Proceedings from the 2012

CCS Cost Workshop

25-26 April 2012
California, US

Published: April 2013,
By: Global CCS Institute, Canberra, Australia

Sponsored by:

CONTENTS

AGENDA

DAY 1	WEDNESDAY, 25 APRIL 2012
08:30 – 9:00	08:30 – 9:00 Registration and/or Continental Breakfast
09:00 – 9:30	Opening Session
	Welcome: Richard Rhudy, EPRI ▪ Purpose and scope of workshop: Richard Rhudy, EPRI ▪ Introduction of participants (all) ▪ Overview of agenda: John Davison, IEAGHG
9:30 – 11:00	Session 1: CCS Costing Methods and Measures
	Overview: Ed Rubin, Carnegie-Mellon (20 minutes) ▪ Respondent 1: Ron Schoff, EPRI (12 minutes) ▪ Respondent 2: Rosa Maria Domenichini, Foster Wheeler (12 minutes) ▪ Respondent 3: Vic Der, Global CCS Institute (12 minutes) ▪ Questions/discussion (34 minutes)
11:00 – 11:30	Break
11:30 – 1:00	Session 2: Understanding the Cost of Demonstration Projects
	Overview: Howard Herzog, MIT (15 minutes) ▪ Australian Demo: Chris Greig, University of Queensland (15 minutes) ▪ Europe Demo: Clas Ekstrom, Vattenfall (15 minutes) ▪ Canada Demo: Maxwell Ball, SaskPower via teleconference (15 minutes) ▪ Questions/discussion (30 minutes)
13:00 – 14:00	Lunch
14:00 – 15:30	Session 3: Transport, Storage, and Utilization
	▪ DOE Transport and Storage Model: Tim Grant, NETL (20 minutes) ▪ Economic value of EOR: Vello Kuuskraa, ARI (20 minutes) ▪ EOR operator perspective: Mike Moore, BlueSource (20 minutes) ▪ Questions/discussion (30 minutes)
15:30 – 16:00	Break
16:00 – 17:30	Session 4: Evaluating Economics of Emerging Processes
	▪ Flavio Franco, Alstom, presented by Carl Bozzuto (20 minutes) ▪ Abhoyjit Bhown, EPRI (20 minutes) ▪ John Wimer, NETL (20 minutes) ▪ Questions/discussion (30 minutes)
17:30 – 18:00	CCS Cost Bibliography: Howard Herzog, MIT; Chris Short, Global CCS Institute
18:00	Adjourn, Day 1
19:00	Dinner

DAY 2	THURSDAY, 26 APRIL 2012
09:00 – 9:45	Panel Discussion: Perspectives on CCS Costs in China
	▪ David Julius, Duke Energy (10 minutes) ▪ Carl Bozzuto, Alstom (10 minutes) ▪ Questions/discussion (25 minutes)
09:45 – 10:00	Charge to breakout sessions (Howard Herzog)
10:00 – 10:20	Break
10:20 – 12:00	Breakout Sessions
	Breakout 1: CCS Costing Methods and Measures Chair: Ed Rubin, Carnegie-Mellon Rapporteur: Ron Schoff, EPRI *Breakout 2: Understanding the Cost of Demonstration Projects* Chair: Howard Herzog, MIT Rapporteur: Dick Rhudy, EPRI *Breakout 3: Transport, Storage, and Utilization* Chair: Chris Short, Global CCS Institute Rapporteur: Sean McCoy, IEA *Breakout 4: Economics of Emerging Processes* Chair: Clas Ekstrom, Vattenfall Rapporteur: John Davison, IEAGHG
12:00 – 13:00	Lunch
13:00 – 14:00	Reports from Breakout Sessions (15 minutes each)
14:00 – 15:00	Wrap-up Session: Ed Rubin, Carnegie-Mellon
	▪ Dissemination of results ▪ Ed Rubin, Carnegie-Mellon (15 minutes) ▪ Discussion (15 minutes) ▪ Recommendations/plans for follow-up action/future meetings (30 minutes)
15:00	Adjourn: Richard Rhudy, EPRI

PARTICIPANTS

Robert Bailes	ExxonMobil
Robin Bedilion	EPRI
Abhoyjit Bhown	EPRI
James Black	NETL
George Booras	EPRI
Carl Bozzuto	Alstom
Dave Butler	CCPC
Robert Craig	ICO2N
Doug Daverne	SaskPower
John Davison	IEAGHG
Vic Der	Global CCS Institute
Des Dillon	EPRI
Rosa Maria Domenichini	Foster Wheeler
James Dooley	PNL
Clas Ekström	Vattenfall
Nils Eldrup	Tel-Tek
Tim Grant	NETL
Chris Greig	U of Queensland
Howard Herzog	MIT
Robin Irons	E.ON
David Julius	Duke
Vello Kuuskraa	ARI
Jeffery Lewis	CCS TLM
Wilfried Maas	Shell
Andrew Maxson	EPRI
Sean McCoy	IEA
Mike Moore	Blue Source
Mike Parker	ExxonMobil
Satish Reddy	Fluor
Richard Rhudy	EPRI
Ed Rubin	Carnegie Mellon University
Ron Schoff	EPRI
Christopher Short	Global CCS Institute
Dale Simbeck	SFA Pacific
Dalton Stuart	EPRI
John Thompsom	Clean Air Task Force
John Tombari	Schlumberger

Rob Trautz	EPRI
Paul Webly	University of Melbourne
Jennifer Wilcox	Stanford
John Wimer	NETL

INTRODUCTION

The third meeting of the Expert Group on CCS costs was held on April 25-26 2013 and hosted by the Electric Power Research Institute in Palo Alto. The current understanding of the costs of CCS were presented at that meeting and the agreed outcomes for the Group to take forward are included in this document. This work program consists of efforts to improve both the transparency of CCS cost calculations and the broader challenges associated with conveying messages around costs to the broader community.

The meeting focused on a number of issues including considering guidelines and recommendations developed by a Task Group for a costing method and nomenclature that could be broadly adopted to produce more consistent and transparent cost estimates for CCS applied to electric power plants; along with how to evaluate emerging proess as well as transport, storage and utilization.

Topics discussed over the two days included:

- What are the main reasons for the reported costs of CCS demonstrations being significantly higher than the numbers in published CCS cost studies?
- What information would be useful to have from demonstration projects to help improve the published cost estimates?
- Should transport and storage form part of the work program to harmonize cost methods and nomencluatrue? And if so, what cost elements can be harmonized?
- How should ‘enhanced oil recovery’ storage operations be incorporated in harmonization efforts for storage? Alternatively, do the cost categories vary compared to saline formations?
- What types of methodologies are used to estimate costs for emergin processes?
- What kind of information should be reported in order to understand ‘what lies behind’ economic evaluations of emerging processes?
- How is the mix of commercially proven and modifications to commercially proven technologies best handled in terms of estimating equipment costs?
- How can uncertainties and risks be assessed in relation to estimated costs?

The meeting was organized by a Steering Group including representatives from: Carnegie Mellon University (Ed Rubin), Electric Power Research Institute (Richard Rhudy), Global CCS Institute (Christopher Short), International Energy Agency (Sean McCoy), IEA Greenhouse Gas R&D Programme (John Davison), MIT Carbon Sequestration Initiative (Howard Herzog) and Vattenfall (Clas Ekström).

Cost issues regarding demonstration projects:

There are many reasons for differences between the benchmark studies and the project cost estimates including:

- Time reference
- Scope (greenfields vs. retrofits)
- Location (available infrastructure, logistics, local costs, climate)
- Maturity (e.g. IGCC is less mature)
- Economies of scale (demonstration projects on smaller side).

Further, there are methodological challenges in comparing technology cost studies with estimated project costs including:

- Benchmark studies not required to be guaranteed
- Project proposals may be have an element of ‘gold plating’ to guard against risk.

Proposed follow-up action:

- Reconcile actual project studies and benchmark studies
- Understand cost evolution as a function of project evolution
- Develop a cost roadmap from FOAK to NOAK.

Transport, storage and utilization issues:

Issues discussed included:

- Exploration cost is all about the likelihood of success; this is dependent on the availability and quality of data.
- Storage costs are not just about the cost at one site, but also the cost of characterizing other options in a portfolio of sites. The whole cost of characterizing the portfolio of sites, many of which will be inappropriate for storage, is covered by a handful of successes. This highlights the need for regional site characterization.
- The ability of larger companies versus small-mid sized producers in managing these risks and their costs presents costing challenges on a standardized basis.

Other issues noted include:

- How do the cost of compliance with regulations affect the cost of storage? Was there an underestimation of these type of costs?
- The time-flow of costs as well as expected problems and time to identify solutions should be included. For example, contingencies in well drilling and completions are typically considered to be around 20-25 per cent in oil and gas projects.
- There is a trade-off between transport and storage costs as increased transport costs to more remote, but less costly, storages locations can be part of the storage assessment (or storage ‘plays’).
- Nomenclature for different levels of cost estimate accuracy for storage could be developed in order to reduce confusions.
- The difference between observed and realized cost estimates is very important—there is large population of sites and associated storage costs, but the higher cost estimates will never be realized. Of course, the characterization costs will be!
- How can risk for storage characterization be best estimated in cost assessments? What is the appropriate change in the rate of return?
- As an EOR project is characteristically different from a pure storage operation, any methodology should encourage the identification of specific assumptions about the value of CO_2, how this is distributed between the source and EOR operation, and the length of time for the revenue stream.

Proposed follow-up action:

Overall, it was recognized that there was limited information in the public domain that addresses many of these issues. It was recommended that:

- Develop common method of cost estimation and nomenclature for transport and storage elements. Give consideration to what transport and storage elements should form part of these efforts, and identify the scope and boundary conditions of these components.
- Cost estimate classifications should be identified in storage specific terms:
  - Specifically, identify categories that correspond to different types of storage activities.
- Develop a classification system that appropriately aligns decreasing levels of uncertainty with additional effort – which will increase costs.

- Uncertainty should be incorporated in all storage cost assessments.
- EOR should not generally be incorporated in harmonization efforts for storage as the cost categories vary when compared to saline formations. EOR is a complicated issue and should generally be treated as a net revenue stream.

Costs of emerging processes

There are a number of challenges in considering the costs of emerging processes. These can include:

- The long timescales associated with introducing new technologies. It is suggested that historical examples of flue gas desulphurization or CCGT's are examples where times frames of 50 years or more were required to transition from idea to 10 per cent of installed capacity:
  - This suggests careful consideration required around timing for when technologies should be rejected. Unless there are fundamental reasons to reject a technology, it should be rejected 'too early' in the development cycle.
- Early developments of a technology often target energy consumption, which is relatively easy to analysis, but minimum energy does not necessarily result in the minimum cost.
- Emerging processes need to be compared against a baseline, but the baseline is itself moving due to technological improvements.
- Scalability can sometimes be an issue, such as the difficulty of synthesizing certain novel solvents at a large-scale. This suggests that assessment of the scalability of a technology may serve as a screening factor for prioritizing funding.
- Existing cost analysis of emerging processes can sometimes omit operating cost assessments due to lack of information. However, operating costs can sometimes be significant, such as the cost of replacing membranes.

Although no consensus was reached regarding issues regarding how to cost emerging processes, the following questions and responses were considered:

- What do we mean by emerging processes?
  - Don't look at costing for new concepts with limited data, uncertainties so large it is pointless.
  - First stage is to assess is it potentially technically feasible – screen based on thermodynamics, kinetics, complexity etc.
  - Only look at costs later.
- What types of methodologies are available to estimate costs for emerging processes?
  - Absolute costs should be identified for real plants, but estimating presents major problems.
  - Relative cost comparisons could be adequate for emerging processes.
  - Clear need to identify a solid baseline reference.
  - What type of baseline can serve: a new plant? a retrofit? with or without existing capture technology?
  - The methodology should identify whether the process has 'headroom', that is - will it have significant advantages?
- In most emerging technologies, some components are proven, others are modified versions, some under development whilst others are entirely theoretical. How can this be handled in terms of estimating equipment costs?
  - Any methodology should narrow costing to new processes or components.
  - The methodology should identify the percentage that is emerging equipment, which is often only 15-20 per cent.
  - This often requires preliminary drawings and estimates (e.g. weight, number of welds etc). Analogues can serve well here for processes/equipment not previously designed.

- How can uncertainties and risks be assessed in relation to estimated costs?
  - Process contingencies are challenging as they reflect plant construction issues, but how to reflect uncertainty whether a process will work as projected?
  - Risks with emerging processes are obviously high, but high contingencies may bias cost estimates upwards inappropriately for emerging process assessments.
  - Can consider a ‘hurdle rate’ rather than a process contingency – but it would be inappropriate to use both.
  - An alternative is to eschew the use of process contingencies, but require sensitivity analysis on new components (performance and costs) as an approach.
  - The methodology should consider how to assess likely cost reductions after it has reached the ‘demonstration stage’ (i.e. the nth plant).
  - Assessment of likely cost reductions are an important element in prioritizing development funding.
  - Often, the process of doing the cost estimate and sensitivity analysis contributes to the learning as much as technological issues.
- What kind of information should be reported in order to understand ‘what lies behind’ economic evaluations of emerging processes?
  - The methodologies and assumptions need to be reported. The framework identified by the Task Force on Costing Methods should be used, subject to restrictions regarding commercial confidentiality and intellectual property issues.

WELCOME

Richard Rhudy

Technical Executive

CCS Cost Workshop

April 25-26, 2012

Palo Alto, California

Welcome

- Organizing Committee
  - John Davison, IEA GHG
  - Clas Ekström, Vattenfall
  - Howard Herzog, MIT
  - Sean McCoy, IEA
  - Richard Rhudy, EPRI
  - Ed Rubin, CMU
  - Chris Short, GCCSI

ELECTRIC POWER RESEARCH INSTITUTE

Welcome

- Economics are important to EPRI
  - Need good cost studies for early development processes and those near commercial development
  - Need to understand difference between generic studies and actual costs of real projects
  - Better understand differences in economics between different regions of the world
- Why we joined the committee that put this effort together
  - Wanted to help bring consistency to costing methodology and result in more easily comparable evaluations

ELECTRIC POWER RESEARCH INSTITUTE

Administration

- Signup sheet
  - Initials on attendance—agenda available
  - Signup for Dinner—maps and directions available
  - Indicate 1st and 2nd breakout choice
  - Indicate if OK to include email on attendance list
  - Approval of presentations
  - Cell phones
  - Safety

Purpose and Scope

- Initial meeting in Amsterdam during GHGT 10
  - Determine the need for a group to focus on CCS costs
- Second meeting in Paris at the IEA offices
  - Several presentations on CCS cost issues
  - Outcome
    - Published report
    - Set up 2 working groups
      - CCS costing methods and measures (Ed Rubin)
      - CCS cost Bibliography (Howard Herzog)
- This is the third meeting
  - Continue the dialogue
  - Report on results of working groups
  - Identify additional efforts the group can undertake

Meeting Structure

- First Day
  - Reports on working groups
  - Topical presentations and discussion
- Second Day
  - Panel discussion
  - Breakout Sessions
  - Wrap-up and recommendations for follow-up

Together…Shaping the Future of Electricity

ELECTRIC POWER RESEARCH INSTITUTE

Overview of the Agenda

John Davison
IEA Greenhouse Gas R&D Programme

Workshop on CCS Costs
EPRI, Palo Alto, April 25th-26th 2012

Day 1, Morning

- Opening Session (9:00-9:30)

- CCS Costing Methods and Measures (9:30-11:00)
  - Overview: Ed Rubin (Carnegie Mellon University)
  - Respondents: Ron Schoff (EPRI)
    Rosa Maria Domenichini (Foster Wheeler)
    Vic Der (GCCSI)
  - Questions/discussion

- Understanding the Cost of Demonstration Projects (11:30-1:00)
  - Overview: Howard Herzog (MIT)
  - Australian Demo: Chris Greig (University of Queensland)
  - Europe Demo: Clas Ekström (Vattenfall)
  - Canada Demo: Maxwell Ball (SaskPower) via teleconference
  - Questions/discussion

Day 1, Afternoon

- Transport, Storage and Utilization (2:00-3:30)
  - DOE Transport & Storage Model: Tim Grant (NETL)
  - Economic Value of EOR: Vello Kuuskraa (ARI)
  - EOR Operator Perspective: Mike Moore (BlueSource)
  - Questions/discussion

- Evaluating Economics of Emerging Processes (4:00-5:30)
  - Flavio Franco (presented by Carl Bozzuto) (Alstom)
  - Abhoyjit Bhown (EPRI)
  - John Wimer (NETL)
  - Questions/discussion

- CCS Cost Bibliography (5:30-6:00)
  - Howard Herzog (MIT) and Chris Short (GCCSI)

Day 2, Morning

- Panel Discussion (09:00 – 09:45)
  Perspectives on CCS Costs in China
  - David Julius (Duke Energy)
  - Carl Bozzuto (Alstom)
  - Questions/discussion

- Breakout Sessions
  - Charge to Sessions: Howard Herzog (9:45 – 10:00)
  - Breakout Sessions (10:20 – 12:00)

    1: CCS Costing Methods and Measures

    2: Understanding Cost of Demonstration Projects

    3: Transport, Storage and Utilization

    4: Economics of Emerging Processes

Day 2, Afternoon

- Report from Breakout Sessions (1:00 – 2:00)
  - 15 minutes each
- Wrap-up Session: Ed Rubin (2:00-3:00)
  - Presentation on dissemination of results
  - Discussion
  - Recommendations / plans for follow-up action
- Adjourn (3:00)

Toward a Common Method of Cost Estimation for Carbon Capture & Storage

Edward S. Rubin

Department of Engineering and Public Policy
Department of Mechanical Engineering
Carnegie Mellon University
Pittsburgh, Pennsylvania

Presentation to the

CCS Cost Workshop

Palo Alto, California

April 25, 2012

The Context for this Talk

At last year's workshop I reviewed/discussed the:

- Common measures & metrics of CCS cost
- General methods of estimating CCS costs (ranging from "ask an expert" to detailed eng'g. studies)
- Specific methods and assumptions used by several leading organizations (EPRI, USDOE, IEAGHG, DECC)
- Influence of uncertainty, variability and bias in CCS cost estimates

Details Available in the Workshop Proceedings

- Available from GCCSI and other sponsoring organizations

- <https://kminside.globalccsinstitute.com/community/extranet/ccs_costs_network>


Proceedings of the

CCS Cost Workshop

22-23 March 2011
Paris, France
Published: October 2011

Sponsored by:

Major Conclusions

- While a number of organizations concerned with CCS have developed detailed procedures for calculating power plant and CCS costs …
- There are significant differences in the costing methods and terminology used by organizations …
- As well as significant differences in the major assumptions employed to analyze CCS systems.
- Often there is a lack of transparency that can lead to confusion, misunderstanding and mis-representation of CCS costs.

The Workshop Recommended …

- An *ad hoc* Task Force be formed to recommend ways to harmonize methods for estimating and reporting CCS costs, including:
  - A common language or nomenclature for cost estimates
  - Improved methods of reporting and communicating CCS costs information
  - Ways to characterize the variability and uncertainty in CCS costs (especially for new/emerging technologies)
  - Methods to properly compare the cost of CCS to other GHG mitigation options

CCS Cost Methods Task Force

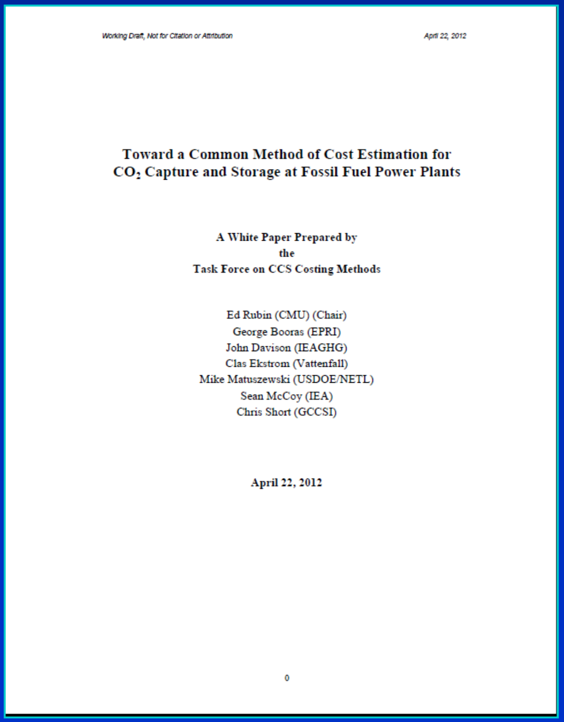
- George Booras (EPRI)
- John Davison (IEAGHG)
- Clas Ekström (Vattenfall)
- Mike Matuszewski (USDOE)
- Sean McCoy (IEA)
- Ed Rubin (CMU) *(Chair)*
- Chris Short (GCCSI)

Task Force Efforts to Date

- Formed in October 2011
- Developed initial goals, tasks and timetable
- Met regularly via teleconference (across 17-hr time zones), plus a day-long meeting in February
- Exchanged drafts and additional comments via email
- Prepared draft White Paper for discussion at this workshop

Our Paper Addresses Six Major Topics Relevant to CCS Costs

- Defining Project Scope and Design
- Defining Nomenclature and Cost Categories for CCS Cost Estimates
- Quantifying Elements of CCS Cost
- Defining Financial Structure and Economic Assumptions
- Calculating the Costs of Electricity and CO_2 Avoided
- Guidelines for CCS Cost Reporting


Working Draft, Not for Citation or Attribution   April 22, 2012

Toward a Common Method of Cost Estimation for CO_2 Capture and Storage at Fossil Fuel Power Plants

A White Paper Prepared by the Task Force on CCS Costing Methods

Ed Rubin (CMU) (Chair)
George Booras (EPRI)
John Davison (IEAGHG)
Clas Ekstrom (Vattenfall)
Mike Matuszewski (USDOE/NETL)
Sean McCoy (IEA)
Chris Short (GCCSI)

April 22, 2012

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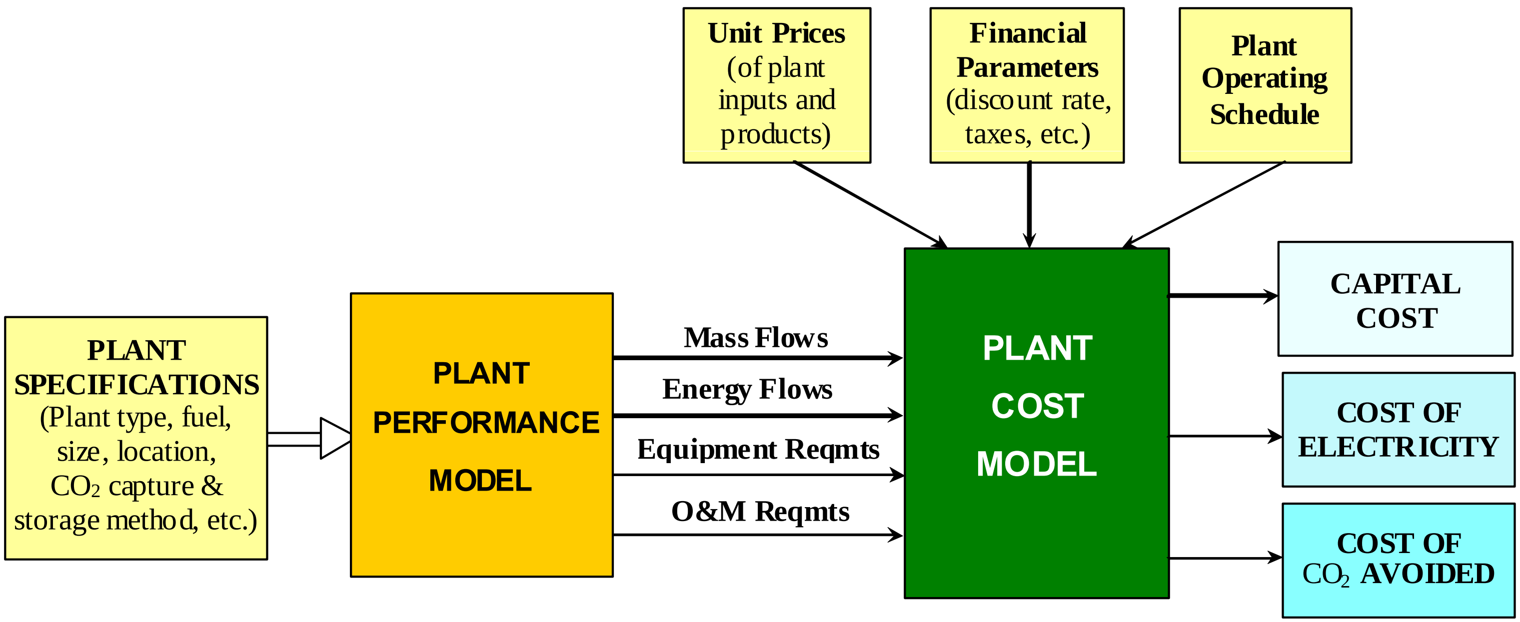
— I will touch briefly on several of these items —

Defining the Project Scope and Plant Designs

A Generalized Project Framework for CCS Cost Estimates

- CCS cost is the difference in power plants costs with and w/o CCS
- Thus, the scope and battery limits of two plants (reference plant and plant w/ CCS) must be clearly specified



Project Classes

- Specifications of scope grow more detailed as cost estimate is finalized for a real project
- Most CCS cost estimates are for Classes I, II and III (based on the EPRI classifications)

Item	Design-Estimate Effort	Project Contingency Range[a] (%)	Design Information Required	Cost Estimate Basis		
				Major Equipment	Other Materials	Labor
Class I (Similar to Amer. Assoc. of Cost Engineers (AACE) Class 5/4)	Simplified	30–50	General site conditions, geographic location and plant layout Process flow/operation diagram Product output capacities	By overall project or section-by-section based on capacity/cost graphs, ratio methods, and comparison with similar work completed by the contractor, with material adjusted to current cost indices and labor adjusted to site conditions.		
Class II (Similar to Amer. Assoc. of Cost Engineers Class 3)	Preliminary	15–30	As for Type Class I plus engineering specifics, e.g.: Major equipment specifications Preliminary P&I[b] flow diagrams	Recent purchase costs (including freight) adjusted to current cost index	By ratio to major equipment costs on plant parameters	Labor/material ratios for similar work, adjusted for site conditions and using expected average labor rates
Class III (Similar to Amer. Assoc. of Cost Engineers Class 3/2)	Detailed	10–20	A complete process design Engineering design usually 20–40% complete Project construction schedule Contractual conditions and local labor conditions	Firm quotations adjusted for possible price escalation with some critical items committed	Firm unit cost quotes (or current billing costs) based on detailed quantity take-off	Estimated man-hour units (including assessment) using expected labor rate for each job classification
				Pertinent taxes and freight included		
Class IV (Similar to Amer. Assoc. of Cost Engineers Class 1)	Finalized	5–10	As for Class III, with engineering essentially complete	As for Class III, with most items committed	As for Class III, with material on approximately 100% firm basis	As for Class III, some actual field labor productivity may be available

[a] Expressed as a percentage of the total of process capital, engineering and home office fees, and process contingency.

Task Force Illustration *(1)*

- While details will vary from project to project, an example of needed information on project scope is shown here in the form of a "checklist" for a reference coal-fired plant without CCS …

- Plant size (net power output, MW)
- Plant location (country, region of country, or state)
- Site characteristics
  - Plant elevation/atmospheric pressure
  - Average ambient dry/wet bulb temperatures
  - Minimum/maximum design temperatures
  - Relative humidity
  - Site topography (i.e., assumed to be clear and level?)
- Generation technology (IGCC, PC, CFB, oxy, etc)
  - Specific technology features
    - Gasifier type (if igcc)
    - Steam conditions (sub, SC, USC, etc.)
    - Condenser pressure
- Fuel characteristics
  - Coal ultimate analysis (including HHV and LHV)
  - Coal ash analysis (including ash fusion temperatures)
  - Coal delivery method (rail, barge, truck, conveyor, etc)
  - Natural gas availability (near pipeline?)
  - Other start-up fuel source (i.e., distillate, etc)
- Air Emission Limits (SO_2, NO_x, particulates, mercury)
- Indoor or outdoor construction?
- Makeup water source and typical quality
- Cooling water system (mechanical draft cooling tower, hyperbolic, once-through, air cooled, hybrid, etc., plus cycles of concentration)
- Waste water disposal method (zero liquid discharge required?)
- Electrical system
  - Transmission system interconnect voltage
  - Switchyard included?
  - Transmission line included? If so, how long?
- Material storage assumptions
  - Coal pile (days of storage?)
  - FGD Sorbent (days of storage?)
  - Ash/FGD solids (days of on-site storage)
- Any special noise limitations?

Task Force Illustration *(2)*

- … and here for the CO_2 transport and storage components of a CCS project using a pipeline and geologic storage.
- In all cases, <u>clear and complete reporting of assumptions is the essential requirement</u>

General Specifications:

- CO_2 design flow rate and capacity factor
- CO_2 purity (including maximum concentrations of key impurities such as water, non-condensable gases, O_2, HSE hazardous compounds such as H_2S, CO, SO_x, NO_x)
- CO_2 pressure and maximum temperature at plant gate

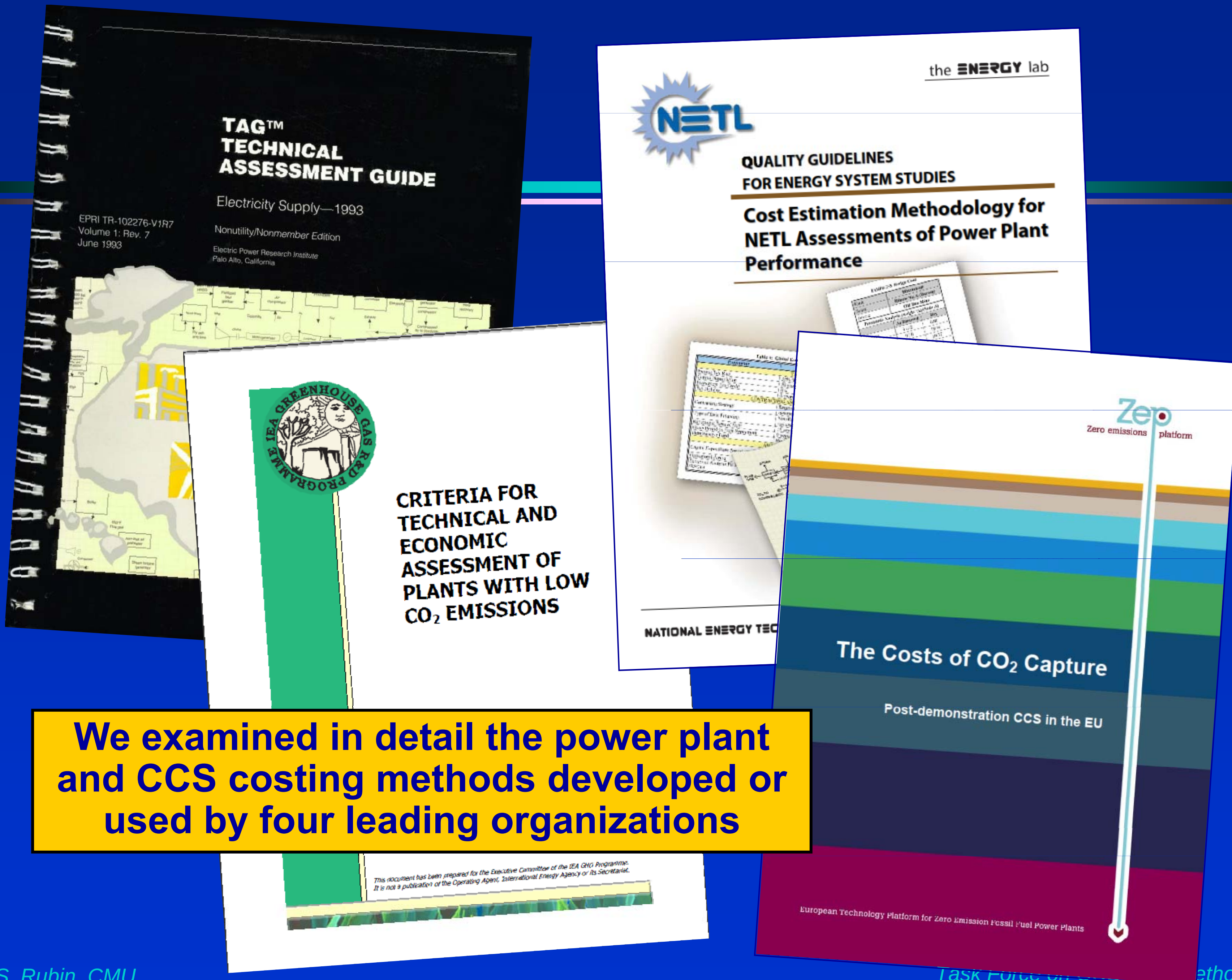
Pipeline Transport (onshore):

- Transport distance
- CO_2 pressure and temperature at storage site well-head
- Routing
- Topography along the route (e.g. bedrock, flat or hilly terrain)
- Numbers of road and river crossings (e.g. micro-tunneling)
- Maximum allowed CO_2 pressure
- Pipeline diameter, steel quality and wall thickness
- Internal and external corrosion protection
- Booster compressors and/or pumps
- Rights of way (e.g. difference between agriculturally used area, sparsely populated or uninhabited areas and populated areas)
- Pigging

Geologic Storage Site (onshore):

- Type of geologic storage site (e.g., saline aquifer, depleted oil/gas field, EOR?)
- Design life (years)
- Initial screening of multiple sites followed by characterization of the selected site(s) needed to establish/estimate:
  - Field/reservoir capacity (Mt stored CO_2)
  - Number of injection wells needed
  - Well depth
  - Geographic extension
  - Legacy wells (if depleted oil/gas field)
  - Number of new exploration and observation wells
- Well class (e.g., in the U.S., Class VI for storage and Class II for EOR)
- Requirements for monitoring, measurement and verification (MMV) during periods of site characterization, injection/operation, and post-closure (e.g., as specified in the U.S. for well Class VI) including:
  - Legal/regulatory requirements for objectives of monitoring (as in EU), as well as more specific requirements, e.g., for MMV technologies (2D, 3D, 4D seismic, monitoring wells), their spatial extent and density, and frequency of measuring campaigns.
  - Requirements imposed by industrial stakeholders
- Decommissioning of injection wells and monitoring wells (after post-closure)
- Liability transfer (to authorities after approved closure of operation)

Defining Nomenclature and Cost Categories



We examined in detail the power plant and CCS costing methods developed or used by four leading organizations

Elements of Capital Cost

- As documented at last year's workshop, while many terms are similar, we also found significant differences both in terminology and the items included …

Table A2. Capital cost elements by cost category

Cost Category	DOE/NETL	EPRI	IEA-GHG	ZEP
BEC	Process equip't	Total constructed costs of all onsite processing and generation units broken into:	Direct materials	Items not identified
	Supporting facilities Labor	Direct field labor Factory equipment Field materials & supplies	Construction costs Other costs	
EPC cost	EPC services	Engineering and home office overhead including fees	EPC services	Percentage only identified
Contingencies	Process Project	Process Project	Project Process	Items not identified
Owner's costs	Pre-paid royalties	Pre-paid royalties		Items not identified
			Feasibility study costs Surveys Land purchases Permitting	
	Financing costs		Financing costs	
	Inventory capital (such as fuel storage, consumables & spare parts)	Inventory capital (such as fuel storage and consumables)	Working capital (Includes inventories of fuel and chemicals)	
			Spare parts	
	Pre-production/startup costs	Start-up (or pre-production) costs	Start-up costs	
		Initial charges for catalysts and chemicals	Initial charges for catalysts and chemicals	
	Other owner's cost		Other misc. costs	

Elements of Total Capital Cost

… as well as differences in how various cost groups are aggregated to determine the total cost reported

DOE/NETL	EPRI	IEA-GHG	ZEP
BEC + EPCC + Contingencies	BEC + EPCC + Contingencies	Installed costs + EPCC + Contingencies	EPCC + *Owner's costs (includes contingencies)*
Total Plant Cost + *Owner's costs*	**Total Plant Cost**	**Total Plant Cost**	
Total Overnight Cost + *IDC* + escalation	+ *AFUDC* + escalation	+ *IDC*	**Total Investment Cost**
	Total Plant Investment + *Owner's costs*	+ *Owner's costs*	
Total As-Spent Capital	**Total Capital Requirement**	**Total Capital Requirement**	

Task Force Recommendation

- We nonetheless found that with only a few changes in each of the four costing methods, the "common language" and costing methodology we sought could indeed be achieved!
- Here is what it would look like for capital costs …

Capital Cost Element to be Quantified	Sum of All Preceding Items is Called:
Process equipment	
Supporting facilities	
Labor (direct & indirect)	
	Bare Erected Cost (BEC)
Engineering services	
	Engineering, Procurement & Construction (EPC) Cost
Contingencies: - process	
- project	
	Total Plant Cost (TPC)
Owner's costs:	
- Feasibility studies	
- Surveys	
- Land	
- Permitting	
- Finance transaction costs	
- Pre-paid royalties	
- Initial catalyst & chemicals	
- Inventory capital	
- Pre-production (startup)	
- Other site-specific items unique to the project (such as unusual site improvements, transmission interconnects beyond busbar, economic development incentives, etc.)	
	Total Overnight Cost (TOC)
Interest during construction	
Cost escalations during construction	
	Total Capital Requirement (TCR)

Task Force Recommendation (con't.)

- … and here's what it would look like for plant operating and maintenance (O&M) cost items

Operating & Maintenance Cost Item to be Quantified	Sum of All Preceding Items is Called:
Operating labor	
Maintenance labor	
Administrative & support labor	
Maintenance materials	
Property taxes	
Insurance	
	Fixed O&M Costs
Fuel	
Other consumables, e.g.: - chemicals - auxiliary fuels - water	
Waste disposal (excl. CO_2)	
CO_2 transport	
CO_2 storage	
Byproduct sales (credit)	
Emissions tax (or credit)	
	Variable O&M Costs

Quantifying CCS Cost Elements

The Devil is in the Details

- Even with a common nomenclature and set of cost elements, different methods of quantifying each item will still result in different costs.

- We compared the methods used by the four organizations and found many similarities as well as some differences
- We did not think it fruitful to seek recommendations or guidelines for all cost items, especially since many key items are opaquely “specified by the contractor”
- On the other hand …

Process Contingency Guidelines

- Items like process contingency cost do merit guidelines, which can help in cost estimation for new CCS processes

Technology Status	Process Contingency (% of Associated Process Capital)
New concept with limited data	40+
Concept with bench-scale data	30-70
Small pilot plant data	20-35
Full-sized modules have been operated	5-20
Process is used commercially	0-10

Source: EPRI, AACE

Overall, we again emphasize the importance of full and detailed reporting to reveal sources of cost differences

Calculating Cost of Electricity and Cost CO_2 Avoided

Cost of Electricity (COE)

$$\text{COE (\$/MWh)} = \frac{\text{(TCC)(FCF)} + \text{FOM}}{\text{(CF)(8760)(MW)}} + \text{VOM} + \text{(HR)(FC)}$$

TCC = Total capital cost ($)

FCF = Fixed charge factor (fraction)

FOM = Fixed operating & maintenance costs ($/yr)

VOM = Variable O& M costs, excluding fuel cost ($/MWh)

HR = Power plant heat rate (MJ/MWh)

FC = Unit fuel cost ($/MJ)

CF = Annual average capacity factor (fraction)

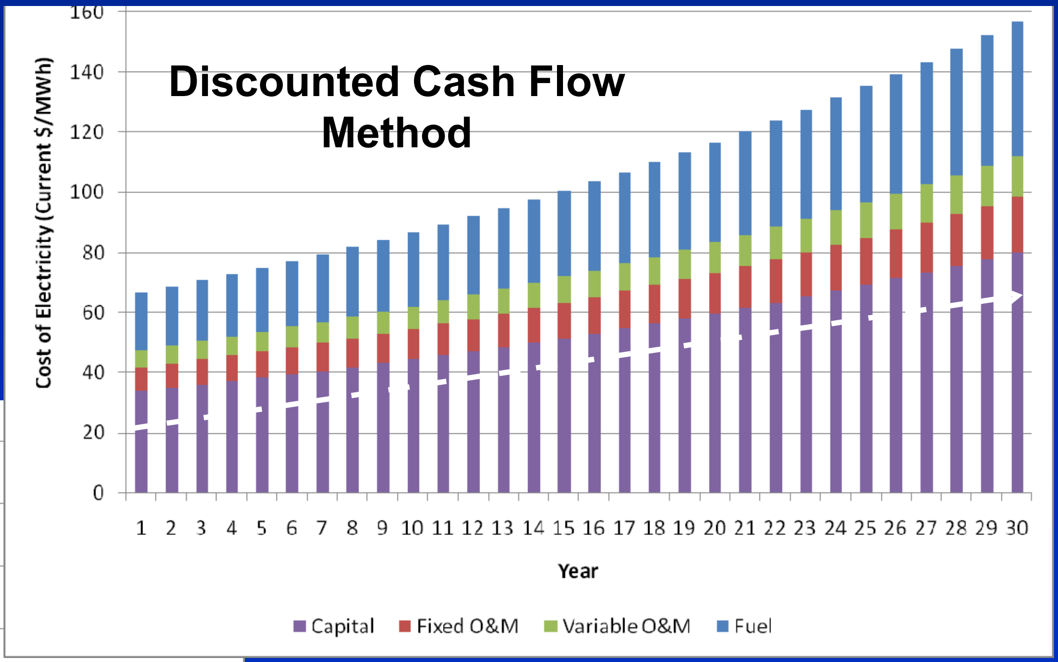
MW = Net power plant capacity (MW)

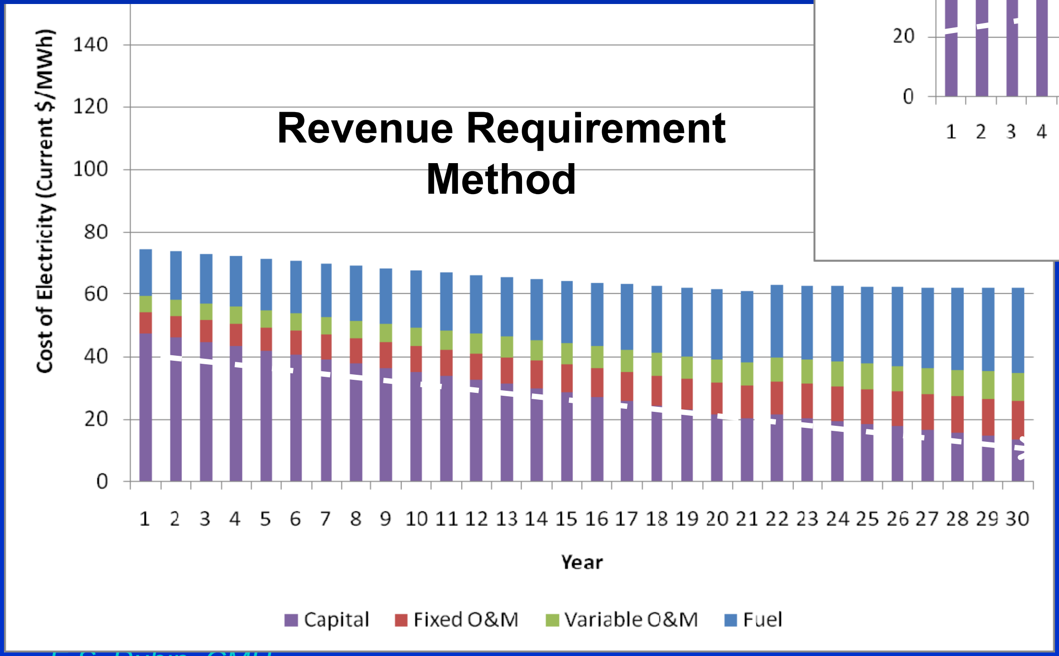
COE is Calculated and Reported in Different Ways

- “Revenue requirement” method
- “Discounted cash flow” method
- Levelized COE
- First-year COE
- Constant (real) dollars
- Current (nominal) dollars

Poor understanding of these differences and their impact is a major sources of confusion regarding power plant and CCS costs

Choice of method and assumptions also can affect the year-by-year COE profile





Note: Charts are for illustrative purposes only and do not reflect a specific technology case

Source: EPRI 2011

Task Force Conclusions

- The different approaches to COE calculation reflect different perspectives related to investment decisions, regulatory activities and other purposes of cost analysis
- The analysis perspective often is not conveyed in CCS cost studies
- For purposes of technology comparisons, both methods will identify the lowest-cost option if used consistently
- Greater attention must be paid to the full reporting of cost-related assumptions and context for the analysis

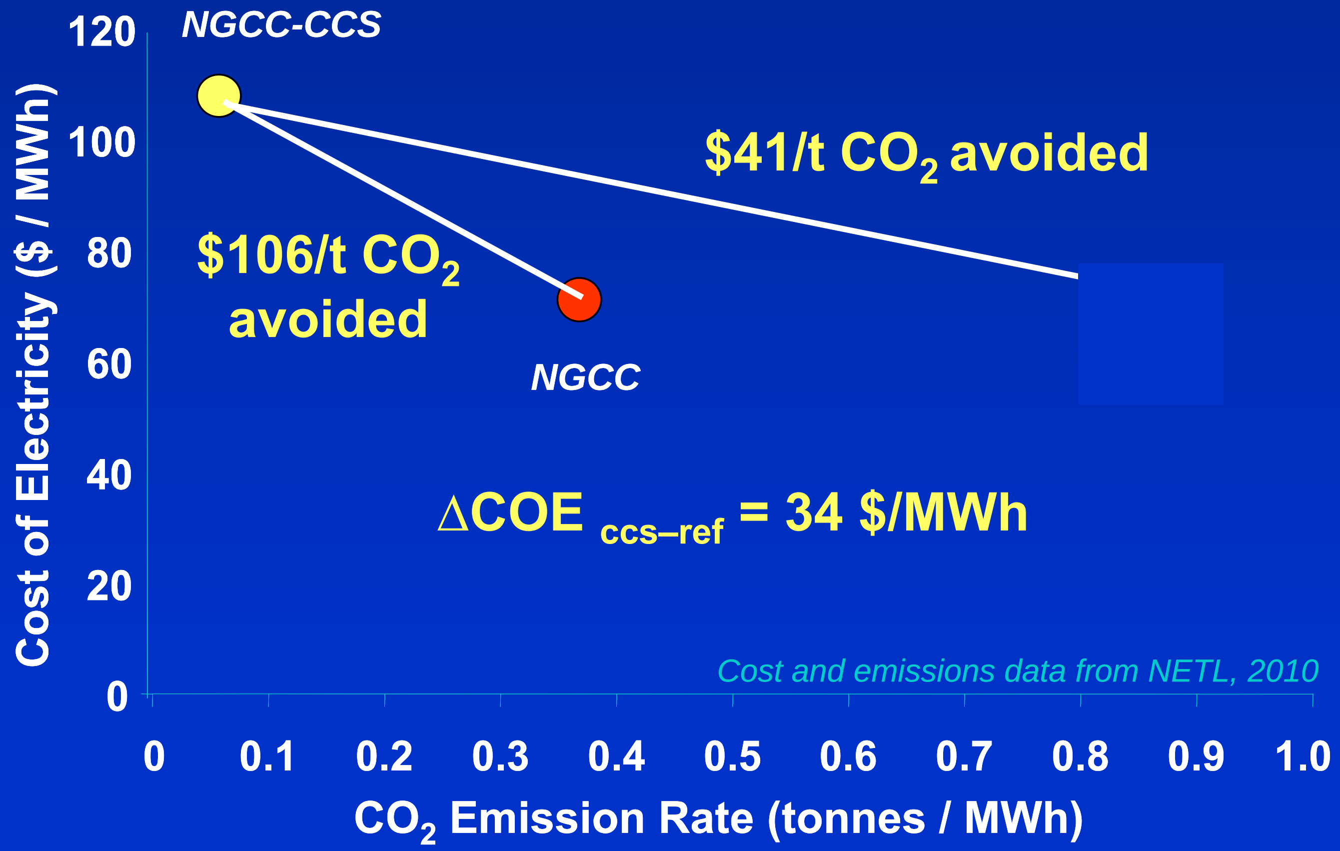
Cost of CO_2 Avoided

- Cost of CO_2 Avoided ($/t CO_2)

$$= \frac{(\mathrm{COE})_{\mathrm{ccs}} - (\mathrm{COE})_{\mathrm{reference}}}{(\mathrm{t\ CO_2/MWh})_{\mathrm{ref}} - (\mathrm{t\ CO_2/MWh})_{\mathrm{ccs}}}$$

- This is the measure most frequently used to quantify the cost of CCS
- It should (but often does not) include the full cost of CCS, i.e., capture, transport and storage (because emissions are not avoided unless/until the CO_2 is sequestered)
- It is a relative cost measure that is very sensitive to the choice of reference plant without CCS

Cost of CO_2 avoided is sensitive to assumed reference plant w/o CCS



What's the Question?

- How much will CCS add to the cost of a particular plant, or plant type?
- What carbon tax would it take for CCS to be less costly for a particular plant?
- What is the least-cost option to meet a strict carbon constraint for a new fossil fuel plant being planned?

Different questions require different reference plants when calculating cost of CO_2 avoided

Cost studies that report avoidance cost need to clearly frame the question being address

Guidelines for CCS Cost Reporting

Task Force Guidelines

- The Task Force has developed a series of "checklists" to suggest the information that should be given in:
  - Technical reports
  - Journal/conf. papers
  - Presentations

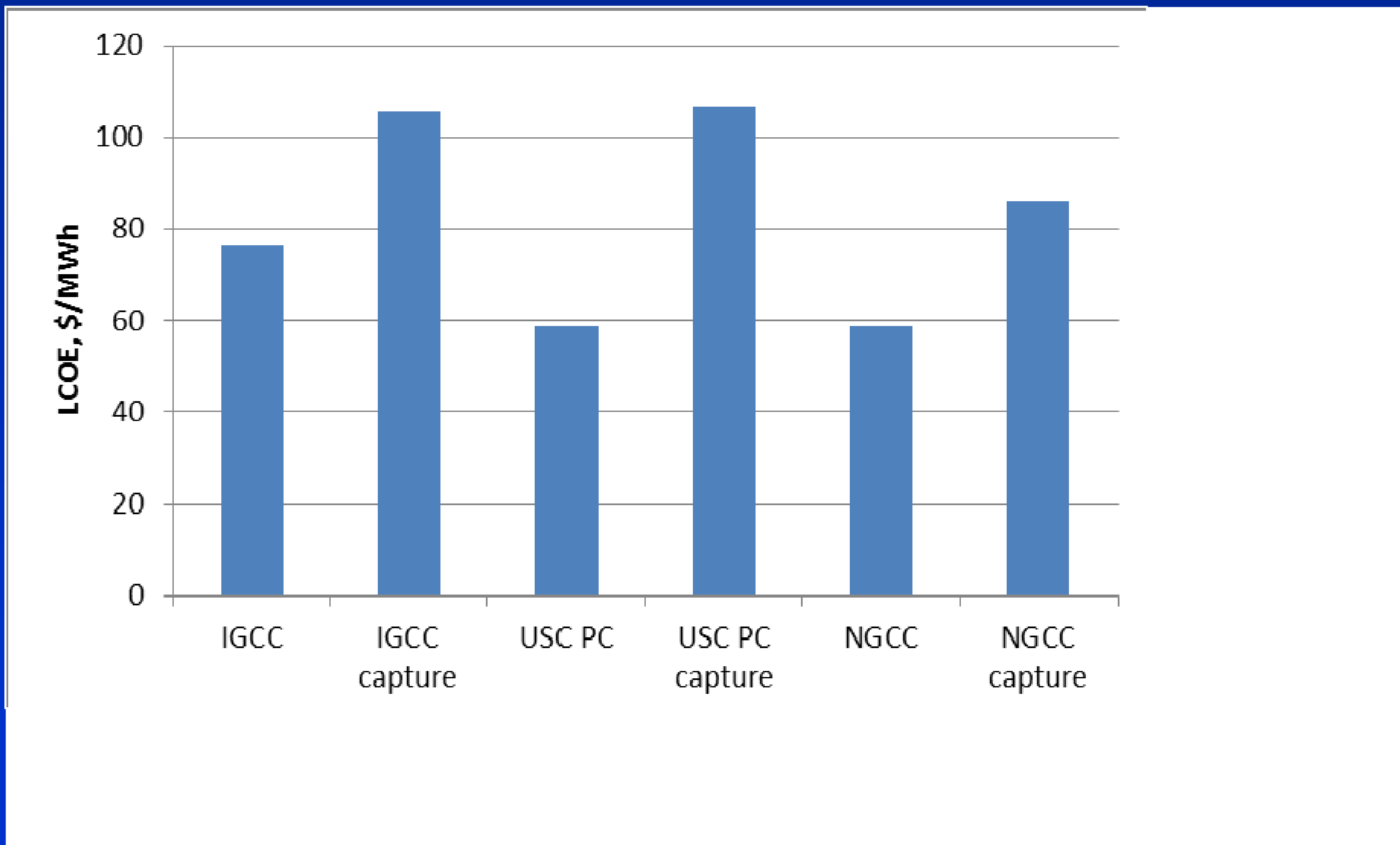
Information Needed	Presentations
Power plants without CO_2 capture (reference/baseline plants)	
Fuel type (class of hard coal, lignite, gas)	X
Power plant type (e.g. PF, BFB, CFB or NGCC)	X
Plant capacity (MW electric)	
- Gross (to define boiler or gas turbine size class)	X
- Net	X
Net electric efficiency and/or heat rate (state if based on LHV or HHV)	X
CO_2 emissions (per MWh net electricity or per MWh fuel; state if LHV or HHV)	X
In addition for power plants with CCS	
Type of power plant CO_2 capture; e.g. post-combustion, oxy-combustion, IGCC with pre-combustion	X
Capture technology (e.g. MEA, advanced amine, chilled ammonia, Selexol, solid absorption/desorption process, etc.	X
Captured CO_2 per MWh net electricity or per MWh fuel (state if LHV or HHV) or "capture rate" (% of produced CO_2)	X
Capital costs	
Type of plant, e.g. first-of-a-kind, N^{th}-of-a-kind	X
Year, currency (to enable later updates and comparisons between studies from different years, using suitable plant/equipment cost indices)	X
Contingencies (sum of process and project contingencies)	X
Resulting "Total Overnight Cost"	X
- Construction cost escalation rate (if applied)	X
O&M costs (excluding CO_2 transport & storage)	
CO_2 emissions cost per tonne (if included)	X
CO_2 transport & storage costs	
Overall net cost per tonne of CO_2 stored, with breakdown into transport and storage (if available).	X
Levelized cost of electricity	
Method/approach used; also state if calculation uses real (constant money values) or nominal (current money values)	X
Interest rate/discount rate/WACC; also state if real or nominal	X
Inflation and other price escalation rates (if applied).	X
Economic lifetime	X
Load factor/equivalent full load operation hours	X
- Fuel prices per GJ or MWh fuel (state HHV or LHV)	X
CO_2 avoidance cost	
State and define reference plant case	X

Task Force Guidelines

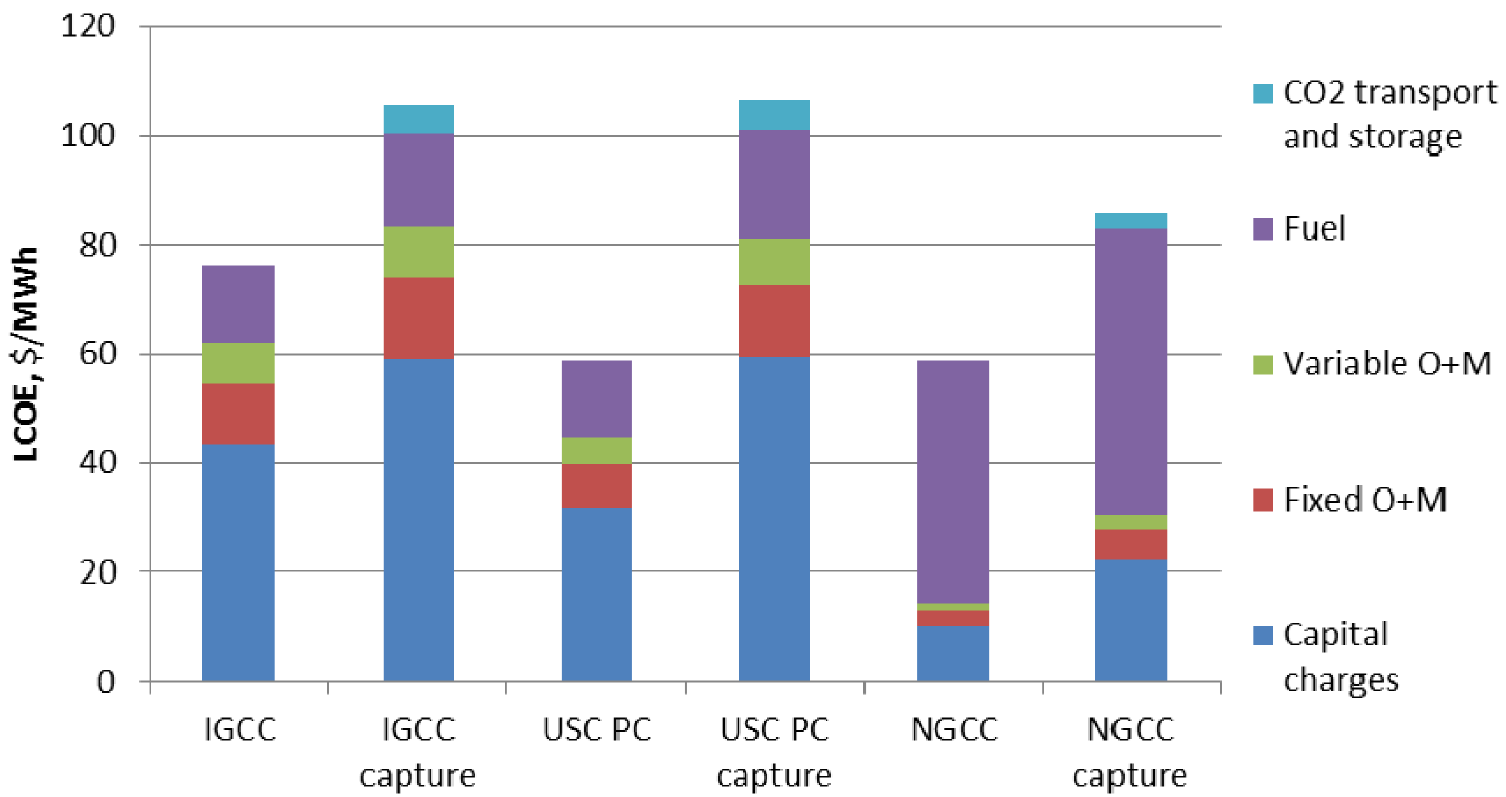
- The complete checklists are in the draft report

Information Needed	Reports	Papers	Presentations
Power plants without CO_2 capture (reference/base line plants)			
Battery limits	X		
Fuel type (class of hard coal, lignite, gas)	X	X	X
- Moisture and ash contents	X	X	
- LHV and HHV. (state "as received", dry matter, dry and ash free).	X	X	
- Definition of LHV	X		
Power plant type (e.g. PF, BFB, CFB or NGCC)	X	X	X
- Steam parameters (pressures/temperatures)	X	X	
- GT-class (e.g. F-class, H-class)	X	X	
- Gasifier type (for IGCC)	X	X	
Plant location type (immediate to port, inland)	X	X	
- Ambient conditions (ISO, other conditions)	X	X	
Cooling water (cooling tower or once through sea/lake/river water)	X	X	
Plant capacity (MW electric)			
- Gross (to define boiler/GT size class)	X	X	X
- Net	X	X	X
Net electric efficiency and/or heat rate (state if based on LHV or HHV)	X	X	X
CO_2 emissions (per MWh net electricity or per MWh fuel; state if LHV or HHV)	X	X	X
Environmental requirements anticipated.	X		
In addition for power plants with CO_2 capture			
Plant capacity (is the boiler/GT capacity or the gross or net output the same as the reference plant)	X	X	
Type of concept for power plant with CO_2 capture; e.g. post-combustion, oxy-fuel, IGCC with pre-combustion	X	X	X
Capture technology (e.g. MEA, advanced amine, chilled ammonia, Selexol etc or solid absorption/desorption process	X	X	X
Delivered captured CO_2:			
- Pressure, temperature	X	X	
- Purity requirements anticipated (at least state if sufficient for transport in carbon steel pipelines or ships)	X		
Captured CO_2 per MWh net electricity or per MWh fuel (state if LHV or HHV), or "capture rate" (% of produced CO_2)	X	X	X

We also have some examples of "Bad" Practice …



… and "Good" Practice for information in graphs and tables



Bituminous coal: $1.6/GJ (LHV), Gas: $7/GJ (LHV**)**, Annual capital charge factor: 0.11
CO_2 transport + storage: $6/t, 90% load factor, Constant $, 2007

Next Steps

We look forward to your:

- Comments and feedback on the draft report and its usefulness to the CCS community
- Thoughts on additional needs to improve the development and understanding of CCS costs (e.g., for emerging technologies, relative to other mitigation options, etc.)
- Suggestions for dissemination and followup

Thank You

rubin@cmu.edu

CCS Cost Workshop

Session 1: CCS Costing Methods and Measures

Respondent #1

Ronald L. Schoff

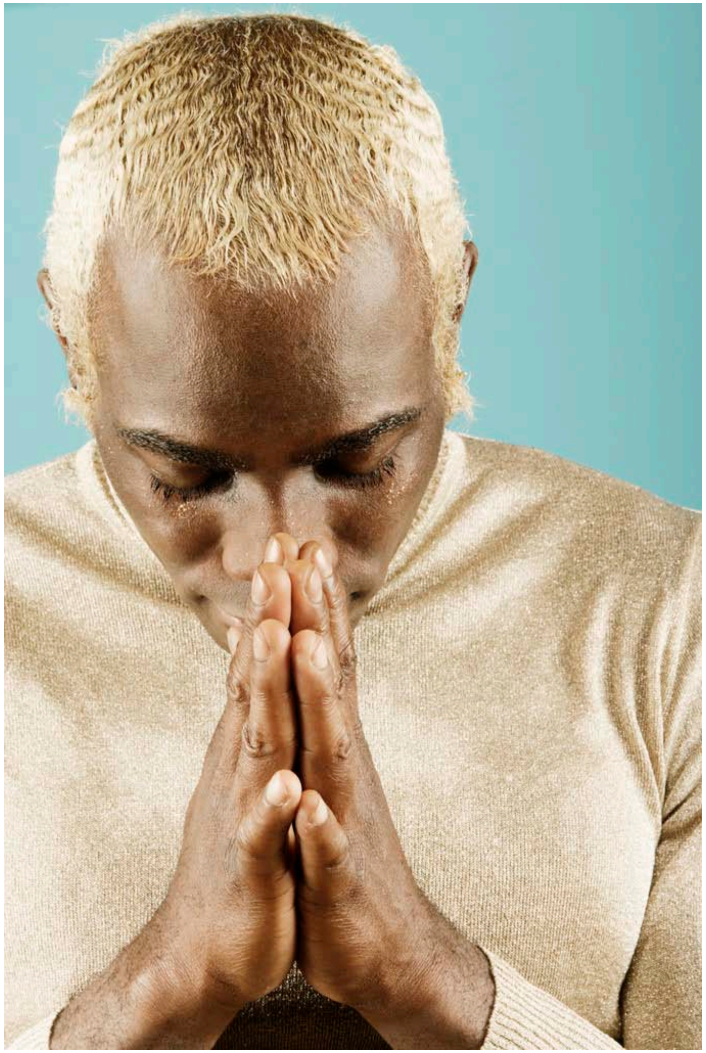
Sr. Project Manager

CCS Cost Workshop – Palo Alto, CA

April 25, 2012

Opening Thoughts

- Noble Effort
- Good Start
- Common Methods Useful
- Reporting Standards Helpful



Design Basis Characteristics

	Study #1	Study #2	Study #3
Fuel	Sub-Bit	Sub-Bit	Sub-Bit
Heating Value (Btu/lb, HHV)	8,220	8,340	8,560
Air Separation Unit	Cryogenic	Cryogenic	Cryogenic
Gasifiers	Siemens	Siemens	Siemens
Acid Gas Removal	Selexol	Selexol	Selexol
Gas Turbines	GE 7F	GE 7F	F Class
Elevation (feet)	2,400’	600’	3,500’
Condenser Backpressure (in. Hg)	1”	2”	1.4”

Same Plant, Different Locations

ELECTRIC POWER RESEARCH INSTITUTE

Performance Characteristics

	Study #1	Study #2	Study #3
Gross Power (MWe)	677	664	635
Auxiliary Power (MWe)	221	196	189
Net Power (MWe)	456	468	446
Thermal Input (MWth)	1,580	1,570	1,455
Net Plant Efficiency (%, HHV)	29%	30%	30.5%
Carbon Capture Rate	92%	85%	90%

Slight Differences in Designs Cause Divergence in Performance

ELECTRIC POWER RESEARCH INSTITUTE

Cost Estimate / Economic Assumptions

	Study #1	Study #2	Study #3
Location	US-GC	US-NW	US-MW
Dollar Year Basis	1Q 2010	1Q 2010	2Q 2007
Coal Price ($/ton)	24	33	15
Operating Labor Rate ($/yr)	100	65	98
Engineering Cost (% of BEC*)	15%	10%	9%
Process Contingency (new eq.)	0%	0%	5%
Project Contingency	20%	10%	17%

Need to Adjust Each Parameter for Comparison – Which to Pick?

