Testimony

Future of Coal
Committee on Energy and Natural Resources
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Thank you, Mr. Chairman, Ranking Member Domenici, and Members of the Committee. I am Bryan Hannegan, Vice President - Environment for the Electric Power Research Institute (EPRI), a non-profit, collaborative R&D organization headquartered in Palo Alto, California. EPRI appreciates the opportunity to provide testimony to the Committee on the MIT "Future of Coal" report, and it is a great personal honor for me to be back in this Committee room on this side of the witness table. My comments today reflect the work of the talented scientists and engineers we have working across our Institute on the many issues associated with electric power generation and use.

I want to focus my comments today on three subjects: (1) EPRI's views on the MIT report, which we believe provides an important foundation on which to consider future energy policy; (2) a detailed view from EPRI on the principal challenges facing coal-based generation in the decades ahead; and (3) highlights of some recent analytical work that EPRI has published emphasizing the importance of advanced coal technologies as part of an overall low-cost, low-carbon portfolio of options to reduce carbon dioxide emissions associated with climate change.

Background

Coal currently provides over half of the electricity used in the United States, and most forecasts of future energy use in the United States show that coal will continue to have a dominant share in our electric power generation for the foreseeable future. Coal is a stably priced, affordable, domestic fuel that can be used in an environmentally responsible manner. Through development of advanced pollution control technologies and sensible regulatory programs, emissions of criteria air pollutants from new coal-fired power plants have been reduced by more than 90% over the past three decades. And by displacing otherwise needed imports of natural gas or fuel oil, coal helps address America's energy security and reduces our trade deficit with respect to energy.

By 2030, according to the Energy Information Administration, the consumption of electricity in the United States is expected to increase by approximately 40% over current levels. At the same time, to responsibly address the risks posed by potential climate change, we must substantially reduce the greenhouse gas emissions intensity of our economy in a way which allows for continued economic growth and the benefits that energy provides. This is not a trivial matter – it implies a substantial change in the way we produce and consume electricity. Technologies to reduce CO_2 emissions from coal will necessarily be one part of an economy-wide solution that includes greater end-use

efficiency, increasing renewable energy, more efficient use of natural gas, expanded nuclear power, and similar transformations in the transportation, commercial, industrial and residential sectors of our economy. In fact, our work at EPRI on climate policy has consistently shown that non-emitting technologies for electricity generation will likely be less expensive than technologies for limiting emissions of direct fossil fuel end uses in other sectors. Paradoxically, as we seek greater limits on CO_2 across our economy, our work at EPRI suggests we will see greater amounts of electrification – but only if the technologies to do so with near-zero emissions are at hand.

The MIT Study

Let me first make some general remarks about the MIT study which is the topic of today's hearing. I should note that while none of the EPRI staff were formally involved in the development of the report, we did comment on earlier drafts of it provided to us by the study's authors. In addition, our former President and CEO, Kurt Yeager, served on the study's Advisory Committee.

We agree with many of the main points of the MIT study:

- In particular, we agree with the study's main finding that CO_2 capture and sequestration (CCS) will be the critical enabling technology that provides for continued coal use even as we reduce our CO_2 emissions.

- We agree that the key to proving CCS capability is the demonstration of CCS at large-scale (> 1 million tons CO_2/year) for both pre- and post-combustion capture with storage in a variety of geologies. The scope of the program described in the MIT report is appropriate.

- We share the view expressed by the MIT report that absent these successful demonstrations at the large scale, CCS will be confined to a narrow set of uses for enhanced oil recovery, and coal's share of future electricity production will decline dramatically as a result.

- We concur with the MIT report that we should avoid choosing between coal technology options – rather, we should foster a "portfolio of technology options":

    - While there are well proven methods for capturing CO_2 resulting from coal gasification, IGCC plants will have larger components and a degree of integration that has not been demonstrated at the commercial scale.

    - In contrast, PC technology is well proven commercially in the power industry, and here the need is for demonstration of post combustion capture at a commercial and affordable scale.

- We agree that there will inevitably be additional costs associated with CCS. EPRI's latest estimates suggest that the levelized cost of electricity (COE) from new coal plants (IGCC or supercritical PC) designed for capture, compression, transportation and storage of the CO_2 will be 50-80% higher than the COE of a conventional supercritical PC (SCPC) plant..

- EPRI's technical assessment work indicates that the preferred technology and the additional cost of electricity for CCS will depend on the coal type, location and the technology employed.

