---|---|---|---|---|
| *Internal parameters* | | | | |
| Wind speed | $v$ | | m/s | |
| Time | $t$ | | h | |
| Number of wind turbines | $N_{\mathrm{turb}}$ | | | |
| TL rated power | $P_{\mathrm{TL}}$ | | MW | |
| TL peak-to-ground voltage | $V_{\mathrm{TL}}$ | | kV | |
| Wind park capacity factor | $CF_{\mathrm{WP}}$ | | % | |
| CAES capacity factor | $CF_{\mathrm{CAES}}$ | | % | |
| SC capacity factor | $CF_{\mathrm{SC}}$ | | % | |
| CC capacity factor | $CF_{\mathrm{CC}}$ | | % | |

[a]Obtained from EPRI accounting rules (EPRI, 1993) with the following assumptions: construction period 2.5 years (3 equal payments), inflation rate 2%/yr, book life 30 years, tax life 20 years, modified accelerated capital recovery system (MACRS) depreciation for tax purposes, corporate tax rate 38.2%, property taxes and insurance 2%/yr, nominal return on equity 10%/yr, nominal return on debt 6.5%/yr, equity/debt share 45%/55%, real discount rate 5%/yr (after-tax weighted real average cost of capital).

[b]Thermal content stated in LHV basis.

[c]Extrapolated from 10 m reference Class 4 wind speed (5.77 m/s) using 1/7 scaling exponent to assumed hub height of 120 m.

[d]Autocorrelation time used is modal non-infinite value obtained from analysis of 51 wind speed time series from the US Great Plains (Milligan, pers. commun., 2003; HPRCC (High Plans Regional Climate Center), 2003; NCDC (National Climatic Data Center), 2004; UWIG (Utility Wind Interest Group), 2004).

[e]This turbine cost is a conservative estimate for 2020, based on two projections (Neij, 1999; Junginger and Faaij, 2003).

[f]Costs determined from information provided by EPRI-DOE (2003) and commercial vendors (N. Desai, pers. commun., 2003; R. Hanes, pers. commun., 2003).

[g]Note that although these costs have subsequently been revised upward (EPRI-DOE, 2004), we felt the original costs better represented "*N*th plant" costs. However, the sensitivity study includes the effects of higher CAES capital and storage costs (see Tables 4 and 5).

[h]Storage cost for mined salt dome.

[i]Capital cost is scaled by 1.47 to account for balance of plant cost.

[j]Assuming cost of land is $4000/acre, as suggested in Hauth et al. (1997).

[k]Natural gas carbon dioxide content (15.16 kgC/GJ) (EIA, 2005) including upstream GHG emissions (2.84 $\mathrm{kgC_{equiv.}}$/GJ) (Wang, 1995).

[l]The $C_p$ for the 1.5 MW turbine in Malcolm and Hansen (2002) was used here.

[m]Cost data from Malcolm and Hansen (2003) were fitted to a four-component model that grouped costs according to their observed power-law trends with rated power (Denkenberger, 2005).

[n]Simple cycle value ($\pm 10\%$ output over the course of a year) from Nakhamkin et al. (2004). For combined cycle value, we reduced this value by 1/3 to account for the much less temperature-sensitive combined cycle output.

wind turbines having a constant turbine efficiency $C_p$ below rated speed ($v_{\mathrm{rate}}$), and with an array efficiency coefficient $\alpha(v)$ that is constant up to $v = v_{\mathrm{rate}}$ and increases toward unity at higher wind speeds (Denkenberger, 2005).

Our CAES model parameters were obtained from several sources (Westinghouse Electric Corporation, 1995; Crotogino et al., 2001; EPRI-DOE, 2003; N. Desai, pers. commun., 2003; R. Hanes, pers. commun., 2003). The system was treated for the most part as a "black box," shown in Fig. 2, with a compressor that adds air to storage until the reservoir is full, and an expander that generates electricity from stored air as needed until the storage reservoir is empty. The performance characteristics were based on a two-stage, intercooled compressor with a pressure ratio of ~50–100, and a two-stage expander turbine with heat recovery for which 4220 kJ of natural gas is consumed per kWh of CAES output. For the base case, the ratio of electricity output to electricity input ($E_o/E_i$) is 1.5. It was assumed that the compressor and expander trains were composed of ~10 units each, in order to maintain efficient operation for the plant as a whole down to 5% of the rated CAES output ($r_{\min}$), with shut-down thereafter. For the base case wind + CAES system (see Section 3), this implied compressor and expander units of ~250 and ~210 MW, respectively. For simplicity it was assumed that the air recovered from the storage reservoir is delivered at constant pressure to the turbine expander.[15]

For transmission, a high-voltage direct current (HVDC) line is superior to an alternating current line at distances of interest for this study ($\geq$750 km). Costs varied with transmission voltage $V_{\mathrm{TL}}$, rated transmission power $P_{\mathrm{TL}}$, transmission length $D_{\mathrm{TL}}$, and some other minor parameters, using equations fitted to data in Hauth et al. (1997); see Tables 1 and 2. The model optimum used voltages of

[15]For aquifers and hard rock that contains a pressure-compensating water column, the reservoir pressure remains constant, so that the assumption accurately describes operation. For salt caverns and dry hard rock reservoirs, the reservoir pressure increases as air is added, so that the air recovered from storage can either be delivered at variable pressure to the turbine or it can be throttled and delivered at constant pressure. Although there is a slight savings in compression energy with variable pressure operation, the required cavity size would be much greater (Karalis et al., 1985).

D-10

Table 2
Model equations

| Parameter | Symbol | Equation | Base value | Units | Reference |
|---|---|---|---|---|---|
| Weibull scale factor | $c$ | $v_{avg}/\Gamma(1+1/k)$ | 9.28 | m/s | |
| Weibull probability | $p(v)$ | $(k/c)(v/c)^{k-1}\exp[-(v/c)^k]$ | | | |
| Wind power flux | $f_W$ | $(\rho_{air}/2)c^3\Gamma(1+3/k)$ | 650 | W/m$^2$ | |
| Wind speed autocorrelation function | $C(t)$ | $\int v(t'+t)v(t')\,dt' = e^{-2t/\theta}$ | | | |
| Wind turbine swept area | $A$ | $(\pi/4)D^2$ | 7850 | m$^2$ | |
| Wind turbine array spacing | $A_{turb}$ | $50D^2$ | 0.5 | km$^2$ | Elliott et al. (1991) |
| Wind turbine cut-out speed | $v_{out}$ | $3.5v_{avg}$ | 28.8 | m/s | Malcolm and Hansen (2002) |
| Wind turbine rated speed | $v_{rate}$ | $v_{avg}r_{rate}$ | 12.33 | m/s | |
| Wind turbine power | $P_{turb}(v)$ | $AC_p\rho_{air}v^3/2,\ v_{in} \leqslant v < v_{rate}$<br>$P_{rate},\ v_{rate} \leqslant v < v_{out}$<br>0, otherwise | | MW | |
| Wind turbine rated power | $P_{rate}$ | $AC_p\rho_{air}v_{rate}^3/2$ | 3.50 | MW | |
| Wind turbine array efficiency | $\alpha(v)$ | $\alpha_0,\ v \leqslant v_{rate}\alpha_0(v/v_{rate})^3,\ v_{rate} < v \leqslant v_{rate}/\alpha_0^{1/3}1,\ v > v_{rate}/\alpha_0^{1/3}$ | | | Denkenberger (2005) |
| Wind park power | $P_{out}(v)$ | $N_{turb}\alpha(v)P_{turb}(v)$ | | MW | |
| Wind park rated power | $P_{WP}$ | $N_{turb}P_{rate}$ | | GW | |
| Transmission line thermal rated power | $P_{th}$ | $p_{th}V_{TL}^2N_CN_P$ | | GW | Empirical fit to Hauth et al. (1997) |
| Transmission line right-of-way width | $W_{ROW}$ | $w_{ROW}(P_{th}N_P)^{1/6}$ | | m | Empirical fit to Hauth et al. (1997) |
| Transmission losses | $P_{loss}$ | $l_{line}D_{TL}P_{TL}^2CF/(V_{TL}^3N_CN_P)+l_{conv}N_{conv}P_{TL}$ | | MW | Empirical fit to Hauth et al. (1997) |
| Wind park capital cost[a] | $C_{WP}$ | $C_{WP,0}(P_{rate,0}/P_{rate})$<br>$[f_{fix}+f_{thr}(v_{rate}/v_{rate,0})^{ethr}+f_{tor}(v_{rate}/v_{rate,0})^{etor}+f_{pow}(v_{rate}/v_{rate,0})^{epow}]$ | 700 | \$/kW | Denkenberger (2005) |
| CAES capital cost | $C_{CAES}$ | $(1+R_{BOP})(C_CP_C+C_EP_E)/P_E+C_Sh_S$ | | \$/kW | |
| SC derated capital cost | $C_{SC}'$ | $C_{SC}(1+R_{SC})$ | 290 | \$/kW | |
| CC derated capital cost | $C_{CC}'$ | $C_{CC}(1+R_{CC})$ | 655 | \$/kW | |
| Transmission line capital cost | $C_{TL}$ | $c_{conv}N_{conv}+D_{TL}[c_{line}V_{TL}(N_CN_P)^{1/2}+c_{ROW}W_{ROW}]/P_{TL}$ | | \$/kW | Empirical fit to Hauth et al. (1997) |
| Wind park annual cost | $A_{WP}$ | $P_{WP}(C_{WP}CCR+C_{WP,F}+C_{WP,V}CF_{WP}HY)$ | | \$/yr | |
| CAES annual cost | $A_{CAES}$ | $P_E[C_{CAES}CCR+C_{CAES,F}+(C_{CAES,V}+p_{NGeff}HR_{CAES})\ CF_{CAES}HY]$ | | \$/yr | |
| Transmission line annual cost | $A_{TL}$ | $P_{TL}C_{TL}CCR$ | | \$/yr | |
| SC annual cost | $A_{SC}$ | $P_{SC}[C'_{SC}CCR+C_{SC,F}+(C_{SC,V}+p_{NGeff}HR_{SC})CF_{SC}HY]$ | | \$/yr | |
| CC annual cost | $A_{CC}$ | $P_{CC}[C'_{CC}CCR+C_{CC,F}+(C_{CC,V}+p_{NGeff}HR_{CC})CF_{CC}HY]$ | | \$/yr | |
| System cost of energy | $COE$ | $(A_{WP}+A_{CAES}+A_{TL}+A_{SC}+A_{CC})/(P_dCF\cdot HY)$ | | ¢/kWh | |

[a]See footnote 'm' under Table 1.

11-6

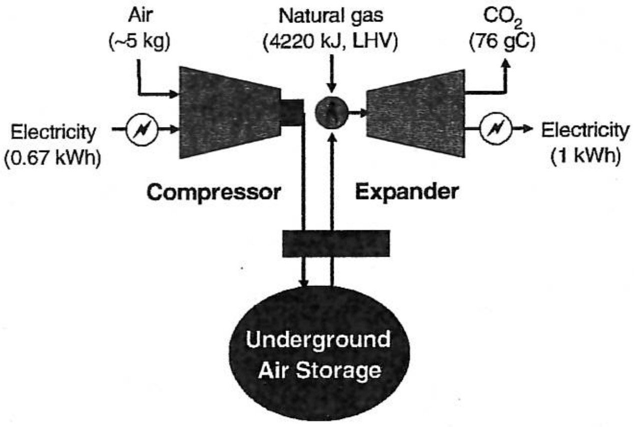



Fig. 2. CAES schematic.

approximately 550–750 kVDC in order to minimize losses; see Section 3.

Our base case assumed a set of costs and performance characteristics that might be realized for wind farms coming on line by 2020. The average wind turbine was assumed to have a rated output of 3.5 MW, rotor diameter of 100 m, hub height of 120 m, and cost of \$700/kW, consistent with recent projections (Neij, 1999; Junginger and Faaij, 2003). All costs were expressed in 2002 inflation-adjusted US dollars. Class 4 winds were assumed, with average wind speed $v_{avg}$ at hub height of 8.22 m/s and power flux $f_W$ of 650 W/m$^2$ (assuming a Weibull shape parameter of $k = 2$). The capital charge rate $CCR$ of 11%/yr was based on the assumption of stable government policy for renewable energy, resulting in a low-risk private investment environment with moderate rates of return on equity.[16] Our base case natural gas price is \$5/GJ. The CAES storage reservoir cost of \$1/kWh used in our base case assumed a salt cavern; the use of aquifers is expected to be considerably less expensive (~\$0.1/kWh) because no excavation is required; hard rock excavation costs are far greater (~\$30/kWh) (EPRI-DOE, 2003).

## 3. Results and discussion

Seven system variables were freely varied[17] in order to minimize the total levelized cost of energy ($COE$): wind park rated power ($P_{WP}$), CAES compressor power ($P_C$), CAES expander power ($P_E$), CAES storage duration ($h_S$), transmission line voltage ($V_{TL}$), SC rated power ($P_{SC}$) and

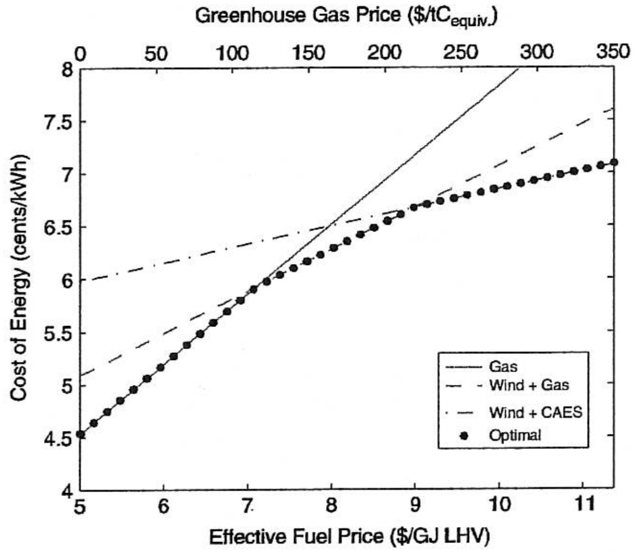



Fig. 3. Cost of energy ($COE$) versus effective fuel price ($p_{NGeff}$). The GHG price $p_{GHG}$, assuming a real fuel price $p_{NG}$ = \$5/GJ, is shown on the top axis. Four data sets are shown. Solid line: gas. Dashed line: wind + gas. Dashed/dotted line: wind + CAES. Black points: optimal (lowest $COE$) system.

