CCS COST NETWORK

2016 WORKSHOP

23–24 MARCH 2016

CAMBRIDGE, MASSACHUSETTS, USA

ORGANISED UNDER THE AEGIS OF THE:

CCS COST NETWORK
INTERNATIONAL ENERGY AGENCY GREENHOUSE GAS PROGRAMME
CHELTENHAM, UK

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Massachusetts of Institute Technology (MIT),
Silverman Skyline Room, Building E14, Room 648

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9:00 Session 1: Framing the Issue (Chair: Howard Herzog, MIT)
- The Cost of CCS: A Review of Recent Studies (Ed Rubin, CMU)
- Methodology of a Detailed CCS Cost Study (Jeff Hoffmann, NETL)

10:30 Break

11:00 Session 2: Project Costs – Industrial Applications (Chair: John Davison, IEAGHG)
- Quest (Wilfried Maas, Shell)
- Illinois Basin/Decatur (Sallie Greenberg, Univ. of Illinois; Ray McKaskle, Trimeric)

12:30 Lunch

1:30 Session 3: Project Costs – Power Applications (Chair: George Booras, EPRI)
- Boundary Dam (Max Ball and Peter Versteeg, SaskPower, via teleconference)
- FutureGen 2.0 (Ken Humphreys, FutureGen 2.0)
- White Rose (Leigh Hackett, GE Power)

3:45 Break

4:15 Session 4: CCS in the context of changing electricity markets (Chair: Sean McCoy, LLNL)
- The value of flexible, firm capacity on a decarbonized grid (Andy Boston, Energy Research Partnership)
- Initial Respondents: Neil Kern (Duke Energy), Geoffrey Bongers (Gamma Energy Technology)

5:30 Adjourn

7:00 Dinner (sponsored by Shell)**,**
EVOO, 350 Third St, Cambridge, MA

Wednesday, March 23, 2016

8:30 Coffee

9:00 Three parallel breakout sessions:

A. Can we reconcile real project and *N^th^* plant costs? How should we present this information to policy makers?
(Co-chairs: Ed Rubin, CMU; George Booras, EPRI)

B. What are the main challenges of industrial and power CCS cost estimation and financing?
(Co-chairs: Jeff Hoffmann, NETL; Howard Herzog, MIT)

C. What can be done to make CCS more competitive? What are realistic expectations for CCS cost reductions over next 10-20 years? By 2050?
(Co-chairs: Wilfried Maas, Shell; Sean McCoy, LLNL)

12:00 Lunch

1:00 Breakout Session Reports

2:00 General Discussion
- What have we learned?
- Where should we be going?

2:45 Next meeting – Topics, Location, Timing

3:00 Adjourn

PARTICIPANTS

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Paul Fennell	Imperial College
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Ken Humphreys	FutureGen 2.0
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Via Teleconference:	
Max Ball	SaskPower
Peter Versteeg	SaskPower

INTRODUCTION

The fourth meeting of the CCS Cost Workshop (also known as the Expert Group on CCS Costs) was held on March 23-24, 2016 at the Massachusetts Institute of Technology (MIT) in Cambridge, Massachusetts. This function is now designated as the CCS Cost Network under the auspices of the International Energy Agency Greenhouse Gas Programme.

The meeting was organized by a Steering Committee including representatives from: Carnegie Mellon University (Ed Rubin), Electric Power Research Institute (George Booras and Richard Rhudy), IEA Greenhouse Gas Programme (John Davison), Lawrence Livermore National Laboratory (Sean McCoy), Massachusetts Institute of Technology (Howard Herzog), National Energy Technology Laboratory (Lynn Brickett), NaturalGas Fenosa (John Chamberlain) and Shell Global (Wilfried Maas).

The purpose of the workshop is to share and discuss the most currently available information on the cost of carbon capture and storage (CCS) in electric utility and other industrial applications, as well as the current outlook for future CCS costs and deployment. The workshop also seeks to identify key issues or topics related to CCS costs that merit further discussion and study.

As shown on the previous pages, the first day of the workshop was a plenary session addressing four general topics, each addressed by invited presentations, followed by a discussion among workshop participants. The second day pursued three topics in more detail via parallel breakout sessions, followed by a plenary session with group reports and discussion.

This document presents brief summaries of each of the four sessions from Day 1 and the three breakout sessions from Day 2, together with the full set of presentations by invited speakers on Day 1. The proceedings of previous workshops are available at: https://www.globalccsinstitute.com/publications/ccs%2520cost%2520workshop

PRESENTATION SUMMARIES

Session 1: Framing the Issue

The purpose of this session was to frame the issue of CCS cost estimates by providing background on the current status of these estimates. The first talk presented the results of a review of recent cost studies found in the open literature. The second presented the methodology that goes into a detailed CCS cost estimate. A brief description of each talk follows.

The Cost of CCS: A Review of Recent Studies
Presented by Edward S. Rubin, Carnegie Mellon University

This presentation was based on a paper written for a special edition of the International Journal of Greenhouse Gas Control[1] that celebrated the tenth anniversary of the 2005 IPCC Special Report on Carbon Dioxide Capture and Storage (SRCCS).[2] The paper included costs of four capture technologies: Supercritical Pulverized Coal (SCPC) with post-combustion capture, SCPC with oxy-combustion capture, Integrated Coal Gasification Combined Cycle with pre-combustion capture, and Natural Gas Combined Cycle with post-combustion capture. Costs for CO_2 transport and storage were also included. The current reported range of costs were presented and compared to the costs found in the SRCCS after adjusting all costs to a common 2013 cost basis. While current capital costs were generally higher than adjusted SRCCS costs, the cost of electricity comparison showed little change primarily because of lower fuel prices and higher assumed capacity factors in recent studies. The ranges of CO_2 avoidance costs also were similar to adjusted SRCCS values after accounting for some changes in CO_2 transport and storage costs. The talk concluded with a discussion of the outlook for future cost reductions.

Methodology of a Detailed CCS Cost Study
Presented by Jeff Hoffmann, National Energy Technology Laboratory (NETL)

NETL has produced a series of baseline studies on the cost and performance of various state-of-the-art CCS power plants.[3] These studies are very detailed and provide a valuable reference for the CCS community. This presentation reviewed the methodology that goes into generating a baseline technology cost estimate for the "next commercial offering." The seven key steps are:

1. Develop a technology analysis plan and solicit feedback from stakeholders.
2. Create a performance model of each power plant based on NETL process models.
3. Integrate carbon capture technology models based on literature and developer input.
4. Adjust balance of plant as needed per the new technology demands.
5. Estimate the capital, operating and maintenance cost of all plant components using the method described in NETL's QGESS documents and elaborated in the Baseline studies.
6. Apply plant financing and utilization assumptions to develop a cost of electricity.
7. Perform sensitivity analyses and provide R&D guidance.

After describing each step in detail, a case study was presented based on a SCPC plant with an amine-based post-combustion CO_2 capture system.

Session 2: Project Costs – Industrial Applications

John Davison introduced the session on industrial capture project costs. He highlighted that there is increasing interest in industrial CCS but cost estimation can be complex, for example due to integration with existing sites and in some cases multiple CO_2 sources. Also, many industrial plants are located in developing countries, where cost data are not easily available. There are examples however some successful industrial CCS projects and

[1] Rubin, E.S., J.E. Davison, and H.J. Herzog, "The Cost of CO_2 Capture and Storage," *International Journal of Greenhouse Gas Control*, **40**, pp 378-400, September (2015).

[2] IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change [Metz, B., O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.

[3] http://www.netl.doe.gov/research/energy-analysis/baseline-studies

presentations were made on two of them: the Quest and Illinois Basin/Decatur projects.

Wilfried Maas of Shell made a presentation about the Quest CCS project and its costs. The Quest project involves capture of CO_2 at a hydrogen plant at the Scotford upgrader near Edmonton, Canada, which processes hydrocarbons from oil sands fields. The capture plant uses Shell's ADIP-X amine process. The captured CO_2 is compressed in a multistage centrifugal compressor and is transported 65km to a saline reservoir storage site. Modular construction involving 69 modules was used for the capture and compression plant, which minimises site construction.

The plant has operated continuously for 6 months during which time 0.5Mt of CO_2 has been injected, exceeding the target rate. The FOAK facilities cost forecast is CAN$812M, equivalent to 752 $/tpa captured. A substantial part of the costs (CAN$137M) is venture costs which could be reduced substantially in NOAK plants. There is an extensive knowledge sharing part of the programme, as described in the presentation slides. Some key messages were:

- It was emphasised that adequate support is needed to demonstrate CCS and reduce costs from FOAK to NOAK to deliver a competitive and viable technology in a decarbonised world.
- For FOAK plants, capital grants (to support build) and OPEX support (to ensure the plant operates) are required, plus other temporary measure (e.g. CCS certificates) if the uptake rate continues to be disappointing.
- Non-financial measures (enabling regulations, liability agreements etc) are also important.
- The main requirement for NOAK plants is expected to be a robust CO_2 price.

Sallie Greenberg of the University of Illinois and Ray McKaskle of Timeric Corporation presented insights into costs of CCS gained from the Illinois Basin – Decatur Project. This project involves compression, dehydration, transmission and storage of high purity CO_2 from a bio-ethanol plant at a rate of 1,000t/d. The pipeline is realtively short (1.9km) but it had to be above ground and insulated. The Illinois project uses reciprocating compressors. An important issue in the selection of reciprocating compressors, rather than the multi-stage centrifugal compressor used at Quest, was greater familiarity and proximity to a local supplier for support and spares. The project costs were presented in detail, showing a cost for compression, dehydration and transmission of $31/t. The capital cost was amortised over the 3 year injection period, costs for a commercial project would be amortised over much longer period, resulting in lower costs. The capital costs were higher than the initial estimate but operating costs were lower. Some significant conclusions are:

- CCS is a major undertaking involving many types of industry, government and financial professional, as well as many industry trades.
- First mover projects can provide useful benchmarks and lessons learned that will benefit future projects.
- Incorporating CCS into existing operational plants comes with additional case-specific challenges and costs.
- Permitting timelines and general economic conditions may impact costs of future projects in ways that are difficult to predict.

Session 3: Project Costs – Power Applications

This session focused on cost estimates for CCS applications in electric power generation applications. The overall session objectives were to learn about the cost of actual CCS projects, including a summary of lessons learned and opportunities for future cost reductions. The projects included one operating post-combustion capture project, and two large-scale oxy-combustion projects that were in the advanced stages of development at the time the projects were cancelled.

Boundary Dam Carbon Capture Project

The first speakers were Max Ball and Peter Versteeg who joined the workshop via teleconference from SaskPower's office in Regina, Saskatchewan. Peter started with a summary operating statistics for the first-of-a-kind Boundary Dam Carbon Capture Project. In 2015 the net power output averaged 107 MW, with the plant being down for maintenance during the month of September. The daily average amount of CO_2 captured was 1,739 tonnes in 2015, however that increased to 2,726 tonnes in February of 2016.

The major factors impacting the capital cost of the project included site-specific, first-of-a-kind (FOAK), and market factors, as well as specific plant design features. The small size of the plant resulted in dis-economies of scale relative to the larger plant sizes assumed in most conceptual studies. Firing lignite also imposed a cost and performance penalty relative to higher rank coals. At the time the plant was constructed, an abundance of other heavy industrial activity in the Province resulted in higher hourly labor costs and reduced productivity. A heavy emphasis was placed on maximizing power output, as opposed to minimizing capital cost.

FOAK issues included schedule extensions due to conducting three parallel CO_2 capture plant FEED studies, additional regulatory requirements to be met, development of operating and environmental health & safety standards for a power plant integrated with a CO_2 capture system. Contingency provisions and design margins were impacted by an "it must work" philosophy. And finally, some components did not perform to their design expectations. A chart showing the wide fluctuations in the price of steel illustrated one example of how market factors adversely impacted the cost during the time period when Boundary Dam plant was constructed.

Based on the learnings from construction, start-up, and initial operation of the Boundary Dam capture plant, SaskPower expects the cost of the next capture plant to be substantially less. Max also noted that their next plant would be designed to reduce CO_2 emissions to essentially natural gas equivalence to meet the Canadian Federal requirements, as opposed to the nominal 90% CO_2 capture capability at Boundary Dam.

FutureGen 2.0

Ken Humphreys, CEO of the FutureGen Alliance gave an overview of the project and the many milestones that were achieved prior to the project being terminated. Unit 4 of the Meredosia Energy Center in Illinois was to be repowered with oxy-combustion and CCS technology. The net plant output was expected to be 167 MW, while capturing 90+% of the CO_2 (or about 1.1 MMT/yr). A 28 mile pipeline would transport the CO_2 to a deep geologic storage site. Some of the many milestones achieved by the project team included:

- Power purchase agreement signed
- Final permits were issued for air, water, pipeline and CO_2 storage
- Subsurface rights were acquired and CO_2 liability management was addressed
- Mega-FEED was completed (70-90% of final design, at a cost of $90 million)
- Project labor agreements were signed.

Unfortunately the federal co-funding expired and the project had to be terminated. The EPC costs were well known due to the fact they had fixed price contracts. The total as-spent capital cost of the power plant was estimated to be $1,256 million, which excludes the over-the-fence ASU and the $423 million cost for the CO_2 pipeline and storage facilities. Ken presented detailed breakdowns for the Owner, Financing and Start-Up costs. Plant operating costs were estimated to be $128/MWh on a 20-year levelized basis. The major operating cost drivers included oxygen, fuel, purchased power, ash disposal & consumables, and CO_2 transportation & storage. The total 20-year levelized LCOE including capital recovery was estimated to be $179/MWh. However, after the MISO energy/capacity sales credit the net cost to the ratepayers would have only been $138/MWh, representing less than a 2% average rate increase.

Lessons learned during the project included how to deal with a very large number of landowners for the CO_2 pipeline right-of-way, and the CO_2 storage subsurface rights. They also found that the EPC negotiations took much longer, and the balance of plant (BOP) was more complicated than originally planned. Future oxy-combustion plants will have reduced capital costs and improved efficiency due to retrofitting newer, larger USC plants that will benefit from economies of scale. CO_2 transportation and storage costs will also benefit from economies of scale.

White Rose CCS Project

The final speaker in this session was Dr. Leigh Hackett from GE Power, who talked about the White Rose CCS Project. The White Rose project is a new ultra-supercritical oxy-combustion plant with a gross output of 448 MW. The plant was designed to capture 90% of the CO_2, or about 2 million tonnes CO_2 per year. The plant would have been the "anchor" project for National Grid's regional CO_2 transport & offshore storage network, where the infrastructure was sized for 17 million tonnes CO_2 per year to enable future projects. The captured CO_2 was to be stored in a deep saline formation offshore, beneath the North Sea.

The UK Department of Energy & Climate Change (DECC) will publish 41 White Rose project key-knowledge reports later in 2016, including the full-chain FEED summary report, FEED lessons learned, FEED risk report, and full-chain project cost estimate report. The term "full-chain" refers to the oxy power plant, the onshore & offshore pipeline networks, and the CO_2 injection & storage systems. The full-chain project cost estimate was classified as an AACE Level 2 estimate for the majority of items, with 90% of the costs based on vendor quotes.

For the DECC reports, the actual White Rose project cost estimates were adjusted and normalized to take out project specific data and allow comparison to other published data. For example, the site was adjusted to US Gulf Coast basis and site preparation costs were removed. The normalized project cost estimate was broken down into externally supplied utilities, the oxy boiler/ASU/gas processing unit, power generation equipment & BOP, onshore pipeline, offshore pipeline, and storage facilities. Dr. Hackett then showed a chart illustrating the savings achievable for follow-on projects where they can take advantage of the existing CO_2 transportation and storage network.

The White Rose Project resulted in lessons learned in the following four key areas:

- Full-chain commercial structuring and management of cross-chain risks
- Non-EOR CO_2 storage business model
- Oversizing and sharing CO_2 transportation & storage infrastructure
- Potential insurance gaps

Key take-aways from the White Rose project were that no significant technical barriers remain to project implementation, full-chain aspects were adequately defined and developed, and the next step is a large-scale commercial project. Dr. Hackett concluded by saying that the UK Government's decision to cancel the UK CCS Competition has stalled commercialization in the UK and Europe and "dented" confidence in CCS.

Session 4: CCS in the Context of Changing Electricity Markets

In the fourth session of the workshop, speakers took a step back from the topic of CCS cost estimation to look at the context for CCS in future electrical systems, what this implies about the value of CCS-equipped generation, and some alternative metrics that might better convey its value to decision makers. The session began with a presentation from Andy Boston (Energy Research Partnership), which was followed by responses from Neil Kern (Duke Energy) and Geoffrey Bongers (Gamma Energy Technology), and then general discussion.

The presentation from Andy Boston captured the lessons from an ERP analysis of future United Kingdom electricity systems, and highlighted three key messages:

- A zero- or very low-carbon electricity system with variable renewables (e.g., solar, wind) needs dispatchable, low-carbon technologies to provide firm capacity
- Policy makers and system operators need to value services that ensure grid stability to establish a market for new providers
- A holistic approach that accounts for the cost of balancing the system would better recognize the importance of firm low carbon technologies than conventional measures of individual technology cost

To illustrate the final point, Andy presented results from his analysis showing that, even though gas-fired generation equipped with CCS had a relatively high LCOE, addition of capacity could result in a net reduction in system cost. His results also clearly showed, however, that the value of a technology is dependent on the existing generation mix and the grid services it provides, which makes these results difficult to generalize. His provocative conclusion was that this value cannot be captured by LCOE.

In the first invited response to the initial presentation, Neil Kern highlighted that Duke Energy sees a paradigm shift in the way traditional utility planning takes place as a result of the growing trend towards distributed generation. The result is that Duke is placing an increased emphasis on flexibility of centralized generation, and seeking to identify non-traditional markets for central stations. In the second invited response, Geoffery Bongers highlighted the multi-attribute comparisons of generating technology in the recently published Australian Power Generation Technology Study. In that study, technologies were evaluated not only on their LCOE, but also on their capital cost, water requirements, CO_2 emissions, waste products, availability and flexibility.

In the ensuing discussion, participants debated whether LCOE is an inadequate metric or is simply being used inappropriately, such as by comparing baseload plants with intermittent renewable that do not provide comparable services (ignoring the additional integration and backup system costs that would be required).

Others felt the true value of dispatchable generation, like fossil-fuels equipped with CCS, can best be measured by the reductions in system-level cost that results as such capacity is added. Others noted that many decision makers want simpler metrics like LCOE. While most participants agreed on the need for ways to make better technology comparisons, and to more clearly quantify the value of CCS, there was no consensus on how this should be done.

BREAK-OUT SESSION SUMMARIES

Session A. Reconciling Real and Estimated CCS Plant Costs

<u>Questions</u>: Can we reconcile real project and N^th^ plant costs? How should we present this information to policy makers?
<u>Co-chairs</u>: Ed Rubin, CMU; George Booras, EPRI; assisted by Kristen Gerdes, NETL

This session focused on identifying the factors that typically contribute to higher costs of initial full-scale installations of CCS and other newly-commercial technologies (often referred to as FOAK, or "first-of-a-kind") relative to the longer-term (NOAK, or "*N^th^*-of-a-kind") costs commonly reported for mature technologies. Additional thoughts on how this information should be presented to policy makers follow the presentation of the factors identified.

Reconciling Actual vs. *N^th^* Plant Costs

In general, the cost of a specific project is affected by several classes of factors, including:

- Site Specific Factors
- Market Factors
- Design Basis Factors
- Project Execution Factors
- Financing/Contracting/Owner's Costs
- FOAK Factors (Planned & Unplanned)

Each of these categories can be further expanded to identify more specific factors that influence actual costs. Given the focus of this workshop on CCS costs, the factors whose cost is exacerbated by FOAK installations are highlight with an asterisk (*).

- Site-Specific Factors
  - Labor Costs, Productivity, Availability/Skill Requirements*
  - Materials cost
  - Seismic activity
  - Ambient conditions (temperature, etc.)
  - Water availability & quality
  - Fuel availability & quality
  - Proximity to CO_2 storage

- Design Basis Factors
  - Scope and battery limits: base plant, capture, transport, storage
  - Fuel type
  - Plant size
  - Pipeline capacity
  - Storage capacity
  - Cooling system design
  - Ambient conditions
  - CO_2 capture rate
  - CO_2 purity requirements
  - Emission standards
  - Brownfield vs. greenfield vs. retrofit
  - Flexibility of operations *
    - Load following*
    - Start-up/shutdown*
    - Flexible capture*

- Market Factors
  - Commodity prices
  - Labor costs
  - Engineering costs
  - Competition and availability
  - Currency exchange rates
  - Construction equipment and services availability
  - CO_2 value
  - Offtake agreements*

  - Regulations and policies
  - Private sector incentives?
  - Public sector tolerance for R&D

- Project Execution Factors
  - Scheduling*
  - Re-design in mid-construction*
  - Modular vs. stick build (shop vs. field fabrication)

- Financing and Other Factors
  - Financing (risk premiums)*
  - Permitting-related costs and delays*
  - Regulatory and legal issues
  - Plant availability, capacity factor, and dispatch expected (when assessing financial viability)*
  - Owner's costs*
  - Contracting strategy (where is the risk?)*

- FOAK Factors (Planned)
  - Schedule length
  - Contingency/over-design
  - Development of training, simulators, maintenance protocols
  - Extended ramp-up
  - Chemical plant operation in a power plant culture
  - Performance guarantee limitations
- FOAK Factors (Unplanned)
  - Performance shortfalls

Presenting to Policy and Decision Makers

Rather than showing how various factors *add* to FOAK plant costs, our approach should be to show how *removing* various cost escalation factors that are unique to, or exacerbated by, FOAK projects will *reduce* the cost of subsequent projects. This could be illustrated, for example, with a set of bar graphs like those presented by SaskPower, but in the reverse order, starting with the high cost of an FOAK installation, with costs then coming down as various cost adders are removed with increasing experience and know-how.

Session B. Challenges of CCS Cost Estimation and Financing

<u>Question</u>: What are the main challenges of industrial and power CCS cost estimation and financing?

(Co-chairs: Jeff Hoffmann, NETL; Howard Herzog, MIT)

The breakout started by asking each participant to respond to the question for this breakout session. The responses and additional questions generated follow:

- How do you capture the global market competitiveness for internationally traded industrial products made with processes including CCS?
- For projects with government support, how do you capture government subsidy (and risk) as it relates to financing?
- How do you capture costs of real world projects?
- How do you effectively estimate project contingencies?
- How can we best assure cost estimates are used in an appropriate manner?
- Since industrial processes are more heterogeneous than fossil-fueled power generation, how to develop a novel plant for policy modeling and market deployment studies that is widely representative?
- The cycle times for industrial processes are long. The developed world is not building new plants and the typical business model is to replace rather than refurbish and retrofit.
- It is difficult to estimate costs in non-OECD countries.
- Policymakers view CCS and renewables as interchangeable. Cost estimating using LCOE support interchangeability.
- Time factor (permitting, etc.) can drive costs higher.
- Credibility of publically available cost estimates is difficult to assess because of frequent lack of transparency in assumptions. The lack of transparency makes it very difficult to calibrate, compare and validate individual published studies.
- Even studies that seem to be reasonably transparent are complicated, and a primer to methodology and intended purpose would be helpful in addressing how to use the studies.
- Studies are made in the context of "something" (i.e., specific policy scenario, fuel price scenario, anticipated future capacity needs), but the "something" is often changing.

After some discussion in trying to get a handle on these many disparate issues, the group focused on two areas to gain some insights.

Cost vs. economic analysis

A major issue for cost estimation is how to develop costs to compare CCS to other technologies. Right now there is an over-reliance on the levelized cost of electricity (LCOE), which is not always a very good metric for comparison. Therefore, there is a need to go beyond the LCOE.

Cost estimates can generate what we term "hard" numbers, as well as context specific numbers. Examples of hard numbers include capital costs and heat rates. While capital costs can vary over time (e.g., inflation) and geography, these variations can generally be captured through sets of cost indices. Other hard number metrics can include process inputs (e.g., water), process effluents, and availability for dispatch.

Doing an economic analysis, such as one that produces an LCOE, requires context. The plant's capacity factor depends on dispatch, which can only be known in the context of the utility system in which the plant operates. There are many project specific factors that depend on the plant's location, permitting requirements of that location, labor environment, access to utilities, etc. The monetizing of risk and the valuation of ancillary services (e.g., capacity) will also vary widely depending on the context.

For comparing CCS to other technologies, developing methods based on the relatively hard numbers involved in a cost estimate (both cost and performance metrics) are preferred. Much more care must be taken when comparing technologies using context dependent numbers like LCOE.

Industrial processes

A big challenge in trying to determine the costs of Industrial CCS (ICCS) is the significant amount of process heterogeneity, both between industrial sectors and within industrial sectors. The appropriate technological approaches for CO_2 capture may vary greatly across industries. While at first blush it may seem that post-combustion capture with amines will always be an option, this may not be so. Impurities associated with exhaust streams may pose a significant challenge to amines. An example is the exhaust stream from the catalytic cracker at the Mongstad refinery, where the SO_3 in the exhaust gas caused the amine process to fail.

A potential major issue with ICCS is maintaining the integrity of the product. While this may not be an issue for post-combustion capture, other pathways that integrate CCS with the process must make sure that they maintain product integrity. As a result, there is a need for more detailed engineering assessments for capture options for the various industrial sectors and a need for more engagement with the industries.

An additional potential barrier to deployment of CCS technologies in the industrial sector is the approach that many industrial business take regarding existing and new assets. Several of the breakout participants suggested that it is more common for industrial sector businesses to run existing capacity to the end of its useful life "as built" or replace with new state-of-the-art infrastructure rather than modify (i.e., retrofit) existing (and potentially outdated) capacity with new add-on processes. Therefore, it is likely that any back-end CCS technologies would compete against 1) alternative lower carbon intensive industrial processes and 2) location for replacement industrial facilities (either regionally or globally). Ultimately, the selection will be for the scenario that leads to the least-cost production of the industrial product and CCS is expected to play a role only if a low-carbon "benefit" can be monetized.

Session C. Making CCS More Competitive

***<u>Questions</u>*: What can be done to make CCS more competitive? What are realistic expectations for CCS cost reductions over next 10-20 years? By 2050?**

(Co-chairs: Wilfried Maas, Shell; Sean McCoy, LLNL)

Round-table comments

- We know how much stuff costs; getting it financed and built is the hard part.
- Real questions about accuracy of public literature costs for capture (e.g., the US government can't even agree on a number) and we're not sure how to add-up the costs. But, from a practical industry standpoint, this isn't a big deal because they're in the right ballpark.
- Variability of costs is, however, a surprise; also, surprised at the cost of compression and injection.
- Worried about risks associated with storage. Looking at risk separately is convenient, but the whole chain matters; what about injection and monitoring costs? What are the costs when we have surprises (e.g., OK seismicity from w/w re-injection, BC seismicity from fracking)?
- The big issue facing CCS is getting the whole thing together; system costs are important.

- Commercial structures are key in getting CCS built but…
- …the commercial case for CCS isn't there, at least in global aggregate near- term; creates an issue of timing, since we to need to work technology development today.
- In a really tough place on the technology development curve: need to de-risk technologies and get policy support. Need some data points.
- Current technologies not socially acceptable, and learning-by-doing won't cut it
- Nonetheless, there is a strong societal case for CCS; but massive market failure means there is no business case for individual developers. Need policy to address the failures.
- Perhaps early projects were too ambitious: they tried to solve both capture and storage simultaneously.
- What is the right scale for CCS: little with high unit cost (and lower risk) or high with low unit cost (and higher risk). Does this argue for small-scale?
- Busy talking about cost, rather than revenue maximization. How can CCS have value to those who are doing it?
- Need to move towards system costs and away from LCOE; however, as bad as LCOE might be, but we don't have a good alternative.
- Don't be too negative on recent progress: much in the technology space has improved over the last decade.

What do we do?