Cost Estimate Results

	Study #1	Study #2	Study #3
Total Plant Cost (billion $)	**2.45**	1.81	1.50
Equipment	0.8	0.7	0.8
Bulk Materials	**0.7**	0.3	**<0.1**
Labor	0.3	0.3	0.2
Specific Plant Cost ($/kW)	**5,350**	3,880	3,370
Air Separation Unit	423	460	571
Gasification Island	1,281	1,035	964
Syngas & CO_2 Processing	**1,252**	700	603
Power Block	**1,333**	660	625
Balance of Plant	1,065	1,028	**609**

Vast Differences Starting to Appear – Bulks & Some Plant Units

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Cost Estimate Results

Cost/Economic Assumptions Adjusted to Common Basis

	Study #1	Study #2	Study #3
Total Plant Cost (billion $)	**2.45**	1.81	1.50
Bare Erected Cost (billion $)	1.8	1.3	1.1
Equipment	0.8	0.7	0.8
Bulk Materials	**0.7**	0.3	**<0.1**
Labor	0.3	0.3	0.2

$0.7B difference escalates to a $1B difference with engineering and contingency included

Wide Spread in Total Plant Cost - from Bare Erected Cost Δ

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Cost Estimate Results

Cost/Economic Assumptions Adjusted to Common Basis

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Power Block	**1,333**	660	625
Balance of Plant	1,065	1,028	**609**
Cost of Electricity ($/MWhr)	**$145**	$117	**$101**

Even with Common Basis, there is a ~45% Spread in COE Values

EPRI ELECTRIC POWER RESEARCH INSTITUTE

Closing Thoughts

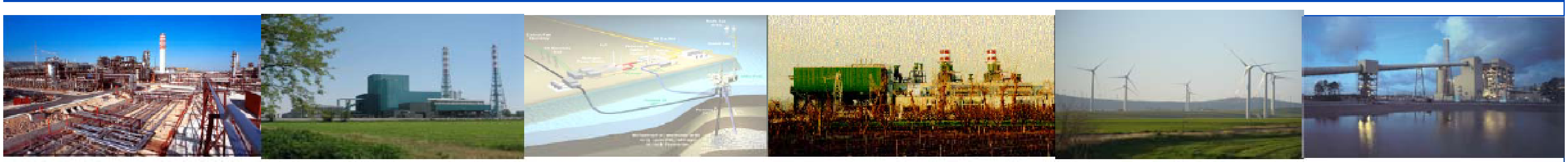
- I do this every day for a living, and this was difficult
  - How is a stakeholder with little or no experience supposed to figure out what to do with this data?
- Having the same plant configuration and fuel is not enough
  - Differences in design practice for EPC and R&D Orgs.
- None of the cost or economic assumptions for the 3 cases were the same
  - Merging to similar basis did not solve the problem
- The issue is more pronounced for new technologies for which there is little industry experience and data to use

Together…Shaping the Future of Electricity

Methodology for CCS cost estimate

The perspective of an E&C company

CCS cost workshop, 25th-26th April 2012 – EPRI, Palo Alto (CA) , USA



R. Domenichini – Director Power Division
Foster Wheeler Italiana

CCS cost estimate

Cost estimate is project specific:

- Client, Location, country…
- CO_2 capture technology selected
- Storage characteristics and distance
- Based on:
  - ✓ Performance calculation
  - ✓ TIC estimate
  - ✓ O&M costs estimate
  - ✓ Financial analysis to define COE (Cost Of Electricity)
  - ✓ COAC (Cost Of Avoiding CO_2) calculation

Performance

- Plant design

  (Feedstock characteristics and product requirements, in particular CO_2 quality)

- Site conditions

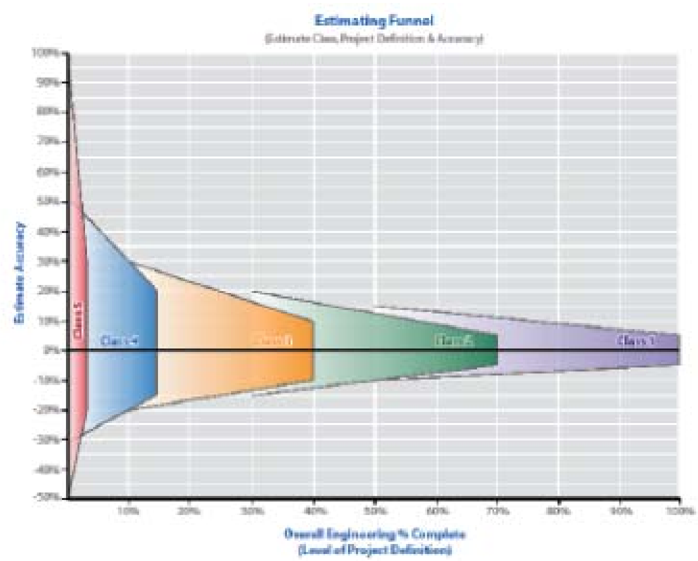
- Performance calculations in different operating conditions

  - Process simulators
  - Licensors' and Vendors' data

TIC (Total Investment Cost) Estimate

Includes:

- Direct materials (equipment and bulk materials)
- Construction (site preparation, civil works, mechanical and I&E erection)
- Other costs (temporary facilities, solvents, catalysts, etc.) and EPC services
- Owner costs, Technology fees, Contingencies



A different Estimate class

- Class 1 FEED +/-10% accuracy

- Class 4
- Class 5 typical for a Feasibility Study

Means a different engineering effort to support the Estimate

TIC Estimate Methodology for a Feasibility Study/Conceptual Design

Technical basis

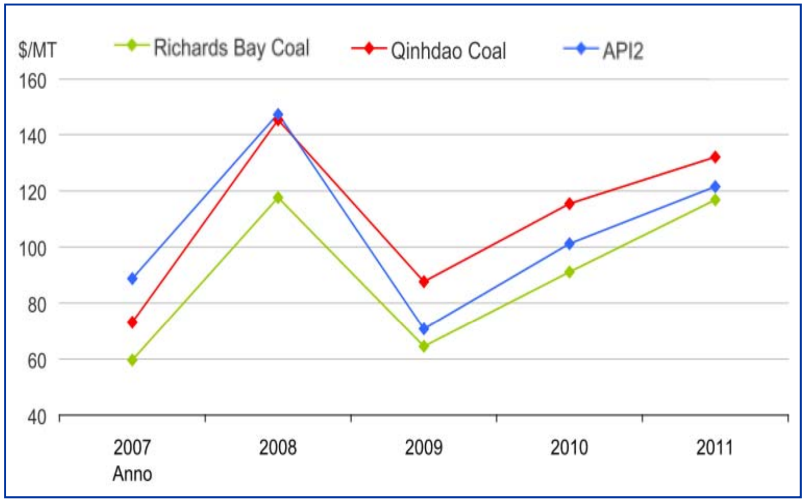
- Sized equipment list (based on plant modeling)
- Vendor budgetary offers for equipment and Package Units (f.i. ASU, Coal preparation, PSA, SRU)
- Process Flow Diagrams (up to class 4 estimate accuracy) / P&IDs (for a more accurate estimate class)

TIC evaluation using

- Aspen© Capital Cost Estimator 7.3.2
  - Aspen database yearly updated, including direct material and construction costs, models to evaluate interconnecting, I&C, electrical equipment…
  - Statistical factors for EPC services, owner costs, temporary facilities, contingency
  - Application of correction factors for site conditions and specific plant characteristics
- Foster Wheeler Database and experience
- Adjustment of Inhouse data based on capacity, site conditions, escalation (year), plant location (erection)

Operating and Maintenance costs

Coal cost. Yearly trend (average) – GME newsletter



- Variable costs (depending on plant load factor):
  - Feedstocks (Coal / Natural Gas)
  - CO_2 emission (carbon tax)
  - Fluxant, Chemicals, Catalysts, Solvents, Water…
  - Cost of CO_2 transport and storage?

- Fixed costs [€/y]
  - Maintenance
  - Direct labour
  - Administrative and general overhead

Strongly affected by market trend and plant location

Financial model

Main financial parameters:

- Discount rate
- Years of plant operation
- Depreciation period
- Inflation rate
- Financial leverage (debt / equity)
- Loan rate and duration
- Taxation
- .....

COE and COAC calculations

$$\mathrm{COAC}\left[\frac{€}{\text{t of } CO_2 \text{ captured}}\right] = \frac{\Delta \text{ Electric Power Cost } [€/\text{kWh}]}{\Delta \text{ Specific } CO_2 \text{ emission } [\text{t/kWh}]}^{(*)}$$

(∗) Δ calculated with respect to the plant w/o CCS

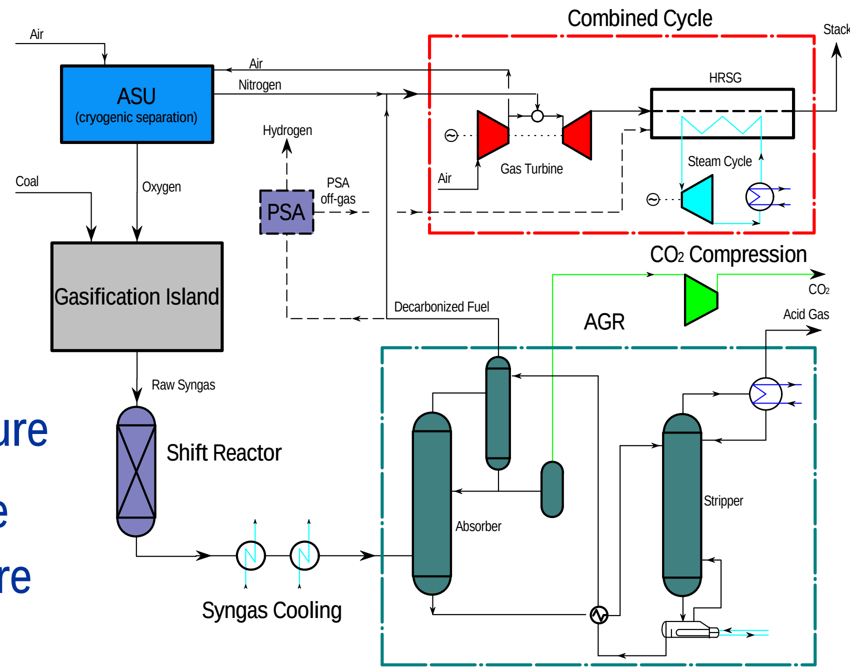
Pre-combustion capture – FW references

IGCC plants in Italy (w/o capture)

	FW role
ISAB Energy Asphalt IGCC, 530 MWe + 20,000 Nm^3/h H_2	EPC LSTK
api Energia VVR IGCC, 288 MWe	EPCm (plant improvement)
SARAS (Sarlux) VVR IGCC, 550MWe + 40,000 Nm^3/h H_2	Consultancy services

ISAB IGCC Plant

Pre-combustion capture – FW References



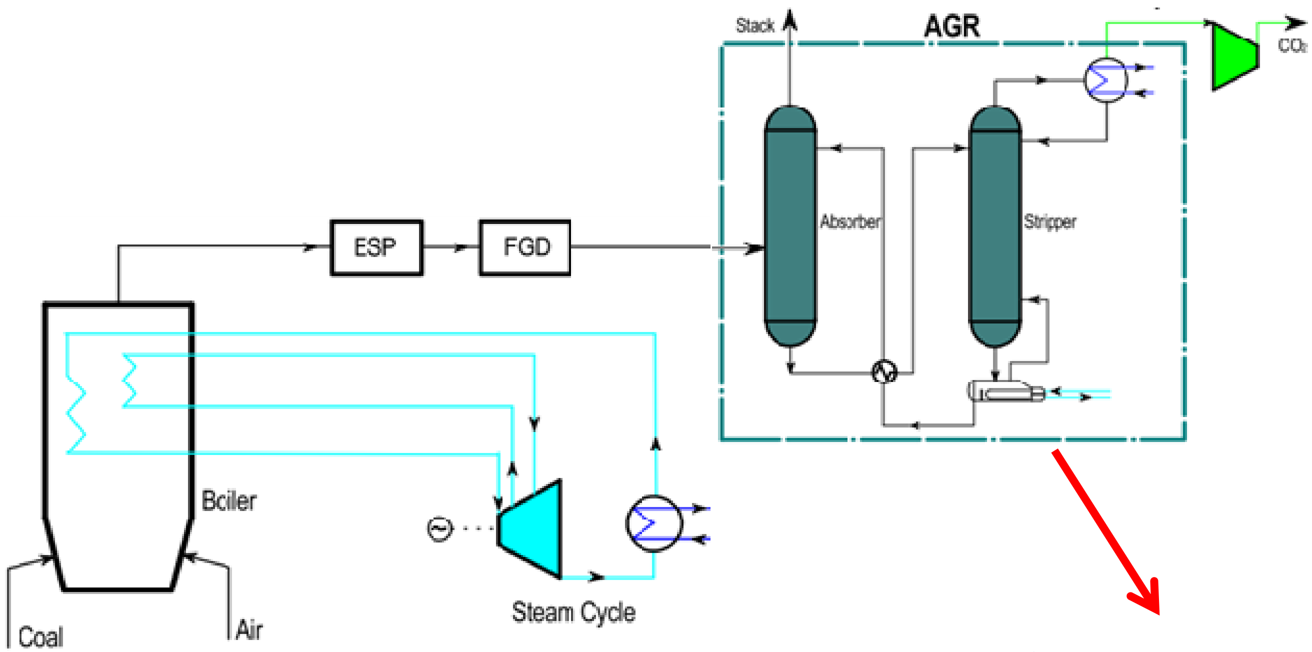
FEEDs (TIC estimate +/-10%)

- ✓ PIEMSA VVR IGCC, 900 MWe, w/o capture
- ✓ DOOSAN Coal IGCC, 300 MWe, w/o capture
- ✓ TATARSTAN Petcoke IGCC, 235 MWe, w/o capture
- ✓ DF1 Project NG ATR+CCU, 475 MWe, w capture
- ✓ HPAD Project NG ATR+CCU, 400 MWe, w capture

More than 40 Feasibility studies with and w/o CCS, f.i.

- ➢ EPRI – Engineering and Economic Assessment of Integrated Gasification Combined Cycle Coal Power Plants for Near-Term Deployment
- ➢ IEA GHG R&D – 7 feasibility studies on CCS since 2003

Post-combustion capture - FW References



FW Recent Reference : FEED (+/-20% TIC Estimate)

Confidential Coal USC PC Power Plant, 250 MWe,
Post Combustion Capture Amine based

FW is manufacturer of large USC PC and SC CFB boilers

Oxy-combustion process - FW References

The Compostilla Project OXYCFB300

FW Flexi-Burn® Oxy-CFB

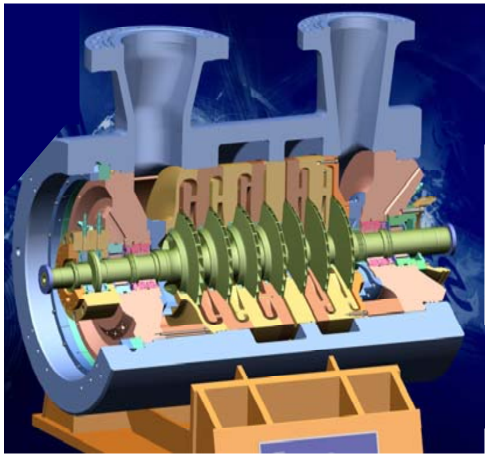
CIUDEN Technology Development Plant Layout

- ✓ Supported by European Energy Program for Recovery
- ✓ CIUDEN Technology Development Plant (30 MWt Oxy-CFB) testing on local anthracite and blends of anthracite/petcok e
- ✓ OXY CFB 300 FEED in progress

Recent Feasibility Study - Veolia Environnement Recherche et Innovation (VERI)

Oxy-combustion CHP generation plants (both revamping and new units)

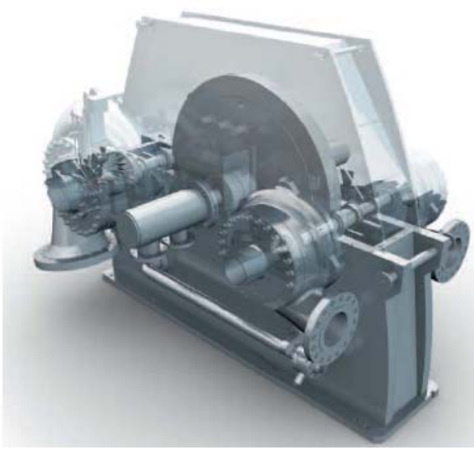
CO_2 compression - FW References



FEED (+/-5% TIC Estimate) - ARCELORMITTAL
ULCOS Project - Steel Making Facilities

- ✓ CO_2 recovery from a BLAST furnace
- ✓ CO_2 injection into a deep saline acquifer
- ✓ NER 300 application submitted

Feasibility Study - IEA GHG R&D Programme
Optimisation of CO_2 compression in CCS system



- ✓ Technical and economical evaluation of compression strategies (for pre, post and oxy-combustion)
- ✓ Assessment of CO_2 compressor characteristics
- ✓ Database of technical and economical offers received from main CO_2 compressor vendor

FW Recent Evaluation of Investment Cost, COE and COAC

CO_2 Capture technology	Specific Investment Cost (*) [$/kWe]	Cost Of Electricity [cents$/kWh]	Cost Of Avoiding CO_2 [$/t]
USC PC w/o CO2 capture (Reference plant)	1900-2100	6 – 9	-
IGCC with pre-combustion capture	3600-3800	10 – 16	75 – 110
USC PC with post-combustion capture	3300-3500	9 – 15	60 – 90
Oxy-combustion power plant	3700-3900	10 - 16	70 – 110

(*) Based on a Class 4 TIC estimate accuracy I

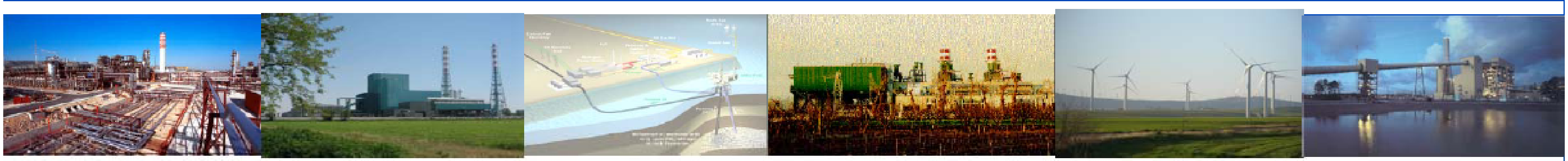
Cost Of Avoiding CO_2 (COAC) - Conclusions

Wide range of variation depending on:

- ✓ Global market fluctuations
- ✓ Country (fuel costs, carbon tax, construction costs…)
- ✓ Plant location (infrastructures, cost of CO_2 transport, construction costs….)
- ✓ Specific fuel, product, CO_2 characteristics, plant and site conditions
- ✓ Financial parameters adopted
- ✓ Reference plant for COAC calculation (USC PC plant w/o CO_2 capture?)

Need of reference values for some parameters to evaluate normalized and comparable COAC

Thank you



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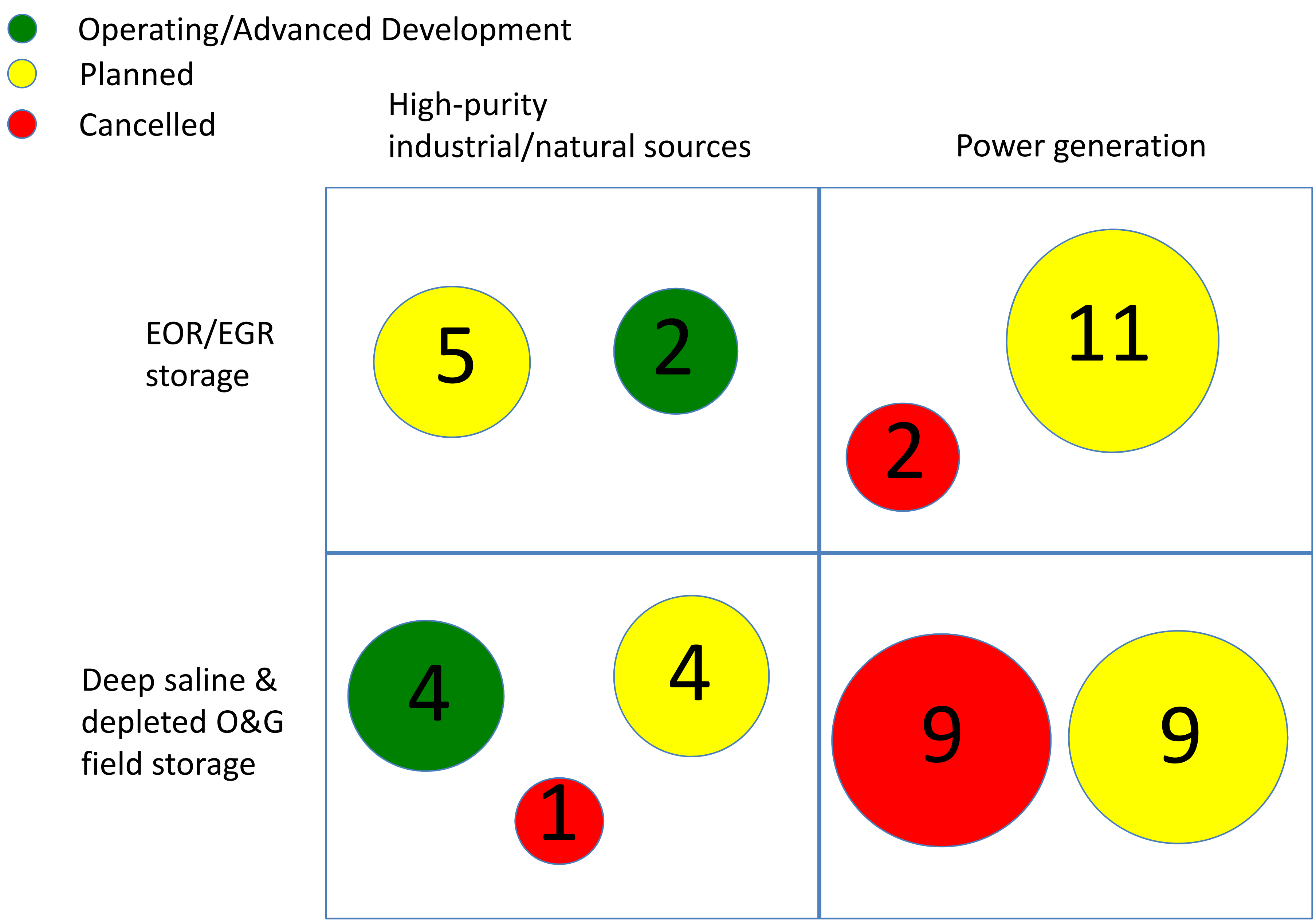
Understanding the Costs of CCS Demonstration Projects

Howard Herzog

MIT

April 25, 2012



Operating/Advanced Development
Planned
Cancelled
High-purity industrial/natural sources
Power generation
EOR/EGR storage
Deep saline & depleted O&G field storage
5
2
11
2
4
4
1
9
9

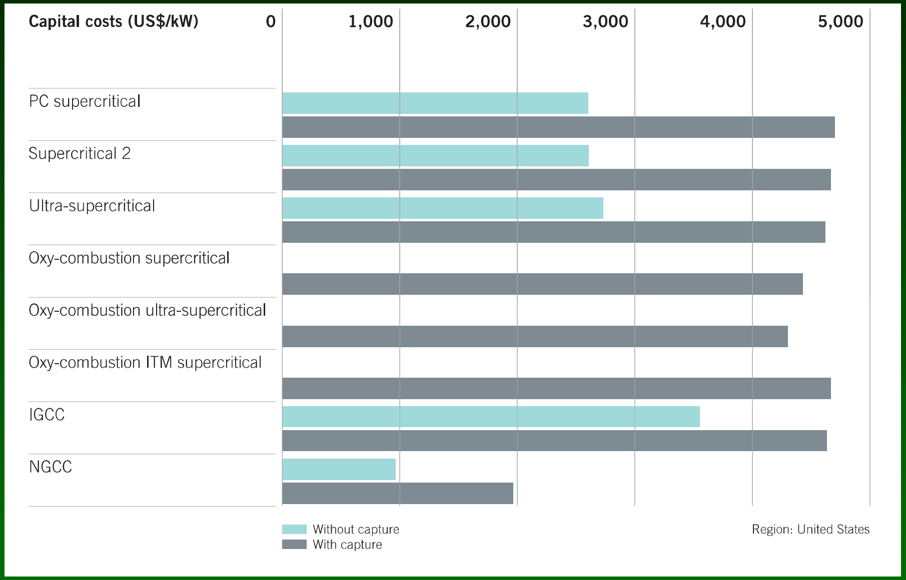
Demonstration Projects

- Lack of financing is the number one reason that demonstration projects fail to go forward
  - Are costs too high?
  - Are financing sources too limited?
  - Is it a combination of both?

The Billionaires Club

- Longannet (UK)
  - 363 MW post-combustion retrofit
  - £1 billion from UK government not adequate (£1.34 billion from FEED)
  - ~ £3,700/kW ($6,000/kW)
- FutureGen (US)
  - 200 MW oxy-combustion retrofit
  - It appears that $1billion from US government may not be adequate
  - Note that FutureGen Alliance members will contribute several hundred million dollars
  - ~$5,000/kW + alliance contribution
- Mongstad (Norway)
  - New amines + chilled ammonia pilot plants
  - ~100,000 tCO_2/yr (~20 MW equivalent)
  - Estimated cost of NOK 5.77 billion
  - ~NOK285,000/kW ($50,000/kW)

Installed Costs for 550 MW net generation and CO_2 capture facility (FOAK from GCCSI 2011 update)



RETROFIT	COST (in $/kW)
Peterhead (hydrogen from natural gas)	2840
Antelope Valley (coal-fired)	2392
AEP Mountaineer (coal-fired)	2843
Longannet (supercritical)	5835
Plant Barry	4375
Average	**3657**
GCCSI Estimate	**~2000 + T&S**

COAL-FIRED	COST (in $/kW)
Janschwalde	8065
Kingsnorth (supercritical)	8330
Average	**8189**
GCCSI Estimate	**~4500 +T&S**

IGCC	COST (in $/kW)
Goldenbergwerk	9091
Sweeny Gasification	6003
ZeroGen	10616
Taylorville	5814
Average	**7881**
GCCSI Estimate	**~4600 + T&S**

Longonnet FEED Study

Chain Segment (in £m)	Pre-FEED	Post-FEED
Capture	559.8	656.5
Transport	198.7	281.2
Storage	318.7	207.8
Total	1077.2	1145.5
Risk & Contingency	102.8	194.8
Total Project Capex	1180.1	1340.3
Range	857 – 1719	1200 – 1519

Questions

- The reported costs of CCS demos appear to be significantly higher than the estimates published in CCS cost studies
  - Is this reality or just perception?
  - What are the reasons for the differences we see?
- Once we understand the costs of CCS demos, what does that tell us about n^{th} plant costs?
  - What are key components of FOAK costs?
  - Can we quantify FOAK costs?

Contact Information

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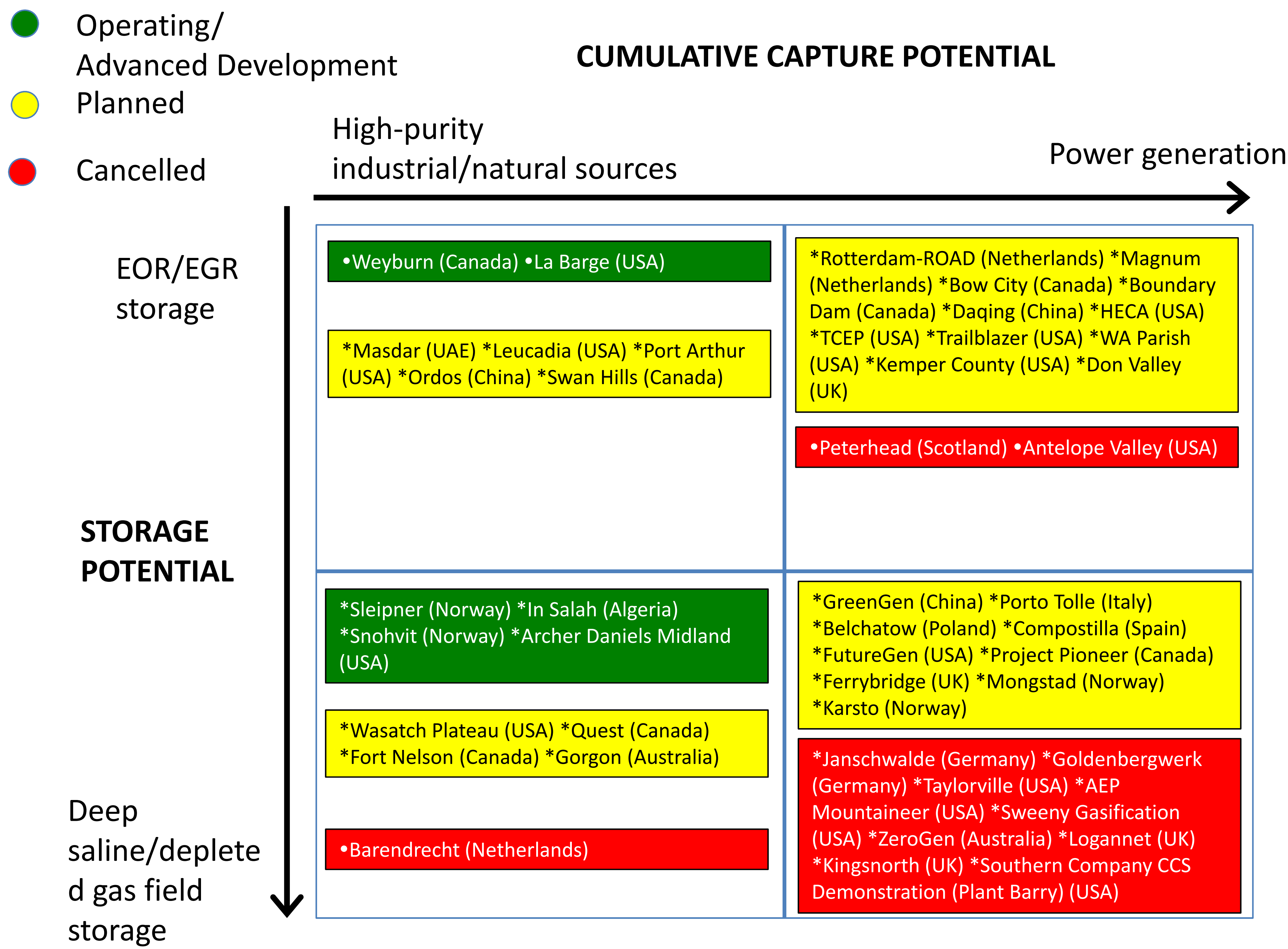

Operating/
Advanced Development
Planned
Cancelled
CUMULATIVE CAPTURE POTENTIAL
High-purity
industrial/natural sources
Power generation
EOR/EGR
storage
STORAGE
POTENTIAL
Deep
saline/deplete
d gas field
storage
•Weyburn (Canada) •La Barge (USA)
*Masdar (UAE) *Leucadia (USA) *Port Arthur (USA) *Ordos (China) *Swan Hills (Canada)
*Rotterdam-ROAD (Netherlands) *Magnum (Netherlands) *Bow City (Canada) *Boundary Dam (Canada) *Daqing (China) *HECA (USA) *TCEP (USA) *Trailblazer (USA) *WA Parish (USA) *Kemper County (USA) *Don Valley (UK)
•Peterhead (Scotland) •Antelope Valley (USA)
*Sleipner (Norway) *In Salah (Algeria) *Snohvit (Norway) *Archer Daniels Midland (USA)
*Wasatch Plateau (USA) *Quest (Canada) *Fort Nelson (Canada) *Gorgon (Australia)
•Barendrecht (Netherlands)
*GreenGen (China) *Porto Tolle (Italy) *Belchatow (Poland) *Compostilla (Spain) *FutureGen (USA) *Project Pioneer (Canada) *Ferrybridge (UK) *Mongstad (Norway) *Karsto (Norway)
*Janschwalde (Germany) *Goldenbergwerk (Germany) *Taylorville (USA) *AEP Mountaineer (USA) *Sweeny Gasification (USA) *ZeroGen (Australia) *Logannet (UK) *Kingsnorth (UK) *Southern Company CCS Demonstration (Plant Barry) (USA)

EPRI CCS COST WORKSHOP
25-26 April 2012

anlecr&d

Australian National Low Emissions Coal Research and Development

Scoping & Estimation of Total Project Investment Cost
Australian Experience

Professor Chris Greig
Director, UQ Energy Initiative

The University of Queensland
Australia

Context

A number of “early mover” CCS proposals associated with low emissions coal utlisation have been studied in Australia:

- Cost estimates have grown significantly from first concept study; and
- Cost estimates have been significantly higher than published benchmarks.

This presentation reflects lessons from ZeroGen but is relevant to most others.

- ZeroGen had more history and had completed more scoping, engineering and associated project studies than others.
- But lessons are consistent.

Summary of Australian Experiences

Scope definition is critical to all estimates (capex & opex)

- Many project estimate benchmarks lack scope definition.
- Scope varies significantly according to site, project organisation and available infrastructure.

Adequate Engineering is essential to achieve estimate integrity

- Limited reference projects for IGCC and none for IGCC with CCS.

Jurisdiction of project impacts on investment cost & time

- Regulation, construction costs and productivity vary widely.

Basis of estimates [scale, time, location, exchange rate…]

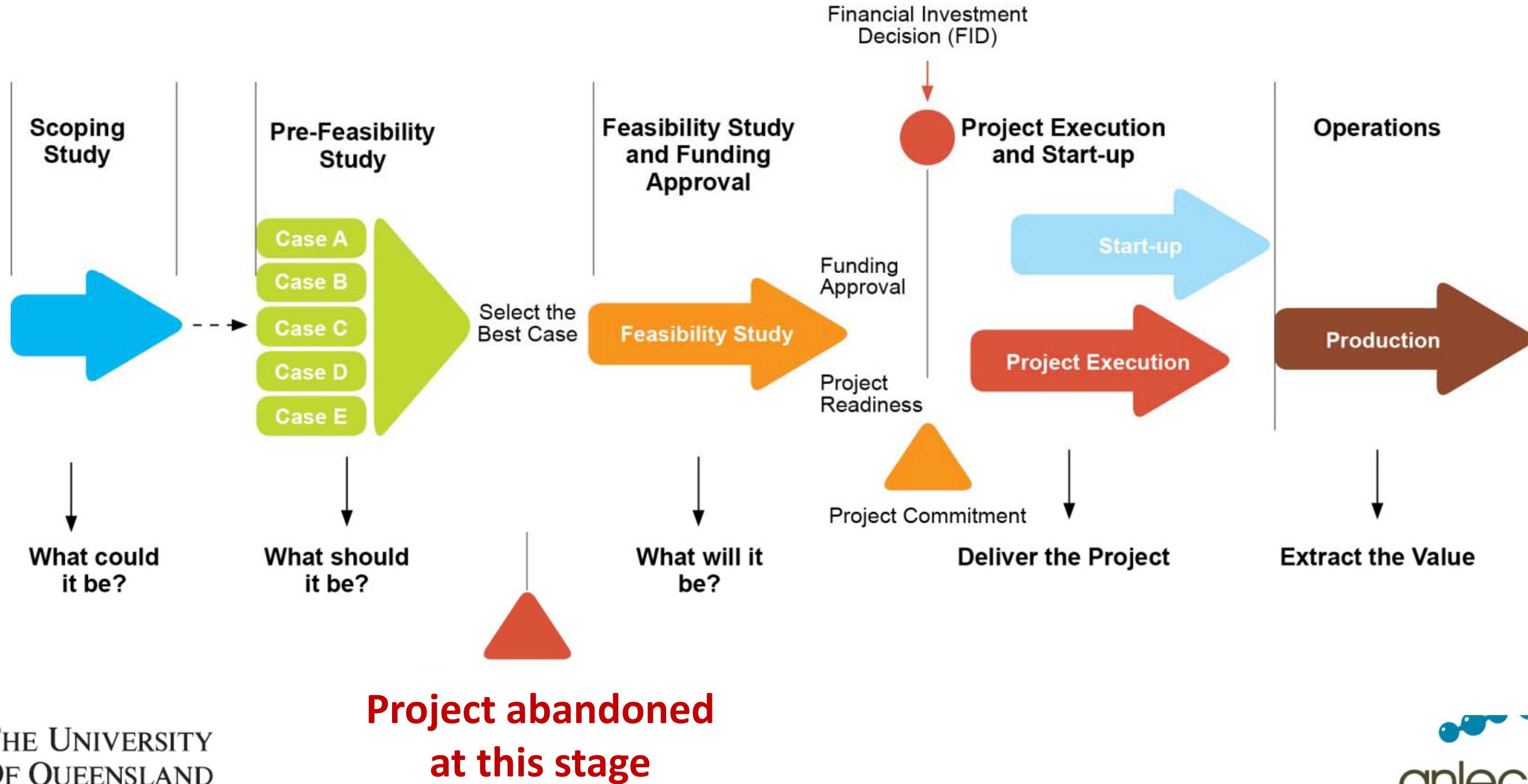
An "Estimate" is always uncertain (one possible cost outcome)

- Must always define the level of uncertainty (eg P_{50} versus P_{80})

The ZeroGen Experience

Stage of Project Development

- ZeroGen had completed a Scoping Study followed by a Prefeasibility Study, at which point the project was abandoned.
- No option considered to have even a remote chance of being taken to FID.



ZeroGen’s Total Investment Cost Estimate

525 MW Gross IGCC / 391 MW Net output

Integrated 65% CO_2 Capture, Transport and Storage

Main Project Cost Area	AUD billions	% Total
ZG Owner’s Costs	$ 0.30	5%
Enabling Works	$ 0.62	11%
Power Plant incl. Balance of Plant	$ 3.90	68%
Carbon Transport & Storage	$0.80	14%
Operations Readiness & Start-up	$0.14	2%
Total Base Cost Estimate	**$5.76**	**100%**
Direct project contingency	$ 0.52	9%
Escalation	$0.65	11%
Total Fully Load Capital Cost (TIC)	**$6.93**	

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TIC is dominated by Power Plant with Capture

In CCS projects, Carbon Storage dominates the development risk

BUT Power with Carbon Capture dominates the capital cost

- **Power plant with capture** and associated costs represent **86% of the total TIC** (after approximate allocation of indirects & contingency)

In the development phase, >80% of the pre-FID investment will generally be associated with identifying, characterising and proving-up the storage resource

- Perhaps not for depleted oil & gas reservoirs or EOR applications where a very large existing sub-surface database is available.

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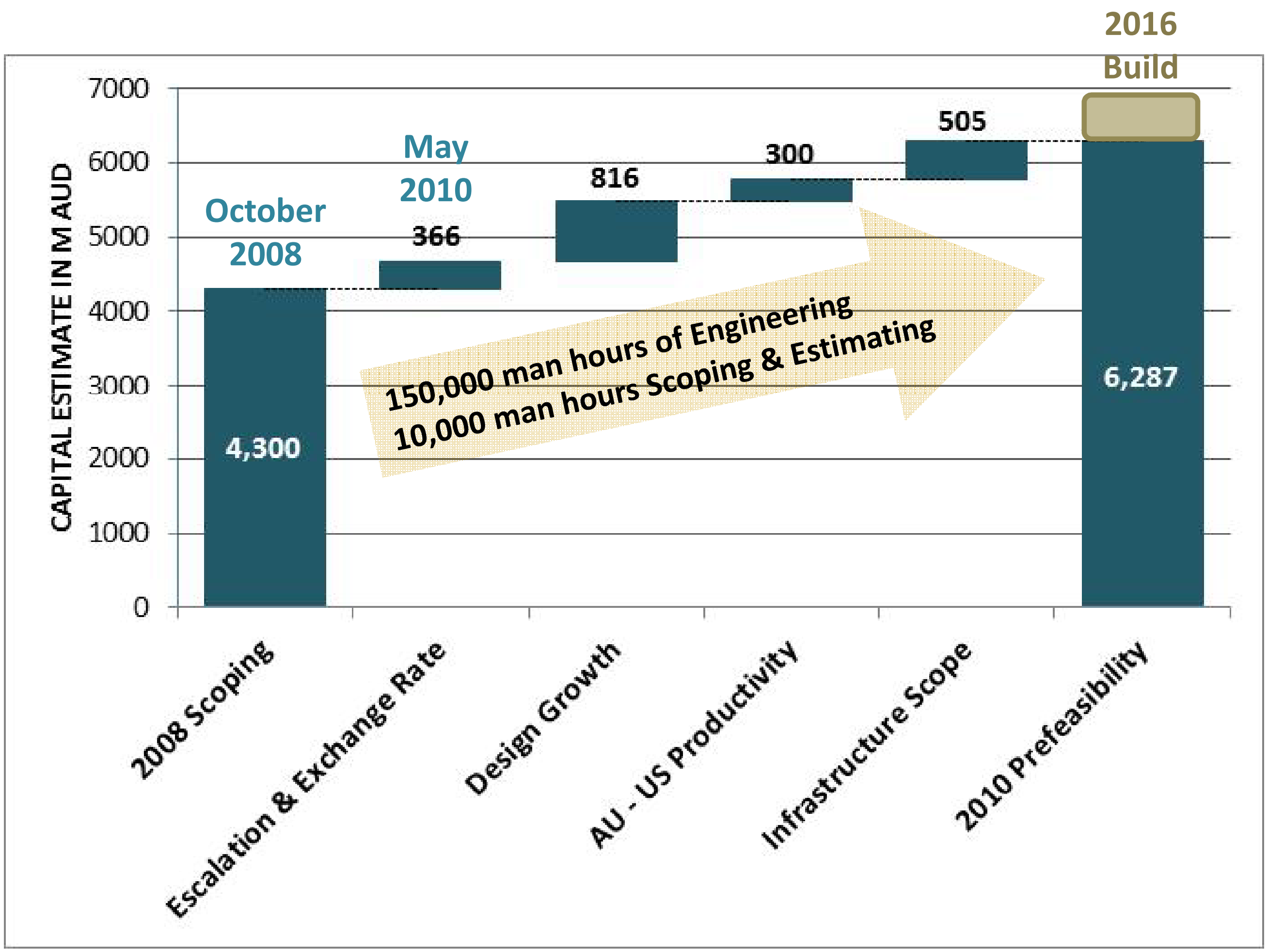
ZeroGen's TIC Estimate grew substantially

Scoping Estimate ($4.3 Billion)

- FX Variation
- Escalation
- **Design Growth**
- **Au-US Productivity**
- **Infrastructure Scope**
- **Forward Escalation**

PFS Estimate ($6.9 Billion)



Reflections on the Estimate Growth

At Scoping Study, a heavy reliance on technology providers for the core EPC scope ⟶ Major Design Growth

- Scoping Study budget does not allow for significant engineering investment
- Vendors in marketing mode and **overstated the level of maturity of design** & estimates
- **Limited industrial reference projects** in low emissions power, for IGCC and none for IGCC with CCS
- Vendors tended to ***align*** **budget estimates to the published benchmarks**

Many of the items outside the EPC scope are factored on the Equipment or EPC scope

- Owner's costs, enabling infrastructure, etc., are typically factored, leading to:
- **Optimism in base EPC estimates are compounded in the TIC estimate**

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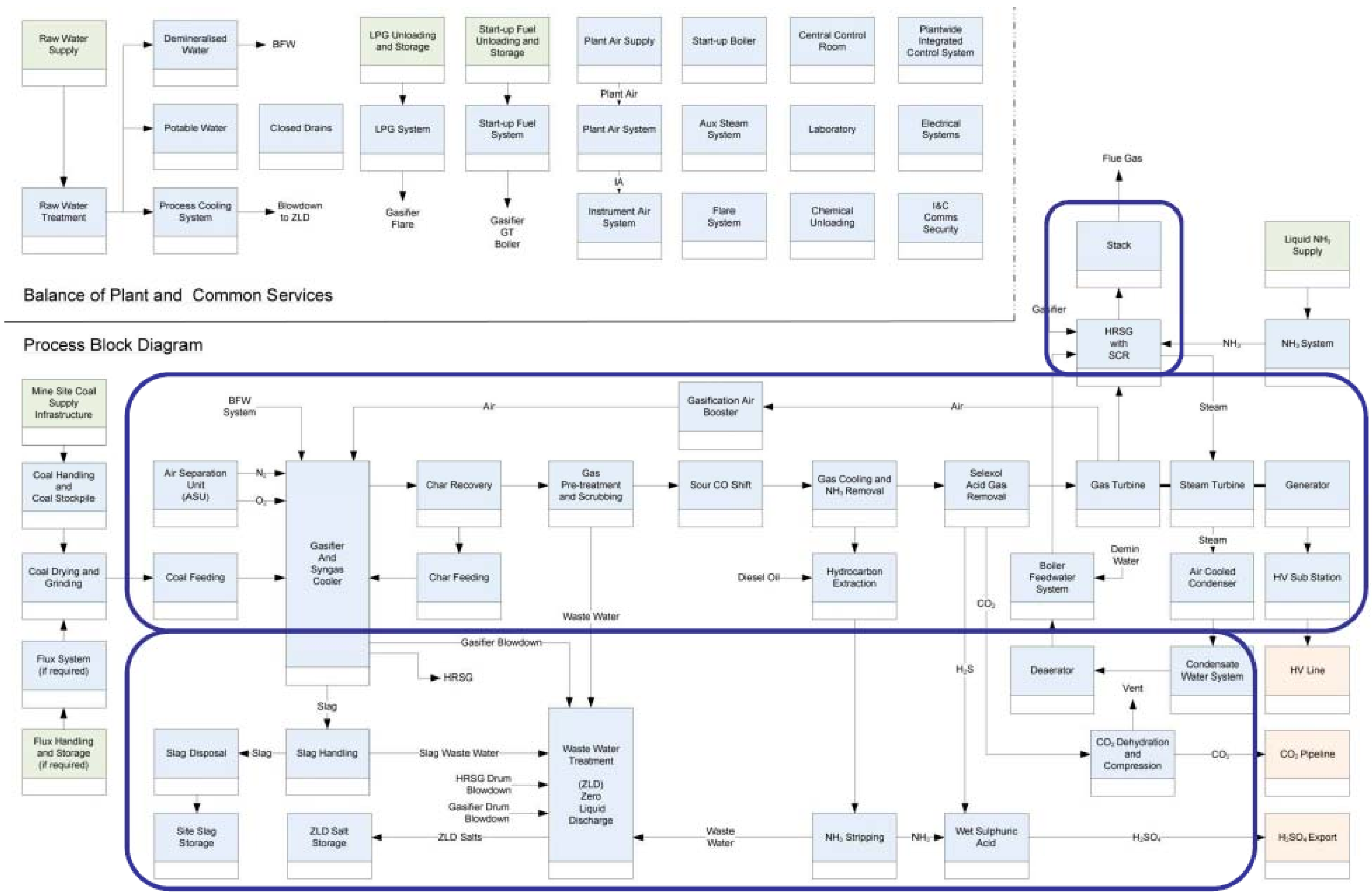
Design Growth > $800 M

Design growth represents the increase in EPC estimates arising from engineering development & maturity, for example:

- **CO_2 Specification** increased from 95% (unstated assumption) to 99.7%
- **Dry Cooling** required in Australia's arid climate
- **Site elevation and high ambient temperatures** reduce gross power output.
- Above factors + more rigour in mass & energy balances leads to **increased parasitic power loss**
- **Energy Recovery** initiatives add scope
- **Flowsheet complexity** increased as plant integration studies**,** start-up & shut-down protocols, etc., add scope
- Increased scope clarity from technology providers identifies significant **EPC exclusions** which must be scoped & delivered by others.
- Design growth also affects **Pre-FID costs to go** for Feasibility & Financial Close activities.

Significant EPC Scope excluded from Supplier Estimates



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Where and Who is developing can affect the cost

Project jurisdiction has a major impact on TIC outcomes

- Most benchmark costs, upon which vendor representations are relying are **Gulf Coast or European Seaboard as a reference** basis.
- Major impacts on scope & enabling infrastructure, productivity, etc.

Project organisation maturity influences associated Owner's cost

New special purpose companies like ZeroGen, lack depth of human resources and systems in hydrocarbons and power industries:

- Building the operations management systems, and
- Recruiting, training and relocation / accommodation of operations team can be a large cost.
- Note experience & **track record in both hydrocarbons & power is critical**.

Enabling Infrastructure & Skills Shortages … unique to Australia in current era > $800 M

Australia experiencing a booming engineering & construction sector in support of historically significant investment in resources & energy.

- Engineering & craft labour in very short supply leads to increased cost & reduced productivity (~ $300 M)

  [> **1.7 x US Gulf Coast** productivity adj. costs]
- Project regulatory systems facing bottlenecks
- Requirement to fly-in / fly-out workers & build high quality construction camps to accommodate itinerant workforce (~ $180 M incl. in Enabling Infrastructure)

Large scale IGCC with CO_2 capture equipment requires importation of very large volume, heavy items + remote construction site facilities

- Requirement for permanent and temporary upgrades in port facilities, roads, power transmission etc. (~ $330 M)

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Australia

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Estimates progress from "Optimistic" to "Not to Exceed" adds > $1,100 M

In the early phase of development, Project Owners / Developers are in "promotion mode"

- Most large scale CCS opportunities are competing for subsidies; and so
- Optimism with understatement of costs and risks is evident.

As projects progress through development, and towards FID, reality bites.

Early mover Demonstrations will rely heavily on capital grants & subsidies to enable FID with limited balance sheet resilience

- Grant **funds tend to be capped** (same for strategic equity)
- **Prudent to use P_{80} or P_{90}** estimate to assure completion
- **Contingency** estimates need to be appropriate
- Conservative **escalation** to nominal time of build costs (Australia high) in ZeroGen case (2012 – 2016)

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Capital Estimates flow to Operating cost estimates and LCOE

TIC estimates grew with project scope, engineering & design maturity, significantly beyond published benchmarks.

At the Prefeasibility Study, **operating cost estimates** are based at least in part on **Percentage of Plant Costs**

- Plant cost estimates increased, and at the same time;
- Net power output estimates reduced; and
- Plant availability estimates also reduced.