CC rated power ($P_{CC}$). We found that, as a function of effective fuel price $p_{NGeff}$, the optimization favored three configurations with unchanging characteristics (as specified by the system variables), rather than continuously varying characteristics.[18] This observation allowed us to represent the optimal system by one of these three sets of variables to a high degree of accuracy, and calculate the optimal $COE$ for a given $p_{NGeff}$ from these variables. A plot of $COE$ versus $p_{NGeff}$ for each of the three systems is shown in Fig. 3. The system with the lowest $COE$ at $p_{NGeff}$ = \$5/GJ (¢4.5/kWh) is composed exclusively of CC gas turbines and is called the "gas" system. The next most expensive system at this $p_{NGeff}$ value (¢5.1/kWh) is composed of a wind park supplemented by mostly CC, with a small amount (10%) of SC gas turbine capacity in the base case. It is called the "wind + gas" system, and its $COE$ line crosses the gas $COE$ line near \$7.1/GJ. Finally, the most expensive system at $p_{NGeff}$ = \$5/GJ (¢6.0/kWh) is composed of a larger wind park, CAES plant, and no gas plant. It is called the "wind + CAES" system, and its $COE$ line crosses the wind + gas $COE$ line near \$9.0/GJ. The optimal system is indicated in Fig. 3 by the dotted line highlighting the least costly option at each value of $p_{NGeff}$.

We call the values of $p_{NGeff}$ at which the optimal system changes the "effective fuel entry prices," and define $p^{wind}_{NGeff}$ as the entry price of wind + gas, and $p^{CAES}_{NGeff}$ as the entry price of wind + CAES.

[16]The $CCR$ used was obtained using EPRI accounting rules (EPRI, 1993) for private financing with parameters summarized in footnote (a) of Table 1. This rate may be compared to private financing rates of 8-12%/yr in the literature (Malcolm and Hansen, 2002; Milborrow, 2005; DeCarolis and Keith, 2006).

[17]While it was possible in principle to vary all seven variables simultaneously in the optimization, this was not done in production runs in order to increase convergence: the CAES expander capacity ($P_E$) was forced to equal the transmission line capacity ($P_{TL}$), and the SC and CC capacities ($P_{SC}$ and $P_{CC}$) were optimized separately, outside the main optimization algorithm.

[18]The one exception to this was $P_{SC}/(P_{SC}+P_{CC})$ for the wind + gas system, which varied continuously with $p_{NGeff}$, from 10% (at $p_{NGeff}$ = \$5/GJ) to 2.5% (at $p_{NGeff}$ = \$11.3/GJ). However, setting this ratio constant had almost no effect on cost.

By historical standards the effective entry gas prices highlighted in Fig. 3 are very high, which suggests poor economic prospects for baseload wind. Consider average gas prices seen by electric generators in the United States. As recently as 2002 this gas price averaged \$3.8/GJ. But since then it has climbed to \$5.5/GJ in 2003, \$6.0/GJ in 2004, and \$7.2/GJ for the first nine months of 2005. It is expected that the gas price will eventually decline somewhat from current high levels, but not to the low levels of the past. The most recent forecast of the US Energy Information Administration (EIA, 2006) is that the natural gas price seen by the average US electric generator will be \$5.4/GJ in 2020 rising to \$6.3/GJ in 2030, suggesting that our base case assumption about the gas price 2020+ may be unrealistically low. However, we explore the impact of higher gas prices on our results in Section 3.1, and find little change in the conclusions reached other than a shift in entry prices.

The equivalent GHG entry prices, assuming an actual fuel price of \$5/GJ, are \$120/tC$_{\text{equiv.}}$ and \$220/tC$_{\text{equiv.}}$, respectively, and are labeled $p_{\text{GHG}}^{\text{wind}}$ and $p_{\text{GHG}}^{\text{CAES}}$. These may be compared with recent GHG prices in the voluntary US market (\$3–7/tC$_{\text{equiv.}}$) (Chicago Climate Exchange, 2005) and in the EU market (\$100–130/tC$_{\text{equiv.}}$) (PointCarbon, 2005). It is widely expected that the GHG price will need to be \$100/tC$_{\text{equiv.}}$ or higher in order to induce significant GHG mitigation; this is supported by macroeconomic modeling of the Kyoto Protocol and its extensions (Manne and Richels, 1999) as well as detailed technology assessments, such as the cost-competition between electricity from coal with $CO_2$ venting versus coal integrated gasification combined cycle (IGCC) with carbon capture and storage (CCS) (Williams, 2004)

Changes in slope of the optimal *COE* versus $p_{\text{NGeff}}$ curve in Fig. 3 occur where system lines cross, and these crossing points are associated with changes in GHG emissions per unit energy for the optimal system. A roughly twofold decrease in GHG emissions occurs in moving from gas (120 gC$_{\text{equiv.}}$/kWh) to wind+gas (73 gC$_{\text{equiv.}}$/kWh), and another roughly twofold decrease occurs in moving to wind+CAES (32 gC$_{\text{equiv.}}$/kWh). This stepwise decrease in slope with $p_{\text{NGeff}}$ reflects decreased consumption of natural gas, and proportionate increase in wind energy per kWh provided by the optimal system. Note that these emissions rates may be compared with emissions from a typical coal steam-electric plant (276 gC$_{\text{equiv.}}$/kWh), a SC natural gas plant (170 gC$_{\text{equiv.}}$/kWh), or a coal IGCC+CCS plant (53 gC$_{\text{equiv.}}$/kWh)[19] (Williams, 2004).

Values of system variables and some other details are given in Table 3, while *COEs* disaggregated by component are presented in Table 4 and Fig. 5. Here we highlight the physical scale of components and capital costs for each system.

The gas system, located entirely at the demand site, is made up of 2.00 GW of CC gas turbines and no SC turbines and requires a capital investment of \$1.32 billion.

For the wind+gas system, the wind park consists of 617 wind turbines of 3.5 MW each, for a rated (maximum) capacity of 2.16 GW. Assuming a turbine spacing of 0.5 km$^2$ per turbine,[20] the wind park occupies an area of 309 km$^2$. The 750 km transmission line, rated at 540 kV, has an input capacity of 2.16 GW capacity; after losses, the delivered capacity is 2.00 GW. Also included in the system at the end of the transmission line are 1.80 GW of CC gas turbines and 200 MW of SC turbines. The total required capital investment is \$3.28 billion, comprised of \$1.51 billion for the wind park, \$520 million for the transmission line, \$1.19 billion for the CC plant and \$60 million for the SC plant.

The wind park for the wind+CAES system is much larger, made up of 1318 turbines producing 4.61 GW rated capacity and occupying 659 km$^2$. The CAES system consists of 2.53 GW compressor capacity, 2.08 GW expander capacity, and an underground storage reservoir of 352 GWh (169 h of storage at rated expander capacity), occupying a volume of $5.0 \times 10^7$ m$^3$. The 750 km transmission line has a rating of 750 kV and 2.08 GW input capacity; after losses, the delivered capacity is 2.00 GW. There are no gas turbines at the demand site. The total capital cost is \$5.54 billion, comprised of \$3.23 billion for the wind park, \$1.68 billion for the CAES plant, and \$630 million for the transmission line.

Fig. 4 shows power duration curves for the three systems. A power duration curve indicates the maximum power output as a function of the number of hours per year that the system runs. (There are 8760 h in a year.)

For the gas system (panel 1), the power duration curve is very simple: the plant runs at full power for ~7900 h (90%) of the year.

For the wind+gas system (panel 2), the wind park delivers full power for only ~1500 h (17%), dropping rapidly as the number of hours increases; above ~7900 h, no power is produced. Thus, the combined SC+CC capacities are also set equal to demand. The total capacity factor of the wind park (average wind park power divided by wind park rated power) is 39%, of which 2% is lost during transmission. The shortfall in energy is made up for by SC (2%) and CC (51%).

For the wind+CAES system (panel 3), there is more than twice as much installed wind power as for wind+gas. This is because most of the "surplus" wind power (power in excess of demand, defined as $P_{\text{WP}} - P_{\text{TL}}$), which is available for ~3100 h (35%) of the year, is stored by the CAES system. About 7% of the surplus energy is "dumped" (curtailed) in the base case when the storage reservoir is full. The directly transmitted wind energy has a capacity factor of 55%. The CAES expander adds another

[19]This emissions rate is also comparable to that from BP's proposed "decarbonized" natural gas CC plant (BP, 2005) when upstream emissions are included (Wang, 1999).

[20]Typical array spacing is 50 squared rotor diameters, arranged as a $5 \times 10$ or $7 \times 7$ diameter matrix.

7-13

Table 3
Optimization results

| | Symbol | Units | Gas | Wind + Gas | Wind + CAES |
|---|---|---|---|---|---|
| *Optimized variables* | | | | | |
| Wind park rated power | $P_{WP}$ | GW | 0 | 2.160 | 4.612 |
| (Number of turbines—3.5 MW each) | ($N_{WT}$) | | | (617) | (1,318) |
| CAES compressor rated power | $P_C$ | GW | 0 | 0 | 2.530 |
| CAES expander rated power | $P_E$ | GW | 0 | 0 | 2.082 |
| CAES storage duration | $h_S$ ($P_E h_S$) | h (GWh) | 0 | 0 | 169 (352) |
| Transmission line voltage | $V_{TL}$ | kV | 0 | 537 | 746 |
| Simple cycle rated power | $P_{SC}$ | GW | 0 | 0.200 | 0 |
| Combined cycle rated power | $P_{CC}$ | GW | 2.000 | 1.800 | 0 |
| *Output variables* | | | | | |
| Transmission line rated power (before losses) | $P_{TL}$ | GW | 0 | 2.160 | 2.082 |
| Capacity factors (relative to annual demand): | | | | | |
| Wind park (generated) | $CF_{WP}$ | % | 0 | 38.7 | 82.6 |
| Wind park (transmitted) | $CF_{WP,trans}$ | % | 0 | 38.7 | 54.8 |
| Wind park (stored via CAES) | $CF_{WP,stor}$ | % | 0 | 0 | 25.9 |
| Wind park (dumped) | $CF_{WP,dump}$ | % | 0 | 0 | 1.9 |
| CAES output | $CF_{CAES}$ | % | 0 | 0 | 39.0 |
| Transmission line (initial) | $CF_{TL}$ | % | 0 | 38.7 | 93.8 |
| Transmission line (loss) | $CF_{TL,loss}$ | % | 0 | 2.4 | 3.8 |
| Simple cycle | $CF_{SC}$ | % | 0 | 2.2 | 0 |
| Combined cycle | $CF_{CC}$ | % | 90.0 | 51.5 | 0 |
| Total | $CF$ | % | 90.0 | 90.0 | 90.0 |
| GHG emissions rate | $E_{GHG}$ | gC$_{equiv.}$/kWh | 120.0 | 72.8 | 31.6 |
| Cost of energy[a] | $COE$ | ¢/kWh | 4.540 | 5.092 | 5.985 |
| Entry effective fuel price | $p_{NGeff}$ | \$/GJ | — | 7.083 | 8.962 |
| Entry GHG price[b] | $p_{GHG}$ | \$/tC$_{equiv.}$ | — | 115.7 | 220.1 |
| Cost of energy (at entry $p_{NGeff}$) | $COE_{NGeff}$ | ¢/kWh | — | 5.929 | 6.680 |

[a]At $p_{NGeff}$ = \$5/GJ.
[b]At $p_{NG}$ = \$5/GJ.

39%, and 4% is lost during transmission. (Note that in order to capture all of the excess wind power, the CAES compressor installed power ($P_C$) must match the surplus wind installed power.)

For wind + CAES, the wind park produces, through either direct transmission or via CAES, 72% of yearly demand,[21] or 80% of produced energy. In contrast, in the wind + gas system, only 36% of yearly demand, or 40% of produced energy, is generated by the wind park. These percentages (80% and 40%) can be viewed as the maximum economical wind penetration on the baseload portion of an electric grid employing the storage and fill-in generation approaches, respectively. The baseload portion of electrical demand supplies the majority of annual energy consumed, so the baseload penetration level is a good approximation of the penetration level for the grid as a whole. Using CAES therefore greatly expands the penetration potential of wind on an electric grid.

The compressor-to-expander power ratio ($P_C/P_E$) in our optimization, 1.22, is quite large compared with those designed to capture off-peak energy for price arbitrage (0.2–0.7) (Crotogino et al., 2001; Wind, 2002; Bell et al., 2003; EPRI-DOE, 2003). For these latter systems, cost optimization leads to a low $P_C/P_E$ ratio because the compressor can store energy during long off-peak periods (two-thirds or more of the time), so its installed power can be smaller than that of the expander, which must deliver back the stored energy only during the short peak period. For baseload wind + CAES, however, the compressor must capture all the surplus wind energy, which exceeds the installed power of the expander in our optimal configuration.

The duration of CAES storage $h_S$ is also large, 169 h in our base case, as compared to 2–30 h for peak-shifting designs. This is due to the significant differences in system objectives as discussed above. It should be pointed out, however, that $h_S$ is strongly dependent on our parameter assumptions, varying by a factor of four up or down over the plausible range of parameter values (see Section 3.1 below). However, even at the low end of its plausible range, $h_S$ is still large compared with peak-shifting values. Our result is in agreement with Cavallo (1996), who used the same an autoregressive algorithm as ours but with $\theta = 10$ h instead of 30 h: we both obtained $h_S \approx 85$ h when the capacity factor is 90%. The only study that found a larger storage duration than our base case was Cavallo and Keck (1995), who examined the effect of a seasonal variation of ±25% in wind power flux, and found 250 h to be optimal in the 90% capacity factor case.

[21]Assuming 80% round-trip electrical efficiency of the CAES system.