- Marginal value of additional paper cost studies is very low.
- UK CCS cost reduction taskforce found that 25% reduction from technology improvement, 50% economies of scale in T&S, 25% from reduction in finance costs; all that is needed are a handful of plants in the UK to reach their cost reduction targets…
- Comments suggest main issue in risk is not capture related: it's the transport and storage that is the problem and where focus needs to be**.** History is filled with programs focused on capture/plant side justified by technology development, few (noteworthy) successes; has this been the wrong focus?
- Need government action to handle T&S problem or no real way to manage risk – fundamental difference between CCS and other technologies in power generation.
- Much of the past CCS focus was based on the presumption that there was going to be a rush to building coal that was going to happen in US and Europe.
- So, what is the state support package for development of a CCS industry? One answer is regulatory frameworks to push deployment: accelerate learning-by-doing and technology innovation. Create a market pull.
- Opposite commercial logic between US and Europe: US wants cheap CO_2 and low-cost sources fill the need; Europe want emissions reductions from expensive sources, who are begging oil and gas to play. For example, in the US physical CO_2 has value, but in Europe it is paper contracts that have the (uncertain) value.
- In the absence of EOR/CCUS, Europe has no revenue in the transport and storage chain.
- US thinking is that the storage side is well understood (from a technology perspective) based on R&D and current operations. Agreement that this is a trans-Atlantic difference, where Europe is more concerned with the transport and storage risk.
- With LCFS, issue is that there are cheaper ways to meet the requirements today via biofuels. Need to hit blend wall before CCS comes into play. However, LCFS in one jurisdiction that can drive CCS somewhere else – opposite to discussion with economic leakage.
- What about carbon takeback obligations? Thinking about this in Europe.
- Energy systems analysis (e.g. IPCC) says CCS is critical and lowest-cost. But analysis is complicated, and question is how to sell it to the public and to policy makers.
- China and SE Asia are wild cards acknowledged by all – huge potential, but capability gaps.
- Another wild card is advanced nuclear technologies; technology and resource availability enables targets to be set (e.g., REGGI, CPP).
- Other drivers (e.g., reductions in water use) may put us in a position to deliver cheaper capture as a co-benefit – like molten carbonate fuel cells.

<u>Question to the group</u>: Will CCS be at 100 USD/MWh and commercially available by 2030?

- 5 No – timing of needs and business case, scale-up cannot be rapid enough; supply chain collapsed and will need to be rebuilt; competition from other technologies; government not willing to acknowledge that prices need to go up (or justify increased prices) to make this all work
- 12 Yes – prices will rise, and CCS will be marginal technology; Asia will do it, initial regulations will spur a discussion of what happens next that will lead to CCS; potential for breakthrough technology; CCS with gas will be where cost happens; cost might be there, but not widely demonstrated; new way of pricing energy in future enables CCS; costs for capture on gas are already there.
- 1 Abstention – don't know enough

Report to Plenary Session:

1. We asked the question: will CCS be commercially available for power generation in 2030 at a cost of $100-120/MWh? 12 responded "yes"; 5 said "no"; and 1 abstention. Disagreement on whether it will actually be deployed, though.
2. Difference between EU and US perspectives on where cost reductions are going to come from: capture technology, versus T&S infrastructure (particularly in regards to risk).
3. Cost reduction requires learning-by-doing which implies markets; need markets!
4. Market for CCS was going to be new coal, but now, not much new coal—at least in developed countries—so now there is a gap before we get to gas.
5. Tension between small-scale with high unit cost but low project cost, hence, lower risk; or large-scale with low unit cost but high project cost, hence higher risk.
6. Marginal benefit of additional cost studies is low.
7. Need to come up with effective means (messaging) to convey importance of CCS in a system context.
8. In the meanwhile, industrial CCS—oil and gas sector—will continue be a big driver. Wild card: what China decides to do is a huge deal.

PRESENTATIONS

Introduction

CCS Cost Network Workshop Overview
Howard J. Herzog

Session 1: Framing the Issue

The Cost of CCS: A Review of Recent Studies
Edward S. Rubin

Methodology of a Detailed CCS Cost Study
Jeff Hoffman

Session 2: Project Costs – Industrial Applications

Quest Project and Its Costs
Wilfried Maas

Insights into Cost of CCS Gained from the Illinois Basin-Decatur Project
Sallie E. Greenberg, Ray McKaskle

Session 3: Project Costs – Power Applications

Project Costs Power Applications
George Booras

Factors Impacting Capital Costs at SaskPower's Boundary Dam Integrated CCS Project
Max Ball and Peter Versteeg

FutureGen 2.0
Ken Humphries

White Rose—Oxy-fuel CCS Project
Leigh A. Hackett

Session 4: CCS in the Context of Changing Electricity Markets

The Value of Flexible, Firm Capacity on a Decarbonised Grid
Andy Boston

Duke Energy
Neil Kern

CCS Cost Network Workshop Overview

Howard Herzog
MIT
March 22-23, 2016

Steering Committee

- Howard Herzog (MIT)
- Ed Rubin (Carnegie Mellon)
- Richard Rhudy/George Booras (EPRI)
- Sean McCoy (LLNL, formerly IEA)
- John Davison (IEAGHG)
- John Chamberlain (Gas Natural Fenosa)
- Wilfried Maas (Shell)
- Lynn Brickett/ Jeff Hoffmann (USDOE/NETL)

Acknowledgements

- IEAGHG – Umbrella for the Cost Network
- MIT Energy Initiative – Meeting Planning
- Sponsors
  - MIT Carbon Sequestration Initiative – Meeting Space, Lunches, and Breaks
    - » API, Chevron, Duke Energy, Entergy, EPRI, ExxonMobil, Shell, Southern Company, Suncor
  - Shell – Workshop Dinner
- Thanks to all the presenters

Howard Herzog / MIT Energy Initiative

History

- Initial Discussions
  - GHGT-10, Amsterdam, September 2010
- Workshops
  - IEA Paris, 22 – 23 March 22-23, 2011
  - EPRI, Palo Alto, CA, April 25-26, 2012
  - IEA , Paris, November 6-7, 2013
- Now sanctioned as a Network under the IEAGHG

Howard Herzog / MIT Energy Initiative

Agenda

- Framing the Issue
  - The Cost of CCS: A Review of Recent Studies (Ed Rubin, CMU)
  - Methodology of a Detailed CCS Cost Study (Jeff Hoffmann, NETL)
- Project Costs
  - Quest (Wilfried Maas, Shell)
  - Illinois Basin/Decatur (Sallie Greenberg, University of Illinois; Ray McKaskle, Trimeric)
  - Boundary Dam (Max Ball and Peter Versteeg, SaskPower via teleconference)
  - FutureGen 2.0 (Ken Humphreys, FutureGen 2.0)
  - White Rose (Leigh Hackett, GE Power)
- CCS in the context of changing electricity markets
  - The value of flexible, firm capacity on a decarbonized grid (Andy Boston, Energy Research Partnership)
  - Initial Respondents: Neil Kern (Duke Energy), Geoffrey Bongers (Gamma Energy Technology)

Breakouts

A. Can we reconcile real project and nth plant costs? How should we present this information to policy makers? (9)
   - Ed Rubin, CMU; George Booras, EPRI

B. What are the main challenges of industrial and power CCS cost estimation and financing? (11.5)
   - Jeff Hoffmann, NETL; Howard Herzog, MIT

C. What can be done to make CCS more competitive? What are realistic expectations for CCS cost reductions over next 10-20 years? By 2050? (18.5)
   - Wilfried Maas, Shell; Sean McCoy, LLNL

Other items

- Internet – MIT GUEST (No password)
- General discussion on Wednesday afternoon on future activities of the Costing Network
- A proceedings of the meeting will be produced as a public document
- Dinner tonight
  - Reception starts at 7 pm
  - Sit down for dinner at 7:30
  - Wine and beer included

Contact Information

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Howard Herzog / MIT Energy Initiative

The Cost of CCS: A Review of Recent Studies

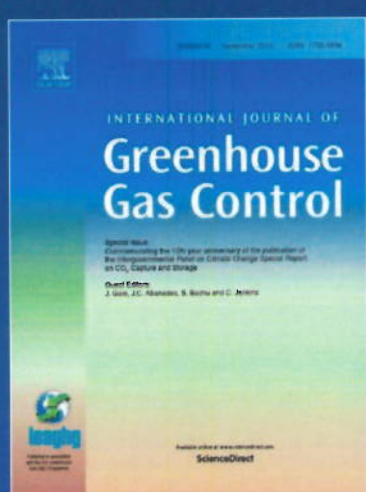
Edward S. Rubin
Department of Engineering and Public Policy
Department of Mechanical Engineering
Carnegie Mellon University
Pittsburgh, Pennsylvania

Presentation to the

CCS Cost Network Workshop
Cambridge, Massachusetts

March 22, 2016

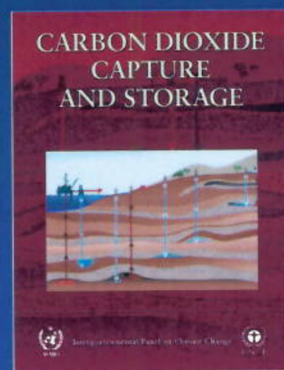
Special Issue of *IJGGC*: 10 Years After the SRCCS



E.S. Rubin, Carnegie Mellon

The IPCC Special Report on CCS

- Commissioned by IPCC in 2003; completed in December 2005
- First comprehensive look at CCS as a climate change mitigation option (9 chapters; ~100 authors)
- Included a detailed review of cost estimates for CO_2 capture, transport and storage options



SRCCS Costs for CO_2 Capture

(excludes transport and storage; all costs in constant 2002 USD)

Performance and Cost Measures	New NGCC Plant		New SCPC Plant		New IGCC Plant	
	Range	Rep. Value	Range	Rep. Value	Range	Rep. Value
Emission rate w/o capture (kg CO_2/MWh)	344 - 379	367	736 - 811	762	682 - 846	773
Emission rate with capture (kg CO_2/MWh)	40 - 66	52	92 - 145	112	65 - 152	108
Percent CO_2 reduction per kWh (%)	83 - 88	86	81 - 88	85	81 - 91	86
Plant efficiency w/ capture, LHV basis (%)	47 - 50	48	30 - 35	33	31 - 40	35
Capture energy reqm't. (% more input/MWh)	11 - 22	16	24 - 40	31	14 - 25	19
Total capital reqm't. w/o capture (US$/kW)	515 - 724	568	1161 - 1486	1286	1169 - 1565	1326
Total capital reqm't. w/ capture (US$/kW)	909 - 1261	998	1894 - 2578	2096	1414 - 2270	1825
Percent increase in capital cost w/ capture	64 - 100	76	44 - 74	63	19 - 66	37
COE w/o capture (US$/MWh)	31 - 50	37	43 - 52	46	41 - 61	47
COE w/ capture only (US$/MWh)	43 - 72	54	62 - 86	73	54 - 79	62
Increase in COE w/ capture (US$/MWh)	12 - 24	17	18 - 34	27	9 - 22	16
Percent increase in COE w/ capture (%)	37 - 69	46	42 - 66	57	20 - 55	33
Cost of CO_2 captured (US$/t CO_2)	33 - 57	44	23 - 35	29	11 - 32	20
Cost of CO_2 avoided (US$/t CO_2)	37 - 74	53	29 - 51	41	13 - 37	23

Source: IPCC, 2005

SRCCS Costs for New Power Plants Using Current Technology

Power Plant System	Natural Gas Combined Cycle Plant	Supercritical Pulverized Coal Plant	Integrated Gasification Combined Cycle Plant
Levelized Cost of Electricity (constant 2002 US$/kWh)			
Reference Plant Cost (without capture)	*0.03–0.05*	*0.04–0.05*	*0.04–0.06*
Added cost of CCS with geological storage	**0.01–0.03**	**0.02–0.05**	**0.01–0.03**
Added cost of CCS with EOR storage	**0.01–0.02**	**0.01–0.03**	**0.00–0.01**
Cost of CO_2 Avoided (constant 2002 US$/tonne)			
Same plant with CCS (geological storage)	40–90	30–70	15–55
Same plant with CCS (EOR storage)	20–70	10–45	(-5)–30

Source: IPCC, 2005

E.S. Rubin, Carnegie Mellon

2015 Cost Update

(Rubin, Davison and Herzog, *IJGGC*)

- Compiled data from recent CCS cost studies in the U.S. and Europe for new power plants with:
  - Post-combustion CO_2 capture (SCPC and NGCC)
  - Pre-combustion CO_2 capture (IGCC)
  - Oxy-combustion CO_2 capture (SCPC)
- Adjusted all costs to constant 2013 US dollars
- Adjusted SRCCS costs from 2002 to 2013 USD using:
  - Capital /O&M cost escalation factors +
  - Fuel cost escalation factors (for COE)
- Compared recent cost estimates to SRCCS values

E.S. Rubin, Carnegie Mellon

Recent Cost Studies Reviewed

- IEAGHG, 2014
- NETL, 2014
- EPRI, 2013
- NETL, 2013a, b
- ES&T, 2012
- IEAGHG, 2012
- Léandri et al., 2011
- GCCSI, 2011
- NETL, 2011a, b, c
- ZEP, 2011a, b, c
- NETL, 2010

16 studies, each with multiple cases

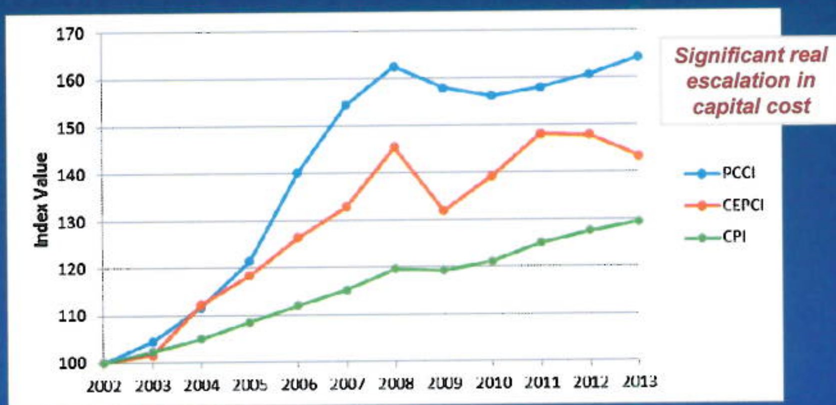
E.S. Rubin, Carnegie Mellon

Differences in Key Assumptions

- Basic power plant design parameters such as net plant efficiency, CO_2 emission rates, and CO_2 capture rates have not changed appreciably since the SRCCS
- Some assumptions affecting CCS costs have changed:
  - Average power plant sizes without CCS are about 10% to 25% larger than in SRCCS studies
  - Assumed capacity factors are higher (by 10 %-pts for PC, plants, 2 %-pts for IGCC plants, and 8 %-pts for NGCC)
  - Fixed charge factor are lower (by about 10% for NGCC, 20% for IGCC and 30% for SCPC)
  - Parameter values often differ for plants with and w/o CCS
  - Increased focus on potential for utilization via CO_2–EOR

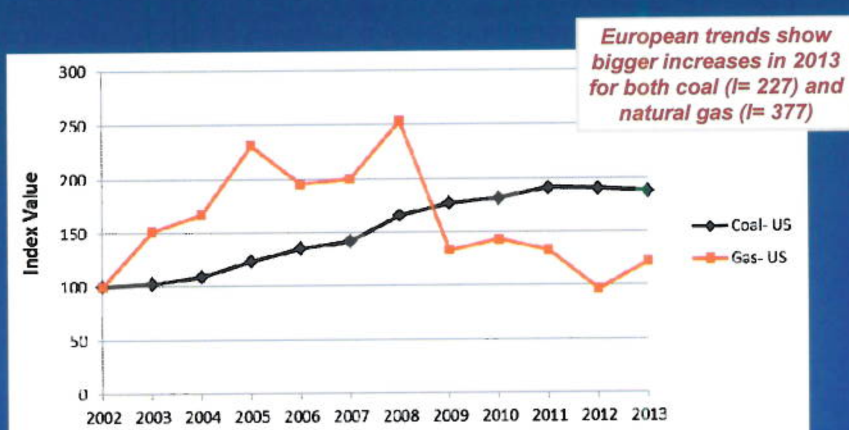
E.S. Rubin, Carnegie Mellon

Capital Cost Trends



CPI= U.S. Consumer Price Index (BLS, 2014)
CEPCI= Chemical Engineering Plant Cost Index (CE, 2014)
PCCI= Power Capital Costs Index (excluding nuclear) (IHS-CERA, 2014)

Fuel Cost Trends for U.S. Power Plants



(Data Source: EIA, 2014)

Capture System Costs Then and Now:

New SCPC Plants w/ Post-Combustion Capture

(Bituminous coals; 90% capture; all costs in constant 2013 US dollars)

Performance and Cost Measures for New SCPC Plants w/ Bituminous Coal	Current Values			Adjusted SRCCS Values			Change in Rep. Value (Current –Adjusted SRCCS)	
	Range		*Rep. Value*	Range		*Rep. Value*		
	Low	High		Low	High		Δ Value	Δ%
Plant Performance Measures								
SCPC reference plant net power output (MW)	550	1030	742	462	758	587	**155**	***26***
Emission rate w/o capture (kg CO_2/MWh)	0.746	0.840	0.788	0.736	0.811	0.762	**0.03**	***3***
Emission rate with capture (kg CO_2/MWh)	0.092	0.120	0.104	0.092	0.145	0.112	**-0.01**	*-7*
Percent CO_2 reduction per MWh (%)	86	88	87	81	88	85	**2**	
Total CO_2 captured or stored (Mt/yr)	3.8	5.6	4.6	1.8	4.2	2.9	**1.7**	*57*
Plant efficiency w/o capture, HHV basis (%)	39.0	44.4	41.4	39.3	43.0	41.6	-0.2	*-1*
Plant efficiency w/ capture, HHV basis (%)	27.2	36.5	31.6	28.9	34.0	31.8	-0.2	*-1*
Capture energy reqm't. (% more input/MWh)	21	44	32	24	40	31	1.1	*3*
Plant Cost Measures								
Total capital reqm't. w/o capture (USD/kW)	2313	2990	2618	1862	2441	2040	**578**	***28***
Total capital reqm't. with capture (USD/kW)	4091	5252	4580	2788	4236	3333	**1247**	***37***
Percent increase in capital cost w/ capture (%)	58	91	75	44	73	63	**13**	
LCOE w/o capture (USD/MWh)	61	79	70	64	87	76	**-6**	***-8***
LCOE with capture only (USD/MWh)	94	130	113	93	144	119	**-6**	***-5***
Increase in LCOE, capture only (USD/MWh)	30	51	43	28	57	43	**0**	***-1***
Percent increase in LCOE w/ capture only (%)	46	69	62	42	65	56	**5**	
Cost of CO_2 captured (USD/t CO_2)	36	53	46	33	58	48	**-3**	***-6***
Cost of CO_2 avoided, excl. T&S (USD/t CO_2)	45	70	63	44	86	67	**-4**	***-6***

(Source: Rubin, Davison, Herzog, 2015)

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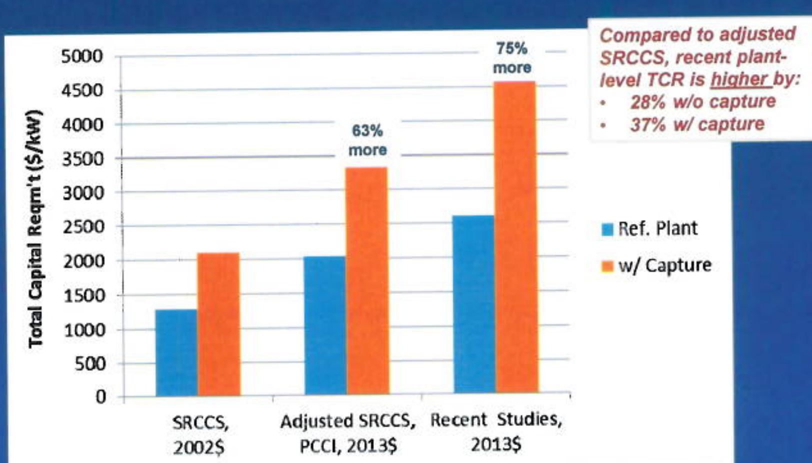
Capital Cost of SCPC Plants

(representative values of cost ranges across studies)



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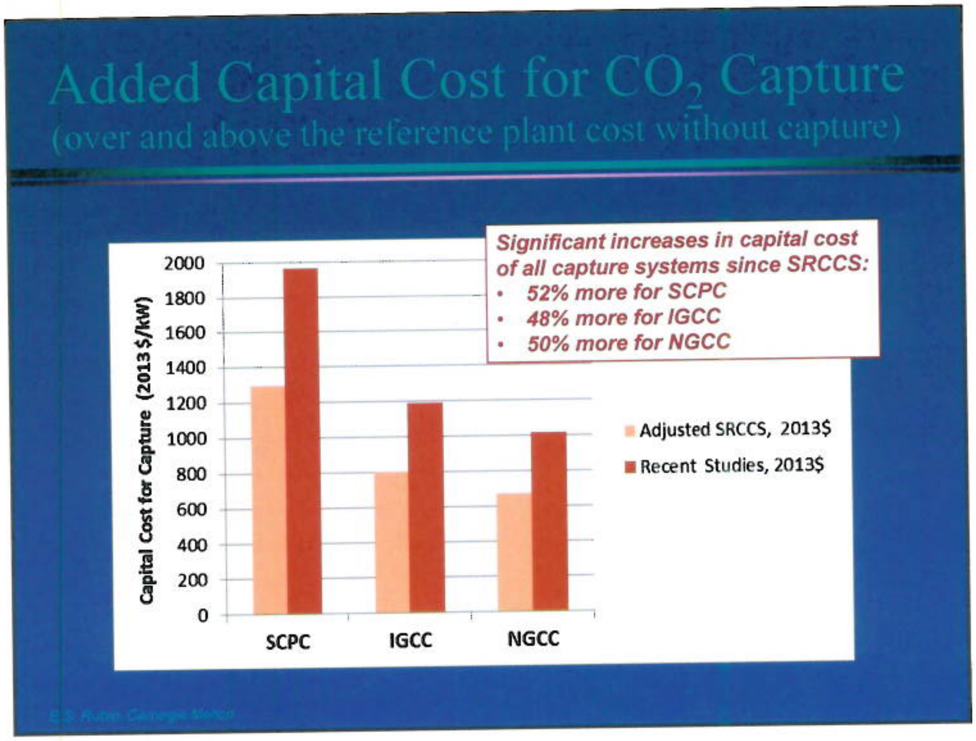
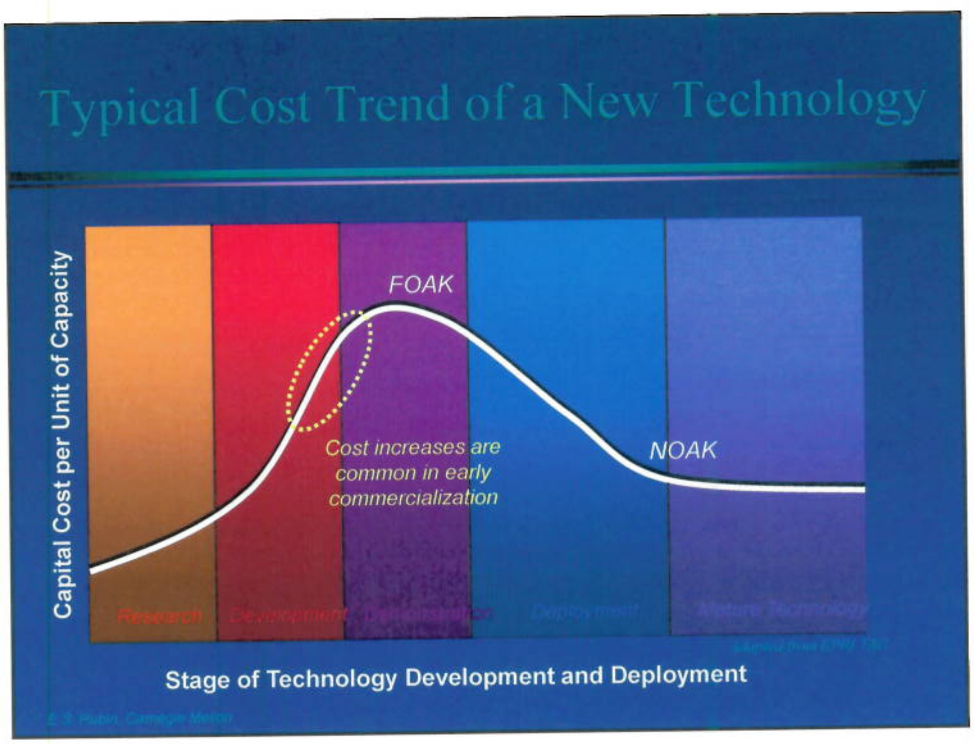
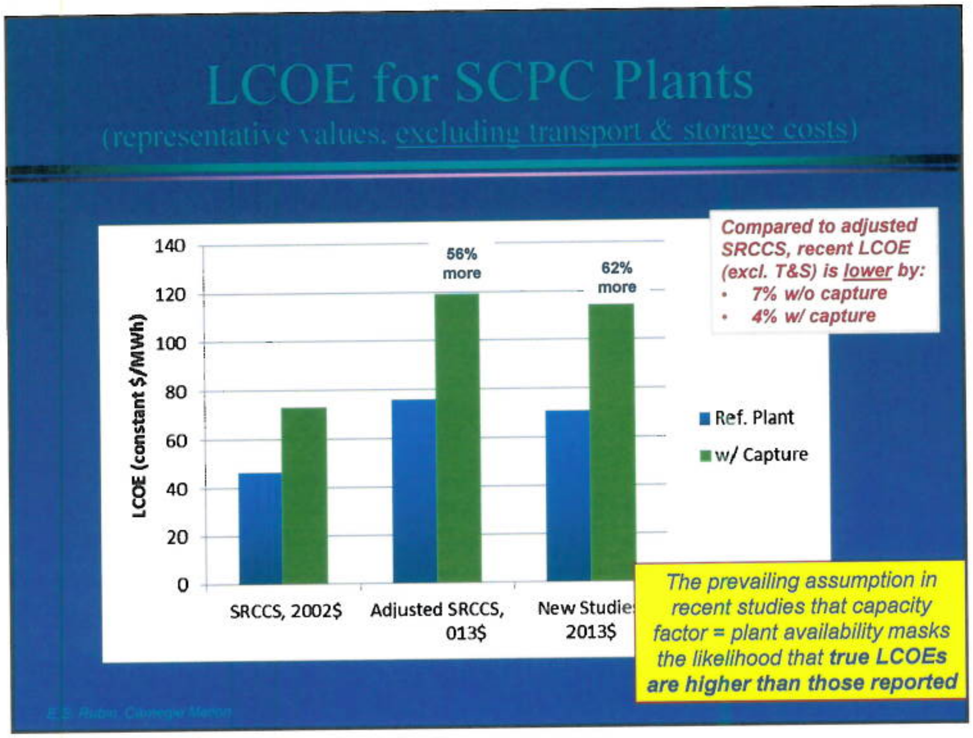
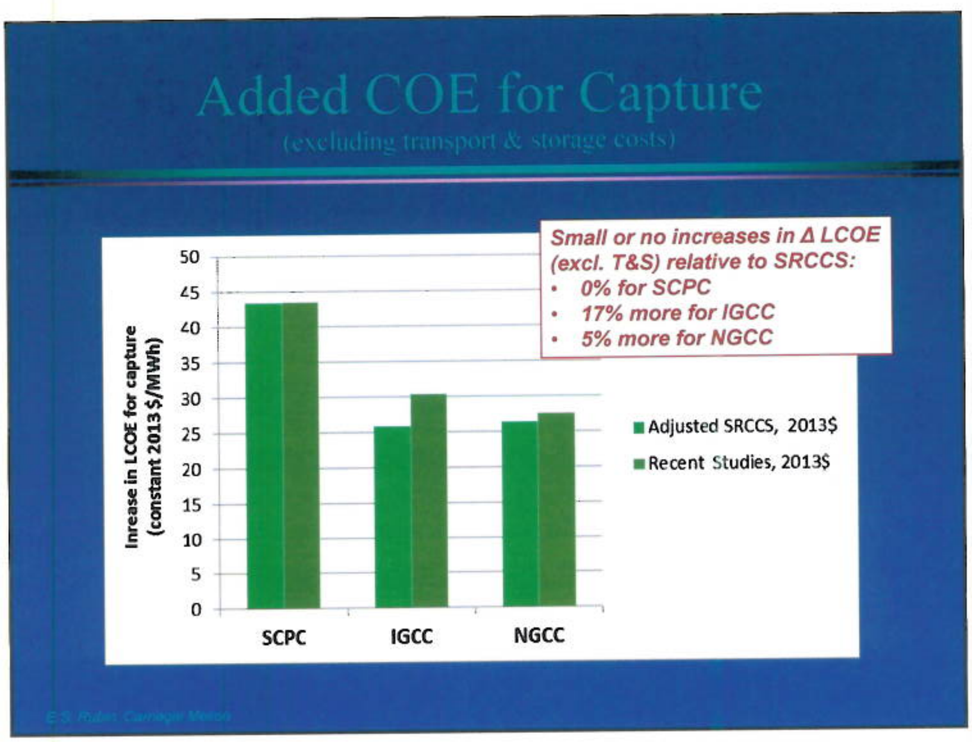

Added Capital Cost for CO_2 Capture
(over and above the reference plant cost without capture)
Significant increases in capital cost of all capture systems since SRCCS:
• 52% more for SCPC
• 48% more for IGCC
• 50% more for NGCC
Capital Cost for Capture (2013 $/kW)
2000
1800
1600
1400
1200
1000
800
600
400
200
0
SCPC
IGCC
NGCC
Adjusted SRCCS, 2013$
Recent Studies, 2013$