➡ **Levelised Cost of Electricity increases compounded.**

And… Early mover projects require operating subsidy in addition to capital grant…

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Summary & Conclusions

Early mover coal fired power with CCS projects face pressure to achieve FID and fail to meet widespread expectations due to:

- Excessive reliance on published benchmarks at scoping stage, with inadequate contingency allowances to reflect uncertainties.
- Optimism combined with competition for "soft funds" leads to understatement of cost & risk.
- Cost escalation through project development as scope & engineering design is matured.
- Project organisation, jurisdiction & site all have a major impacts on direct and indirect elements of TIC.
- Early mover projects often lack balance sheet resilience and so closer to FID, estimates are required to approach "not to exceed" eg., P_{80} or P_{90}.
- Escalation of operating costs translates to operating costs estimates.
- Similar optimism is often seen in early estimates of plant efficiency.
- These three adverse trends compound in the LCOE estimates.

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THANK YOU

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Understanding the Cost of Demonstration Projects. Europe Demo CCS Cost Workshop 25th – 25th April, 2012

Clas Ekström, Vattenfall

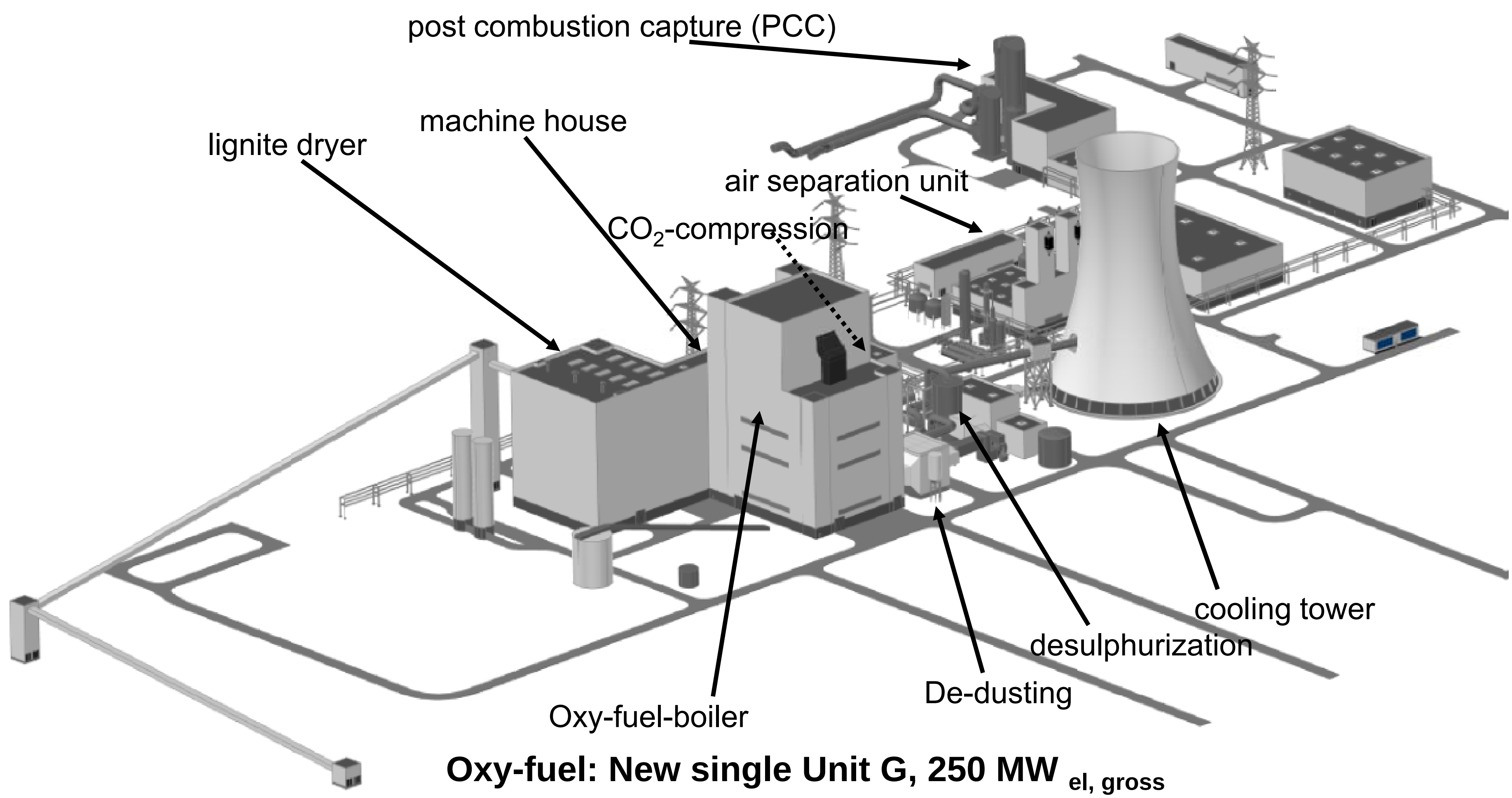
25th April, 2012
Confidentiality - None (C1)

Vattenfall's Jänschwalde Lignite fired Power Plant
South East of Berlin, Germany

VATTENFALL

New CO_2 Capture Demo

Post-combustion: 20% of flue gas (50 MW $_{el,\ net\ eq.}$) after FGD of existing boiler F2, in Unit F



Oxy-fuel: New single Unit G, 250 MW $_{el,\ gross}$

VATTENFALL

Planned to start operate 2015/16.
Terminated due to impasse in German CCS law.

- The EU-supported CCS demo project was planned to have been operational by 2015/16, and would have demonstrated this climate-protection technology for the first time at a significant power plant scale.

- Due to ongoing impasse in the German CCS law - currently insufficient will in German federal politics to implement the European CCS directive - Vattenfall during late 2011 saw itself forced to stop plans for this project.

- Vattenfall announced its termination on 5th December, 2011.

- This presentation is based on extensive planning and engineering work performed until decision to terminate the project.

Oxy-fuel Demo compared to Full Scale plant

		State-of-the-art Power Plant[1]	Oxy-Fuel Full Scale Optimised[1]	Oxy-fuel Demo Unit G
Steam parameters	(bar/°C/°C)	280/600/620	280/600/620	286/600/610
Fuel		Pre-dried lignite	Pre-dried lignite	Pre-dried lignite
Gross output capacity	MW	1 000	1 049	250
Own consumption	MW	80	270	83
Net output capacity	MW	920	779	167
Efficiency (LHV, gross)	%	54	56	53
Efficiency (LHV, net)	%	50	42	36
Specific CO_2 emission	g/kWh_{net}	804	86	106
CO_2 capture rate	%	-	90	90
Captured CO_2	t/h	-	631	169
Full load operating time	hours/a	7 500	7 500	7 700
Investment	M€	1 960	2 570	1 005
Specific investment	€/kW el, net	2 130	3 297	6 016

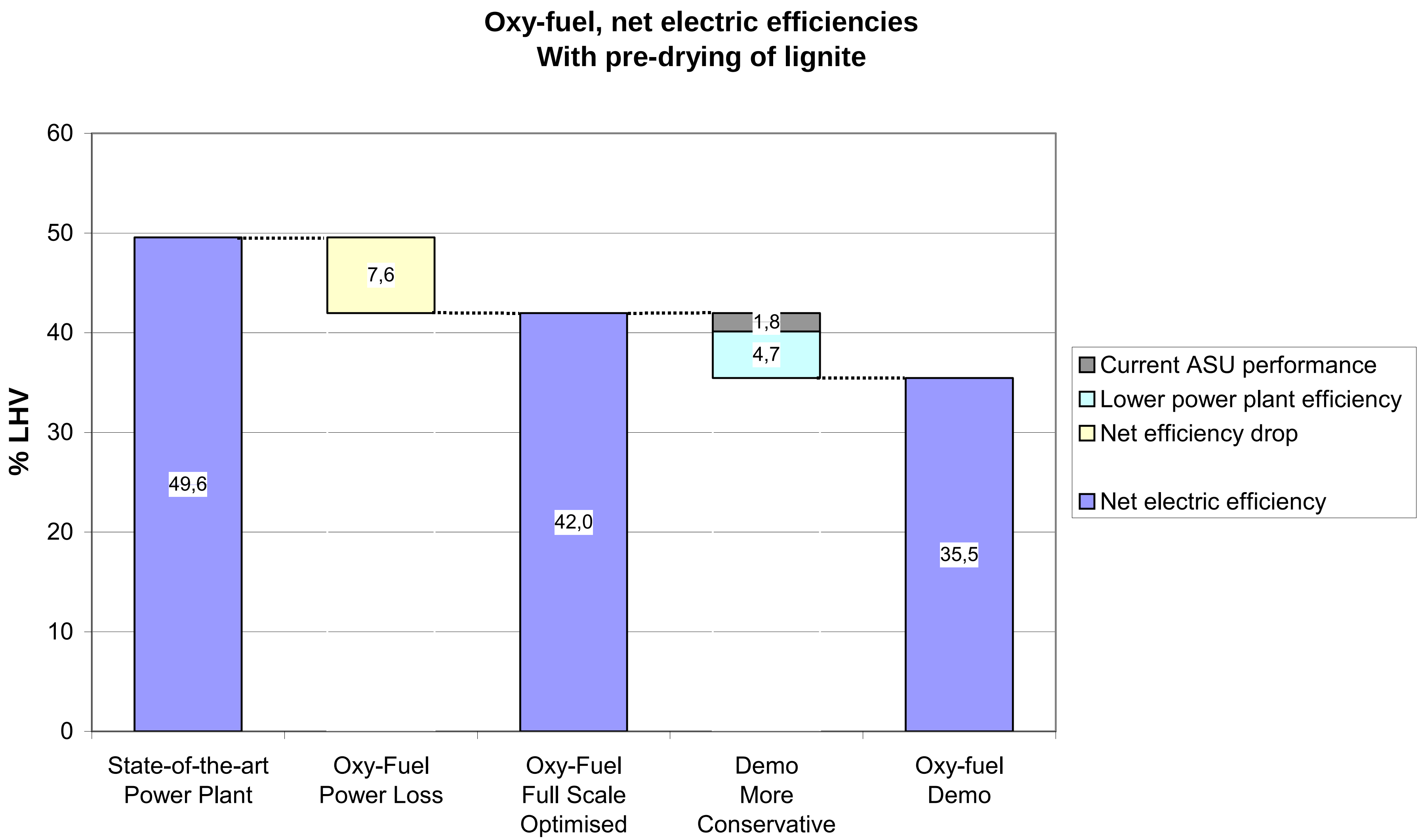
[1] Vattenfall in-house studies and ZEP CO_2 Capture Cost Study (2009 – 2011)

Post-combustion Demo compared to Full Scale plant

		State-of-the-art Power Plant[1]	Post-combustion Full Scale[1]	Jänschwalde Power Plant F2	Post-combustion Demo 20% of flue gas from F2
Fuel		Pre-dried lignite	Pre-dried lignite	Raw lignite	Raw lignite
Gross output capacity	MW	1 000	859	265	42
Own consumption	MW	80	174	15	10
Net output capacity	MW	920	685	250	32
Efficiency (LHV, gross)	%	53	46	40	32
Efficiency (LHV, net)	%	49	37	38	24
Specific CO_2 emission	g/kWh_{net}	809	110	933	174
CO_2 capture rate	%	-	90	-	90
Captured CO_2	t/h	-	677	-	50
Full load operating time	hours/a	7 500	7 500		7 700

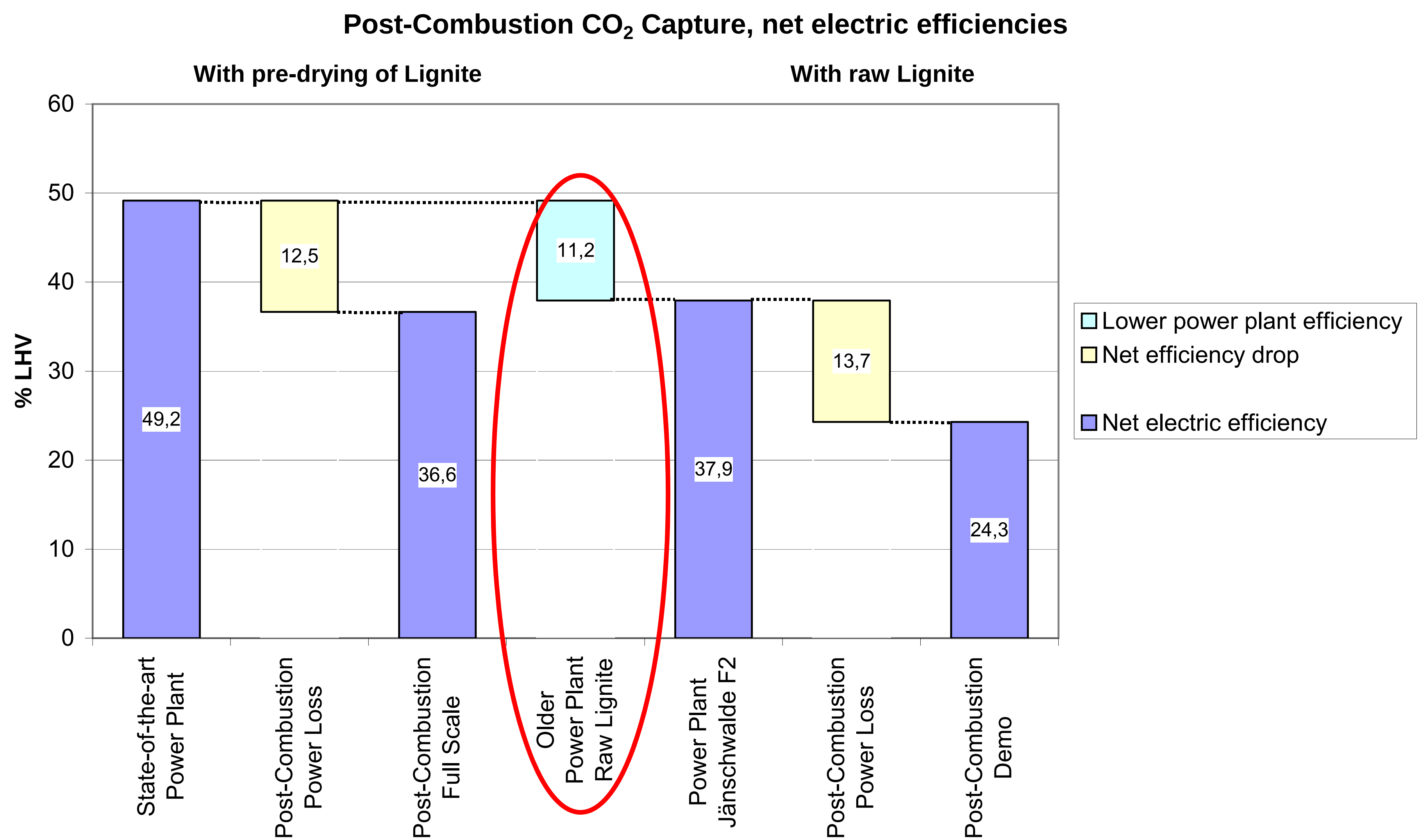
[1] Vattenfall in-house studies and ZEP CO_2 Capture Cost Study (2009 – 2011)

Oxy-fuel. Efficiencies for Demo vs. Full Scale plants.

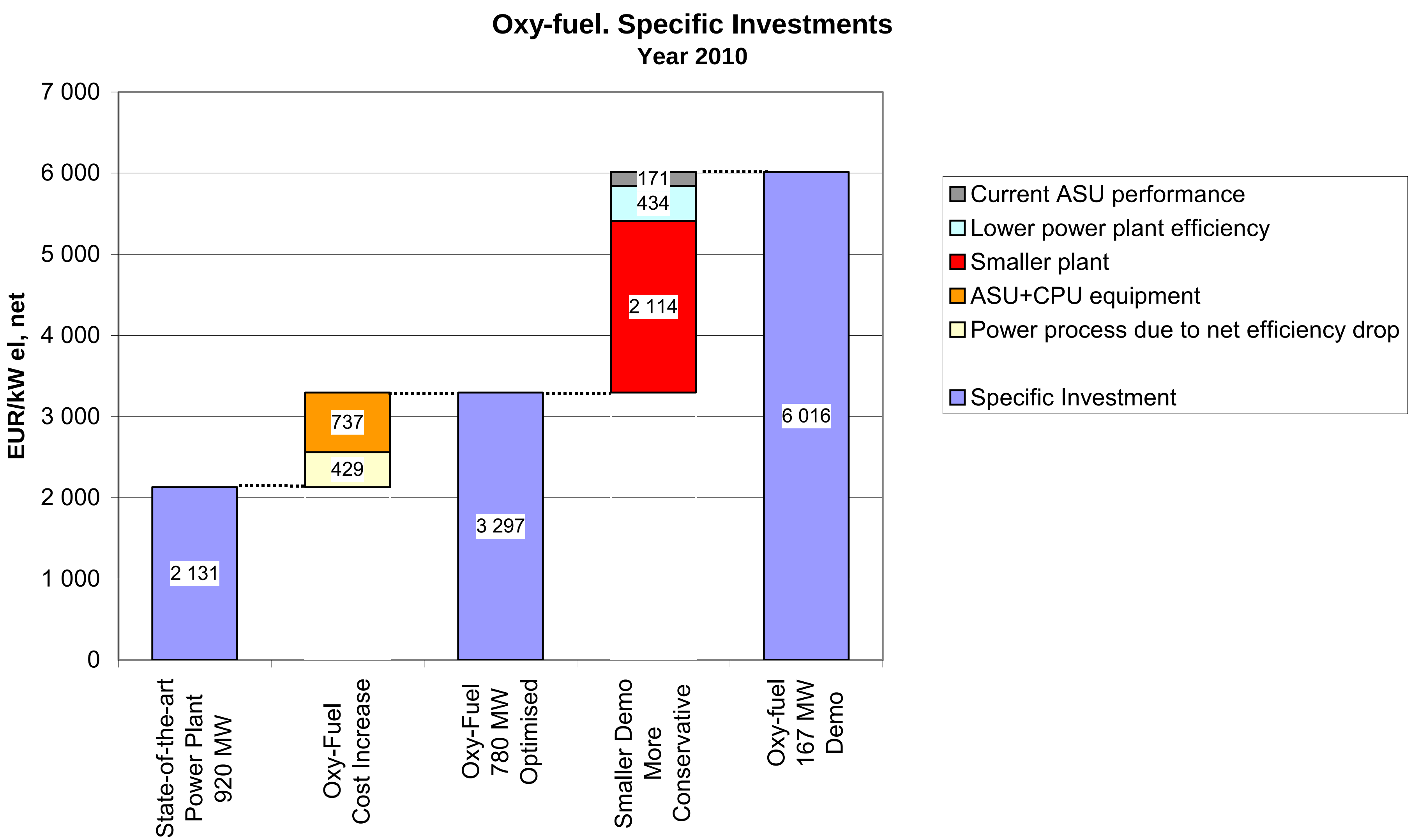


VATTENFALL

Post-combustion. Efficiencies for Demo vs. Full Scale plants



Oxy-fuel. Investments for Demo vs. to Full scale plants



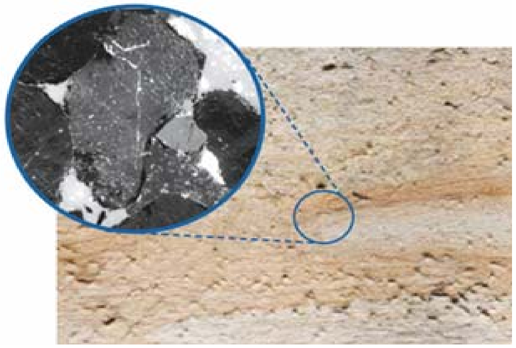
VATTENFALL

CCS Demo Project

Power plant
CO_2- capture

CO_2-Transport via
Pipeline
54 km, north

Geological
CO_2 – storage
Saline aquifer



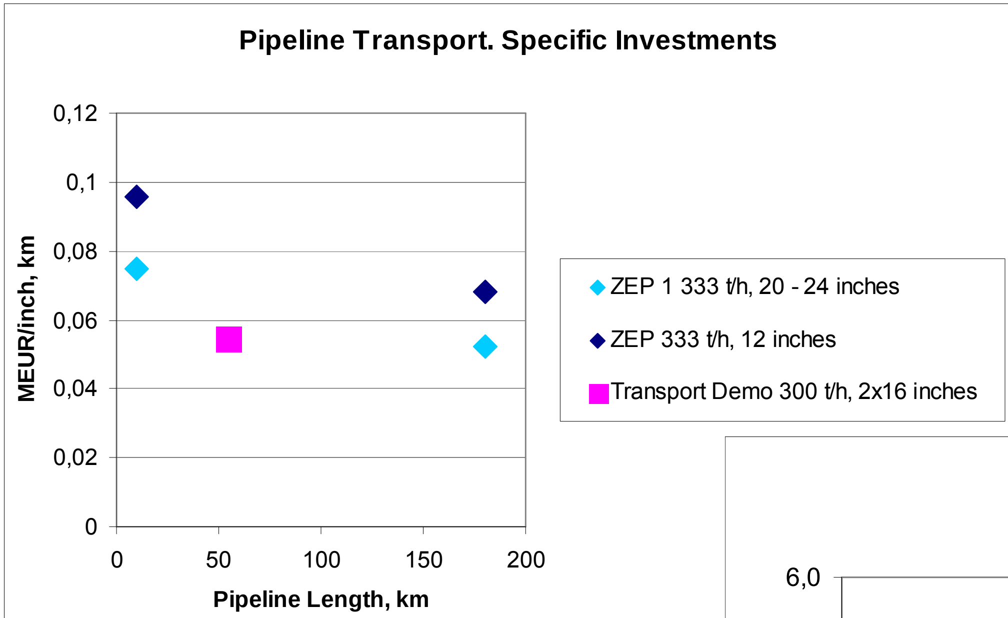
Target: Parallel development for CO_2 capture and storage

VATTENFALL

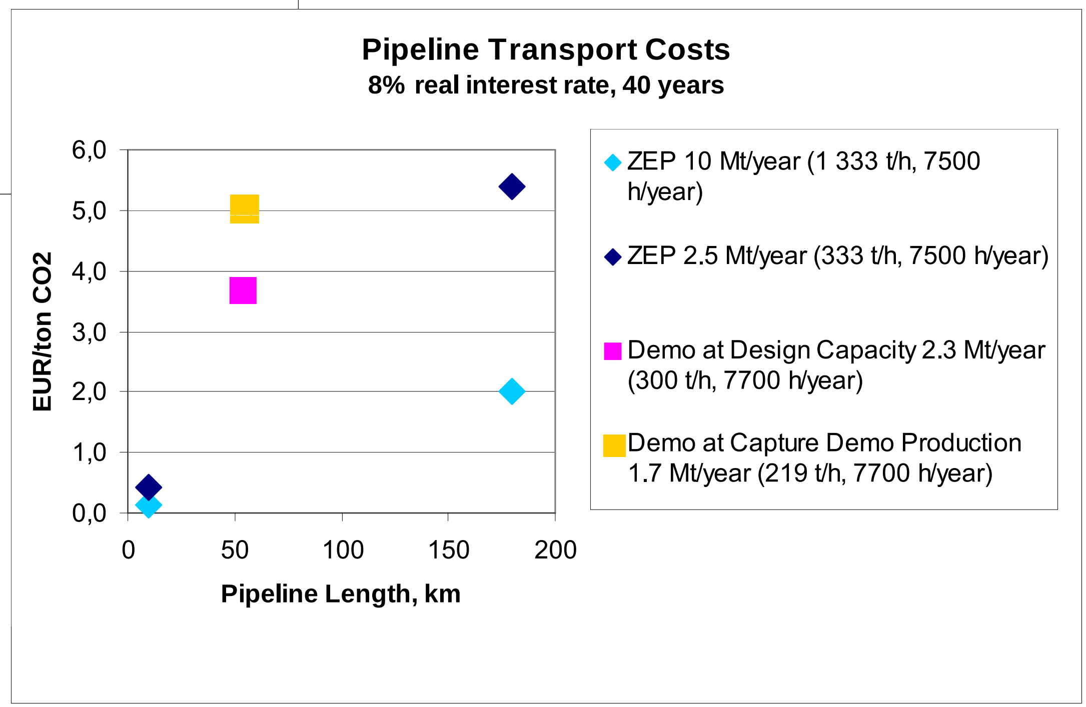
Pipeline transport of CO_2
On-shore, dense populated areas Continental Europe

		ZEP CO2 Transport Cost Study (2009 - 2011)		Transport Demo
Design CO_2 flow-rate	t/h	333/1 333	333/1 333	300
CO_2 from capture demo	t/h	-	-	219
Full load operating time	hours/a	7 500	7 500	7 700
Transported CO_2 ;				
- at design flow-rate	million t/a	2.5/10	2.5/10	2.3
- CO_2 from capture demo	million t/a	-	-	1.7
Pipeline length	km	10	180	54
Pipeline diameter	mm	305 (12 inches)/ 508(20 inches)	305 (12 inches)/ 610 (24 inches)	400 (16 inches) 2 pipes
Investment	M€	12/15	148/226	93

Pipeline CO_2 transport costs

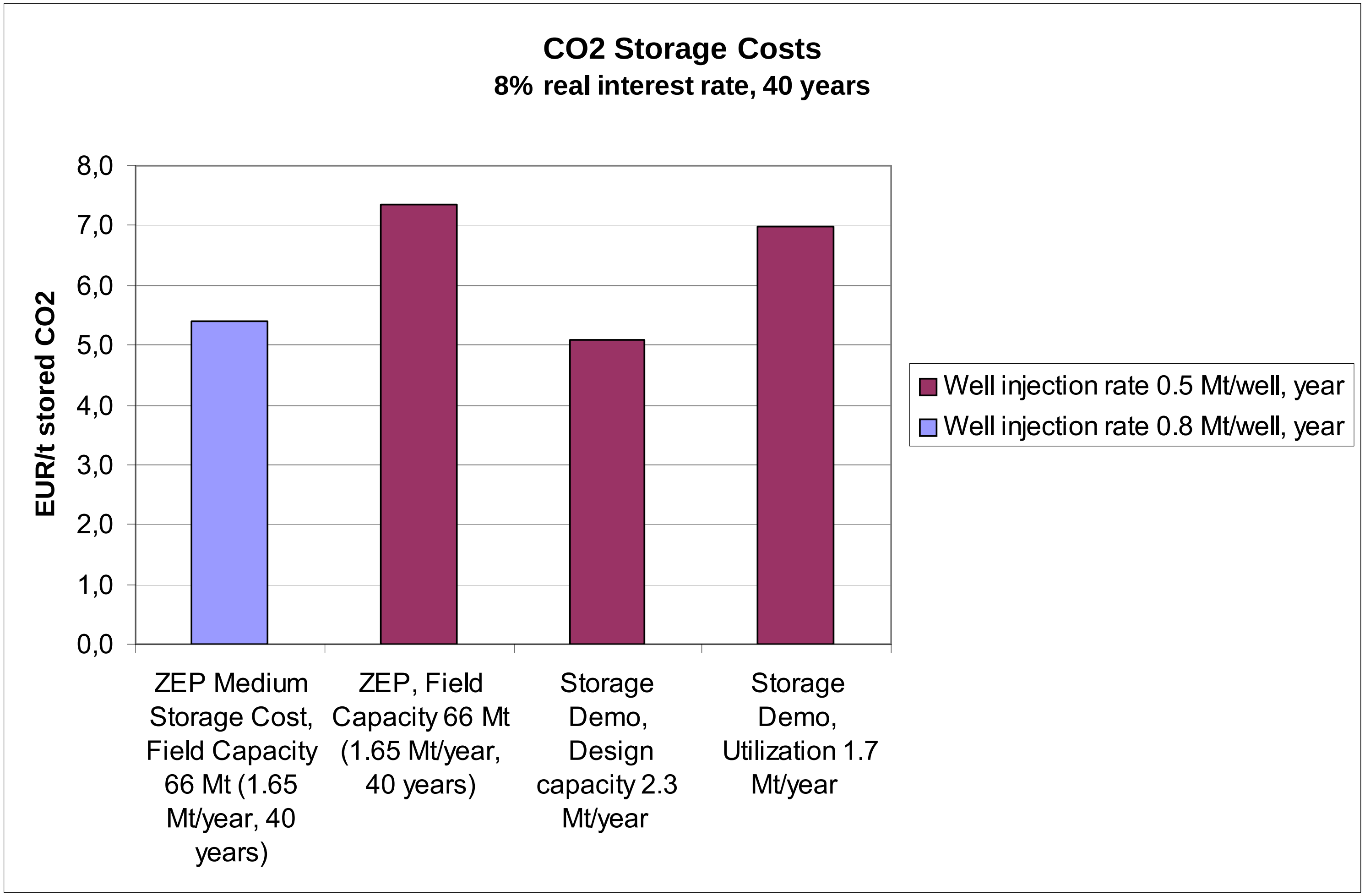


Distance, Capacity and Utilisation key specific cost drivers



Costs for Storage of CO_2. Saline Aquifers, On-shore

Field Capacity, Well Injection Rate and Utilisation key specific cost drivers



Summary

Oxy-fuel Demo vs. Optimized full-scale plants:

- Main reasons for higher specific investments for the smaller demo plant;
  1) Scale effects
  2) Lower power plant efficiency
  3) Current ASU performance

Transport and storage of the captured CO_2:

- Capacity and utilisation key specific cost drivers
- For pipeline transport also distance
- For geologic storage also well injection rate (Mt CO_2 /well, year)

clean CO_2al™ Project | SaskPower

Integrated Carbon Capture & Storage Demonstration
Boundary Dam Power Station

EPRI CCS Cost Workshop
April 24, 2012

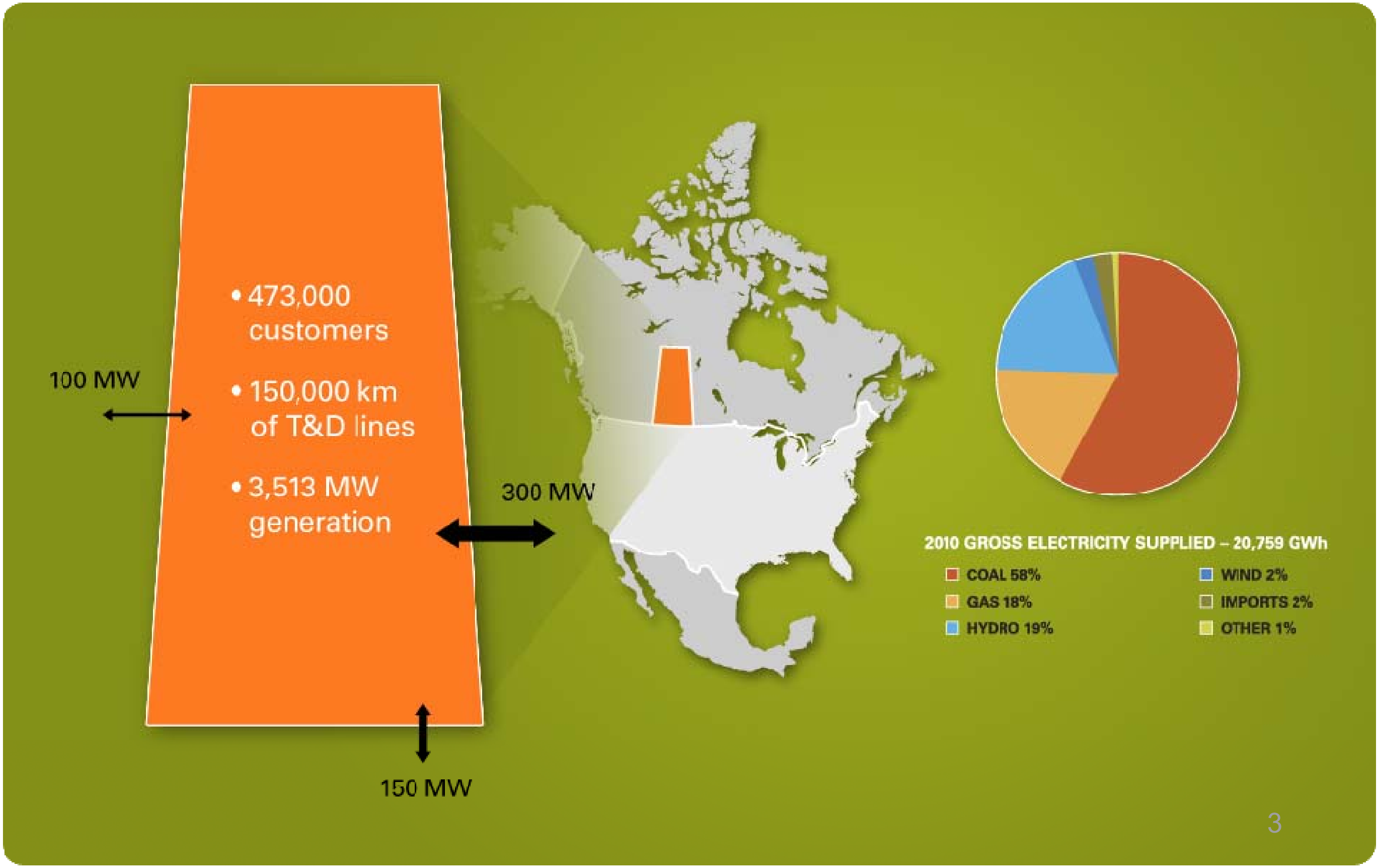
Doug Daverne, P. Eng.,

Manager, BD3 Clean Coal Project

Agenda

- Project Background – Economic Factors
  - Regulations
  - Objectives
  - Saskatchewan CO2 EOR experience
- BD3 ICCS Project
  - Scope
  - Cost
  - Economics
  - Current Status

Welcome to Saskatchewan



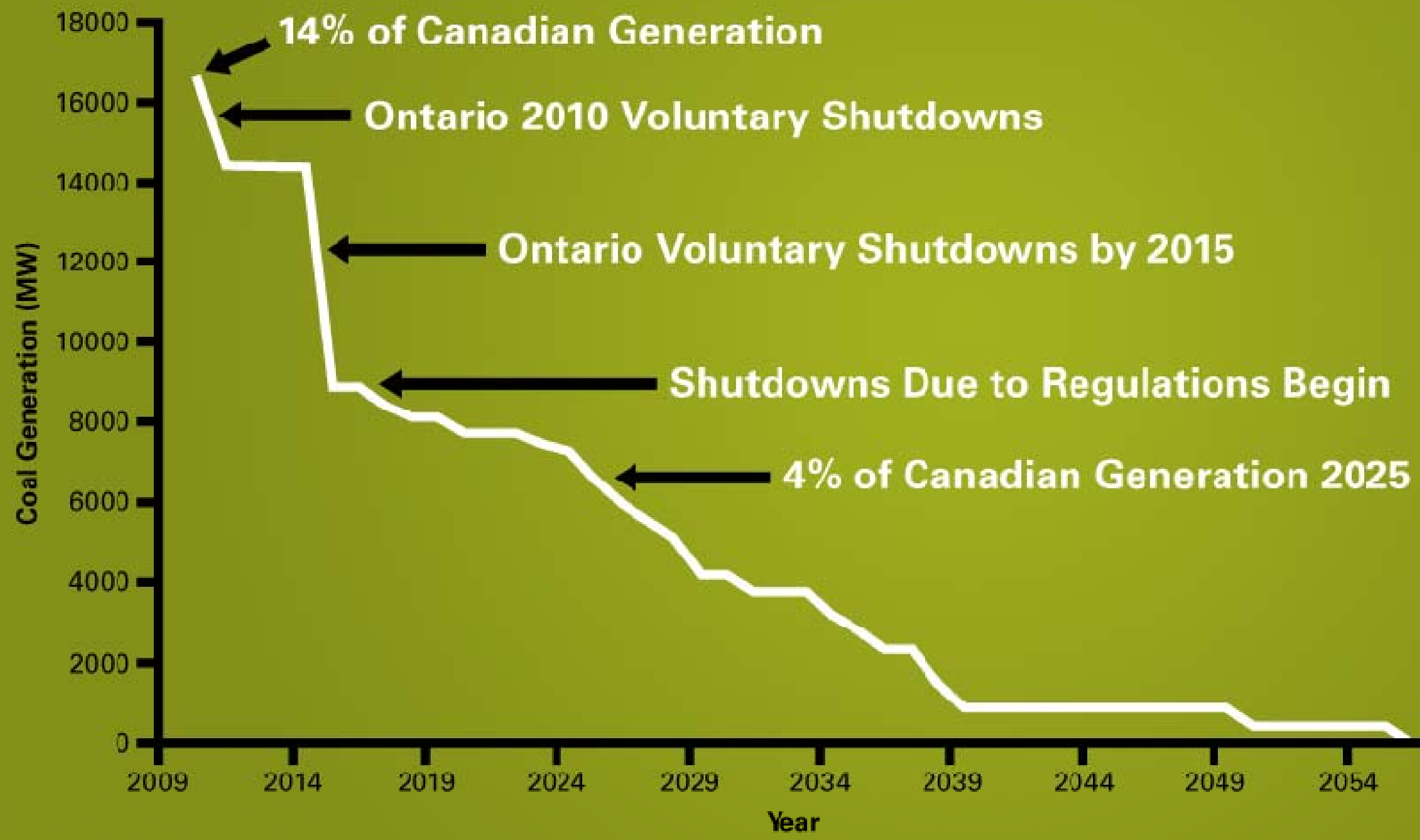
Greenhouse Gas (GHG) Emissions Reductions

GHG Requirements (discussed to date)

Proposed Federal regulation to limit CO_2 from coal-fired electricity generation:

- Establishes performance standard of 360 – 420 tonnes CO_2 /GWh ("Clean as Gas")
- To become law in 2012 and applied in 2015
- Existing units must comply when they reach 45 years of age or shut down
- Currently emit approx. 1100+ tonnes/GWh
- BD3 ICCS 90% capture – 140 tonnes/GWh

Coal Generation in Canada – The Decline



BD ICCS Demonstration

Key Deliverables:

1) Life Extension - Refurbish Unit 3 to allow an additional 30 years of reliable, safe operation

2) Performance Upgrades - Upgrade Unit 3 criteria emissions control (SOx, NOx) as well as improve efficiency

3) CO_2 Capture Technology – incorporate technology that best meets our overall Corporate objectives – both near and long term

4) Competitive COE – all of the above to be accomplished with a COE at or below that of the next lowest supply option – Nat. Gas CC. Requires a CO_2 sale to EOR off-taker to achieve.

5) In-Service Q1 2014

6) Significant Improvement in Environmental Performance

BD ICCS Demonstration

Why BD3?

1) Valuable Existing Assets

- lowers capital costs = lower cost of electricity

2) Right Size:

- 1 million tonnes of CO_2 per year matches enhanced oil recovery (EOR) market

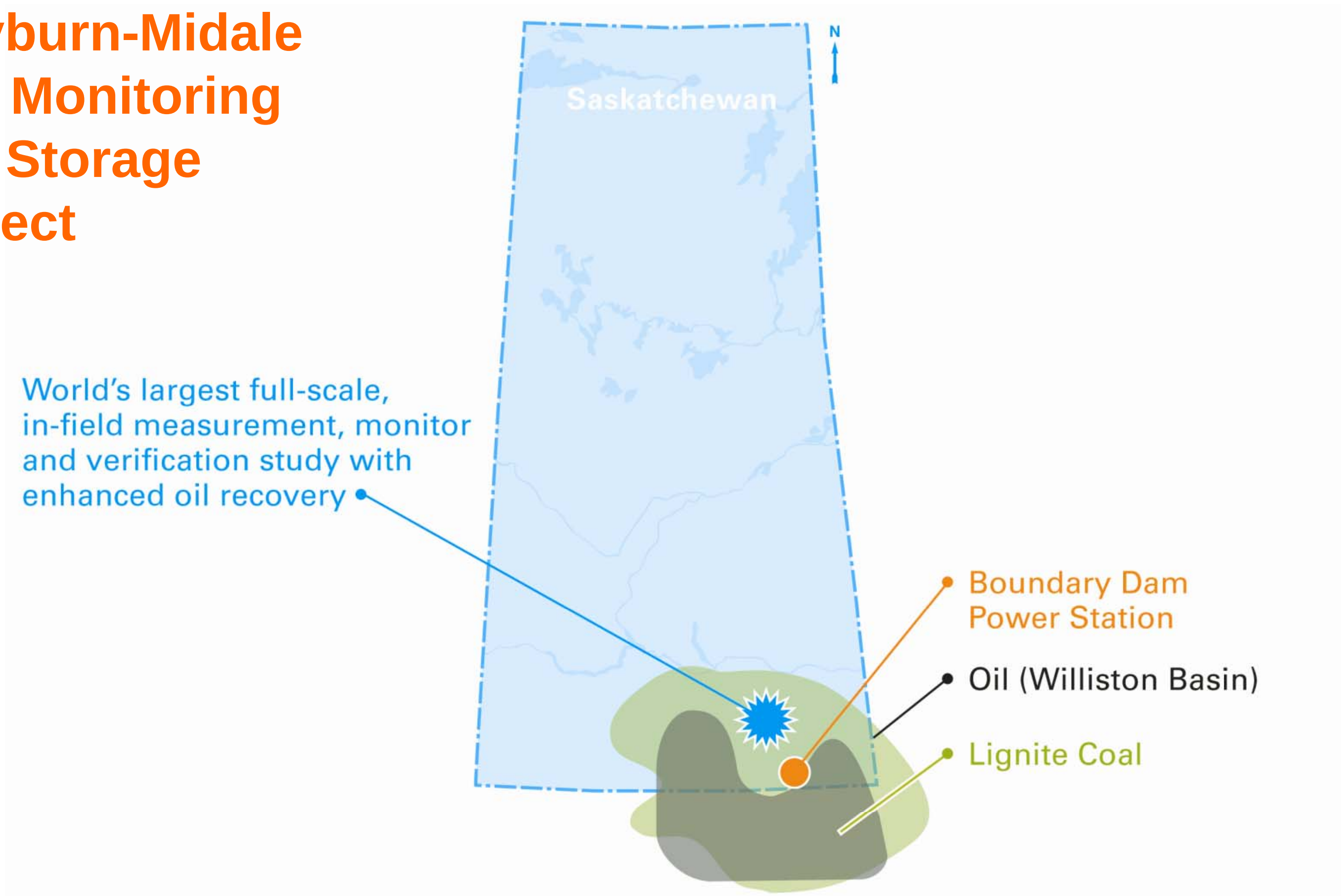
3) BD3 reaches major life cycle decision in 2013 –

- If no action – default is retirement – 0 MW

4) Applicable to other aging coal fired units

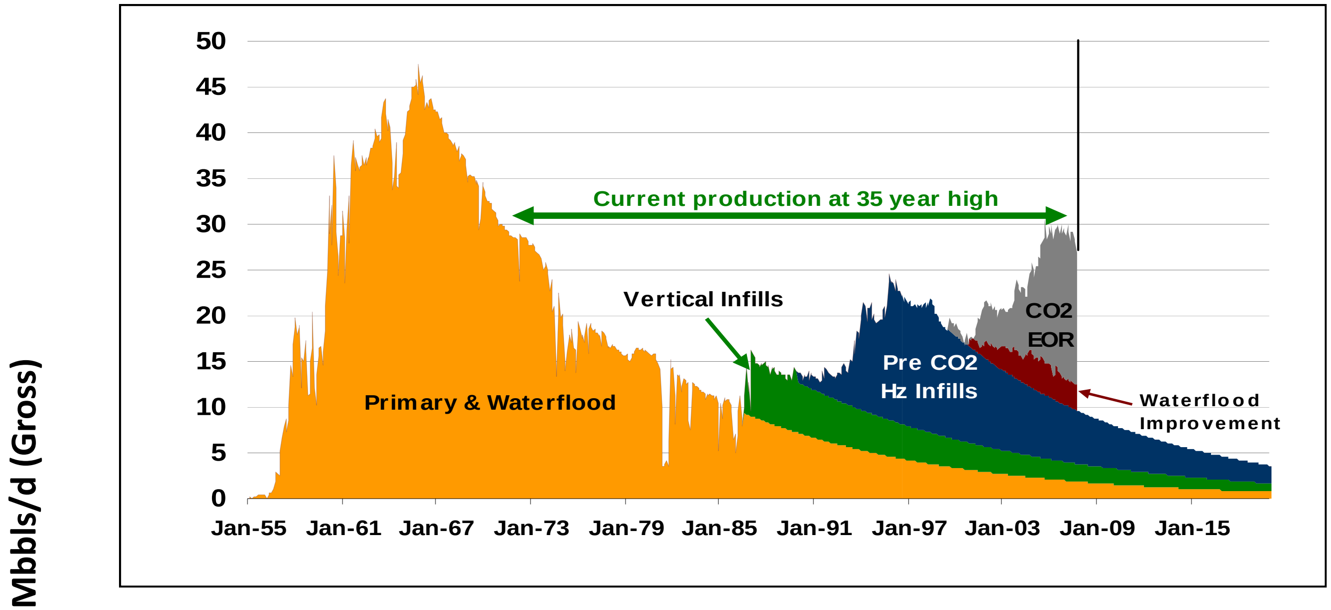
Saskatchewan Experience in CO_2 Storage

Weyburn-Midale CO_2 Monitoring and Storage Project



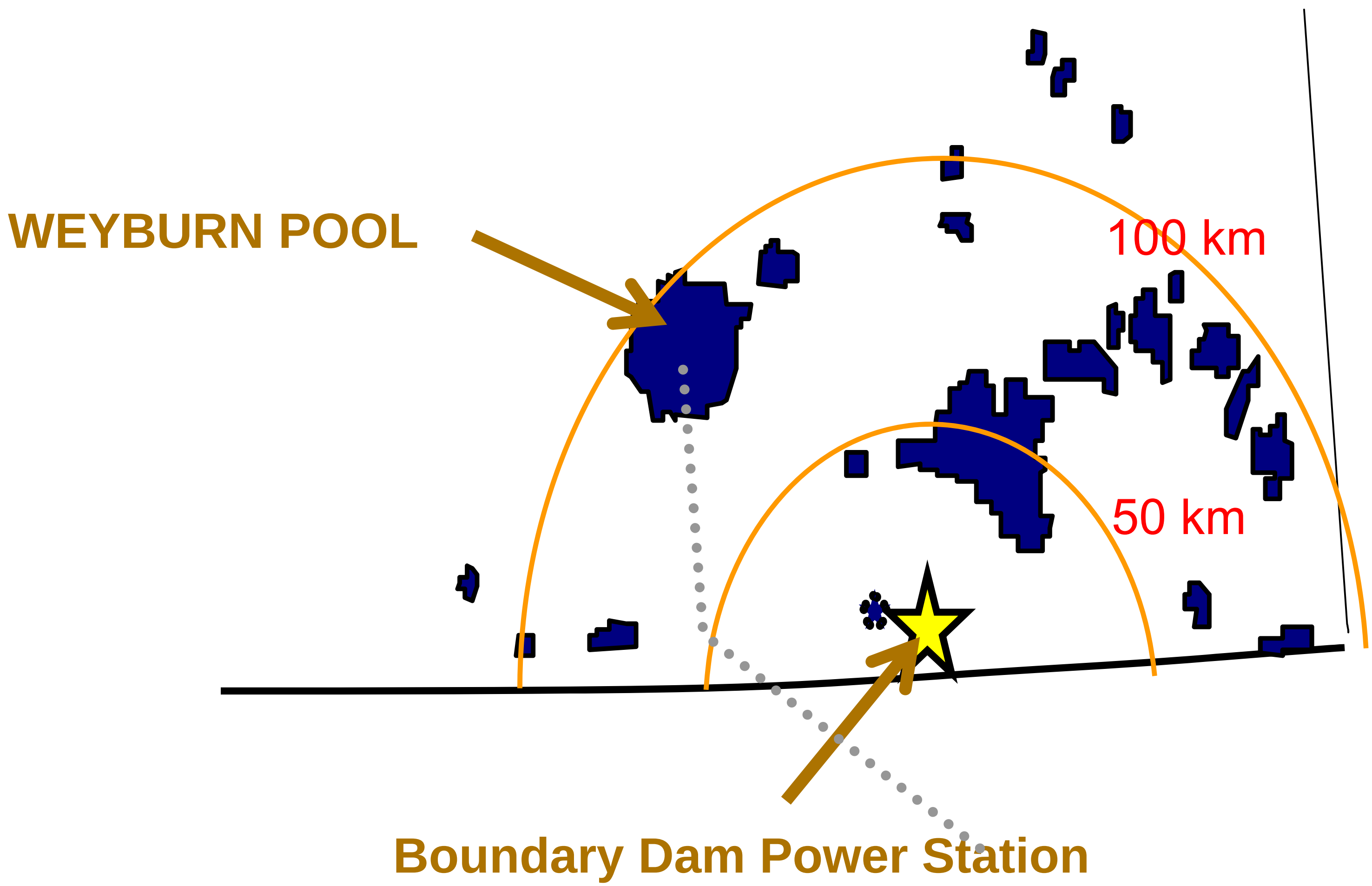
Total Oil Production at Weyburn

- Around 30,000 bbl/day: a 35-year high
- 20,000 bbl/d are due to the CO_2 flood

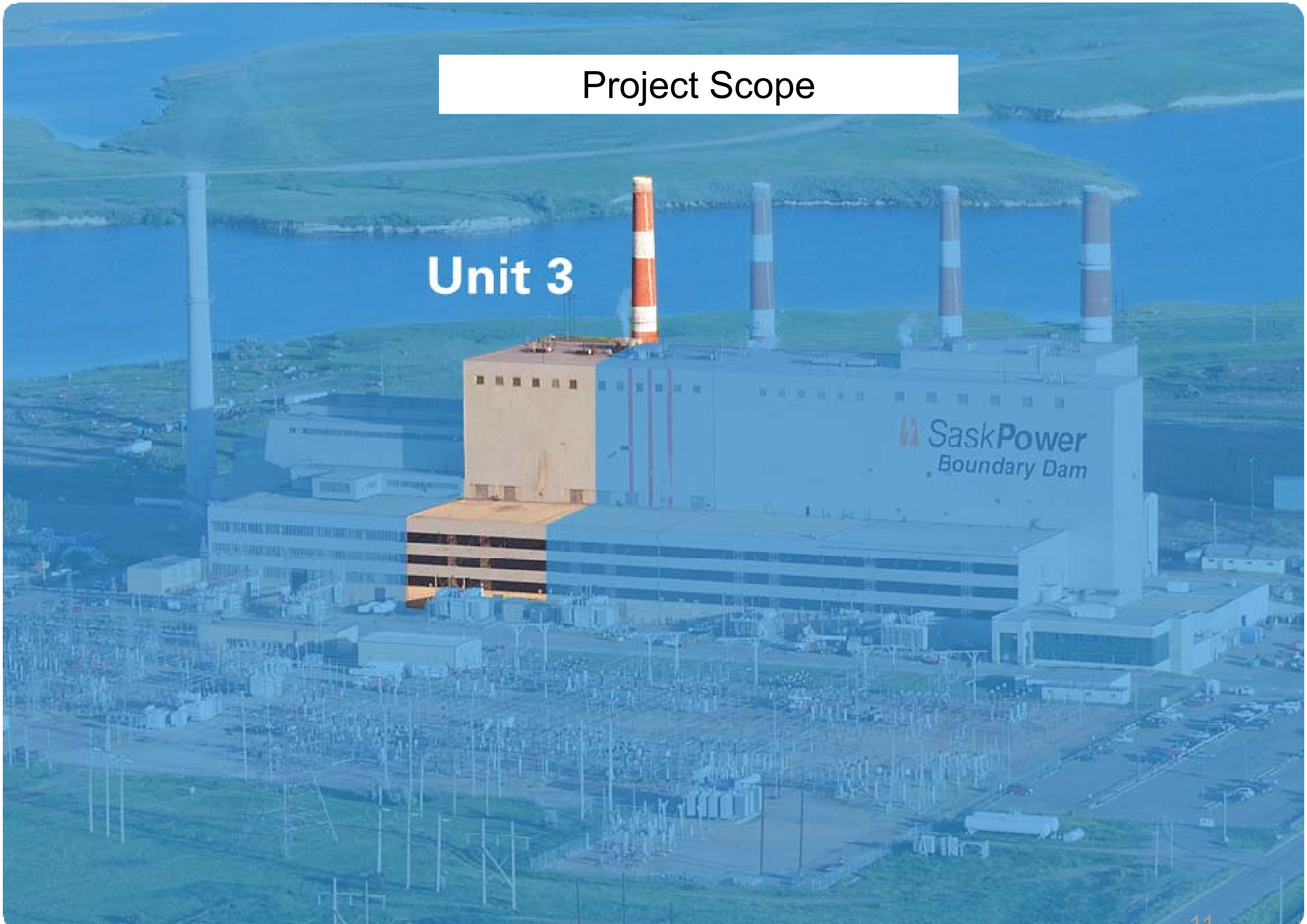


CO_2 stored equivalent to removing <u>more than 8 million cars</u> off the road for a year

Southeast Reservoirs of Interest

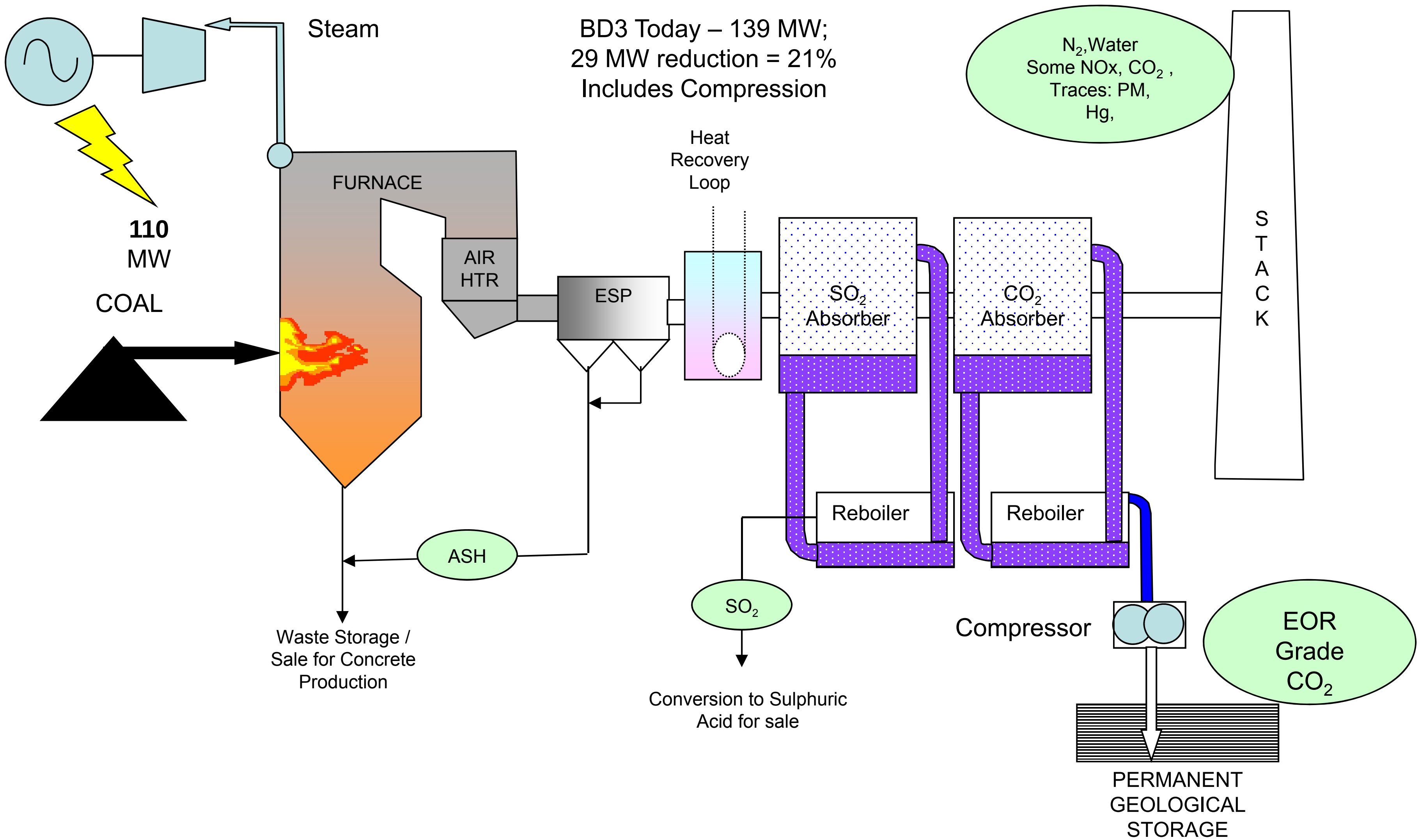


Project Scope




Unit 3

BD 3 Repowered



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SO_2/CO_2 Capture Plant

SO_2 and Carbon Capture Plant

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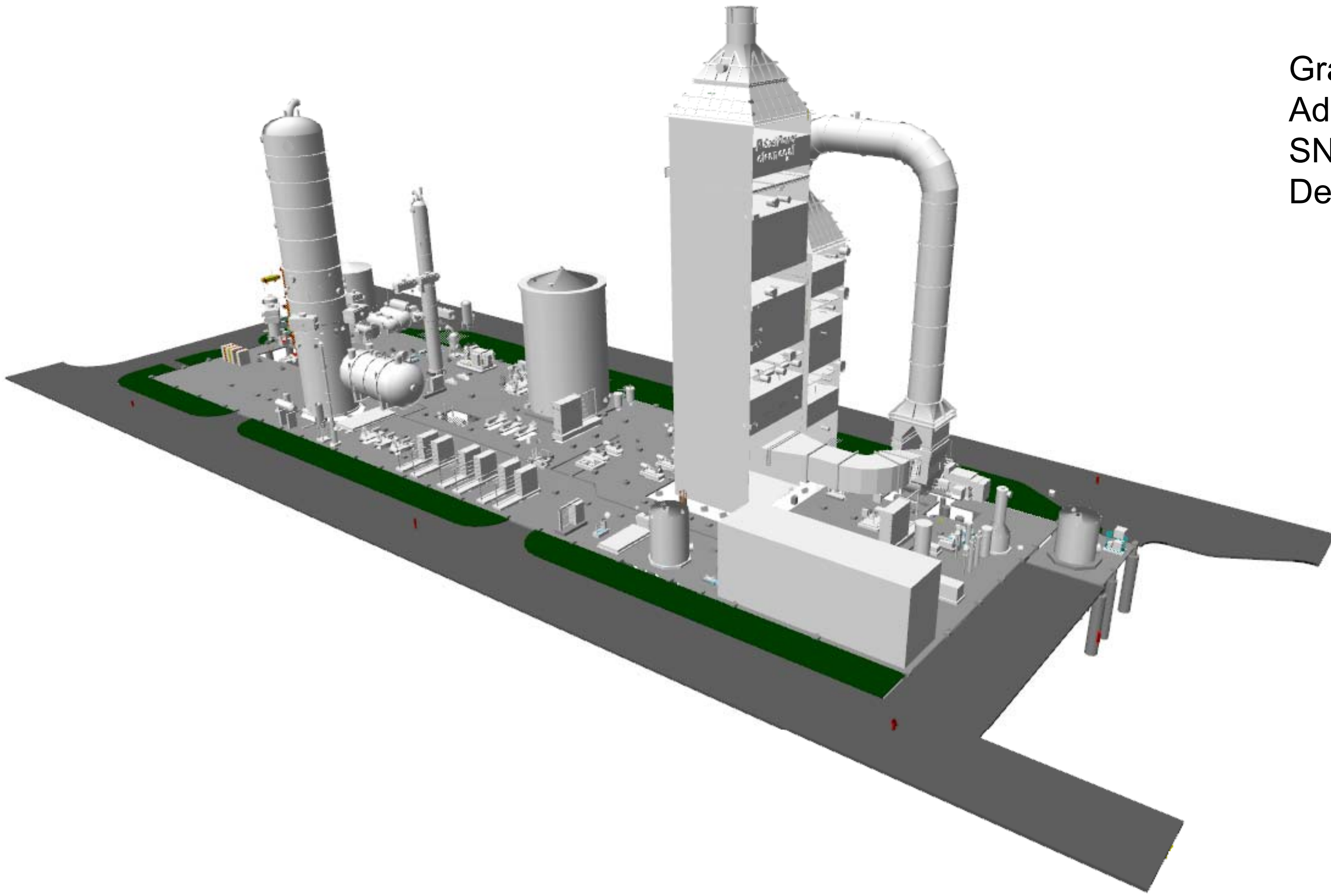