7-14

Table 4
Disaggregation of the cost of energy (*COE*) for the three optimized systems, assuming base case parameters and $p_{\mathrm{NGeff}} = \$5/\mathrm{GJ}$. Transmission loss cost and sensitivities to some system parameters are also shown. Note for wind resource parameters ($v_{\mathrm{avg}}, k, \theta$), system is reoptimized in each case

| | Gas | | Wind + Gas | | Wind + CAES | |
|---|---|---|---|---|---|---|
| | ¢/kWh | % | ¢/kWh | % | ¢/kWh | % |
| Wind park | | | | | | |
| Capital | 0.000 | 0.00 | 1.029 | 20.21 | 2.159 | 36.08 |
| Fixed O&M | 0.000 | 0.00 | 0.200 | 3.93 | 0.421 | 7.03 |
| Variable O&M | 0.000 | 0.00 | 0.334 | 6.56 | 0.685 | 11.45 |
| CAES | | | | | | |
| Plant capital | 0.000 | 0.00 | 0.000 | 0.00 | 0.889 | 14.85 |
| Storage capital | 0.000 | 0.00 | 0.000 | 0.00 | 0.235 | 3.93 |
| Fixed O&M | 0.000 | 0.00 | 0.000 | 0.00 | 0.051 | 0.85 |
| Variable O&M | 0.000 | 0.00 | 0.000 | 0.00 | 0.039 | 0.65 |
| Fuel | 0.000 | 0.00 | 0.000 | 0.00 | 0.841 | 14.06 |
| Transmission | | | | | | |
| Converter capital | 0.000 | 0.00 | 0.142 | 2.78 | 0.137 | 2.28 |
| Line/ROW capital | 0.000 | 0.00 | 0.214 | 4.21 | 0.286 | 4.78 |
| Losses | 0.000 | 0.00 | 0.121 | 2.38 | 0.243 | 4.06 |
| SC | | | | | | |
| Capital | 0.000 | 0.00 | 0.040 | 0.78 | 0.000 | 0.00 |
| Fixed O&M | 0.000 | 0.00 | 0.017 | 0.33 | 0.000 | 0.00 |
| Variable O&M | 0.000 | 0.00 | 0.003 | 0.06 | 0.000 | 0.00 |
| Fuel | 0.000 | 0.00 | 0.111 | 2.18 | 0.000 | 0.00 |
| CC | | | | | | |
| Capital | 0.919 | 20.24 | 0.807 | 15.84 | 0.000 | 0.00 |
| Fixed O&M | 0.158 | 3.48 | 0.139 | 2.72 | 0.000 | 0.00 |
| Variable O&M | 0.130 | 2.86 | 0.073 | 1.43 | 0.000 | 0.00 |
| Fuel | 3.333 | 73.42 | 1.863 | 36.59 | 0.000 | 0.00 |
| Total *COE*[a] | 4.540 | 100.00 | 5.092 | 100.00 | 5.985 | 100.00 |
| *Sensitivities* | | | | | | |
| GHG emissions cost ($p_{\mathrm{GHG}} = \$100/\mathrm{tC_{equiv.}}$) | +1.200 | +26.43 | +0.728 | +14.30 | +0.316 | +5.28 |
| Production tax credit (PTC)[b] | 0.000 | 0.00 | −0.796 | −15.63 | −1.530 | −25.59 |
| PTC and $C_{\mathrm{WP}} = \$1000/\mathrm{kW}$ | 0.000 | 0.00 | −0.355 | −6.97 | −0.605 | −10.10 |
| $v_{\mathrm{avg}} = 7.53\,\mathrm{m/s}$ ($f_{\mathrm{W}} = 500\,\mathrm{W/m^2}$, wind power class 3) | 0.00 | 0.0 | +0.191 | +3.76 | +0.468 | +7.82 |
| $v_{\mathrm{avg}} = 8.81\,\mathrm{m/s}$ ($f_{\mathrm{W}} = 800\,\mathrm{W/m^2}$, wind power class 5) | 0.00 | 0.0 | −0.118 | −2.31 | −0.128 | −2.14 |
| $k = 1.5$[c] | 0.00 | 0.0 | +0.048 | +0.95 | +0.214 | +3.58 |
| $k = 3.0$[c] | 0.00 | 0.0 | +0.056 | +1.10 | +0.181 | +3.03 |
| $\theta = 10\,\mathrm{h}$ | 0.00 | 0.0 | 0.00 | 0.0 | −0.145 | −2.43 |
| $\theta = 60\,\mathrm{h}$ | 0.00 | 0.0 | 0.00 | 0.0 | +0.347 | +5.79 |

[a]Totals may not match component sums due to rounding.
[b]Here we assume that the production tax credit (PTC, ¢1.9/kWh) applies to all wind electricity reaching the transmission line, equal to directly transmitted energy plus 80% of stored CAES energy.
[c]These runs performed while keeping the mean wind speed constant at the base case value (8.22 m/s).

### 3.1. Sensitivity studies

Our base case represents only one possible set of parameter assumptions, and many of these parameters affected the system variables, cost of energy, and effective fuel price at which wind parks and/or CAES would be built in lieu of gas. In this section, we explore the most important parameters affecting *COE* and $p_{\mathrm{NGeff}}$. (Unless otherwise indicated, the *COE* is reported for $p_{\mathrm{NGeff}} = \$5/\mathrm{GJ}$).

We present the sensitivity studies in the context of disaggregations of the *COE* for the three optimized base case systems presented in Table 4 and Fig. 5. For each system component, the costs of capital, operations and maintenance (O&M) and, where applicable fuel and transmission losses are shown. Table 4 also shows the sensitivities of the *COE* to several parameters. Note that, for each of the sensitivities relating to the three wind resource parameters ($v_{\mathrm{avg}}$, $k$ and $\theta$), the system was reoptimized.

The sensitivity to changes in cost components can be gleaned from the base case disaggregated costs by an appropriate scaling of the *COE* share, assuming no changes in overall system variables (which we have verified empirically to be a good approximation for changes of $\sim<\pm 20\%$ in component costs). Thus, for wind + gas, the wind park capital comprises 20% (¢1.0/kWh) of overall *COE*, so a 20% increase in capital cost (to \$840/kW)

7-15

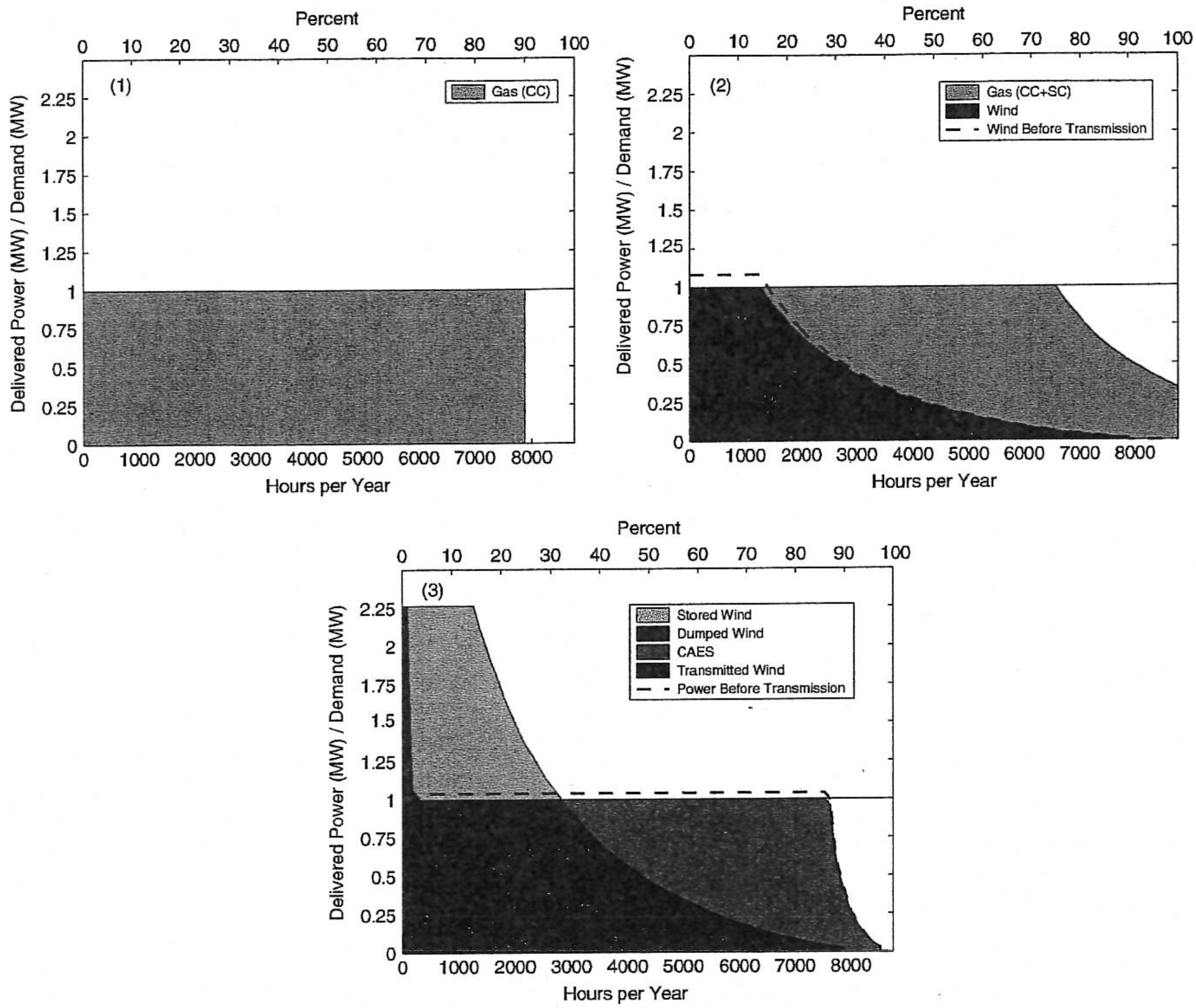



Fig. 4. Power duration curves for the three optimized base case systems. Areas indicate energy produced. Remote power before transmission losses is indicated by thick broken line. Panel 1: Gas Panel 2: Wind + gas. Panel 3: Wind + CAES.

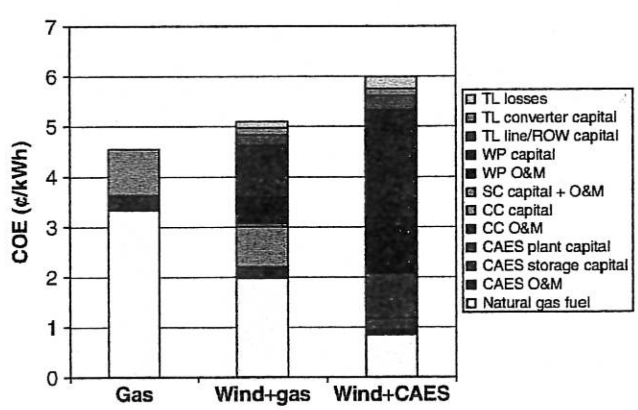



Fig. 5. Disaggregation of the cost of energy (*COE*) for the three optimized base case systems.

translates into a *COE* increase of 4% (¢0.2/kWh). For wind + CAES, where the wind park capital cost is larger share of the total, the impact on the COE of a 20% increase is approximately double.

Changes in the capital charge rate (*CCR*) have a relatively large impact on the *COE* for the more capital-intensive systems, because that parameter affects all capital costs. Thus, a 20% increase in *CCR* (to 13.2%/yr) will increase the *COE* by 12% (¢0.7/kWh) for wind + CAES (for which capital accounts for 58% of the total *COE* in the base case) but only 4% (¢0.2/kWh) for gas (for which capital accounts for only 20% of the *COE* in the base case).

Similarly, when the capital components are a small share of total *COE*, changes in the fuel or O&M costs will have a larger effect on the *COE*. For instance, fuel use comprises

7-16

73% of the *COE* in the gas base case, whereas it is only 14% for wind + CAES. Thus, a 20% increase in fuel price (to \$6/GJ) increases the *COE* of the gas system by 15% (¢0.7/kWh) but only 3% (¢0.2/kWh) for wind + CAES.

Missing from the above discussion is consideration of possible differential market risk among the three systems modeled. The gas system is most vulnerable to fuel price (and, to a lesser extent, GHG price) risk, whereas the wind + gas system and, particularly, the wind + CAES system, are more exposed to technological risk. However, the assumptions we have made here are that, by 2020, both fuel price and technology risks are relatively low, thus justifying the use of low *CCR* values for all technologies. If one wished to apply a different set of risk assumptions, a straightforward way to estimate the resulting economic competition would be to apply different *CCR* values among the technology components, and calculate new *COE* values using the data in Table 4.

In many countries, economic incentives exist to help encourage the growth of wind energy. These incentives can take the form of fixed rate contracts, tax credits, or other mechanisms. In the US, the production tax credit (PTC) has been in place for several years[22] to help defray the cost of producing electricity from wind. It is currently ¢1.9/kWh. Applying this credit to generated wind electricity reduces the base case *COE* of wind + gas by ¢0.8/kWh, and of wind + CAES by ¢1.5/kWh.[23] However, it is unlikely that the PTC, which was designed to help subsidize expensive capital, would still be in effect when the cost of wind turbines reaches \$700/kW. Therefore, applying the PTC with current wind turbine capital costs (assumed \$1000/kW), the base case *COE* of wind + gas is reduced by ¢0.4/kWh, and of wind + CAES by ¢0.6/kWh; see Table 4 for details. These savings are of the same order of magnitude as other changes discussed above.

An important trade-off exists between transmission distance ($D_{TL}$) and wind power class (expressed as $v_{avg}$ or $f_W$). We see in Table 4 that the transmission line and right-of-way (ROW) contributions to the *COE*, which scale with distance, are 4% for wind + gas and 5% for wind + CAES, for the base case of $D_{TL} = 750$ km and $f_W = 650\,W/m^2$ (class 4 winds at 120 m). The losses are approximately equally split between fixed (converter) and distance-dependent (line) contributions for 750 km in each case, and so add 1% and 2% to the *COE* for wind + gas and wind + CAES, respectively. Thus, for a 1500 km transmission line, the *COE* would be 5% (¢0.3/kWh) and 7% (¢0.4/kWh) higher, respectively. For no transmission line, all transmission capital and losses, including the fixed converter costs, disappear, so the *COE* decreases by 9% (¢0.5/kWh) and 11% (¢0.7/kWh). The effect of changing the wind resource by one wind power class ($\pm 150\,W/m^2$) is also shown in Table 4. It is asymmetric about the base case, with a larger change in *COE* occurring when lowering the wind class. Thus, lowering the wind resource by one power class has approximately the same effect on *COE* as increasing the transmission distance by ~500 km for wind + gas, and ~900 km for wind + CAES, while increasing the wind resource by one power class is equivalent to decreasing the transmission distance by ~300 and ~400 km, respectively.[24] This trade-off is often not appreciated when estimating wind energy costs, as higher wind classes tend to be more remote from demand centers; thus, some of the advantage of higher wind classes is nullified by higher transmission costs.

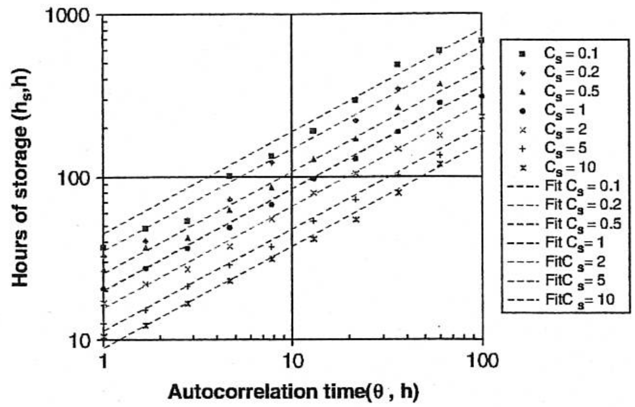



Fig. 6. Duration of storage ($h_S$) versus autocorrelation time ($\theta$) for several values of storage cost ($C_S$). Note axes are both logarithmic. Fits (see text) shown by dashed lines.