Typical Cost Trend of a New Technology
Capital Cost per Unit of Capacity
FOAK
Cost increases are common in early commercialization
NOAK
Research
Development
Stage of Technology Development and Deployment



LCOE for SCPC Plants
(representative values, excluding transport & storage costs)
Compared to adjusted SRCCS, recent LCOE (excl. T&S) is lower by:
• 7% w/o capture
• 4% w/ capture
LCOE (constant $/MWh)
140
120
100
80
60
40
20
0
56% more
62% more
SRCCS, 2002$
Adjusted SRCCS, 013$
New Studie 2013$
Ref. Plant
w/ Capture
The prevailing assumption in recent studies that capacity factor = plant availability masks the likelihood that true LCOEs are higher than those reported
E.S. Rubin, Carnegie Mellon



Added COE for Capture
(excluding transport & storage costs)
Small or no increases in Δ LCOE (excl. T&S) relative to SRCCS:
• 0% for SCPC
• 17% more for IGCC
• 5% more for NGCC
Inrease in LCOE for capture (constant 2013 $/MWh)
50
45
40
35
30
25
20
15
10
5
0
SCPC
IGCC
NGCC
Adjusted SRCCS, 2013$
Recent Studies, 2013$
E.S. Rubin, Carnegie Mellon

Transport and Storage Costs

(relative to adjusted SRCCS)

Onshore pipelines (250 km):

- Recent U.S. costs are similar to SRCCS: European costs are significantly higher (esp. for 3 $MtCO_2$/yr)

Geological storage (onshore):

- Low end of cost range is substantially higher: high end of cost range is slightly higher
- EOR credits are substantially higher (~\$15–40/tCO_2)

E.S. Rubin, Carnegie Mellon

Total Plant LCOE (2013 \$/MWh)

for CO_2 capture, transport and geological storage

Case	NGCC with post-combustion capture	SCPC with post-combustion capture	IGCC with pre-combustion capture
Without EOR			
SRCCS (adjusted)	56 – 110	94 - 163	92 – 150
Recent Studies	63 – 122	95 - 150	112 – 148
With EOR credits			
SRCCS (adjusted)	48 – 100	76 – 139	77 – 128
Recent Studies	48 – 112	61 – 121	83 – 123

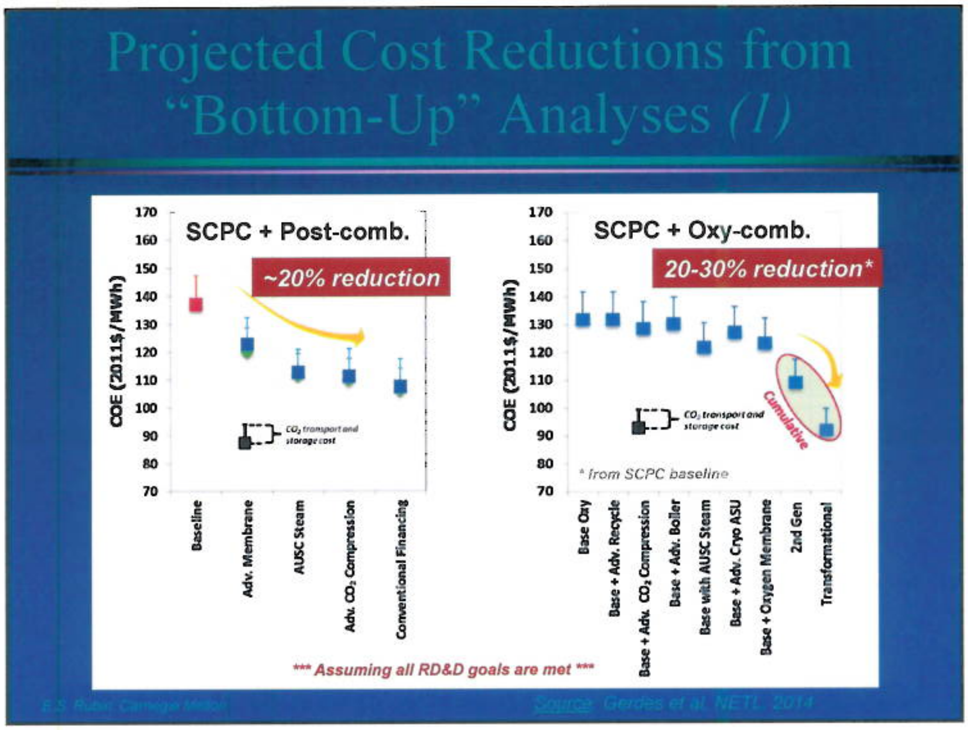
Mitigation costs (\$/tCO_2 avoided) also are roughly similar to adjusted SRCCS costs

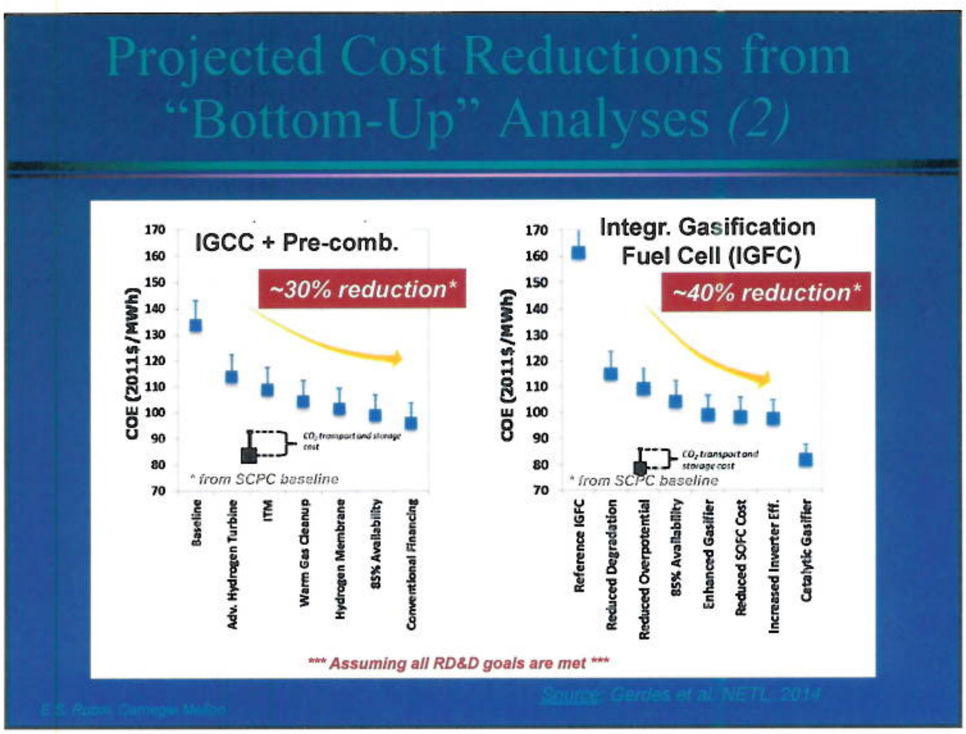
E.S. Rubin, Carnegie Mellon

Other Conclusions from the Study

- For new SCPC plants oxy-combustion capture shows potential to be cost competitive with post-combustion capture
- Based on current cost estimates for the four CCS pathways analyzed, there are no obvious winners or losers

The outlook for future cost reductions


Projected Cost Reductions from "Bottom-Up" Analyses (1)
SCPC + Post-comb.
~20% reduction
COE (2011$/MWh)
170
160
150
140
130
120
110
100
90
80
70
CO_2 transport and storage cost
Baseline
Adv. Membrane
AUSC Steam
Adv. CO_2 Compression
Conventional Financing
SCPC + Oxy-comb.
20-30% reduction*
Cumulative
* from SCPC baseline
Base Oxy
Base + Adv. Recycle
Base + Adv. CO_2 Compression
Base + Adv. Boiler
Base with AUSC Steam
Base + Adv. Cryo ASU
Base + Oxygen Membrane
2nd Gen
Transformational
*** Assuming all RD&D goals are met ***
E.S. Rubin, Carnegie Mellon
Source: Gerdes et al. NETL, 2014


Projected Cost Reductions from "Bottom-Up" Analyses (2)
IGCC + Pre-comb.
~30% reduction*
COE (2011$/MWh)
170
160
150
140
130
120
110
100
90
80
70
CO_2 transport and storage cost
* from SCPC baseline
Baseline
Adv. Hydrogen Turbine
ITM
Warm Gas Cleanup
Hydrogen Membrane
85% Availability
Conventional Financing
Integr. Gasification Fuel Cell (IGFC)
~40% reduction*
Reference IGFC
Reduced Degradation
Reduced Overpotential
85% Availability
Enhanced Gasifier
Reduced SOFC Cost
Increased Inverter Eff.
Catalytic Gasifier
*** Assuming all RD&D goals are met ***
E.S. Rubin, Carnegie Mellon
Source: Gerdes et al. NETL, 2014

Projected Cost Reductions from a "Top-Down" Analysis

(Learning curves plus energy-economic modeling)

(Percent cost reduction, 2001–2050)*

Power Plant System	Reduction in Cost of Electricity ($/MWh)	Reduction in Mitigation Cost ($/t$CO_2$ avoided)
SCPC –CCS	14% – 44%	19% – 62%
NGCC –CCS	12% – 40%	13% – 60%
IGCC –CCS	22% – 52%	19% – 58%

* Range based on low and high global carbon price scenarios.

Source: van der Broek et al, 2010

What does it take to achieve these cost reductions ?

- Sustained R&D
- Markets for CCS technology
  (created by policy carrots and sticks)
- Learning from experience

Thank You

rubin@cmu.edu

Driving Innovation ♦ Delivering Results

Methodology of a Detailed CCS Cost Study

CCS Cost Network Workshop

March 22, 2016

Jeff Hoffmann, Travis Shultz

NETL

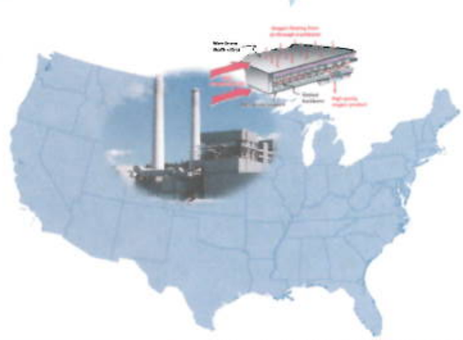
Marc Turner, Vincent Chou, Norma Keuhn,
Arun Iyengar, Mark Woods - BAH

Presentation Overview

- **Systems Engineering & Analysis (SEA)**
  - Emphasis on Energy Process Analysis Team (EPAT)
- **Overview of Techno-economic Analysis (TEA) Approach**
- **NETL Cost and Performance Baseline for Fossil Energy Plants**

Systems Engineering and Analysis
Overview

- **Multi-disciplined engineering and economic analytical capabilities supporting evaluation of:**
  - Process components and systems of components for conventional and advanced energy technologies
  - Engineering tools and expertise to evaluate research and development progress, assist in identifying and overcoming barriers.
  - Expert capabilities to assess "full-chain" aspects of energy systems
    - Fossil and non-fossil competing assets
    - Energy markets, challenges to new technology adoption
    - Life-cycle environmental aspects at single plant, regional and broad deployment scale
- **Analytical efforts and associated work products inform:**
  - NETL R&D Efforts
  - DOE-FE Program focus and planning
  - Domestic and global energy and environmental decision making

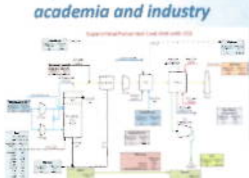


Commercialization

Systems Engineering and Analysis
Work Products and Tools of Note

NETL Cost and Performance Baseline for Fossil Energy Plants

- *Detailed, transparent account of plant information*
- *Key resource for government, academia and industry*



NETL CO_2 Saline Storage Cost Model

NETL Carbon Capture Retrofits Database (CCRD)

NETL CO_2 Capture, Transport, Utilization and Storage - National Energy Modeling System (CTUS-NEMS)

- *Adopted by EIA; used in AEO 2014*
- *Facilitates and encourages EPSA interactions*

Techno-Economic Analysis (TEA)
Transparent, Consistent Approach

What does a TEA consist of?

1. **Reference case:** state-of-the-art (SOA) power plant should be similar to those found in the Baseline studies
2. **Advanced case(s):** Novel technology replaces SOA technology in reference plant

What to expect from a TEA?

- Defined approach allows for credible comparison within and across similar studies
- The common metric derived and compared is Cost of Electricity (COE) and net power plant efficiency (HHV & LHV)
- Comparison between cases can provide:
  - Representation and quantification of the benefits of the novel technology.
  - Identification and potential quantification of performance and cost goals for the novel technology.
- Sensitivity studies change a parameter in the novel technology and the impact it has on the technology and balance of plant.
  - Identification of critical performance and cost parameters, inform R&D prioritization decisions.

Techno-Economic Analysis (TEA)
Methodology

1. **Develop technology analysis plan (TAP) and solicit feedback from stakeholders.**
2. **Create a performance model based on models from the NETL Baselines.[1-3]**
3. **Integrated novel technology based on literature and developer input replacing (where applicable) state-of-the-art technologies**
4. **Adjusted balance of plant as needed per the new technology demands (steam demands, coal feed rates, etc.)**
5. **Cost the balance of plant and novel technology using the methodology described in NETL's QGESS documents and used in the Baseline studies.[4]**
6. **Apply economic assumptions to develop a cost of electricity (COE).[4]**
7. **Perform sensitivity analyses and provide R&D guidance**

1. *QGESS: Performing a Techno-economic Analysis for Power Generation Plants, DOE/NETL-2015/1726*
2. *QGESS: Process Modeling Design Parameters, DOE/NETL-341/042514*
3. *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, DOE/NETL-2010/1397, Revised July 2015*
4. *QGESS: Cost Estimation Methodology for NETL Assessments of Power Plant Performance, DOE/NETL-2011/1455*

Technology Analysis Plan
Purpose and Structure

What is a TAP?

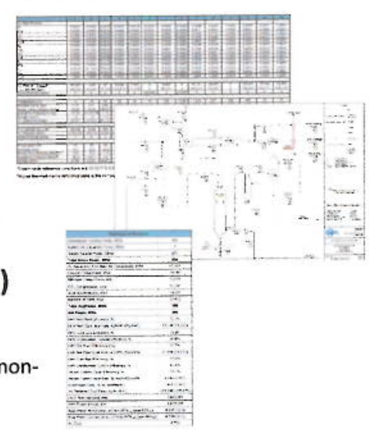
- A TAP discusses the approach and methodology required to conduct the TEA
- Presented to stakeholders prior to starting the TEA
  - Document assumptions
  - Ensure valuable product
- Updated as the TEA is performed - changes should be noted in a final document

TAP
- Objective: Aspirational Goals OR Current State of Technology
- Reference Plant (Baseline studies)
  - Plant Wide Assumptions
  - Reason for reference case and planned deviations
- Novel Technology Cases
  - High Level BFD's
  - Case Evaluation Table
- Novel Technology Design Basis
  - Performance Assumptions and Basis
  - Cost Assumptions and Basis
  - Proposed Sensitivity Analysis
  - Technology Integration Plan
- Expected Deliverable and Time Frame

Case	Baseline (Reference)	Case Study		
		Case 1	Case 2	Case 2A
Technology Combinations				
CO_2 Removal	Selexol	Novel Capture Tech.		
Enabling Tech.	Std. Tech.		Enabled Tech.	
CO_2 Purification	No			Yes

SEA Energy Process Analysis Team
Process Performance Modeling

Robust modeling utilizing thermo-physical process software tools (e.g., ASPEN Plus, ChemCAD, Thermoflow, etc.)



INPUTS (Detailed Design Basis)

- Ambient conditions
- Technology performance
- Feed and product specifications
- Environmental requirements

OUTPUTS (Major Process Unit Granularity)

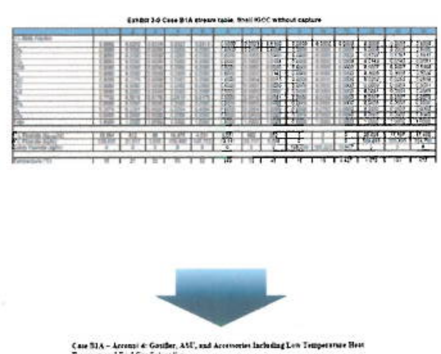
- Heat and Material Balances
- Process Performance Characteristics (i.e., efficiency, consumables, product and non-product effluent streams)
- Facility Emissions

Process Performance Modeling
Foundation Aspects

- **Key Specifications**
  - Site conditions
  - Feedstock and consumable specifications
  - Steam cycle conditions
  - Boiler/gasifier performance
  - Syngas processing
  - Integration with balance-of-plant
- **Performance Basis**
  - Technology supplier/vendor data
  - Laboratory (i.e., R&D) data
  - Theoretical (i.e., thermophysical models, equations of state, etc.)
  - Target (i.e., meeting program goals and objectives)

Process Performance Modeling
Primary Outputs

- **Material Streams**
  - Composition
  - Flows
  - Physical properties
  - Enthalpies
- **Unit Operations**
  - Material flow rates
  - Energy inputs and outputs
- **Major Equipment**
  - Count
  - Key specifications
  - Critical Design Conditions (flow, pressure, temperature, etc.)



Process Economic Modeling
Equipment Costing Basis

- **Vendor Quotes**
  - Significant process elements
    - ASU
    - Gasifier
    - Turbine generators
    - AGR (sulfur, CO_2) processes
- **Third-party EPC Databases**
  - Conditioning of vendor quotes
  - Balance-of-plant including:
    - Foundations
    - Piping
    - Instrumentation
    - Ancillary equipment
- **Program Targets**

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Process Economic Modeling
Process Capital Costing Elements

process equipment
supporting facilities
direct and indirect labor
} BEC

BEC
EPC contractor services
} EPCC

EPCC
process contingency
project contingency
} TPC

TPC
pre-production costs
inventory capital
financing costs
other owner's costs
} TOC

TOC
escalation during capital expenditure period
interest on debt during capital expenditure period
} TASC / TCR

Bare Erected Cost
Engineering, Procurement and Construction Cost
Total Plant Cost
Total Overnight Cost
Total As-Spent Cost

BEC, EPCC, TPC, TOC and TCR are all "overnight" costs expressed in base-year dollars.

TASC is expressed in mixed-year current dollars, spread over the capital expenditure period.

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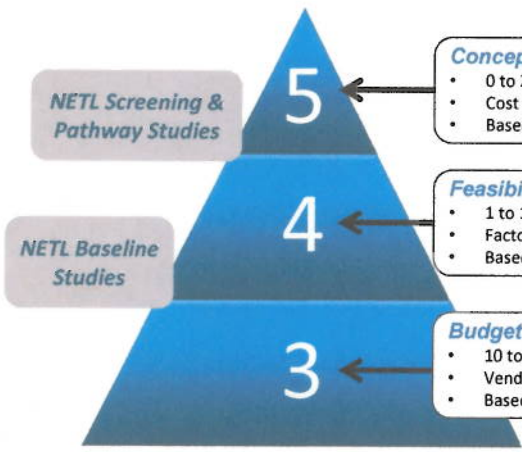
Process Economic Modeling
Estimate Classification



Concept Screening (-20% / +100% Accuracy)
- 0 to 2% project definition
- Cost factored on system / major subsystem capacity
- Based on technical analogs / engineering judgment

Feasibility Study (-15% / +50% Accuracy)
- 1 to 15% project definition
- Factored equipment costs
- Based on preliminary mass and energy balances

Budget Estimate (-10% / +30% Accuracy)
- 10 to 40% project definition
- Vendor quotes, third-party EPC estimates
- Based on detailed process and economic modeling

Estimate classifications are consistent with AACE International Recommended Practice No. 18R-97 *Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries*, revised November 29, 2011

Process Economic Modeling
Cost of Electricity (COE)

- **COE the most frequent metric of interest, used to represent the required selling price of electricity generated**
  - Net of other product (for co-production) and byproduct revenues
  - Usually annualized over assumed economic life of facility (~30-35 years)
  - Long-term interest/investor return rolled into a capital charge factor (CCF)
  - Includes fixed and variable operating costs, with variable operating costs calculated based on average annual capacity factor

Fixed Operating Costs	Variable Operating Costs
Annual Operating Labor Cost	Maintenance Material Cost
Maintenance Labor Cost	Fuel
Administrative & Support Labor	Other Consumables
Property Taxes and Insurance	Waste Disposal
	Emission Costs

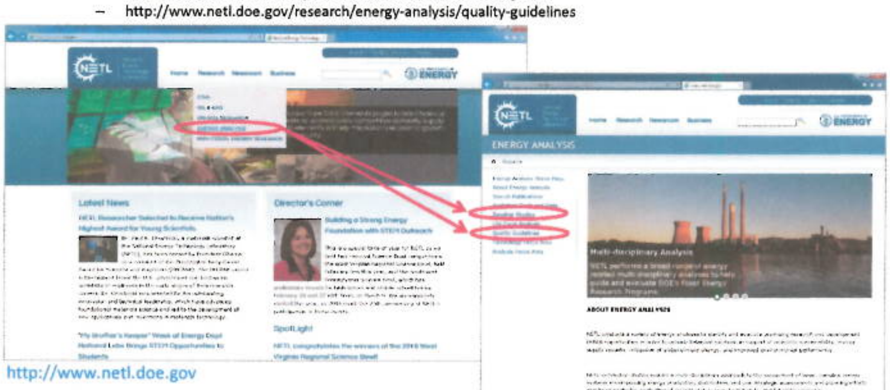
- **Transparent approach allowing for sensitivity analyses of key performance and economic inputs**

Quality Guidelines for Energy System Studies
Comprehensive Documentation

Title	Description
Detailed Coal Specifications	Provides detailed specifications for seven coals commonly used with detailed production information
Specifications for Selected Feedstocks	Provides recommended specifications for natural gas and coal that are commonly found in NETL energy system studies.
Process Modeling Design Parameters	Documents the process modeling assumptions most commonly used in systems analysis studies and the basis for those assumptions. The large number of assumptions required for a systems analysis makes it impractical to document the entire set in each report. This document serves as a comprehensive reference for these assumptions as well as their justification.
CO_2 Impurity Design Parameters	Summarizes the impurity limits for CO_2 stream components for use in carbon steel pipelines, enhanced oil recovery (EOR), saline formation sequestration, and co-sequestration of CO_2 and H_2S in saline formations.
Capital Cost Scaling Methodology	Provides a standard basis for scaling capital costs, with specific emphasis on scaling exponents. This document contains a listing of frequently used pieces of equipment and their corresponding scaling exponent for various plant types, along with their ranges of applicability.
Cost Estimation Methodology	Summarizes the cost estimation methodology employed by NETL in its assessment of power plant performance.
Carbon Dioxide Transport and Storage Costs	Addresses the cost of CO_2 transport and storage (T&S) in a deep saline formation with respect to plant location and region-specific aquifers.
Fuel Prices for Selected Feedstocks	Provides an estimate of the market price delivered to specific end-use areas of four coals that are commonly used as feedstocks in the energy system studies sponsored by NETL. Also includes the estimated market price for natural gas delivered to three different regions.

NETL TEA Reporting
Publically Available Documents

- **Cost and Performance Baseline for Fossil Energy Plants**
  - A Series of documents that provide Baseline's for comparison
  - http://www.netl.doe.gov/research/energy-analysis/baseline-studies
- **Quality Guidelines for Energy System Studies (QGESS) Documents**
  - A series of documents that provide the details to performing TEAs
  - http://www.netl.doe.gov/research/energy-analysis/quality-guidelines



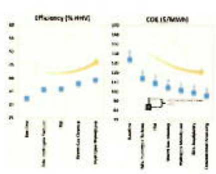
http://www.netl.doe.gov

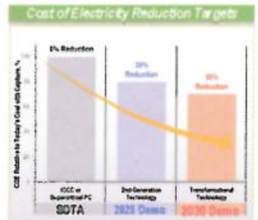
http://www.netl.doe.gov/research/energy-analysis

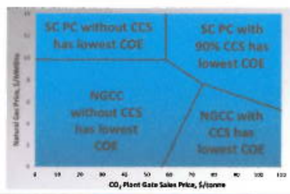
TEA Use
Evaluate Progress and Inform Decisions

NETL Current and Future Technology Pathway Studies

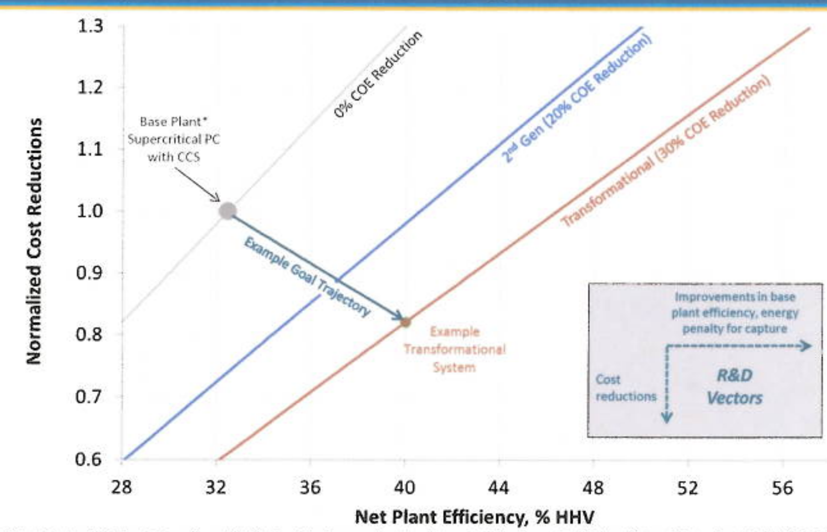
IGCC, IGFC, Oxy-combustion, Post-Combustion Capture







TEA Use Example:
R&D Trajectories to Meet Program Goals



**State-of-the-Art Coal with Carbon Capture from NETL "Cost and Performance Baseline, Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity" (July 2015). Normalized cost reductions represents reduction in annualized capital and non-fuel O&M cost (on a $/MMBtu fuel input basis) compared to the Base Plant.*

Case Study

NETL Baseline Study Cases B12A and B12B
Bituminous-fired Supercritical Pulverized Coal (SCPC) Plant

NETL Baseline Studies
Overarching Objective

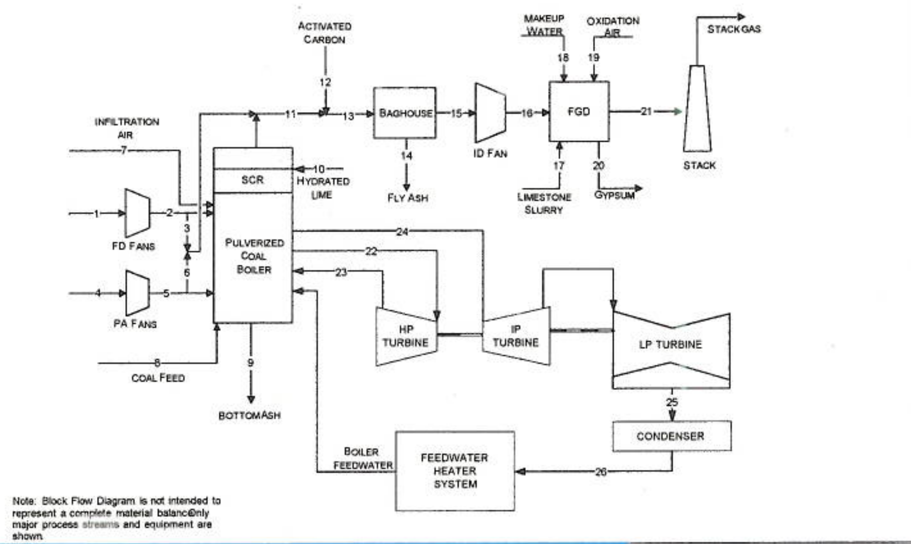
- **Determine cost and performance estimates of near-term commercial offerings for power plants, both with and without current technology for CO_2 capture**
  - Consistent design requirements
  - Up-to-date performance and capital cost estimates
  - Technologies built and deployed in the near-term
- **Provides baseline cost and performance**
  - Compare existing technologies
  - Guide R&D for advancing technologies within the DOE Office of Fossil Energy (FE), NETL Programs

Reports referenced:

U.S. DOE, NETL, July 2015, *Cost and Performance Baseline for Fossil Energy Plants, Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3*, Pittsburgh, PA : Department of Energy, 2015. Report DOE/NETL-2015/1723