Graphics Adapted from SNC-Lavalin Design Model

Major Vessels (Q3 2011 to Q2 2012)

SNC·LAVALIN

SO_2 and Carbon Capture Plant

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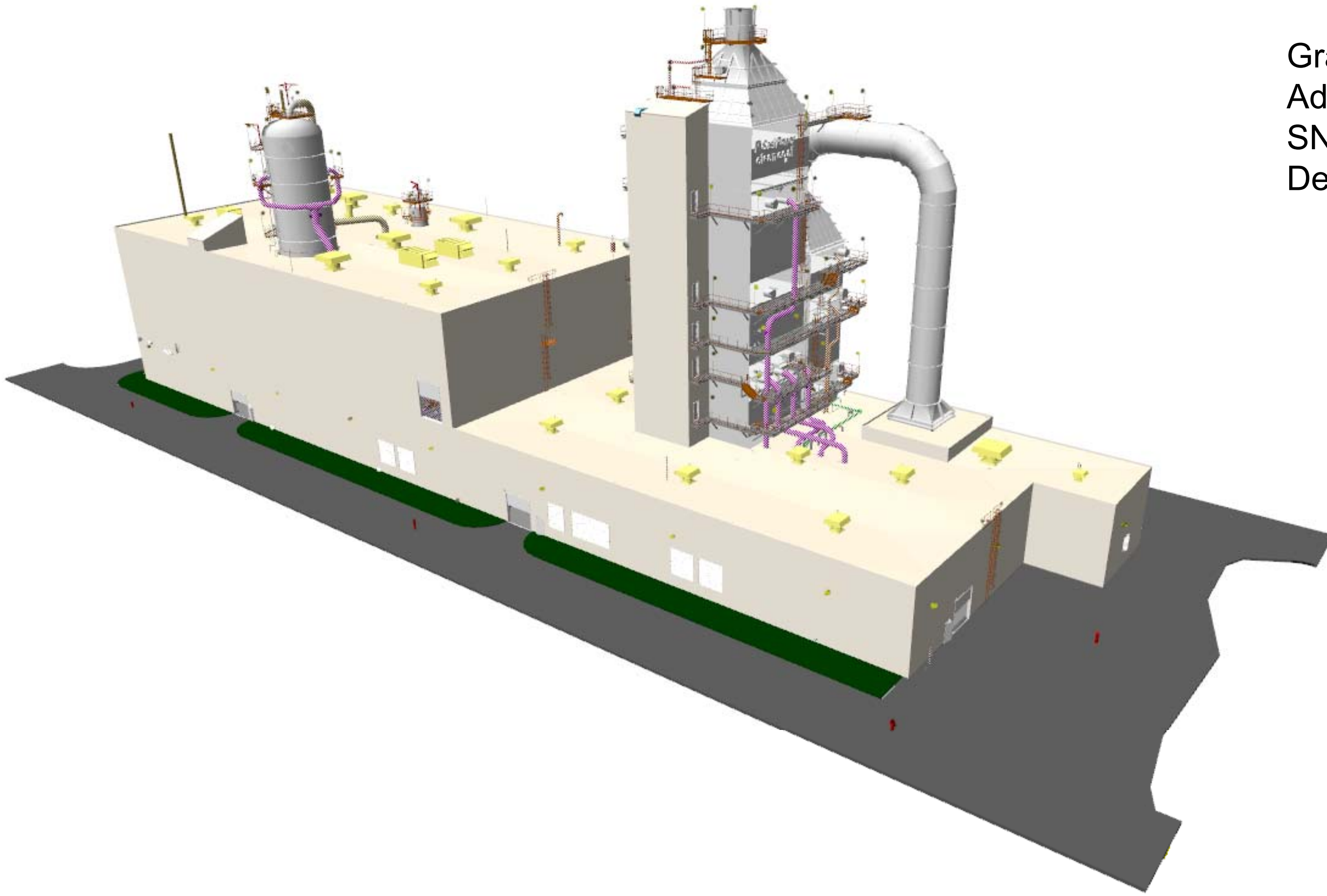

Graphics Adapted from SNC-Lavalin Design Model

Completed (Q4 2013)

SNC·LAVALIN

New Carbon Ready Plant 180 days after end of life

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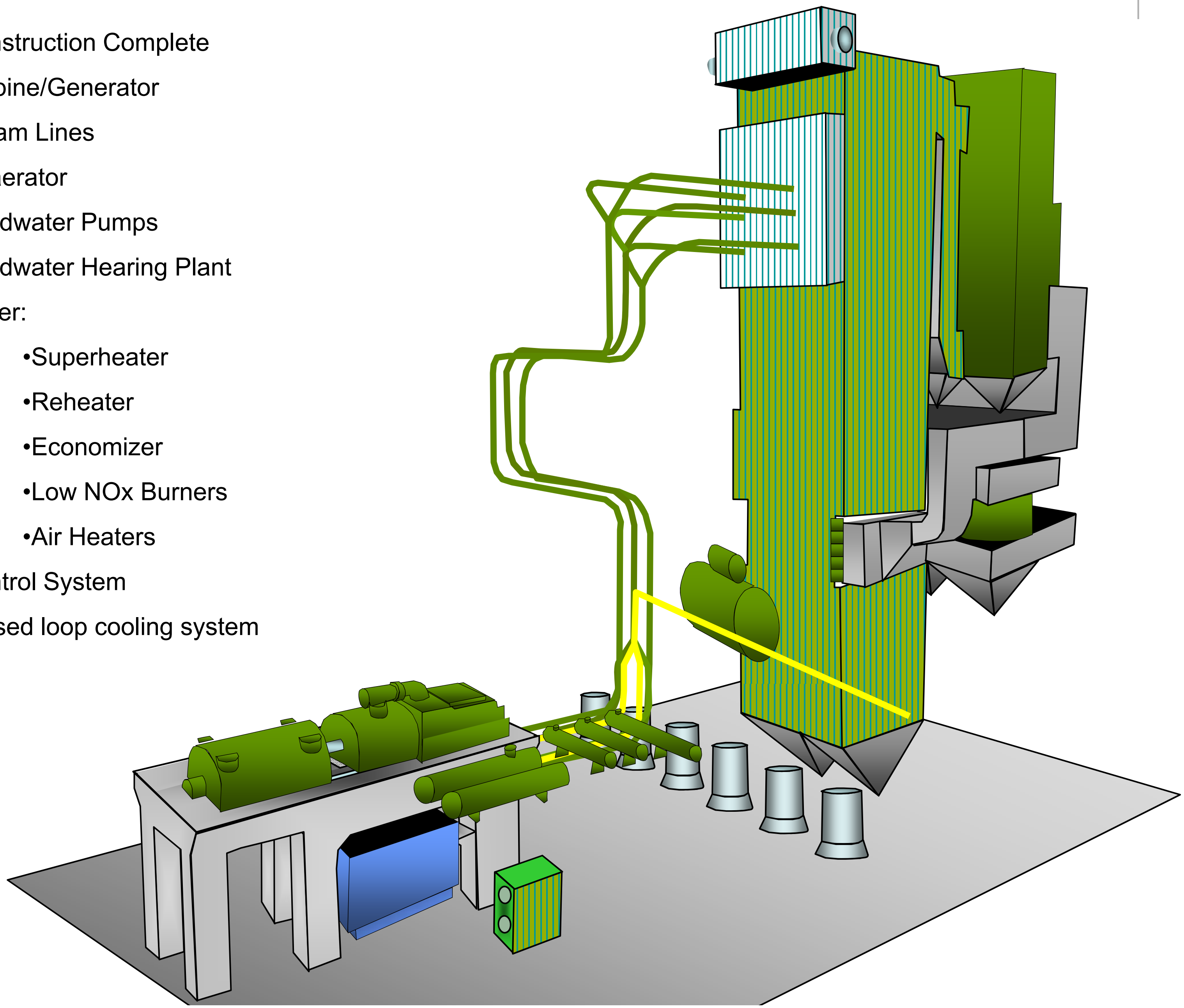
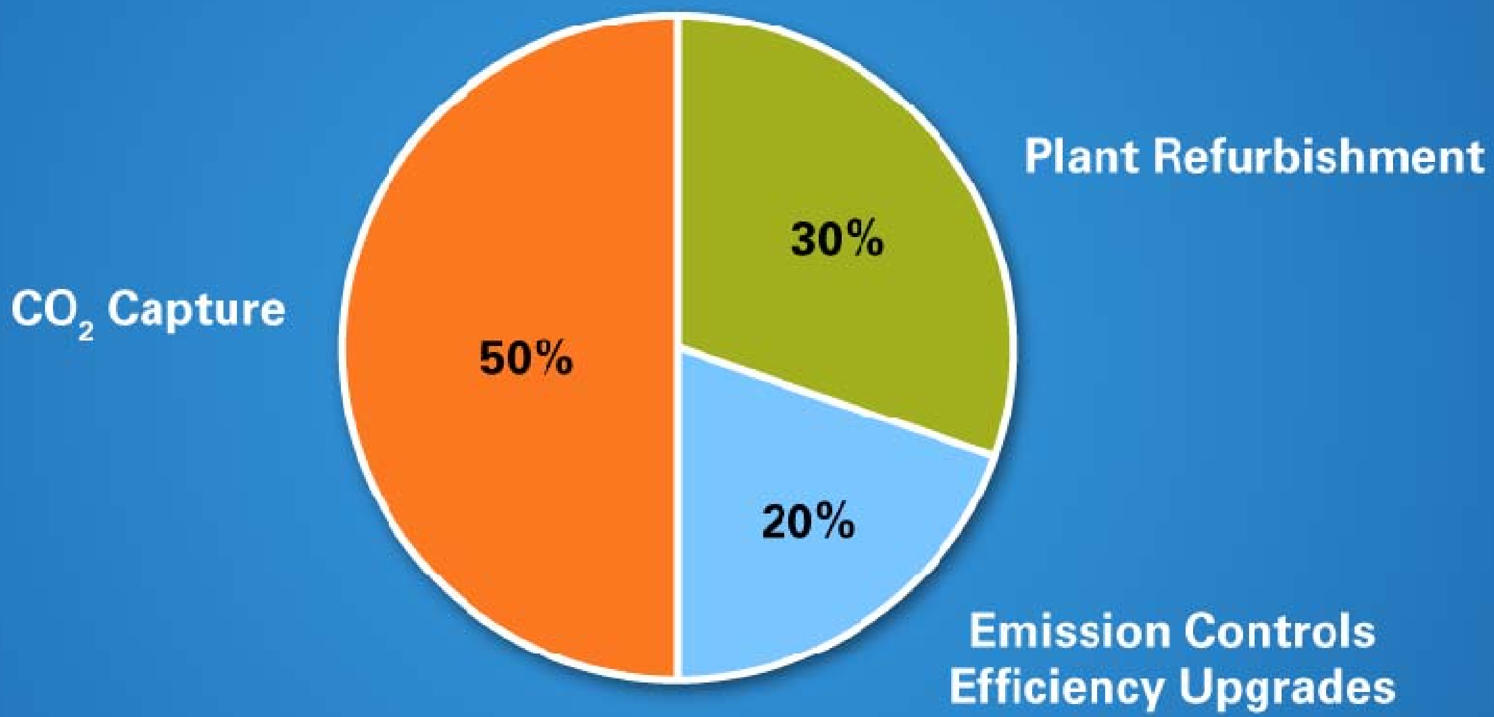
- Construction Complete
- Turbine/Generator
- Steam Lines
- Deaerator
- Feedwater Pumps
- Feedwater Hearing Plant
- Boiler:
  - Superheater
  - Reheater
  - Economizer
  - Low NOx Burners
  - Air Heaters
- Control System
- Closed loop cooling system



Stantec

Graphics Adapted from Stantec Design Model

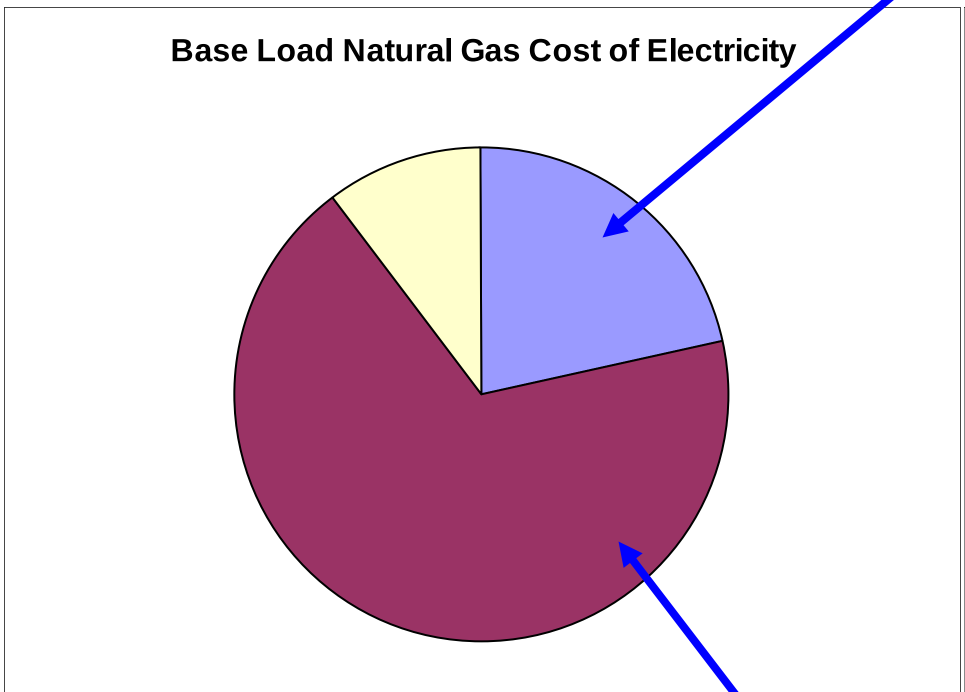
Boundary Dam Project Capital Cost Breakdown

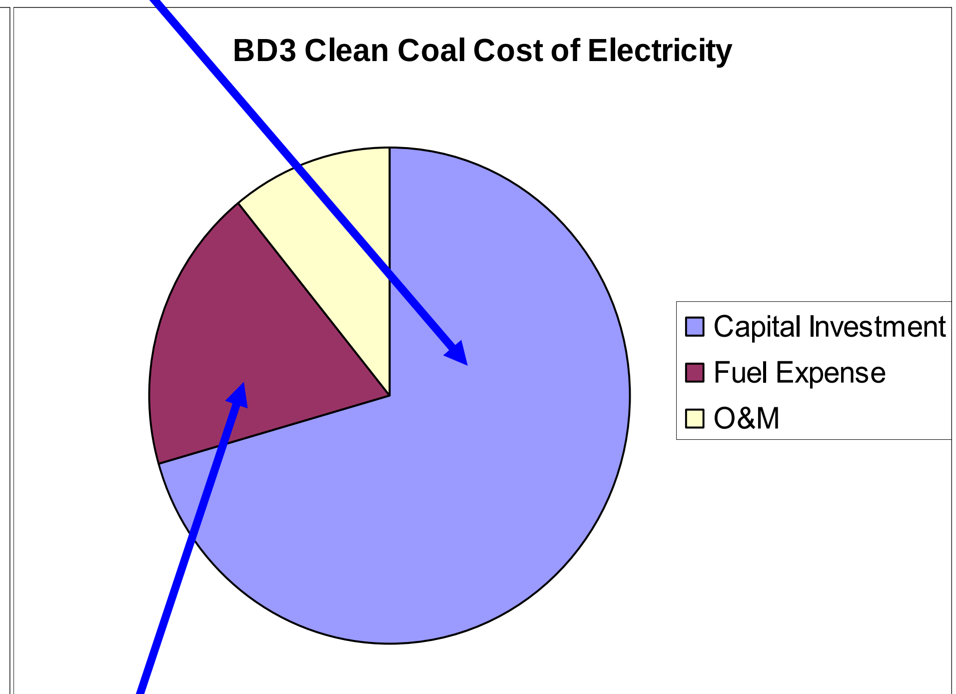


Perceptions of “Cost”

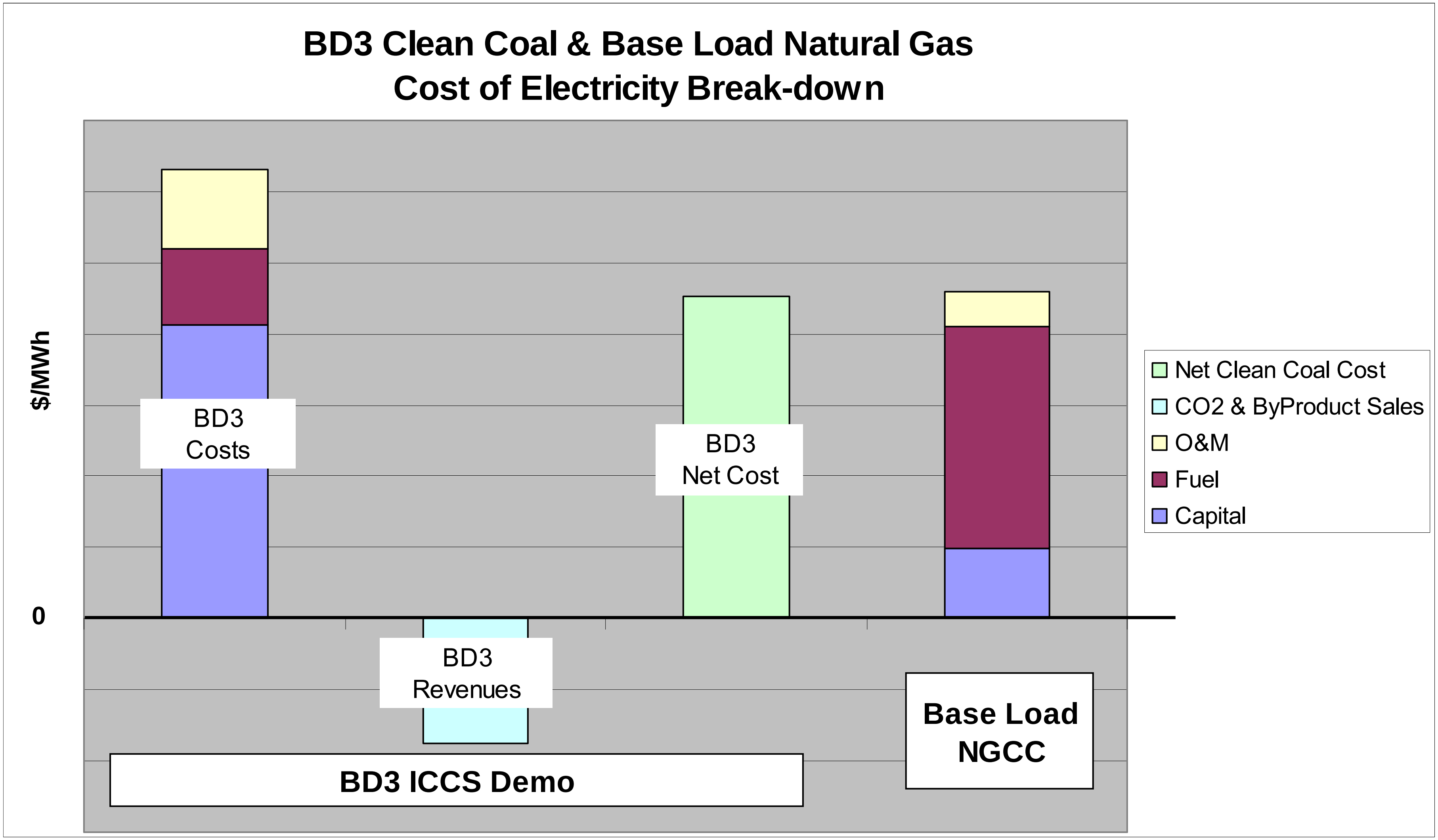
clean co2al™ Project | SaskPower

Initial Capital Cost Straightforward to Understand





Long Term Costs Less Well Understood


BD3 Clean Coal & Base Load Natural Gas
Cost of Electricity Break-down
$/MWh
0
BD3
Costs
BD3
Revenues
BD3
Net Cost
BD3 ICCS Demo
Base Load
NGCC
Net Clean Coal Cost
CO2 & ByProduct Sales
O&M
Fuel
Capital

Progress to Date

clean co$_2$al™ Project | SaskPower

- SaskPower is overall project manager
- SO2/CO2 Capture System selected – Cansolv Technologies/SNC Lavalin EPC – Competitive process
- Compressor – MAN Turbo
- Heat rejection and compression BOP – SNC
- Turbine & Generator - Hitachi
- Boiler upgrade - B&W Canada
- Balance of plant engineering and procurement in progress; approx. 85% of contracts awarded by dollar value

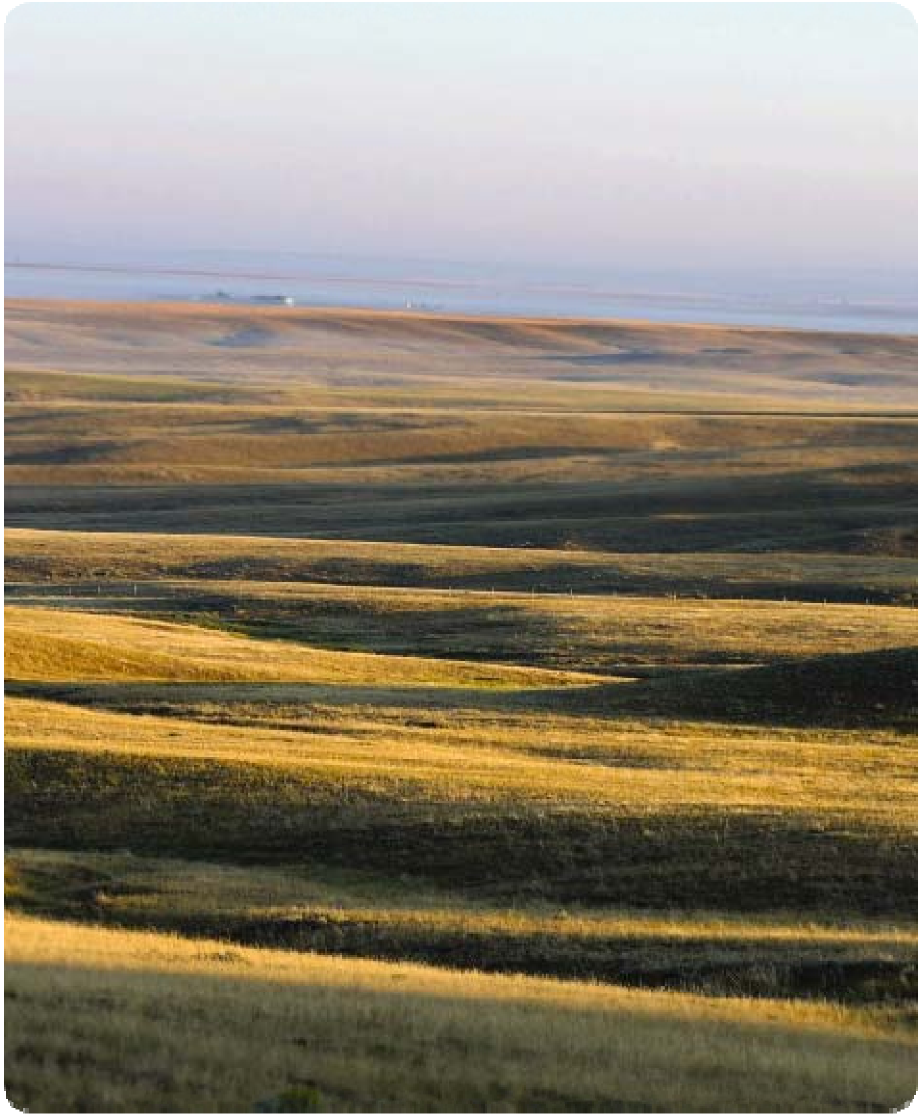
Progress to Date

clean co_2al™ Project | SaskPower

- Schedule
  - Power plant rebuild – March through August 2013 – then start-up – producing power
  - CO_2 Capture start-up and commissioning fall 2013
  - Full commercial operation – Q1 2014


03/16/2012

Conclusions



- Preserves coal as a fuel source and maintains fuel mix diversity.
- Cost of electricity competitive with natural gas.
- Provides information needed for making future decisions.
- Develops EOR CO_2 buyer market - has significant positive economic impact for the provincial economy.

CCS projects in Saskatchewan

- SaskPower Boundary Dam Integrated Carbon Capture and Storage Demonstration Project;
- SaskPower Carbon Capture Test Facility
- CO_2-EOR (International Energy Agency GHG Weyburn-Midale CO_2 Monitoring & Storage Project)
- Deep Saline CO_2 Storage (Aquistore)
- Petroleum Technology Research Centre (PTRC)
- International Performance Assessment Centre (IPAC)
- International Test Centre (ITC)

SaskPower

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Development/Owner's Engineer

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EPC Contractor - SO_2/CO_2 System

SNC•LAVALIN

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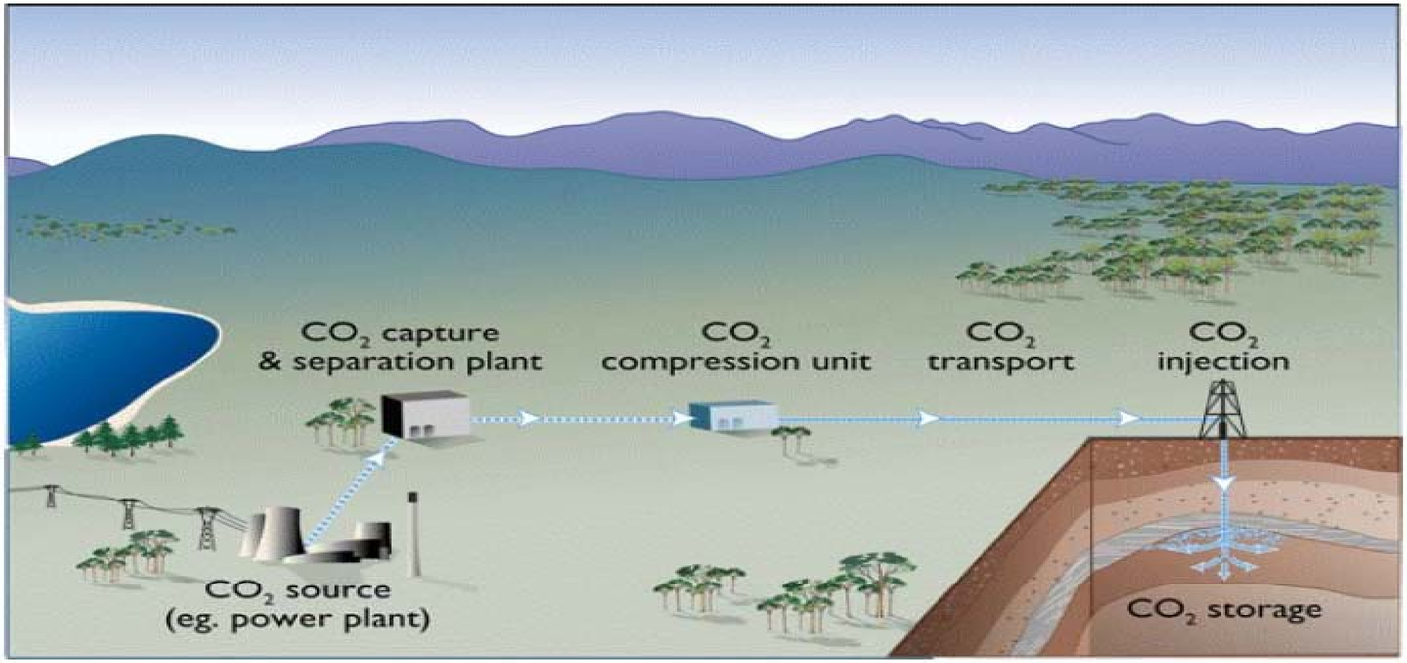
Questions?
SaskPower

NATIONAL ENERGY TECHNOLOGY LABORATORY



NETL CO_2 Injection & Storage Cost Model

EPRI-CCS Cost Workshop, Palo Alto, CA – April 25-26, 2012

Tim Grant and Dave Morgan – National Energy Technology Laboratory

Jason Valenstein, Andrea Poe and Marta Milan – Booz Allen Hamilton, Inc.

Richard Lawrence – Advanced Resources International, Inc.

NETL CO_2 Injection and Storage Cost Model

Introduction

Model Description

Geologic and Cost Databases

Model Runs

Conclusions

NETL CO_2 Injection and Storage Cost Model

Purpose of our model

- **Estimate cost for a single site**
  - Saline storage
  - O&G and EOR in near future
- **Provide data to generate national or regional storage cost supply curves**
- **Provide cost analysis of various sequestration technology**

NETL CO_2 Injection and Storage Cost Model

Existing NETL Models

- Estimating Carbon Dioxide Transportation and Storage Costs , pre-cursor to the current *CO_2 Transportation & Storage Cost Model*
- Capture-Transport-Storage (CTS) model to model pipeline development for transportation of captured CO_2 from source to sink
- Power Supply Financial Model (PSFM) to model the cost of capture for an IGCC or Super-critical PC plant

CO_2 Injection and Storage Cost Model

Geologic Module

Activity Cost Module

Financial Module

NETL CO_2 Injection and Storage Cost Model

Sequence of events for CO_2 storage operations and framework for CO_2 Transportation & Storage Cost Model

Regional evaluation for a specific site	Site selection & characterization	Permitting	Operations	Post-Injection Monitoring	Long-term Stewardship
Negative Cash Flow			Positive Cash Flow Injection Fee	Negative Cash Flow	Trust fund covers costs
Estimate of volume of emissions to sequester and pore space needed over project life.	Assemble data; acquire new data; drill new well(s) & acquire seismic; establish data baselines; get necessary permits.	Submit all plans and financial responsibility for permit application – UIC & State	Finish construction of surface facilities and MVA grid; Tie injection wells to CO_2 supply.	Present PISC & site closure plan to Director; apply for reduced time period	Another entity accepts long-term stewardship
Data research – geologic, geophysical, engineering, financial & social. Initial modeling of potential site.	Finish assembling acreage block.	Director approves drilling of injection wells. State (DEP) approves site permit. Approval of other permits as needed.	Inject Captured CO_2. Annual MIT for injection wells; workovers as needed.	Follow PISC & site closure plan, periodic testing and reporting.	Operator & other parties relieved of liability unless negligent, etc.
Regional geologic evaluation to identify several prospective areas for storage operations .	Prepare plans required for UIC Class VI and state permits. FEED for injection wells, surface facilities and MVA grid.	Drill injection wells, incorporate new well data in plans and present to Director.	Drill additional monitoring wells and remediate existing wells (corrective action) as necessary as plume expands. Well workovers & equip. maintenance as necessary.	Establish non-endangerment; closure approved; P&A all wells & restore site(s).	Other entity oversees trust fund, pays site costs, settles all claims.
Begin to assemble acreage block. Will need more acreage than actually used +30 yrs later. Hopefully first site selected will prove correct.	Assemble financial responsibility package for UIC and state permits.	Director approves injection. Have 180 days to submit MRV plan per Subpart RR regs.	Follow all plans, AoR review every 5 yrs, annual reporting. Pay into to fund for LT Stewardship; P&A injection wells, some financial responsibility instruments released.	With closure of Class VI permit, Director releases financial responsibility instruments. State awards Certificate of Completion & assumes long-term stewardship.	
0.5 to 1 year	3 to 5 years		30 to 50 years	10 to 50+ years	Rest of Civilization

NETL CO_2 Injection & Storage Cost Model

- **Some caveats and assumptions**
  - This is not a reservoir model, geo-engineering equations are used to estimate parameters that impact costs.
  - Reservoir architecture is defined by porosity, permeability and height. Variability reflecting depositional facies is not considered.
  - Injection rate of CO_2 over life of project is assumed to be constant.
  - Injected CO_2 in reservoir is assumed to roughly occupy the area of a cylinder defined by the height of the reservoir and the radius of the surface area of the plume.
  - Circular area of the plume defines the extent of the Area of Review (AoR).
  - Growth of CO_2 plume is uniform over the operational period.
  - AoR review – data/seismic acquisition, interpretation, report preparation and presentation to EPA occur in same year.
  - Field equipment, field pipelines, initial monitoring wells/corrective action wells and MVA grid constructed and operational/sampled in first year of operations.
  - Monitoring wells are drilled and full year sampling occur in same year.
  - Annual injection rate, time span of stages and costs are applied to all reservoirs comprising the cost supply curve.

NETL CO_2 Injection and Storage Cost Model

Introduction

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Conclusions

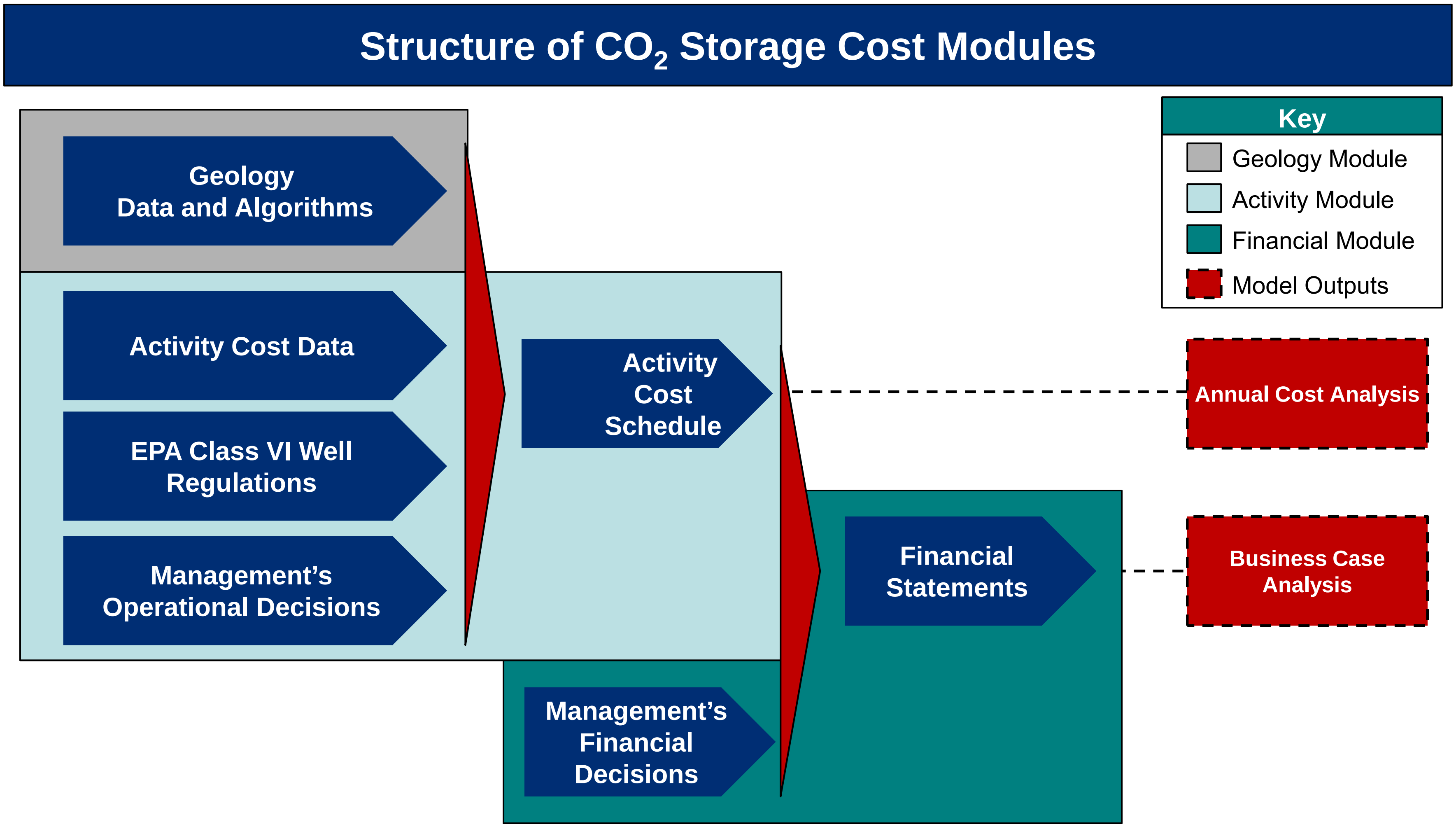
Sources

NETL CO_2 Injection & Storage Cost Model

Input tables allow for various Management decisions that impact project costs.

Project Management Decision	Cost Impact
Volume of CO_2 sequestered annually	Size of the project
Duration of the Sequestration Stages (Site Characterization, Operations, etc.)	Time Value of Money
Instrument(s) of Financial Responsibility	Upfront cost of project and Time Value of Money
Technology choices and application for site characterization and/or MVA	Project costs incurred
Spacing (well density) of Monitoring Wells	Total number of Wells to drilled and operated
Frequency of various activities performed (i.e. how often seismic is run 3,5,7 years.)	Frequency and timing of material costs as they are incurred

NETL CO_2 Injection and Storage Cost Model



NETL CO_2 Injection and Storage Cost Model

Geology Module Provides Data and Parameters That Drive Storage Costs

Geology Data

Reservoir Formation Data

Parameters Calculated with Geo-engineering Equations

Areal Extent of CO_2 Plume

CO_2 Injectivity and Maximum Rate of CO_2 Injection per Injection Well

Project Cost informed

- Extent of AoR.
- Extent of leasing activity, secure pore space rights.
- Seismic/MVA Costs relating to AoR.
- Number of monitoring wells to be drilled.
- Corrective Action – Number of old wells within AoR

- Number of injection wells needed to inject a user-specified maximum daily mass of CO_2

NETL CO_2 Injection & Storage Cost Model

Geologic Data Sources: Database, User or Geo-engineering Calculations

11	**Meaning of cell colors in this sheet**	
12	Title or heading rows	
13	Overview or Instruction sections	
14	Inputs from other sheets	
15	Inputs specified in this sheet	
16	Key outputs used in other sheets	
17	Other critical outputs or intermediate calculations	
18	Geological parameters from geology database	
19	Intermediate values	

Values from geology database

Values specified by user

Values calculated for a few parameters with geo-engineering equations; used if not available from database or user

52	**2.4.1 Determination of Geologic Parameters**							
53	Injection formation number	Form_num	1		References formation number in sheet "Geol DB Sal"			
54	**Parameter**	**Parameter Name**	**Database**	**Specified Value**	**Calculated Value**	**Selection Control**	**Selected Value**	**Units**
55	*General Formation Characteristics*							
56	Formation identifier	Form_ID	Arbuckle1	Glorietta2		1	Arbuckle1	
57	Formation name	Form_name	Arbuckle	Glorietta		1	Arbuckle	
58	Formation state	Form_ST	OK	NM		1	OK	
59	Region	Form_Reg	OK - N	Permian - NW		1	OK - N	
60	Basin	Form_Basin	Northern Shelf Area	Permian		1	Northern Shelf Area	
61	RCSP region	Form_RCSP	SWP	SWP		1	SWP	
62	*Lithology and Depositional Environment*							
63	Lithology	Form_lith	Dolomite	Clastic		1	Dolomite	
64	Depositional environment	Form_dep	Peritidal	Shallow Shelf		1	Peritidal	
65	Geologic age	Form_age	Ordovician	Permian		1	Ordovician	
66	*Latitude and Longitude at Centroid of Surface Area*							
67	Latitude at Centroid of Surface Area	Alat	-98.554415			1	-98.554415	degrees
68	Longitude at Centroid of Surface Area	Along	36.399382			1	36.399382	degrees
69	*Surface Area*							
70	Total surface area of injection formation	AForm	10,620	10,000		1	10620	mi2
71	*Depths*							
72	Depth to top of injection formation	Ltop	6,562	6,000		1	6562	ft
73	Depth to midpoint of injection formation	Lmid	6,848	6,200		1	6848	ft
74	Depth to bottom of injection formation	Lbot	7,134	6,400		1	7134	ft
75	Thickness of injection formation	htot	572	400		1	572	ft
76	*Temperature*							
77	Temperature of injection formation at top of formation	tmp_top	139	100	149	1	139	degF
78	*Lithostatic Pressure*							
79	Lithostatic pressure of injection formation at top of formation	Plith_top			6,562	1	6,562	psia

User selects which values to use

Values used in the model

NETL CO_2 Injection & Storage Cost Model

Activity Cost Data is entered into 44 input tables that cover all costs up until Long-term Stewardship

	Global Parameters	Last Update	Source
1	Labor Rates	9/1/2011	EPA (via Cost Model Version 1)
2	**Activity-Specific Parameters**		
	Regional evaluation for site selection		
	Purchase/Acquire/Analysis (PAA):	9/1/2011	EPA (via Cost Model Version 1)
	Site Characterization		
	Purchase/Acquire & analyze: (data/software not acquired	9/1/2011	Cost Column: EPA (via Cost Model Version 1) Volume of Hours: NETL estimates from ? (via Cost Model Version 1)
	Prepare:	9/1/2011	EPA (via Cost Model Version 1)
	Modeling:	9/1/2011	EPA (via Cost Model Version 1)
	Corrective Action Planning	9/1/2011	EPA (via Cost Model Version 1)
	Front-End Engineering & Design	9/1/2011	EPA (via Cost Model Version 1)
	Preparation of plans for Class VI permit	9/1/2011	EPA (via Cost Model Version 1)
	Land leasing:	9/1/2011	EPA (via Cost Model Version 1)
	Permits:	9/1/2011	EPA (via Cost Model Version 1)
	Injection well drilling:	9/1/2011	EPA (via Cost Model Version 1)
	Subpart RR (Subpart UU for EOR Projects):	9/1/2011	EPA (via Cost Model Version 1)
	???		
	Financial responsibility: [$146.85]	9/1/2011	EPA (via Cost Model Version 1)
	Operations		
	Gathering Field Data:	9/1/2011	EPA (via Cost Model Version 1)
	Corrective Action (CA):	9/1/2011	EPA (via Cost Model Version 1)
	General Storage Field Infrastructure Capital Costs	9/1/2011	EPA (via Cost Model Version 1)
	General Storage Field Infrastructure O&M costs	9/1/2011	EPA (via Cost Model Version 1)
	Produced Water Treatment facilities Capital Costs	9/1/2011	EPA (via Cost Model Version 1)
3	**Parameters used across Multiple Stages**		
	Fees per tonne (other expenses):	9/1/2011	EPA (via Cost Model Version 1)
	Fees, One-Time (other expenses):	9/2/2011	EPA (via Cost Model Version 1)
	Periodic Reports:	9/1/2011	EPA (via Cost Model Version 1)
	Fluid Samples	9/1/2011	EPA (via Cost Model Version 1)
	Gas Samples	9/1/2011	EPA (via Cost Model Version 1)
	Aerial/Satellite Survey	9/1/2011	EPA (via Cost Model Version 1)
	Geophysical Survey: Surface Seismic: 3D:	11/16/2011	Personal Communication with Tim Grant. Illinois ADM Decatur Phase III Project.
	Geophysical Survey: Surface Seismic: 2D:	11/16/2011	Personal Communication with Tim Grant. Hannes Leetaru, Illinois State Geological Survey.
	Geophysical Survey: Wellbore Seismic:	9/1/2011	May not use
	Geophysical Survey: Electrical:	11/16/2011	May not use - Personal Communication with Tim Grant. Xianjin Yang, Lawrence Livermore National Laboratory.
	Other Geophysical	9/7/2011	May not use - Personal Communication with Tim Grant. Seafloor Gravity Survey – Sleipner Field (Karen Klugger project manager).
	Atmospheric:	11/16/2011	Eddy Covariance Equipment Unit Costs: Personal Communication with Tim Grant. Illinois ADM Decatur Phase III Project. All Other costs: EPA (via Cost Model Version 1)
	Injection Well Monitoring:	9/1/2011	EPA (via Cost Model Version 1)
4	**Well-Drilling Costs**		
	Permits	4/1/2008	API - 2006 Joint Association Survey on Drilling Costs, April 2008 (via Cost Model Version 1)
	Drilling Costs	4/1/2008	API - 2006 Joint Association Survey on Drilling Costs, April 2008 (via Cost Model Version 1)
	Wireline (Geophysical) Logging:	4/1/2008	API - 2006 Joint Association Survey on Drilling Costs, April 2008 (via Cost Model Version 1)
	Core Recovery:	4/1/2008	API - 2006 Joint Association Survey on Drilling Costs, April 2008 (via Cost Model Version 1)
	Fluid Recovery:	4/1/2008	API - 2006 Joint Association Survey on Drilling Costs, April 2008 (via Cost Model Version 1)
	Well Tests:	4/1/2008	API - 2006 Joint Association Survey on Drilling Costs, April 2008 (via Cost Model Version 1)
	Well Seismic:	4/1/2008	API - 2006 Joint Association Survey on Drilling Costs, April 2008 (via Cost Model Version 1)
	Analysis:	4/1/2008	API - 2006 Joint Association Survey on Drilling Costs, April 2008 (via Cost Model Version 1)
	Completion:	4/1/2008	API - 2006 Joint Association Survey on Drilling Costs, April 2008 (via Cost Model Version 1)
	Monitor Well Downhole Equipment:	4/1/2008	API - 2006 Joint Association Survey on Drilling Costs, April 2008 (via Cost Model Version 1)
	Operations & Maintenance:	4/1/2008	API - 2006 Joint Association Survey on Drilling Costs, April 2008 (via Cost Model Version 1)
	Annual Mechanical Integrity Test:	4/1/2008	API - 2006 Joint Association Survey on Drilling Costs, April 2008 (via Cost Model Version 1)
	Plug & Abandon:	4/1/2008	API - 2006 Joint Association Survey on Drilling Costs, April 2008 (via Cost Model Version 1)

Key to Input Table Groupings

1. Global parameters used in all activities – i.e. Labor Rates
2. Stage - Specific Parameter(s)
3. Parameters used in Activities across Multiple Stages (i.e. Permitting, Operations, etc.)
4. Well Drilling Cost Parameters

This table provides a quick link to various cost items (Input worksheet). Cost data source and most recent up-date are posted in this table.

44 Tables in order

1. Labor Rates 1	12. Subpart RR	23. Gas Samples	34. Wireline
2. PAA 2	13. Finan. Resp.	24. Aerial Survey	35. Core Rec.
3. Software	14. Gath. F. Data	25. Seismic 3D	36. Fluid Rec.
4. Prepare	15. CA	26. Seismic 2D	37. Well Tests
5. Modeling	16.GSFICC	27. Wellbore Seis	38. Well Seismic
6. CA Plans	17. GSFIO&M	28. Elec. Survey	39. Analysis
7. Front End E&D	18. PWTCC	29. Other Geo	40. Completion
8. Permit Prep	19. Fee per tonne 3	30. Atmospheric	41. M. Equip
9. Land Leasing	20. One time fees	31. Inj. Monitoring	42. O&M
10. Permits	21. Reporting	32. Permits 4	43. MIT
11. Injection Well	22.Fluid Samples	33.Drilling Costs	44. P&A

NETL CO_2 Injection & Storage Cost Model

Tables in the Input Sheet develop our Schedule of Activities throughout the project's stages

1 Parameters are consistent across all activities

ie. Labor rates

2 Activity-Specific Parameters

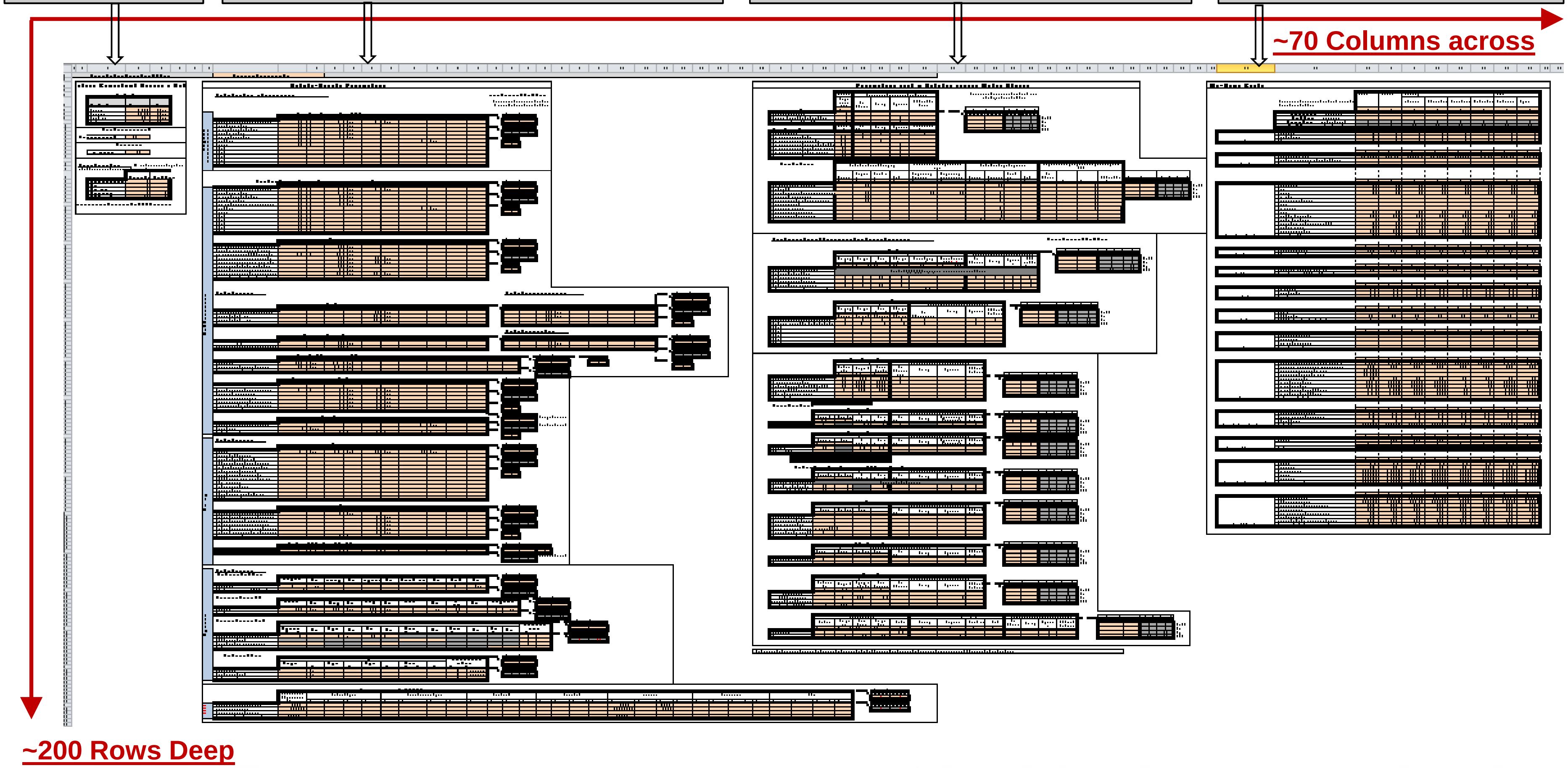
ie. Labor hours per activity, activity specific fixed and variable costs

3 Parameters used in Activities across Multiple Stages

ie. Fluid sampling done before, during and after operations

4 Well Drilling Costs

ie. Permits, drilling, wireline, core and fluid recovery, equipment, tests, O&M, MIT, etc…



NETL CO_2 Injection & Storage Cost Model

Activity Costs are derived from the various management decisions and inputs and are posted in the year(s) that they occur in a separate worksheet in the module.

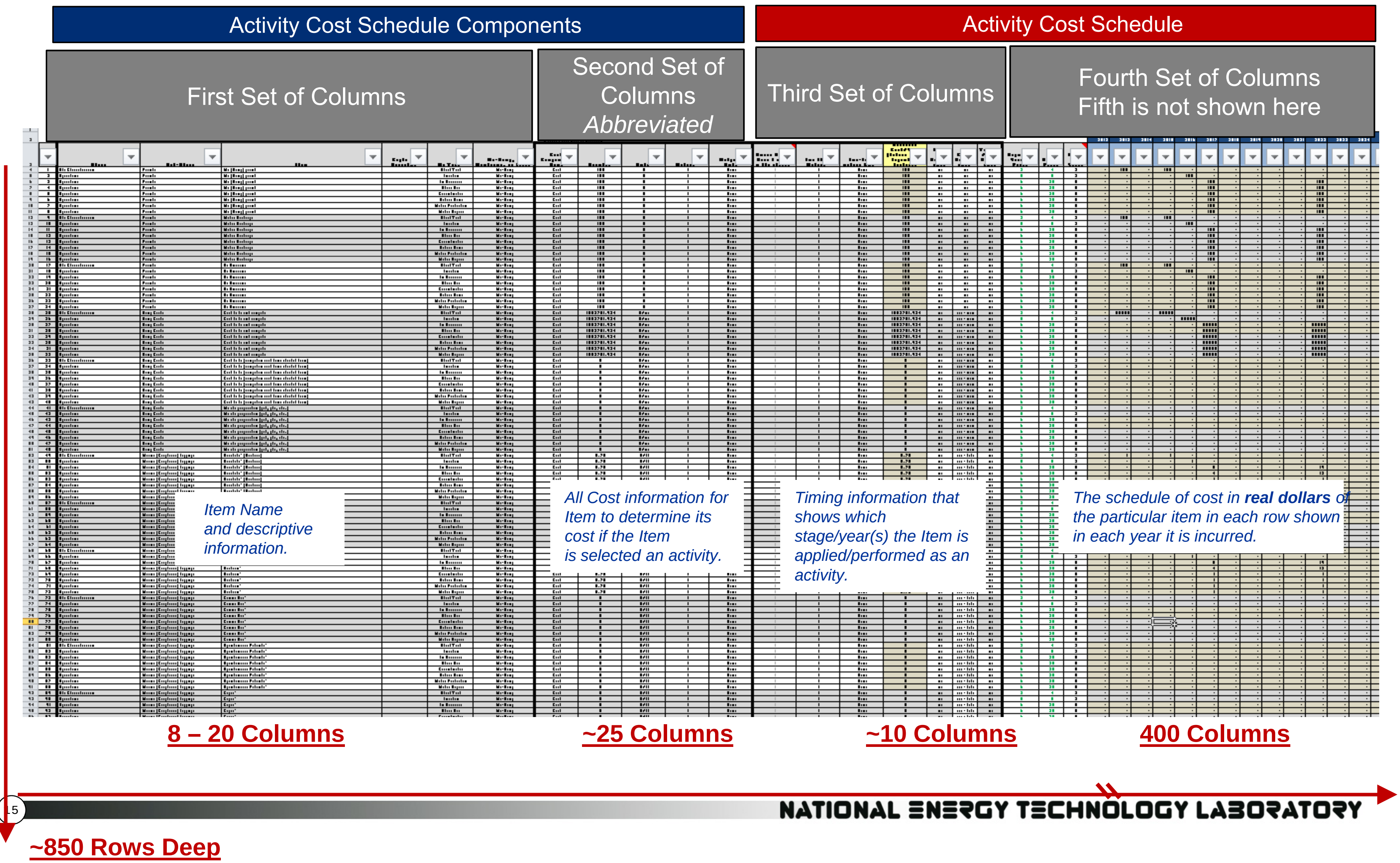
Activity Cost Schedule Diagram

Activity Cost Schedule Components			Activity Cost Schedule	
First Set of Columns	Second Set of Columns	Third Set of Columns	Fourth Set of Columns	Fifth Set of Columns
Item Name and descriptive information	All Cost information for Item to determine its cost if the Item is selected an activity	Timing information that shows which stage/year(s) the Item is applied/ performed as an activity	The schedule of cost in **real dollars** of the particular item in each row shown in each year it is incurred	The schedule of cost in **escalated dollars** of the particular item in each row shown in each year it is incurred **These Escalated Dollars are fed into the financial module to perform our business case analysis*
8 – 20 Columns	~25 Columns	~10 Columns	200 Columns	200 Columns

Spreadsheet Footprint

NETL CO_2 Injection & Storage Cost Model

Activity costs are calculated and posted in their respective year(s) in this worksheet:
- Escalation is calculated here if selected



NETL CO_2 Injection & Storage Cost Model

The Depreciation schedule tracks total depreciated amounts affecting tax payments in any given year.

	Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
2097		2097									
	years	85	84	83	82	81	80	79	78	77	76
		125,884	18,597,850	172,420	172,420	5,614,629	50,484,213	362,820	362,820	362,820	362,820
		1,481	221,403	2,077	2,103	69,316	631,053	4,593	4,652	4,712	4,774
	Check	-	-	(0)	-	(0)	-	-	-	-	-
	Total In Year D&A										
2012	1,481	1,481	-	-	-	-	-	-	-	-	-
2013	222,884	1,481	221,403	-	-	-	-	-	-	-	-
2014	224,961	1,481	221,403	2,077	-	-	-	-	-	-	-
2015	227,064	1,481	221,403	2,077	2,103	-	-	-	-	-	-
2016	296,380	1,481	221,403	2,077	2,103	69,316	-	-	-	-	-
2017	927,433	1,481	221,403	2,077	2,103	69,316	631,053	-	-	-	-
2018	932,026	1,481	221,403	2,077	2,103	69,316	631,053	4,593	-	-	-
2019	936,677	1,481	221,403	2,077	2,103	69,316	631,053	4,593	4,652	-	-
2020	941,389	1,481	221,403	2,077	2,103	69,316	631,053	4,593	4,652	4,712	-
2021	946,163	1,481	221,403	2,077	2,103	69,316	631,053	4,593	4,652	4,712	4,774
2022	1,622,358	1,481	221,403	2,077	2,103	69,316	631,053	4,593	4,652	4,712	4,774
2023	1,627,261	1,481	221,403	2,077	2,103	69,316	631,053	4,593	4,652	4,712	4,774
2024	1,632,231	1,481	221,403	2,077	2,103	69,316	631,053	4,593	4,652	4,712	4,774
2025	1,637,270	1,481	221,403	2,077	2,103	69,316	631,053	4,593	4,652	4,712	4,774
2026	1,642,380	1,481	221,403	2,077	2,103	69,316	631,053	4,593	4,652	4,712	4,774
2027	2,382,518	1,481	221,403	2,077	2,103	69,316	631,053	4,593	4,652	4,712	4,774
2028	2,387,776	1,481	221,403	2,077	2,103	69,316	631,053	4,593	4,652	4,712	4,774
2029	2,393,112	1,481	221,403	2,077	2,103	69,316	631,053	4,593	4,652	4,712	4,774
2030	2,398,527	1,481	221,403	2,077	2,103	69,316	631,053	4,593	4,652	4,712	4,774
2031	2,404,024	1,481	221,403	2,077	2,103	69,316	631,053	4,593	4,652	4,712	4,774
2032	3,215,996	1,481	221,403	2,077	2,103	69,316	631,053	4,593	4,652	4,712	4,774
2033	3,221,666	1,481	221,403	2,077	2,103	69,316	631,053	4,593	4,652	4,712	4,774

- **Can select whether or not a particular item will be expensed or capitalized.**
- **Straight line depreciation.**
- **Capitalized items are summed and posted in the financial module.**

NETL CO_2 Injection & Storage Cost Model

Financial Module:

- **The purpose of the Financial Module to apply a business scenario against the cost activities to solve for how much money it needs to charge to store a tonne of CO_2 to breakeven**

- **Breakeven means**
  - All project expenses, including financial responsibility are paid for
  - All loans are paid off including interest
  - All taxes are paid
  - The owners receive their required return on capital

NETL CO_2 Injection & Storage Cost Model

Financial statements, project DCF valuation, and a breakeven analysis posted in Financial Module.

Financial Statements

Income Statement	2012	2013	2014	2015	2016	2017	2018	2019	2020
Operating Cashflows									
Gross Revenue (solved)	-	-	-	-	-	32,215,711	33,182,182	34,177,648	35,202,977
Expenses (O&M, Permitting, Plans...)	-	955	-	-	1,043	4,836,917	3,918,875	4,036,441	4,157,534
Earnings Before Interest Taxes, D&A (EBITDA)	-	(955)	-	-	(1,043)	27,378,794	29,263,307	30,141,206	31,045,443
Non-Operating									
Interest Income	0	-	-	-	-	-	465,082	971,136	1,504,903
Interest Expense									
Taxes	-	-	-	-	-	4,124,708	4,425,654	4,424,026	4,422,377
Depreciation and Amortization	1,481	222,884	224,961	227,064	296,380	927,433	932,026	936,677	941,389
Net Income	(1,481)	(223,839)	(224,961)	(227,064)	(297,424)	22,326,652	24,370,709	25,751,640	27,186,579

Balance Sheet	2012	2013	2014	2015	2016	2017	2018	2019	2020
Assets									
Cash and Cash Equivalensts including PISC Reserve	-	-	-	-	-	23,254,085	48,556,820	75,245,137	103,373,106
Accounts Receivable	-	-	-	-	-	33,182,182	34,177,648	35,202,977	36,259,066
Property, Plant, and Equipment (PP&E)	125,884	18,722,253	18,671,789	18,619,248	24,006,812	74,194,645	73,630,032	73,060,826	72,486,969
Deferred Tax Asset	-	-	-	-	-	-	-	-	-
Total Assets	125,884	18,722,253	18,671,789	18,619,248	24,006,812	130,630,912	156,364,499	183,508,940	212,119,141
Liabilities									
Accounts Payable	955	-	-	1,043	4,836,917	3,918,875	4,036,441	4,157,534	4,282,260
Long Term Debt	69,236	10,299,933	10,599,351	10,696,078	13,786,516	32,354,242	19,147,609	5,570,858	-
Total Liabilities	70,191	10,299,933	10,599,351	10,697,122	18,623,433	36,273,116	23,184,050	9,728,392	4,282,260
Equity									
Paid-In-Capital	(56,647.62)	(8,369,437.72)	(77,589.00)	(77,589.00)	(2,526,987.85)	(15,141,236.03)	-	-	-
Other Equity	112,340	(2,154,335)	(10,746,723)	(10,846,597)	(16,393,869)	1,194,772	1,186,659	16,023,248	22,904,319
Total Equity	55,693	(10,523,772)	(10,824,312)	(10,924,186)	(18,920,857)	(13,946,464)	1,186,659	16,023,248	22,904,319

Statement of Cash Flows	2012	2013	2014	2015	2016	2017	2018	2019	2020
Operating Activities									
Net Income	-	-	-	-	-	7,660,172	8,219,072	8,216,048	8,212,985
Depreciation & Amortization	1,481	222,884	224,961	227,064	296,380	927,433	932,026	936,677	941,389
Cash Flow from (Used in) Operating Activities	(1,481)	(222,884)	(224,961)	(227,064)	(296,380)	6,732,739	7,287,046	7,279,371	7,271,596
Investing Activities									
Cash Flow from (Used in) Investing Activities	(125,884)	(18,597,850)	(172,420)	(172,420)	(5,614,629)	(50,484,213)	(362,820)	(362,820)	(362,820)
Financing Activities									
Cash Provided by Owners	56,648	8,369,438	77,589	77,589	2,526,988	15,141,236	-	-	-
Cash Provided by Debtors/ Lenders	69,236	10,229,313	94,831	94,831	3,088,541	18,505,955	-	-	-
Cash Flow from (Used in) Financing Activities	125,884	18,598,750	172,420	172,420	5,615,529	33,647,191	-	-	-

Notes

Income Statement
Expenses from the Activity Cost Module. Revenues are solved for in a breakeven analysis

Balance Sheet
Keeps track of the depreciation of the capital expenses (from depreciation schedule).
Informs the Tax consequences in the Income statement

Capital Expenses
Taken from Activity Module; reflect when investments are made in the Cash Flow Statement

NETL CO_2 Injection & Storage Cost Model

User Inputs:

- **Financial Assumptions on Capitalization (and Debt)**

- **Whether or not to fund PISC and If so over what period**

2. Financial Model Inputs

2.1 Financial Inputs	Value	Definition
Capitalization	45%	Percent Equity
Cost of Equity	15%	
Cost of Debt	5%	(interest rate)
Tax Rate	38%	(matches PSFM)
		Assumed initial startup capital
Operations Start Year	7	
Operations End Year	36	
PISC Period Start Year	37	
PISC Period End Year	61	
PISC Funding Period Start Year	7	
PISC Funding Period End Year	36	
Annual Tonnes Injected	4,100,000	
Cost per Tonne	11.55	dollars
Escalation Rate	3%	
Interest on PISC reserve	3%	

Defer	1
Fund PISC Reserve?	1
If Yes, Type 1	
If No, Type 0	

NETL CO_2 Injection & Storage Cost Model

PISC is funded per the schedule set out by the user:

Table 1	**PISC Reserve Fund Schedule**										
	PISC Funding Period	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**PISC Fundin**	**PISC Funding**	**PISC Fundin**	**PISC Fundir**
	PISC Drawdown Period	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**
	PISC Drawdown Required (REAL)	-	-	-	-	-	-	-	-	-	-
	Total Real Value of PISC Reserve	**116,102,551**									
	Total Escalated Value of a fully funded PISC Reseve in any given project y	130,674,444	134,594,677	138,632,517	142,791,493	147,075,238	151,487,495	156,032,120	160,713,083	165,534,476	170,500,510
	Target Year to have PISC fully funded:	**36**									
	PV of Fully funded PISC Reserve From the starting year	-	-	-	-	-	-	156,032,120	-	-	-
	PV of Fully funded PISC Reserve. Step 2:	**156,032,120**									
	Future value of fully funded PISC reserve	-	-	-	-	-	-	-	-	-	-
	Future value of fully funded PISC reserve. Step 2:	**367,699,911**									
	Periods where PISC deposits are made	0	0	0	0	0	0	1	1	1	
	Number of Periods	**30**									
	Rate	**3%**									
	PISC Deposit a level payment that hits the funding target	-	-	-	-	-	-	5,201,071	5,357,103	5,517,816	5,683,350
	Beginning Balance	-	-	-	-	-	-	-	5,201,071	10,714,206	16,553,448
-	Simple Interest	-	-	-	-	-	-	-	156,032	321,426	496,603
	Deposit	-	-	-	-	-	-	5,201,071	5,357,103	5,517,816	5,683,350
draw down											
	PISC Drawdown	-	-	-	-	-	-	-	-	-	-
	End Balance	-	-	-	-	-	-	5,201,071	10,714,206	16,553,448	22,733,401
be included in (	**Actual PISC Deposits made**	-	-	-	-	-	-	5,201,071	5,357,103	5,517,816	5,683,350
	Actual PISC Funds applied to Project	-	-	-	-	-	-	-	-	-	-
Add back to (	**PISC Residuals**	-	-	-	-	-	-	-	-	-	-

NETL CO_2 Injection & Storage Cost Model

Financial Responsibility:

There are 2 types of instruments. The ones we fund and the ones we don't. The latter is cheaper.

Lowest Cost options:

- **Self Insure** – "we're good for it"– Equity makes the payment when due. We do not include unplanned bills in the model.
- **Insure** – We pay someone else a fee to pay for our unplanned expenses if we incur them on top of having Equity pay all of their bills when due.
- **Letter of credit** – We pay a bank something like .15% per year to have access to all the money we'd need to cover something unplanned. If we needed to take money from the bank this would get very expensive because we'd owe them interest on our principal. Equity pays the planned bills when due.

In between:

Surety Bond – either we fund it, or we have a guarantor that basically "Self Insures" it.

Highest cost options:

- **Trust Fund** and **Escrow Accounts** are tied. They both require paying money in upfront. The drivers of how expensive they will be depend on how early the money goes in and how much must go in.
  - The most expensive scenario is to fund 100% of Financial Responsibility in the first year of the project.
  - A lower cost option would be to fund it over the operating period so project revenues could be used rather than equity and debt.

NETL CO_2 Injection & Storage Cost Model

The Model Solves for a Breakeven Price

Intermediate values (Gray/white used to distinguish rows, columns, or sections)

2. Financial Model Inputs

2.1 Financial Inputs	Value	Definition
Capitalization	45%	Percent Equity
Cost of Equity	15%	
Cost of Debt	5%	(interest rate)
Tax Rate	38%	(matches PSFM)
		Assumed initial startup capital
Operations Start Year	7	
Operations End Year	36	
PISC Period Start Year	37	
PISC Period End Year	61	
PISC Funding Period Start Year	7	
PISC Funding Period End Year	36	
Annual Tonnes Injected	4,100,000	
Cost per Tonne	11.55	dollars
Escalation Rate	3%	
Interest on PISC reserve	3%	

Output	
NPV	0
IRR	NA

Defer	1

Fund PISC Reserve?	1
If Yes, Type 1	
If No, Type 0	

Solve for First Year Storage Price per Tonne

Breakeven Discussion

The breakeven analysis is a goal seek function that solves for the first year price of CO2 storage with NPV at 0 for a given cost of owners' equity

NETL CO_2 Injection and Storage Cost Model

Introduction
Model Description
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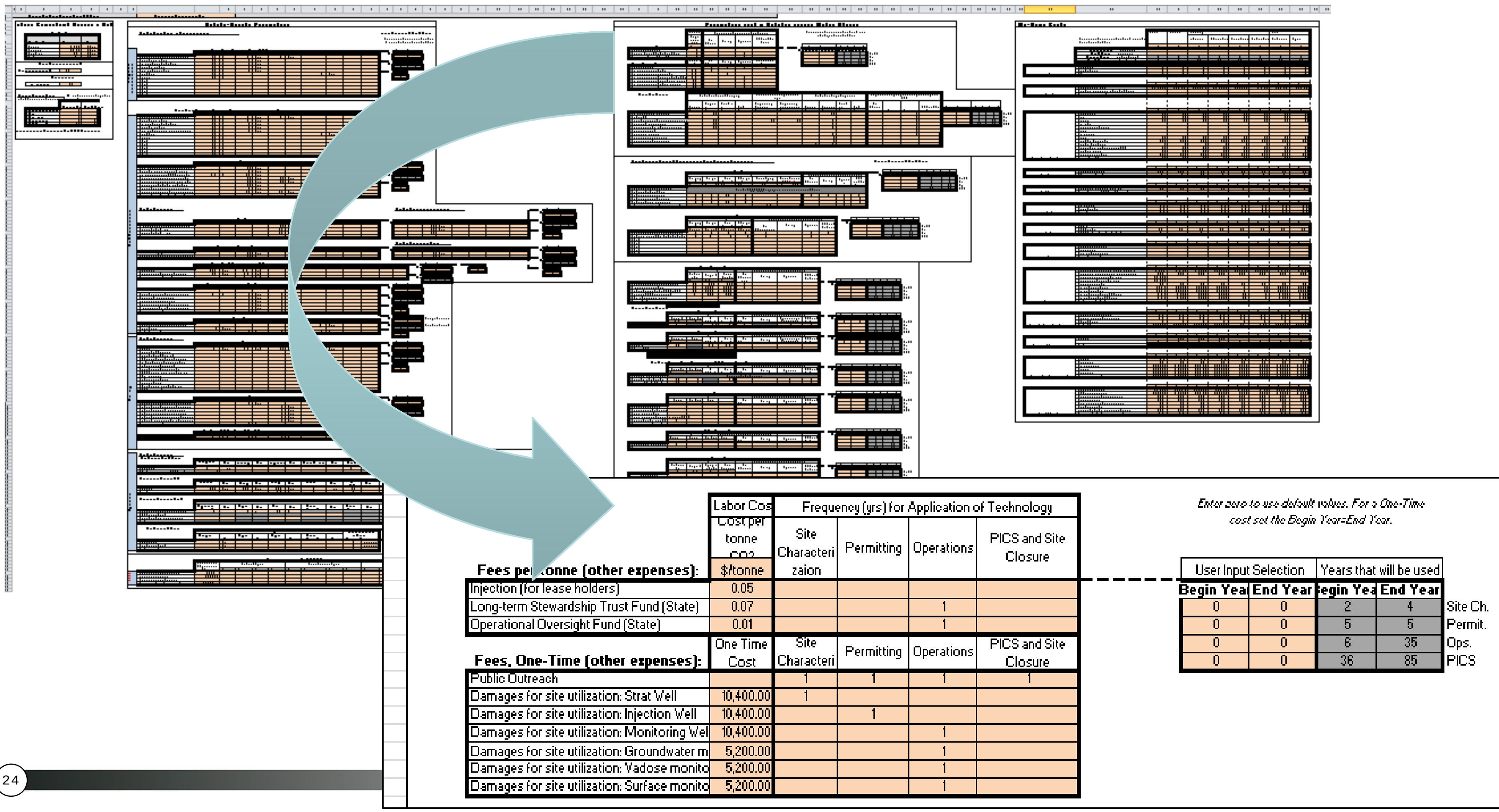
NETL CO_2 Injection and Storage Cost Model

Cost database resides in the Activity Cost module
- ***Current cost values are those used by EPA in their economic analysis***
- ***Well costs based on API-JAS 2006 study***
- ***Working on updating cost database***
- ***Model user can enter their own cost data***



Fees per tonne (other expenses):	Labor Cost / Cost per tonne CO2 ($/tonne)	Frequency (yrs) for Application of Technology: Site Characterization	Permitting	Operations	PICS and Site Closure
Injection (for lease holders)	0.05				
Long-term Stewardship Trust Fund (State)	0.07			1	
Operational Oversight Fund (State)	0.01			1	

Fees, One-Time (other expenses):	One Time Cost	Site Characteri	Permitting	Operations	PICS and Site Closure
Public Outreach		1	1	1	1
Damages for site utilization: Strat Well	10,400.00	1			
Damages for site utilization: Injection Well	10,400.00		1		
Damages for site utilization: Monitoring Wel	10,400.00			1	
Damages for site utilization: Groundwater m	5,200.00			1	
Damages for site utilization: Vadose monito	5,200.00			1	
Damages for site utilization: Surface monito	5,200.00			1	

User Input Selection: Begin Yea	End Year	Years that will be used: Begin Yea	End Year	
0	0	2	4	Site Ch.
0	0	5	5	Permit.
0	0	6	35	Ops.
0	0	36	85	PICS

NETL CO_2 Injection & Storage Cost Model

Input tables allow the model user to:

- Accept cost already posted
- Enter their own cost information
- Select in which stage cost occurs
- Frequency of cost (once, every year, every 5 years)

The user indicates which stage or stages this cost is incurred by entering a number, and the number indicates the frequency of the activity within the stage (annual, every 5 years, 10 years, etc…)

	Labor Cos	Frequency (yrs) for Application of Technolog			
	Cost per tonne CO2	Site Characterizaion	Permitting	Operations	PICS ar Clo
Fees per tonne (other expenses):	$/tonne				
Injection (for lease holders)	0.05				
Long-term Stewardship Trust Fund (State)	0.07			1	
Operational Oversight Fund (State)	0.01			1	
Fees, One-Time (other expenses):	One Time Cost	Site Characteri	Permitting	Operations	and Site Closure
Public Outreach		1	1	1	1
Damages for site utilization: Strat Well	10,400.00	1			
Damages for site utilization: Injection Well	10,400.00		1		
Damages for site utilization: Monitoring Wel	10,400.00			1	
Damages for site utilization: Groundwater m	5,200.00			1	
Damages for site utilization: Vadose monito	5,200.00			1	
Damages for site utilization: Surface monito	5,200.00			1	

Enter zero to use default values. For a One-Time cost set the Begin Year=End Year.

User Input Selection		Years that will be used		
Begin Yea	**End Year**	**egin Yea**	**End Year**	
0	0	2	4	Site Ch.
0	0	5	5	Permit.
0	0	6	35	Ops.
0	0	36	85	PICS

The user indicates the beginning year and end year of the stage

Costs of each item are entered here

NETL CO_2 Injection & Storage Cost Model

Types of wells and well technology for sequestration operations

Well-Drilling Costs

"999" is used to turn off water costs

Enter zero to use default values. For a One-Time cost set the Begin Year=End Year.

Section	Item	Strat Test	ON/OFF (x=on; blank=off)	Injection	ON/OFF (x=on; blank=off)	Monitoring: In Reservoir	ON/OFF (x=on; blank=off)	Monitoring: Above Seal	ON/OFF (x=on; blank=off)	Monitoring: Dual Completion	ON/OFF (x=on; blank=off)	Monitoring: Groundwater	ON/OFF (x=on; blank=off)	Monitoring: Vadose Zone	ON/OFF (x=on; blank=off)	Water: Production	ON/OFF (x=on; blank=off)	Water: Disposal	ON/OFF (x=on; blank=off)
	Begin Year - user input year	0		6		0		0		0		0		0		999		999	
	End Year - user input year	0		6		0		0		0		0		0		999		999	
	Begin Year - year that will be used	2		6		7		7		7		7		7		999		999	
	End Year - year that will be used	4		6		36		36		36		36		36		999		999	
	Periodic	2		1		5		5		5		5		5		999		999	
		$/well		$/well		$/well		$/well		$/well		$/well		$/well		$/well		$/well	
4.1 Permits	Well (Drilling) permit	100				100		100		100		100		100		100		100	
	Water Discharge																		
	Air Emissions																		
Drilling Costs are Calculated by state. These cells reference the sheet "Drilling Costs."		$/well		$/well		$/well		$/well		$/well		$/well		$/well		$/well		$/well	
4.2 Drilling Costs	Cost to drill and complete	863960.7466	x	846058.3647	x	828155.9829	x	773492.2217	x	828155.9829	x	136659.4031	x	10932.75225	x	846058.3647	x	846058.3647	x
	Cost to drill (completion cost items checked below)									0									
	Well site preparation (pad, pits, etc.)									0									
		$/ft/well		$/ft/well		$/ft/well		$/ft/well		$/ft/well		$/ft/well		$/ft/well		$/ft/well		$/ft/well	
4.3 Wireline (Geophysical) Logging:	Resistivity* (Electrical)	0.75		0.75		0.75		0.75		0.75		0.75	x	0.75		0.75		0.75	
	Density*	0.75		0.75		0.75		0.75		0.75		0.75		0.75		0.75		0.75	
	Neutron*	0.75		0.75		0.75		0.75		0.75		0.75		0.75		0.75		0.75	
	Gamma Ray*																		
	Spontaneous Potential*																		
	Caliper*																		
	Temperature*																		
	Sonic*	0.75		0.75		0.75		0.75		0.75		0.75		0.75		0.75		0.75	
	Quad-Combo (includes *)	1.25	x	1.25	x	1.25	x	1.25	x	1.25	x	1.25		1.25		1.25		1.25	
	Triple-Combo (less Sonic)	0.9		0.9		0.9		0.9		0.9		0.9		0.9		0.9		0.9	
	Nuclear Magmetic Resonance (NMR)	0.75	x	0.75	x	0.75	x	0.75		0.75	x	0.75		0.75		0.75		0.75	
	Borehole Imaging	0.75	x	0.75	x	0.75	x	0.75	x	0.75	x	0.75		0.75		0.75		0.75	
	Casing Inspection Log	4.15		4.15		4.15		4.15		4.15		4.15		4.15		4.15		4.15	
	Cement Bond Log	0.25		0.25	x	0.25	x	0.25	x	0.25	x	0.25		0.25		0.25		0.25	
		$/well		$/well		$/well		$/well		$/well		$/well		$/well		$/well		$/well	
	Casing Inspection Log Move In/Move Out Cost	2070		2070		2070		2070		2070		2070		2070		2070		2070	

NETL CO_2 Injection and Storage Cost Model

Geology Database

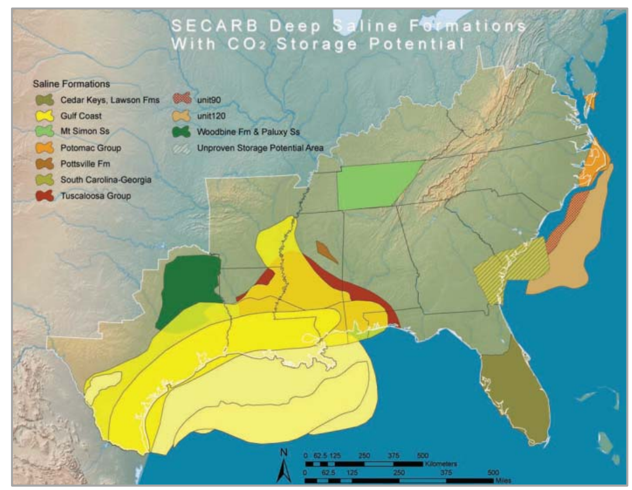
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	UID	Formation Identifier	Formation Name	State	Region	Basin	RCSP	Reservoir Type	Lithology	Depositional Environment	Geologic Age	Area (sq miles)	Depth - top (ft)	Thickness (ft)	Res. Pressure (psi)	Res. Temp (°F)	Porosity (%)	Permeability (mD)	Salinity (mg/L)	Main Source Reference
2	1	Arbuckle1	Arbuckle	OK	OK - N	Northern Shelf Area	SWP	Saline	Dolomite	Peritidal	Ordovician	10,620	6,562	572	2,640	139	10.0	50.0	150,000	42
3	2	Cedar Keys-Lawson1	Cedar Keys-Lawson	FL	NE-Thin-Shallow	South Florida	SECARB	Saline	Carbonate	Reef	Cretaceous	8,500	3,550	300	NA	101	25.0	25.0	NA	a,14,45
4	3	Cedar Keys-Lawson2	Cedar Keys-Lawson	FL	Central+NW-Thick	South Florida	SECARB	Saline	Carbonate	Reef	Cretaceous	13,500	4,800	500	NA	113	22.0	25.0	NA	a,14,45
5	4	Cedar Keys-Lawson3	Cedar Keys-Lawson	FL	S-Thin-Deep	South Florida	SECARB	Saline	Carbonate	Reef	Cretaceous	6,400	4,600	300	NA	111	23.0	25.0	NA	a,14,45
6	5	Conasauga1	Conasauga	OH	OH - E	Appalachian	MRCSP	Saline	Clastic	Peritidal	Cambrian	21,200	8,000	150	NA	NA	8.0	6.0	NA	21,40,44
7	6	Copper Ridge1	Copper Ridge	OH	OH - SE	Appalachian	MRCSP	Saline	Dolomite	Peritidal	Cambrian	6,000	7,000	75	NA	NA	5.0	5.0	NA	21
8	7	Copper Ridge2	Copper Ridge	PA	PA - SW	Appalachian	MRCSP	Saline	Dolomite	Peritidal	Cambrian	5,500	9,000	75	NA	NA	5.0	5.0	NA	21,41
9	8	Copper Ridge3	Copper Ridge	WV	WV - W	Appalachian	MRCSP	Saline	Dolomite	Peritidal	Cambrian	7,000	8,250	65	NA	NA	10.0	100.0	NA	21
10	9	Dakota1	Dakota	CO	Piceance - S	Piceance	SWP	Saline	Clastic	Strandplain	Cretaceous	2,900	4,715	130	2,216	158	14.0	750.0	35,000	42
11	10	Dakota2	Dakota	CO	Piceance - N	Piceance	SWP	Saline	Clastic	Strandplain	Cretaceous	2,600	4,230	130	1,987	158	14.0	750.0	35,000	42
12	11	Dakota3	Dakota	CO	San Juan - N	San Juan	SWP	Saline	Clastic	Strandplain	Cretaceous	1,300	5,935	190	2,789	203	7.5	0.4	13,500	42
13	12	Dakota4	Dakota	NM	San Juan - S	San Juan	SWP	Saline	Clastic	Strandplain	Cretaceous	10,780	3,000	82	1,410	114	17.0	1.0	10,000	42
14	13	Dakota5	Dakota	UT	Uinta	Uinta	SWP	Saline	Clastic	Strandplain	Cretaceous	5,800	11,500	40	5,365	123	12.0	20.0	23,000	42,52
15	14	Devonian1	Devonian	NM	Permian - NW	Permian	SWP	Saline	Carbonate	Shallow Shelf	Permian	4,960	10,000	100	4,665	160	6.0	10.0	100,000	42
16	15	Domengine	Domengine	CA	Sacremento - S	Sacremento	WESTCARB	Saline	Clastic	Shallow Shelf	Tertiary	2,300	4,200	375	NA	NA	28.0	100.0	NA	3,14,16
17	16	Duperow-Lower1	Duperow - Lower	MT	MT-CENT	Kevin Dome	BSCP	Saline	Carbonate	Peritidal	Devonian	4,850	3,800	300	NA	NA	15.0	20.0	>10,000	5,47
18	17	Duperow-Upper1	Duperow - Upper	MT	MT-CENT	Kevin Dome	BSCP	Saline	Carbonate	Peritidal	Devonian	4,850	3,400	400	NA	NA	7.0	10.0	>10,000	5,47
19	18	Entrada1	Entrada	CO	San Juan - N	San Juan	SWP	Saline	Clastic	Eolian	Jurassic	1,500	5,155	150	2,423	186	24.0	300.0	11,000	42
20	19	Entrada2	Entrada	NM	San Juan - S	San Juan	SWP	Saline	Clastic	Eolian	Jurassic	7,420	3,000	131	1,410	114	24.0	200.0	10,000	42
21	20	Entrada3	Entrada	CO	Sand Wash - S	Sand Wash	SWP	Saline	Clastic	Eolian	Jurassic	2,900	5,025	170	2,362	133	20.0	400.0	8,500	42

Formation information: State, Region, Basin, RCSP, Lithology, Depositional Environment, Geologic Age, Area, Depth, Thickness, Res. Pressure, Res. Temp, Porosity, Permeability, Salinity

Saline database based on the NATCARB database with formation data provided by numerous sources. Majority of the data is gleaned from publicly available publications and studies by NATCARB Regional Carbon Sequestration Partnerships (RCSPs).

Other sources include the USGS, the Gulf Coast Carbon Center of the Bureau of Economic Geology at the University of Texas, State Geologic Surveys, National Laboratories and Universities. Some reservoir data for deep saline horizons was inferred from wells drilled into the same horizon at shallower depths.

Saline database: 48 Formations in 25 Basins across 23 States = 151 reservoirs



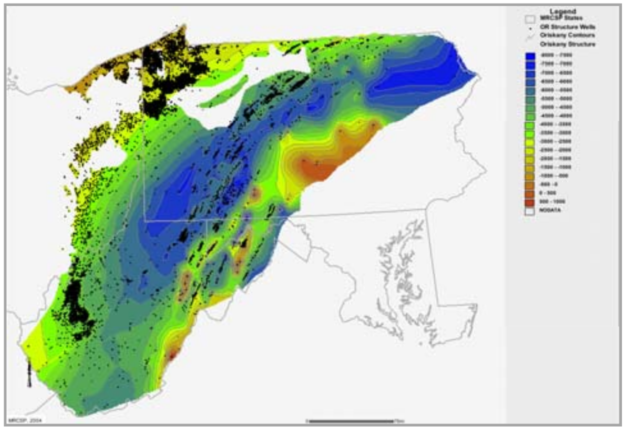
SECARB Delineation of Studied Areas

NETL CO_2 Injection and Storage Cost Model

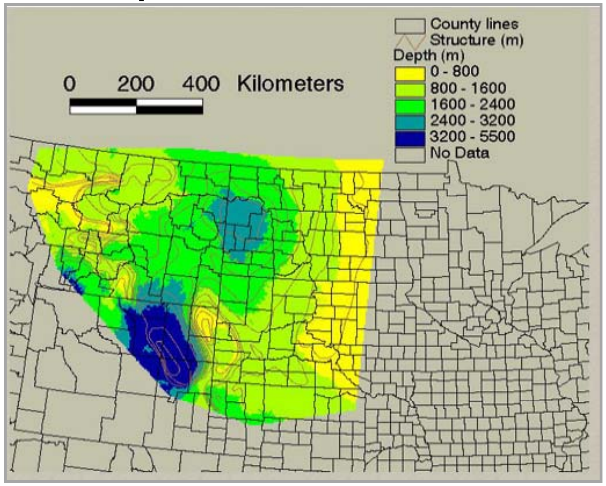
Areal *Extent of* Saline Reservoir

- In the model's geologic database, the saline formations were split spatially mainly by state and basin.
- If sufficient geologic study was available to provide a range of reservoir parameters by area, some formations could be further delineated based on those parameters.
- For instance, contoured porosity data of the Mount Simon formation in Michigan was available and allowed division of the state by regions based on areas of high, medium and low porosity. The Midwest Regional Carbon Sequestration Program (MRCSP) extensively contoured formation structure and thickness and made these maps available on their web site.
- The Gulf Coast Carbon Center has similar maps of twenty-one potential storage horizons from all regions of the U.S.
- From these various sources, the potential storage capacity for formations listed in the geologic database could be defined based on to the gross height of the formation with its area in square miles calculated in ArcGIS.

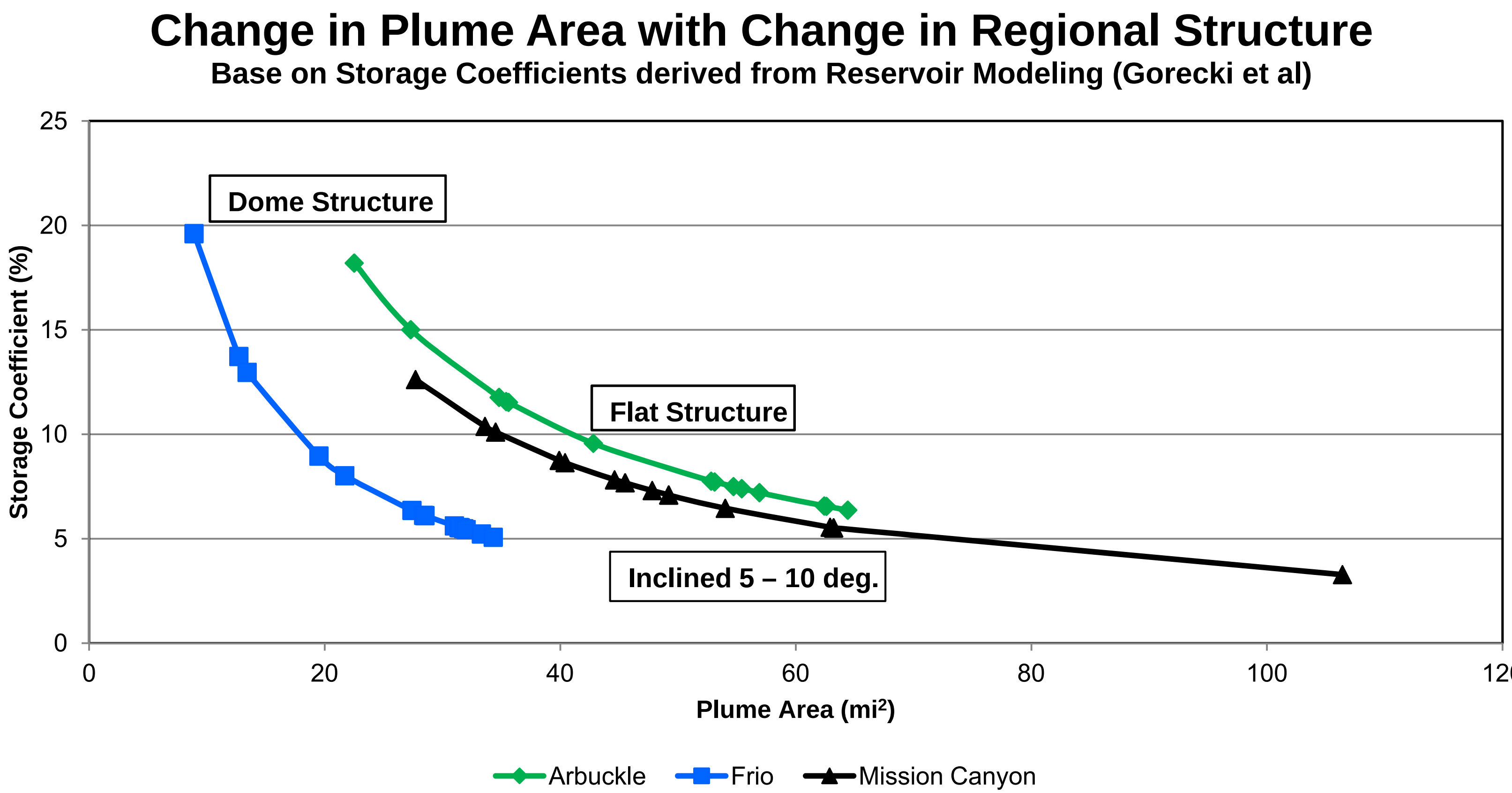
Example of MRCSP Contour Map - Oriskany Sst Structure



Example of GCCC Contour Map – Madison Group Structure, Williston Basin



NETL CO_2 Injection and Storage Cost Model



	Formation Height	Porosity	Lithology	Depositional Environment
Frio	500 ft	27.5 %	Sandstone	Fluvial
Mission Canyon	545 ft	12 %	Limestone	Shallow Shelf
Arbuckle	572 ft	10 %	Dolomite	Peritidal

NETL CO_2 Injection and Storage Cost Model

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NETL CO_2 Injection and Storage Cost Model

Modeler Inputs

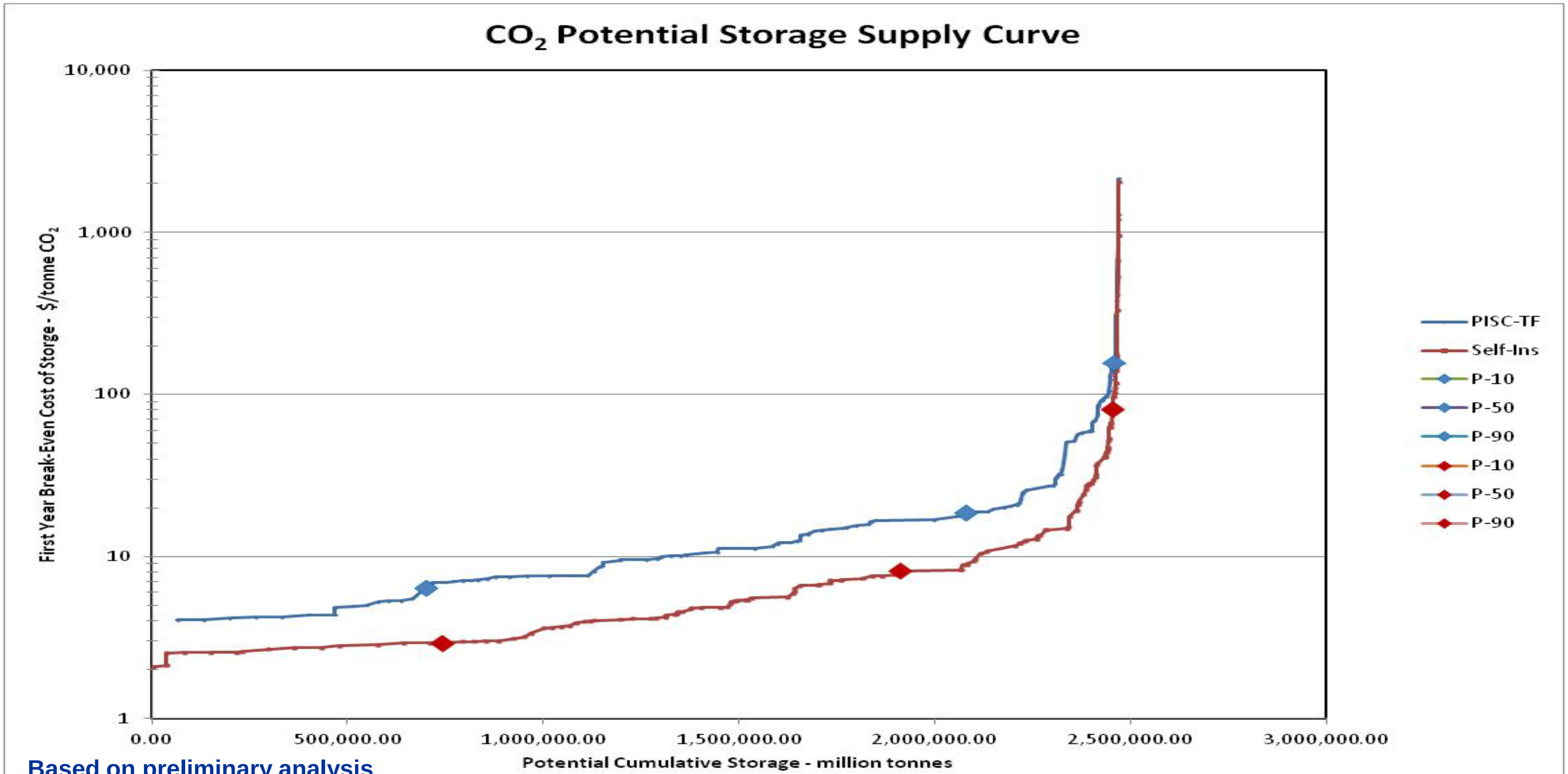
- *Select annual of CO_2 to be sequestered.*
- Select a geologic horizon listed in the geologic database for cost analysis or enter own proprietary reservoir data
- Select technologies as well as for other operational and labor *costs and their respective costs .*
- *If preferred, enter own cost data.*
- Select begin year and time duration for each of the stages.

Model Outputs

- Model can be run to provide cost analysis of a single site or to generate data to create a cost supply curve of multiple potential sites
- The cost for each stage, injection rate, reservoir and financial parameters for each reservoir formation in the database is posted.
- Stage costs posted are escalated cost per escalation rate selected.
- Data related to the cost supply curve is posted in a new worksheet created when the model's macro is run.
- Output data can be sorted per modeler's discretion for analysis.

NETL CO_2 Injection and Storage Cost Model

- Impact on cost due to selection of Financial Responsibility instrument
- All cost based on sequestering 123 million tonnes over 30 years; Flat Structure
- The storage cost supply curve has a cumulative storage potential of 2,471,161 million tonnes
  - Atlas 3rd: 1,123,430 to 13,406,090 million tonnes Saline storage potential for L48
- Financial Parameters: Equity = 45%, Cost of Equity = 20%, Escalation = 3%



Based on preliminary analysis

NETL CO_2 Injection and Storage Cost Model

Self-Ins P-50 Flat	P-10	P-50	P-90
Cost / tonne - $	2.64	4.64	14.61
Formation Height - ft	857	715	520
Porosity - %	0.28	0.21	0.17
Permeability - md	391	240	167
Plume Area – mi^2	24.4	44.2	147.2
Injection Wells	2.27	4.78	33.24
Monitoring Wells	20.4	36.3	118.72
Count	15	72	128
States	5	17	22
Formations	4	21	40
Potential Storage - Mt	741,226	1,139,878	1,596,871
Cum Elec + Ind Emissions to 2114 - Mt	451,247		

NETL CO_2 Injection and Storage Cost Model

Self-Insurance P-50 Flat

	P-10	P-50	P-90
States	California, Texas, Illinois, Indiana, Alabama	Colorado, Florida, Georgia, Kentucky, Maryland, Michigan, Mississippi, Montana, North Dakota, New Mexico, Ohio, Oklahoma,	Louisiana, Pennsylvania, South Dakota, West Virginia, Wyoming.
Formations	Repetto Ss, Frio, Mt. Simon, L. Tuscaloosa	Arbuckle, Cedar Keys-Lawson, Conasauga, Domengine, Entrada, Hermosa, Madison, Minnelusa, Mokelumne River, Morrison, Paluxy, Red River, Starkey, Waste Gate, Weber, Winters, Woodbine.	Copper Ridge, Dakota, Devonian, Duperow, Fountain, Glorietta, Leadville, Lyons, Mesaverde, Muddy, Nugget, Rose Run, San Andres, St. Peter, Stevens, Sunniland, Sylvania, Tensleep,
Basins	Los Angeles, Gulf Coast, Illinois, Kankakee Arch	Appalachian, Cincinnati Arch, Coastal Plain, East Texas, Michigan, N. Shelf Area, Paradox, Piceance, Powder River, Sacremento, San Juan, South Florida, Williston.	Big Horn, Canon City, Denver, Findlay Arch, Green River, Kevin Dome, La Barge Platform, Permian, San Joaquin, Sand Wash, Wind River.

NETL CO_2 Injection and Storage Cost Model

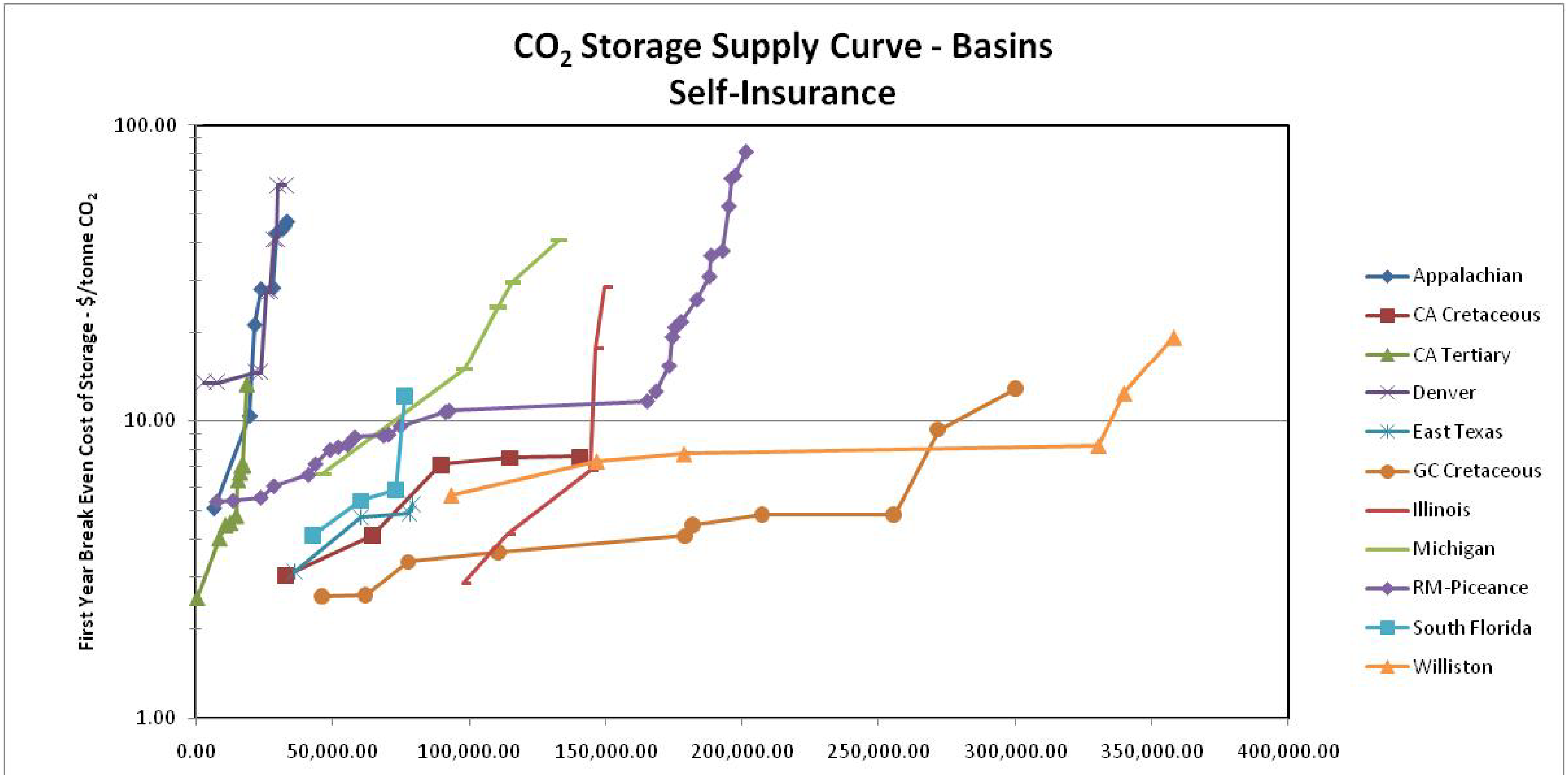
PISC-TF P-50 Flat	P-10	P-50	P-90
Cost / tonne - $	4.80	9.89	34.30
Formation Height - ft	980	742	525
Porosity - %	0.30	0.20	0.17
Permeability - md	403	232	167
Plume Area – mi^2	13.44	36.87	136.90
Injection Wells	2.4	4.25	40.06
Monitoring Wells	11.53	30.47	110.51
Count	15	72	128
States	2	16	22
Formations	4	20	39

NETL CO_2 Injection and Storage Cost Model

PISC-TF P-50 Flat

	P-10	P-50	P-90
States	California, Texas	Alabama, Colorado, Florida, Georgia, Illinois, Indiana, Kentucky, Maryland, Michigan, Mississippi, Montana, North Dakota, Oklahoma, Wyoming.	Louisiana, New Mexico, Ohio, Pennsylvania, South Dakota, West Virginia.
Formations	Repetto Ss, Mokelumne River, Starkey, Frio.	Arbuckle, Cedar Keys-Lawson, Domengine, Hermosa, L. Tuscaloosa, Madison, Minnelusa, Morrison, Mt. Simon, Nugget, Paluxy, Red River, Waste Gate, Weber, Winters, Woodbine.	Conasauga,Copper Ridge, Dakota, Devonian, Duperow, Entrada, Fountain, Glorietta, Leadville, Lyons, Mesaverde, Muddy, Rose Run, San Andres, St. Peter, Stevens, Sunniland, Sylvania, Tensleep,
Basins	Los Angeles, Sacremento, Gulf Coast,	Cincinnati Arch, Coastal Plain, East Texas, Illinois, Kankakee Arch, La Barge Platform, Michigan, N. Shelf Area, Paradox, Piceance, Powder River, San Juan, South Florida, Williston.	Appalachian, Big Horn, Canon City, Denver, Findlay Arch, Green River, Kevin Dome, Permian, San Joaquin, Sand Wash, Wind River.

NETL CO_2 Injection and Storage Cost Model



Based on preliminary analysis.

Disaggregation of the earlier Cost Supply Curve illustrate individual basin potential cost characteristics

NETL CO_2 Injection and Storage Cost Model

Introduction
Model Description
Geologic and Cost Databases
Model Runs

Conclusions

NETL CO_2 Injection and Storage Cost Model

Concluding comments:

- **This is not a reservoir model, geo-engineering equations are used to estimate parameters that impact costs.**
- **Purpose of model is to understand the composition of costs that impact CO_2 sequestration operations.**
- **Model is undergoing revisions to improve model transparency and ability to audit the costing process.**
- **Risk needs to be incorporated in model at many levels:**
  - Present testing scenario enjoys complete success.
- **A test matrix has been developed to provide a range of sequestration scenarios against which to test NETL's CO_2 Injection and Storage cost model in conjunction with NETL's other CCS models.**
- **What is the cost of storage? It depends on…**

NETL CO_2 Injection and Storage Cost Model

Acknowledgements

NETL Strategic Center for Coal:

Sean Plasynski – Director Office of Coal & Power R&D
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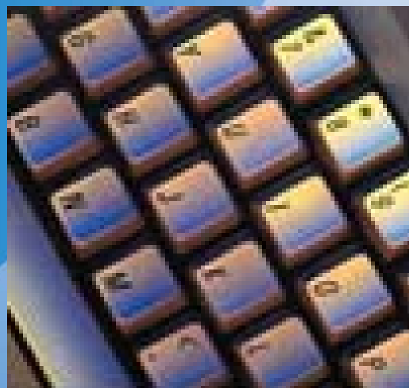
John Wimer – Director Office of Program Planning & Analysis (OPPA)
Chuck Zelek – Director Benefits Division OPPA

Contractors (ESPA):

Booz Allen Hamilton
Advanced Resources International



Using the Economic Value of CO_2-EOR to Accelerate the Deployment of CO_2 Capture, Utilization and Storage (CCUS)

Prepared For:
EPRI CCS Cost Workshop

Prepared By:
Vello A. Kuuskraa, President
ADVANCED RESOURCES INTERNATIONAL, INC.
Arlington, VA

April 25-26 2012
Palo Alto, CA

Unconventional Resources • Enhanced Recovery • Carbon Sequestration

Advanced Resources International, Inc.

Outline for Presentation

1. Status of CO_2 Enhanced Oil Recovery
2. Demand for CO_2 by the EOR Industry
3. Economic Value of CO_2-EOR
4. Concluding Thoughts and Observations

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1. Status of CO_2 Enhanced Oil Recovery

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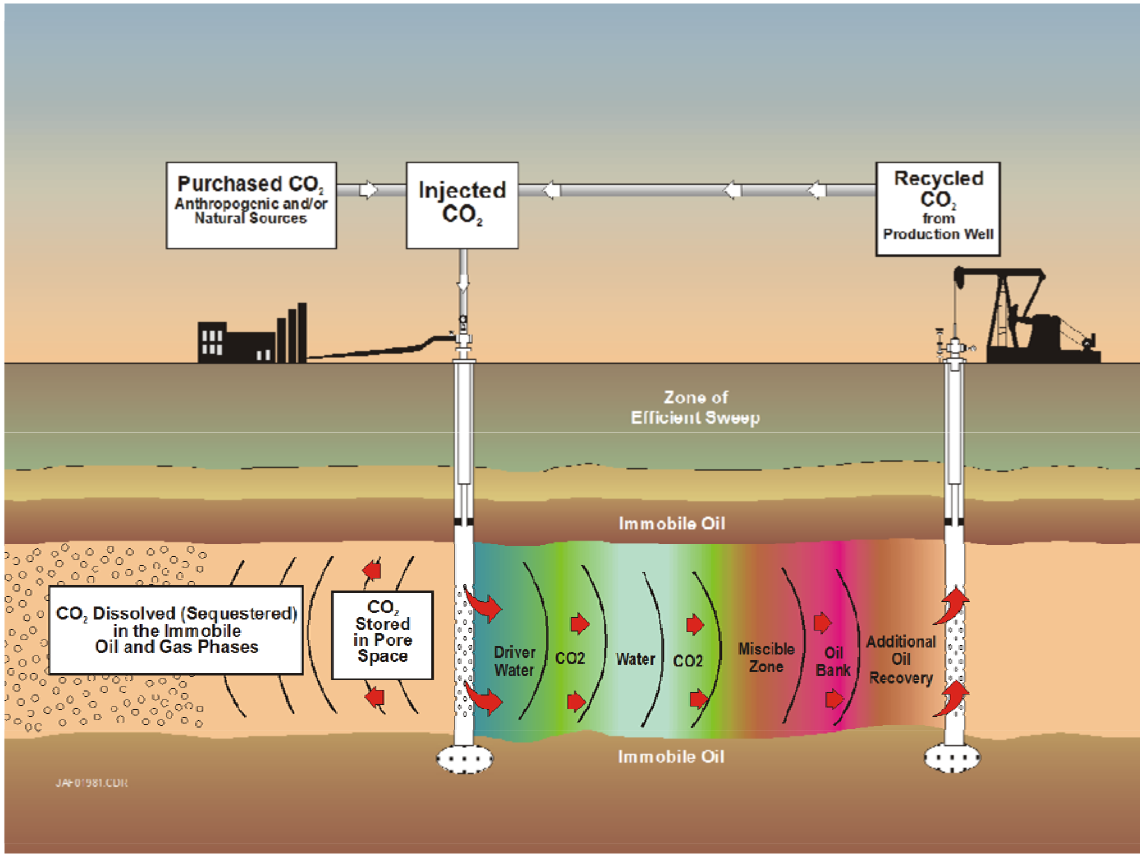
Introduction to CO_2-EOR Technology



CO_2-EOR is used to improve oil recovery from deep, light oil fields.

CO_2 is injected at high pressure often with alternating injections of water.

The CO_2 that is produced jointly with the oil is recycled (injected back into the oil reservoir).

At the end of the CO_2-EOR project, ~100% of the purchased CO_2 is stored in the oil field, if the operator closes the oil field at pressure.

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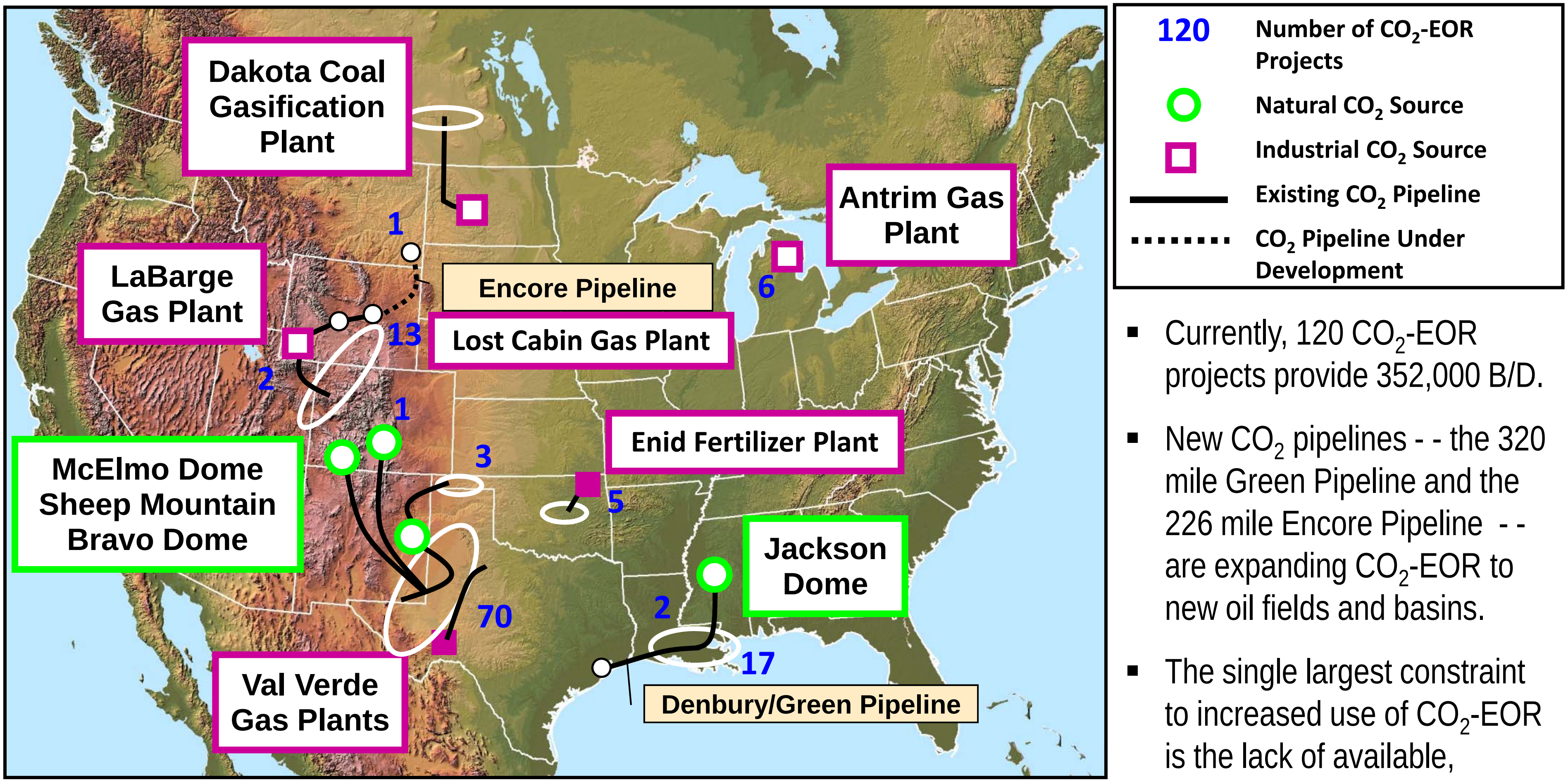
U.S. CO_2-EOR Activity



Source: Advanced Resources International, Inc., based on Oil and Gas Journal, 2012 and other sources.