Another important trade-off involves the impacts of the autocorrelation time (θ) and the cost of storage ($C_S$) on the optimal CAES storage duration ($h_S$). Fig. 6 shows $h_S$ versus θ for a number of values of $C_S$. We found that the dependence of $h_S$ on θ and $C_S$ could be fit very well by

$$h_S(\theta, C_S) = 20.1\,\theta^{0.62} C_S^{-0.35}, \tag{2}$$

where $h_S$ and $\theta$ are expressed in hours, and $C_S$ is in \$/kWh.[25] The fits are shown in Fig. 6. For our base case of $\theta = 30$ h and $C_S = \$1$/kWh, we obtain $h_S = 166$ h, close to the observed 169 h. Decreasing θ or increasing $C_S$ by a factor of three reduced $h_S$ by 49% and 32%, respectively. The $h_S$ showed little dependence on changes in other parameters. The *COE* increased markedly (by more than ¢2/kWh) when θ and/or $C_S$ increased to the highest values in their respective ranges, but there was relatively little cost savings (less than ¢0.4/kWh) when decreasing these values.

We have discussed the system sensitivities to *COE* above, but have not considered the resulting changes in the entry

[22]However, the only PTC that the US Congress has supported has expired every two years, creating an uneven investment environment that has had a negative impact on the growth of wind power in the US.

[23]Here we assume that the credit applies to all wind electricity reaching the transmission line, equal to directly transmitted energy plus 80% of stored CAES energy.

[24]For an HVDC transmission system. If instead an HVAC system were used (which is less expensive at short distances), the equivalent decrease in transmission distance would be smaller.

[25]The data point at θ = 100 h and $C_S$ = \$10/kWh was omitted from the fit, as the model did not always build wind + CAES even at $p_{NGeff}$ = \$12.2/GJ, the highest value explored.

7-17

prices $p_{\text{NGeff}}^{\text{wind}}$ and $p_{\text{NGeff}}^{\text{CAES}}$. Because changes in cost tend to affect only the intercepts of the *COE* versus $p_{\text{NGeff}}$ lines, and because the slopes for all three systems are relatively shallow, small changes in *COE* intercepts translate into large changes in entry prices. For instance, as discussed above, a 20% increase in wind park capital cost increases the *COE* of wind + gas by 4% and of wind + CAES by 8%. However, the corresponding increases in $p_{\text{NGeff}}^{\text{wind}}$ and $p_{\text{NGeff}}^{\text{CAES}}$ are 11% ($0.8/GJ) and 12% ($1.1/GJ), respectively. The impacts of a 20% increase in *CCR* are even larger: 15% ($1.0/GJ and $1.4/GJ, respectively). Table 5 shows the sensitivities in entry prices $p_{\text{NGeff}}$ (and $p_{\text{GHG}}$) for plausible changes in many parameters. The common observation is that relatively modest changes in parameter values can have large effects, as much as $\pm\$1/\text{GJ}$ or greater in some cases. If we reasonably assume that all the parameters listed in Table 5 are uncoupled from one another and may take on any value in the displayed range, then we can obtain a simple estimate of the total uncertainty in $p_{\text{NGeff}}$ by adding average sensitivities in quadrature. The results are $\Delta p_{\text{NGeff}}^{\text{wind}} = \pm\$2.2/\text{GJ}$ and $\Delta p_{\text{NGeff}}^{\text{CAES}} = \pm\$4.1/\text{GJ}$, or $\Delta p_{\text{GHG}}^{\text{wind}} = \pm\$120/\text{tC}_{\text{equiv.}}$ and $\Delta p_{\text{GHG}}^{\text{CAES}} = \pm\$230/\text{tC}_{\text{equiv.}}$. However, it should be pointed out that changes in $p_{\text{NGeff}}^{\text{wind}}$ and $p_{\text{NGeff}}^{\text{CAES}}$ tend to be in the same direction, so the large uncertainty does not invalidate the conclusion that wind + gas is more economical than wind + CAES over a wide range of parameter assumptions. We therefore assign relatively little certainty to the absolute value of the entry prices, emphasizing instead the relative values, and recognize that the true entry prices will depend sensitively on many parameter assumptions, some of which will be determined by technical progress, while others will be determined by both local and global economic conditions.

### 3.2. Dispatch cost considerations

It was assumed for the base case analysis that all competing options are baseload systems operated at 90% capacity factor. Although this assumption simplified the comparative analysis, the capacity factors would differ among the options in a real energy market. A key parameter determining the capacity factor of any option under market conditions is the "dispatch cost": the sum of all short-run marginal costs (fuel cost + variable O&M cost + GHG cost). Moreover, the capacity factor for each option depends on the dispatch cost of not just the energy systems studied, but also the dispatch costs for all the other energy systems on the grid as well. For a given set of power generating systems, the grid operator determines the capacity factors of these systems by calling first on the system with the least dispatch cost. Under this condition, deployment in sufficient quantity of the technology with the least dispatch cost can lead to a reduction of the capacity factors, and thus an increase in the *COE*s of the competing options on the system.

As a result of the increases in natural gas prices in the US noted earlier this phenomenon has resulted in reducing capacity factors for natural gas CC plants originally designed for baseload operation to average utilization rates in the range 30–50% where coal plants are available to compete in dispatch (Thambimuthu et al., 2005).

In principle, this downward pressure on capacity factors for options with high dispatch costs could be avoided with "take-or-pay" contracts that require the generator to provide a specified fixed amount of electricity annually. But uncertainties about future fuel prices, technological change, and future electricity demand make such contracts rare. So plants are typically designed to be able to compete in economic dispatch.

To illustrate the implications of the dispatch rule for the relative "real world" economics of the systems studied here, Table 6 shows for both $p_{\text{GHG}} = \$0/\text{tC}_{\text{equiv.}}$ and $\$100/\text{tC}_{\text{equiv.}}$ dispatch costs for the base case systems and three coal options with which these systems are likely to compete on many grids, e.g., in the US—existing coal plants and new coal IGCC plants with both $CO_2$ vented and $CO_2$ capture and storage (CCS). A GHG price of $\$100/\text{tC}_{\text{equiv.}}$ is singled out because that is essentially the price at which CCS becomes cost-competitive for new coal power plants, and thus represents a threshold price for a climate mitigation policy targeting deep reductions in GHG emissions.

Table 6 shows that, unlike the other options, the dispatch costs for both the wind + gas and wind + CAES systems vary from low values of ¢0.8–0.9/kWh when only electricity is being provided by wind power to much higher maximum values when the wind is not blowing and the supplemental power system (gas turbine or CAES expander) is operating. The maximum dispatch costs shown for the wind systems are the relevant ones that determine whether a 90% capacity factor can be defended in the market.

It is beyond the scope of the present study to calculate the market capacity factors for the options studied—which would require specification of the entire generation system and the demand profile for the customers served by the grid. However, one can acquire an understanding of the prospects for defending a 90% capacity factor from the information presented in Table 6.

Consider a hypothetical situation where there are only two competing 2 GW supply systems on the grid (wind + CAES plus one other from Table 6) contending for a 90% capacity factor and a total grid demand (e.g., at night) of only 2 GW. The market price at that time would be the lesser of the dispatch costs of these two options. The system with the higher dispatch cost would shut-down completely then to avoid losing money, thereby reducing its annual average capacity factor and increasing its COE. Table 6 shows that at $p_{\text{GHG}} = \$0/\text{tC}_{\text{equiv.}}$, wind + CAES has a lower maximum dispatch cost than gas and wind + gas, and thus would have no difficulty defending a 90% capacity against either of the alternatives involving natural gas during periods of low demand. However, under our base case assumptions, wind + CAES would have difficulty

7-18

Table 5
Entry price sensitivities for wind and CAES

| | | | $p_{NGeff}^{wind}$ ($/GJ) | $p_{GHG}^{wind}$ ($/tC$_{equiv.}$) | $p_{NGeff}^{CAES}$ ($/GJ) | $p_{GHG}^{CAES}$ ($/tC$_{equiv.}$) |
|---|---|---|---|---|---|---|
| Base case | See Table 3 | | 7.083 | 115.7[a] | 8.962 | 220.1[a] |
| Parameter | Value or change (±) | Units | $\Delta p_{NGeff}^{wind}$ ($/GJ) | $\Delta p_{GHG}^{wind}$ ($/tC$_{equiv.}$) | $\Delta p_{NGeff}^{CAES}$ ($/GJ) | $\Delta p_{GHG}^{CAES}$ ($/tC$_{equiv.}$) |
| *CCR* | –20 | % | –1.041 | –57.8 | –1.379 | –76.6 |
| | +20 | | +1.041 | +57.8 | +1.371 | +76.2 |
| $p_{NG}$ | –20 | % | +0.999 | +55.5 | +1.009 | +56.1 |
| | +20 | | –0.996 | –55.3 | –0.998 | –55.4 |
| $C_C$, $C_E$ | –20 | % | 0.000 | 0.0 | –0.825 | –45.8 |
| | +20 | | 0.000 | 0.0 | +0.839 | +46.6 |
| $C_S$ | 0.1 | $/kWh | 0.000 | 0.0 | –1.257 | –69.8 |
| | 0.5 | | 0.000 | 0.0 | –0.613 | –34.0 |
| | 2 | | 0.000 | 0.0 | +0.980 | +54.4 |
| | 10 | | 0.000 | 0.0 | +5.803 | +322.4 |
| $C_{WP}$ | –20 | % | –0.792 | –44.0 | –1.059 | –58.8 |
| | +20 | | +0.790 | +43.9 | +1.060 | +58.9 |
| $C_{TL}$ | –20 | % | –0.349 | –19.4 | –0.154 | –8.6 |
| | +20 | | +0.353 | +19.6 | +0.154 | +8.6 |
| $C_{SC}$, $C_{CC}$ | –20 | % | +0.019 | +1.0 | +0.814 | +45.2 |
| | +20 | | –0.028 | –1.5 | –0.792 | –44.0 |
| $f_W$ (wind power class) | 500 (3) | W/m$^2$ | +0.725 | +40.3 | +1.182 | +65.7 |
| | 800 (5) | | –0.429 | –23.8 | –0.144 | –8.0 |
| $k$[b] | 1.5 | | +0.259 | +14.4 | +0.952 | +52.9 |
| | 3.0 | | +0.253 | +14.0 | –0.103 | –5.7 |
| $\theta$ | 10 | h | +0.020 | +1.1 | –0.662 | –36.8 |
| | 60 | | –0.002 | –0.1 | +1.337 | +74.3 |
| $D_{TL}$ | 0 | km | –1.713 | –95.2 | –0.778 | –43.2 |
| | 500 | | –0.356 | –19.8 | –0.169 | –9.4 |
| | 1000 | | +0.359 | +19.9 | +0.167 | +9.3 |
| | 1500 | | +1.083 | +60.2 | +0.507 | +28.2 |
| $r_{rate}$ | 1.4 | | –0.194 | –10.8 | –0.487 | –27.1 |
| | 1.6 | | +0.300 | +16.6 | +0.598 | +33.2 |
| $E_o/E_i$ | –20 | % | 0.000 | 0.0 | +1.202 | +66.8 |
| | +20 | | 0.000 | 0.0 | –0.901 | –50.0 |
| *CF* | –10 | % | –0.130 | –7.2 | –0.709 | –39.4 |
| | +10 | | +0.001 | +0.1 | +0.758 | +42.1 |
| $HR_{CAES}$ | –10 | % | 0.000 | 0.0 | –0.649 | –36.1 |
| | +10 | | 0.000 | 0.0 | +0.759 | +42.2 |
| $HR_{CC}$ | –10 | % | –0.746 | –41.4 | –1.443 | –80.2 |
| | +10 | | +0.727 | +40.4 | +1.710 | +95.0 |
| $HR_{SC}$ | –10 | % | +0.019 | +1.0 | –0.016 | –0.9 |
| | +10 | | –0.041 | –2.3 | +0.032 | +1.8 |
| $r_{min}$ | –100 | % | 0.000 | 0.0 | –0.010 | –0.5 |
| | +100 | | 0.000 | 0.0 | +0.031 | +1.7 |
| $l_{line}$, $l_{conv}$ | –50 | % | –0.228 | –12.7 | –0.216 | –12.0 |
| | +50 | | +0.179 | +9.9 | +0.194 | +10.8 |
| Quadrature sum[c] | | | ±2.156 | ±119.8 | ±4.112 | ±228.4 |

[a] $p_{GHG}$ assumes $p_{NG}$ = $5/GJ.
[b] $v_{avg}$ held constant at base case value.
[c] Average absolute change for each parameter category added in quadrature.

7-19

Table 6
Total and dispatch costs for alternative generation options

| Technology | CF (%) | GHG emissions ($gC_{equiv.}$/kWh) | $0/$tC_{equiv.}$ Total cost at base case capacity factor (¢/kWh) | $100/$tC_{equiv.}$ Total cost at base case capacity factor (¢/kWh) | $0/$tC_{equiv.}$ Dispatch cost (¢/kWh) | $100/$tC_{equiv.}$ Dispatch cost (¢/kWh) |
|---|---|---|---|---|---|---|
| Average coal plant[a] | — | 276 | — | — | 2.16 | 4.93 |
| Coal IGCC, $CO_2$ vented[b] | 85 | 237 | 3.96 | 6.33 | 1.80 | 4.17 |
| Coal IGCC, $CO_2$ capture and storage[b] | 85 | 53 | — | 6.14 | — | 3.36 |
| Gas[c] | 90 | 120 | 4.54 | 5.74 | 3.48 | 4.69 |
| Wind + gas[c] | 90 | 73 | 5.09 | 5.82 | 0.86 to 3.48[d] | 0.86 to 4.69[d] |
| Wind + CAES[c] | 90 | 32 | 5.99 | 6.30 | 0.83 to 2.35[d] | 0.83 to 3.15[d] |

[a]For a $1.4/GJ coal price, a ¢0.67/kWh variable O&M cost, and a 34.3% power plant efficiency—the average projected for US coal plants in 2020 (EIA, 2005).

[b]IGCC costs are based on Williams (2004) adjusted for the financing rules of the current study, a $1.4/GJ coal price, and (in the $CO_2$ capture and storage case, which involves capturing $CO_2$ accounting for 85% of the carbon in the coal) storage in an aquifer 2 km underground located 200 km from the power plant. The capacities, overnight capital costs, and efficiencies of the IGCC plants are 827 MW, $1135/kW, and 38.0% for the $CO_2$ venting option and 730 MW, $1428/kW, and 31.5% for the $CO_2$ capture and storage option. The dispatch cost for the $CO_2$ capture and storage option includes the total cost of $CO_2$ transport and storage (at $9/$tCO_2$).

[c]For the optimized base case systems described in the present study, with $5/GJ gas price, 650 W/$m^2$ wind resource, and 750 km HVDC transmission line.