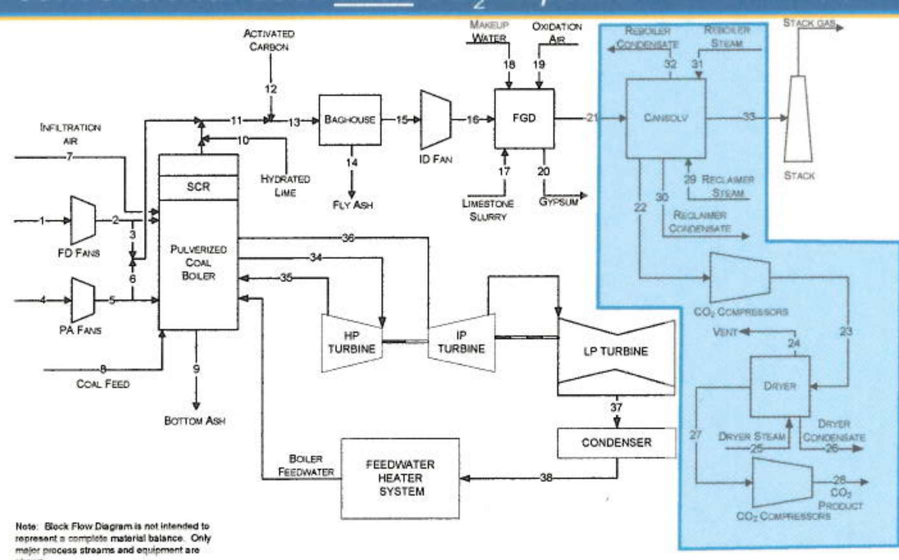
U.S. DOE, NETL, June 2015, *Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 capture rate in coal-fired power plants*, Pittsburgh, PA : Department of Energy, 2015. Report DOE/NETL-2015/1720

Supercritical Pulverized Coal Power Plant
*"Conventional" Coal **without** CO_2 Capture*



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Supercritical Pulverized Coal Power Plant
*Conventional Coal **with** CO_2 Capture*



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Supercritical Pulverized Coal Power Plant
Environmental Controls

NETL

Criteria Pollutants – February 2013 New Source Performance Standards

- **PM**
  - Fabric filter
- **NO_X**
  - Low NO_x burners with over fire air
  - Selective Catalytic Removal (SCR) (83 – 85 % reduction)
- **SO_2**
  - Wet limestone Flue Gas Desulfurization (FGD)
  - 98% removal

Hazardous Air Pollutants - March 2013 Utility Mercury and Air Toxic Standards

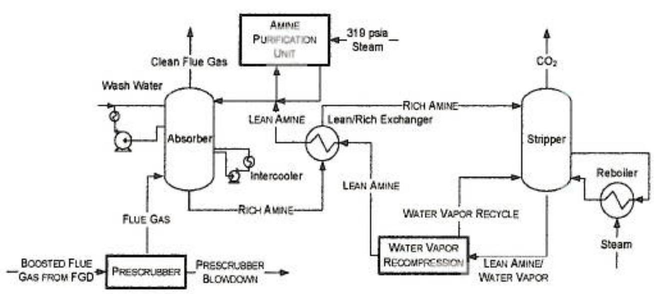
- **Mercury, Hydrochloric Acid**
  - Activated carbon injection (ACI) removed in fabric filter with direct sorbent injection (DSI) for SO_3 removal to improve effectiveness of activated carbon injection
  - Co-benefit capture (removal of 90% for bituminous coal) of SCR, fabric filter and wet FGD combination

Polishing systems required in CO_2 capture cases (to meet performance requirements of the capture system) drive model plant emissions even lower

Supercritical Pulverized Coal Power Plant
CO_2 Capture and Compression

NETL

- **Pre-treatment**
  - Lowers SO_x to ~ 1 ppmv from ~40 ppmv out of FGD
- **Cansolv CO_2 Capture Process**



Supercritical Pulverized Coal Power Plant
CO_2 Capture and Compression (continued)

- **Cansolv CO_2 Capture Process Details**
  - 90 % CO_2 capture
  - Steam extraction from crossover pipe between IP and LP sections of steam turbine
  - Product CO_2 ~ 30 psia
- **CO_2 Compression System**
  - CO_2 compressed to 2,200 psig
  - 8 stages (2.23 to 1.48 stage pressure ratios)
  - Intercooling in each stage
    - Water knockout in first 3 stages
  - TEG dehydration unit between stages 4 and 5
    - 300 ppmw H_2O in CO_2 product

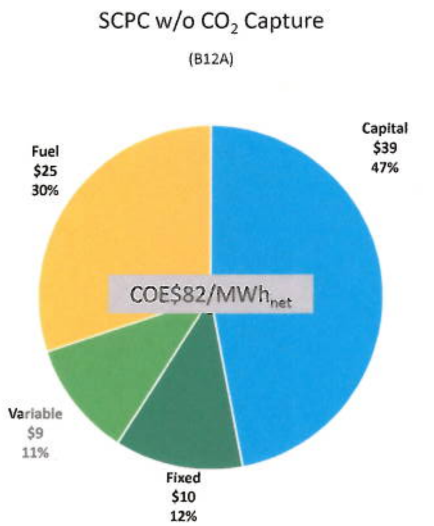
Supercritical Pulverized Coal Power Plant
Summary Performance and Cost Results

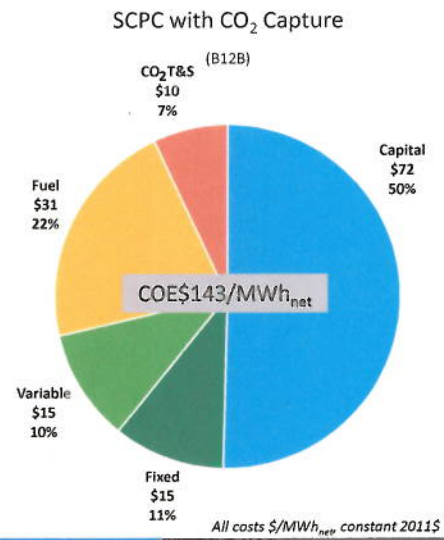
Case	B12A	B12B
CO_2 Capture	0%	90%
Gross Power (MW)	580	642
Auxiliary Power Summary		
Balance of Plant	27	35
Flue Gas Cleanup	3	4
CO_2 Capture	-	16
CO_2 Compression	-	36
Total Aux. Power (MW)	**30**	**91**
Net Power (MW)	550	550
Heat Rate (Btu/kWh)	8,400	10,500
Efficiency (HHV)	41	33
Energy Penalty[1]	-	8

Case	B12A	B12B
CO_2 Capture	0%	90%
Total Plant Cost, in Millions 2011\$[2]		
Base Plant	947	1,111
Gas Cleanup (SOx/NOx/Hg/HCl/PM)	167	197
CO_2 Capture	-	484
CO_2 Compression	-	98
Total	**1,114**	**1,890**
Cost of Electricity, \$/MWh (2011\$)		
Capital	39	72
Fixed	10	15
Variable	9	15
Fuel	25	31
CO_2 T&S	-	10
Total[3]	**82**	**143**
CO_2 Captured (w/o T&S), \$/tonne (2011\$)		
Compared to SCPC or NGCC	-	58

[1] CO_2 Capture Energy Penalty = Percent points decrease in net power plant efficiency due to CO_2 Capture
[2] Total Plant Capital Cost (Includes contingencies and engineering fees but not owner's costs
[3] 85% Capacity Factor

Supercritical Pulverized Coal Power Plant
Cost of Electricity Components





All costs $/MWh$_{net}$, constant 2011$

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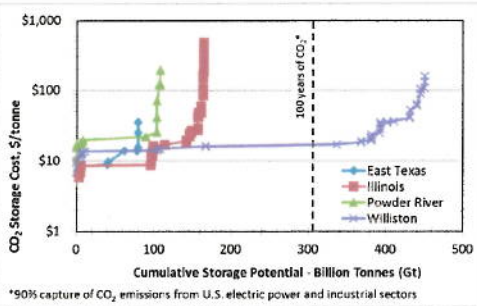
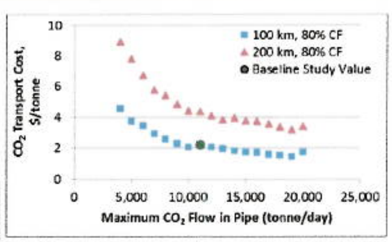
Supercritical Pulverized Coal Power Plant
CO_2 Transport and Storage Costs

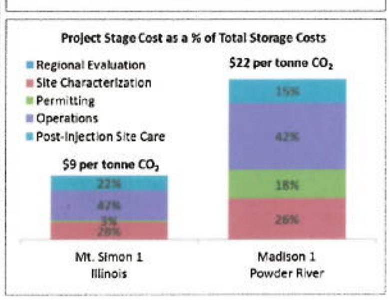
- **CO_2 Transportation and Storage (T&S) Costs[1]**
  - CO_2 transported 100 km, stored in the Illinois Basin due to Midwest plant location and monitored for 80 years
  - CO_2 T&S costs added on to the cost of electricity (COE)



*90% capture of CO_2 emissions from U.S. electric power and industrial sectors

[1]National Energy Technology Laboratory. *Quality Guidelines for Energy System Studies: Carbon Dioxide Transport and Storage Costs in NETL Studies.* Pittsburgh, PA : Department of Energy, 2014. DOE/NETL-2014/1653





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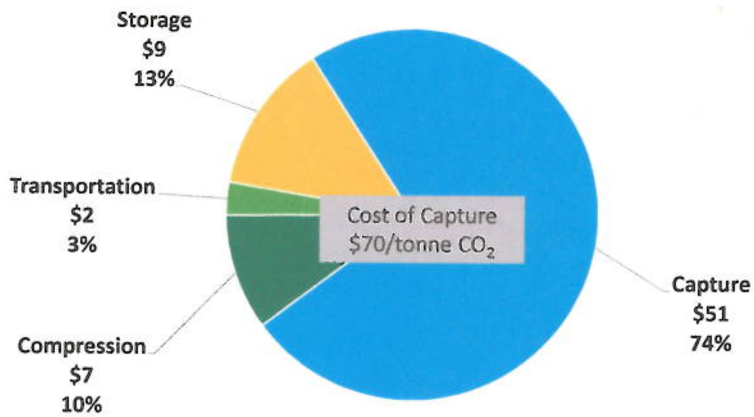
Supercritical Pulverized Coal Power Plant
Cost of Capture Components



All costs in \$/tonne CO_2, constant 2011\$

NETL Cost and Performance Studies
Important Considerations

Capital Costs:

- Point estimates, consistent with AACE Class 4 (accuracy -15% to + 30%)[1]
- Intended to represent a "near-term" commercial offering (not Nth plant)
- Designed using a specific design basis

Costs of mature technologies and designs, PC and NGCC Plants without CO_2 Capture

- Estimates reflect nth-of-a-kind
- Costs have comparatively low uncertainty resulting from serial deployments (i.e., "learning ***from previous*** efforts") as well as continuing R&D

Costs of emerging technologies and designs, PC and NGCC Plants with CO_2 Capture, all IGCC Plants

- Use same fundamental cost estimating methodology as mature plant designs
- Does not fully account for the unique cost premiums associated with true first-of-a-kind (FOAK) projects ("learning ***while executing current*** effort") initial, complex integrations of emerging technologies in a commercial application
- FOAK efforts are near certain to incur costs greater than those reflected in these reports

[1]**National Energy Technology Laboratory.** *QGESS: Cost Estimation Methodology for NETL Assessments of Power Plant Performance.* Pittsburgh, Pa : U.S. Department of Energy, April 2011. DOE/NETL-2011/145

NETL Cost and Performance Studies
Important Considerations (continued)

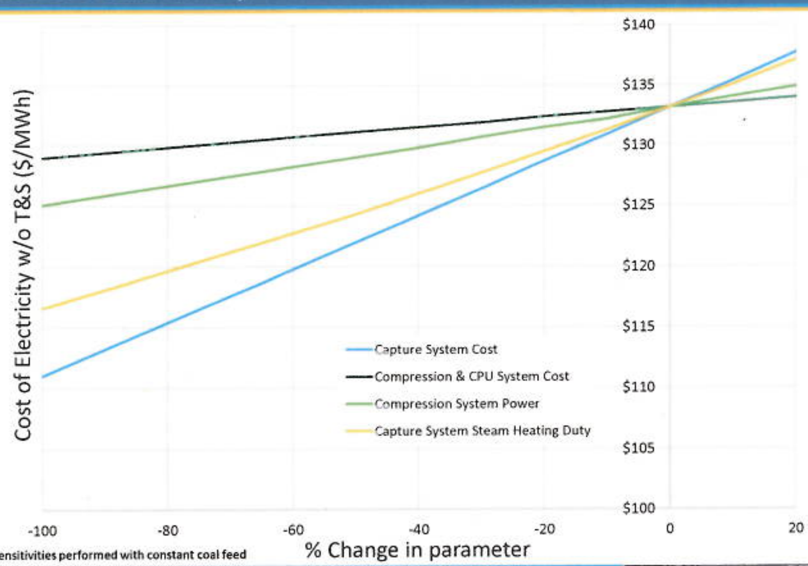
Other Factors:

- **Actual reported project costs for all of the plant types are also expected to deviate from the cost estimates in this report due to project- and site-specific considerations**
  - i.e. contracting strategy, local labor costs, seismic conditions, water quality, etc.
  - Current work is evaluating the impact of site-specific factors

Future Cost Trends:

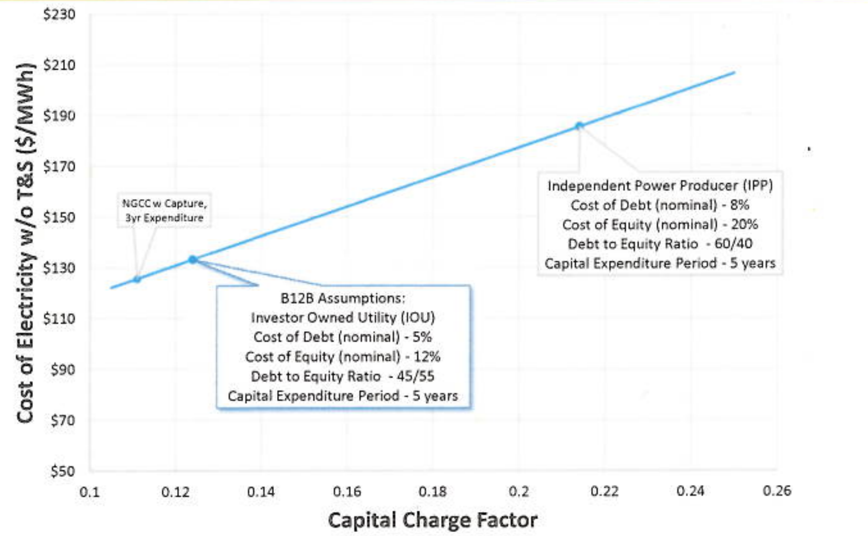
- **Continuing research, development, and demonstration (RD&D) is expected to result in designs that are more advanced than those assessed by this report, leading to costs that are lower than those estimated**

NETL Cost and Performance Studies
COE Sensitivity to CCS Parameters



Sensitivities performed with constant coal feed

NETL Cost and Performance Studies
COE Sensitivity to Financial Assumptions



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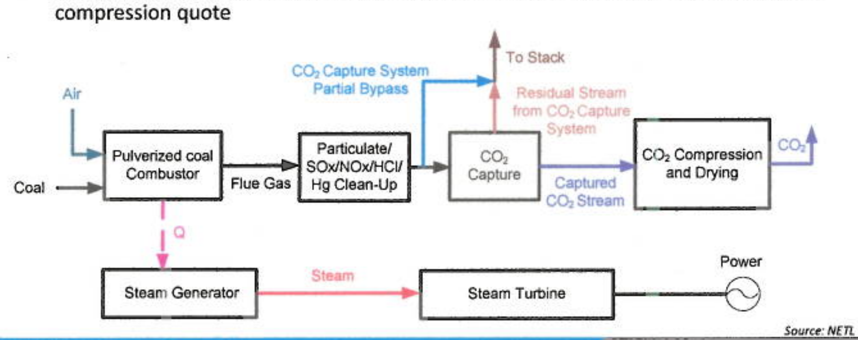
SCPC Partial CO_2 Capture Side-Case
Evaluate Across a Range of CO_2 Emission Rates

- **Evaluate the cost and performance of a BB SCPC plant (Case B12B) that is modified for partial CO_2 capture with all other design assumptions remaining constant**
  - An appropriate portion of the flue gas stream exiting the desulfurization step is directed towards the Cansolv CO_2 capture system to evaluate systems with CO_2 emissions ranging from ~ 1700 – 210 lb/MWh-net
  - The remaining flue gas stream is allowed to bypass the CO_2 capture system and is sent to the stack without further treatment
  - Cost and performance scaled from 90% capture Cansolv quote and accordingly sized compression quote



Source: NETL

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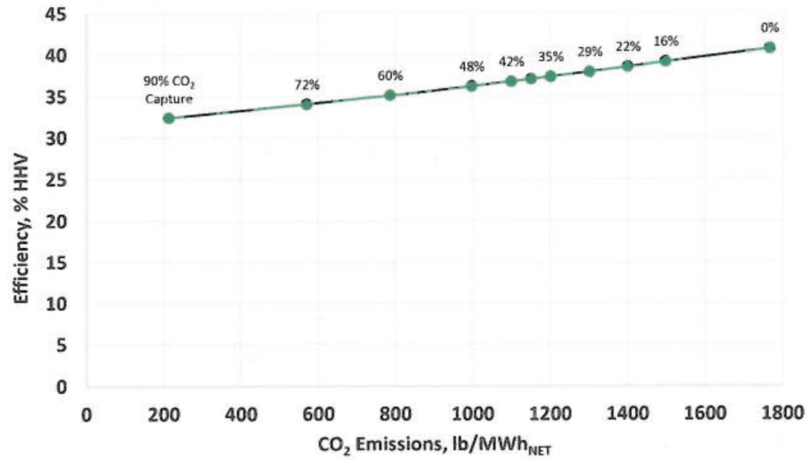
SCPC Partial CO2 Capture Side-Case

Efficiency vs CO_2 Emissions

NETL



U.S. DOE, NETL, June 2015, Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 capture rate in coal-fired power plants, Report DOE/NETL-2015/1720

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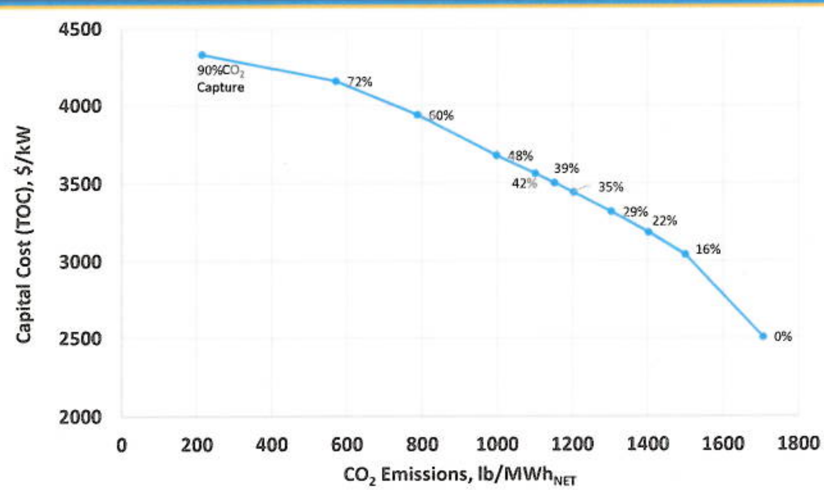
SCPC Partial CO2 Capture Side-Case

Capital Cost vs CO_2 Emissions

NETL



U.S. DOE, NETL, June 2015, Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 capture rate in coal-fired power plants, Report DOE/NETL-2015/1720

* Fully-loaded design rates; does not account for start-up, shutdown, performance degradation between maintenance, part-load operation, etc.

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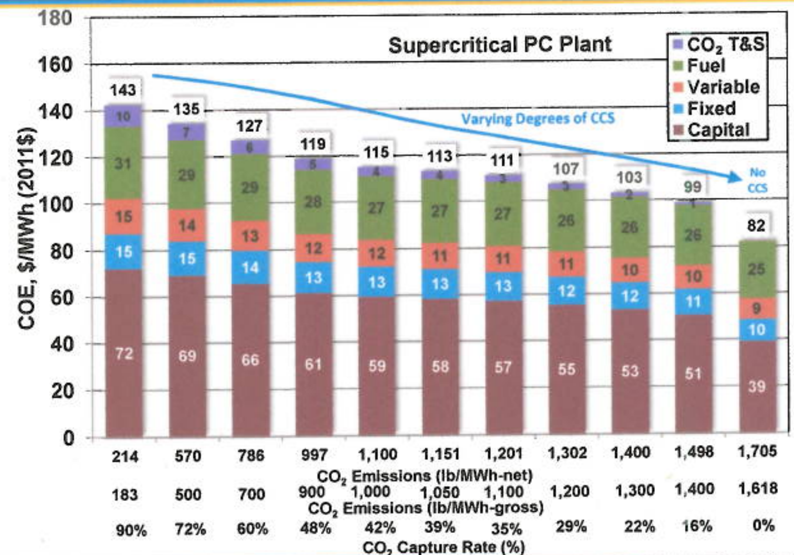
SCPC Partial CO2 Capture Side-Case

COE Including T&S



*Note that the non-capture coal plant and capture coal plant cases use different finance structures

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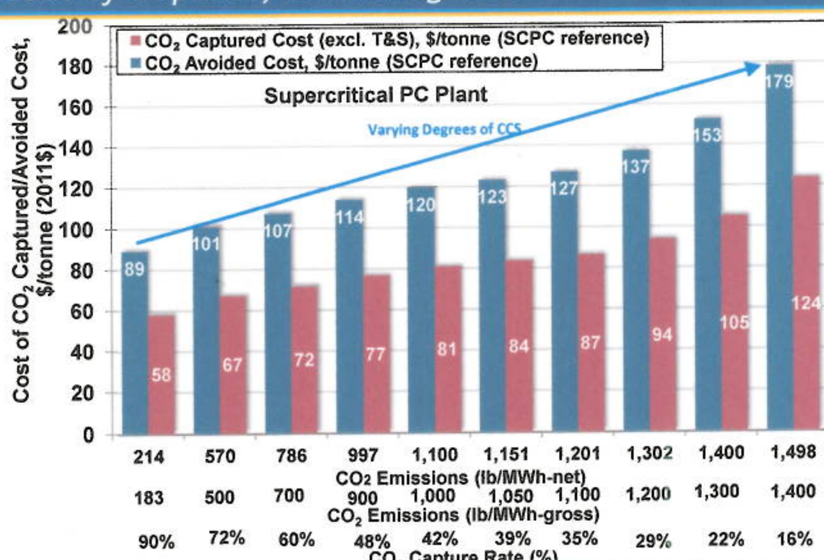
SCPC Partial CO2 Capture Side-Case

Cost of Capture, excluding T&S



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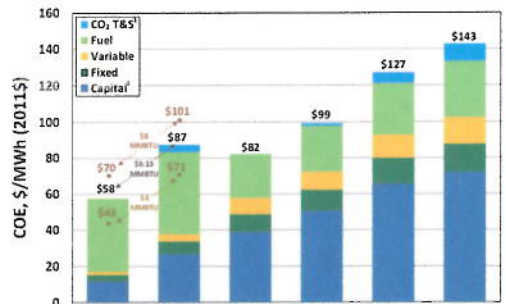
NETL Cost and Performance Baseline

Summary Results

- **With state-of-the-art technology, adding 90% CO_2 capture and storage (CCS) significantly increases the cost of electricity (COE)**
  - 45-65% for NGCC
  - ~75% for pulverized coal (PC)
- **Lower capture rates for PC plants decrease the COE penalty, but result in a higher cost of capture**
  - e.g. $87/tonne versus $58/tonne for 35% and 90% capture, respectively
  - Due in part to diseconomies of scale
- **RD&D is needed to reduce the costs of advanced coal power with CCS**



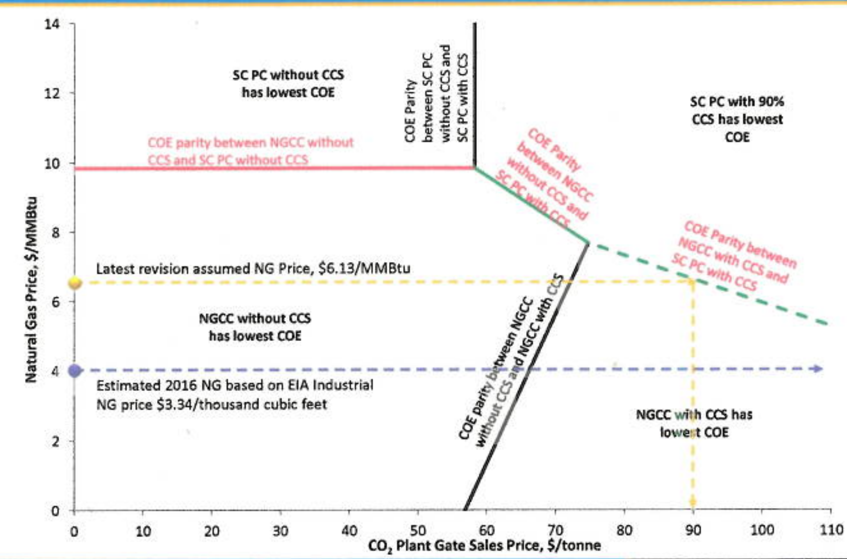
Plant Type	NGCC		Supercritical PC Plant			
Capture Rate	0%	90%	0%	16%	35%	90%
CO_2 Emissions[3] (lb/MWh-gross)	773	82	1,618	1,400	1,100	183
Efficiency (HHV)	51.5%	45.7%	40.7%	39.2%	37.4%	32.5%
Cost of Capture[4] ($/tonne)		$71		$124	$87	$58

Source: NETL Cost and Performance Baseline for Fossil Energy Plants: Volume 1a: Bituminous Coal (PC) and Natural Gas (NGCC) to Electricity (July 2015) & Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants (June 2015)

[1]T&S = transport (100 km) and storage in a Midwest saline formation [2]+30%/-15% uncertainty range; different finance structure utilized for non-capture and capture plants
[3]Fully-loaded design rates; does not account for start-up, shutdown, performance degradation between maintenance, part-load operation, etc.
[4]Excludes CO_2 T&S; relative to non-capture NGCC and non-capture supercritical PC design for NGCC and PC capture designs, respectively

NETL Cost and Performance Baseline

COE Parity Map



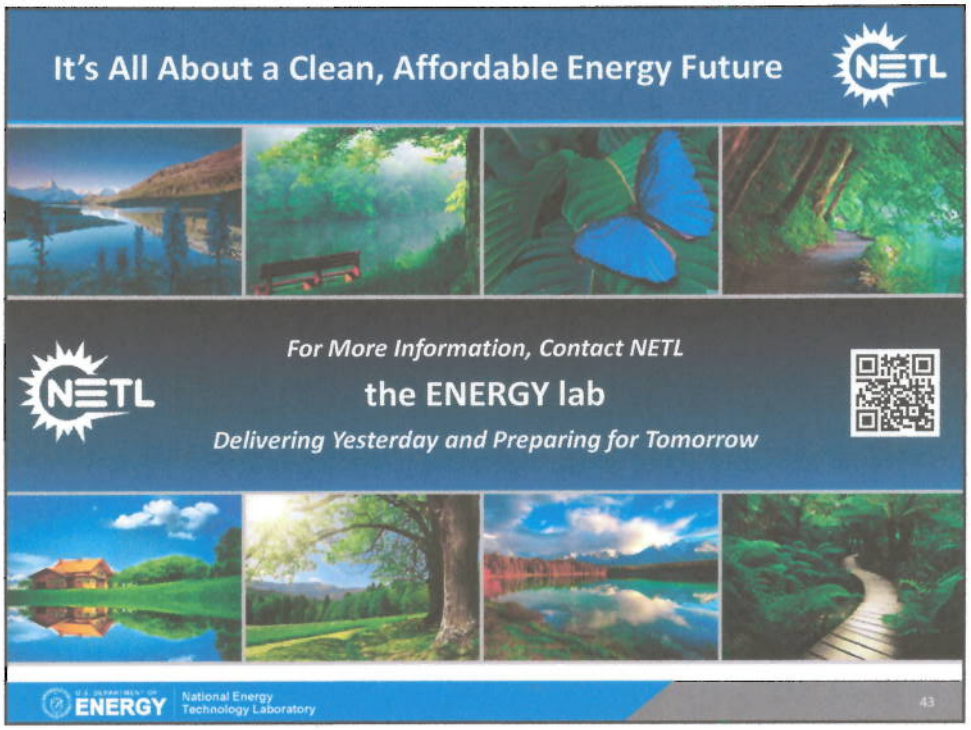
NETL Cost and Performance Baseline
Additional Observations

- **Lower capture rates result in lower COE**
  - Lower capital and operating costs
  - Lower solvent regeneration energy steam use
- **CO_2 capture cost (\$/tonne CO_2) higher at lower capture rates**
  - Economies of scale
  - Less CO_2 available for sale
- **Capture system (capital cost and solvent regeneration energy) and compression capital cost significantly impact CO_2 capture cost**
  - R&D needed to address all
- **Bulk of the cost to capture, transport and store CO_2 is in the CO_2 capture system**

NETL Cost and Performance Baseline
Most Recent Updates

- **Cost and Performance Baseline for Fossil Energy Plants, Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3 (DOE/NETL-2015/1723)**
- **Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants (DOE/NETL-2015/1720)**
  - Includes PC and IGCC cases
- **Cost and Performance Baseline for Fossil Energy Plants, Volume 1b: Bituminous Coal (IGCC) to Electricity, Revision 2 – Year Dollar Update (DOE/NETL-2015/1727)**

http://www.netl.doe.gov/research/energy-analysis/energy-baseline-studies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QUEST PROJECT AND ITS COSTS

IEAGHG /GCCSI 4th CCS cost workshop Boston 23-24/3-2016

Wilfried Maas
General Manager Carbon Capture & Storage

Shell Global Solutions International

DEFINITIONS & CAUTIONARY NOTE

Reserves: Our use of the term "reserves" in this presentation means SEC proved oil and gas reserves.