- Currently, 120 CO_2-EOR projects provide 352,000 B/D.
- New CO_2 pipelines - - the 320 mile Green Pipeline and the 226 mile Encore Pipeline - - are expanding CO_2-EOR to new oil fields and basins.
- The single largest constraint to increased use of CO_2-EOR is the lack of available, affordable CO_2 supplies.

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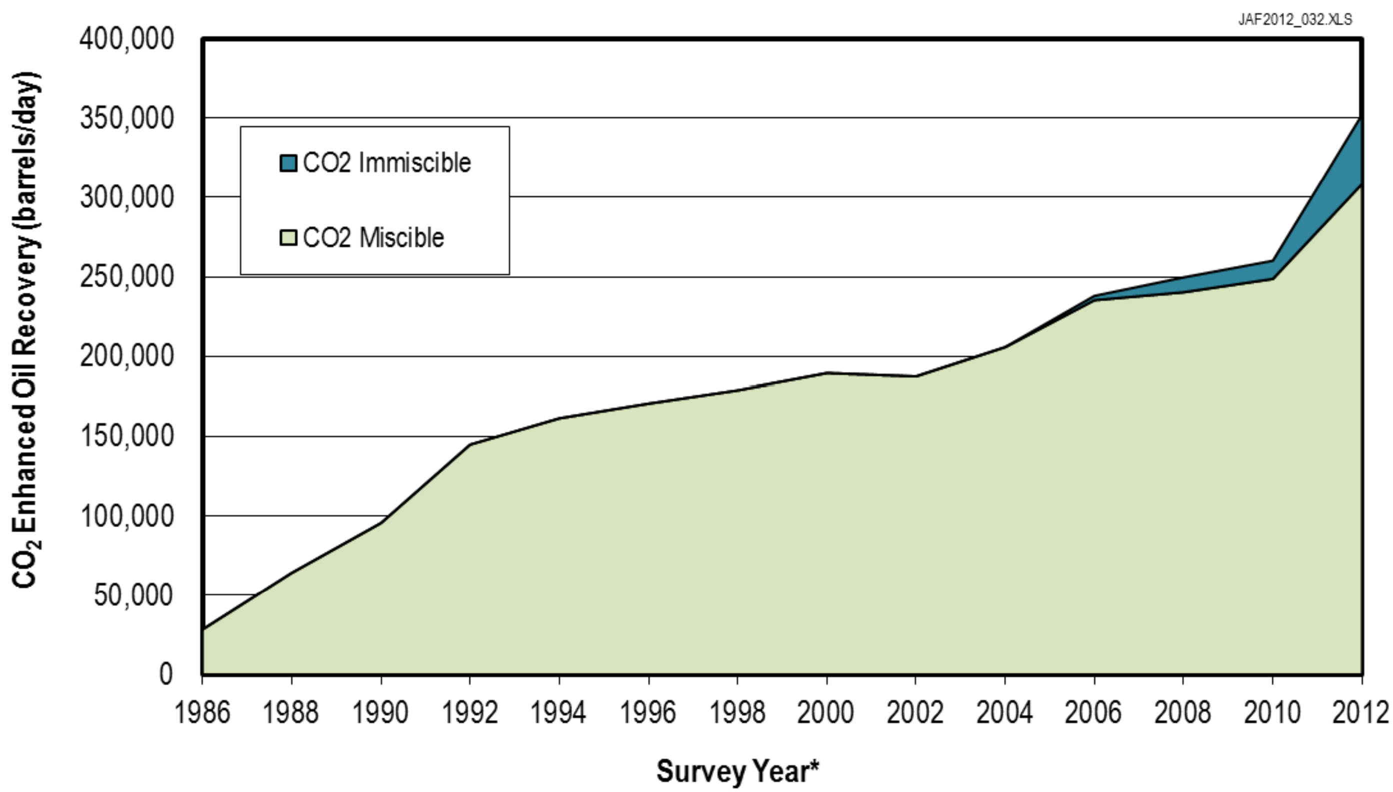
Crude Oil Production from CO_2-EOR

Oil production from CO_2-EOR has nearly doubled during the past 5 years. In 2012, it represents 6% of total U.S. crude oil production.



*Data is for EOR production rate at end of prior year; U.S. crude oil production of 6.02 MMB/D in 2012.
Source: Advanced Resources Int'l. and the Oil and Gas Journal, 2012.

2. Demand for CO_2 by the EOR Industry

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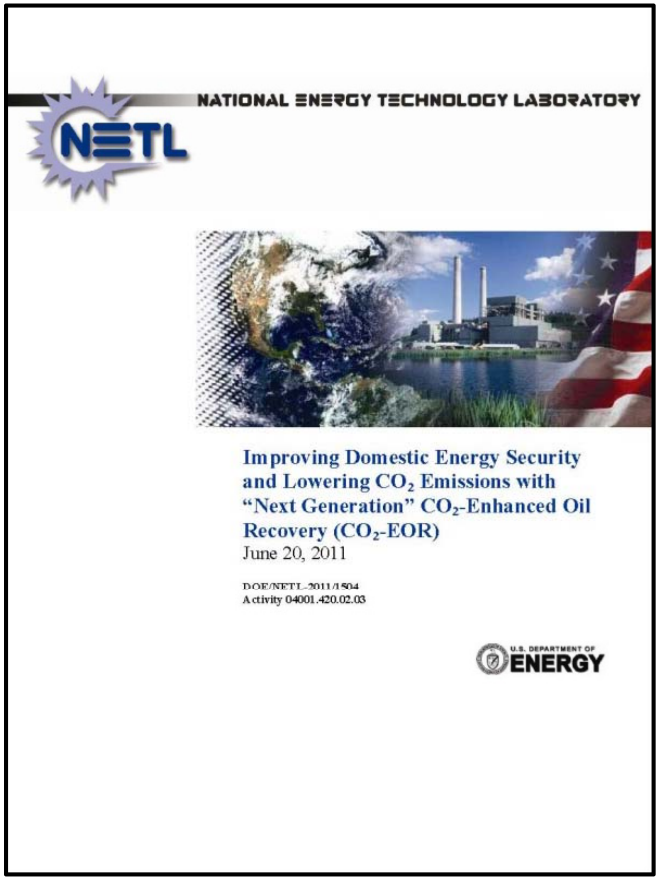
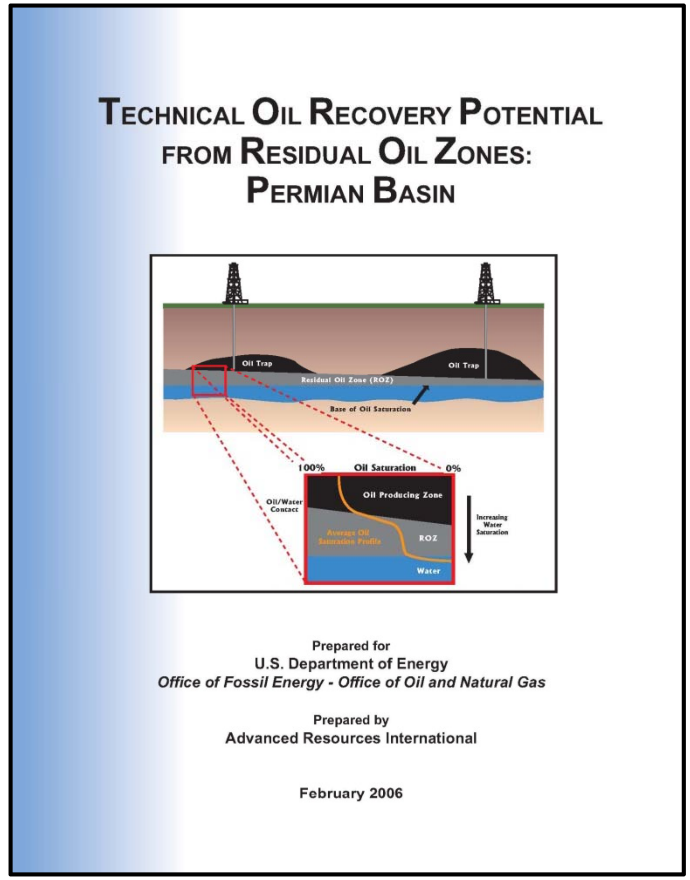
Oil Recovery and CO_2 Demand/Storage: "Next Generation" CO_2-EOR Technology

Two publically available reports, prepared by Advanced Resources Int'l for U.S. DOE/NETL, provide the analytical foundation for the estimates of CO_2 demand by the EOR industry.





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Demand for CO_2 by the EOR Industry

The economic demand from CO_2-EOR is for 25 billion metric tons of CO_2; remaining natural and gas processing sourced CO_2 supplies can only provide about 3 billion metric tons.* Development of ROZ “fairways” would add 8 billion metric tons of economic CO_2 demand.

CO_2-EOR can help accelerate the capture and storage of anthropogenic CO_2 from coal- and gas-fired power plants:

- The Weyburn integrated CO_2-EOR and CO_2 storage project is the existing “poster child”.
- Summit’s Texas Clean Energy IPCC Project, with 2.5 million metric tons per year of captured CO_2 serves as the new “model” for CCUS.

A large-scale national pipeline network is needed for linking the Ohio Valley and Southeast U.S. captured CO_2 emissions with Mid-Continent, Rockies and West Texas oil fields and ROZ “fairways”.

*CO_2 from natural sources currently provides 55 MMmt per year; CO_2 from natural gas processing plants currently provide 13 MMmt per year of CO_2 to the EOR industry, an additional 1 MMmt per year is from other industrial plants. The CO_2 captured from North Dakota gasification (3 MMmt/year) is transported to Canada.

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Oil Recovery and CO_2 Demand/Storage: "Next Generation" CO_2-EOR Technology*

Reservoir Setting	Oil Recovery*** (Billion Barrels)		CO_2 Demand/Storage*** (Billion Metric Tons)	
	Technical	Economic**	Technical	Economic**
L-48 Onshore	104	60	32	17
L-48 Offshore/Alaska	15	7	6	3
Near-Miscible CO_2-EOR	1	*	1	*
ROZ (below fields)****	16	13	7	5
Sub-Total	136	80	46	25
Additional From ROZ "Fairways"	40	20	16	8

*The values for economically recoverable oil and economic CO_2 demand (storage) represent an update to the numbers in the NETL/ARI report "Improving Domestic Energy Security and Lowering CO_2 Emissions with "Next Generation" CO_2-Enhanced Oil Recovery (CO_2-EOR) (June 1, 2011).

**At $85 per barrel oil price and $40 per metric ton CO_2 market price with ROR of 20% (before tax).

***Includes 2.6 billion barrels already being produced or being developed with miscible CO_2-EOR and 2,300 million metric tons of CO_2 use from natural sources and gas processing plants.

**** ROZ resources below existing oilfields in three basins; economics of ROZ resources are preliminary.

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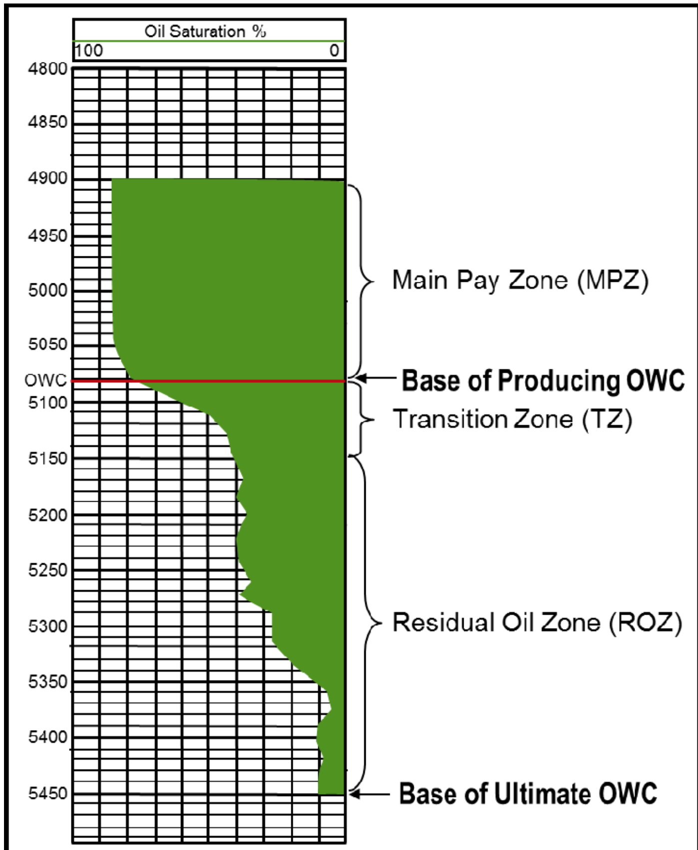
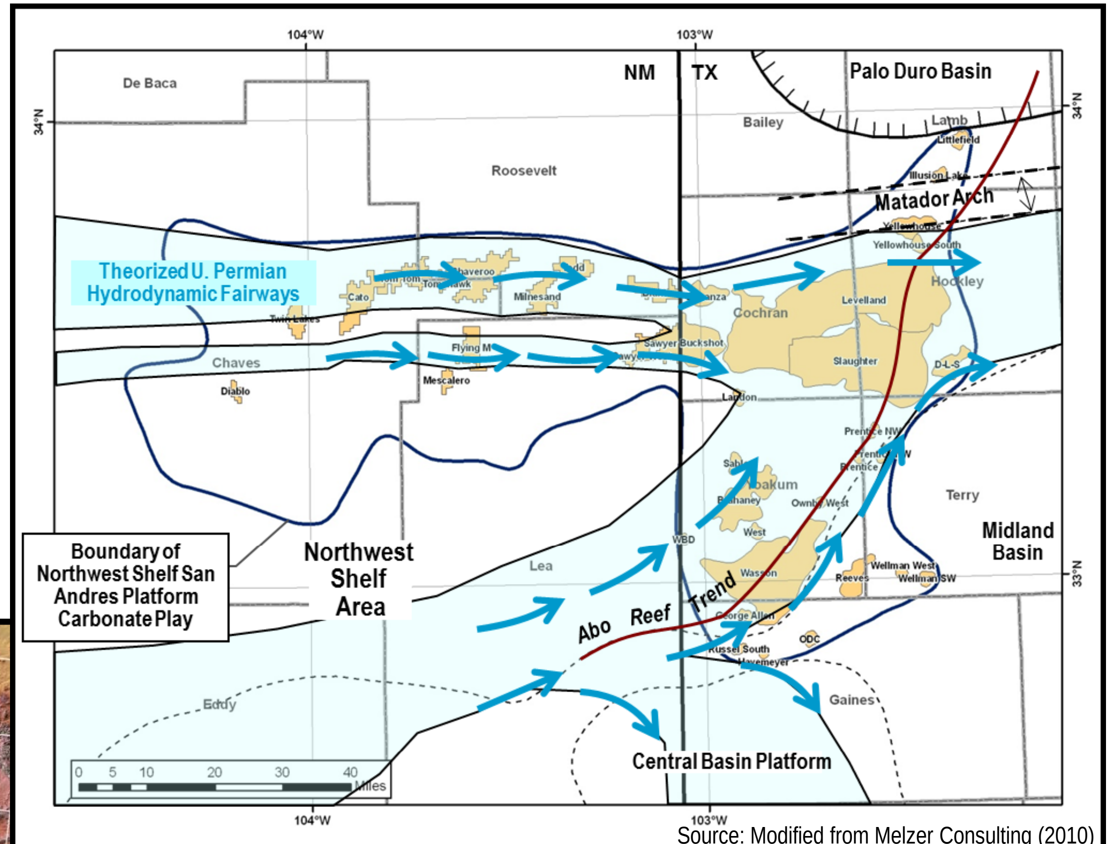
Application of CO_2-EOR to the Residual Oil Zone (ROZ) Resource

Oil Saturation Profile in the TZ/ROZ

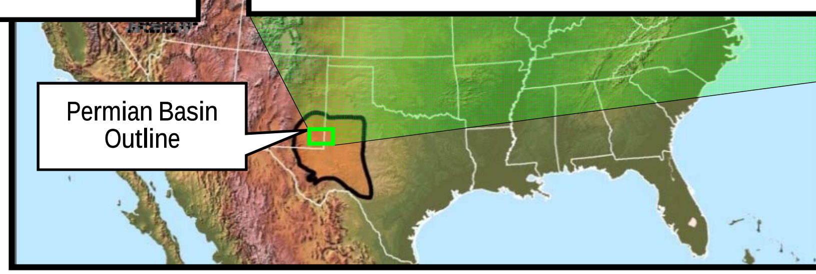


Source: Adapted from Wasson Denver Unit Well

Permian Basin ROZ "Fairways"



Source: Modified from Melzer Consulting (2010)



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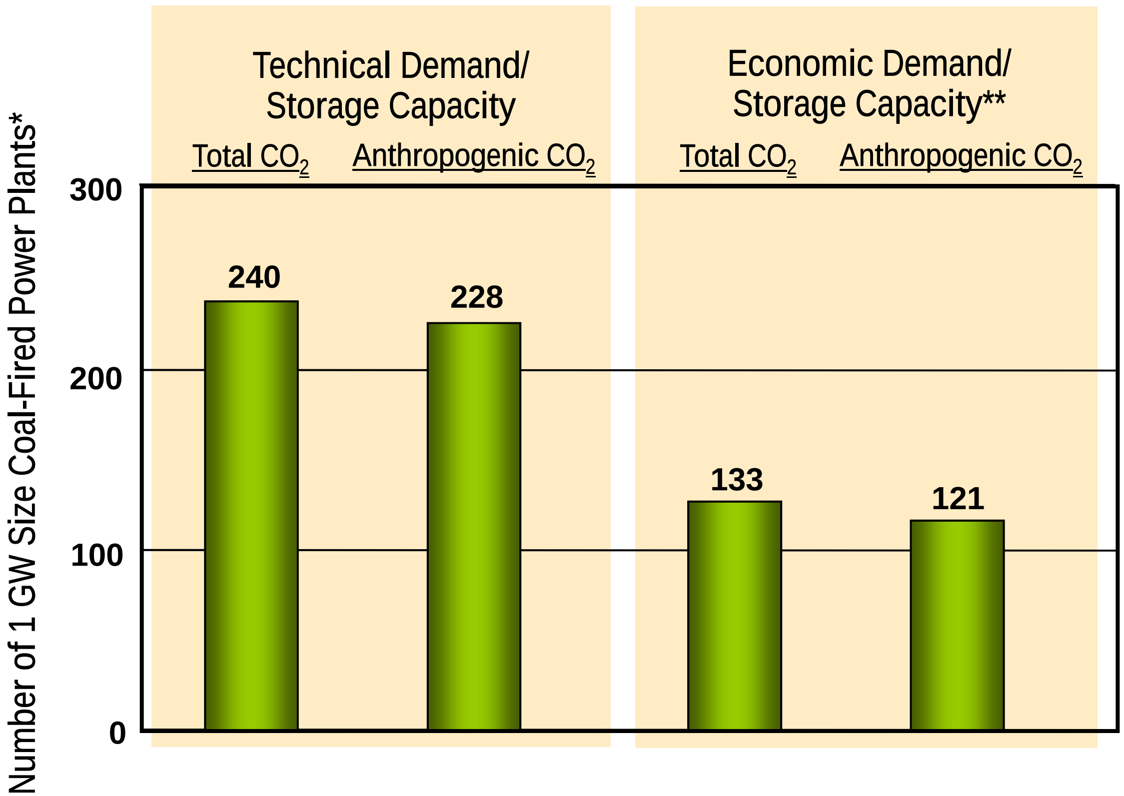
Demand for CO_2: Number of 1 GW Size Coal-Fired Power Plants



*Assuming 7 MMmt/yr of CO_2 emissions, 90% capture and 30 years of operations per 1 GW of generating capacity.
**At an oil price of $85/B, a CO_2 market price of $40/mt and a 20% ROR, before.
Source: Advanced Resources Int'l (2011).

Reservoir Setting	Number of 1GW Size Coal-Fired Power Plants***	
	Technical	Economic*
L-48 Onshore	170	90
L-48 Offshore/Alaska	31	14
Near-Miscible CO2-EOR	5	1
ROZ**	34	28
Sub-Total	240	133
Additional From ROZ "Fairways"	86	43

*At $85 per barrel oil price and $40 per metric ton CO_2 market price with ROR of 20% (before tax).
** ROZ resources below existing oilfields in three basins; economics of ROZ resources are preliminary.
***Assuming 7 MMmt/yr of CO_2 emissions, 90% capture and 30 years of operation per 1 GW of generating capacity; the U.S. currently has approximately 309 GW of coal-fired power plant capacity.

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Advanced Power Plants Plan to Use EOR for CO_2 Storage

Southern Company's Kemper County IGCC Plant

- 582 MW fueled by Mississippi Lignite
- Will Capture 65% of CO_2
- Negotiating agreement to sell 1.1 to 1.5 million tons of CO_2 per year for EOR (170-225 MMcfd)
- Project expected to cost $2.4 B and be operational by 2014.

*Source: Mississippi Power, Denbury Resources

Summit's Texas Clean Energy IGCC Project

- 400 MW IGCC with 90% capture
- Located near Odessa in Permian Basin
- Sell 2.5 million tons of CO_2 per year to EOR market
- Expected cost $1.75 B; $350 MM award under CCPI Round 3.

Source: Siemens Energy

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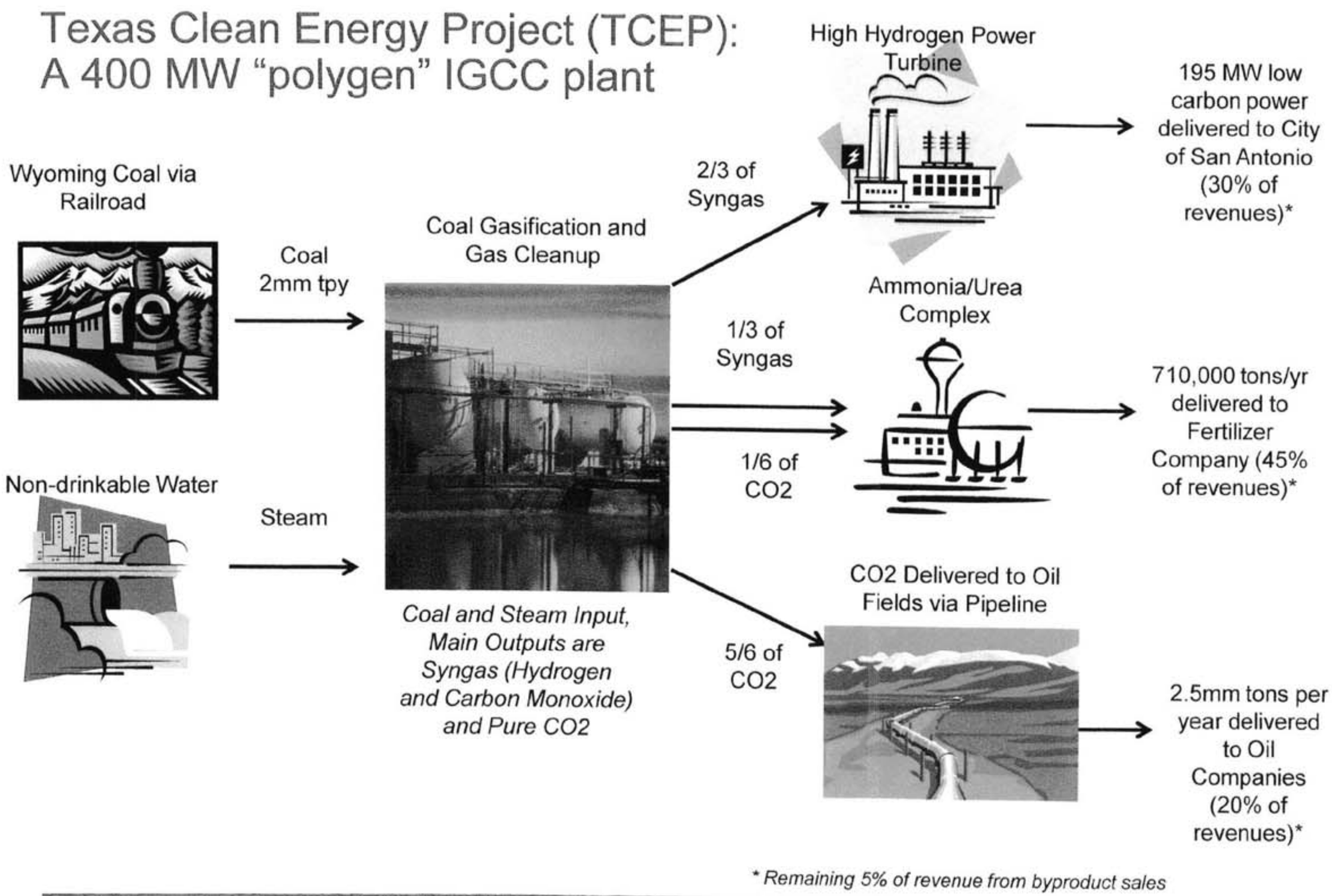
Texas Clean Energy Project (TCEP): A 400 MW "Polygen" IGCC Plant



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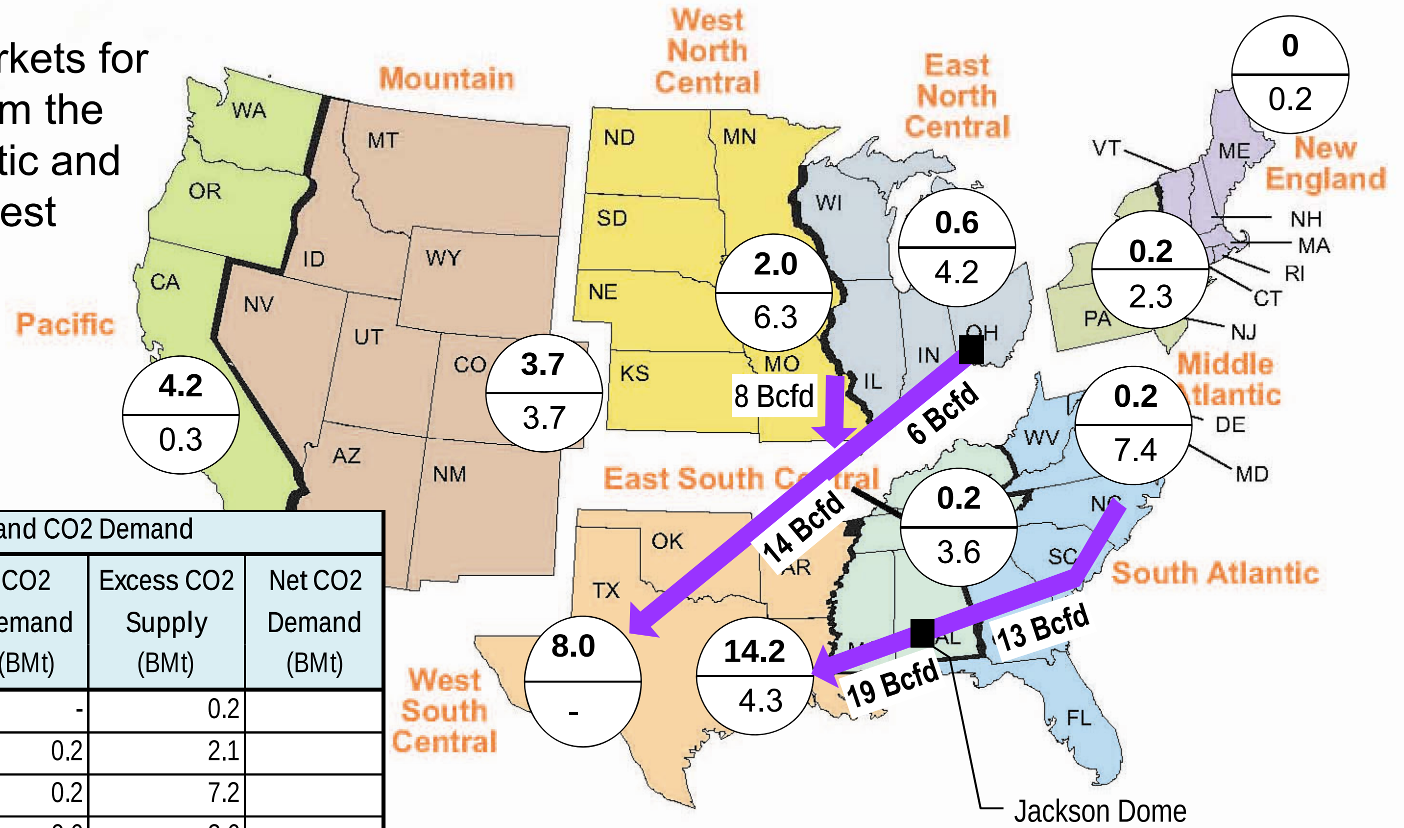
Linking CO_2 Supplies with CO_2-EOR Demand

The primary EOR markets for excess CO_2 supplies from the Ohio Valley, South Atlantic and Mid-Continent is East/West Texas and Oklahoma.



Captured CO2 Supplies and CO2 Demand				
Region	Captured CO2 Supplies* (BMt)	CO2 Demand (BMt)	Excess CO2 Supply (BMt)	Net CO2 Demand (BMt)
New England	0.2	-	0.2	
Middle Atlantic	2.3	0.2	2.1	
South Atlantic	7.4	0.2	7.2	
East North Central	4.2	0.6	3.6	
West North Central	6.3	2.0	4.3	
East South Central	3.6	0.2	3.3	
West South Central	4.3	14.2		9.9
Mountain	3.7	3.7		
Pacific	0.3	4.2		3.8
Total	32.2	25.3	20.8	13.7
ROZ "Fairways"		8.0		8.0

* Capture from 200 GW of coal-fired power plants, 90% capture rate.

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Pacific

4.2 — CO_2 Demand by EOR (Bmt)

0.3 — Captured CO_2 Emissions (Bmt)

Sources: EIA Annual Energy Outlook 2011 for CO2 emissions; NETL/Advanced Resources Int'l (2011) CO2 demand.

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Linking CO_2 Supplies with CO_2-EOR Demand

The transportation costs for delivering CO_2 with large capacity pipelines ranges from $4 to $13 per metric ton, depending on distance and the capital recovery factor (CRF).

	350 Miles	600 Miles	1,000 Miles
Capex	$0.9 billion	$1.6 billion	$2.7 billion
Annual O&M	$4.7 million	$80 million	$134 million
Cost/mt			
@ 10% CRF	$3.60/mt	$6.20/mt	$11.40/mt
@ 12% CRF	$4.10/mt	$7.00/mt	$12.90/mt

The key assumptions included in the transportation cost calculation include:

- CO_2 flow rate (112,000 mt/d; 2.1 Bcfd)
- Capacity factor (0.95)
- Pressure (inlet 2,100 psi; outlet 1,820 psi)
- No. of booster stations (20/33)
- Electricity price (5.5 ¢/kwh)
- Pipe size (32 in OD)

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CO_2 Transportation Costs: 600 mile, 32 in. (OD) CO_2 Pipeline

Inputs

CO2 Pipeline Properties			
CO2 mass flow rate (tonnes/day)			112,000
Intial CO2 Pressure Pinitial (MPa)			14.5
CO2 Pressure into pipeline			14.5
CO2 Pressure out of Pipeline			12.5
Δ Pressure			2
Pipeline Operating Pressure			13.5
Average Distance Between Booster Stations (mi)			30
Include Booster Stations in Pipeline Cost?			Yes
Operating Temperature of Pipeline (C) Range: -1.1 - 82.2 C Non-Inclusive			18.33
Plant Properties			
Capacity Factor			0.95
Hours/Day of Operation			24
Location Properties			
Use Decimal Format. Valid for Northwestern Lat/long Coordinates	Source Latitude	-	
	Source Longitude	-	
	Sink Latitude	-	
	Sink Longitude	-	
Distance (mi)			600
Terrain			Grassland
Financial Properties			
Price of Electricity (kwh)			0.055
Options for Annualizing Figures			Capital Recovery Factor
Length of Project (yrs)			30
Interest Rate			12%
Capital Recovery Factor			0.12
Inflation Indicies (Base Year=2005)			
Fabricated Metal Products			137
Labor (Construction)			128
Producer Price Index			127.8

Outputs

Costs	Annual	Per Ton CO2	Project PV
Compression			
Capital	$0	$0.00	$0
O&M	$0		$0
Electricity	$0	$0.00	$0
Total Compresson	$0	$0.00	$0
Pipeline			
Capital			
Pipeline	$139,174,516	$3.58	$1,159,787,637
Booster	$52,887,751	$1.36	$440,731,254
Total	$192,062,267	$4.95	$1,600,518,891
O&M			
Pipeline	$57,989,382	$1.49	$0
Booster	$22,036,563	$0.57	$0
Total	$80,025,945	$2.06	$0
Total Pipeline	$272,088,212	$7.01	$1,600,518,891
Total Costs	$272,088,212	$7.01	$1,600,518,891

Other Statistics	
IPSCO Pipe Stats	
Pipeline Internal Diameter	31.124
Outer Diameter	32
Reference Number	249
Annual Electricity Used (kw/h)	400,664,777
Tonnes CO2 Transported/year	38,836,000
Number of Booster Stations Needed	20
Number of Compressor Trains Needed	0

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Economic Value of CO_2 Enhanced Oil Recovery

The CO_2-EOR industry would create a market for captured CO_2 emissions from the electric power and other industries, equal to over $1 trillion* (less costs for CO_2 transportation).

The production of 80 billion barrels of oil with “Next Generation” CO_2 would help revitalize the U.S. economy and create large new sources of revenues:

- Overall revenues and economic activity equal to $6.8 trillion.
- New Federal and state revenues, from royalties, severance taxes and income taxes of $1.6 trillion.
- Markets for domestic services and sales of materials of $2.1 trillion.

*Assumes 90% of total CO_2 demand is met by anthropogenic CO_2; oil prices of $85 per barrel and CO_2 sales price of $40/mt.

Distribution of Revenues from "Next Generation" CO_2-EOR

Revenue Recipient	Value Chain Function	Revenues	
		Per Barrel ($)	TOTAL ($ billion)
1. Federal/State Treasuries	Royalties/Severance/Income Taxes	$19.80	$1,580
2. Power/Industrial Companies	Sale of Captured CO_2 Emissions	$14.10	$1,130
3. Other	Private Royalties	$7.70	$620
4. Oil Industry	Return of/on Capital	$16.90	$1,350
5. U.S. Economy	Services, Materials and Sales	$26.50	$2,120
	Total	$85.00	$6,800

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Distribution of Economic Value of Incremental Oil Production from CO_2-EOR

Notes		Oil Industry	Federal/ State	Power Plant/Other	Private Royalties	U.S. Economy
1	Domestic Oil Price ($/B)	$85.00				
2	Less: Royalties	($14.90)	$2.50		$12.40	
3	Production Taxes	($3.50)	$4.10		($0.60)	
4	CO2 Purchase Costs	($16.00)		$14.10		$1.90
5	CO2 Recycle Costs	($9.60)				$9.60
6	O&M/G&A Costs	($9.00)				$9.00
7	CAPEX	($6.00)				$6.00
	Total Costs	($59.00)		-		
	Net Cash Margin	$26.00	$6.60	$14.10	$11.80	**$26.50**
8	Income Taxes	($9.10)	$13.20	-	($4.10)	**-**
	Net Income ($/B)	$16.90	$19.80	$14.10	$7.70	**$26.50**

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Notes: (1.) Assumes $85 per barrel of oil; (2.) Royalties are 17.5%; 1 of 6 barrels produced are from federal and state lands; (3.) Production and ad valorem taxes of 5%, from FRS data; (4.) CO_2 market price of $40/tonne, including transport; 0.4 tonne of purchased CO_2 per barrel of oil; CCS would meet 88% of CO_2 demand; (5.) CO_2 recycle cost of $16/tonne; 0.6 tonnes of recycled CO_2 per barrel of oil; (6.) O&M/G&A costs from ARI CO_2-EOR cost models; (7.) CAPEX from ARI CO_2-EOR cost models; (8.) Combined Federal and state income taxes of 35%, from FRS data.

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Concluding Thoughts and Observations

1. ***CO_2-EOR Needs CCS.*** Large-scale implementation of CO_2-EOR needs CO_2 supplies captured from power plants.

2. ***CCUS Benefits from CO_2-EOR***. The revenues (and cost avoidance) from sale of CO_2 to EOR (combined with other policies) can help accelerate the deployment of CCUS.

3. ***CO_2-EOR Offers Large CO_2 Storage Capacity.*** CO_2-EOR in oil fields and residual oil (ROZ) fairways can accommodate a major portion of the CO_2 captured from coal-fired power plants for the next 30 to 40 years.

4. ***CCUS and CO_2-EOR Need Supportive Policies and Actions.*** Supportive policies and incentives for pre-built CO_2 pipelines would greatly accelerate the integrated use of CO_2-EOR and CCUS.

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Questions?

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Advanced Resources International, Inc.

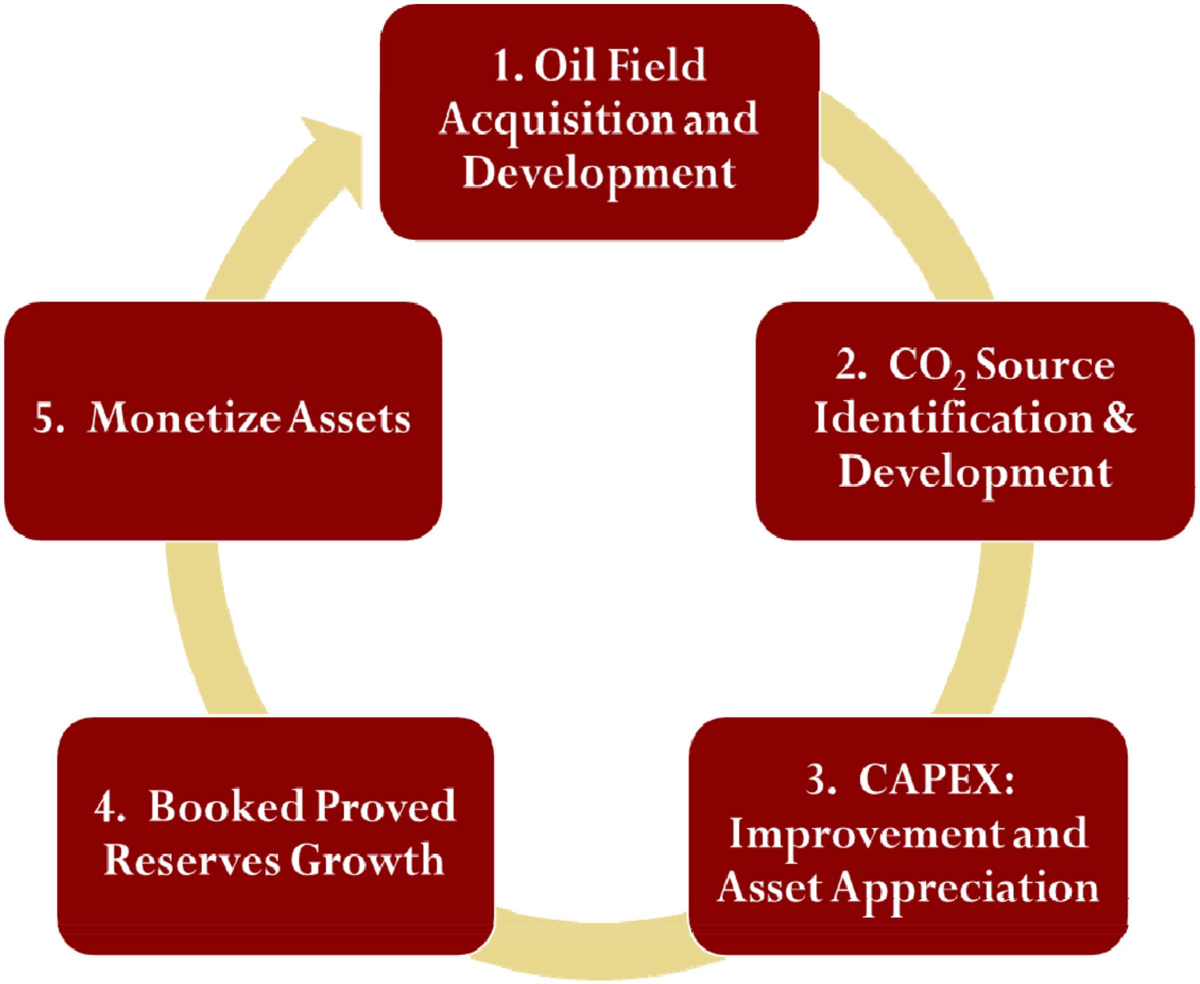
EPRI-MIT
CCS COST WORKSHOP

“Transport, Storage, and Utilization: EOR Operator Perspective”

Michael E. Moore
Vice President External Affairs and Business Development
Blue Strategies LLC
Executive Director NACCSA

Palo Alto, CA
April 25-26, 2012

CO_2-EOR Asset Cycle



CO_2 EOR – Industry Overview

- CO_2 EOR has been in commercial use for ~ 40 Years
- US Industry Statistics
  - Currently injecting ~ 2 bcf/day of fresh CO_2 – re-injection is about the same, 20% of which is from anthropogenic sources
  - Currently producing ~240,000 bbls/d of incremental oil, a nine-fold increase from 1986 levels of 28,000 bbls/d
  - 39-48 billion barrels of incremental oil are economically recoverable via CO_2 EOR[1]
  - Recovery rates 7% - 20% of OOIP
  - Each barrel of oil recovered requires approximately 6-7 mcf of original CO_2
- CO_2 Sourcing and Transportation
- It is all about the reservoir and oil characteristics
  - This is exploitation of known reserves
  - With the right reservoir and oil characteristics recovery is assured

Current CO2 EOR Operators			
Company	Miscible Projects	Locations	Incremental Production (Mbo/d)
Occidental	29	TX, NM	90.2
Hess	6	TX	25.3
Kinder Morgan	1	TX	24.2
Chevron	4	CO, TX, NM	21.3
Denbury Resources	13	MS, LA	17.8
Merit Energy	7	WY, OK	13.6
ExxonMobil	2	TX, UT	11.7
Anadarko	4	WY	9
Whiting Petroleum	3	TX, OK	6.9
ConocoPhillips	2	TX, NM	5.5
12 other independents	28	TX, OK. UT, KS, MI	14.9
Total	**99**		**240.4**

(1) According to Advanced Resources International,

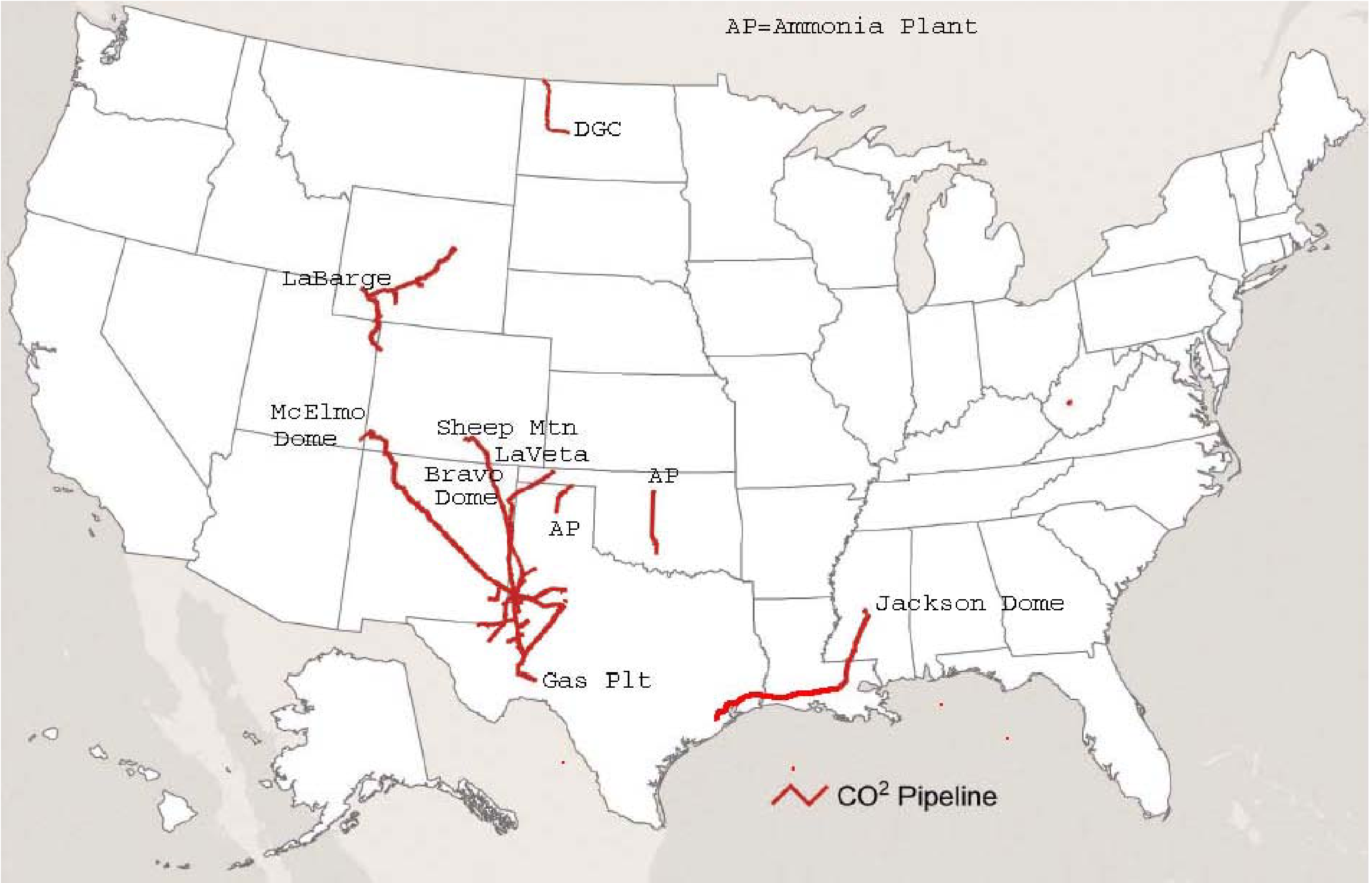
Natural vs. Industrial

- Cost of production, past and expected
- Qualities and existing infrastructure
- Contracting
- Geographic competitive issues
- Supply

Infra-structure
Developed vs. Undeveloped

- 4000+ miles in operation
- Primarily natural sources
- Size of source anchors pipelines
- Expansions underway or being devised
- “Build it and they will come” not a gamble the industry will take

Existing CO_2 Transport Infrastructure



Likely Future CO_2 Pipeline Layout

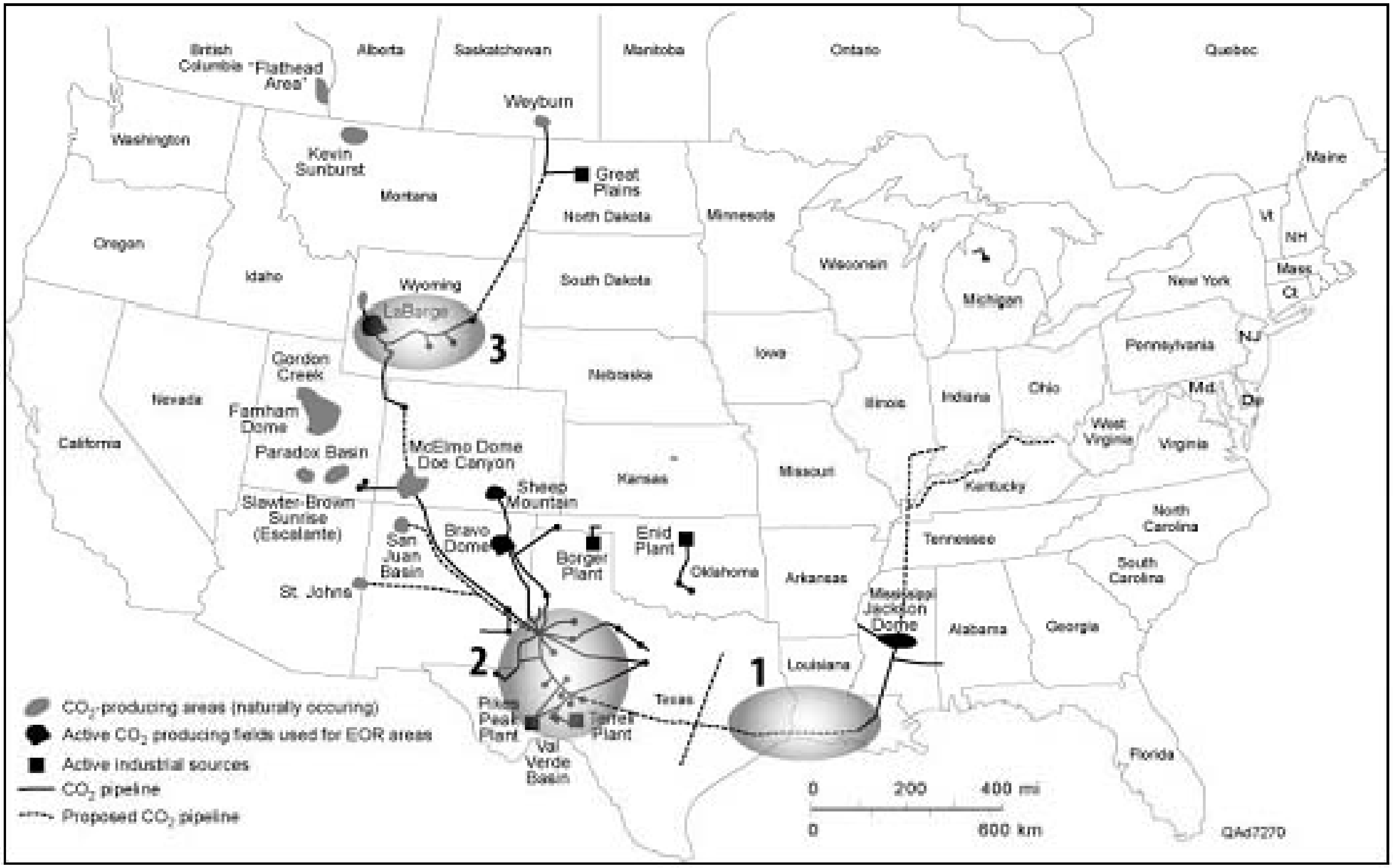


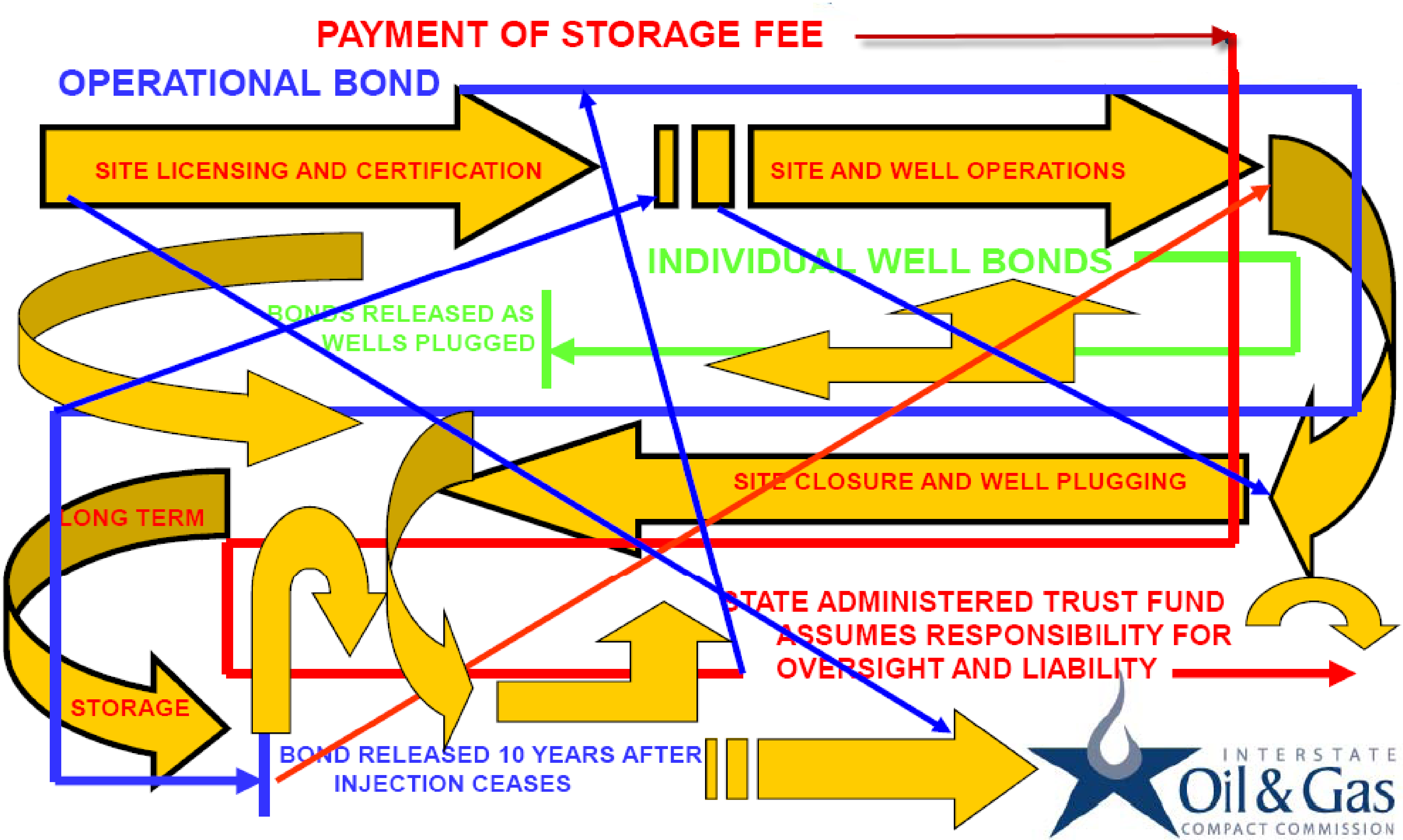
Fig 2: A Framework Depiction of a Natonal CO2 Pipeline Network ("The Horseshoe"). The Shaded ellipses Represent Three Areas Where Very Large EOR/CCS Projects are Active or Proposed

Status of State/Federal Regulations Commercial Impacts

- All oil & gas states with ongoing CO_2-EOR are set, new areas problematic
- Unitization
- Eminent domain for storage and pipelines (does not enjoy FERC opportunities like natgas)
- EPA vs. States
- Pore space for storage

CO_2 Permitting-Management

Source: IOGCC



Contracting

- Term
- Quality
- Quantity
- Pressure
- Firm/not firm
- Balancing
- Third party sales
- Transaction reporting

Valuation

- Typically a % of the value of produced crude oil market value-with CO_2 delivered to the field facilities on an mcf basis
- Quality variables
- Delivered pressure
- Firm/not firm
- Variable volume/timing
- Carbon opportunities, obligations and risks

CO_2 Sources/Specs

Source: IOGCC www.iogcc.state.ok.us

Component	Kinder Morgan CO_2 Pipeline Specs[50]	Ethanol Plant[51]	Great Plains Synfuels Plant[52]	Gas Processing Plant[53]	Coffeyville Resources Ammonia-UAN Fertilizer Plant[54]	Food-Grade CO_2 Specs[55]
CO_2	≥ 95 vol%	> 98 vol%	96.8 vol%	≥ 96 vol%	99.32 vol%	≥ 99.9 vol%
Water	≤ 30 lb/MMcf	Dry	< 25 ppm	≤ 12 lb/MMcf	0.68 vol%	≤ 20 ppmw
H_2S	≤ 20 ppmw		< 2 vol%	≤ 10 ppmw		≤ 0.1 ppmv
Total Sulfur	≤ 35 ppmw	40 ppmv	< 3 vol%	≤ 10 ppmw		≤ 0.1 ppmv
N_2	≤ 4 vol%	0.9 vol%	0 ppm			None
Hydrocarbons	≤ 5 vol%	2300 ppmv	1.3 vol%	≤ 4 vol%		CH4: ≤ 50 ppmw; others: ≤ 20 ppmw
Hydrocarbons	≤ 5 vol%	2300 ppmv	1.3 vol%	≤ 4 vol%		CH4: ≤ 50 ppmw; others: ≤ 20 ppmw
O_2	≤ 10 ppmw	0.3 vol%	0 ppm	≤ 10 ppmw		≤ 30 ppmw
Other	Glycol: ≤ 0.3 gal/MMcf		0.8 vol%			≤ 330 ppmw
Temperature	≤ 120°F	120°F	100°F	≤ 100°F	100°F	

Risk and Commercial Considerations for Industrially Sourced CO_2

- Typical BAU, full rights under mineral lease to use and leave CO_2 behind per permitting parameters
- Mineral leases are just that…
- Sequestration and term/type of obligations begins to change the rights/obligations subsurface
- As part of a carbon mitigation process, entanglement of the source’s obligations with the EOR operators
- Undefined and unlimited risk depending on contracting and State/Federal regulations
- Private company vs. publically held

Current Developments/Drivers

- CCUS Methodology Released January 2012 by C2ES
- NEORI – Phase I work done
- NRAP – Developing subsurface technical "playbook"
- 45(Q) modifications efforts underway has prompted numerous studies on size and scope of EOR opportunity from industrial sources
- MWGA – developing action plan for CO2 infrastructure and opportunity in the mid-central states
- California's Cap & Trade program instigated current interests and developments for CCUS and CO2-EOR –Storage utilization
- EPA's GHG Rule Implementation has instigated a closer look at CO2-EOR-Storage as first storage pathway for CCS implementation
- DOE's shift from CCS to CCUS, making CO2-EOR-Storage a preferred pathway
- Crude oil (WTI) pricing now in the \$80-\$110/bbl range
- ROZ is creating strong interest in large volume/long term CO2 sources
- CO2-EOR-Storage protocols for Registry use underway

Questions & Thank You!