[d]Dispatch cost varies depending on plant operation. *Wind+gas:* For wind park exactly meeting demand (here assumed 2 GW), dispatch cost is ¢0.86/kWh (variable O&M of wind park + TL losses). For CC gas turbine supplementation, dispatch cost is ¢3.48/kWh ($0/$tC_{equiv.}$) or ¢4.69/kWh ($100/$tC_{equiv.}$) (variable O&M of CC + fuel cost + GHG cost). For SC gas turbine supplementation, dispatch cost is 4.83 ¢/kWh ($0/$tC_{equiv.}$) or 6.52 ¢/kWh ($100/$tC_{equiv.}$). CC turbine dispatch cost is shown, as SC turbine contributes a minor amount of generation (2.2% in base case) and would not be a deciding factor at the low grid system demand levels relevant to the defense of a 90% system capacity factor. *Wind+CAES:* For wind park exactly meeting demand, dispatch cost is 0.83 ¢/kWh (note lower TL losses than for wind + gas). For wind park at maximum output, storing energy via CAES compressor, dispatch cost is ¢2.02/kWh (variable O&M of wind park and CAES compressor (assumed $\frac{1}{2}$ of total CAES variable O&M) + TL losses of transmitted wind). For CAES expander (no wind output), dispatch cost is ¢2.35/kWh ($0/$tC_{equiv.}$) or ¢3.15/kWh ($100/$tC_{equiv.}$) (variable O&M of CAES compressor + fuel cost + GHG cost + TL losses). These costs assume no foresight about future wind output and market electricity price.

sustaining a 90% capacity factor if there were competing coal options on the grid.

However, at $p_{GHG} = \$100/tC_{equiv.}$, wind + CAES has the least dispatch cost. Its closest competitor would be coal IGCC with CCS, but if dispatch competition were to force the capacity factor of that option down only modestly to 80%, its total *COE* would be higher than that of wind + CAES at 90% capacity factor.

At $p_{GHG} = \$35/tC_{equiv.}$, the dispatch cost for wind + CAES (¢2.6/kWh) would become the least for all the options. However, dispatch competition would have to force the capacity factor of a new coal IGCC plant with CCS down to 50% to make its COE the same as for wind + CAES at 90% capacity factor.

Thus, the prospects are good that wind + CAES baseload units would be strongly competitive with all the alternatives considered under a tough ($100/$tC_{equiv.}$) climate change mitigation policy, and in some circumstances even under a relatively modest ($35/$tC_{equiv.}$) policy. It should also be noted that although the outlook for providing baseload power with natural gas CC plants would typically be poor in regions where such plants must compete in dispatch with coal plants, natural gas would be highly competitive in providing baseload power via wind + CAES power plants, which could become a major market growth opportunity for natural gas in a world of high natural gas prices and a tough climate change mitigation policy.

### 3.3. Caveats

We have not considered all issues that might make wind + gas and/or wind + CAES less competitive than gas or other generation technologies. One issue is the seasonality of the wind resource, which is frequently anti-correlated with peak summer demand. Another concern focuses on outage rates: in addition to outages incurred when the wind is not blowing and the storage reservoir is empty, wind + CAES incurs additional outages due to maintenance like all generation systems. However, for both the wind + gas and wind + CAES systems, maintenance-related outage rates may be lower than those of the gas system if the maintenance for each component (wind park, and SC/CC or CAES plant) is performed when other system components are idle. In that case, if gas has a 90% capacity factor as we have modeled, then wind + gas will have a larger capacity factor (and therefore lower *COE*), because some of the maintenance can be performed while the wind turbines provide all the energy. However, wind + CAES, because outages occur *both* when the CAES reservoir is empty *and* during maintenance, will have a smaller capacity factor (and therefore higher *COE*). Along the same lines, the reliability of long-distance transmission lines, which we have assumed to be 100% reliable, may be lower, particularly as distance increases, which would raise the *COE* of both wind + gas and wind + CAES relative to gas.

7-20

Low-cost geologic reservoirs for CAES may not be available in all areas. While it is estimated that some form of suitable geologic storage is present in 75–80% of the US land area (EPRI-DOE, 2003), the type of geology varies: salt domes are prevalent in the Great Plains, Rocky Mountain and Gulf States regions; saline aquifers are ubiquitous in the Great Plains, Midwest and Appalachian regions; some regions contain only expensive hard rock; a few regions (the Southeast, much of California, and Nevada) contain no suitable geologic formations (Cohn et al., 1991). However, for the most part, the areas of potentially favorably geology overlap substantially with regions of high-quality wind resources. It remains to be determined from high-resolution geologic surveys just how prevalent this overlap is, though such surveys have not been completed for the US or any other region. Also, experience with the use of aquifers for CAES is limited.

There are also a number of options not considered in this study that may make wind parks and/or CAES more competitive than our analysis suggests. One option is simply to include a wider geographic diversity of wind parks, to increase wind's firm power and thereby decrease supplemental generation costs of both wind + gas and wind + CAES, though increased transmission costs may offset some of this advantage. Another option is to run the system in an intermediate-load configuration so as to provide power that has higher market value per unit energy than the baseload plant that is the focus of the present analysis. Indeed, all currently proposed CAES and wind + CAES projects focus on intermediate- or peak-demand markets (Wind, 2002; Bell et al., 2003; Desai and Pemberton, 2003). A third possibility is a reduction in the wind turbine rated power, which has been shown to lower the overall *COE* by reducing array losses and boosting the wind park capacity factor (Denkenberger, 2005). A final option is the incorporation of under-utilized gas turbine capacity into CAES systems, which under some circumstances might significantly lower capital costs for CAES (Nakhamkin et al., 2004).

## 4. Conclusions

This study has attempted to model the cost of producing baseload wind energy and its competition with fossil baseload energy. Under our base case assumptions with fixed 90% capacity factors for all the options, wind energy does not begin to compete with CC gas in terms of total cost of energy (*COE*) until effective fuel costs exceed \$7/GJ, and wind + CAES does not compete until above \$9/GJ. However, in real electricity markets, systems with lowest short-run marginal cost are dispatched first, maximizing capacity factors for those systems while diminishing capacity factors and raising the total cost of high-marginal cost competitors. We find that wind + CAES has the lowest short-run marginal cost above a GHG emissions cost of $\$35/\mathrm{tC_{cquiv.}}$ compared with gas, wind + gas, as well as a number of coal technologies; thus, wind + CAES will support very high capacity factors in a competitive market. Moreover, with a significant price on GHG emissions ($\sim\$100/\mathrm{tC_{cquiv.}}$), both wind + gas and wind + CAES will be important competitors in terms of total *COE* with coal integrated gasification combined cycle with carbon capture and storage (IGCC + CCS).

The use of energy storage, via CAES in this study, but in principle any cost-effective storage technology, also significantly boosts the ultimate penetration level for wind energy on an electric grid to 80 + %, compared to an upper limit of ~40% for wind with conventional backup power that is determined by wind's low capacity factor. This higher penetration level is possible by significantly increasing the wind park capacity relative to the capacity of the transmission line (in our optimization, this ratio is 2.22), and by using a large CAES storage reservoir (169 h at full CAES expander output). The "excess" wind capacity generates energy that is captured by CAES and retransmitted when needed, allowing the wind + CAES system to achieve a very high capacity factor (90%).

Shifting from fill-in backup to storage also significantly reduces the already-low GHG emissions from $76\,\mathrm{gC_{cquiv.}}$/kWh (wind + gas) to $32\,\mathrm{gC_{cquiv.}}$/kWh (wind + CAES). This emissions rate is about one-fourth of that for CC gas ($120\,\mathrm{gC_{cquiv.}}$/kWh) and almost one-tenth of that for a typical coal steam-electric plant ($276\,\mathrm{gC_{cquiv.}}$/kWh.) Only the emissions from coal IGCC + CCS plants are comparable ($\sim 50\,\mathrm{gC_{cquiv.}}$/kWh).

Our results depend, in some cases sensitively, on the choice of parameter values, and in addition, there are a number of unexplored issues that could either enhance or detract from the competitiveness of wind + CAES or wind + gas compared to other technologies. However, we feel that our analysis has generated a set of robust results that underscore the inherent attractiveness of these technologies with low emissions, low variable costs and falling capital costs that offer the potential to be highly competitive in baseload power markets. Additional modeling and case studies will be required to determine the role that wind energy can play in future electricity markets under various policy, cost and geographic circumstances.

## References

Archer, C.L., Jacobson, M.Z., 2005. Evaluation of global wind power. Journal of Geophysical Research 110, D12110.

Bell, L.D., Royer, B.E., Sanders, J.B., 2003. Letter to the public utilities commission of Ohio on behalf of Norton Energy Storage, LLC. OPSB Case No. 99-1626-EL-BGN, November 14.

BP, 2005. Introducing decarbonised fuels. 30 June. URL: http://www.bp.com/genericarticle.do?categoryId = 97&contentId = 7006978.

BTM Consult ApS, 2004. International Wind Energy Development—World Market Update 2003. BTM Consult ApS, Ringkøbing, Denmark.

Bullough, C., Gatzen, C., Jakiel, C., Koller, M., Nowi, A., Zunft, S., 2004. Advanced adiabatic compressed air energy storage for the integration of wind energy. Proceedings from the European Wind Energy Conference, London, UK, 22–25 November.

7-21

Cavallo, A.J., 1995. High-capacity factor wind energy systems. Journal of Solar Energy Engineering 117, 137–143.

Cavallo, A.J., 1996. Storage system size as a function of the wind speed autocorrelation time for a wind energy baseload system. Proceedings of the European Union Wind Energy Conference, 20–24 May, Göteborg, Sweden.

Cavallo, A.J., 1997. Wind turbine cost of electricity and capacity factor. Journal of Solar Energy Engineering 119, 312–314.

Cavallo, A.J., Keck, M.B., 1995. Cost effective seasonal storage of wind energy. In: Musial, W.D., Hock, S.M., Berg, D.E. (Eds.), Wind Energy, Solar Energy Division, vol. 16. American Society of Mechanical Engineers, New York, pp. 119–125.

Chicago Climate Exchange, 2005. CCX Carbon Market Report, vol. 2, no. 4, April. Chicago, USA. URL: http://www.chicagoclimateexchange.com/news/newsletters/CCX_carbonmkt%20report_april05.pdf (accessed June 13).

CREIA (Chinese Renewable Energy Industries Association), 2004. Wind power, In: Overview of Renewable Energy Development in China: Recent Progress and Future Prospects. Clean Development Mechanism in China, Office of National Coordination Committee on Climate Change. URL: http://cdm.ccchina.gov.cn/english/NewsInfo.asp?NewsId=24 (accessed July 21, 2005).

Cohn, A., Louks, B., Nakhamkin, M., 1991. The application of humidification to integrated coal gasification/compressed air storage power plants. Report GS-7453, Electric Power Research Institute, Palo Alto, CA.

Crotogino, F., Mohmeyer, K.U., Scharf, R., 2001. Huntorf CAES: more than 20 years of successful operation. Solution Mining Research Institute Meeting, Orlando, FL, 23–25 April.

Czisch, G., 2004. Least-cost European/Transeuropean electricity supply entirely with renewable energies. Unpublished paper.

DeCarolis, J.F., Keith, D.W., 2006. The economics of large scale wind power in a carbon constrained world. Energy Policy 34, 395–410.

Denholm, P., 2006. Improving the technical, environmental and social performance of wind energy systems using biomass-based energy storage. Renewable Energy 31, 1355–1370.

Denholm, P., Kulcinski, G.L., Holloway, T., 2005. Emissions and energy efficiency assessment of baseload wind energy systems. Environmental Science Technology 39 (6), 1903–1911.

Denkenberger, D.C., 2005. Optimal wind turbine rated speed taking into account array effects, the larger system, and climate impacts. Master's Thesis, Department of Mechanical and Aerospace Engineering, Princeton University.

Desai, N., Pemberton, D., 2003. Economic value of compressed air energy storage in conjunction with large scale wind in McCamey. Unpublished manuscript, Ridge Energy Storage and Grid Services, LLC, August 21.

Dillon, D.J., Panesar, R.S., Allam, R.J., White, V., Gibbins, J., Raines, M.R., 2004. Oxy-combustion processes for $CO_2$ capture from advanced supercritical PGF and NGCC Power Plants. Proceedings of the Seventh International Conference on Greenhouse Gas Control Technologies (GHGT-7), Vancouver, Canada, 5–9 September.

EIA (Energy Information Administration), 2005. Annual Energy Outlook 2005. URL: http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html (Accessed on 27 December 2005).

EIA (Energy Information Administration), 2006. Annual Energy Outlook 2006, Early Release. URL: http://www.eia.doe.gov/oiaf/aeo/index.html (Accessed on 12 December 2005).

Elliott, D.L., Wendell, L.L., Gower, G.L., 1991. An assessment of the available windy land area and wind energy potential in the contiguous United States. Report Number PNL-7789, U.S. Department of Energy and Pacific Northwest Laboratory.

Elliott, D., Schwartz, M., Scott, G., Haymes, S., Heimiller, D., George, R., 2001. Wind energy resource atlas of Mongolia. Report Number NREL/TP-500-28972, National Renewable Energy Laboratory, U.S. Department of Energy. .

EPRI (Electric Power Research Institute), 1993. Technical Assessment Guide, vol. 2: Electricity End Use, Part 2: Commercial Electricity Use. EPRI, Palo Alto, CA.

EPRI-DOE., 2000. Evaluation of Innovative Fossil Fuel Power Plants with $CO_2$ Removal. EPRI report number 1000316. Interim report, December.

EPRI-DOE, 2003. EPRI-DOE handbook of energy storage for transmission and distribution applications. Report Number 1001834, EPRI, Palo Alto, CA and the US Department of Energy, Washington, DC.

EPRI-DOE, 2004. EPRI-DOE handbook supplement of energy storage for grid connected wind generation applications. Report Number 1008703, EPRI, Palo Alto, CA and the US Department of Energy, Washington, DC.

European Commission, 2003. External costs: research results on socio-environmental damages due to electricity and transport. In: ExternE: Externalities of Energy. A Research Project of the European Commission, Brussels. Report number EUR 20198. URL: http://www.externe.info/externpr.pdf (Accessed on 16 September 2004).

EWEA (European Wind Energy Association), 2004. Executive summary. In: Chandler, H. (Ed.), Wind Energy: The Facts. An Analysis of Wind Energy in the EU-25. URL: http://www.ewea.org/documents/Facts_Summary.pdf (Accessed 4 August 2004).

Gas Turbine World, 2003. Gas Turbine World Handbook, vol. 23. Pequot Publishing, Fairfield, Connecticut.

Global Wind Energy Council (GWEC), 2006. Record year for wind energy: Global wind power market increased by 43% in 2005, press release, 17 February, Brussels. URL: http://www.gwec.net/uploads/media/Statistics2005_170206.pdf (Accessed 16 March 2006).

Goswami, Y., 2004. Transitioning to a renewable energy future: three perspectives. World Renewable Energy Congress (WREC) VII, Denver, CO, August 29–September 3.

Hauth, R.L., Tatro, P.J., Railing, B.D., Johnson, B.K., Stewart, J.R., Fink, J.L., 1997. HVDC power transmission technology assessment. Report ORNL/Sub/95-SR893/1, Oak Ridge National Laboratory, Oak Ridge, Tennessee.

HPRCC (High Plains Regional Climate Center), 2003. Wind data retrieval. University of Nebraska, Lincoln. URL: http://www.hprcc.unl.edu/cgi-bin/winddr.cgi.