Resources: Our use of the term "resources" in this presentation includes quantities of oil and gas not yet classified as SEC proved oil and gas reserves. Resources are consistent with the Society of Petroleum Engineers 2P and 2C definitions.

Organic: Our use of the term Organic includes SEC proved oil and gas reserves excluding changes resulting from acquisitions, divestments and year-average pricing impact.

Shales: Our use of the term 'shales' refers to tight, shale and coal bed methane oil and gas acreage.

The companies in which Royal Dutch Shell plc directly and indirectly owns investments are separate entities. In this document "Shell", "Shell group" and "Royal Dutch Shell" are sometimes used for convenience where references are made to Royal Dutch Shell plc and its subsidiaries in general. Likewise, the words "we", "us" and "our" are also used to refer to subsidiaries in general or to those who work for them. These expressions are also used where no useful purpose is served by identifying the particular company or companies. "Subsidiaries", "Shell subsidiaries" and "Shell companies" as used in this document refer to companies over which Royal Dutch Shell plc either directly or indirectly has control. Companies over which Shell has joint control are generally referred to as "joint ventures" and companies over which Shell has significant influence but neither control nor joint control are referred to as "associates". The term "Shell interest" is used for convenience to indicate the direct and/or indirect ownership interest held by Shell in a venture, partnership or company, after exclusion of all third-party interest.

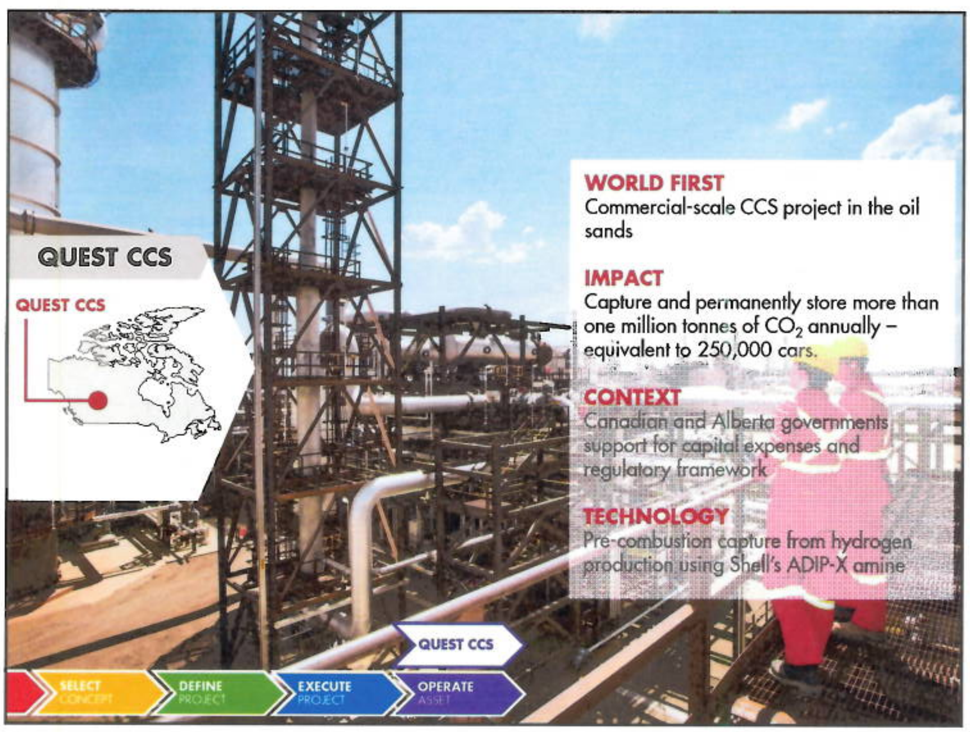
This presentation contains forward-looking statements concerning the financial condition, results of operations and businesses of Royal Dutch Shell. All statements other than statements of historical fact are, or may be deemed to be, forward-looking statements. Forward-looking statements are statements of future expectations that are based on management's current expectations and assumptions and involve known and unknown risks and uncertainties that could cause actual results, performance or events to differ materially from those expressed or implied in these statements. Forward-looking statements include, among other things, statements concerning the potential exposure of Royal Dutch Shell to market risks and statements expressing management's expectations, beliefs, estimates, forecasts, projections and assumptions. These forward-looking statements are identified by their use of terms and phrases such as "anticipate", "believe", "could", "estimate", "expect", "intend", "may", "plan", "objectives", "outlook", "probably", "project", "will", "seek", "target", "risks", "goals", "should" and similar terms and phrases. There are a number of factors that could affect the future operations of Royal Dutch Shell and could cause those results to differ materially from those expressed in the forward-looking statements included in this presentation, including (without limitation): (a) price fluctuations in crude oil and natural gas; (b) changes in demand for Shell's products; (c) currency fluctuations; (d) drilling and production results; (e) reserves estimates; (f) loss of market share and industry competition; (g) environmental and physical risks; (h) risks associated with the identification of suitable potential acquisition properties and targets, and successful negotiation and completion of such transactions; (i) the risk of doing business in developing countries and countries subject to international sanctions; (j) legislative, fiscal and regulatory developments including potential litigation and regulatory measures as a result of climate changes; (k) economic and financial market conditions in various countries and regions; (l) political risks, including the risks of expropriation and renegotiation of the terms of contracts with governmental entities, delays or advancements in the approval of projects and delays in the reimbursement for shared costs; and (m) changes in trading conditions. All forward-looking statements contained in this presentation are expressly qualified in their entirety by the cautionary statements contained or referred to in this section. Readers should not place undue reliance on forward-looking statements. Additional factors that may affect future results are contained in Royal Dutch Shell's 20-F for the year ended 31 December, 2015 (available at www.shell.com/investor and www.sec.gov). These factors also should be considered by the reader. Each forward-looking statement speaks only as of the date of this presentation, 23 March, 2015. Neither Royal Dutch Shell nor any of its subsidiaries undertake any obligation to publicly update or revise any forward-looking statement as a result of new information, future events or other information. In light of these risks, results could differ materially from those stated, implied or inferred from the forward-looking statements contained in this presentation. There can be no assurance that dividend payments will match or exceed those set out in this presentation in the future, or that they will be made at all.

We use certain terms in this presentation, such as discovery potential, that the United States Securities and Exchange Commission (SEC) guidelines strictly prohibit us from including in filings with the SEC. U.S. Investors are urged to consider closely the disclosure in our Form 20-F, File No 1-32575, available on the SEC website www.sec.gov. You can also obtain this form from the SEC by calling 1-800-SEC-0330.

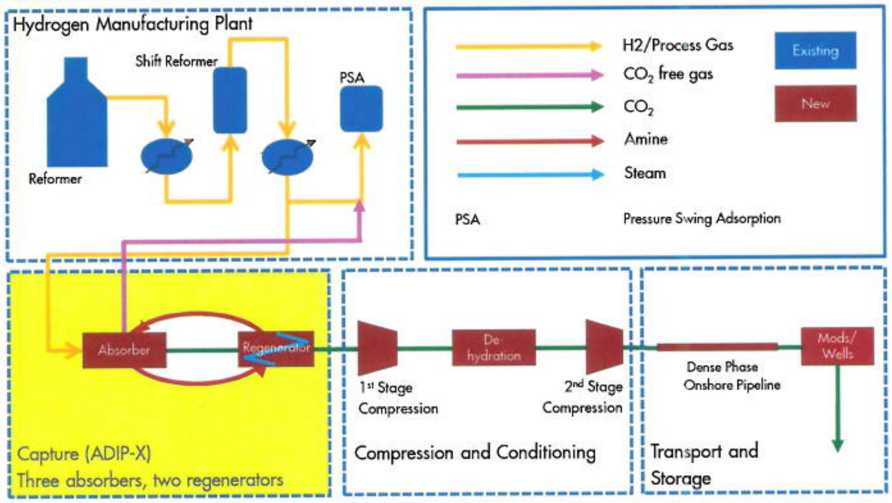
AGENDA

- **Quest Project and Performance**
- Funding & Knowledge sharing
- Project Costs

Shell Global Solutions International March 2016

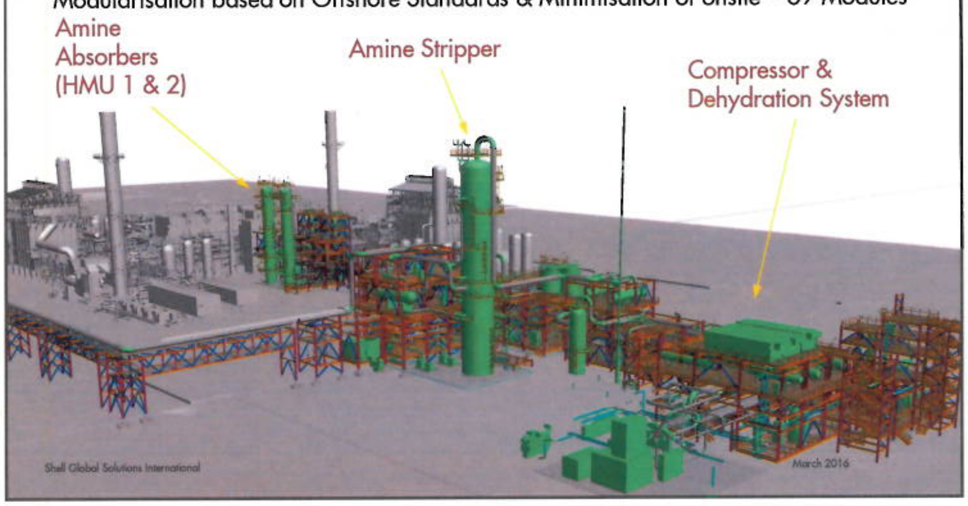


QUEST CCS PROJECT



DESIGN – CAPTURE AND COMPRESSION

Shell ADIP-X Amine process (99%+ pure CO_2), 1.2 Mtpa capacity
Multistage centrifugal compressor to 8.5 – 14 MPa (supercritical state)
TEG dehydration unit, CO_2 with 4-6 lbs/MMscf
Modularisation based on Offshore Standards & Minimisation of onsite – 69 Modules



QUEST "HARDWARE"

- Capture plant in Fort Saskatchewan, approx 50 km N.E. of Edmonton
- Capture at the Scotford Upgrader from 3 Hydrogen Manufacturing Units
- CO_2 transported by 12" pipeline to storage, with 6" laterals
- Pipeline to 65 km north of the Upgrader
- Route selected to meet stakeholder requirements:
  - 28 km follows existing ROW
  - Drilled under North Saskatchewan River
  - 30+ re-routes to accommodate landowner wishes
- Base plan: 3 injection wells and associated monitoring

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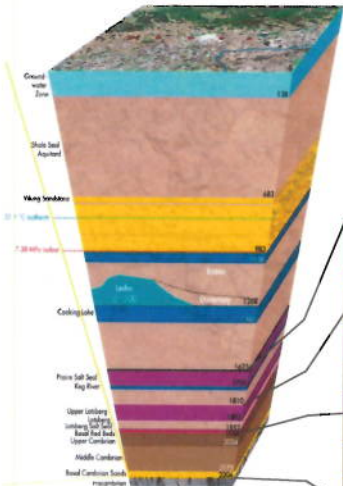
March 2016

QUEST STORAGE



85m	Prairie Evaporite	– Additional Seal	
100m	Upper Lotsberg Salt	– Ultimate Seal	
75m	Lower Lotsberg Salt	– Secondary Seal	BCS Storage Complex
60m			
10m			
70m	Upper Cambrian Shale	– Primary Seal	
130m	Middle Cambrian Sand		
	Basal Cambrian Sand	– Storage Reservoir	
40m	PreCambrian Shield		

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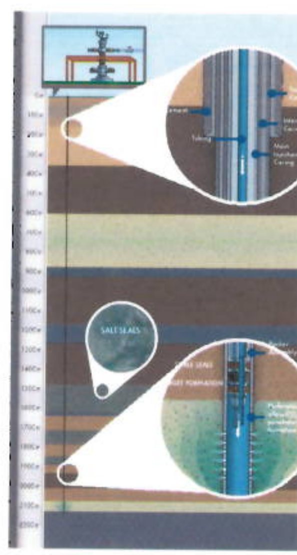
March 2016

CO_2 STORAGE

- CO_2 stored in porous rock containing natural brine
- Basal Cambrian Sands (BCS) selected
  - 2,300 m, Prairies deepest sandstone
  - Multiple cap rock and salt seal layers, no significant faulting visible from wells or seismic
  - Well below hydrocarbon bearing formations and potable water zones in the region
  - Relatively few wells drilled into the BCS, none within 10km of the proposed storage site
- Wells and Drilling
  - Three injection wells
  - Conventional drilling methods
  - Multiple steel casings for wells, 3 in freshwater zone, all cemented to surface



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March 2016

TIMELINE

Regulatory Hearing ▪ Approvals received	Mar 2012 Aug 2012
Final Investment Decision (FID)	Sep 2012
Well Program ▪ 2 additional injection wells ▪ Associated deep monitoring and groundwater wells ▪ Baseline	Q4 2012
Capture & Pipeline completed ▪ Pipeline construction ▪ Capture construction	 Q4 2014 Q2 2015
Operations Handover ▪ Full production	Q2 2015 Q3 2015

- Continuous capture and storage since August 2015, exceeding target rate
- Commercial tests complete – 3 months ahead of target

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March 2016

MEASUREMENT, MONITORING AND VERIFICATION PLAN

- Comprehensive : Geosphere to Atmosphere and entire lifecycle
- Risk-based, site-specific
- Independently (DNV) certified MMV and storage plan

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March 2016

REGULATORY DEVELOPMENT & STAKEHOLDER ENGAGEMENT

- Public project disclosure (booklet, news release and open house)
- Stakeholder consultation program
- Open Houses
- Quest Cafés
- Bi-annual County and Town Council updates
- Monthly Community Advisory Panel Meetings (CAP) on MMV program

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March 2016

CCS- KEY REGULATORY APPLICATIONS/PERMITS

- Tenure Sequestration Lease
- CO_2 Disposal Scheme
- Environmental Assessment (Federal and Provincial)
- Emergency Response Plan
- Well and pipeline licenses

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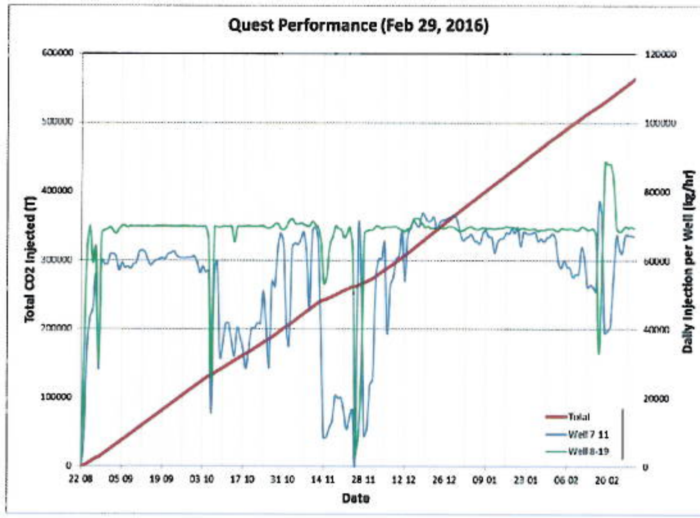
March 2016

6 MONTHS INJECTION



- We prepared for issues related to start up and responded accordingly
- **Successfully injected 500,000 tonnes in less than 6 months!**

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AGENDA

- Quest Project and Performance
- **Funding & Knowledge sharing**
- Project Costs

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March 2016

FUNDING AGREEMENTS & REVENUES

- Government Funding Support – CAN$865 M
  - CAN$120 M Canadian Federal Government (Pre FID)
  - CAN$745 M Alberta Province (Construction, Startup and 10 years operation)
  - Extensive knowledge sharing
  - Stringent monitoring (Measurement, Monitoring & Verification) plan
  - NPV Zero commitment
- Revenues – GHG offsets (credits)
  - Net amount – stored CO_2, less direct and indirect emissions (13-18% of injected)
    - Design Captured & Stored 1.08 mt/a , Avoided 0.94 mt/a
  - Credits to be used first by Shell's Alberta assets for regulatory compliance
  - A second set of credits will be received as early developer

KNOWLEDGE SHARING

- Extensive knowledge sharing part of the program
- http://www.energy.alberta.ca/CCS/3845.asp

  Facility Design
  Construction Schedule
  Geological Formation Selection
  Facilities Operations :Capture, Transportation, Storage& Monitoring, Maintenance and Repairs
  Regulatory approvals
  Public Engagement
  Cost and Revenues
  Timeline
  General Project Assessment

  Extensive Detailed reporting

  Flow Diagram, H&M balance, Plot plan, Work Breakdown,, MMV, Closure Plan , Annual Status Reports, Screening reports etc., P&ID;s
- Analogous to Knowledge sharing in the (now cancelled) UK CCS commercialisation program

  https://www.gov.uk/government/collections/carbon-capture-and-storage-knowledge-sharing

AGENDA

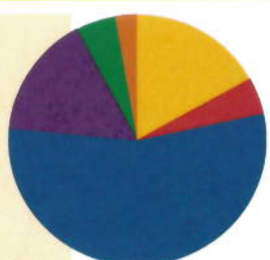
- Quest Project and Performance
- Funding & Knowledge sharing
- **Project Costs**

QUEST COSTS

First of a kind facilities cost forecast

- Venture: CAN$137M
- Tie-in work: CAN$38M
- Capture: CAN$446M
- Pipeline: CAN$128M
- Subsurface: CAN$40M
- Contingency: CAN $23M

Total CAN$812M -> 752 $/tpa captured



- Overall Venture Costs
- Tie-in/Brownfield Work
- Capture Facility
- Pipeline (Transport)
- Subsurface (Wells/MMV)
- Total Contingency, Inflation & Market Escalation

Anticipated Project Operating Costs :

$44M per annum -> 41 $/ton captured

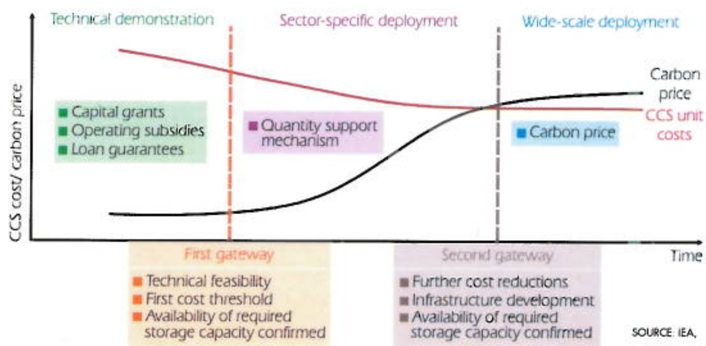
Potential savings for future projects

- Reduced venture costs
- Reduced capture costs
- Reduced pipeline/subsurface costs

Watch the release of the 2015 reports
- which will show actual performance numbers from startup year
  - Under budget & under schedule

1 CDN =0.99 USD (2011)

CCS DEMONSTRATION REQUIRES SUPPORT MECHANISMS



- CO_2 emissions penalty generally too low currently to get CCS going
- CCS demo capital grants are too significant to sustain for a long period
- Additional mechanisms will be required to get CCS demonstated at scale

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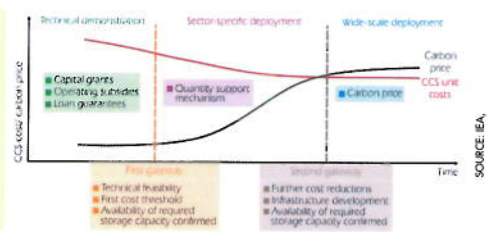
CCS WILL REQUIRE DEMONSTRATION SUPPORT, EFFECTIVE POLICIES NEEDED

Objective – adequate support is needed to demonstrate CCS and reduce costs from FOAK to NOAK to deliver a competitive and viable technology in a decarbonised world.



FIRST OF A KIND → **N^th OF A KIND**

DEVELOPMENT	DEMONSTRATION	DEPLOYMENT
Capital grants *(support build)*		
Opex support *(ensure plant operates)*		
		Robust CO_2 price
... plus other temporary measures (e.g. CCS certificates) if the uptake rate continues to be disappointing		
Non-Financial measures (enabling regulations, liability agreements, etc)		

MGSC | Midwest Geological Sequestration Consortium

TRIMERIC CORPORATION

Insights into Costs of CCS Gained from the Illinois Basin – Decatur Project

Sallie E. Greenberg, Ph.D. and the MGSC Project Team
Advanced Energy Technology Initiative
University of Illinois – Illinois State Geological Survey

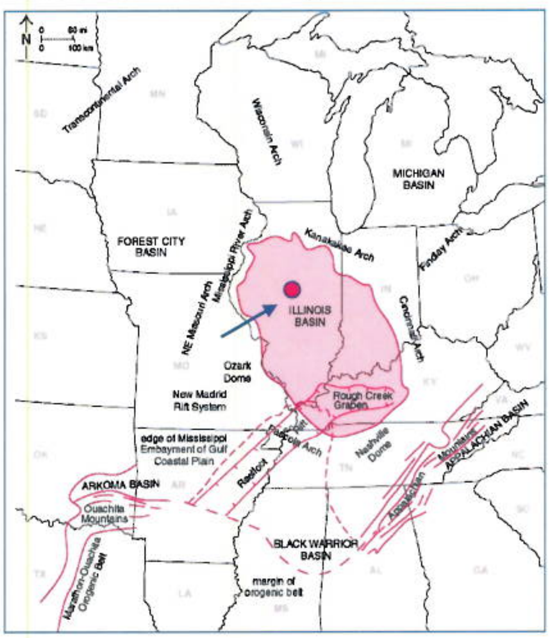
Ray McKaskle, P.E. and the Trimeric Project Team

22 March 2016 – IEAGHG CCS Cost Network Workshop at the Massachusetts Institute of Technology

ILLINOIS

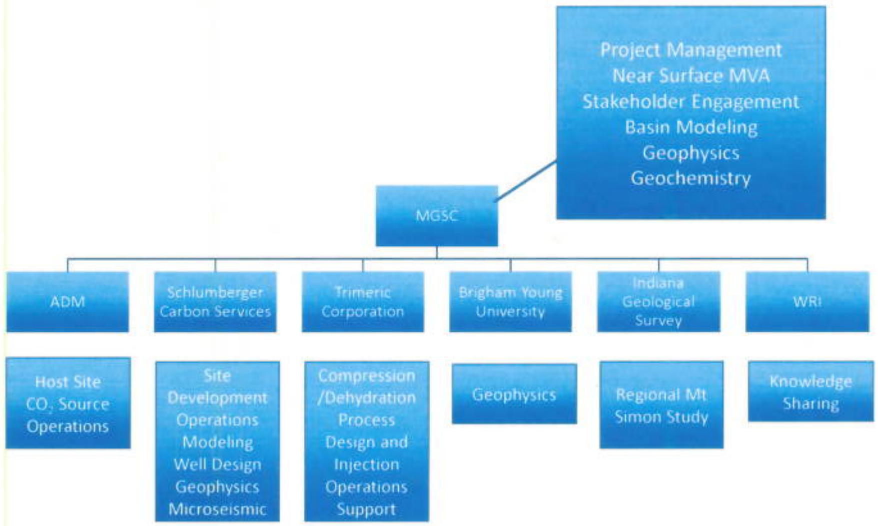
PRAIRIE

Illinois Basin – Decatur Project Scope



A collaboration of the Midwest Geological Sequestration Consortium, the Archer Daniels Midland Company (ADM), Schlumberger Carbon Services, and Trimeric Corporation and other subcontractors to inject one million metric tons of anthropogenic carbon dioxide at a depth of 7,000 +/- ft (2,000 +/- m) to test geological carbon sequestration in a saline reservoir at a site in Decatur, IL

MGSC Phase III Team



MGSC Program Goals

Prove Injectivity and Capacity

Demonstrate Security of Injection Zone

Contribute to Best Practices

IBDP Accomplishments

IBDP is the first demonstration-scale (one million tonne) U.S. project to use carbon dioxide (CO_2) from an industrial/biofuel source within the DOE Regional Carbon Sequestration Partnership (RCSP) program

IBDP is a fully integrated demonstration project comprised of compression - dehydration facility, 1.9 km pipeline for delivery of supercritical CO_2 to injection, and observation system on an intensely monitored site

IBDP injection is the result of nine years of Phase III effort from funding to storing CO_2 in the reservoir, includes site characterization, permitting, risk assessment, public engagement, drilling, injection operations, reservoir geology, engineering, and geophysics, and baseline, injection, and post-injection monitoring and analysis

Illinois Basin – Decatur Project Site (on ADM industrial site)

A Dehydration/ compression facility location
B Pipeline route (1.9 km)
C Injection well site
D Verification/ monitoring well site
E Geophone well

Operational Injection: 17 November 2011

- IBDP is the first one million tonne carbon capture and storage project from a biofuel facility in the US
- Injection completed November 2014
- Intensive post-injection monitoring under MGSC through 2017

Total Injection (26 November 2014): 999,215 tonnes

Insights into Costs of CCS Gained from IBDP

- **IBDP Scope and Scale Definition:**
  - Capture of low pressure, water-saturated, high purity CO_2 from biofuels production
  - Compression, dehydration, transportation, storage, and MVA represent what is done AFTER post-combustion flue gas capture at a power plant or other industrial facility
  - Injection rate of 1,000 tonne / day represents about 50 MW_e of CO_2 or 10% scale of a 550 $MW_{(net)}$ power plant with 90% capture
  - Broader, overall project costs will be presented first, followed by a detailed examination of the capital and operating costs for the compression, dehydration, and transportation facilities

IBDP Overall Project Costs

- Pre-injection
  - Budget Period 3 (12/18/07 to 4/30/10): Cost $22,226,960
- Injection
  - Budget Period 4 (5/1/10 to 1/15/15): Cost $66,077,449
- Post-injection
  - Budget Period 5 (1/16/15 to12/17/17): Cost $21,659,483

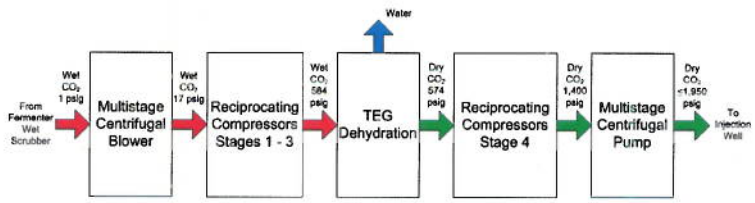
- DOE Share $ 87,318,798 79%
- Non-DOE Share $ 22,645,094 21%
- Total Value $109,963,892

Project Cost Breakdown (in progress)

Wells (11/2013)	Infrastructure (11/2013)	Geophysical (11/2013)	Geologic (11/2013)	MVA (12/2015)
Injection $8,581,000	Well site Prep & Utilities $673,000	Two 3D seismic surveys $6,800,000	Well Logging $1,650,000	Groundwater wells $282,000
Verification $6,377,00	Data Acquisition System $387,000	Baseline 3D VSP $280,000	Coring $202,000	Equipment $324,000
Geophone $589,000	Office/training/ Computer Facility $73,000	Three repeat 3D VSPs $960,000	Core Analysis $409,000	Chemical Analyses $591,000
		Microseismic and surface sensors $1,277,000	(Above applies to injection and verification wells)	Risk Assessment $170,000
TOTALS $15,547,000	$1,133,000	$9,217,000	$2,261,000	$1,127,000

Compression/Dehydration not included here. Items in Purple based on BP4.
All totals subject to change by end of project

Facility Overview (1 of 2)
Compression, Dehydration, Transmission Facilities



Facility Overview (2 of 2)
Compression, Dehydration, Transmission Facilities

IBDP Capital Costs
for Compression, Dehydration, and Transmission Facilities

Cost Categories	Costs, (2009 – 2011 US $ MM)	Actual % of TDIC	Typical Range* (% of TDIC)
Purchased Equipment	6.1	30	15-40
Purchased-Equipment Installation	1.9	9	6-14
Instrumentation and Controls	1.0	5	2-12
Piping	5.1	25	4-17
Electrical Systems	3.0	15	2-10
Buildings and Yard Improvements	0.9	5	4-23
Total Direct Cost (TDC)	18.0		
Engineering	1.9	9	4-20
Construction Expenses	0.4	2	4-17
Total Indirect Cost (TIC)	2.3		
Total Direct and Indirect Cost (TDIC)	20.3		

*Typical Ranges from Peters and Timmerhaus, 2003

IBDP Capital and Operating Costs / Tonne Injected
for Compression, Dehydration, and Transmission Facilities

Cost Categories	Costs, (2009 – 2014) US $ / tonne
Capital Costs	20.34
Electrical Power	7.76
Operating Labor	1.32
Supervisor Labor	0.20
Maintenance	1.22
Other Operating Costs	0.61
Total	31.45

- Important statements regarding this table:
  - Capital costs are amortized over the three-year injection period, amortization period would be much longer on a typical commercial project
  - All costs in this table except for capital costs are derived using typical industry values as actual values are either confidential or not available
  - Host site provided Plant Overhead functions, which would be an additional estimated $ 2.01 / tonne at a green-field location
  - If scaling costs for future projects, suggest using mid-2010 for capital costs and late-2014 for operating costs

Lessons Learned Regarding Project Costs
for Compression, Dehydration, and Transmission Facilities

Capital costs were higher than the initial estimate, but operating costs were lower → Net effect < 5% increase in $ / tonne injected

- Scope Changes
  - Design capacity increased by 21%
  - Multistage centrifugal pump added
  - Above ground transmission pipeline insulation added
- Items (highest to lowest) with higher than original cost estimates
  - Transmission pipeline and insulation costs
  - Process and cooling water piping
  - Structural
  - Electrical
  - Engineering

Factors That Affected Project Costs
for Compression, Dehydration, and Transmission Facilities

- Installation within a major operating industrial facility can increase project costs / complexity
  - Transmission pipeline had to be above ground and had to be insulated
  - Two equipment buildings required instead of one due to underground piping
  - These experiences may be informative with respect to installing a CO_2 capture retrofit within an existing power plant or other industrial facility
- UIC permitting timeline extended the facility construction schedule

Considerations for Costs on Future Projects

- It would help to know or at least to have a firmer estimate of the required injection pressure prior to process design and ordering compression equipment
- Planning for future projects can be informed by timeline required to obtain injection permits on first mover projects
  - We thought compressor 52-week lead time would be critical path, but turned out not to be so in this case
  - Longer project timelines may allow alternate equipment selection and / or more favorable pricing
- Pricing for future projects may be influenced (up or down) by overall economic conditions in general and for the oil and gas industry in particular

Conclusions

- Carbon capture and storage is a major undertaking involving many types of industry, government, and financial professionals, as well as many industry trades
- First mover projects can provide useful benchmarks and lessons learned that will benefit future projects
- Incorporating CCS into existing, operational power plants or other industrial facilities comes with additional, case-specific challenges and costs
- Permitting timelines and general economic conditions may impact costs on future projects in ways that are difficult to predict

MGSC Midwest Geological Sequestration Consortium

ILLINOIS — PRAIRIE RESEARCH INSTITUTE — ILLINOIS STATE GEOLOGICAL SURVEY — ENERGY — NETL

Acknowledgements

- The Midwest Geological Sequestration Consortium is funded by the U.S. Department of Energy through the National Energy Technology Laboratory (NETL) via the Regional Carbon Sequestration Partnership Program (contract number DE-FC26-05NT42588) and by a cost share agreement with the Illinois Department of Commerce and Economic Opportunity, Office of Coal Development through the Illinois Clean Coal Institute.
- The Midwest Geological Sequestration Consortium (MGSC) is a collaboration led by the geological surveys of Illinois, Indiana, and Kentucky.
- Landmark Graphics software via their University Donation Program and cost share plus Petrel software via Schlumberger Carbon Services.