    - Without CCS, supercritical pulverized coal (SCPC) has an advantage over IGCC. However, the additional CCS cost is generally lower with IGCC than for SCPC.

    - Some studies show an advantage for IGCC with CCS with bituminous coal, but with lignite coal SCPC with CCS is more generally preferred. With sub-bituminous coals, SCPC with CCS and IGCC with CCS appear to show similar costs.

- At the same time, our initial work with post-combustion CO_2 capture technologies suggests we can potentially reduce the current 30% energy penalty associated with CCS to something closer to 10% over the longer-term. Improvements in IGCC plants offer the same potential for reducing cost and energy penalty as well.

- We also concur with MIT's assessment of the need to consider the entire integrated system for capture, transportation and storage of CO_2 at scale, and note that the existing FutureGen program is one good example of how this can be done. FutureGen is recognized around the world as a meaningful carbon sequestration project, and it has become a model for similar projects in other parts of the world. Others are needed, and we welcome the recent 10 MW pilot plant and the 200-MW plant announcement by AEP in that regard.

- We believe that the greater impediment to expanded CCS may be the development of public acceptance and suitable regulatory and legal frameworks. Absent a consistent and predictable approach to siting and permitting facilities for the transport and storage of CO_2, the capital costs and risks associated with these projects will likely prevent them from moving forward. The question of ownership of the stored CO_2 and the liability for any release or leakage is also not well understood. And most notably, the environmental fate of the captured and stored CO_2 is also an open scientific area worth further study.

- We see value in the approach taken by the various DOE Regional Carbon Sequestration Partnerships and do not agree with MIT's assessment that these existing programs are "completely inadequate". However, we do see the need to significantly accelerate the schedules and increase the scope of these programs to allow large scale tests and demonstrations of the full range of CCS technologies.

- We view the question of whether to retrofit an existing coal-based plant for CCS as a matter of economics and reliability: if the technologies exist to do so at a cost low enough to keep the plant in operation reliably, the owner may incorporate CCS retrofits particularly as they make additional modifications to the system to meet new stringent air pollution controls. EPRI is initiating analytical work in this area to better understand the potential for retrofits on existing coal-based generation units.

- With respect to the construction of new coal-based generation units, we disagree with the MIT report's categorical conclusion that pre-investment in "capture-ready" features is

uneconomic. EPRI views this as a matter of perception on when and how restrictions on CO_2 emissions may occur: as the prospect of limits becomes more likely, such pre-investment becomes more worthy of consideration.

- The rapid pace of expansion in global coal generation capacity (105 GW added in China last year alone) underscores the need to focus on enabling large-scale CCS technology as soon as possible, regardless of discussions on domestic or international policy frameworks to reduce CO_2 emissions.

In the paragraphs that follow, we provide further detail on EPRI's view of the critical needs for coal-based generation in a carbon-constrained world.

Increasing Coal Plant Efficiency

In the 1950s and '60s, the United States was the world's pioneer in power plants using thermodynamically efficient "supercritical" and "ultra-supercritical" steam conditions. Exelon's coal-fired Eddystone Unit 1, in service since 1960, still boasts the world's highest steam temperatures and pressures. Because of reliability problems with some of these early units, U.S. designers retreated from the highest supercritical steam conditions until the 1980s and '90s when international efforts involving EPRI and U.S., European, and Japanese researchers concentrated on new, reliable materials for high-efficiency pulverized coal plants. Given the prospect of potential CO_2 regulations (and efforts by power producers to demonstrate voluntary CO_2 reductions), the impetus for higher efficiency in future coal-based generation units has gained economic traction worldwide. In fact, the majority of new pulverized coal (PC) plants announced over the last two years will employ high-efficiency supercritical steam cycles, and several will use the ultra-supercritical steam conditions heretofore used only overseas (aside from Eddystone).

EPRI is working with the Department of Energy, the Ohio Coal Development Office, and major equipment suppliers on an important initiative to qualify a whole new class of nickel-based "superalloys," which will enable maximum steam temperatures to rise from an ultra-supercritical steam temperature of 1100ºF to an "advanced" ultra-supercritical steam temperature of 1400ºF. Combined with a modest increase in steam pressure, this provides an efficiency gain that reduces a new plant's carbon intensity (expressed in terms of CO_2 emitted per megawatt-hour (MWh)) by about 20% relative to today's state-of-the-art plant. If capture of the remaining CO_2 is desired, improved efficiency will also reduces the required size of any necessary equipment.