Hinrichs-Rahlwes, R., 2004. Linking the world with renewable energy. World Renewable Energy Congress (WREC) VII, Denver, CO, August 29–September 3.

Holttinen, H., 2005. Impact of hourly wind power variations on the system operation in the Nordic countries. Wind Energy 8, 197–218.

ILEX Energy Consulting, 2002. Quantifying the system costs of additional renewables in 2020. Department of Trade and Industry (DTI), UK. URL: http://www.dti.gov.uk/energy/developep/080scar_report_v2_0.pdf (Accessed 22 December 2004).

Junginger, M., Faaij, A.P.C., 2003. A global experience curve for wind energy. Proceedings of the 2003 European Wind Energy Conference, Madrid, Spain, 16–19 June, NWS-E-2003-37.

Karalis, A.J., Sosnowicz, E.J., Stys, Z.S., 1985. Air storage requirements for a 220 MWe CAES plant as a function of turbomachinery selection and operation. IEEE Transactions on Power Apparatus and Systems PAS-104 (4), 803–808.

Keith, G., Leighty, W., 2002. Transmitting 4,000 MW of new windpower from North Dakota to Chicago: new HVDC electric lines or hydrogen pipeline. Draft Report submitted to Environmental Law and Policy Center, Chicago, 28 September.

Kelly, H., Weinberg, C.J., 1993. Utility strategies for using renewables. In: Johansson, T.B., Kelly, H., Reddy, A.K.N., Williams, R.H. (Eds.), Renewable energy: Sources for fuels and electricity. Island Press, Washington, DC, pp. 1011–1069.

Lew, D.J., Williams, R.H., Shaoxiong, X., Shihui, Z., 1998. Large-scale baseload wind power in China. Natural Resources Forum 22 (3), 165–184.

Lower Colorado River Authority, 2003. Study of electric transmission in conjunction with energy storage technology. Unpublished Report, Texas State Energy Conservation Office, August 21.


7-22

Malcolm, D.J., Hansen, A.C., 2002. WindPACT turbine rotor design study. National Renewable Energy Laboratory, Golden, CO.

Malcolm, D.J., Hansen, A.C., 2003. WindPACT turbine rotor design, specific rating study. National Renewable Energy Laboratory, Golden, CO.

Manne, A., Richels, R., 1999. The Kyoto protocol: a cost-effective strategy for meeting environmental objectives? In: Weyant, J.P. (Ed.), The Energy Journal, Kyoto Special Issue 1–23, International Association for Energy Economics.

McFarlane, A.R., Veers, P.S., Schluter, L.L., 1994. Simulating high frequency wind for long durations. Solar Energy Division 15, 175–180.

Milborrow, D., 2005. The giant stirs and shakes its fist at wind. Windpower Monthly 21 (6), 43–47.

Musial, W., Butterfield, S., 2004. Future for offshore wind energy in the United States, conference paper preprint. Report Number NREL/CP-500-36313, National Renewable Energy Laboratory, Golden, Colorado. URL: http://www.nrel.gov/docs/fy04osti/36313.pdf.

Nakhamkin, M., Wolk, R.H., van der Linden, S., Hall, R., Patel, M., 2004. New compressed air energy storage concept improves the profitability of existing simple cycle, combined cycle, wind energy, and landfill gas power plants. American Society of Mechanical Engineers (ASME) Turbo Expo, Vienna, Austria, 14–17 June.

NCDC (National Climatic Data Center), 2004. NOAA Satellite and Information Service, US Department of Commerce. URL: http://www.ncdc.noaa.gov/oa/ncdc.html.

Neij, L., 1999. Cost dynamics of wind power. Energy 24, 375–389.

Parent, G., 2004. Trends in renewable energy: country reports. World Renewable Energy Congress (WREC) VII, Denver, CO, August 29–September 3.

PointCarbon, 2005. EUA price last 30 days. Oslo, Norway. http://www.pointcarbon.com (accessed July 18).

Steineger, M., 2005. California utilities set to beat target. Windpower Monthly 21 (6), 34–35.

Thambimuthu, K., et al., 2005. "Capture of $CO_2$," Chapter 3 in Carbon Dioxide capture and storage. A Special Report of the Intergovernmental Panel on Climate Change, WMO and UNEP. Cambridge University Press, New York.

Timms, S., 2004. Linking the world with renewable energy. World Renewable Energy Congress (WREC) VII, Denver, CO, August 29–September 3.

UWIG (Utility Wind Interest Group), 2004. UWRAP—wind data retrieval. NREL Utility Wind Resource Assessment Program. URL: http://www.uwig.org/uwrapdata/UWrapSearch.cfm.

Wang, M.Q., 1999. GREET 1.5—Transportation Fuel-Cycle Model: Volume 2, Detailed Results, ANL/ESD-39, vol. 2. Center for Transportation Research, Argonne National Laboratory, Argonne, Illinois. URL: http://greet.anl.gov/pdfs/esd_39v2.pdf (accessed January 28, 2005).

Westinghouse Electric Corporation, 1995. Technical description of compressed air energy storage facility: 440 MW (nominal), 50 Hz, Westinghouse proprietary document, September.

Williams, R.H., 2004: IGCC: Next steps on the path to gasification-based energy from coal, a report prepared for the National Commission on Energy Policy. NCEP Technical Appendix: Expanding Energy Supply. In: The National Commission on Energy Policy, Ending the Energy Stalemate: A Bipartisan Strategy to Meet America's Energy Challenges, Washington, DC, December.

Wind, T., 2002. Compressed air energy storage in Iowa. Unpublished Report, Iowa Association of Municipal Utilities, Ankeny, Iowa, March 18.

World Wind Energy Association (WWEA), 2006. Worldwide wind energy boom in 2005: 58.982 MW capacity installed. Press release, 7 March, Bonn, Germany. URL: http://www.wwindea.org/pdf/press/PR_Statistics2005_070306.pdf (accessed 16 March 2006).

Zlokovic, V.S., 1969. Wind-power plant and energy storage. Elektroprivreda 22 (9–10), 377.

7-23

*CONFERENCE PROCEEDINGS*

# Comparing Coal IGCC with CCS and Wind-CAES Baseload Power Options in a Carbon-Constrained World

Samir Succar, Jeffery B. Greenblatt, Robert H. Williams

*FIFTH ANNUAL CONFERENCE ON CARBON CAPTURE AND SEQUESTRATION - DOE/NETL*

*May 8 - 11, 2006*

7-24

## Abstract

Coal integrated gasification combined cycle (IGCC) with carbon capture and storage (CCS) has emerged as a potentially cost-effective carbon mitigation strategy. However carbon policies that make energy systems such as IGCC with CCS competitive with conventional fossil power generators will also bring other low carbon technologies into play.

In particular, two strategies for generating baseload power from wind are investigated: pairing wind with dedicated natural gas generation and coupling wind energy to compressed air energy storage (CAES). The costs and performance of these options are analyzed in comparison to coal IGCC with and without CCS.

We find that wind with natural gas backup faces significant challenges in economic dispatch competition due to high fuel prices. However CAES, a commercially ready technology, makes it possible to transform wind power into a baseload power option with the low short-run marginal cost needed to compete in baseload markets. Moreover, geologies suitable for CAES seem to be reasonably well distributed in wind-rich regions of the United States (e.g., Great Plains) where much of the new capacity for coal power generation is being planned. An economic analysis indicates that costs and greenhouse gas emission levels of wind-CAES systems fired with natural gas will be comparable to those of coal IGCC with CCS, and could be strong competitors for coal IGCC with CCS in providing baseload electricity in a carbon-constrained world.


## Introduction

The integrated gasification combined cycle (IGCC) facilitates the production of electricity from coal with low greenhouse gas (GHG) emission rates via pre-combustion capture of $CO_2$ and $CO_2$ storage in geological media [1]. A coal IGCC plant with carbon capture and storage (CCS) typically becomes competive with a coal IGCC plant with $CO_2$ vented when GHG emissions are valued at a price ~ \$100 per tC [2]. However when the greenhouse gas emissions price ($p_{GHG}$) reaches this level, other low carbon generation technologies may be competitive as well. The future of coal IGCC with CCS will depend on how the performance and economics of this technology compare with other low-carbon generation options and how well it is able to compete in economic dispatch.

Wind energy offers lower production costs than most other sources of renewable, low carbon energy. However, due to the intermittency of wind, it is not possible to make a direct comparison between wind generation costs and those of coal IGCC, which will serve as baseload plants. But a baseload power system made up of wind power plus dispatchable backup generation can be compared to a coal IGCC plant.

Two options for backing wind are utilizing dedicated stand-alone generation capacity and energy storage. Natural gas generation is chosen as the stand-alone backup generation technology due to its low capital costs and its fast ramping rates that are well suited to balancing rapid fluctuations in wind power output. CAES is chosen as the energy storage technologies due to its low cost at large scale and potential widespread availability. A wind/CAES system would store excess wind electricity by using it to run compressors that store high-pressure air in underground geologic formations such as saline aquifers or salt domes. This mechanical energy can be retrieved by burning a suitable fuel (e.g., natural gas) in the high pressure air recovered from storage and expanding the combustion products in a gas turbine expander to make electricity. In this way, a wind farm coupled to CAES (or wind/CAES) can store excess wind energy and use it to generate electricity at later times when wind speeds diminish.

While many studies have looked more broadly at the issues associated with integrating wind and energy storage [3-5], a number of studies have also focused on wind specifically with CAES [6, 7] including studies focused on system costs [8-11] and emissions [12]. Although both CAES and pumped hydroelectric storage meet the cost requirements for long-duration storage (> 8 hrs) [13], pumped storage offers limited availability since its economic viability depends on utilizing preexisting reservoirs suitable for storage. CAES however can be implemented in a wide variety of formations that appear to be readily available in the wind-rich Great Plains [14-16]. This is also the same region where most of the capacity for new coal generation is currently being planned.

## Methodology

Costs are analyzed for four low-carbon baseload power generation options: coal IGCC with $CO_2$ vented (IGCC-V), coal IGCC with CCS (IGCC-C), wind coupled to compressed air energy storage (wind/CAES) and wind energy with dedicated natural gas generation (wind/gas).

Cost estimates are for plants with an 85% capacity factor using the financing model in the EPRI Techincal Assessment Guide. The assumed financing parameters are 55% debt (4.4%/y real cost) and 45% equity (14.2%/y real cost), a 30-year (20-year) plant (tax) life, a 38.2% corporate income tax rate, a 2%/y property tax/insurance rate, and an owner's cost of 5.5% of the total installed capital cost. Under these conditions the discount rate (real weighted after-tax cost of capital) is 7.9%/year, and the levelized annual capital charge rate is 15.0%/year. Plant construction requires four years, with the capital investment committed in four equal payments, so that interest during construction factor (IDCF) is 1.124 with Base Case financing.[1] All costs are expressed in 2002 inflation-adjusted U.S. dollars.

| Table 1: **Coal IGCC System Parameters** [17] | | |
|---|---|---|
| | **IGCC-V** | **IGCC-C** |
| Fate of $CO_2$ | Vented | Captured |
| Capacity Factor (%) | 85 | |
| Levelized Annual Capital Charge Rate (%) | 15 | |
| Installed capacity $MW_e$ | 826.5 | 730.3 |
| $CO_2$ Storage Rate ($tCO_2$/hour) | 0 | 626.6 |
| Greenhouse Gas Emissions ($gC_{equiv}$/kWh) | 237 | 52.7 |
| Efficiency, LHV | 0.380 | 0.315 |
| $CO_2$ Transport/Storage \$/$tCO_2$ (100km pipeline) | 0 | 6.82 |
| $CO_2$ Transport/Storage \$/$tCO_2$ (200km pipeline) | 0 | 11.1 |
| Overnight Construction Cost, \$/$kW_e$ | 1135 | 1428 |

| Table 2: **Wind System Parameters [10]** | | |
|---|---|---|
| | **Wind/CAES** | **Wind/Gas** |
| Capacity Factor (%) | 85 | |
| Installed capacity $MW_e$ | 2000 | |
| Levelized Annual Capital Charge Rate (%) | 15 | |
| Wind Farm Rated Power $MW_e$ | 3090 | 2000 |
| CAES Expander Capacity $MW_e$ | 2000 | 0 |
| CAES Compressor Capacity $MW_e$ | 1090 | 0 |
| Natural Gas Backup Capacity $MW_e$ [2] | 0 | 336(SC)/1597(CC) |
| Hours of Storage at CAES Exp Capacity | 73 | 0 |
| Wind Turbine Specific Rating [19] | 1.19 | 1.34 |
| Transmission Line Voltage (kV) | 751 | 569 |
| Transmission Loss % (500km) | 2.72 | 4.20 |
| Transmission Line Load Factor After Losses | 0.85 | 0.43 |
| Wind Energy Transmitted Directly (TWh/y) | 12.2 | 8.91 |
| Wind Energy Input to CAES (TWh/y) | 3.46 | 0 |
| Natural Gas Output (TWh/y) [2] | 0 | 0.879(SC)/6.45(CC) |
| Greenhouse Gas Emissions ($gC_{equiv}$/kWh) | 23.2 | 61.8 |
| Backup System Heat Rate (kJ/kWh)[2] | 4220 | 9350(SC) / 6670(CC) |
| Wind Capital Cost at Nominal Rating \$/$kW_e$ | 923 | 923 |
| Backup System Capital Costs \$/$kW_e$[2] | 453 | 234(SC)/571(CC) |
| CAES Storage Volume Cost \$/kWh | 1.75 | 0 |

Energy quantities are expressed on a lower heating value (LHV) basis, except energy prices are on a higher heating value (HHV) basis—the norm for US energy pricing. Energy prices of \$1.31/GJ for coal and \$5.05/GJ for natural gas are based on a 30-year levelized 2010 price (EIA 2006). The GHG fuel emissions include the $CO_2$-equivalent upstream GHG emissions (estimated in the GREET model of Argonne National Laboratory as 1.00 $kgC_{equiv}$ per GJ of coal and 2.84 $kgC_{equiv}$ per GJ of natural gas) resulting in a total GHG emissions rate of 25.0 $kgC_{equiv.}$ and 18.0 $kgC_{equivv.}$ per GJ of coal and natural gas, respectively.

Coal IGCC plant performances, capital costs, and O&M costs[3] are derived from a 2003 study on coal IGCC by Foster Wheeler Energy carried out for the International Energy Agency's Greenhouse Gas R&D Programme [17].

---

[1] LACCR*(total installed capital cost—including interest charges accumulated during construction) = the annual capital charge. Alternatively, the annual capital charge = IDCF*LACCR*OCC (where OCC = overnight construction cost), so that IDCF*LACCR is the OCC multiplier

[2] Natural Gas Backup generation is comprised of a combination of natural gas combined cycle (CC) and simple cycle gas turbine (SC) systems.

Cost modeling of wind energy systems and transmission as well as optimization methodology for variable scaling of wind turbine components (i.e. derating) are as described in previous studies unless otherwise noted [10, 18, 19].