ILLINOIS — ILLINOIS STATE GEOLOGICAL SURVEY — Schlumberger Carbon Services — ENERGY — NETL

Post-Injection Activities

- 3D Surface Seismic Survey – January 2015
  - Processing nearly complete
- Post-injection VSP, permit interim period – January 2015
  - Working to improve comparisons between repeat VSPs
- Post-injection near surface monitoring
  - Moving from injection monitoring to reduced program
- Knowledge and data sharing best practices
  - Publications
  - National and international research collaborations
  - Collective data sets
  - Teaching data sets

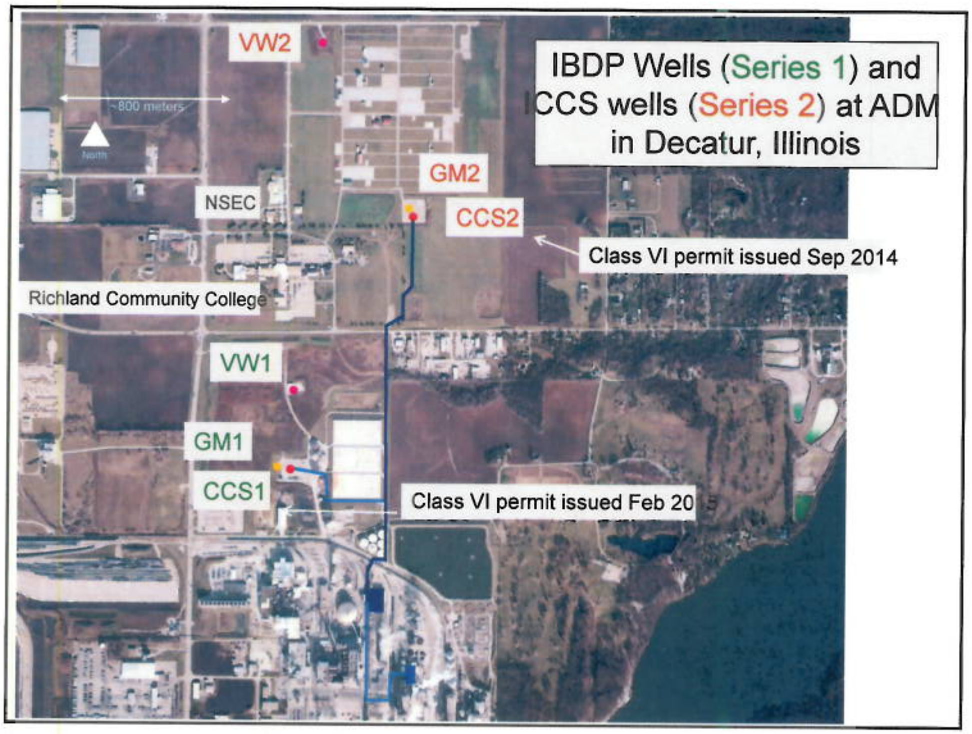
CCS in Decatur, IL USA

Illinois Basin – Decatur Project

- Large-scale demonstration
- Volume: 1 million tonnes
- Injection period: 3 years
- Injection rate: 1,000 tonnes/d
- Compression capacity: 1,100 tonnes/day
- Status: Post-injection monitoring

Illinois Industrial CCS Project

- Industrial-scale
- Volume: 5 million tonnes
- Injection period: 3 years
- Injection rate: 3,000 tons/d
- Compression capacity: 2,200 tonnes/day
- Status: Pre-injection monitoring


IBDP Wells (Series 1) and
ICCS wells (Series 2) at ADM
in Decatur, Illinois
VW2
~800 meters
North
GM2
NSEC
CCS2
Class VI permit issued Sep 2014
Richland Community College
VW1
GM1
CCS1
Class VI permit issued Feb 20

ELECTRIC POWER RESEARCH INSTITUTE

Session 3: Project Costs
Power Applications

George Booras
Principal Technical Leader

CCS Cost Network Workshop
Massachusetts Institute of Technology
March 22, 2016

Session 3: Overview and Objectives

This session will focus on cost estimates for CCS applications in electric power generation

<u>Objectives</u>

- Learn about the cost of actual projects
- Major capital cost areas
  - CO_2 capture, compression, and pipeline
  - Upgrades to upstream process equipment
  - Balance of plant and owner's costs
- Comparisons of final project cost to initial estimates
  - Scope changes? Construction delays? Equipment/labor cost increases?
- Summary of lessons learned
- Opportunities for future cost reductions

2

ELECTRIC POWER RESEARCH INSTITUTE

Session 3: Power Projects and Speakers

1) Boundary Dam Carbon Capture Project
   Max Ball and Peter Versteeg*
   SaskPower

2) FutureGen 2.0
   Ken Humphreys
   FutureGen Industrial Alliance

3) White Rose CCS Project
   Leigh Hacket
   GE Power

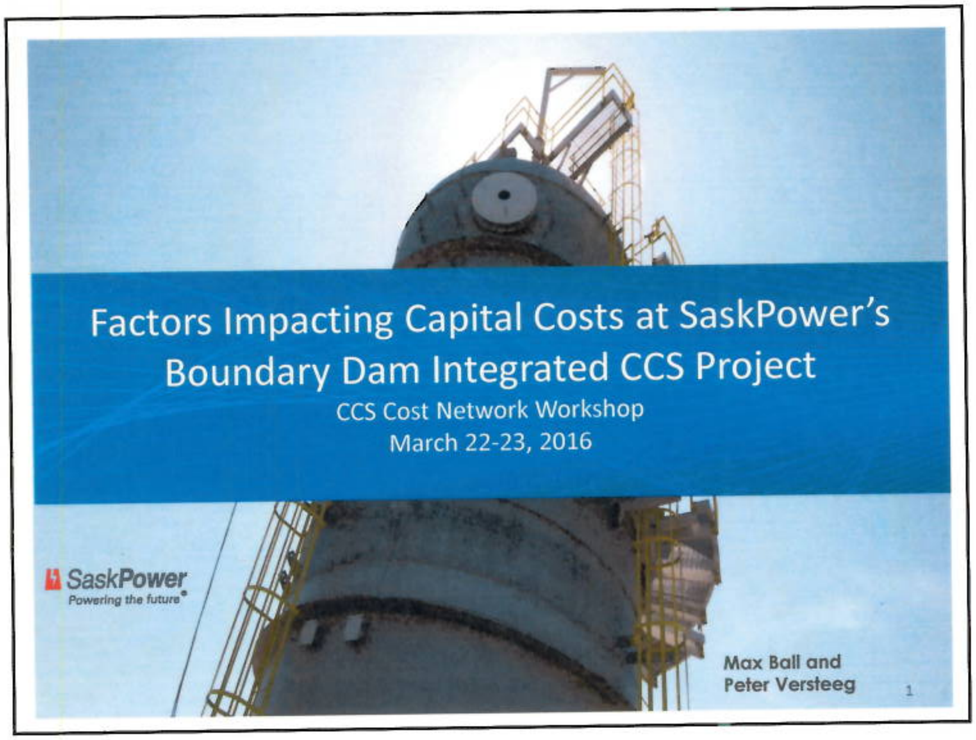
* via teleconference

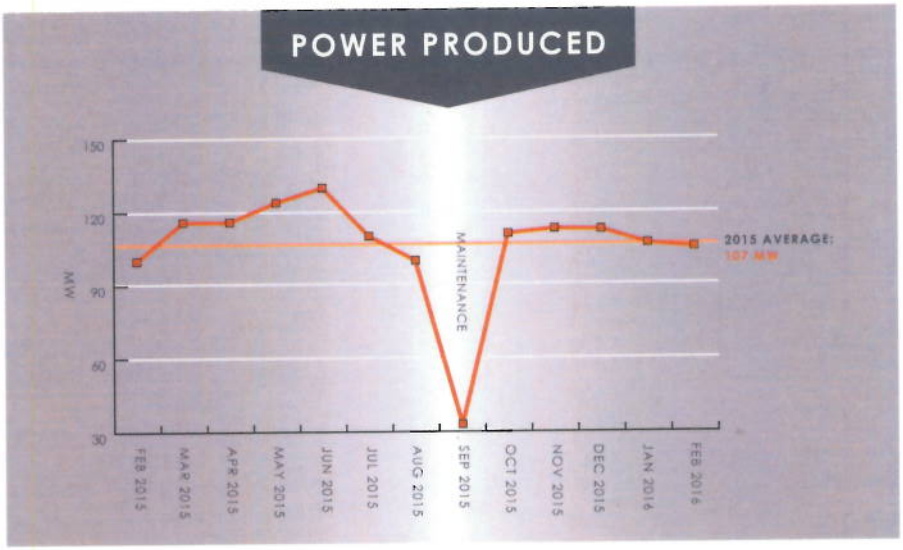
3

Together…Shaping the Future of Electricity

4

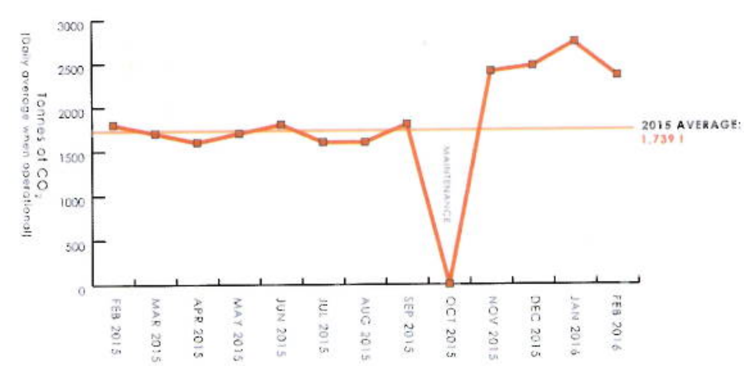
Factors Impacting Capital Costs at SaskPower's Boundary Dam Integrated CCS Project





3

In February, the daily average of CO_2 captured by Unit #3
PEAKED AT 2,726 TONNES.



674,000 TONNES
captured since operational start-up

2014: 114,000 t | 2015: 426,000 t | 2016: 134,000 t

4

Potential for CCS at SASKPOWER

Unit	Initial Investment	Final Investment	In Service
BD 4/5	2017	**2019***	**2025***
BD 6	2022	2024	**2028***
PR 1	2024	2026	**2030***
PR 2	2026	2026	**2030***
Shand 1	2037	2039	**2043***
New Build	New costs more than rebuild today		

*** Fixed by Regulation**

5

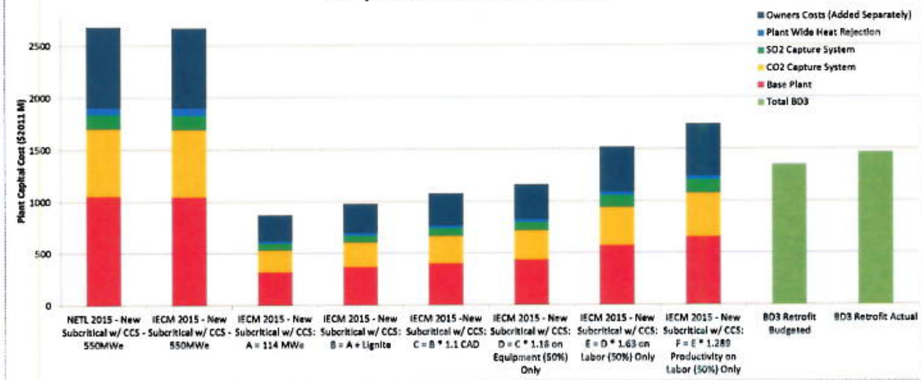
Factors Impacting Capital Costs

- **Site Specific Factors**
- **First of a Kind Factors**
- **Market Factors**
- **Design Features**

6

Site Specific Factors

NETL and IECM Estimated Plant Capital Costs Applied in the SK Context, Comparison to Public BD3 Costs



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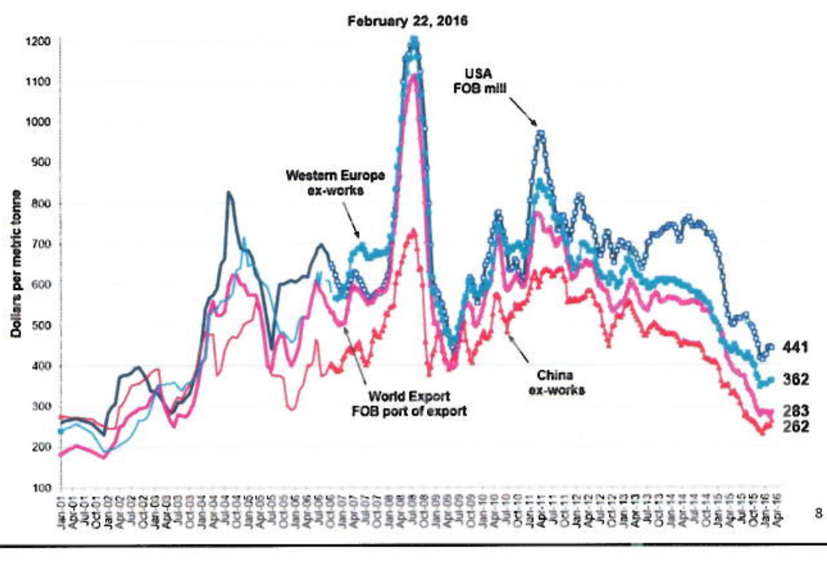
Market Factors

SteelBenchmarker™ **HRB Price**

USA, China, Western Europe and World Export
(WSD's PriceTrack data, Jan. 2001 - March 2006; SteelBenchmarker data begins April 2006)



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Clean Energy for a Secure Future

FutureGen 2.0

Ken Humphreys
Chief Executive, FutureGen Alliance
MIT Cost Workshop
March 22, 2016

www.FutureGenAlliance.org

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FutureGen 2.0

- Repower Meredosia Energy Center with oxy-combustion and CCS technology
  - Repowered gross: 167-Mwe
  - Near-zero emissions
  - CO_2 capture rate: 90%+
  - CO_2 capture volume: 1.1 MMT/yr
  - Pipeline transport: 28 miles
  - Deep geologic storage
  - 60%/40% Illinois/PRB

Design	Construction	Power Production w/CCS	Post-closure monitoring
2010	2014	2018	2038

2088

2

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FutureGen Alliance

Project Status and Cost Context

- Expiration of federal co-funding terminated the project
  - CAPEX within DOE and ICC-approved budgets
  - Operating costs well below the statutory rate caps
- Project was "well advanced" at the time of termination contributing to an extremely high degree of cost certainty
- Costs must be interpreted within the context of this first of a kind project
  - FutureGen's size and host site well matched to project purpose of proving out the technology
  - Subsequent retrofit applications quite different
    - Newer, larger plants
    - SC or USC
    - EOR or storage hub

FutureGen Alliance

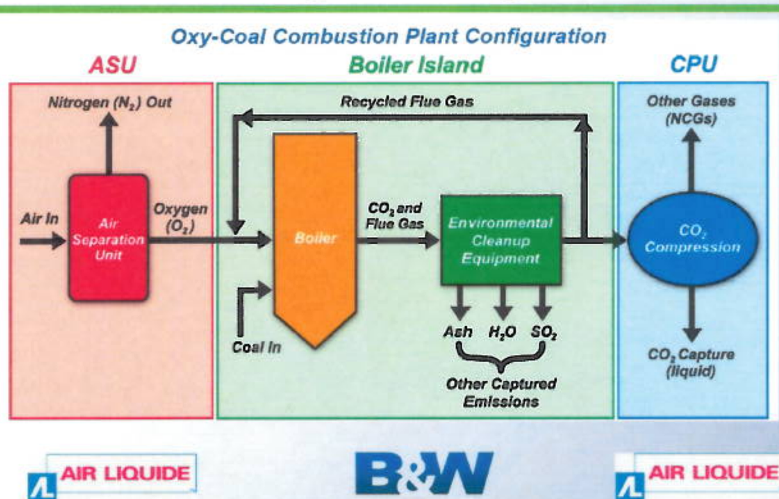
Project Well Advanced

- Power Purchase Agreement signed
- Power Plant Asset Purchase Agreement signed
- Final air, water, pipeline, and storage permits issued
- MISO grid interconnection agreement finalized
- Subsurface storage rights acquired
- CO_2 liability management addressed
- Mega-FEED complete (70 – 90% final design complete)
- Project Labor Agreement signed
- Early construction activities initiated
  - Initial demolition and excavation
  - Geologic characterization well complete
- EPC contract costs known
- Final stage of financing due diligence

Meredosia Energy Center Host Site

- Recently idled and well maintained in a retrofit-ready condition.
- Unit 4 steam turbine in excellent condition (< 20,000 hrs of operation)
- Coal handling and other selected infrastructure to be utilized
- Existing air permit (modified) provided flexibility beneficial to FOAK retrofit
- Existing MISO transmission infrastructure simplifies interconnection requirements

Power Plant Repowering



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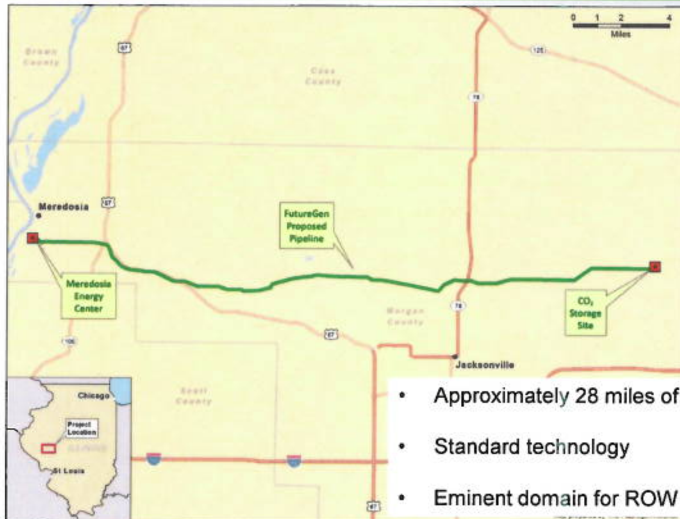
CO_2 Pipeline



- Approximately 28 miles of 10" pipe
- Standard technology
- Eminent domain for ROW

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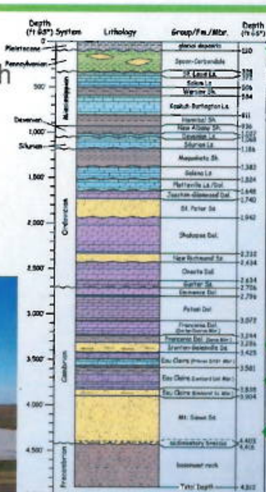
CO_2 Storage Site

- High quality storage reservoir
  - Drilled to expected to reservoir depth (~4500 ft) in Mt Simon formation
  - Seismic surveys completed
  - Hydrologic testing completed
  - Core analysis and modeling completed



Well Water

Addt'l Seal

Primary Seal

CO_2 stored

FutureGen Alliance Confidential Information

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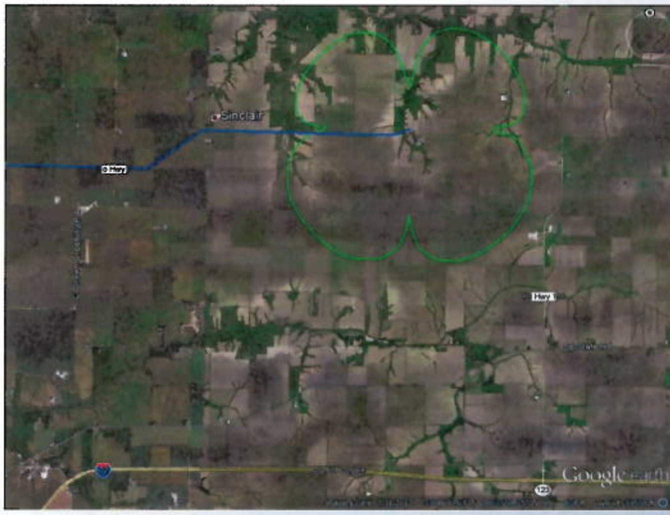
CO_2 Storage Site

Main Injection Location



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CO_2 Storage Site

Land Acquisition

- Subsurface rights for 20-year, 4000-acre plume secured
- Opportunistically acquiring buffer zone around permitted area
  - Increases flexibility
  - Reduces litigation risk
  - Increases power plant lender comfort

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CO_2 Storage Site
Subsurface Monitoring Network

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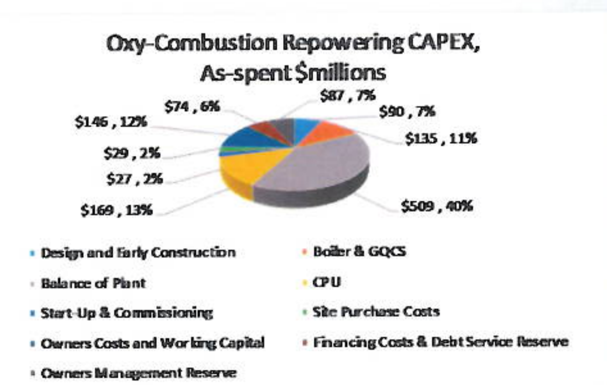
Power Plant CAPEX - $1256M



- ASU, & pipeline/storage over-the-fence.
- As-spent based on 2015 construction start.

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Power Plant CAPEX: Owner Costs

Cost Category	Total Cost As-Spent $millions
Legacy Equipment	$72.0
Project Development/Management Costs	$22.4
Capital Spares	$8.9
O&M Training & Mobilization	$5.0
Builder's Risk & General Liability	$8.2
Property Tax	$2.7
Initial Fuel Pile & Consumables	$2.5
Interconnection	$1.5
State Sales Tax	$0.0
Owner G&A & IWC LOC Fee	$22.3
Total Owner Costs (excludes island specific start-up costs)	$146

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Power Plant CAPEX: Financing Cost

- Project financed
- Construction Bank Loan followed by a long-term bond financing

Cost Category	Total Cost As-Spent $millions
Legal & Consulting Fees	$6
Upfront Financing Fees	$13
Origination Fees	$10
Commitment Fees During Construction	$5
Interest During Construction	$31
Bond Placement Fees (Term Financing)	$9
Initial Debt Service Reserve - LOC Commitment Fees	<$1
Total Financing Costs	$74

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Power Plant CAPEX: Start-up Cost

- Start-up costs for legacy equipment and integrated plant testing.
- Island-specific start-up costs are included in equipment island CAPEX budget.