However, realization of this opportunity will not be automatic – in fact, it will require a renewed, sustained R&D commitment and substantial investment in demonstration facilities to bring new technologies to market. The European Union has embraced such a strategy and is midway through its program to demonstrate a pulverized coal plant with 1300ºF steam conditions, which was realistically planned as a 20-year activity.

Efficiency improvements will also be important for other coal power technologies. The world's first supercritical circulating fluidized-bed (CFB) plant is currently under construction in Poland.

The greatest increase in efficiency for integrated gasification combined cycle (IGCC) units will come from increases in the size and efficiency of the gas turbines and improvements in their ability to handle hydrogen rich "syngas" that would be produced in IGCC plants designed for CO_2 capture.

CO_2 Capture Technology

Carbon capture and storage (CCS) technologies can be feasibly integrated into virtually all types of new coal-fired power plants, including IGCC, PC, CFB, and variants such as oxy-fuel combustion. For those constructing new plants, it is unclear which type of plant would be economically preferred if it were built to include carbon capture. All have relative competitive advantages under various scenarios of available coal types, plant capacity, location, sales of by-products, etc.

Although carbon capture appears technically feasible for all coal power technologies, it poses substantial engineering challenges (requiring major investments in R&D and demonstrations) and comes at considerable cost. However, analyses by EPRI and the Coal Utilization Research Council suggest that once these substantial investments are made, the cost of CCS becomes manageable, and ultimately coal-based electricity with CCS can be cost competitive with other low-carbon generation technologies.

Post-combustion CO_2 separation processes (placed after the boiler in the power plant) are currently used commercially in the food and beverage and chemical industries, but these applications are at a scale much smaller than that needed for power producing PC or CFB power plants. These processes themselves are also huge energy consumers, and without investment in their improvement, they would reduce plant electrical output by as much as 30% (creating the need for more new plants). CO_2 separation processes suitable for IGCC plants are used commercially in the oil and gas and chemical industries at a scale closer to that ultimately needed, but their application necessitates development of modified IGCC plant equipment, including additional chemical process steps and gas turbines that can burn nearly pure hydrogen.

EPRI's most recent cost estimates suggest that for PC plants, the addition of CO_2 capture using the currently most developed technical option, amine solvents, along with drying and compression, pipeline transportation to a nearby storage site, and underground injection, would add about 60–80% to the net present value of life-cycle costs of electricity (expressed as levelized cost-of-electricity, or COE, and excluding storage site monitoring, liability insurance, etc.). This translates into a potentially large hike in consumers' electric bills.

The COE cost premium for including CO_2 capture in IGCC plants, along with drying, compression, transportation, and storage, is about 40–50%. Although this is a lower cost increase in percentage terms than that for PC plants, IGCC plants initially cost more than PC plants. Thus, the bottom-line cost to consumers for power from IGCC plants with capture may be comparable to that for PC plants with capture.

A utility's choice between these technologies will depend on available coals and their physical-chemical properties, desired plant size, the CO_2 capture process and its degree of integration with other plant processes, plant elevation, the value of plant co-products, and other factors. For example, IGCC with CO_2 capture generally shows an economic advantage in studies based on low-

moisture bituminous coals. For coals with high moisture and low heating value, such as sub-bituminous and lignite coals, a recent EPRI study shows PC with CO_2 capture being competitive.

It should be noted that IGCC plants (like PC plants) do not capture CO_2 without substantial plant modifications, energy losses, and investments in additional process equipment. As noted above, however, the magnitude of these impacts could likely be reduced substantially through aggressive investments in R&D. Historical experience with the development of environmental control technologies for today's power plants suggests that technological advances from "learning-by-doing" will likely lead to significant cost reductions in CO_2 capture technologies as the installed base of plants with CO_2 capture grows. An International Energy Agency study led by Carnegie Mellon University suggested that overall electricity costs from plants with CO_2 capture could come down by 15% relative to the currently predicted costs after about 200 systems were installed. Furthermore, despite the substantial cost increases for adding CO_2 capture to coal-based IGCC and PC power plants, their resulting cost-of-electricity is still usually less than that for natural gas-based plants at current and forecasted natural gas prices.