## Findings

Disaggregated costs for the four baseload power systems are presented in Table 3. The generation costs are compared at three stages by adding GHG emissions and transmission costs incrementally. The GHG costs scale with the emissions levels for each of the technologies. While the IGCC-V system has the largest emissions rate (237 $gC_{equiv}$/kWh) it is found that IGCC-C and wind/gas have very similar emissions (53 and 62 $gC_{equiv}$/kWh respectively). The wind/CAES system has the lowest GHG emission rate of 23 $gC_{equiv}$/kWh. In part this is due to the larger fraction of power delivered directly from wind relative to wind/gas system (see Table 2). This is largely a function of optimizing both the sizing the wind farm and the wind turbine specific rating [10, 19]. The low heat rate for CAES electricity (4220 kJ/kWh) also contributes to the low emissions profile for the wind/CAES system.

When GHG emissions are valued at $100/tC, the wind/CAES system is competitive with the coal IGCC options at the busbar. However, if the wind resource being exploited is 500 km more remote from the electricity market being served than the coal IGCC options, then the coal IGCC-C option becomes the least costly (see bottom of Table 3). The effect of these factors on the relative economics of these systems underscores the sensitivity of the results to climate policy strength and wind resource remoteness.

Table 3: **Disaggregated Generation Costs for Coal IGCC and Baseload Wind, $/MWh (class 5 winds, $923/kW wind capital)**

| | IGCC Vent | IGCC w/CCS | Wind/CAES | Wind/Gas |
|---|---|---|---|---|
| Fixed Costs | | | | |
| Capital | 25.70 | 32.32 | 52.95 | 32.86 |
| Fixed Operations and Maintenance | 3.39 | 4.96 | 3.75 | 3.76 |
| Dispatch Costs | | | | |
| Variable Operations and Maintenance | 4.49 | 4.76 | 8.29 | 4.88 |
| Fuel (NG = $5.05/GJ HHV, Coal = $1.31/GJ HHV) | 13.07 | 15.77 | 7.23 | 19.31 |
| $CO_2$ Transport and Storage Cost[4] | 0.00 | 5.86 | 0.00 | 0.00 |
| *Total Dispatch Cost* | *17.56* | *26.39* | *15.52* | *24.19* |
| **Total Generation Cost** | **46.64** | **63.67** | **72.22** | **60.81** |
| | | | | |
| GHG emissions costs, $p_{GHG}$=$100/tC | 23.68 | 5.27 | 2.32 | 6.18 |
| *Total Dispatch Cost + $p_{GHG}$* | *41.24* | *31.66* | *17.83* | *30.38* |
| **Total Generation Cost + $p_{GHG}$** | **70.32** | **68.94** | **74.54** | **67.00** |
| | | | | |
| Cost of 500km Dedicated TL for Remote Wind | 0.00 | 0.00 | 4.09 | 3.25 |
| **Total Generation Cost + $p_{GHG}$ + TL** | **70.32** | **68.94** | **78.63** | **70.25** |

Table 3 also shows that the dispatch costs (i.e. the sum of all short-run marginal costs: fuel + variable operations and maintenance + GHG emissions cost) are larger for wind/gas than for wind/CAES despite a lower overall COE. This has important implications for the viability of wind/gas as a baseload generation option, as discussed in the next section.

---

[3] In the original FWE study property taxes and insurance (PTI) were included in O&M costs. With the assumed EPRI TAG financing model, PTI is accounted for in the levelized annual capital charge rate instead.

[4] Assuming CO2 is transported by pipeline 100 km for storage in an aquifer and that the maximum injection rate is 1000 t/d per well

## Dispatch Cost Concerns

### Capacity Factors Assumptions

In the above discussion of generation costs it is assumed all competing options are baseload systems operating at 85% capacity factor. This assumption must be examined more closely with respect to the relative dispatch costs for competing technologies. The capacity factor for each option depends on how well it can compete in economic dispatch on the grid. For a given set of power generating systems, the grid operator determines the capacity factors of these systems by calling first on the system with the least dispatch cost. Under this condition, deployment in sufficient quantity of the technology with the least dispatch cost can lead to a reduction of the capacity factors and thus an increase in the COE of the competing options on the system.

As a result of the recent increases in natural gas prices in the U.S. this phenomenon has resulted in reducing capacity factors for natural gas combined cycle plants originally designed for baseload operation to average utilization rates in the range 30-50% where coal plants are available to compete in dispatch [20].

In principle this downward pressure on capacity factors for options with high dispatch costs could be avoided with "take-or-pay" contracts that require the generator to provide a specified fixed amount of electricity annually. But uncertainties about future fuel prices, technological change, and future electricity demand make such contracts rare.

### Variable Dispatch Costs

Since dispatch costs determine the relative suitability of different options for baseload operation, it is necessary to examine closely the dynamics of dispatch for both wind options. Furthermore, although we can treat the dispatch costs from coal IGCC as approximately constant in this context, the dispatch costs from wind cannot be treated as a simple average. Wind/gas and wind/CAES will operate at the lowest dispatch costs when all the electricity is being provided directly by wind, when fuel expenditures are zero. But dispatch costs will increase significantly as backup generation comes on line to balance shortfalls in wind output. Thus it is important to analyze the variations in dispatch costs for these options, not simply their average value as reported in Table 3.

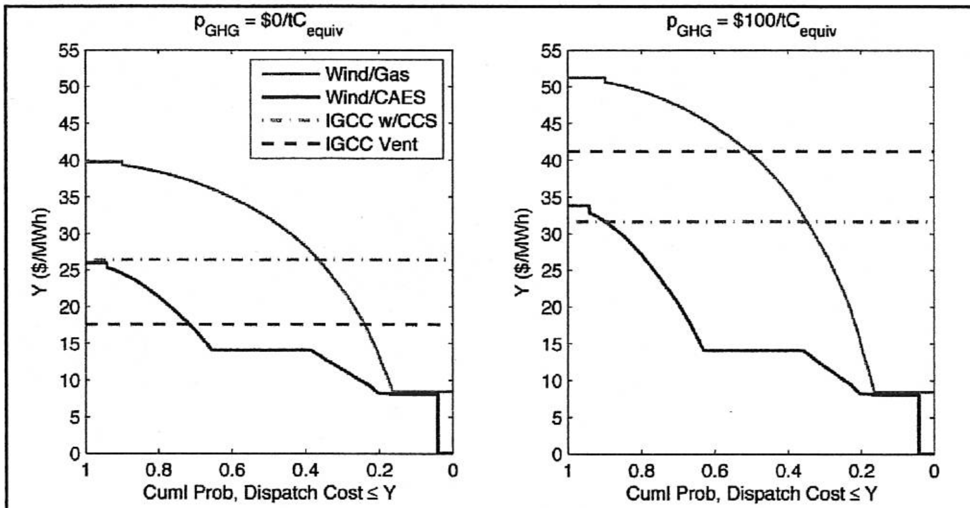



Figure 1 Variable dispatch costs for wind/gas and wind/CAES in comparison with coal IGCC costs at two different GHG emissions prices

The dispatch cost of the wind/gas and wind/CAES systems will vary with the wind input according to whether wind is transmitting power directly or whether the backup system is deployed. Figure 1 shows the variation in dispatch costs in a manner similar to a "load-duration" curve or, more precisely, as an inverse cumulative probability curve counting from the top end of the distribution. The choice of horizontal axis (in reverse order from 1 to 0) can be useful since horizontal axis values at the intersection of the wind curves with each constant-cost IGCC line indicate the percent of time that it can deliver power at a lower dispatch cost. These dispatch cost curves are evaluated at both $p_{GHG}$=\$0/tC and \$100/tC.

Dispatch costs are the same lowest value for both the wind/gas and wind/CAES systems when all power comes directly from the wind array (right portion of each plot in Figure 1) but that dispatch costs rise at very different rates as the fraction of power coming from the backup system increases (left portion of each plot). In addition, the wind/CAES system has an intermediate dispatch cost regime where CAES compressors are running to store wind energy that cannot be transmitted; this appears as a step in intermediate ranges on the wind/CAES line.

Figure 1 shows that wind/gas has the highest dispatch cost of all the options when natural gas generation is dispatched in significant quantities to balance wind output. This is true in both panels of Figure 1 regardless of the price on GHG emissions. At \$0/tC wind/gas cannot compete in economic dispatch relative to the lowest cost coal technology for more than 30% of the time and even at \$100/tC it will be competitive less than 40% of the time. Hence a baseload-level capacity factor cannot be sustained with wind/gas where coal or wind/CAES capacity is available and thus given current natural price projections it is unlikely that wind/gas will be a viable baseload strategy for the foreseeable future.

This does not mean however that wind backed by existing reserve capacity cannot serve intermediate load applications. In fact, if diurnal variations in wind speed are positively correlated with demand for electricity, it is likely that the economics of wind backed by supplemental capacity could be quite favorable for serving intermediate loads even at very high penetrations, but such an analysis is outside the scope of this paper.

On the other hand, the wind/CAES system, because of its low heat rate (4220 kJ/kWh) and higher utilization rate of wind (see Table 2), is able to run at a lower dispatch cost than both coal options more than 70% of the time without a GHG price and more than 90% of the time for $p_{GHG}$=\$100/tC. Thus from the point of view of dispatch costs, wind/CAES has the potential to be a competitive baseload technology with respect to coal IGCC. Consequently the analysis that follows will focus on the competition between wind/CAES and coal IGCC systems. The wind/gas technology, although capable of delivering electricity at a competitive cost, is not a viable baseload strategy for the reasons stated above and will not be considered further.

## *Total Generation Cost*

The costs of energy of three base load power plants were analyzed as a function of GHG price.

Costs for IGCC-C are presented as a band showing the upper and lower bounds for $CO_2$ pipeline costs. Costs for $CO_2$ transport and for aquifer storage are based on a model developed by Ogden [21], assuming that the maximum $CO_2$ injection rate per well is 1000 t/day (a typical value for mid-continental aquifers) and that $CO_2$ is transported by pipeline 100 km to 200km (corresponding to a total cost for $CO_2$ transport and storage of \$6.8 to 11.1 per tonne of $CO_2$, respectively).

Cost bands for wind/CAES reflect 0 to 500km of dedicated high voltage transmission. Since equal transmission costs applied to both systems appear only as equal offsets (and thus would not affect the relationship between systems) the lower bound for wind (0 km transmission) can be interpreted more generically as the case of equal transmission costs between wind and coal. Likewise the upper bound reflects a 500km transmission distance differential of wind relative to coal.

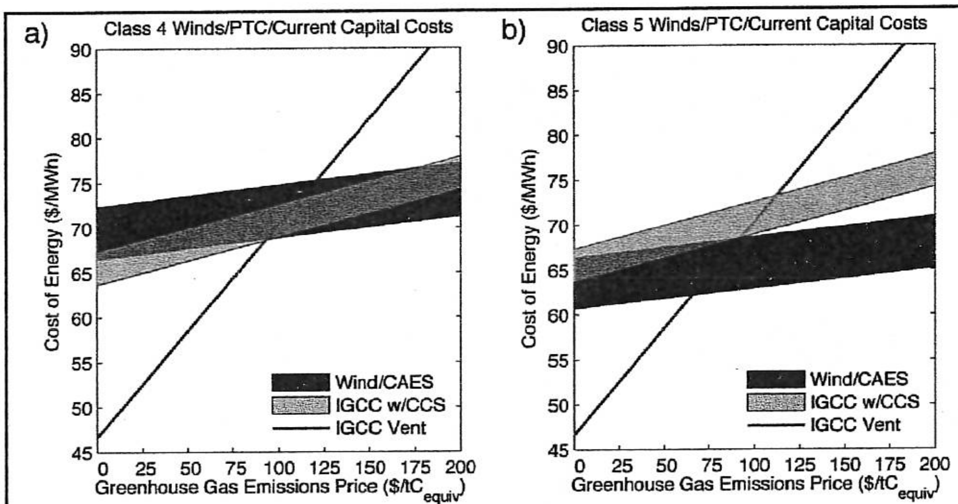



Figure 2 System cost dynamics under a GHG emissions price with current capital costs with a 1.9¢/kWh production tax credit (PTC) for wind.

The generation costs (\$/MWh) of all four systems are analyzed as a function of greenhouse gas emissions costs with variations in three principle variables: wind resource strength, wind production tax credit (PTC), and capital costs for wind and CAES.

Wind resources of class 4 (8.23 m/s mean wind speed and 650 W/m$^2$ mean wind power density at a hub height of 119 meters) and class 5 (8.8 m/s, 800 W/m$^2$) were explored. While current wind development takes place predominantly in regions with resources of class 5 and above, future capital cost reductions and wind turbine technology improvements may make class 4 winds economically viable thus significantly enhancing wind energy potential worldwide (especially in North America, Europe and Middle East/Africa [22]). Therefore this range captures both current conditions and projected frontiers for wind development.

Figure 2 shows the cost competition between IGCC-C and wind/CAES under both wind resource conditions with current capital costs for wind [23] and CAES [13, 24] as well as a production tax credit (PTC) of 1.9 cents per kWh applicable to the first 10 years of plant life—the current situation in the United States.

This figure shows that wind resource strength and location has a profound effect on the cost effectiveness of wind/CAES. Moving from a Class 4 remote wind site (the upper edge of the blue band in Figure 2a) to a Class 5 local wind site (the lower edge of the blue band in Figure 2b), wind/CAES goes from lying entirely above the IGCC-C cost band to entirely below it. This also shows the coupled tradeoff of wind resource strength and remoteness: the cost of exploiting a remote class 5 resource is nearly equivalent to that of developing a local class 4 site.

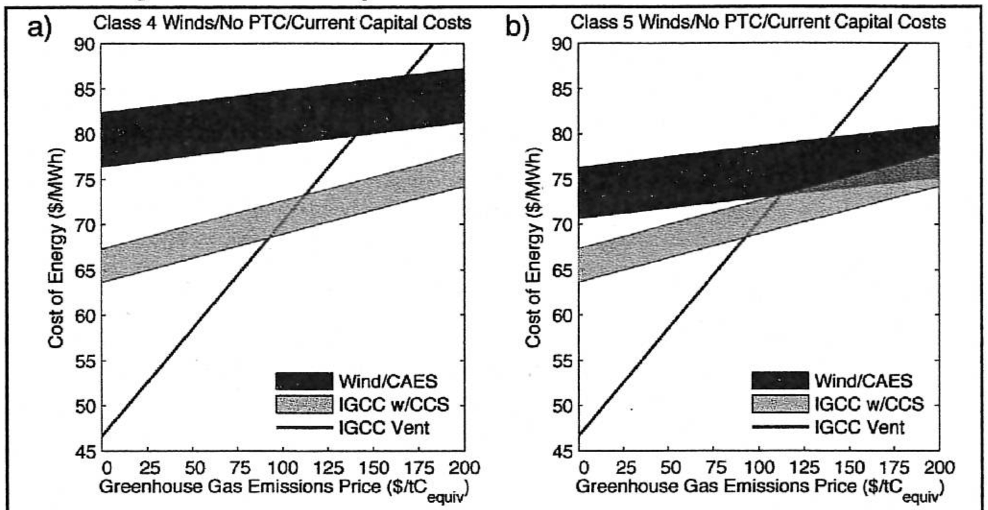



Figure 3 System cost dynamics under a GHG emissions price with current capital costs and no PTC

Nevertheless we see that in the absence of a price on GHG emissions, IGCC with $CO_2$ vented is clearly the least costly option in both cases. But the wind/CAES and IGCC-C technologies begin to compete with the IGCC-V option at comparable GHG emission prices.