Cost Category	Total Cost As-Spent $millions
Start-up of Legacy Equipment	$10
Fuel and other Consumables	$24
Purchased Power	$8
Credit for Power Sold	($15)
Total Start-up Costs (excludes island specific start-up costs)	$27

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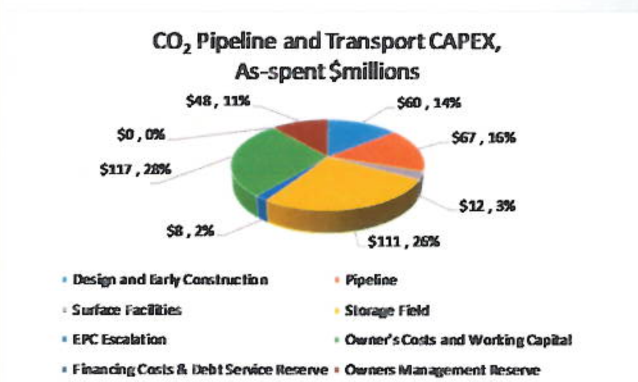
CO_2 Pipeline & Storage CAPEX - $423M



- 100% cash financed with no equity return
- Excludes visitor & training center

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CO_2 Storage CAPEX: Owner Cost

- Includes pipeline and storage
- All cash basis with no return on equity

Cost Category	Total Cost As-Spent $millions
Land Acquisition	$27.7
Project Development/Management Costs	$12.1
Builder's Risk & General Liability	$3.3
Property Tax	$0.3
CO2 Trust Fund	$51.9
State Sales Tax	$0.0
Owner G&A, IWC, & Fees	$21.7
Total Owner Costs	$117

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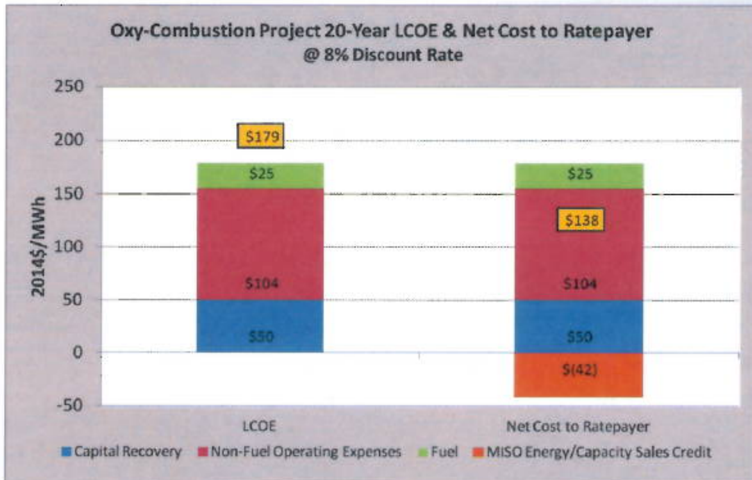
OPEX Cost Drivers

- OPEX is driven by five key costs areas:
  - Oxygen
  - Fuel
  - Purchased power
  - Ash disposal & consumables
  - CO_2 transport & storage
- These cost categories account for 80% of the operating costs

Levelized Cost of Electricity



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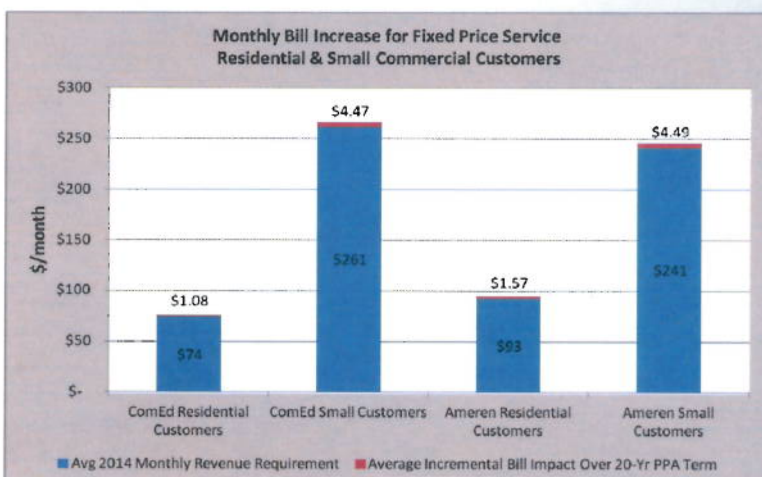
Net Cost to Ratepayers



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Commercial

Informing Nth Plant Costs

- Aggregate costs largely irrelevant
- Component costs very relevant
- Potential for Nth plant economic improvement on retrofits
  - Power
    - Economies of scale (e.g., 500-MWe)
    - Pre-existing, modern environmental controls
    - Supercritical retrofit
    - ASU competition
    - Vendor experience
    - Full wrap
  - Storage
    - Economies of scale

FutureGen 2.0

Principal Partners

NETL

Alpha Natural Resources

AngloAmerican

Peabody Energy

JOYGLOBAL

GlencoreXstrata

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DOE Acknowledgment and Disclaimer

"This material is based upon work supported by the Department of Energy under Award Number DE-FE0001882 and DE-FE0005054."

White Rose – Oxy-fuel CCS Project

Dr. Leigh A. Hackett

CCS Cost Network Workshop MIT

March 22-23, 2016

Imagination at work

White Rose project

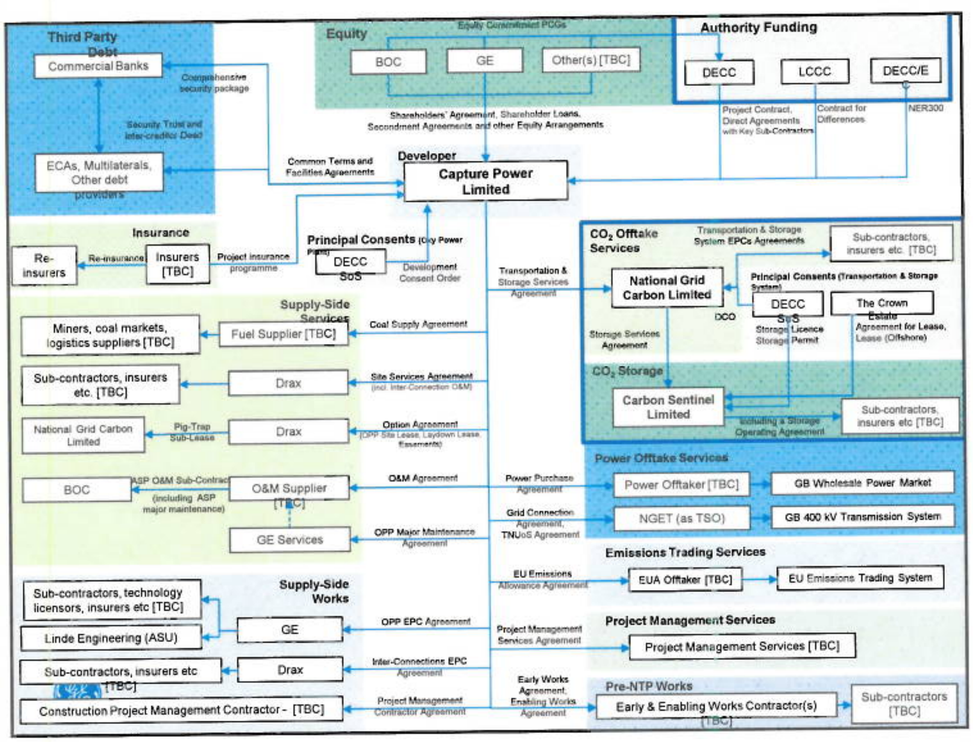
White Rose - Project summary

- A new modern ultra-supercritical Oxy-Power Plant, up to 448MWe (gross)
- Clean power generated for the equivalent needs of 630,000 homes
- 100% of flue gas treated, 90% CO_2 capture rate → 2 million tonnes CO_2/year
- Potential to co-fire biomass
- Anchor project for National Grid's regional CO_2 transport & offshore storage network
- Yorkshire & Humber CCS cluster covers almost 20% of UK's CO_2 emissions
- Infrastructure planned to be sized for 17 million tonnes CO_2/year to enable future projects
- CO_2 to be permanently stored in a deep saline formation offshore, beneath the North Sea

Project key-knowledge reports

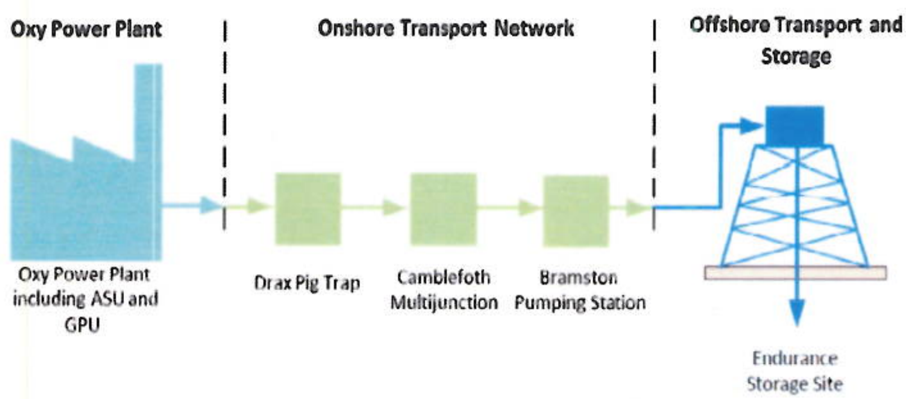
- 41 documents to be published by Department of Energy & Climate Change (DECC), UK including:
  - Full-chain FEED summary report
  - Full-chain basis of design
  - Full-chain FEED lessons learnt
  - Full-chain FEED risk report
  - Full-chain project programme
  - Full-chain project cost estimate report
  - Financing feasibility report
  - Financial model
  - Project execution plan
  - Various technical documents

Commercial landscape



Capex estimate

White Rose full-chain CCS project



Full Chain Interim Cost Estimate – Basis

- Cost estimate performed through 2015 assuming an NTP late 2015 as part of FEED work.
- Capture Power managed the estimating process (alignment, basis, reviews, etc)
  - OPP - Input from GE, BOC, Drax and owners costs by CPL
  - T&S – Input from NGC
- Market enquiries undertaken for 90% of the project's costs.
- Costs assessed to be equivalent to AACE Level 2 for the majority of items.
- Monte Carlo analyses performed for calculation of uncertainty bands and establishment of P_{50}, P_{10} and P_{90} values.

Cost Estimate for dissemination[1]

Oxy Power Plant

- Cost estimate adjusted to take out project specifics allowing comparisons with other published data:
  - Site preparation costs removed
  - US Gulf Coast basis
  - Construction through to Mechanical Completion
  - Owners costs (Development costs, Implementation team, Advisors, Site specific costs, insurances, etc.)
  - Hedging costs (exchange rate as of November 2015)
- Transport & Storage network
  - cost estimate corresponds to an oversized network, e.g. 17 MTA capacity pipeline
  - No location adjustments made (i.e. UK basis).

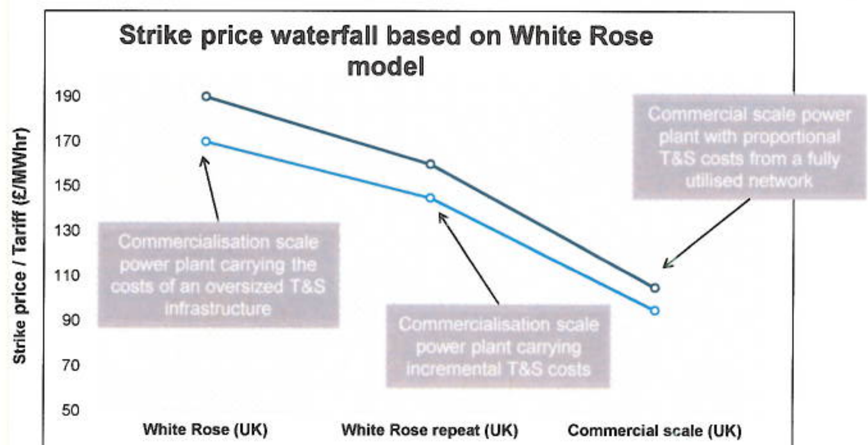
[1] Preview of information yet to be published by the UK DECC through Key Knowledge Deliverable

Normalised Capex estimate

#	Cost element	Notes	P_{50} (£m)	P_{10}	P_{90}	Drivers of uncertainty
1	Externally supplied OPP utilities	Interconnections for coal, limestone, water etc.	49	-3%	+3%	Commodity and labour prices
2	Oxyfuel boiler, Air Separation Unit and Gas Processing Unit	Equipment	455	-2%	+3%	Commodity and labour prices, technology risks
3	Oxy-power plant generation equipment and BoP	Including civils and erection for element 2	471	-3%	+4%	Commodity and labour prices
4	Onshore CO_2 pipeline	Including multi-junction, pumping station, metering and owner's costs	358	-6%	+6%	Commodity and labour prices
5	Offshore pipeline	Including landfall and owner's costs	225	-11%	+11%	Commodity and labour prices, offshore risks
6	Storage facilities	Including the platform, wells, metering and owner's costs	344	-17%	+21%	Commodity and labour prices, offshore risks, storage risk

[1] Nominal, NTP assumed November 2017

Strike price projections for follow-on projects



Projects assumed to tie in to White Rose T&S

Strike prices 2012 real terms

Lessons learnt

Commercial

White Rose Key Commercial Lessons Learnt

The 4 key commercial lessons learnt that are presented are relevant to projects that have some or all of the following characteristics:

- No liquid, demonstrable and commercially financeable CO_2 transport and storage (T&S) system available.
- No value associated with the CO_2 going to store, e.g. Saline storage or depleted oil and gas without EOR. (Waste disposal business!)
- Lack of liquid market for available CO_2 to the T&S system
- Independent developers for the individual chain links with limited (capped) cross chain liabilities
- Limited recourse project finance approach for one or more chain links, with no cross security over the other assets
- Others

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1. Full-chain commercial structuring.

Management of cross-chain risks: **challenges**

- The inter-dependence of individual businesses across the full CCS scope raises cross-chain risk issues.
- Most significant manifestation is the cross chain default risk or "Project on Project risk".
  - Limited appetite of investors and lenders to accept significant cross chain risks outside of their control e.g.
    - Construction delays of another chain link
    - Unavailability of another chain link (performance issues)
    - Insolvency of another chain link
- Commercial projects not readily financeable in absence of resolution of Project on Project risks

1. Full-chain commercial structuring.

Management of cross-chain risks: **considerations**

- Potential solution via decoupling the T&S links from the generation link from a risk perspective, with an entity (State) absorbing cross chain default/performance risk
- T&S infrastructure could be structured as national infrastructure project.
- In the UK a regulated asset based (RAB) model could for example be considered:
  - Regulator licenses the T&S operator who provides the CO_2 T&S storage service.
    - Regulator has powers to enforce obligations and of step-in (Special Administration)
  - Regulated return for the provider of the T&S infrastructure, with KPI incentives
    - Regulator determines amounts to be charged to users
  - Financial support package for non-availability of Users, CCS risks, Others?
- Generation projects could be developed on traditional models, however.
  - Market price support for CCS costs required and,
  - T&S availability protection required e.g. financial compensation

2. Non-EOR CO_2 storage business model

Seeking storage business investment: **challenges**

- Non-EOR related CO_2 storage is a "high" risk and "low" return business, especially for offshore solutions:
  - Potential liabilities in the unlikely event of CO_2 leakage.
  - Likely returns capped by energy markets and regulators (latter in a regulated model).
- Limited market appetite for accepting long-term CO_2 storage risk especially, in absence of insurance solutions.
- Oil & gas investors deem returns as insufficient unless EOR is involved.
- Financial and other investors unable to bring requisite skills.

2. Non-EOR CO_2 storage business model

Seeking storage business investment: **considerations**

- Non-EOR related storage could be structured as national infrastructure projects:
  - e.g. UK RAB model
- Long-term storage risk underwriting
  - State backed support for storage liabilities (time dependent financial support, or insurance of last resort, etc.)
  - Decommissioning support (funding adequacy)
  - Timely hand over of store to State following decommissioning.
- De-risk sufficiently to attract institutional investors willing to accept low-risk lower reward opportunities.
  - Would have benefit of reducing costs of Storage albeit by transferring risk to the state.

3. Oversizing and sharing T&S infrastructure

T&S infrastructure: **challenges**

- Point-to-point minimum necessary T&S infrastructure development, linked to a single generator unlikely to be competitive for most commercial projects.
- Significant economies of scale and value for money are to be realized if T&S infrastructure developed as a "right sized" shared regional network.
- Risk allocation and 3rd party access rights
  - Who takes the risk of developing the right sized infrastructure and who benefits from access rights? (unlikely to be a single generator)
  - Who takes the risk with respect to future demand for CO_2 storage capacity? (dependent upon government policies)
  - Who takes the performance risk of the T&S assets including storage risks? (too big to fail?)
- T&S charging methodology for anchor and follow-on projects.
  - Through users or separate funding approach for T&S infrastructure?
  - Average or incremental pricing approach?

3. Oversizing and sharing T&S infrastructure

T&S infrastructure : **considerations**

- T&S needs to be developed along the lines of regional networks and needs planning to achieve economies of scale and optimum deployment:
  - Regional potential for CO_2 capture clusters including power and industrial emitters
  - Storage locations, capacity and development, including EOR/EGR potential
  - Infrastructure sizing, routing and build-out program.
- High up-front development costs especially for storage
  - Will require some level of financial support, especially with uncertainty over CCS future
- T&S providers will very likely require a degree of risk insulation:
  - Revenue certainty for failure of CCS market to develop or failure/default of user(s)
  - Long term CO_2 storage risks
  - Change in market circumstances, e.g. change in Law
- Up front clarity on 3rd party access, charging methodology, funding approach, etc.

4. Insurance

Potential insurance gaps: **challenges**

- Construction phase:
  - Adequacy of insurance coverage for CCS related risks was not confirmed, e.g. Delayed Start-up (DS) coverage for CCS specific equipment and for offshore risks.
- Operational phase:
  - Insurance coverage was not available for storage risk.
  - Adequacy of insurance coverage for CCS related risks was not confirmed, e.g. Business Interruption (BI) coverage for CCS specific equipment and offshore risks.
  - Longer-term market-appetite for operational insurances could only be assessed after operational feedback from one or more projects available.

4. Insurance

Potential insurance gaps: **considerations**

- UK DECC had proposed mechanisms to share costs associated with impact from specific CCS related construction and operational risks .
- Mechanisms were under discussion to address the storage risk and the financial instrument requirements of the EU CCS directive:
  - Establishment of a specific ring-fenced storage risk mitigation fund built over the initial operational years and maintained until handing back of the store.
  - Potential government support backing shortfalls that cannot be covered through the fund.
- Discussions were ongoing with DECC in relation to the concept of "insurer of last resort", however the need had not been fully established or agreed.
- These mechanisms may be beneficial to support initial CCS projects more widely until an insurance market is adequately developed particularly for "CCS" risks.
- In the UK a regulated utility model for T&S infrastructure could be developed to include cost recovery for certain risks which are not adequately insured.

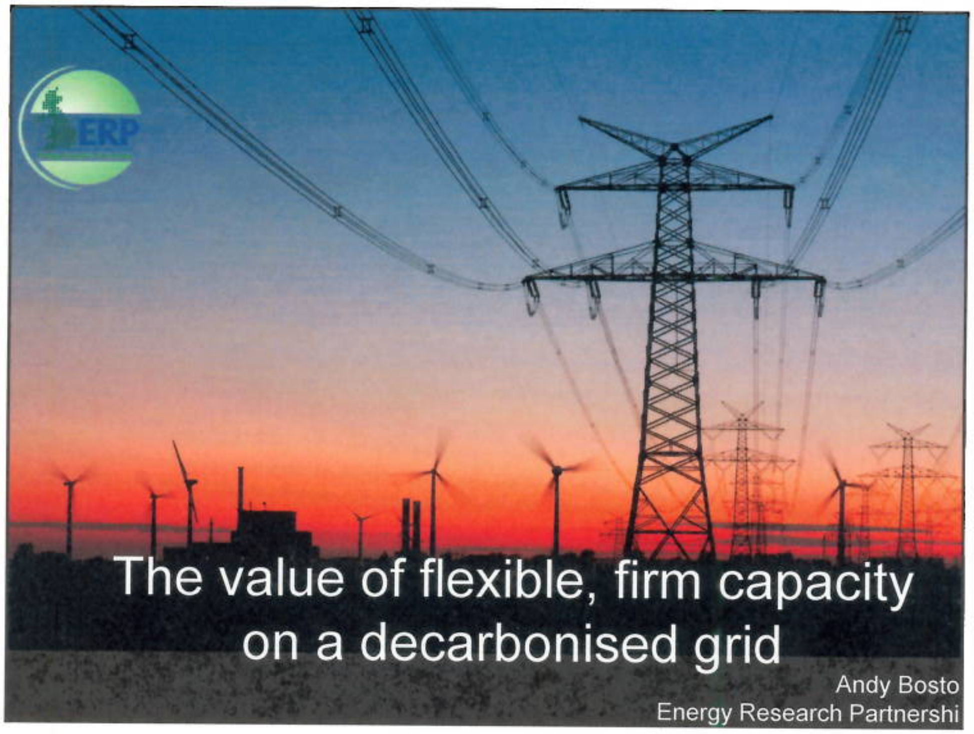
Key Take-aways

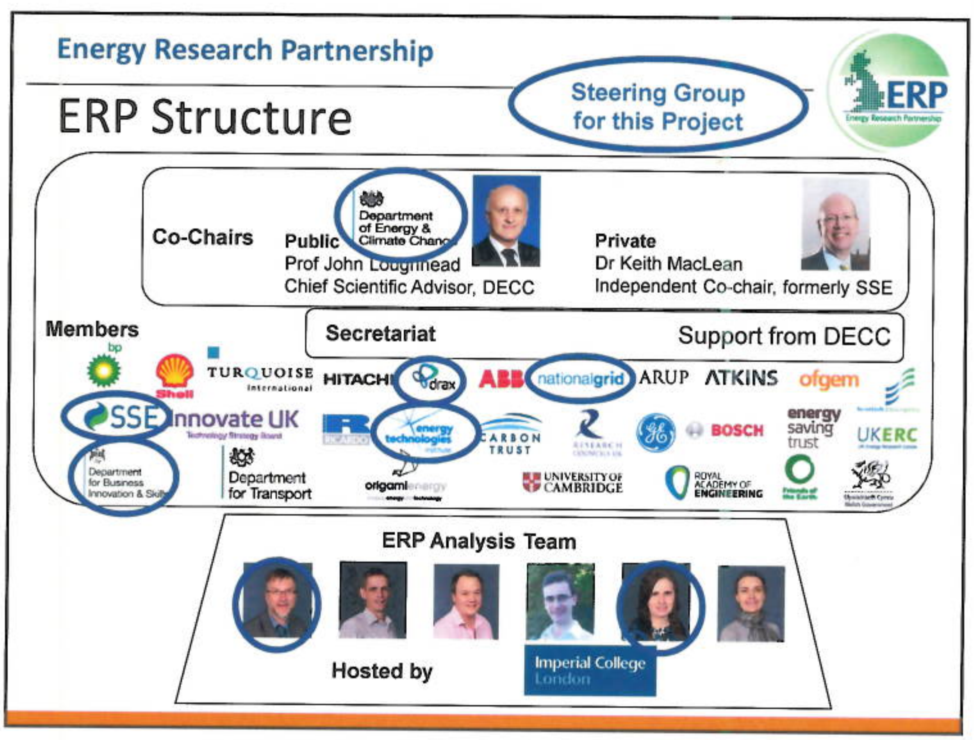
Key take-aways

- There were no significant technical impediments to project implementation.
  - Limited benefits from further R&D for oxy-fuel based CCS
- Full-chain aspects were adequately defined and developed:
  - Basis of design
  - Interfaces
  - Metering & monitoring
  - Commissioning
  - Operation & controls etc.
- large-scale commercialization projects the next logical step in the technology development road-map.
- UK Government decision to cancel the UK CCS Competition has stalled commercialization in the UK and Europe and dented confidence in CCS

Key take-aways

- CCS can be competitive with other forms of low-carbon generation including renewables and new nuclear
- Deployment of appropriate commercial structures key to enabling large-scale roll-out of flexible or base-load CCS:
  - De-link generation business models from potential T&S impact and vice versa.
  - Government support desirable for cross chain default and storage risk, at least for the initial projects.
  - Non-EOR storage is a low-return waste disposal business; de-risking the business key for attracting private sector investments.
- To achieve economies of scale and compete with other clean energy technologies T&S infrastructure needs to be right-sized and planned, considering:
  - Regional requirements, clusters and storage locations and capacities
  - Potential CO_2 uses (EOR/EGR)
- Long-term policy certainty and consistency essential for attracting investments.


ERP
The value of flexible, firm capacity on a decarbonised grid
Andy Bosto
Energy Research Partnershi


Energy Research Partnership
ERP Structure
Steering Group for this Project
ERP Energy Research Partnership
Co-Chairs
Public
Department of Energy & Climate Change
Prof John Loughhead
Chief Scientific Advisor, DECC
Private
Dr Keith MacLean
Independent Co-chair, formerly SSE
Members
Secretariat
Support from DECC
bp
Shell
TURQUOISE International
HITACHI
drax
ABB
nationalgrid
ARUP
ATKINS
ofgem
SSE
Innovate UK
Technology Strategy Board
RICARDO
energy technologies institute
CARBON TRUST
BOSCH
energy saving trust
UKERC
Department for Business Innovation & Skills
Department for Transport
origami energy
UNIVERSITY OF CAMBRIDGE
ROYAL ACADEMY OF ENGINEERING
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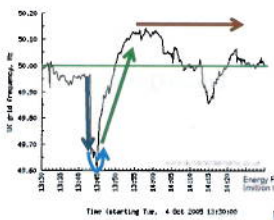
ERP Analysis Team
Hosted by
Imperial College London

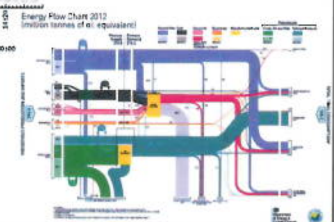
Energy Research Partnership

Key Messages

A zero- or very low- carbon system with weather dependent renewables needs low carbon technologies to provide firm capacity



Policy makers and system operators need to value services that ensure grid stability so new providers feel a market



A holistic approach to system cost would better recognise the importance of firm low carbon technologies and the cost of balancing the system

Energy Research Partnership

ERP Modelling

ERP modelling stacked generation to meet demand exploring different mixes of low carbon technologies on the system. It met the following criteria on an hourly basis:

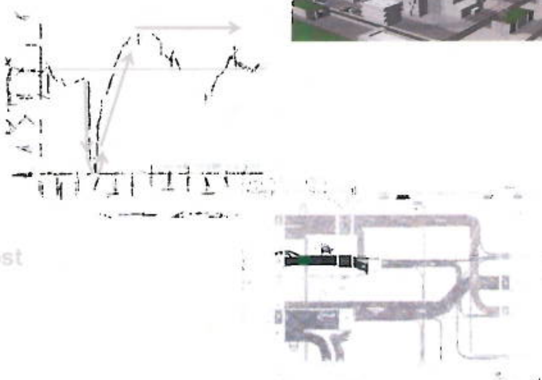
- Energy balancing – nearly all modelling does this, at least on an annual basis
- Sufficient firm capacity – ensures peak demand can be met
- Sufficient flexibility – the model ensures there's sufficient reserve, response and inertia at all times.