Engineering analyses by EPRI, DOE, and the Coal Utilization Research Council suggests that costs could come down faster through CO_2 capture process innovations or, in the case of IGCC plants, fundamental plant improvements—provided sufficient RD&D investments are made. EPRI pathways for reduction in capital cost and improvement in efficiency are embodied in two companion RD&D Augmentation Plans developed under the collaborative CoalFleet for Tomorrow program. Efforts toward reducing the cost of IGCC plants with CO_2 capture will focus on adapting more advanced and larger gas turbines for use with hydrogen-rich fuels, lower-cost oxygen supplies, improved gas clean-up, advanced steam cycle conditions, and other activities.

For PC plants, the progression to advanced ultra-supercritical steam conditions will steadily increase plant efficiency and reduce CO_2 production. Improved solvents are expected to greatly reduce post-combustion CO_2 capture process. EPRI is working to accelerate the introduction of novel, alternative CO_2 separation solvents with much lower energy requirements for regeneration. Such solvents—for example, chilled ammonium carbonate—could reduce the loss in power output imposed by the CO_2 capture process from about 30% to about 10%. A small pilot plant (5 MW-thermal) is being designed for installation at a power plant in Wisconsin later this year; success there would warrant a scale-up to a larger pilot or pre-commercial plant. An EPRI timeline (compatible with DOE's timeframe) for the possible commercial introduction of post-combustion CO_2 capture follows.

The introduction of oxy-fuel combustion may allow further reductions in CO_2 capture costs by allowing the flue gas to be compressed directly, without any CO_2 separation process and reducing the size of the supercritical steam generator. Boiler suppliers and major European and Canadian power generators are actively working on pilot-scale testing and scale-up of this technology.

EPRI stresses that no single advanced coal generating technology (or any generating technology) has clear-cut economic advantages across the range of U.S. applications. The best strategy for meeting future electricity needs while addressing climate change concerns and economic impact lies in developing multiple technologies from which power producers (and their regulators) can choose the one best suited to local conditions and preferences.

Assuring timely, cost-effective coal power technology with CO_2 capture entails simultaneous and substantial progress in RD&D efforts on improving capture processes and fundamental plant systems. EPRI sees the need for government and industry to pursue these and other pertinent RD&D efforts aggressively through significant public policy and funding support. Early commercial viability will likely come only through firm commitments to the necessary R&D and demonstrations and through collaborative arrangements that share risks and disseminate results.

Transportation and Geologic Storage

Geologic sequestration of CO_2 has been proven effective by nature, as evidenced by the numerous natural underground CO_2 reservoirs in Colorado, Utah, and other western states. CO_2 is also found in natural gas reservoirs, where it has resided for millions of years. Thus, evidence suggests that depleting or depleted oil and gas reservoirs, and similar "capped" sandstone formations containing saltwater that cannot be made potable, are capable of storing CO_2 for millennia or longer. Geologic sequestration as a strategy for reducing CO_2 emissions is being demonstrated in numerous projects around the world.

Three relatively large projects -- the Sleipner Saline Aquifer CO_2 Storage (SACS) project in the North Sea off of Norway; the Weyburn Project in Saskatchewan, Canada; and the In Salah Project in Algeria -- together sequester about 3 to 4 million metric tons of CO_2 per year, which approaches the output of just one typical 500 megawatt coal-fired power plant. With 17 collective years of operating experience, these projects suggest that CO_2 storage in deep geologic formations can be carried out safely and reliably. Furthermore, CO_2 injection technology and subsurface behavior modeling have been proven in the oil industry, where CO_2 has been injected for 30 years for enhanced oil recovery (EOR) in the Permian Basin fields of west Texas and Oklahoma. Regulatory oversight and community acceptance of injection operations are well established.

In the United States, DOE has an active R&D program (the "Regional Carbon Sequestration Partnerships") that is mapping geologic formations suitable for CO_2 storage and conducting pilot-scale CO_2 injection validation tests across the country. These tests, as well as most commercial applications for long-term storage, will compress CO_2 to a liquid-like "supercritical" state to maximize the amount stored per unit volume underground. As a result, virtually all CO_2 storage applications will be at least a half-mile deep, helping reduce the likelihood of any leakage to the atmosphere, which would defeat the purpose of sequestering the CO_2 in the first place.