An analysis of systems costs in the absence of a PTC (Figure 3), shows that wind/CAES will be competitive with IGCC-C only under the most favorable combination of conditions. For the systems we have modeled, only a class 5 wind resource without additional transmission costs can come in near the $100/tC price at which we expect to see IGCC-C becoming competitive with IGCC-V. Furthermore, it is only because of its low emissions rate that wind/CAES can compete at all; the shallow slope of the cost line allows wind/CAES to enter at high GHG emissions prices despite relatively high fixed costs. Therefore under current capital conditions and with $p_{GHG}$ = $100/tC wind/CAES can only compete if class 5 winds are available at no greater transmission distance than coal IGCC-C and if CCS costs exceed $11/tCO$_2$ (i.e. the $CO_2$ pipeline distances is greater than 200 km).

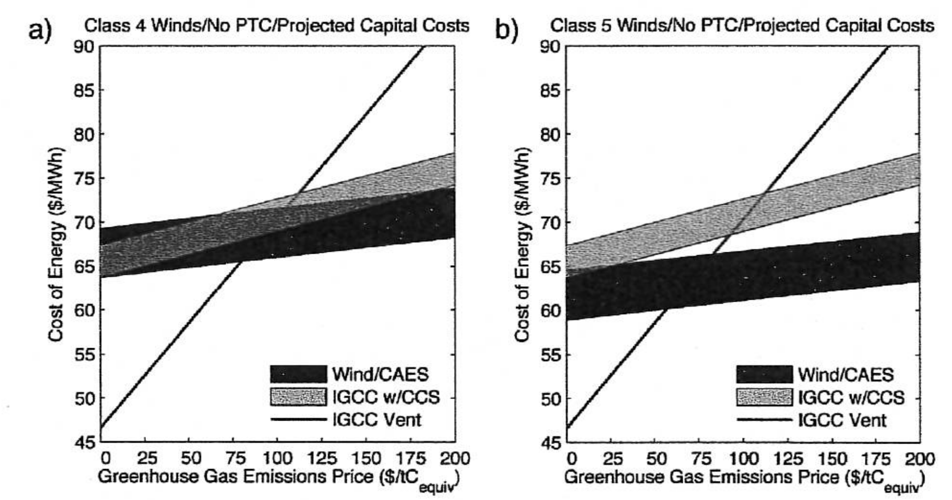



Figure 4 System cost dynamics under a GHG emissions price with 24% projected capital cost reductions for wind turbine and CAES turbomachinery (no PTC)

The potential for capital cost reduction is significant for both wind and CAES technologies. There have been large sustained growth rates in global wind capacity in recent years: 29.3% average annual global capacity growth over the past ten years and 27.9% over the past five years [25]. If these trends continue, they will likely drive significant cost buy-downs for wind capital in coming years. Assuming a somewhat reduced 20% annual growth rate, and using average progress ratios for wind of 0.81-0.95 [26, 27], the 24% capital cost reductions assumed for Figure 4 could be realized within a 5-20 year timeframe.

In addition, the small scale of current CAES deployment suggests that significant cost reductions could be realized with very modest capacity additions.

The capital costs for IGCC could likewise see significant reductions, however the near-term costs reported by Foster Wheeler Energy used here (total plant costs of $1135/kW$_e$ and $1428/kW$_e$ for $CO_2$ vented and stored respectively) already reflect some cost reductions relative to IGCC plants that would be built today. As a result IGCC costs are regarded as already incorporating some learning and thus have not been modified for the analysis of projected capital costs in Figure 4.

Capital cost reductions would not only make class 5 resources more broadly viable for wind/CAES without subsidy, but under a wide range of conditions they would make class 4 wind resources economical as well. This in turn could significantly extend the range of sites available for wind/CAES and ease the need for additional transmission costs for wind as less remote sites become viable. This is significant since the bottom edge of the class 4 wind/CAES band corresponding to a zero transmission distance differential is competitive with respect to IGCC-C at all GHG prices without a PTC. Thus if capital cost buy-downs over the next 5-20 years can make class 4 wind resources viable, this has the potential to not only reduce the capital costs of the turbines themselves, but to reduce the infrastructure costs associated with wind and to make wind/CAES viable over a broader geographical area.

Over the longer term, of course, it will be desirable to exploit remote Class 4 wind as well because so doing would greatly magnify the exploitable wind resources. On a global basis, the exploitable Class 5+ wind resource is estimated at 80.5 PWh/y compared to 185.0 PWh/y for Class4+ [28]. These figures exceed the global consumption of electricity in 2002 by factors of 5.7 (for classes 5 and above) and 13.0 (for classes 4 and above) [29].

# Conclusions

The viability of wind and coal IGCC baseload electricity options will depend on a handful of critical factors. While IGCC-V is the least-costly baseload power option investigated without a price on GHG emissions, climate policies equivalent to a carbon price ~ $100/tC could bring several low-carbon technologies to the table. While wind with dedicated natural gas backup generation can operate at competitive total costs, it is unlikely that it will be able compete under economic dispatch in baseload markets for the foreseeable future. Wind with CAES storage however can operate at much lower short-run marginal costs with total costs very similar to IGCC-C under several credible scenarios. The relative economics of these systems will depend largely on the quality and remoteness of wind resource available for wind/CAES systems. Furthermore, the competitiveness of wind/CAES may be enhanced as growth rates in wind buy down capital costs making less remote sites economically viable in the near future.

# References


[1] P. Chiesa, S. Consonni, T. Kreutz, and R. Williams, "Co-production of hydrogen, electricity and CO2 from coal with commercially ready technology. PartA: Performance and emissions," *International Journal of Hydrogen Energy*, vol. 30, pp. 747-767, 2005.

[2] T. Kreutz, R. Williams, S. Consonni, and P. Chiesa, "Co-production of hydrogen, electricity and CO2 from coal with commercially ready technology. Part B: Economic analysis," *International Journal of Hydrogen Energy*, vol. 30, pp. 769-784, 2005.

[3] M. Korpaas, A. T. Holen, and R. Hildrum, "Operation and sizing of energy storage for wind power plants in a market system," *International Journal of Electrical Power & Energy Systems*, vol. 25, pp. 599-606, 2003.

[4] J. V. Paatero and P. D. Lund, "Effect of energy storage on variations in wind power," *Wind Energy*, vol. 8, pp. 421-441, 2005.

[5] B. Sorensen, "Dependability of Wind Energy Generators with Short-Term Energy-Storage," *Science*, vol. 194, pp. 935-937, 1976.

[6] G. L. Arnulfi and M. Marini, "Analysis of transient performance of a compressed air energy storage plant," Atlanta, GA, United States, 2003.

[7] I. Arsie, V. Marano, G. Nappi, and G. Rizzo, "A model of a hybrid power plant with wind turbines and compressed air energy storage," Chicago, IL, United States, 2005.

[8] A. J. Cavallo, "High-capacity factor wind energy systems," *Journal of Solar Energy Engineering, Transactions of the ASME*, vol. 117, pp. 137-143, 1995.

[9] J. F. DeCarolis and D. W. Keith, "The economics of large-scale wind power in a carbon constrained world," *Energy Policy*, vol. 34, pp. 395-410, 2006.

[10] J. B. Greenblatt, S. Succar, D. Denkenberger, R. H. Williams, and R. H. Socolow, "Baseload wind energy: Modeling the competition between gas turbines and compressed air energy storage for supplemental generation," *Energy Policy*, in Press.

[11] I. Arsie, V. Marano, G. Rizzo, and M. Moran, "Energy and Economic Evaluation of a Hybrid Power Plant with Wind Turbines and Compressed Air Energy Storage," Atlanta, GA, United States, 2006.

[12] P. Denholm, G. L. Kulcinski, and T. Holloway, "Emissions and energy efficiency assessment of baseload wind energy systems," *Environmental Science and Technology*, vol. 39, pp. 1903-1911, 2005.

[13] EPRI-DOE, "Handbook of Energy Storage for Transmission and Distribution Applications," EPRI, DOE, Palo Alto, CA, Washington, DC 2003.

[14] W. F. Adolfson, J. S. Mahan, E. M. Schmid, and K. D. Weinstein, "Geologic issues related to underground pumped hydroelectric and compressed air energy storage," Boston, MA, USA, 1979.

[15] B. R. Mehta, "Siting compressed - air energy storage plants," presented at Proceedings of the American Power Conference, Chicago, IL, USA, 1990.

[16] K. Allen, "CAES: the underground portion," *IEEE Transactions on Power Apparatus and Systems*, vol. PAS-104, pp. 809-12, 1985.

[17] FWE, " Potential for Improvement in Gasification Combined Cycle Power Generation with CO2 Capture," Foster Wheeler Energy Ltd (Italy and UK) May 2003 2003.

[18] D. Denkenberger, J. B. Greenblatt, and R. H. Socolow, "Optimal Wind Turbine Rated Speed Taking Into Account Array Effects and Capacity Factor," *ASME Electric Power 2004* 2004.

[19] S. Succar, D. Denkenberger, J. B. Greenblatt, and R. H. Williams, "An Integrated Optimization Of Large-Scale Wind With Variable Rating Coupled To Compressed Air Energy Storage," *Proceedings of AWEA Windpower 2006, Pittsburgh, PA*, 2006.

[20] K. Thambimuthu, M. Soltanieh, J. C. Abanades, R. Allam, O. Bolland, J. Davison, P. Feron, F. Goede, A. Herrera, M. Iijima, D. Jansen, I. Leites, P. Mathieu, E. Rubin, D. Simbeck, K. Warmuzinski, M. Wilkinson, R. H. Williams, M. Jaschik, A. Lyngfelt, R. Span, and M. Tanczyk, "Capture of CO2 " in *Carbon Dioxide Capture and Storage, a Special Report of the Intergovernmental Panel on Climate Change*, B. Metz, O. Davidson, H. Coninck, M. Loos, and L. Meyer, Eds. New York, NY: Cambridge University Press, 2005.

[21] J. M. Ogden, "Modeling infrastructure for a fossil hydrogen energy system with CO2 sequestration," *Proceedings of the 6th International Conference on Greenhouse Gas Control Technologies, Kyoto, Japan, October.*, 2002.

[22] M. J. Grubb and N. I. Meyer, "Wind energy: resources, systems and regional strategies," in *Renewable Energy: Sources for Fuels and Electricity*, T. B. Johansson, H. Kelly, A. K. N. Reddy, and R. H. Williams, Eds.: Island Press, 1993, pp. 157 -212.

[23] D. J. Malcolm and A. C. Hansen, "WindPACT turbine rotor design study," National Renewable Energy Laboratory, Golden, CO 2002.

[24] EPRI-DOE, "Energy Storage for Grid Connected Wind Generation Applications," EPRI, DOE, Palo Alto, CA, Washington, DC 1008703, 2004.

[25] GWEC, "Record year for wind energy: Global wind power market increased by 43% in 2005," Global Wind Energy Council, Brussels, Belgium 17 Feb, 2006 2006.

[26] M. Junginger, A. Faaij, and W. C. Turkenburg, "Global experience curves for wind farms," *Energy Policy*, vol. 33, pp. 133-150, 2005.

[27] L. Neij, "Cost dynamics of wind power," *Energy*, vol. 24, pp. 375-389, 1999.

[28] J. B. Greenblatt, "Wind as a source of energy, now and in the future," InterAcademy Council, Amsterdam, Netherlands October 1 2005.

[29] EIA, "International Energy Annual 2002," Energy Information Administration, Washington, DC DOE/EIA-0219(2002), 2002.

# Testimony of Reid Nelson
# (Private Citizen)
# on HB 2949

This bill seeks to set the "foundation of the state's energy plan" without mentioning energy efficiency. Whereas, KCPL spokespersons have stated that energy efficiency should be considered a "first fuel," and spokespersons for the KCC state that, "There is no doubt that energy efficiency is probably the fastest, quickest, least costly way to gain in the whole energy picture..." (KCC video)( http://www.kcc.state.ks.us/energy/indexhtm)

Ignoring implementation of any future energy efficiency measures, the bill projects that Kansas will need significant additional baseload generation by 2020. This statement presumes load growth of 1.3% until 2015, and then 1.6% to 2020. However, these figures appear to rely on a "base case" of load growth forecast, wherein projected electricity demand relies on "business as usual," including current utility-efficiency practices.

These estimates should be adjusted drastically downward, because the legislature and ratepayers will likely turn to energy efficiency programs and DSM (demand side management) to bring demand down to .5% or less. Failure to factor in efficiency (our "First Fuel,") creates a gross overestimate of our need for baseload.

The idea that Kansas should and can reduce demand is based on the following:

1. The Western Governor's Association's 2006 Energy Efficiency Task Force found that adoption of "best practice" policies can reduce load growth in western states (including Kansas) 75% over the next 15 years. See Western Governor's Association Clean and Diversified Energy Initiative, pg. x (2006)(http://www.westgov.org/wga/initiatives/cdeac/energy)

2. The State of Vermont shows what is possible. Its efficiency program, "Efficiency Vermont," aggressively pursues efficiency and demand-side programs. Prior to Efficiency Vermont's efforts, demand growth in Vermont was similar to Kansas', increasing at 1.5% per year. However, as of 1008 Vermont stopped load growth altogether. The CEO of Efficiency Vermont recently stated, "And we're not done [reducing] at 1.5%". See Salina Journal, 3/3/08.

3. A recent report, commissioned for Texas, determined that aggressive efficiency policies "can limit growth in energy usage to just one-fifth of the forecast growth over the next 15 years. This would provide $38 billion of net benefits to the Texas economy." Power to Save, pg.10 (January, 2007) (http://www.docs.nrdc..org/globalwarming/glo).

4. The efficiency programs require a surcharge on electric bills. The 2.8% surcharge which Vermont employed, is typical. But the rate of return, according to the Western Governor's Association, is $3 for every $1 levied. In Texas, the return will be 4 to 1, returning $4.40 to the Texas economy for every $1 invested. Power to Save, pg. 11. Use of the "best practices" in efficiency programs translates into a reduced energy bill for consumers by 23% over the "business as usual" scenario. See Western Governors Pg. 51.

Select Committee on Energy & Environment For the Future
3/12/08
Attachment # 8

Conclusion: This bill, by failing to consider efficiency programs and their effect on baseload requirements, appears to set Kansas on a course which is very costly for its ratepayers.