Energy Research Partnership

Firm Zero-C Capacity

A zero- or very low- carbon system with weather dependent renewables needs low carbon technologies to provide firm capacity

Policy makers and system operators need to value services that ensure grid stability so new providers feel a market



A holistic approach to system cost would better recognise the importance of firm low carbon technologies and the cost of balancing the system

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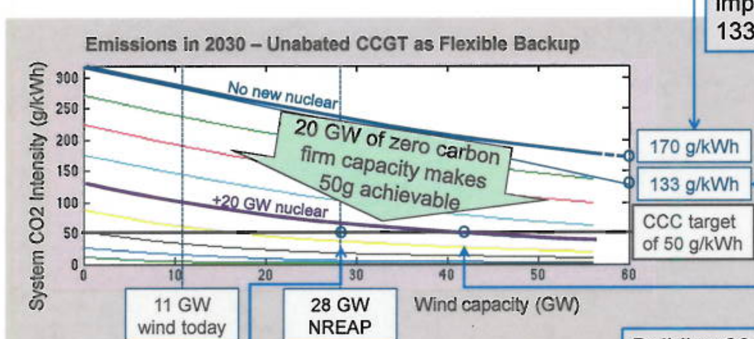
Energy Research Partnership

The need for firm capacity

With no new nuclear (or any other zero carbon firm capacity), the best that 60 GW of onshore wind can achieve is about 170 g/kWh

Infinite storage or demand side response could improve that to 133 g/kWh



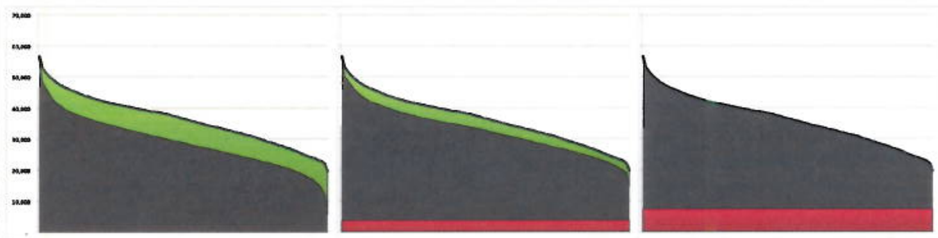
If wind build didn't exceed the National Renewable Energy Action Plant then 23 GW of nuclear would achieve 50 g/kWh

Building 20 GW of nuclear means 50 g/kWh can be achieved with 42 GW of onshore wind

Energy Research Partnership

Load Duration for 20% low carbon

Renewable | Mix | Zero Carbon Firm



Renewable	Mix	Zero Carbon Firm
17 GW PV	8 GW PV	No PV
17 GW Wind	8 GW Wind	No Wind
No ZCF	4 GW ZCF	8 GW ZCF
67 GW CCGT	63 GW CCGT	59 GW CCGT
330 g/kWh	330 g/kWh	330 g/kWh

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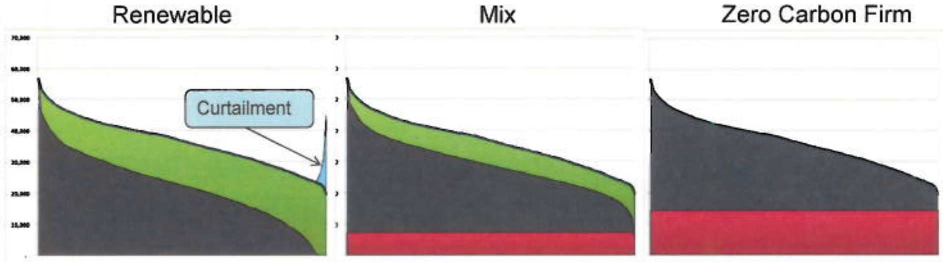
Load Duration for 40% low carbon

Renewable | Mix | Zero Carbon Firm



Renewable	Mix	Zero Carbon Firm
49 GW PV	24 GW PV	No PV
49 GW Wind	24 GW Wind	No Wind
No ZCF	8 GW ZCF	16 GW ZCF
67 GW CCGT	59 GW CCGT	51 GW CCGT
212 g/kWh	210 g/kWh	210 g/kWh

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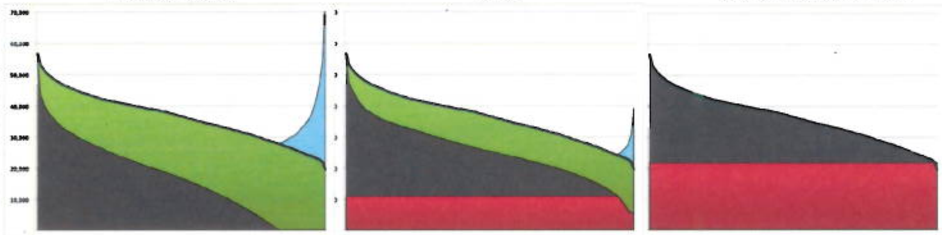
Load Duration for 60% low carbon

Renewable	Mix	Zero Carbon Firm



73 GW PV	37 GW PV	No PV
73 GW Wind	37 GW Wind	No Wind
No ZCF	12 GW ZCF	24 GW ZCF
67 GW CCGT	55 GW CCGT	43 GW CCGT
158 g/kWh	143 g/kWh	139 g/kWh

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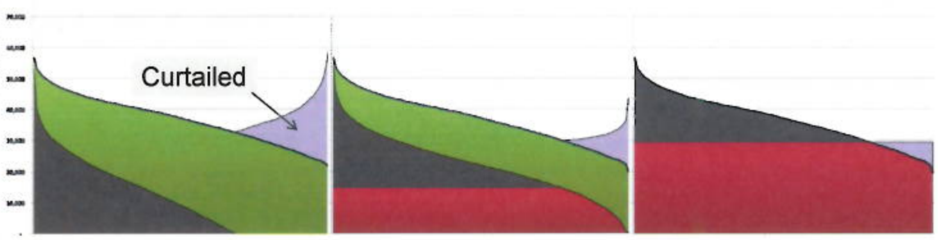
Load Duration for 80% low carbon

Renewable	Mix	Zero Carbon Firm



68 GW PV	34 GW PV	No PV
68 GW Wind	34 GW Wind	No Wind
No ZCF	16 GW ZCF	32 GW ZCF
67 GW gas	51 GW gas	35 GW CCGT
128 g/kWh	98 g/kWh	91 g/kWh

Energy Research Partnership

Load Duration for 80-100% Renewable

6h storage, 80% renew | 48h storage, 80% renew | 48h storage, 100% renew

6h storage, 80% renew	48h storage, 80% renew	48h storage, 100% renew
68 GW PV	68 GW PV	86 GW PV
68 GW Wind	68 GW Wind	86 GW Wind
No ZCF	No ZCF	No ZCF
67 GW CCGT	67 GW gas	67 GW gas
30 GW 6h store	30GW 48h store	30GW 48h store
112 g/kWh	98 g/kWh	50 g/kWh
6% curtailment	1% curtailment	8% curtailment

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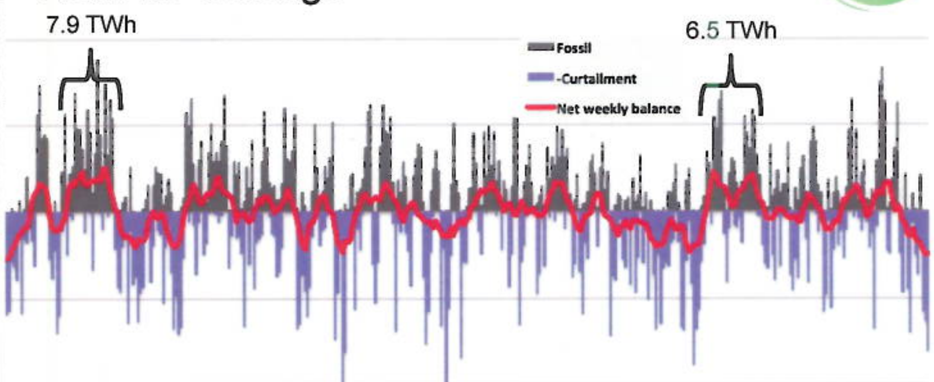
Role for Storage

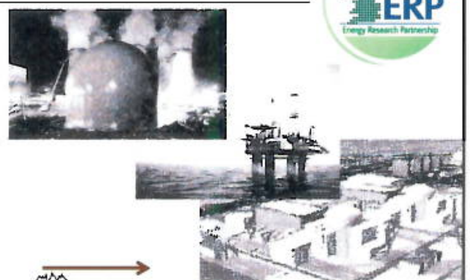


Scenario: There's sufficient weather dependent renewables to meet demand, PV and Wind balanced to eliminate summer/winter imbalance
For storage to eliminate fossil (or other firm capacity) would require ~15GW to hold ~8 TWh ready for lulls in output with 1-2 cycles p.a.
Hence providing security is probably not best role for storage
But 25 cycles above, or diurnal cycles or reserve, response or inertia may be.

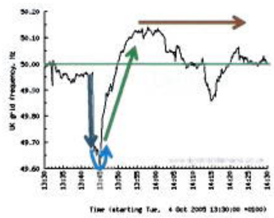
Energy Research Partnership

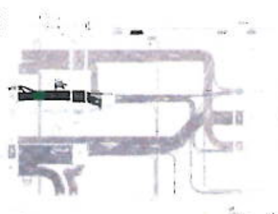
Valuing Flexibility

A zero- or very low- carbon system with weather dependent renewables needs low carbon technologies to provide firm capacity



Policy makers and system operators need to value services that ensure grid stability so new providers feel a market

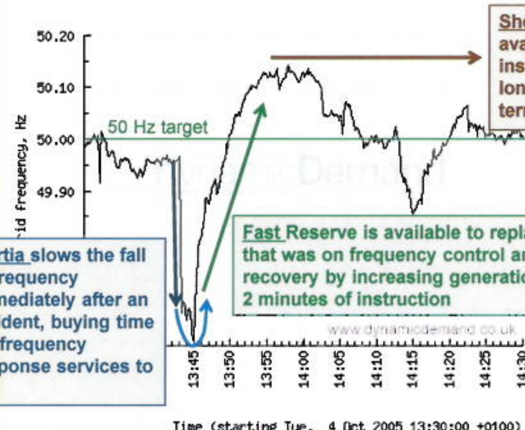




A holistic approach to system cost would better recognise the importance of firm low carbon technologies and the cost of balancing the system

Energy Research Partnership

Essential Grid Services



Short Term Operating Reserve (STOR) is available within 5-20 minutes of instruction, although some can be as long as 4 hours. This provides a longer term replacement for the lost generation

Generator loss incident
1000MW is lost at 13:43. Frequency drops to 49.6 Hz before recovery begins. Statutory limit is 49.5 Hz.

Fast Reserve is available to replace plant that was on frequency control and aid recovery by increasing generation within 2 minutes of instruction

Inertia slows the fall in frequency immediately after an incident, buying time for frequency response services to act

There are 22 ancillary services NG buy, but these four are key for energy balancing + the need for firm capacity > peak demand*

Frequency response automatically increases generation or decreases demand to begin recovery. Acts in 10-30s window (primary) or 30s-30m window (secondary)

* Others include: voltage control; MaxGen, warming and fast start contracts for fossil; intertrips; transmission constraint agreements; SO to SO (interconnector) services; black start.

Energy Research Partnership

ERP

The Need for Market Pull

There are technical services essential for grid stability

Balance of grid services

SUPPLY is disappearing

Traditional suppliers are going:
- Closure of coal & ...
- closure of auxiliary gas turbines
- Closure of Oil
- AGR end of life
- Poor economics & low load factors of gas

DEMAND is increasing

More intermittent renewables + larger unit size (new nuc.):
- Greater need for reserve
- Less inertia (stability)
- Greater demand for response
- Response has to be faster

NEW SUPPLY? but little incentive
- Dynamic use of interconnectors
- Storage
- Existing demand => responsive
- New active demand (EV, HP)
- New gas plant
- New CCS
- Flexible biomass
- Existing embedded generation

Little or no value is attributed to some essential grid services.
New providers cannot develop if there is no long term market signal

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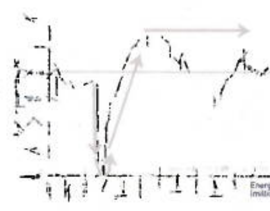
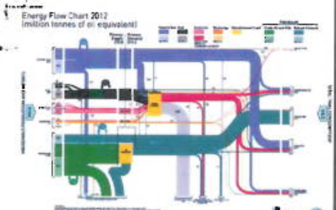
ERP

Holistic Evaluation

A zero- or very low- carbon system with weather dependent renewables needs low carbon technologies to provide firm capacity



Policy makers and system operators need to value services that ensure grid stability so new providers feel a market



A holistic approach to system cost would better recognise the importance of firm low carbon technologies and the cost of balancing the system

Energy Research Partnership

The Need for a Holistic Approach

Traditional approach – all that matters is delivery of energy so calculate the levelised cost of energy.

$$\text{LCOE} = \frac{\text{all costs annualised*}}{\text{annual energy production*}}$$

* These can be reduced with an annual discount factor

Example using DECC costs

LCOE		£/MWh
1st	Wind	81
2nd	Nuclear	87
3rd	Gas-CCS	91

This is simple and **works well for conventional thermal & hydro** comparisons – When energy is delivered they can all offer other services:

- flexibility (load following, reserve, response)
- inertia
- firm capacity

However this doesn't work for technologies

- that only deliver some of these services
- deliver no energy
- increase the need for some grid services

- Wind
- PV
- Nuclear
- Storage
- Demand Resp.
- Interconnectors

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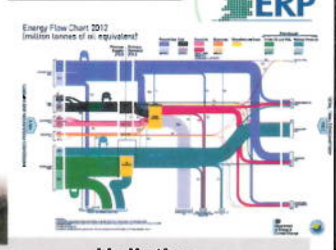
Key Messages

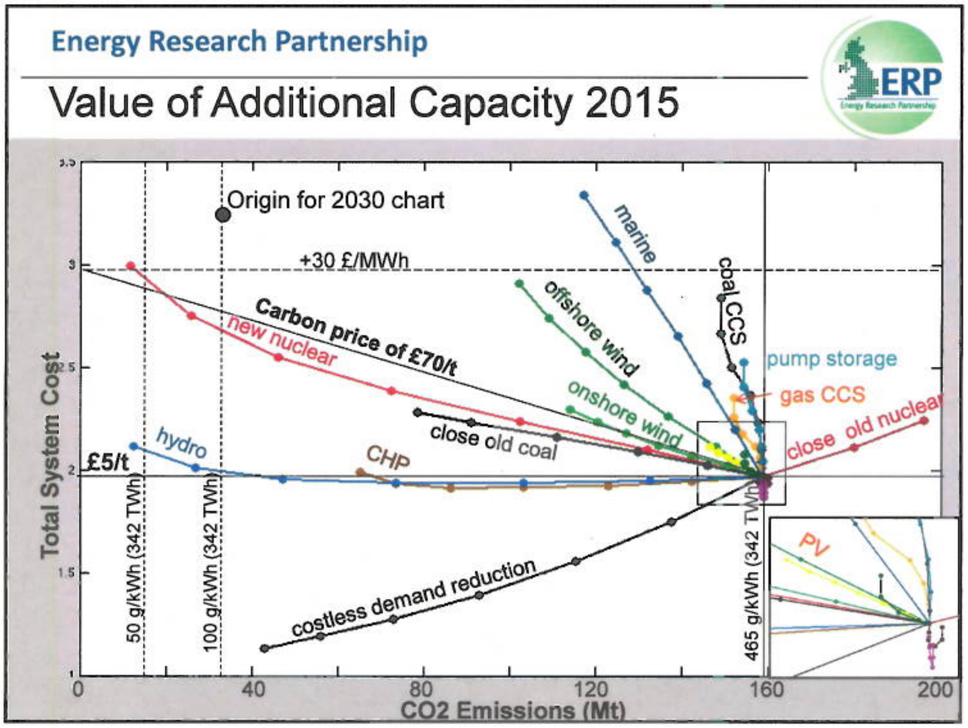
A holistic approach to system cost would better recognise the importance of firm low carbon technologies and the cost of balancing the system



	Additional services provided / increased need			Traditional	Holistic: Reduction in system cost	
Tech.	Provides Flexibility	Inertia	Firm Cap.	LCOE (£/MWh)	Net Value to pure gas sys. (£/MWh)	Net Value to Sys with 30 GW wind (£/MWh)
Nuclear	doubtful	yes	yes	87	11	8
Wind	demands	very little	very little	81	-3	-17
Gas-CCS	yes	yes	yes	91	6	4

- Previous 1st choice is different
- Value changes with the system
- Diminishing returns effect

The values here are not important, but it illustrates fact that the holistic approach values CCS firmness and flexibility



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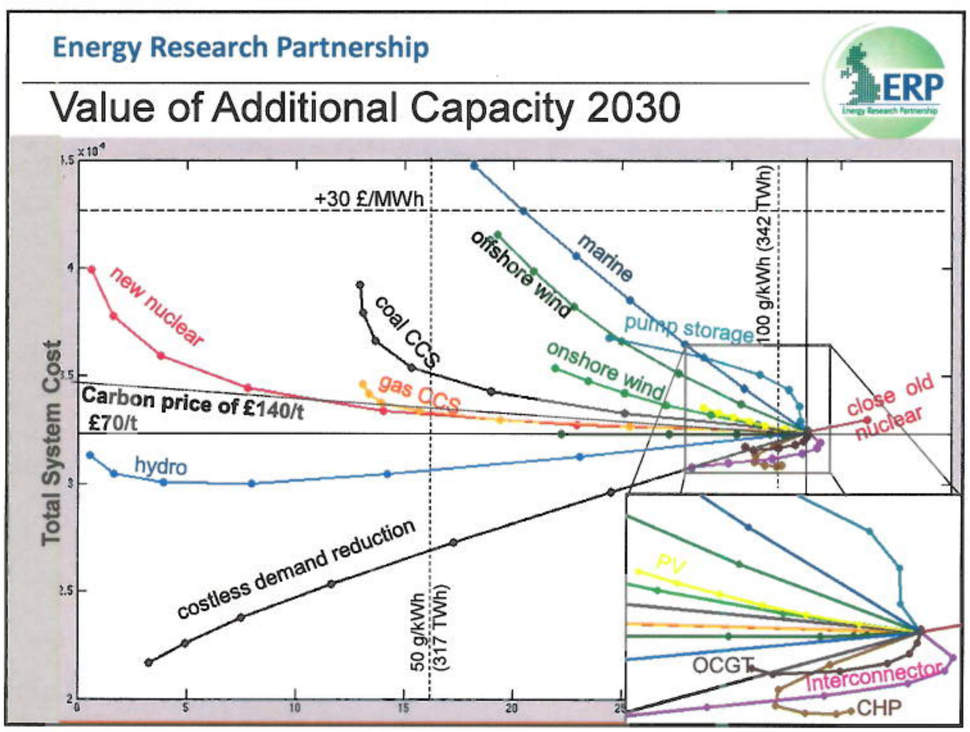
Value of Additional Capacity 2015
ERP
Origin for 2030 chart
+30 £/MWh
Carbon price of £70/t
new nuclear
marine
offshore wind
coal CCS
pump storage
gas CCS
onshore wind
close old nuclear
hydro
close old coal
CHP
£5/t
PV
costless demand reduction
50 g/kWh (342 TWh)
100 g/kWh (342 TWh)
465 g/kWh (342 TWh)
Total System Cost
CO2 Emissions (Mt)



Energy Research Partnership
Value of Additional Capacity 2030
ERP
+30 £/MWh
marine
offshore wind
new nuclear
coal CCS
pump storage
100 g/kWh (342 TWh)
onshore wind
gas CCS
Carbon price of £140/t
£70/t
close old nuclear
hydro
PV
costless demand reduction
50 g/kWh (317 TWh)
OCGT
Interconnector
CHP
Total System Cost

Energy Research Partnership

Could UK Have it's Own EnergieWende?

In essence – **yes** – UK needs a strategic narrative:

- Public engagement
- Policy Stability
- Investor Confidence

http://erpuk.org/project/public-engagement/

The same as Germany's– **no** – GB & German systems and objectives are chalk & cheese

Drive for low price	Acceptance of high subsidies
Build gas stations	Mothball new gas
Close all coal stations	Building coal stations
Close coal mines	Subsidise coal mines
Life extend old nuclear	Close old nuclear early
Island - Weak interconnection	Small part of large System

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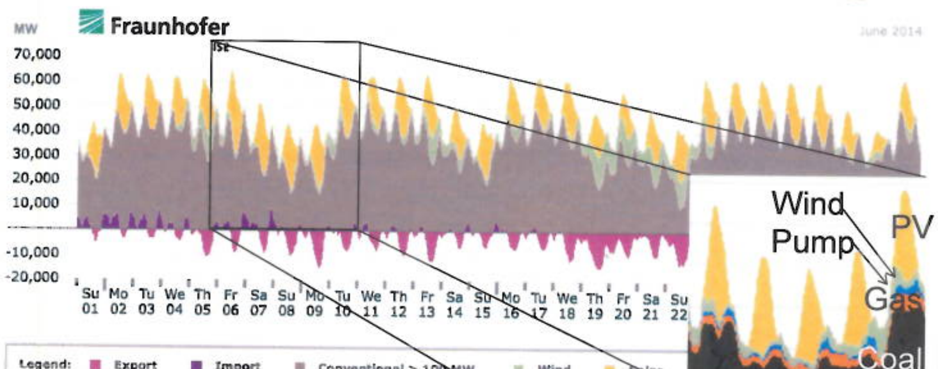
Germany



June 2014 showing how exports (pink below) correlate strongly with PV generation (yellow)

Lignite (with the highest CO2 emissions) is inflexible so a large proportion of renewable generation is exported to avoid de-loading it.

Energy Research Partnership

Key Messages

A zero- or very low- carbon system with weather dependent renewables needs companion low carbon technologies to provide firm capacity	• Cannot decarbonise to 50 g/kWh by weather dependent renewables alone • Storage, demand side & interconnection help • 15-20GW of new nuclear, biomass or fossil CCS is essential • Provides clean supply for dark, windless weeks
Policy makers and system operators need to value services that ensure grid stability so new providers feel a market	• Some necessary services (e.g. inertia/ frequency response) are free or mandated • Demand for them is growing • Traditional providers (fossil) are disappearing • Weather dependent renewables are not consistent suppliers • New providers can't develop with no market

A holistic approach to system cost would better recognise the importance of firm low carbon technologies and the cost of balancing the system	• The value of a technology is dependent on
	  • the existing generation mix
	  • the grid services it provides
	• So it cannot be valued by a single number such as levelised cost of energy (LCOE)

Duke Energy

DUKE ENERGY®

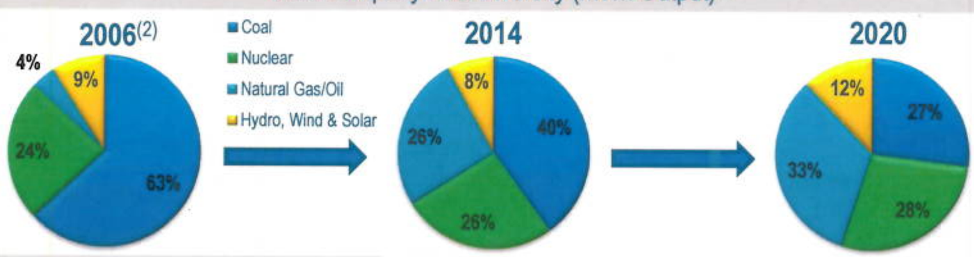
2016 MIT CCS Cost Network Workshop
Cambridge, MA

Neil Kern, March 22, 2016

Moving toward a lower carbon footprint and increased fuel diversity

DUKE ENERGY

Total Company Fuel Diversity (MWh Output)(1)



Reduction of US Generation Emissions from 2005-2014[3]

CO_2 ↓ 19% SO_2 ↓ 85% NOx ↓ 64%

- Additions of pollution control equipment
- Retirement of higher emitting plants
- Decreased coal generation
- Increased gas generation

Total Company Carbon Intensity(4)

2006		2014		2020 (Est.)
1.27 lbs/kwh	↓ 17% →	1.06 lbs/kwh	↓ 6-15% →	0.9-1 lbs/kwh

Key Takeaways

- Greater diversification of generation mix by 2020
- Expected 33% decrease in coal between 2014 and 2020
- Expected 27% increase in natural gas/oil between 2014 and 2020

(1) 2020 estimate does not reflect the recently-finalized EPA Clean Power Plan
(2) 2006 data does not include Progress Energy
(3) The divestment of our non-regulated Midwest coal and natural gas generation in April 2015 further reduces total CO2 emission to 22%, SO2 emissions to 86%, and NOx emissions to 65% from the 2005 to 2014 timeframe
(4) 2020 carbon intensity range could be impacted by customer demand, generation mix, weather, fuel availability and prices

2

6 Mega Trends Affecting Centralized Generation

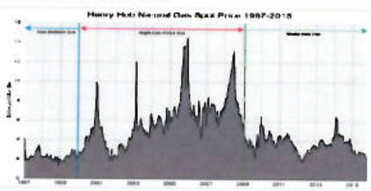
DUKE ENERGY

1. Environmental Regulations

Effect: Increasing pressure, especially on existing coal fleet, with proposed and enacted regulations.
Need: Understand best technology options to enable development of comprehensive and effective compliance strategies.

2. Natural Gas; Availability and Pricing

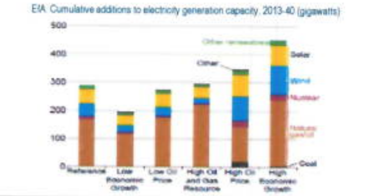
Effect: Lowest cost new generation is NGCC. Duke Energy's generation fleet is converging to around ⅓ nuclear, ⅓ coal, ⅓ natural gas.
Need: Maintain balanced generation portfolio. Support the development of advanced nuclear and fossil generation technology.



3. Reduced Emphasis on Nuclear and Coal Fleets

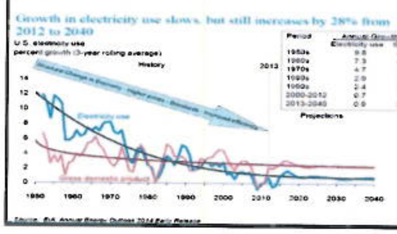
Effect: Coal plant retirements. Construction of new NGCC to replace retired coal plants. Nuclear licenses expiring. Increasing deployment of distributed generation.
Need: Long-term operations, flexibility and viability.

EIA Cumulative additions to electricity generation capacity, 2013-40 (gigawatts)



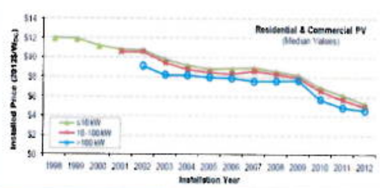
4. Decreasing Demand Growth

Effect: Generation fleet expansion curtailed.
Need: Maintain balanced generation portfolio. Long-term operation and viability of generation centralized fleet.



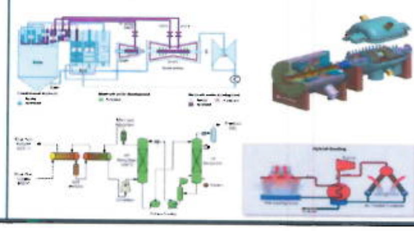
5. Decreasing Distributed Generation and Renewable Costs

Effect: Disruptive technology impacting traditional electric utility business model. Increasingly decentralized generation. Costs are decreasing faster than fossil generation assets and are able to be rapidly deployed.
Need: Maintain balanced generation portfolio. Long-term operation and viability of generation centralized fleet.



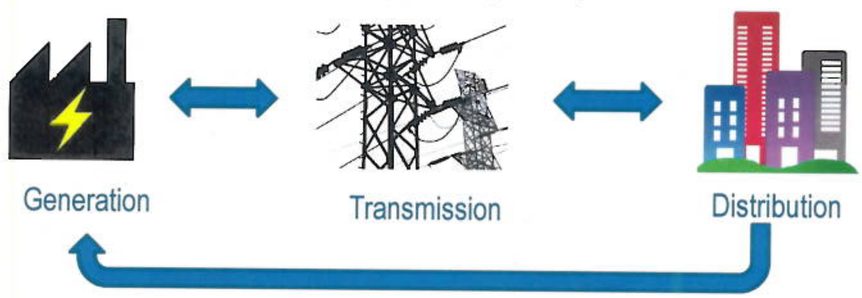
6. New Technology

Effect: Opportunity to transfer knowledge and technology into business to address key generation issues.
Need: Technology roadmaps aligned with business needs.



Utility Planning for the Future

- Paradigm shift from how traditional utility planning takes place.



- Distribution planning could significantly influence generation planning in the future.
- Generation must be able to serve the grid and respond quickly to changing grid signals.
- Must maintain the goal of providing reliable electricity to customers at all times.

4

Flexibility Overview

- Flexibility
  - Generation
    - Operational
      - Load following
      - Ramp rates/ Ancillaries
      - Minimum load
      - Layup
    - Deployment
      - Site constraints
      - Construction time
      - Minimize financial risks
      - Liabilities
    - Product
      - Size & Capacity
      - Technology application
      - Modular
      - Prefabrication
  - Transmission & Distribution
  - System Operations
  - Demand Side

Air	Climate	Water	Land & Natural Resources	Waste & Chemical Management
Criteria Pollutants NOx / SO_2	NSPS – New & Modified Sources	316(a) – Thermal	Transmission Siting and Permitting	Coal Ash
PM, NOx, SO_2	NSPS – Existing Sources	316(b) – Cooling Water Intake Structures	Avian Protection	PCBs in Electrical Equipment
Regional Haze/Visibility		Effluent Guidelines Limitations	Endangered Species	HazMat Transport
Hazardous Pollutants		Waters of the United States	Vegetation Management	
		NPDES Pesticide Permits		
		Waterbody-Specific Standards		
		Stormwater Permits		
		Ash Pond Groundwater		

Future generation must capture flexible attributes while maintaining reliable and environmentally sustainable performance.

Value of Firm Capacity of Central Generation

Dispatchable Power

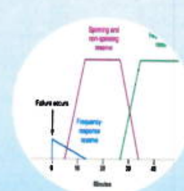
- Asset output is able to be controlled by the system operator

System Inertia

- Ensure grid frequency stability

Peak Capacity

- Dispatch energy at peak demand
- Rapid response



Reserve Capacity

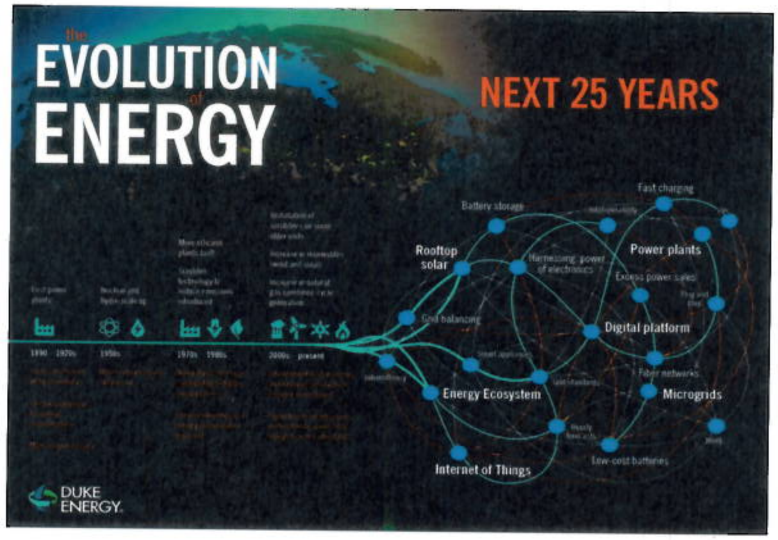
- Provide day ahead reserve capacity
- Provide safety margin

Value of Firm Capacity and Flexibility are Related but not Interchangeable

Pictures: GE, Cal ISO, ORNL 6

Conclusion

- Currently, there is no standard metric for quantifying the value of flexibility.
- Central generation has a place in the future but its role will be significantly different (i.e. more flexible)
- CCS technology must not hinder flexibility.
- Explore non-traditional markets for central stations (polygen, CHP, desalinization, etc.)
- Technologies must be economically competitive to justify ongoing O&M spend.



7

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8

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