Michael E. Moore

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North American Carbon Capture & Storage Association

CO_2 Sources/Specs

Pipeline	Dakota Gas	Exxon	Denbury	Kinder Morgan
Location	ND/SK	WY	MS/LA	NM/TX
CO_2 Source	Anthropogenic	Anthropogenic	Natural	Natural
Specifications				
Carbon Dioxide	95% min	95% min	99% min	95% min
Water	< 100 ppm	< 30 lbs/MMSCF	< 30 lbs/MMSCF	< 30 lbs/MMSCF
Methane	< 0.5%	NS	NS	NS
Ethane	< 1%	NS	NS	NS
Propane	< 0.5%	NS	NS	NS
Hydrocarbons	NS	NS	NS	< 5%
Hydrogen Sulfide	< 2.0%	< 20 ppm	< 10 ppm	< 20 ppm
Oxygen	< 0.5%	< 10 ppm	NA	< 10 ppm
Nitrogen	< 1%	< 4%	< 0.5%	< 4%
Mercaptans	< 250 ppm	NS	NS	NS
Total Sulfur	NS	< 35 ppm	< 35 ppm	< 35 ppm
Glycol	NS	< 0.3 gal/MMscf	NA	< 0.3 gal/MMscf
Temperature	NS	< 120 ºF	< 90 ºF	< 120 ºF
NS = not specifed				

Table 3. Specifications for selected US CO_2 pipelines. Source: R. Hattenbach, Blue Source Ltd.

Techno-Economic Status of the Pre-Combustion Route

IEA / EPRI - Palo Alto – 25-26/04/2012

Authors: Sina Rezvani and Dave Ashok

Univ. of Ulster, WP1.2 Leader

Presenter : Carl Bozzuto for Flavio Franco

Alstom UK, SP1 Leader

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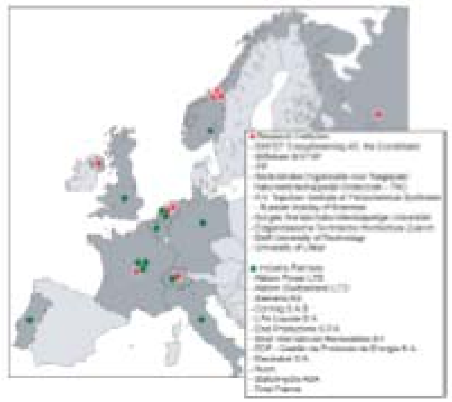
DECARBit

- A large scale European FP7 project (2008 to 2012)
- Focus on high potential, cost-efficient advanced capture techniques in pre-combustion schemes
- Enable production of hydrogen-rich fuel gases for use in gas turbines
- Enable pre-combustion plants by developing key gas turbine knowledge and components
  - Low emission gas turbines
  - Capable of burning near 100% hydrogen
- Take key pre-combustion tehnologies to pilot testing and experimental validation
- Improving the economics and reducing CO2 avoidance costs
- Build on successful EU FP6 programmes – ENCAP, CACHET, COACH, DYNAMIS

Partners



Total budget: 15.5 M Euros
Duration: 4 years
Coordinator: SINTEF Energy AS
16 core partners plus industrial contact group of 5 companies

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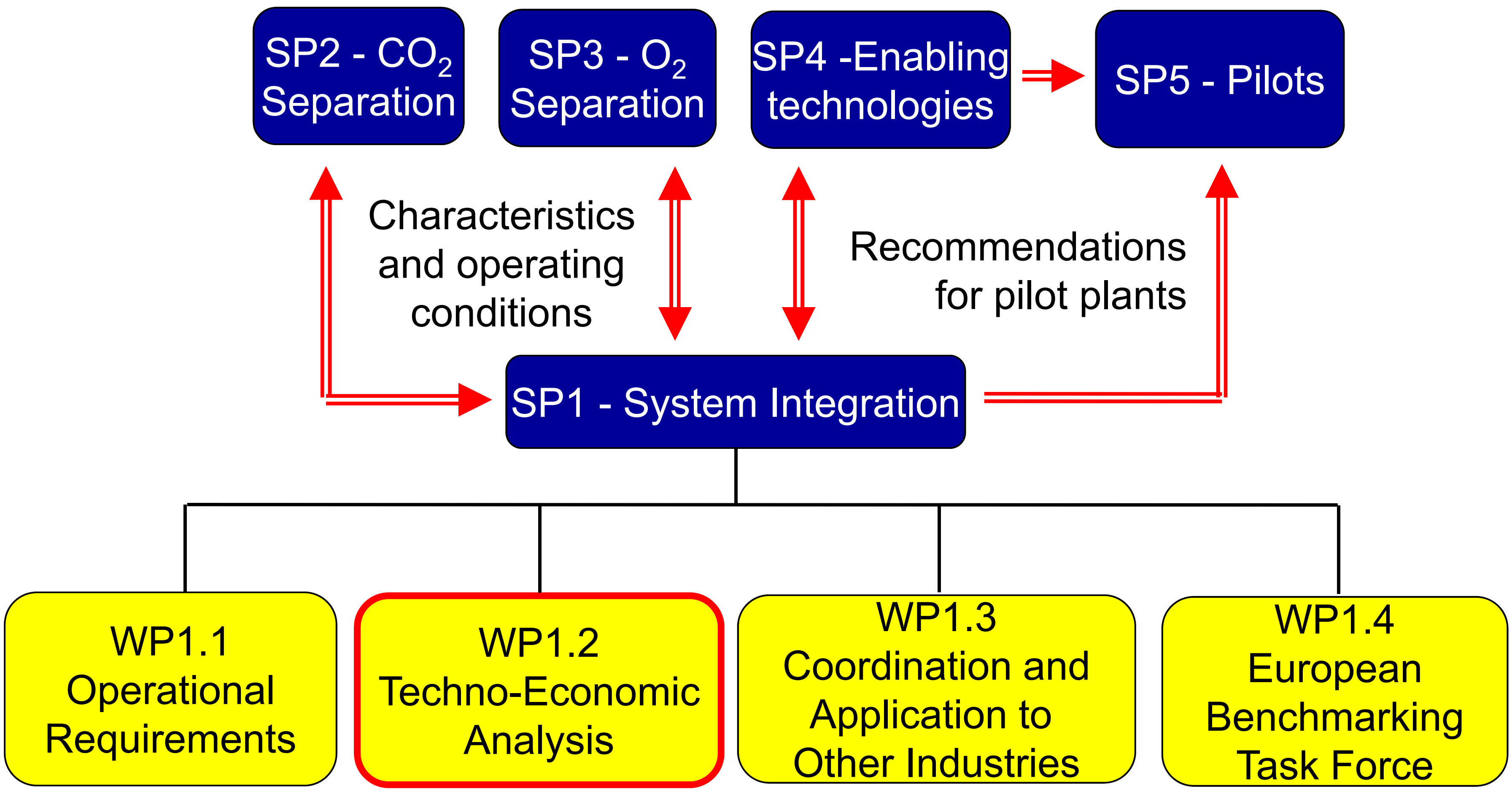
SP1 and its interactions with Other SPs



DECARBit SP1 - Cycles

- WP1.1 - Definition and analysis of four advanced cycles, integrating four different gas separation processes studied in DECARBit
  - CO_2 separation with CO_2 sorbent - Pressure Swing Adsorption - PSA
  - CO_2 separation with solvent and membrane contactor - Membrane Gas Desorption - MGD
  - Low temperature CO_2 separation
  - High temperature membrane air separation - OTM (ITM)
- WP1.4 - Definition and analysis of a Base Case cycle, with capture using selexol, within the European Benchmarking Task Force

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Base cycle - CO_2 capture with selexol

Base Case Characteristics

Gas turbine output: 283 MWe

Gross electric power output: 457 MWe

Ancillary power consumption: 104 MWe

Net electric power output: 353 MWe

Capture rate: 91.27 %

DECARBit SP1 - Economics

- WP1.2 - Techno-economic analysis
  - Costing of critical components
  - Total capital investment of the four novel IGCC systems, according to the EBTF methodology
  - Power plant cost sensitivity
  - Calculation of the Cost of Electricity (COE) = Breakeven Electricity Selling Price (BESP)
  - Sensitivity analysis: COE vs. variations of several parameters
  - Calculation of CO_2 capture and avoidance costs
  - Refinement based on the results of the pilot plants in progress
- WP1.3 - Communication with other SPs and application to other industries

Main Economic Assumptions

Parameter	Default value	Variability
Discounted Cash Flow	8%	4% to 12%
Specific Investment	2763 €/kW for LT 3463 €/kW for ITM	-10 to +50%
Fuel cost	3 €/GJ	±50%
O&M cost	€ 35.9-42.5 million / annum	±50%
Capacity factor	85% after 2 years operation (1 year 40%, second year 60%)	40 to 90%
Efficiency losses	0%	-2 to -5 % points
Construction time	4 years	
Budget allocation	20%, 30%, 30%, 20%	
Power plant lifetime	25 years	
Membrane lifetime	6 years	4-12 years

- The selected cycles operate at base load
- Reference year is 2008
- EPC costs bottom up and scaled up exponentially

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Cost evaluation of the IGCC plant with OTM (ITM)

- Critical components (CC): Membrane modules and auxiliary equipment (AE)
- Cost of components given as a function of flux
- $J_{O2} = f(T, \Delta p, L, d, \dot{m}, \sigma_{amb})$
  - J_{O2}: O2 flux, T: temp, Δp: pressure difference, L: membrane length, d: thickness of the dense layer, $\dot{m}$: sweep gas flow rate, σ_{amb}: Ambipolar conductivity
- $O\&M = f(J_{O2}, LT, O\&M_{AE})$
  - LT Membrane lifetime, O&M: Operating and maintenance costs, $O\&M_{AE}$: O&M of AE
- Three cost calculations:
  - Low: 100% integration, higher flux rates, no cryogenic N_2 requirements
  - Expected: 100% integration, low cryogenic N_2 requirements
  - High: 50% integration, high N_2 requirements (cryogenic N_2 to GT and gasifier)

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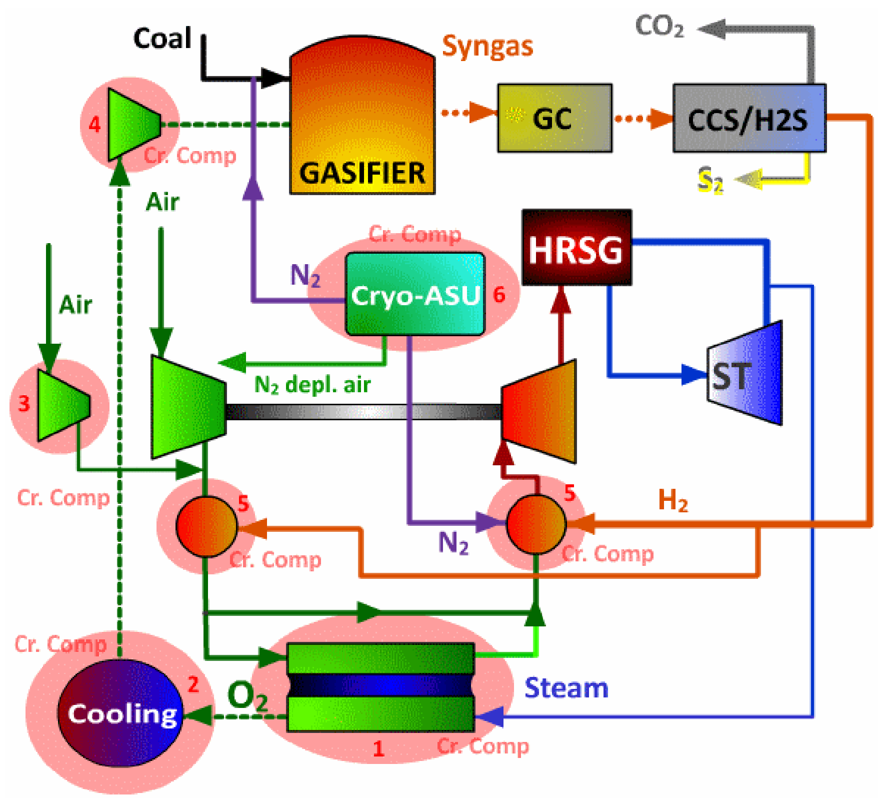
Component costs of the IGCC plant with OTM



Flux →

Specific membrane cost ↓

€/m2	0.5 g/m2.s	1 g/m2.s	2 g/m2.s	3 g/m2.s	4 g/m2.s	6 g/m
500	40	20	10	7	5	[illegible]
1000	80	40	20	13	10	7
1500	120	60	30	20	15	[illegible]
2000	160	80	40	27	20	[illegible]
2500	200	100	50	33	25	[illegible]
3000	240	120	60	40	30	20
3500	280	140	70	47	35	[illegible]
4000	320	160	80	53	40	[illegible]
4500	360	180	90	60	45	30
5000	400	200	100	67	50	[illegible]
5500	440	220	110	73	55	[illegible]
6000	480	240	120	80	60	[illegible]

Membrane cost in M€

€/m2	0.5 g/m2.s	1 g/m2.s	2 g/m2.s	3 g/m2.s	4 g/m2.s	6 g/m2.s
500	7.00	3.50	1.75	1.17	0.87	0.58
1000	14.00	7.00	3.50	2.33	1.75	1.17
1500	21.00	10.50	5.25	3.50	2.62	1.75
2000	28.00	14.00	7.00	4.67	3.50	2.33
2500	35.00	17.50	8.75	5.83	4.37	2.92
3000	42.00	21.00	10.50	7.00	5.25	3.50
3500	49.00	24.50	12.25	8.17	6.12	4.08
4000	55.99	28.00	14.00	9.33	7.00	4.67
4500	62.99	31.50	15.75	10.50	7.87	5.25
5000	69.99	35.00	17.50	11.67	8.75	5.83
5500	76.99	38.50	19.25	12.83	9.62	6.42
6000	83.99	42.00	21.00	14.00	10.50	7.00

Annualised cost of membrane replacement

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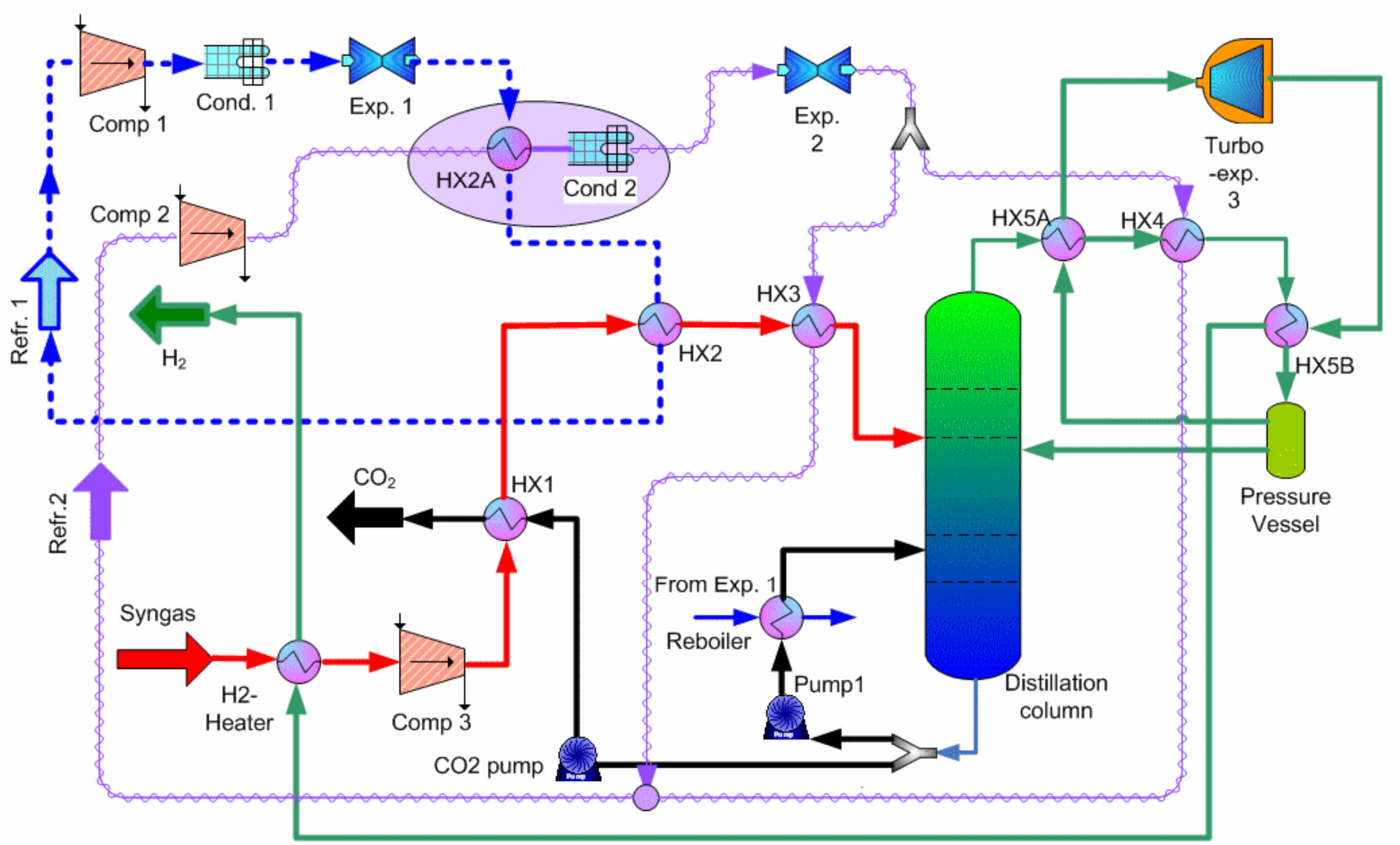
Cost evaluation of the IGCC plant with Low Temp

- Components: Heat exchangers, pumps, compressors, expanders and distillation column
- Cost LT technology $= f(T, p, p_{CO2}, \dot{m}, c)$
  - T: temp, p: syngas pressure, $\dot{m}$: syngas flow rate, c: CO2 recovery rate, p_{CO2}: CO_2 partial p.
- O&M cost: No solvent losses -> Lower variable O&M costs
- Cost calculation in ECLIPSE, ASPEN and models available in the literature
  - Equipment size and type according to the mass and energy balance implemented within ECLIPSE
  - ECLIPSE highest cost (25% higher than ASPEN)
  - Literature lowest values
  - Costs reflecting values for different heat exchanger types

Component costs of IGCC w/ Low Temp.



The process has several heat exchangers

Component costs of IGCC w/ Low Temp.

Module	Type	Feature 1	Unit 1	Feature 2	
HX2	Heat exchanger	126.83	m2	10.5	
P-Comp	Compressor	11230	kW	/	
HX2A	Heat exchanger	888	m2	66	
HX3	Heat exchanger	0.9	m2	66	
E-Comp	Compressor	3570	kW	/	
HX5a	Heat exchanger	983	m2	66	
HX4	Heat exchanger	765	m2	66	
H-EXP	Expander	4000	kW	/	
CO2	Pump	430	m3/hr	/	
HX5b	Heat exchanger	1300	m2	66	
H2-Heater	Heat exchanger	3700	m2	44	
Cool CO2	Heat exchanger	2.1	m2	66	
HX1	Heat exchanger	3002	m2	142	
Cool-PR	Heat exchanger	5800	m2	10	
Reboiler	Heat exchanger	970	m2	66	D
P-EXP	Expander	1000	kW	/	/
E-Exp	Expander	312	kW	/	/
Fan1	Rotary blower	3500	kW	/	/
S-Comp	Centrif-comp	6710	kW	/	
DC	Distillation Column	10X3	m	12	t

	2008 k€	
Module	Cost with ST HX	Cost with PF HX
HX2	500	435
P-Comp	6000	6000
HX2A	1600	1392
HX3	70	60.9
E-Comp	2500	2500
HX5a	1700	1479
HX4	1550	1348.5
H-EXP	4000	4000
CO2	1000	1000
HX5b	2100	1827
H2-Heater	4250	4250
Cool CO2	20	20
HX1	2550	2550
Cool-PR	6500	4500
Reboiler	1200	1200
P-EXP	1150	1150
E-Exp	580	580
Fan1	4550	4550
S-Comp	4300	4300
Distillation Column	5800	5800
Refrigerant tanks	1400	2520
Glycol Unit	600	800
Plant Integration	7623.36	7623.36
Total	**61543**	**59886**

Hence detailed study was made of the costs of heat exchangers

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Cost evaluation of the IGCC plant with MGD

- CO_2 absorption as in the conventional Selexol system
- CO_2 desorption in a membrane contactor array instead of using a flash tank
  - Reduced pumping power for solvent regeneration
  - Non-selective membrane: PVTMS (Poly-vinyltrimethylsilane)
- $Cost = f(T, \Delta p, \dot{m}_s, \dot{m}_g, c, J)$
  - J: CO_2 molar flux through the membrane contactor into the solvent, T: temp, Δp: pressure difference, $\dot{m}_s$: Solvent flow rate, $\dot{m}_g$: gas flow rate
  - Membrane cost: 125 €/m^2 + housing + other auxiliaries
- Membrane area: 175.000 m^2 at a flux rate of 0.55g/m^2.s
  - Lean solvent feed: 5 °C, 37 bar, 1267.6 kg/s solvent + 10.1 kg/s dissolved gases
  - Rich solvent output: 60 °C, 37 bar, 1267.6 kg/s solvent + 100.8 kg/s dissolved gases

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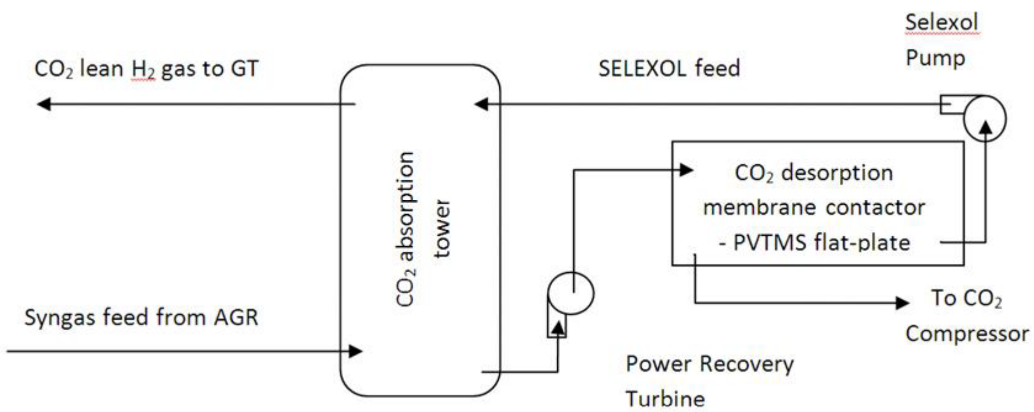
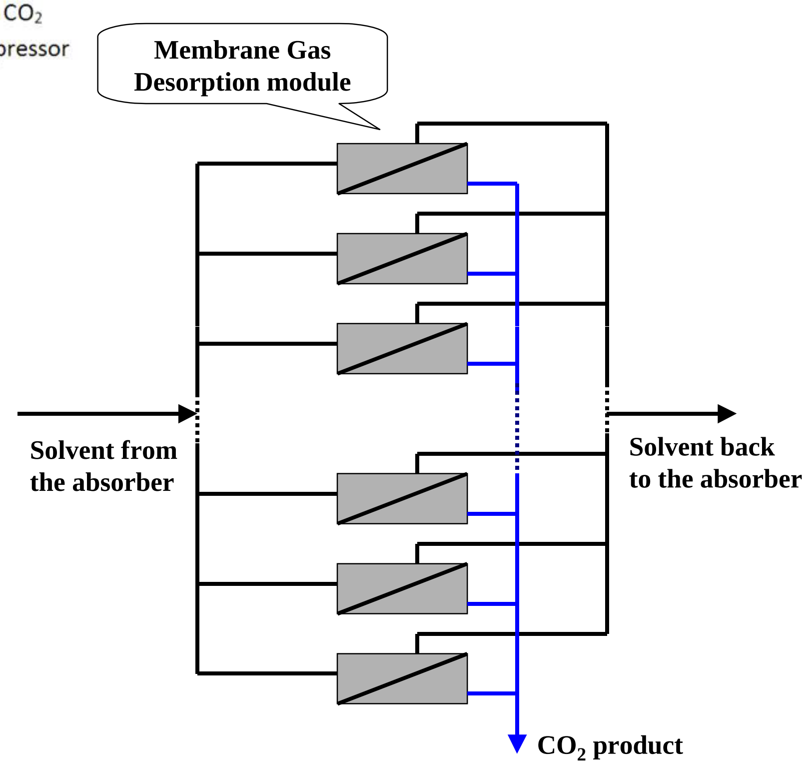
Component costs of IGCC w/ MGD





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Component costs of IGCC w/ MGD

Equipment	Equip. Cost (k€)	Total Direct Cost (k€)
CO_2 Absorption Tower	8849	14159
Power Recovery Turbine for CO_2 Rich Solvent: Not Applicable for MGD		
Solvent Sump Tank	950	1520
MGD Modules	21875	35000
Selexol Pump	172.5	627.1
Refrigeration System	3430	5488
Heat Exchangers	2990	4784
Misc. costs as in EBTF	5259	8415
Total	43527	70000

Summary of costs

Total membrane cost as a function of specific membrane cost and flux

Cost €/m2	Flux 0.25	Flux 0.5	Flux 0.75	Flux 1	Flux 1.5	Flux 2
50	19.20	9.60	6.40	4.80	3.20	2.40
75	28.80	14.40	9.60	7.20	4.80	3.60
100	38.40	19.20	12.80	9.60	6.40	4.80
125	48.00	24.00	16.00	12.00	8.00	6.00
150	57.60	28.80	19.20	14.40	9.60	7.20
175	67.20	33.60	22.40	16.80	11.20	8.40
200	76.80	38.40	25.60	19.20	12.80	9.60
225	86.40	43.20	28.80	21.60	14.40	10.80
250	96.00	48.00	32.00	24.00	16.00	12.00
275	105.60	52.80	35.20	26.40	17.60	13.20
300	115.20	57.60	38.40	28.80	19.20	14.40

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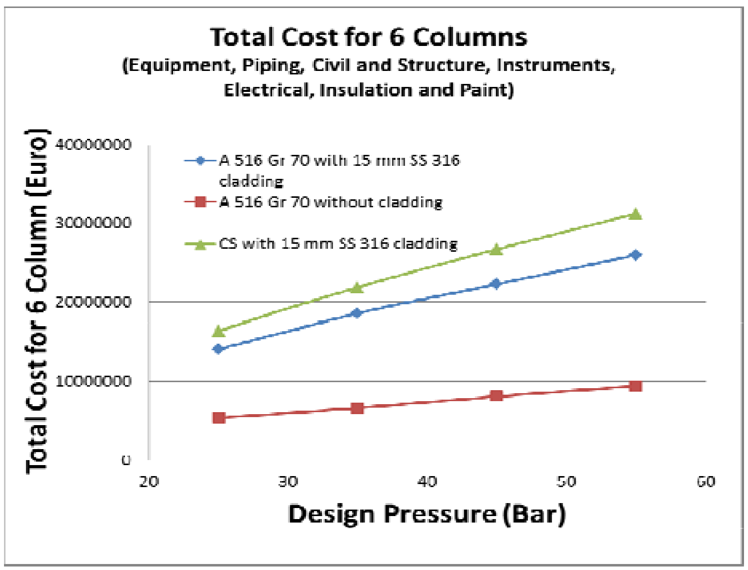
Cost evaluation of the IGCC plant with PSA

- *Cost = f(Y, t, p_d, p_{CO2}, m, c, x)*
  - Y: adsorption isotherm of CO_2 (Nm^3/kg), t: residence time, p_d: design pressure, p_{CO2} : CO_2 output p. m: gas flow rate, c: capture rate, x: cost of sorbent
  - The above parameters determine the number of vessels, vessel size, materials, valves and piping
  - Cost calculation with carbon steel and carbon steel with different claddings (Carbon steel adequate according to Nelson Curve)
  - Activated carbon as sorbent
- Operating cost
  - Sorbent warm-up, moisture removal, reactivation costs

Component costs of IGCC w/ PSA

Total Direct Costs

Equipment		Specification	Quantity	Investment (M€)
Adsorption Column (Carbon Steel)		10 m Tall x 6 m Diameter	6	10.8
Total direct cost (TDC) of Adsorption Columns installed			6	**19.5**
Activated Carbon		282.6 m^3 / bed, @ 1 €/ kg	848 tonnes	0.900
TDC of Adsorption materials				**1.44**
Automatic Valves	Operating	Fire Safe, 300#	80	2.1
	Redundant		30	
Manual Valves,	Instrument isolation, gas venting, flame arrestors, drain lines, fire Safe, 300#		150	1.35
TDC of Valve and other instruments (200 % of valve cost)				**6.9**
TDC of Miscellaneous Equipment				**5.25**
TDC of PSA plant				**33.09**



Annual Operating Costs

Parameter	Value
Cost of Adsorbent (AC) warm-up	0.2 € / kg
Feed / Total duration of a cycle	6 / 20 minute
Number of cycles in a day (4 modules)	240 cycles
Adsorbent (AC) Quantity (20 % in excess for periodic replenishment)	1005 tonnes
Period of moisture removal from Adsorbent	1500 cycles
Annual cost of moisture removal	**1.8 M€**
Period of Reactivation of Activated Carbon	10 years
Cost of reactivation	0.6 € / kg
Annual cost of reactivation	**0.06 M€**
Miscellaneous	1.6 M€
Total Annual OPEX	**3.46 M €**

Main Techno-economic results

		DECARBit				EBTF	
Parameter	Unit	PSA	MGD	LT	ITM	with CCS	w/o CCS
Net electricity output	MW	370.9	379.1	396.5	365.1	352.7	391.5
Efficiency	%	36.6%	39.0%	40.2%	37.7%	36.7%	46.9%
CO_2 emitted	kg/MWh	136.6	118.8	208.9	90.1	88.9	757.6
CO_2 Captured	kg/MWh	838.0	795.7	678.5	897.0	864.5	0.0
Total plant cost	M€	1147	1187	1096	1264	1134	926
Specific investment	€/kWe net	3095	3129	2763	3463	3213	2371
Annual fuel costs	M€/yr	82.8	78.7	80.0	78.5	78.9	66.6
Fixed O&M costs	M€/yr	27.6	27.5	28.0	26.7	25.6	22.1
Variable O&M costs	M€/yr	11.1	14.7	7.9	15.8	8.57	5.8
BESP	€/MWh	85.7	85.1	77.8	90.6	86.0	64.6
Cost of CO_2 avoided	€/tonne	35.3	33.2	25.1	40.4	32.3	NA
Cost of CO_2 captured	€/tonne	25.1	25.7	19.5	29.0	23.9	NA
Capture rate	%	86.0%	87.0%	76.5%	91.0%	91.0%	NA

Contingency: 15% (higher values recommended for novel cycles)
BESP= Breakeven electricity selling price (equivalent to COE)
SI includes construction costs

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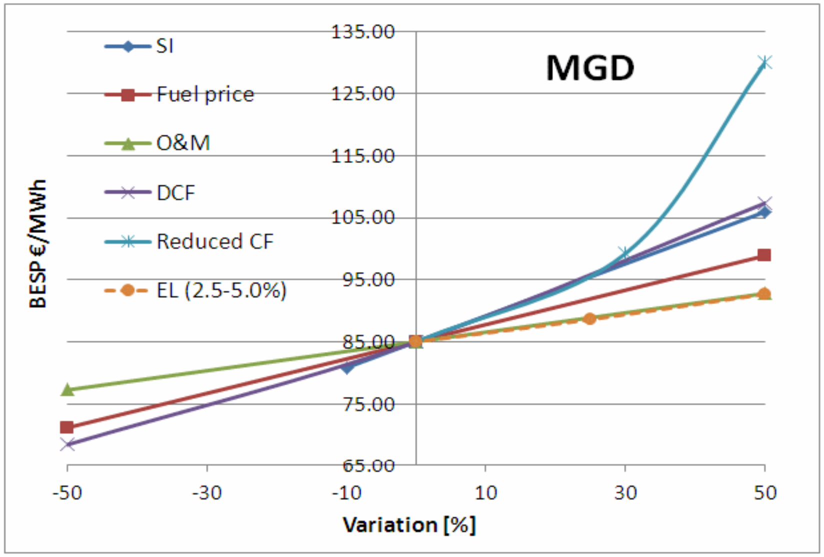
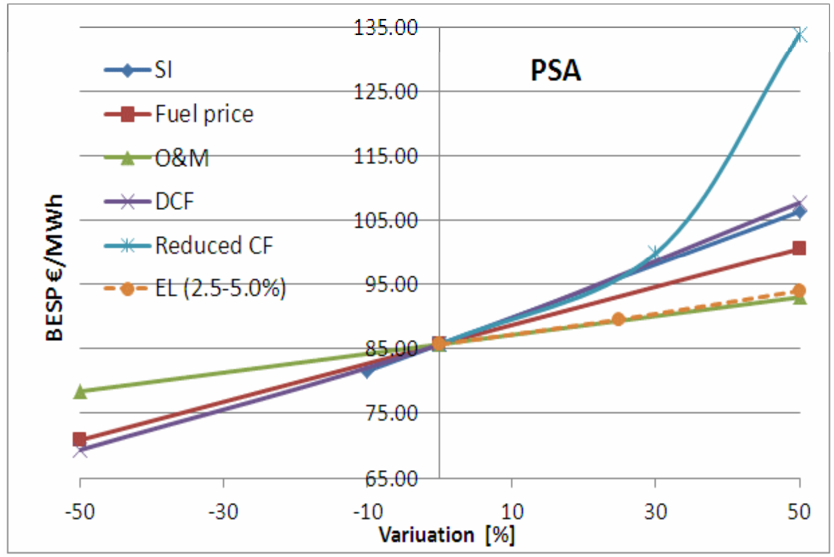
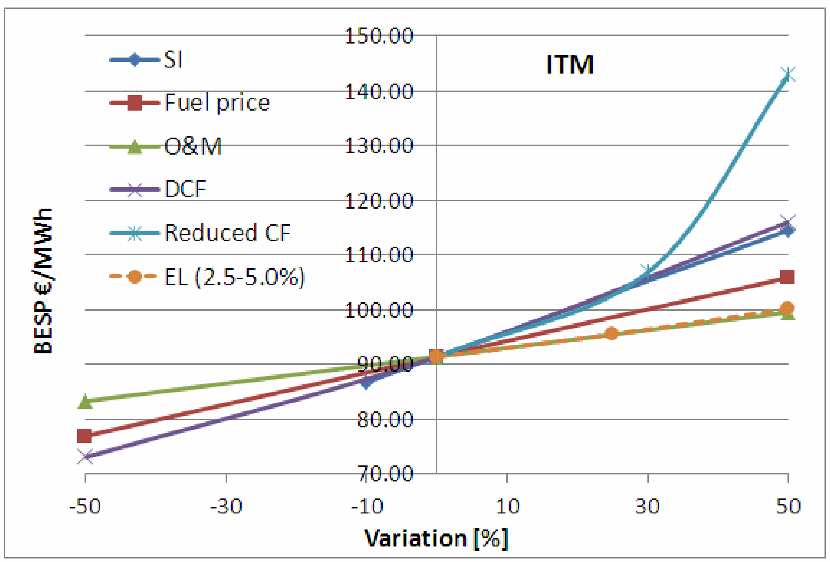
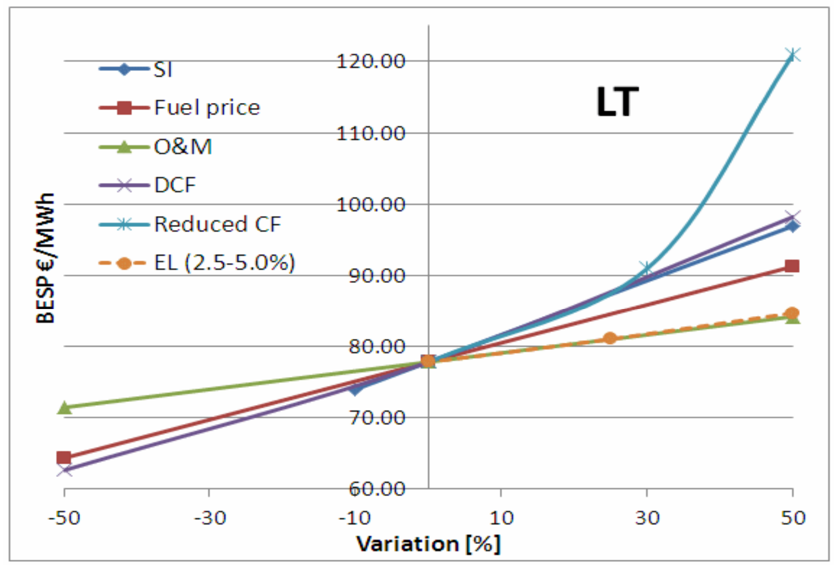
Sensitivity Analysis - COE





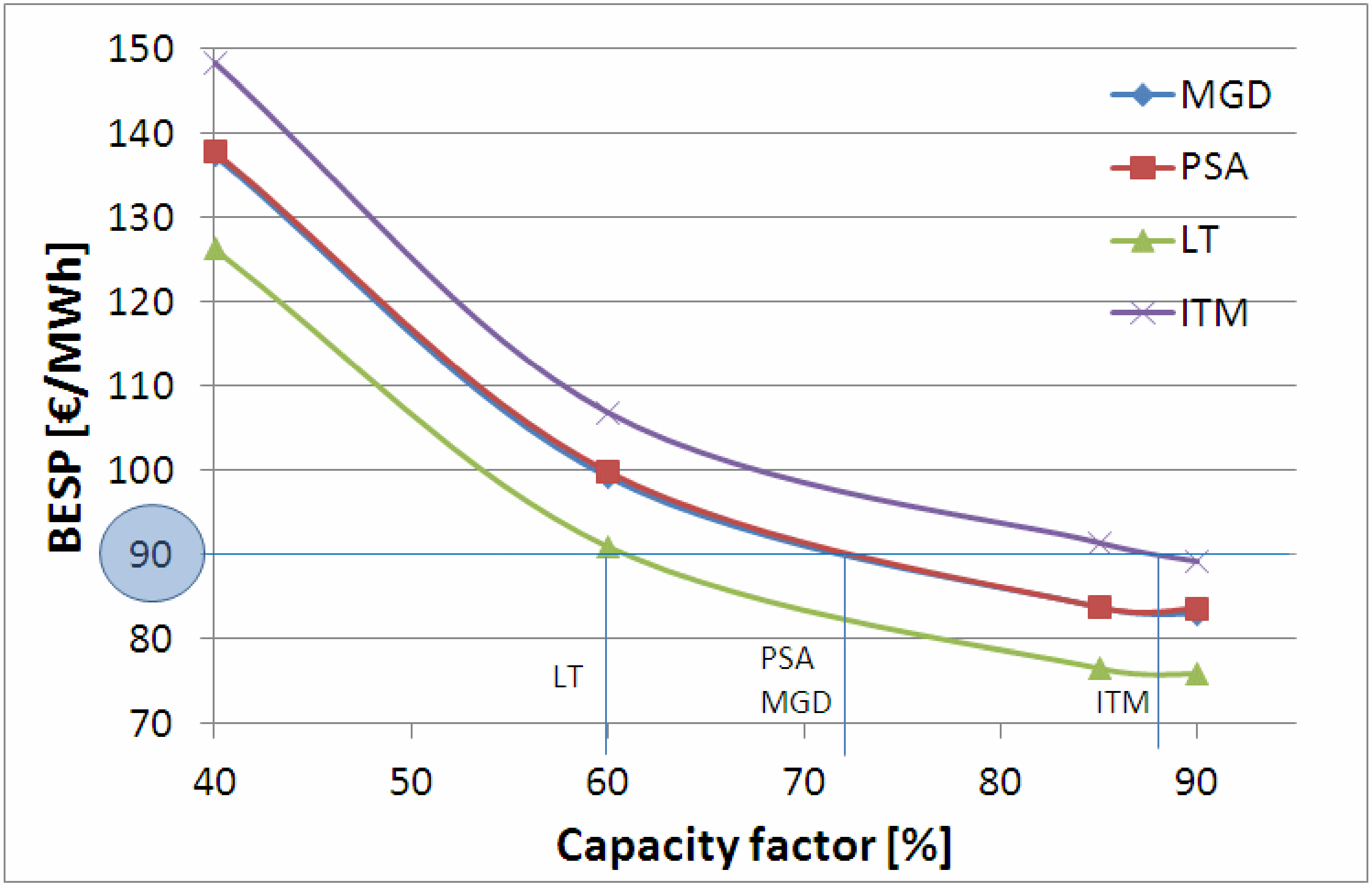




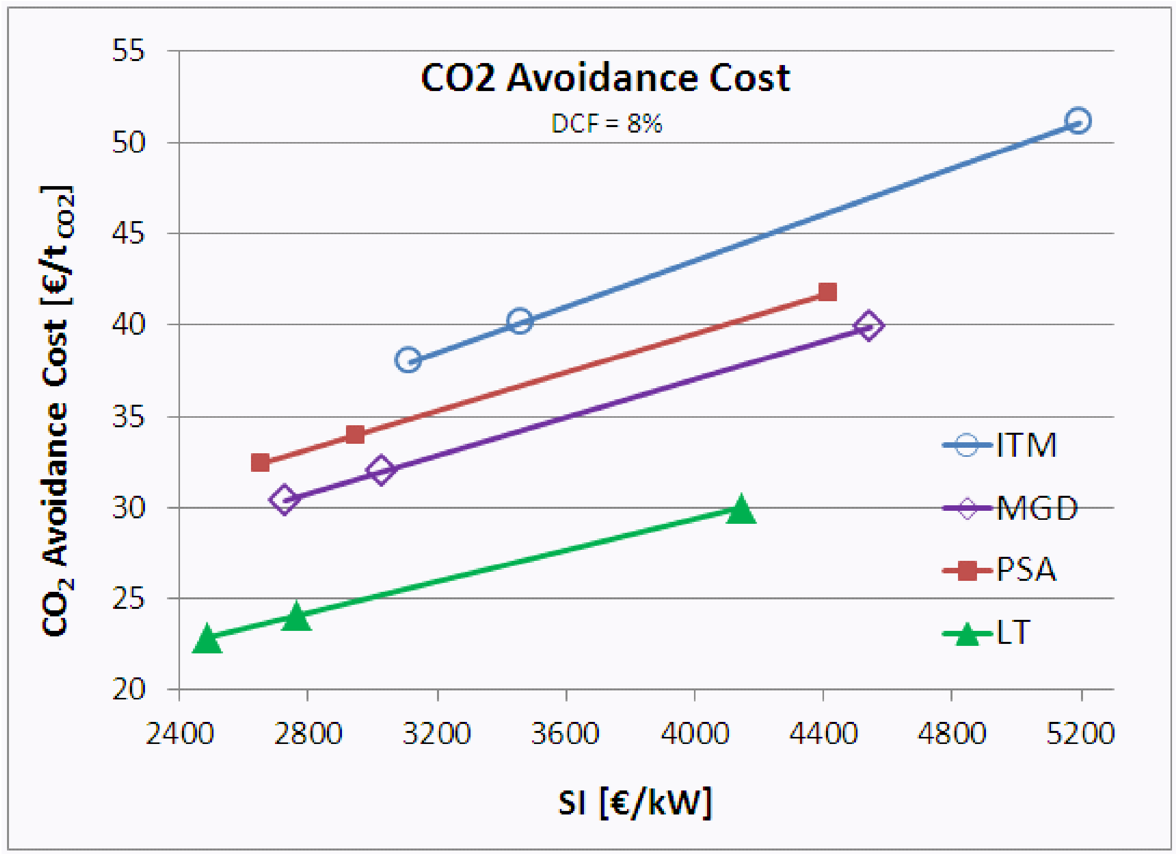
EL: Possible efficiency losses 2.5 and 5 % points

Capacity factor

Comparing technologies



Sensitivity analysis - CO_2 Av. Costs



Conclusions

- Low temperature technology best result but already well optimised within DECARBit
- There is still room for improvement with regard to OTM (ITM) integrated IGCC technology
  - Improved power plant configuration and OTM integration
  - Higher flux rates (Membrane development)
  - Higher operating pressures
- MGD: higher flux rates from the pilot plant
- PSA: lowest capital investment, with the challenges:
  - to improve efficiency (high power consumption)
  - to increase capture rate

Thank you !

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Capture Plant Cost Variations

		Overall Cost (TDC) in M€ (Equipment Cost + Install. Cost)			
		PSA	MGD	LT	ITM
Cost Sensitivity of CO_2 Capture Plant	Low	25.0	49.0	42.0	38.85
	Medium	33.1	70.0	60.0	59.58
	High	46.0	119.0	78.0	101.70
Total direct IGCC plant cost without CCS		687.1	674.3	651.2	720.0
Total direct IGCC plant cost with CCS	Low	712.0	723.3	693.2	758.85
	Medium	720.7	744.3	711.1	779.58
	High	733.0	793.3	729.2	821.70

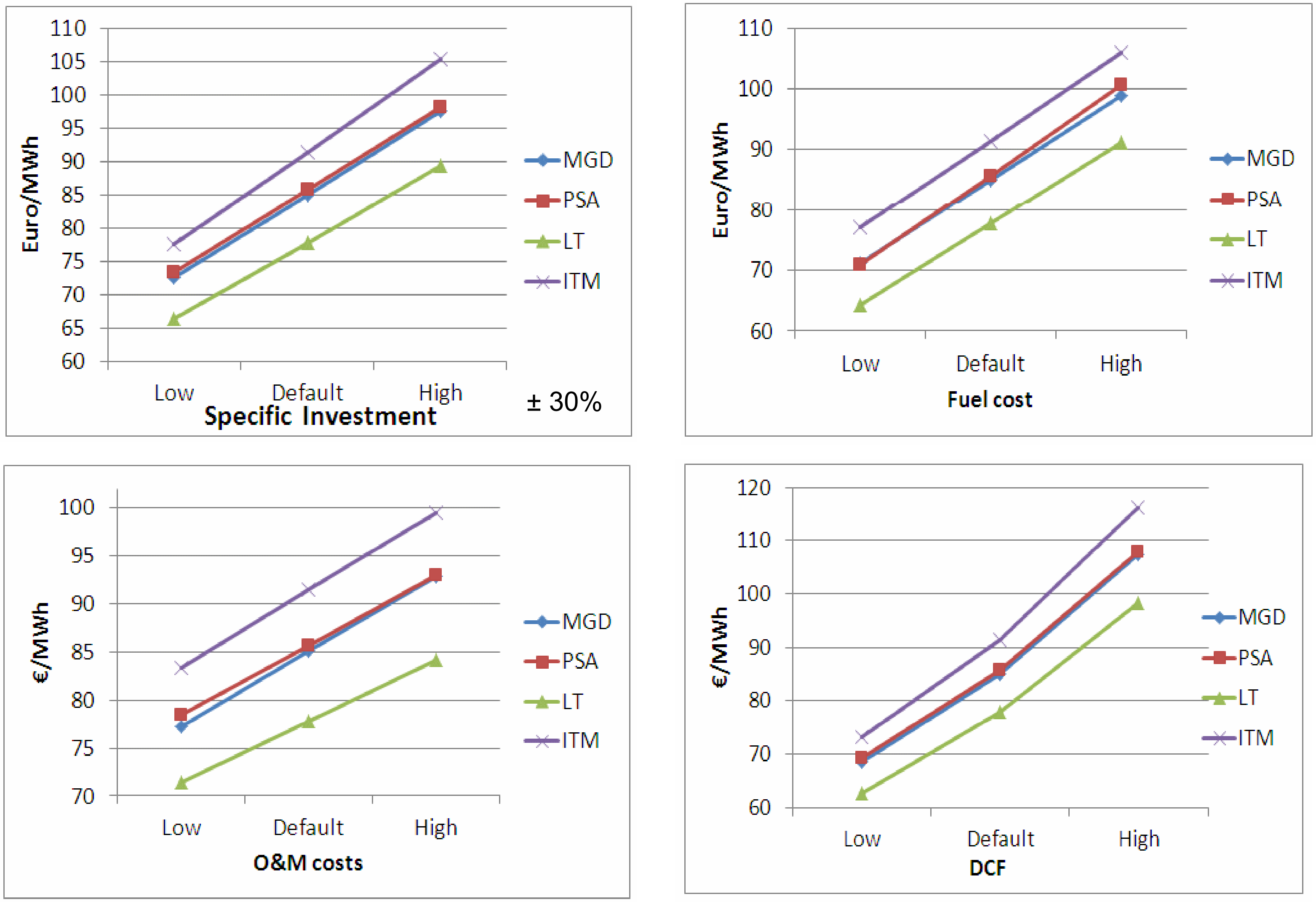
Total direct costs: Excluding contingencies, construction and indirect costs

OTM plant cost variations

		Low cost	Expected Cost	High Cost
1	Air compressor	0.0	0.0	18.0
2	O_2 Compressor	9.0	11.0	14.0
3	Burner modification	0.8	1.0	1.2
4	Heat exchangers	1.8	2.0	2.4
5	Membrane module	27.0	40.0	49.0
6	Cryo. N_2 plant	9.0	19.0	40.0
	Total cost	47.6	73.0	124.6

- At fixed techno-economic assumptions
- Cost variation according to plant configurations
  - OTM high variation depending on plant configurations: integration, membrane costs and cryogenic N_2 plant configuration options

Sensitivity analysis - COE



Acronyms

- LT: Low temperature technology
- MGD: Membrane Gas Desorption (using membrane Contactors)
- PSA: Pressure Swing adsorption
- OTM: Oxygen/Ion Transport Membrane (or ITM)
- SI: Specific Investment
- O&M: Operating and maintenance cost
- EL: Efficiency loss in 2.5 and 5 %-point
- CF: Capacity factor
- BESP: Breakeven Electricity Selling Price (=COE)
- EBTF: European Benchmarking Taskforce

Evaluating Economics of Emerging Processes

Abhoyjit S. Bhown

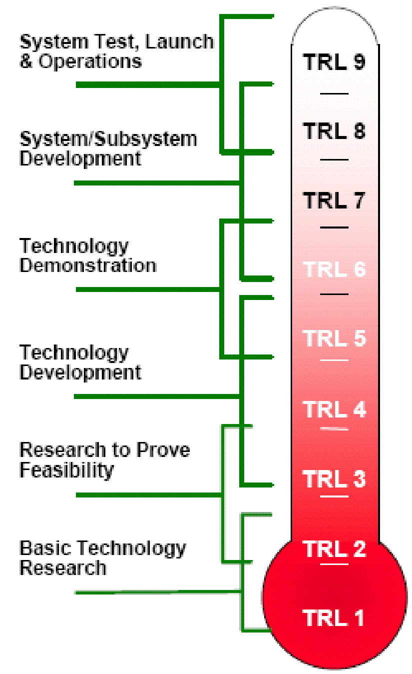
CCS Cost Workshop

Palo Alto, CA

April 25-26, 2012

Technical Readiness Level (TRL)

Technology Readiness Level (TRL)		
Demonstration	9	Normal commercial service
	8	Commercial demonstration, full-scale deployment in final form
	7	Sub-scale demonstration, fully functional prototype
Development	6	Fully integrated pilot tested in a relevant environment
	5	Sub-system validation in a relevant environment
	4	System validation in a laboratory environment
Research	3	Proof-of-concept tests, component level
	2	Formulation of the application
	1	Basic principals observed, initial concept

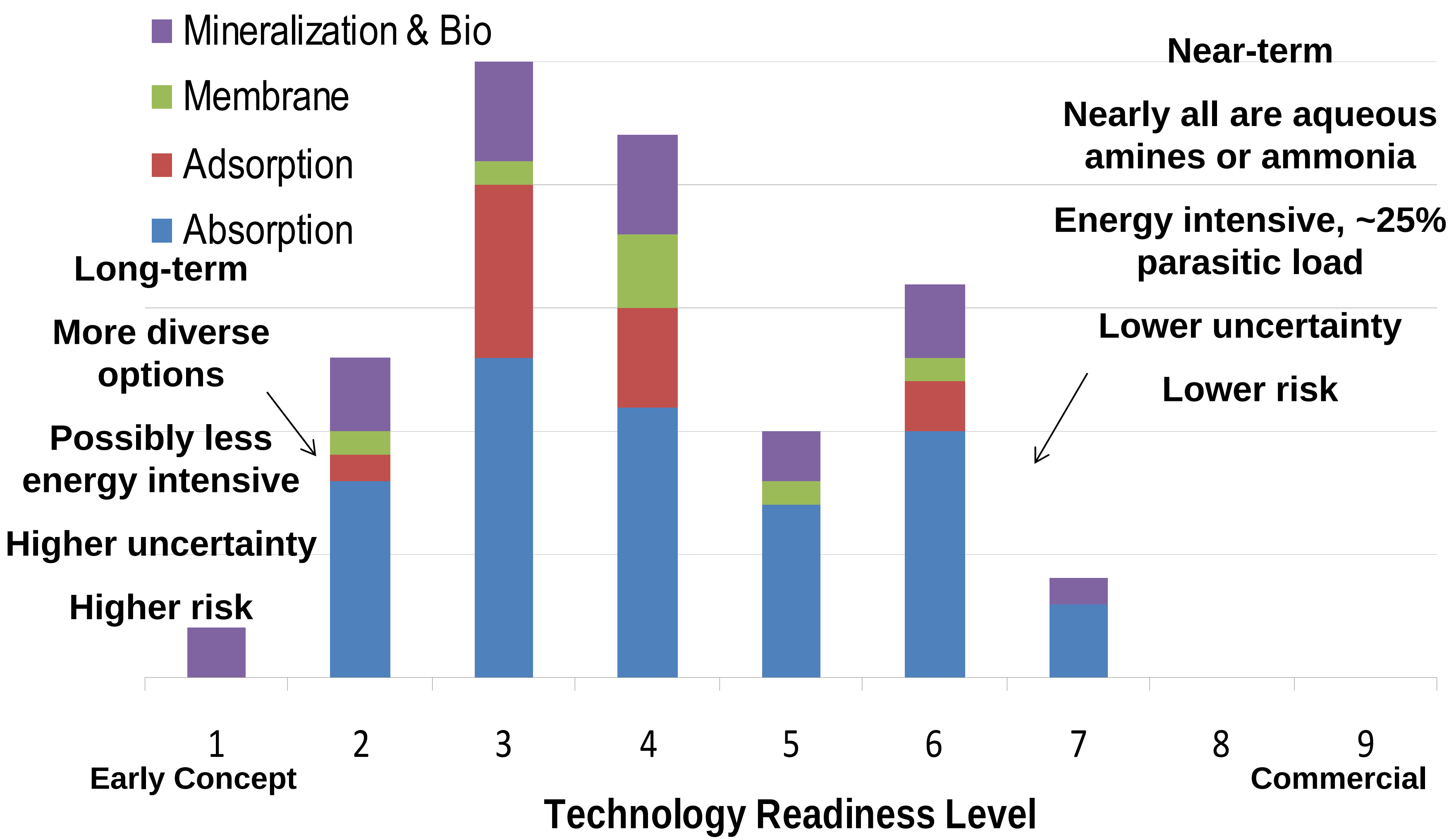


Source: NASA

TRL is NOT based on economic viability!

EPRI ELECTRIC POWER RESEARCH INSTITUTE

TRL of Post-Combustion Capture R&D



ELECTRIC POWER RESEARCH INSTITUTE

Cost Issues

- Even for "Near-Term" MEA, reports vary considerably
  - Energy consumption varies, <3.0 to >6.0 GJ/tonne CO_2
  - Costs varies, ~$60 to >$100/tonne CO_2
- Cost impacted by technical assumptions in process in addition to financial assumptions.
- Early-stage technologies tend to have high technical uncertainty, lots of unknowns, and unbounded optimism of inventor. This leads to significant variance in cost estimates.
- What can we do?