DOE's Regional Carbon Sequestration Partnerships represent broad collaborative teaming of public agencies, private companies, and non-profits; they would be an excellent vehicle for conducting larger "near-deployment scale" CO_2 injection tests to prove specific U.S. geologic formations, which EPRI believes to be one of the keys to commercializing CCS for coal-based power plants. Evaluations by these Regional Partnerships and others suggest that enough geologic storage capacity exists in the United States to hold several centuries' worth of CO_2 emissions from coal-based power plants and other stationary sources. However, the distribution of suitable storage formations across the country is not uniform: some areas have ample storage capacity whereas others appear to have little or none.

Thus, CO_2 captured at some power plants would be expected to require pipeline transportation for several hundred miles to suitable injection locations, which may be in other states. While this adds cost, it doesn't represent a technical hurdle because CO_2 pipeline technology has been proven in oil field EOR applications. As CCS is applied commercially, EPRI expects that early projects would take place at coal-based power plants near sequestration sites or an existing CO_2 pipeline. As the number of projects increases, regional CO_2 pipeline networks connecting multiple sources and storage sites would be needed.

There is still much work to be done before CCS can implemented on a scale large enough to significantly reduce CO_2 emissions into the atmosphere. In addition to large-scale demonstrations at U.S. geologic formations, many legal and institutional uncertainties need to be resolved. Uncertainty about long term monitoring requirements, liability, and insurance is an example. State-by-state variation in regulatory approaches is another. Some geologic formations suitable for CO_2 storage underlie multiple states. For private companies considering CCS, these various uncertainties translate into increased risk.

The Promise of CCS

Recent EPRI work has illustrated the necessity and the urgency to develop carbon capture and storage (CCS) technologies as part of the solution to satisfying our energy needs in an environmentally responsible manner. Our "Electricity Technology in a Carbon-Constrained Future" study, which I am pleased to have led, suggests that with aggressive R&D, demonstration, and deployment of advanced electricity technologies, it is technically feasible to slow down and stop the increase in U.S. electric sector CO_2 emissions, and then eventually reduce them over the next 25 years while simultaneously meeting the increased demand for electricity. However, even under the most aggressive technology assumptions, the pace at which we can do so is substantially slower than that envisioned under several of the pending bills currently before this Committee and the Congress as a whole.

To develop this analysis, we compiled data on the currently and likely future cost and performance of various electricity technologies from our Technical Assessment Group work, various public-private technology R&D roadmaps, and expert opinions from academia, industry, and the NGO community in the published literature. From this information, EPRI established specific technology deployment targets in seven areas: efficiency, renewables, nuclear generation, advanced coal generation, carbon capture and storage (CCS), plug-in hybrid electric vehicles (PHEV) and distributed energy resources. We then calculated the net change in CO_2 emissions from the electric sector which would result from achieving each of those technology targets compared to the underlying assumptions in the Base Case of the 2007 Annual Energy Outlook published by the Energy Information Administration (EIA). The results are shown in Figure 1.

The most encouraging aspect of the study is that, as we move toward 2030, CO_2 emissions levels from the U.S. electric sector can begin falling fairly dramatically. However, this will require the long-term commitment of billions of dollars in energy research, development and deployment in every aspect of electric generation, transmission and consumption. It will not be cheap, nor will it be easy to accomplish. While one could argue that CO_2 reductions from some of these targets could

be slightly higher or somewhat lower, the overall picture is clear – we can get to a low-carbon future, but only with substantial consistent investment, smart policy choices and a realistic timeline.

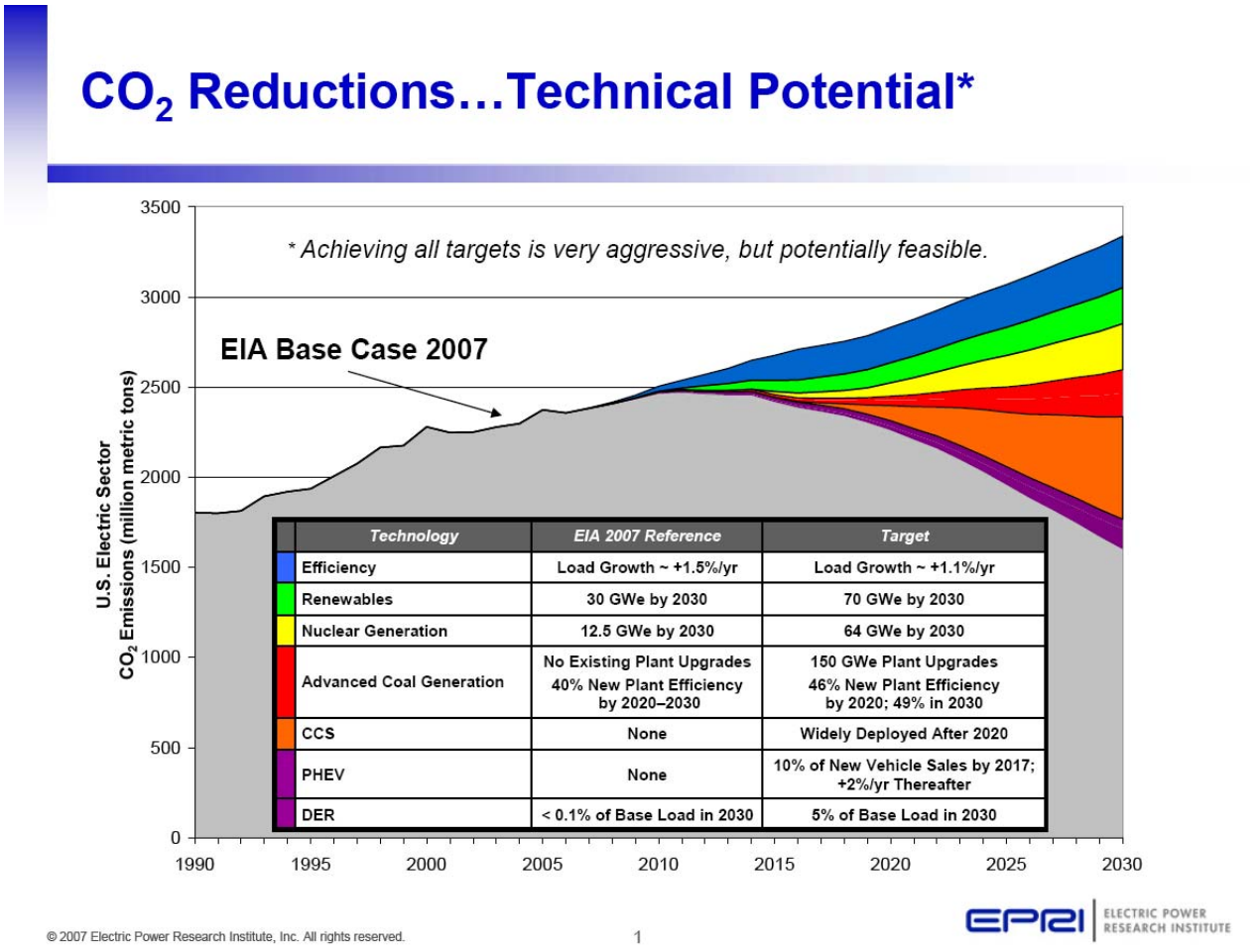

Figure 1: Technical potential for CO_2 emissions reductions from the U.S. electric power sector, assuming significant new technology RD&D investments and the aggressive deployment of the resulting technologies over the next 25 years.

Of the seven options we analyzed, we believe that the greatest reductions in future U.S. electric sector CO_2 emissions are likely to come from applying CCS technologies to nearly all new coal-based power plants coming on-line after 2020. In fact, the longer we delay in developing the capability to deploy CCS technologies that can be deployed at a commercial scale, the longer we will have to wait for the resulting substantial reductions in CO_2 and correspondingly, reductions in the risk of future climate change.

Furthermore, preliminary economic work conducted by EPRI to extend this study shows that absent both CCS and advanced nuclear technologies, achieving these aggressive CO_2 emissions reductions would be extremely costly. We estimate that the costs to the U.S. economy would roughly triple – to nearly $2 trillion over the next 50 years—compared to costs if CCS and advanced nuclear technologies were commercially available. This large difference in economic cost arises from the

lack of low-cost, low-carbon technologies to reduce future CO_2 emissions growth on a large scale: in a world without CCS and nuclear, we rely instead on massive fuel switching to natural gas (with attendant price increases and import dependence) and on price-induced conservation driven by very large carbon prices (which would more than likely trigger any "safety valve" set in legislation). Our preliminary economic work suggests that the timeline for any cost-effective program of CO_2 emissions reductions should be dictated by our expectation of technology development and deployments in the decades ahead.

We are continuing with further technical and economic analysis, and we expect to release our final economic analysis later this year. I would be pleased to update the Committee as our work evolves in the weeks and months ahead.