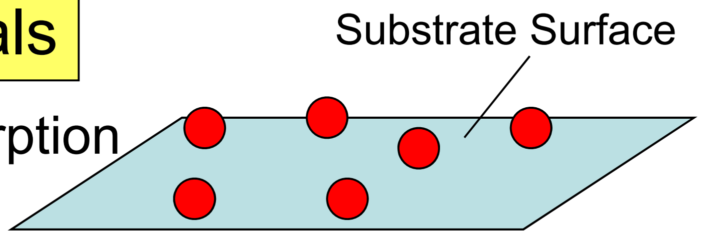
How Early Stage (TRL 1-3) Developers Are Working Today

- DOE drives significant early-stage research, and performance targets are represented as max COE increase
- Costs for near-term technologies (TRL 5-7) are dominated by energy consumption, and new technologies (TRL 1-4) almost exclusively first focus on energy consumption
- Energy consumption (of major unit operations) is relatively straightforward to analyze since it involves thermo
- Cost analysis is not straightforward, nor consistent, nor well-defined
- Hence, much early-stage work today focuses on energy consumption

An Example: Adsorption Processes

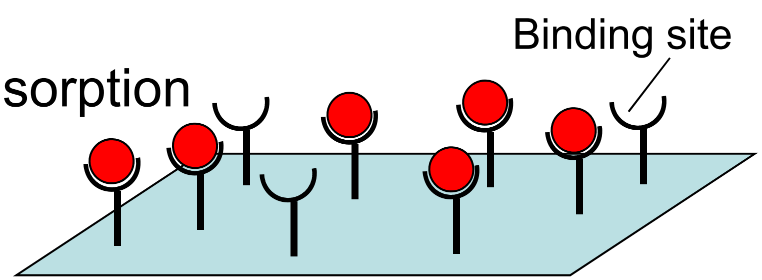
Materials

Physisorption



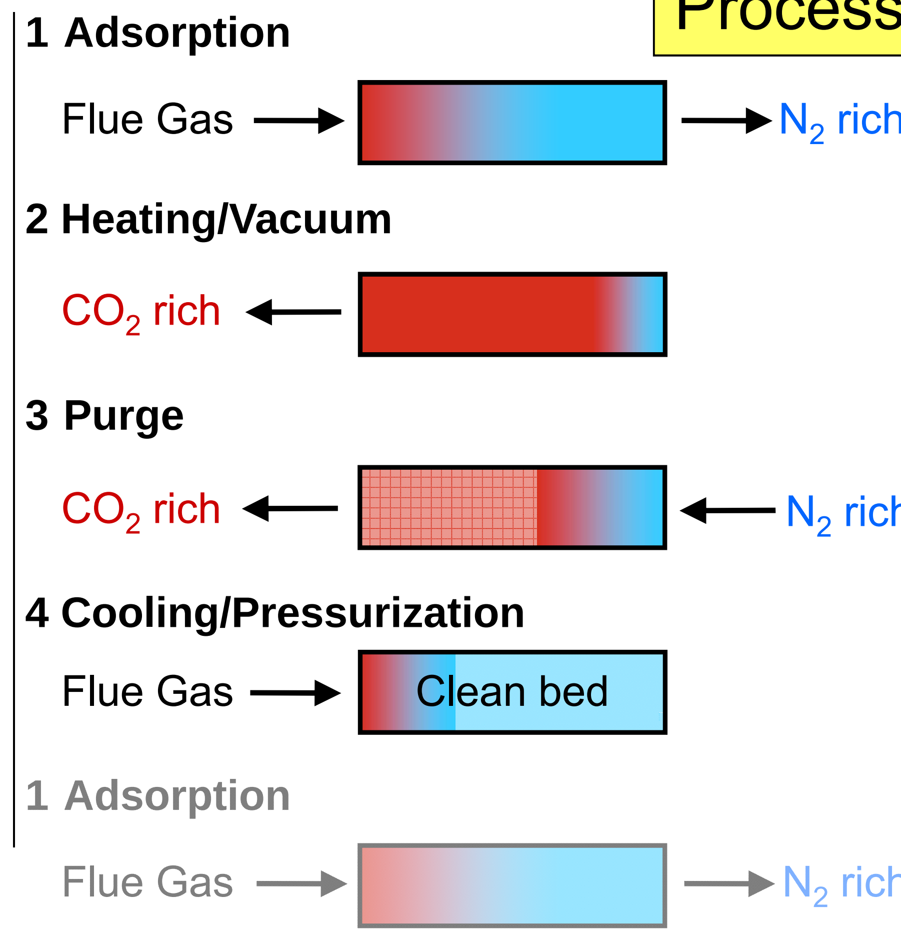
- Adsorption directly onto substrate
- Hard to adsorb/Easy to desorb (low ΔH)
- Thermally stable, low capacity, low selectivity

Chemisorption



- Adsorption onto binding sites
- Easy to adsorb/Hard to desorb (high ΔH)
- Less Stable, high capacity, high selectivity
- Binding sites can be poisoned

Process



A Simple Analysis…

- Assume mass and thermal equilibrium in bed, i.e., neglect all mass and heat transfer resistance
- Energy consumption depends only on final pressures and temperatures
  - Sensible heat: heats and cools bed. Provides driving force to produce CO_2
  - Desorption heat: desorbs CO_2 (equal to heat of adsorption, ΔH). Actually produces the CO_2

$$Q = \left(\underbrace{C_p \rho_{sorbent} \Delta T}_{\text{Sensible heat requirement}} + \underbrace{\Delta h_{CO2} \Delta q_{CO2} + \Delta h_{N2} \Delta q_{N2}}_{\text{Desorption heat requirement}} \right) \Big/ CO_{2\,\mathrm{Pr}\,oduced}$$

…Applied to a Power Plant

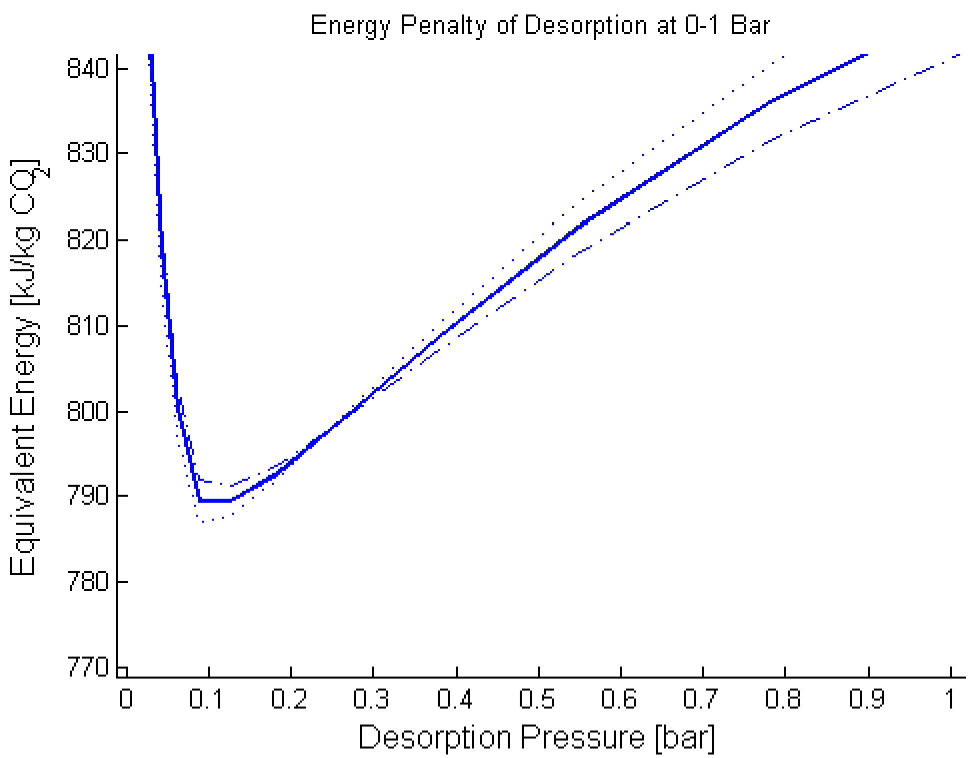
- We look at the equivalent energy as a measure of parasitic load*

$$W_{eq} = \left(0.75Q \cdot \eta_{carnot} + W_{comp}\right)$$

- Minimum heat requirement is not necessarily minimum parasitic load or minimum COE increase (not every BTU is created equal)

*From Gary Rochelle's group, UT Austin

Some Results



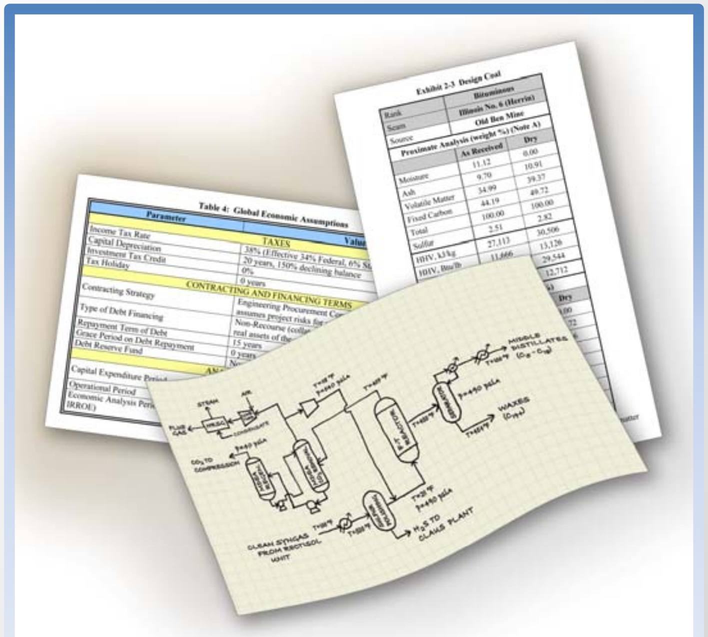
- For some class of sorbents, we see ~5% reduction in energy consumption by operating under 0.1 bar
- Is vacuum worth it? Should chemists be designing materials suitable for vacuum?

What Would Help Early-Stage Technology Developers (TRL 1-3)

- Very low cost (free?), open, reference plant(s)
- Very low cost (free?), open, easy-to-use, specific, costing routine(s) – even if error bars are large
- Reporting of key performance and cost metrics on same basis – even if error bars are large
- Does run the risk of results that don't mean much, except perhaps for relative comparisions
- TRL 4-7 and TRL8-9 need more sophisticated, detailed approaches.

Together…Shaping the Future of Electricity

ELECTRIC POWER RESEARCH INSTITUTE



Evaluating Economics of Emerging Carbon Capture Processes

CCS Cost Workshop
April 25-26, 2012

John Wimer
Director, Office of Program Planning & Analysis

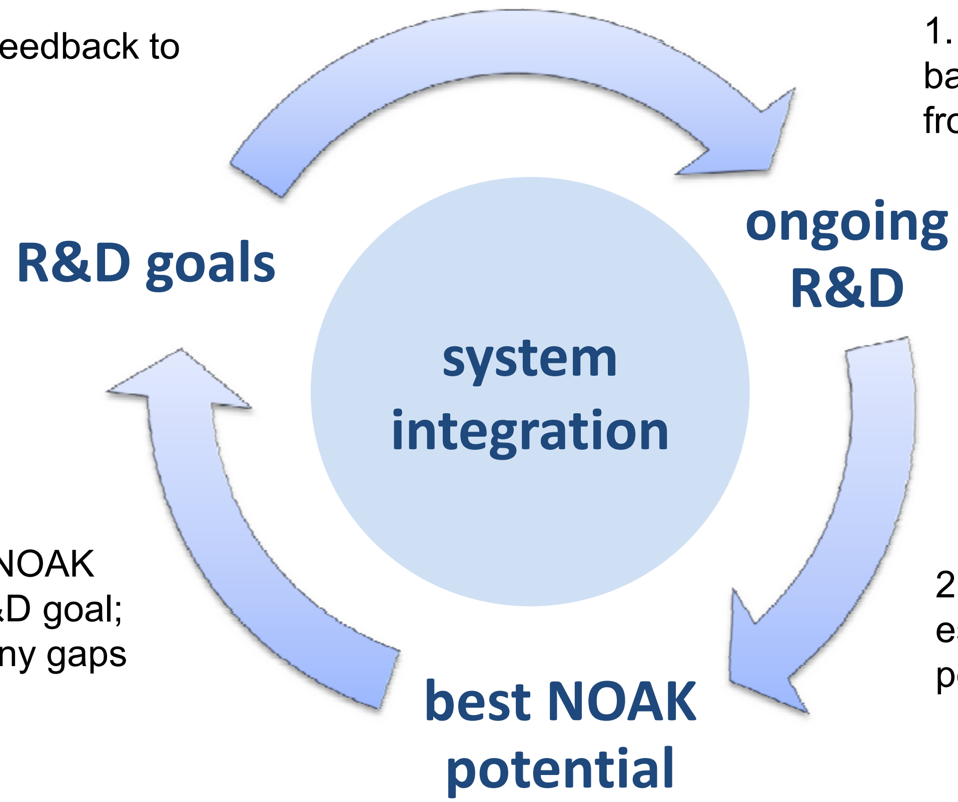
Presentation Outline

- Purpose and Scope of NETL's Evaluations of Emerging Carbon Capture Technologies
- Examples of NETL Studies
- Keys to Estimating Costs for Emerging Capture Technologies
- Challenges
- Call for Papers – 2012 AIChE Annual Meeting

Evaluating the Performance of Emerging Technologies

4. Provide feedback to researchers

1. Assess technology based on current data from ongoing R&D



2. Based on initial assessment, estimate best possible NOAK performance potential

3. Compare best NOAK performance to R&D goal; determine if/how any gaps can be closed

Emerging Carbon Capture Processes
Purpose of NETL Evaluations

Guide and evaluate DOE's Carbon Capture R&D Program

- Compare best potential of emerging technology with R&D goals and competing technologies, including current state-of-the-art
  - Metrics: emissions, COE (capex, O&M, IRR), efficiency
  - Screening studies provide initial check of potential to meet R&D goals
  - Aids in setting technically supportable R&D goals
  - Baseline studies establish current SOA performance

- Identify integration and performance requirements
  - Technology pathway studies examine integrated performance of multiple emerging technologies and compare alternative pathways

- Forecast the potential national benefits of successful R&D under various market and regulatory scenarios
  - Metrics: environmental (e.g., emissions reductions), economic (e.g., cost savings, employment), energy security (e.g., import displacement)

Emerging Carbon Capture Processes
Scope of NETL Evaluations

- Primary focus is on coal conversion, although many technologies also apply to natural gas and industrial processes
  - Pre-, post- and oxy-combustion
  - Gasification and combustion pathways
  - Electric power and coproduction (fuels, chemicals)
  - Electric utility and industrial applications

- CO_2 fate: primarily direct geologic storage, but utilization also considered (e.g. EOR, materials)

- Large and diverse R&D portfolio
  - ~ 70 capture technology concepts
  - Maturity ranges from laboratory tests to commercial demos
  - Multiple applications and operating conditions

Candidate Emerging CO_2 Capture Technologies

Pre-Combustion

Laboratory/Bench Scale
< 0.5 MWe

- 3 Solvent
- 4 Solid Sorbents
- 9 Membranes

Demonstrations

- Southern
- Summit
- HECA

Post-Combustion

Laboratory/Bench Scale
< 0.5 MWe

- 17 Solvents
- 12 Solid Sorbents
- 11 Membranes

Pilot Scale
0.5 – 25 MWe

- 4 Solvents
- 1 Sorbent
- 1 Membrane

Demonstrations

- NRG Energy

Oxy-combustion (PC oxy-combustion, pressurized oxy-combustion, chemical looping)

Laboratory/Bench Scale
< 0.5 MWe

- 3 concepts

Pilot Scale
0.5 – 5 MWe

- 4 concepts

Demonstrations

- Future-Gen 2.0

Industrial

Demonstrations

- ADM
- Air Products
- Leucadia

National Carbon Capture Center

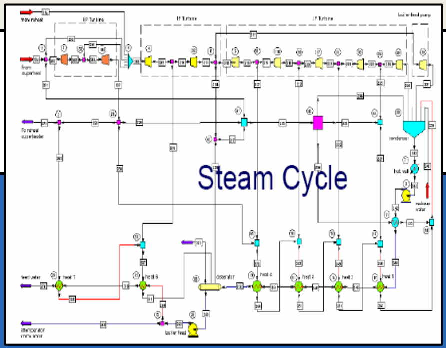
Pilot Scale

- PC: 1 Mwe Slipstream
- IGCC: 0.5 Mwe Slipstream

Process & Cost Engineering

1. Process Simulation (Aspen Plus®, Thermoflow)

- All major chemical processes and equipment are simulated
- Detailed mass and energy balances
- Performance calculations (products, efficiency, emissions)



2. Cost Estimation

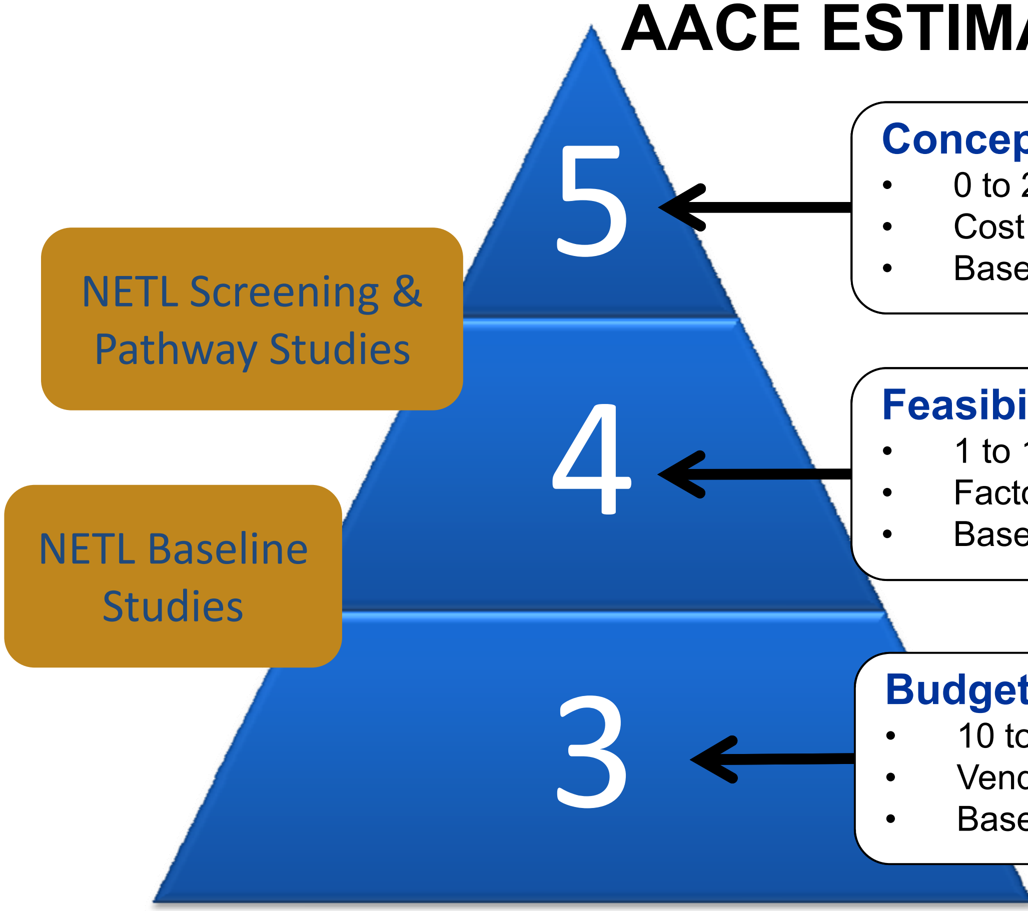
- Capital and O&M costs
- Based on inputs from process simulation
- Vendor quotes, EPC database, published data/correlations, commercial software, DOE RD&D projects, internal estimates, R&D targets

3. Discounted Cash Flow Analysis

- Current dollar analysis using NETL's Power Systems Financial Model
- Project finance structure
- Capital expenditure and operational schedule
- Taxes and depreciation
- Inflation and escalation rates

Classes of NETL Cost Estimates

AACE ESTIMATE CLASS



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

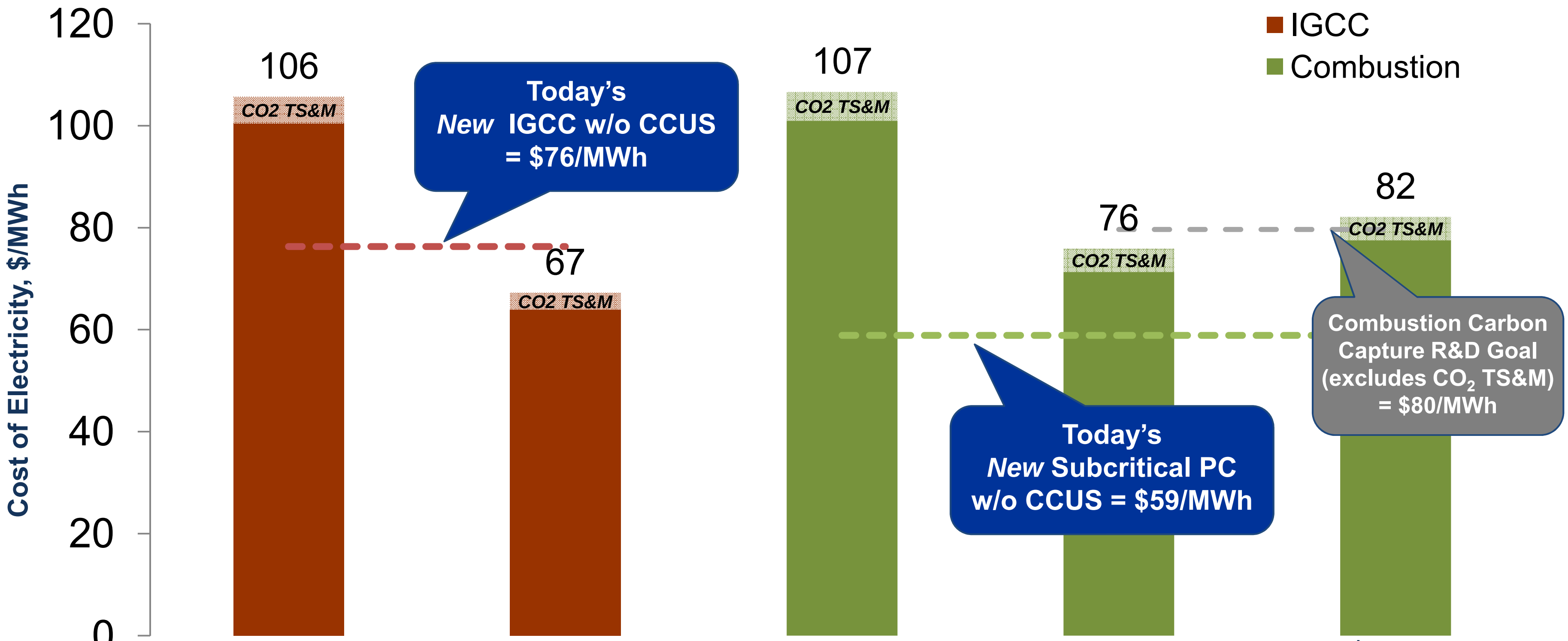
Feasibility Study (-15% / +50% Accuracy)
- 1 to 15% project definition
- Factored equipment costs
- Based on preliminary mass and energy balances

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

Process flow diagrams (PFDs) and piping and instrument diagrams (P&IDs) are the primary documents that define project scope. Association for the Advancement of Cost Engineering International (AACE) Recommended Practice No. 18R-97 describes the AACE cost estimate classification system.

New Plants

R&D Goals for 2nd Generation CCUS Systems



IGCC w/CCUS R&D Progress to Date
- Adv. F turbine
- 80% Availability

2nd Gen IGCC w/CCUS
- Coal pump
- WGCU
- H_2 membrane
- ITM
- Adv H_2 turbine (>2600 F TIT)
- 85% Availability

Today's Supercritical PC w/CCUS
- Air-fired
- 3500 psig/ 1100F/1100F
- Wet FGD
- Amine absorber for CO_2 separation
- 85% Availability

2nd Gen Advanced Oxy-Combustion PC w/CCUS
- Oxy-fired combustion
- Boiler-integrated ITM
- Adv. USC steam cycle (4000 psig/1350F/1400 F)
- Compact oxyfuel-specific boiler
- SO_x co-sequestration
- 85% Availability

2nd Gen Advanced Post-Combustion PC w/CCUS
- Advanced solvents, sorbents or membranes
- Adv. USC steam cycle (5000 psig/1350F/1400 F)
- Advanced CO_2 compression
- 85% Availability

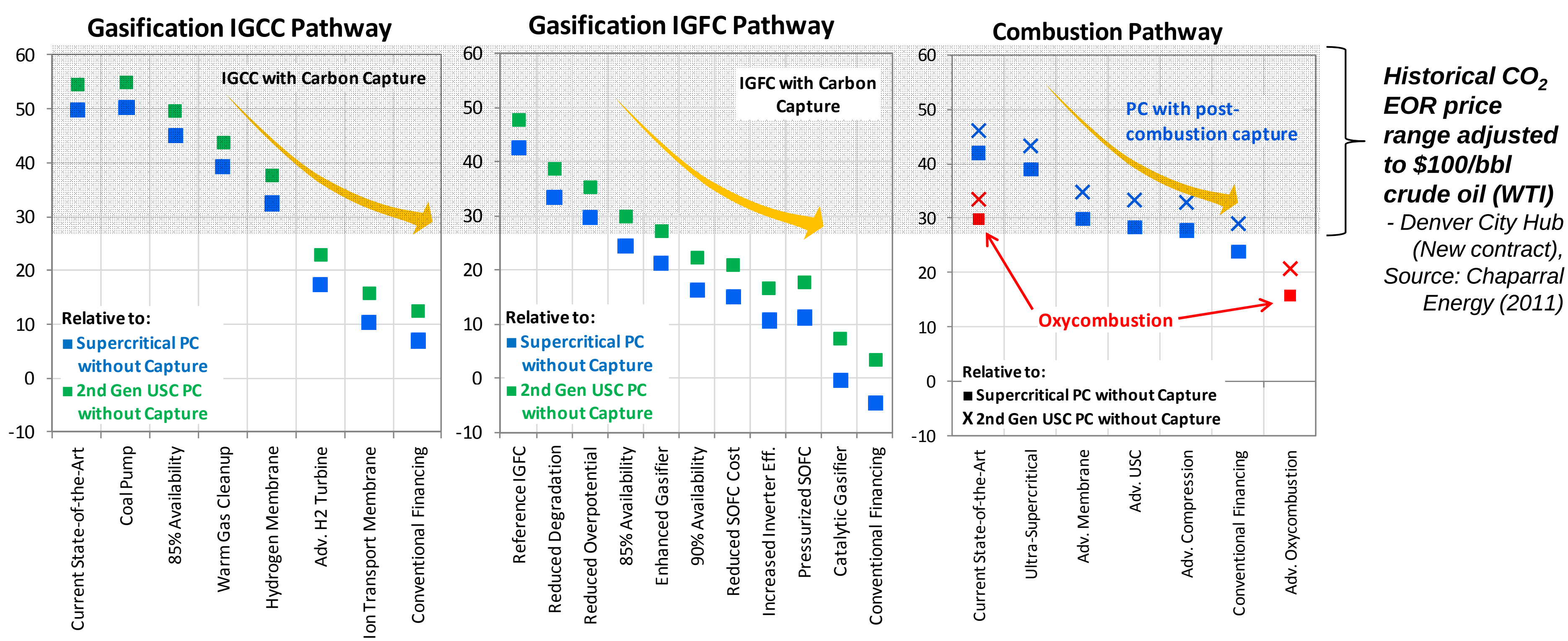
Key Assumptions:
- June 2007 dollars (equivalent to January 2010 dollars per Chemical Engineering Plant Cost Index)
- $1.64/MMBtu coal price
- Representative CO_2 storage costs in a favorable saline aquifer

TS&M = Transport, Storage & Monitoring   TIT = turbine inlet temperature   WGCU = warm gas cleanup   ITM = ion transport membrane   USC = Ultra supercritical   FGD = Flu Gas Desulfurization

Fossil Energy R&D Program

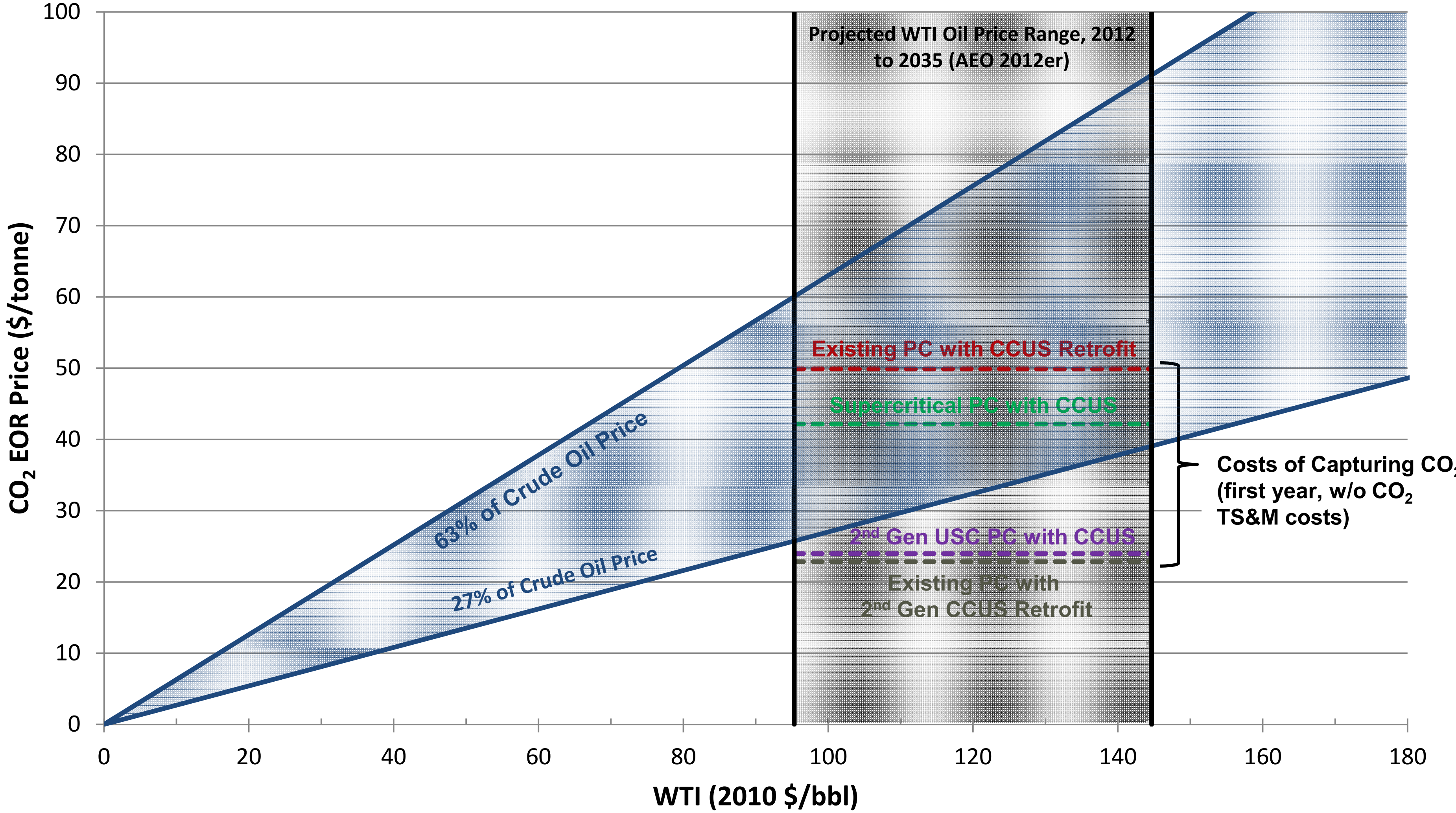
Driving Down the Cost of Capturing CO_2 for Coal Power Plants

Capture costs (\$/tonne of CO_2) are for CO_2 compressed to 2,200 psig at the plant gate. They exclude costs for transport, storage and monitoring of CO_2.



Integrated Gasification Combined Cycle (IGCC), Integrated Gasification Fuel Cell (IGFC), Pulverized Coal (PC)

Future Oil Prices May Support CO_2 Prices for EOR that are Equal to or Above CO_2 Capture Costs

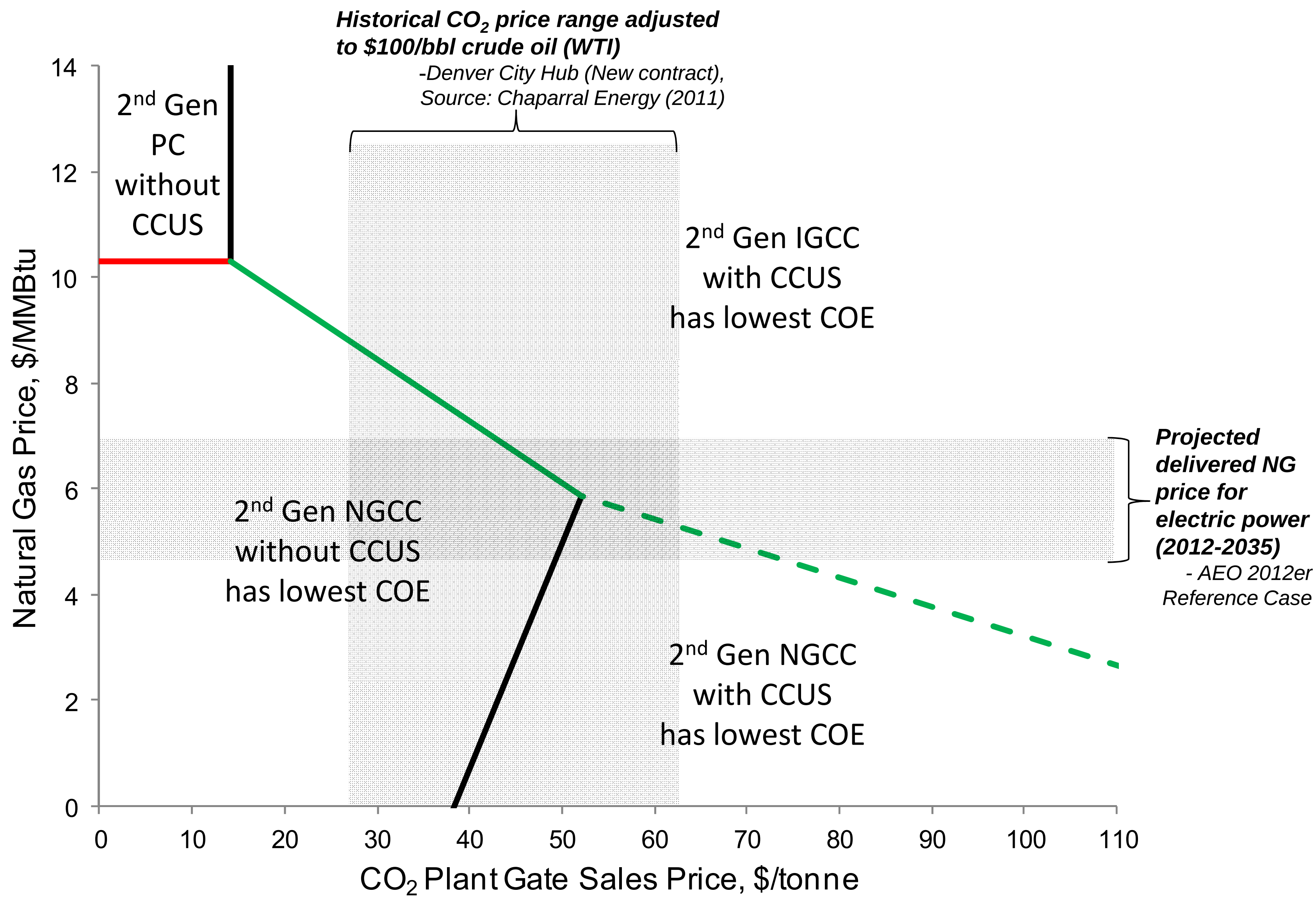


From 2008 to 2011, the market price of CO_2 (expressed in $/MCF) for EOR, quoted at the Denver City, TX "hub", varied between 1.4% and 3.3% of the WTI Crude oil price (expressed in $/bbl). Restating this correlation, the market price of CO_2 (expressed in $ per metric tonne) would be 27% to 63% of the crude oil price ($/bbl). Source: Chaparral Energy "US CO_2 & CO_2 EOR Developments" Panel Discussion at CO_2 Carbon Management Workshop December 06, 2011

NETL

Lowest Cost Power Generation Options

MIDWEST (sea level): *2nd Gen NGCC versus 2nd Gen Coal (Bituminous)*



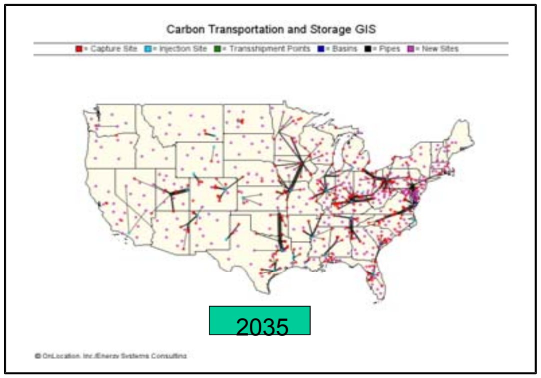
2nd Gen NGCC uses J-Frame turbine, conventional carbon capture; Assumes capacity factor = availability (i.e. all plants including NGCC are base load).
June 2011 Dollars; Assumes bituminous coal at delivered price of $2.94/MMBtu

NETL

Macroeconomic Analysis

- National Energy Modeling System (NEMS)
  - DOE/EIA's official energy-economic model
- Energy Velocity Suite
  - Licensed database of U.S. power plants
- NETL/WVU Econometric Input/Output Model
  - Used to estimate GDP and employment impacts
- IMPLAN
  - Input/output employment impacts
- GAMS
  - Optimization modeling
- Independently Developed Models and Analyses

The Benefits Division Analysis Process

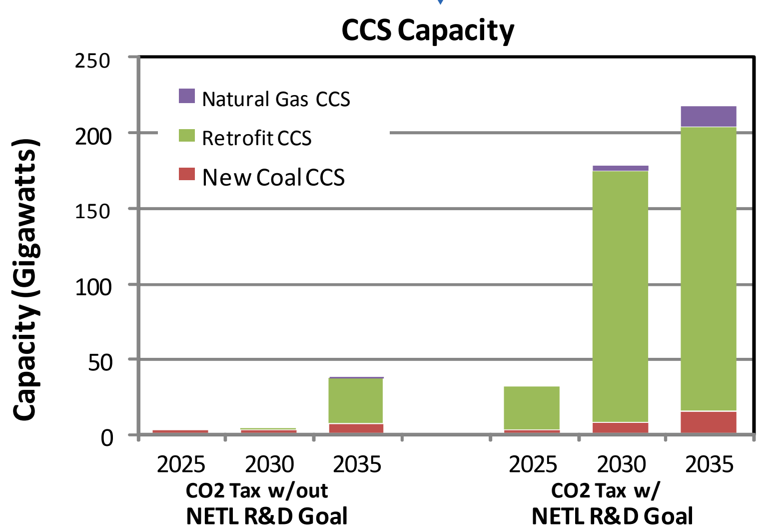


	Benefit Metrics for EPEC Program		
Scenario	**Cumulative Employment* (Thousands)**	**Electricity Expenditure Savings through 2035 (billions $2008)**	**Annual CO2 Emissions Reductions in 2035 (mmt)**
CES	791	18 (ROI 23:1)	1316
CO_2 Tax	Not Evaluated	23 (ROI 28:1)	2010

Develop new models and/or refine existing models

Project deployment of SCC R&D technologies under competitive market scenarios

Estimate potential benefits of SCC R&D programs



Keys to Estimating Cost of Emerging Carbon Capture Processes

- Capture technology development stage
  - Cost estimates require design and performance data
  - Available data a function of development stage: concept to commercial demo
  - Important to understand basis for design and performance assumptions
- Standard design basis guide – consistent basis for comparison
  - System boundaries
  - Plant size, capacity factor
  - Application requirements (e.g. emissions, load follow)
  - Capital cost accounts
  - O&M cost accounts
  - Financial methodology

NETL's Quality Guidelines for Energy System Studies

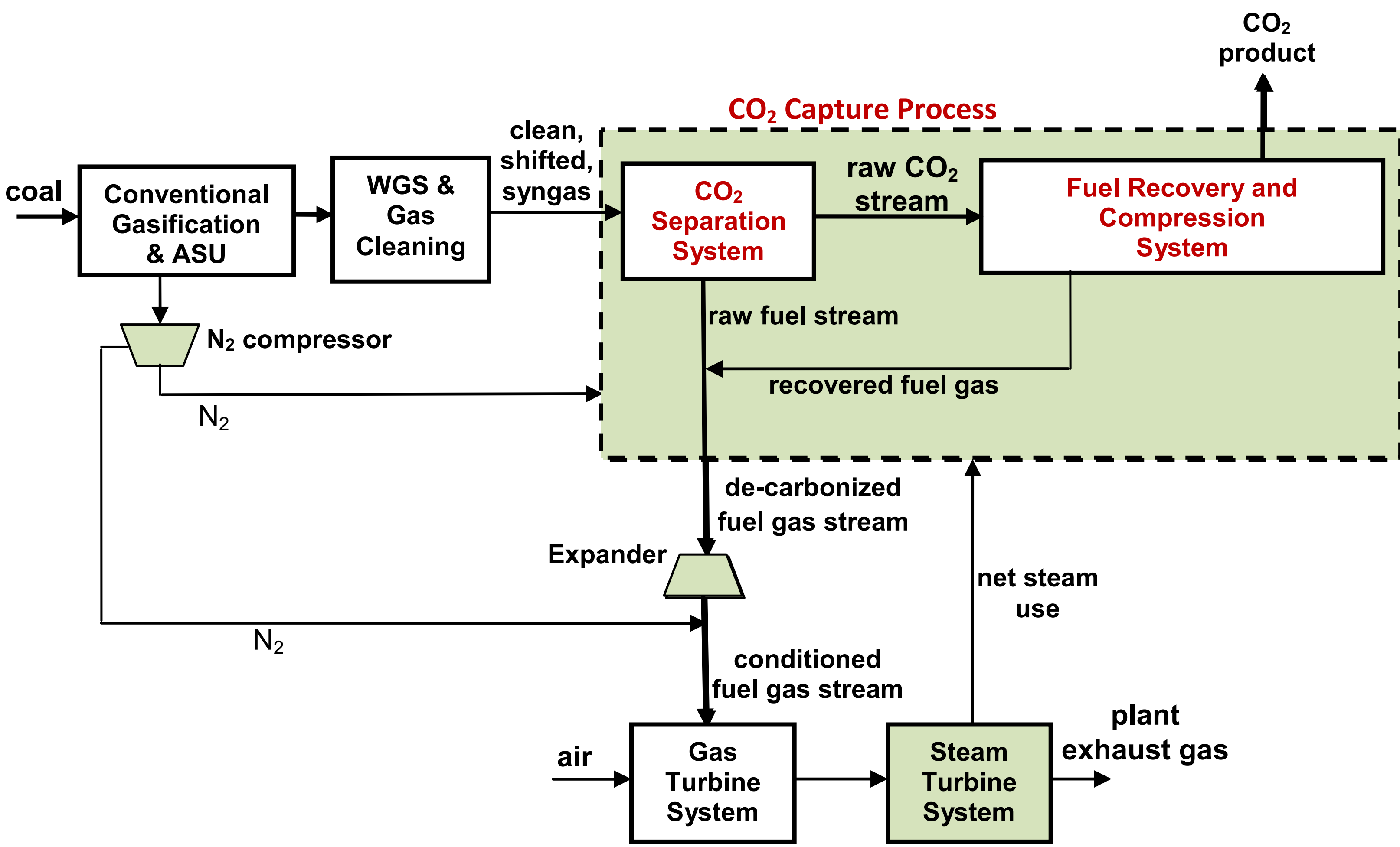
- Specifications for Selected Feedstocks
- Process Modeling Design Parameters
  - E.g. ambient conditions, component design and performance
- Energy Balances and Enthalpy Reference States
- CO_2 Impurity Design Parameters
- Technology Learning Curve (FOAK to NOAK)
- Cost Estimation Methodology for NETL Assessments of Power Plant Performance
  - Consistent set of capital and O&M cost elements
  - Consistent set of financial assumptions, with options (e.g. high and low risk)
- Estimating Carbon Dioxide Transport, Storage, and Monitoring Costs

Evaluation Options

- Levels of studies – e.g. order of magnitude, screening, definitive
- Level of simulation – e.g. black-box vs modeling and sizing
- State of technology maturity
  - Contingencies
  - FOAK vs NOAK

IGCC Capture Process Illustration

Capture Process Cost Includes Multiple Subsystems

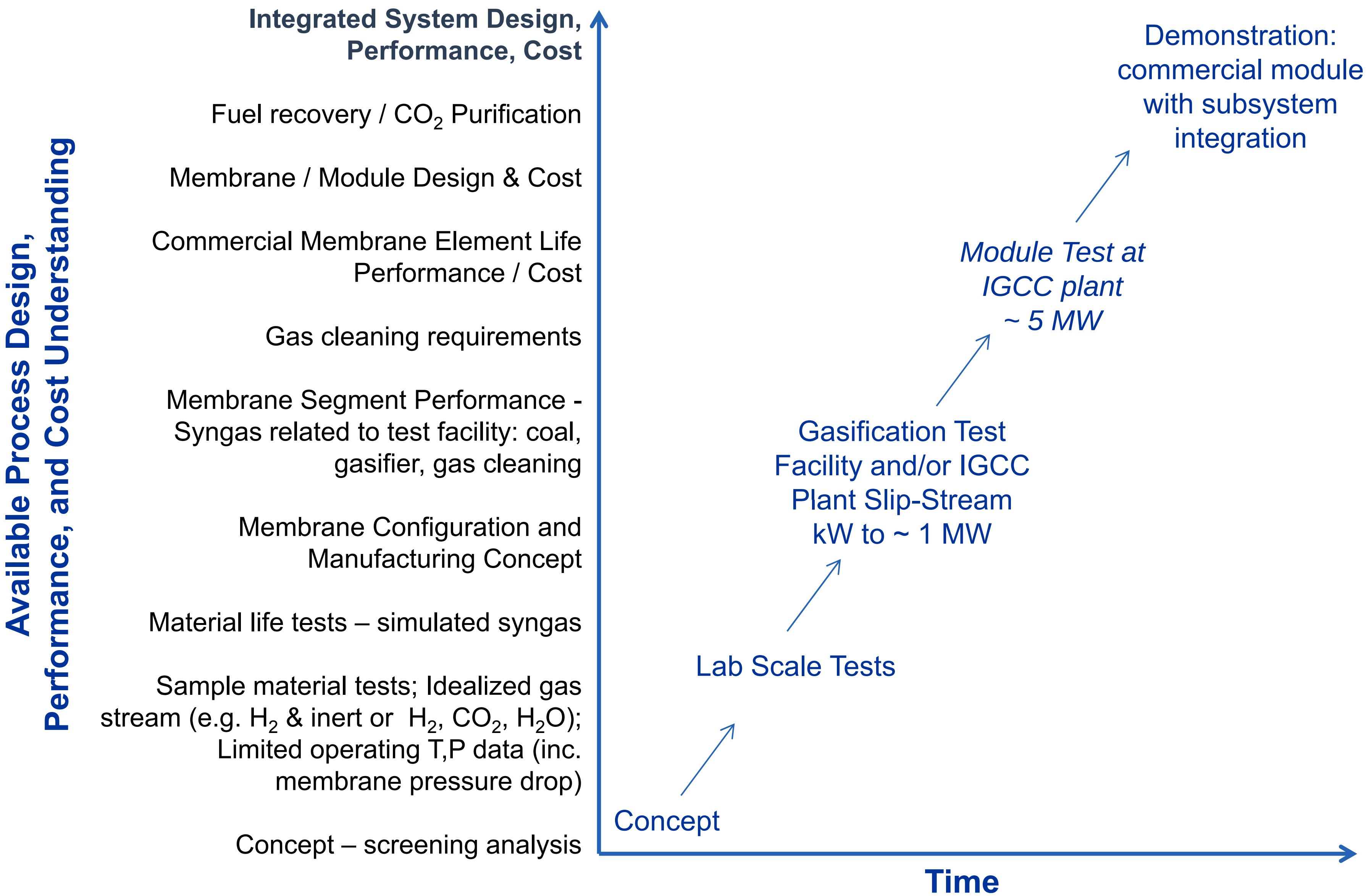


Capture System Cost is Function of Capture Process Understanding

Example: IGCC plant with membrane capture

- Analysis must consider costs of subsystems associated with the capture system
- Cost is associated with a given energy system concept and application
  - Example is an IGCC power plant with humid gas cleaning
  - Specified fuel gas delivery T/P (gas turbine)
- Cost requires capture technology design, performance and cost information
  - Hydrogen membrane example: membrane material, fabrication, surface configuration, permeances, degradation, etc)
- Membrane system design and cost estimated from
  - Membrane surface area required
  - Membrane pressure vessel design and cost
  - Membrane cost (new and replacement)
  - Syngas cleaning (if required to meet life requirement)
  - Fuel recovery and compression subsystem design and cost

Illustration of Available Data for Estimation



Process Contingencies

Process contingencies are associated with the development status

State of Technology Development	Process Contingency (Applied to Subsystem BEC)
	AACE*
New Concept with limited data	40+%
Concept with bench-scale data	30% to 70%
Small pilot plant data	20% to 35%
Full-size modules have been operated	5% to 20%
Process is used commercially	0% to 10%

- When emerging technology development stage is pre-pilot plant, projected design and performance are used as basis for cost; knowledge and data limitations recognized; sensitivity analysis of key process parameters used to estimate cost

- AACE recommendations are consulted in conjunction with engineering judgment. A 20% process contingency is frequently applied for emerging technologies.

*Source: AACE International Recommended Practice No. 16R-90, *Conducting Technical and Economic Evaluations in the Process and Utility Industries*

Cost Estimating Challenges

- Knowledge required for design and projecting performance of emerging technologies is not available
  - Requires projecting design and performance
  - Important to document assumptions
- Cost estimates are frequently underestimated due to incomplete representation of the capture process
  - E.g. processing of input and output process streams, systems integration
- Establishing the appropriate basis for the cost estimate (e.g. application, system boundaries, financial methodology)
- Establishing the appropriate metric that addresses the question being asked

NETL Perspective

Evaluating Economics of Emerging Carbon Capture Processes

- Cost estimates for emerging technologies depend on the question being asked

- NETL systems analyses
  - Guide and evaluate R&D
  - Establish cost and performance goals
  - Compare best potential of emerging technology with R&D goals and competing technologies
  - Identify integration and performance requirements
  - Forecast the potential national benefits of successful R&D

- Two important features of NETL cost estimates
  - Understanding the development status and developing a technically sound basis for process design and performance
  - Maintaining a standard design basis guide

- Challenges
  - Limited knowledge and data for emerging technologies
  - Establishing the appropriate basis for the cost estimate

AIChE Call for Papers

Annual Meeting in Pittsburgh, PA

Oct. 28 to Nov. 2, 2012

- Topical D: Accelerating Fossil Energy Technology Development Through Integrated Computation and Experimentation program

- System Analysis – Methods to Evaluate and Compare the Economics of CCUS Technologies
  - Co-Chairs: Mark Woods (mark.woods@CONTR.netl.doe.gov) and John Wimer (john.wimer@netl.doe.gov)

- System Analysis – Gas Separation Processes Utilizing Solvents, Sorbents & Membranes
  - Co-Chairs: Mike Matuszewski (michael.matuszewski@netl.doe.gov) and John Wimer (john.wimer@netl.doe.gov)

- Deadline for submissions is Wednesday, 5/2/12
- To submit, go to http://aiche.confex.com/aiche/2012/cfp.cgi

ADDITIONAL INFORMATION

System Analysis – Methods to Evaluate and Compare the Economics of CCUS Technologies

- Wednesday, 10/31/2012 3:30 - 6:00
- The objective of this session is to describe various methodologies used to evaluate the cost and performance of carbon capture, utilization and sequestration (CCUS) technologies and discuss how they might be standardized to permit more meaningful comparisons among different studies. Major topics include design basis specifications, definition of cost and performance metrics, and techniques for assessing economic feasibility. Questions that may be addressed include:
  - What aspects of a design basis could be standardized for CCUS studies: ambient conditions, fuel specifications, capacity factors, finance structures, carbon dioxide purity, emergency venting, storage/utilization specifications, etc.? How might a standard design basis be complicated by environmental regulations that vary internationally?
  - Commonly used terms and metrics are frequently defined differently across studies, e.g., capital costs, operating and maintenance costs, cost of electricity, cost of capturing/avoiding CO2. Can definitions for these terms be standardized?
  - What are the most frequently used methods to calculate metrics that measure economic performance, such as cost of electricity and cost of avoiding carbon dioxide emissions? How do techniques differ between retrofit applications and greenfield plants? How should carbon dioxide utilization opportunities be factored into economic evaluations, e.g., selling carbon dioxide for enhanced oil recovery?
  - What techniques should be used when assessing conceptual or non-commercial technologies? How should process contingencies and learning curves be applied? How should developmental cost targets, first-of-a-kind costs, and nth-of-a-kind costs be related and compared?

System Analysis – Gas Separation Processes Utilizing Solvents, Sorbents & Membranes

- Wednesday, 10/31/2012 12:30 – 3:30
- The objective of this session is to evaluate the cost and performance of solvent, sorbent & membrane technologies in the context of carbon capture, utilization and sequestration (CCUS). Major topics include: CO2 separation from fossil energy power plants; process and technology development and improvements; optimization and comparison of CCUS processes. Questions that may be addressed include:
  - What are the major cost and performance consequences of solvent-, sorbent- & membrane -based CCUS technologies? How is the cost of electricity impacted after implementing CCUS? What is the resultant cost to capture carbon emissions? To what degree are plant heat rate, water use, and other relevant operations affected by implementation of CCUS?
  - What promising developmental pathways have been identified? What is the relative potential of these technologies for CCUS? Are these developmental pathways cost- or performance-limited?
  - How may major bottlenecks in conventionally-proposed CCUS processes be removed? Can these bottlenecks be attributed to technology limitations or sub-optimal process design choices? What techniques might be used for systematic optimization of these processes?
  - What market conditions are required to motivate the implementation of CCUS? What cost of CO2 capture would result in favorable economics for enhanced oil recovery? What carbon tax level would be required to motivate CCUS?
  - How might CCUS technology help to address recently proposed environmental regulations on non-CO2 emissions?

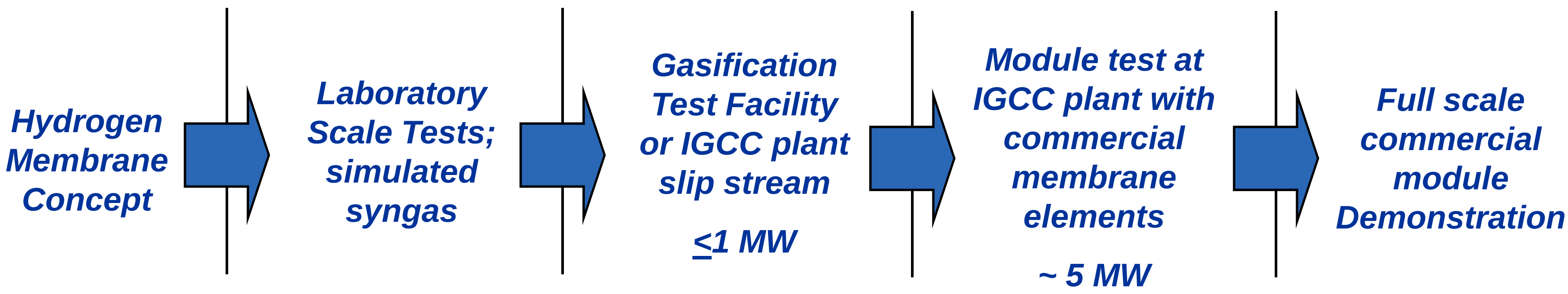
Hydrogen Membrane Capture Illustration

Limited data are available for emerging capture processes

System: Reference IGCC plant with Humid Gas Cleaning and 90% CO_2 capture

Screening Criteria:

- *Shifted syngas (~ 97% CO shift)*
- *Syngas composition (humid gas sulfur and other trace species)*
- *Operating T, P (syngas T, P; fuel gas delivery T, P*
- *Component separation and flux (H_2 , CO_2 H_2O permeating)*
- *Membrane surface configuration (e.g., shell & tube)*
- *Membrane material and fabrication*
- *Membrane life*
- *Membrane cost*
- *Fuel recovery system cost*



Cost Estimation Approach

- Adjustments from Reference Costs
  - Scales reference costs based on key design parameters
    - Plant output (gross and net), capacities, flow rates, number of trains, thermal duties, temperatures, pressures, etc.
  - Factors to the cost basis date
  - Adjusted for project location and specific labor market
  - Modified to incorporate project specific requirements
  - Regularly calibrated to incorporate the most current data
- EPC cost database
  - Extensive database of equipment, material, and installation costs
  - Continually updated with most current project information, including quotations and purchase orders
  - Estimated costs benchmarked / validated against EPC cost database including recent and on-going projects

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GLOBAL CCS INSTITUTE

Cost Library

Howard Herzog, Christopher Short, Kathryn York

WWW.GLOBALCCSINSTITUTE.COM

CCS COST LIBRARY: PURPOSE

- Increase access to cost studies
- Help providers of cost estimates share studies more widely
- Improve collaboration
- Provide an historical repository

3 objectives of knowledge sharing

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  - large-scale integrated project, capture, transport (pipeline, shipping), storage (saline aquifer, EOR)
  - Demonstration, FOAK, NOAK, Learning curve
  - IGCC, PCC, oxy-fuel, NGCC CCS
  - Bituminous coal, lignite, natural gas
  - etc

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- Two-stage IT process

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CCS COST LIBRARY: PROTOTYPE

CCS Library: Costs

Filter:

Title	Authors	Date	Pages	Publisher	Short Abstract
Cost assessment of fossil power plants equipped with CCS under typical scenarios	Leandri, Jean-Francois; Paelinck, Philippe; Skea, Adrian; Bohtz, Christian	2011/06/01	20	Alstom	The work is based on the experience developed by Alstom on conventional turnkey plants and on the last five years of experience gained on CCS demonstration plants and reference designs. Different capture technologies are considered in the evaluation and comparison of the impact of CCS on future commercial fossil-fuelled power plants (coal and gas).
Expert elicitation of cost, performance, and RD&D budgets for coal power with CCS	Chan, Gabriel; Anadon, Laura D; Chan, Melissa; Lee, Audrey	2010/09/28	8	Belfer Center for Science and International Affairs Harvard Kennedy School, Harvard University	There is uncertainty about the ex-ante returns to research, development, and demonstration programs in the United States on carbon capture and sequestration (CCS) technology. To quantify this uncertainty, we conducted a written expert elicitation of thirteen experts in fossil power and CCS technologies from the government, academia, and the private sector. We asked experts to provide their recommended budget and allocation of RD&D funds by specific fossil power and CCS technology and type of RD&D activity for the United States.
CO2 control technology effects on IGCC plant performance and cost	Chen, Chao; Rubin, Edward S; Berkenpas, Michael	2006/09/25	12	Carnegie Mellon University	As part of the USDOE's Carbon Sequestration Program, we have developed an integrated modeling framework to evaluate the performance and cost of alternative carbon capture and storage (CSS) technologies for fossil-fueled power plants in the context of multi-pollutant control requirements.
Realistic costs of carbon capture	Al-Juaied, Mohammed; Whitmore, Adam	2009/07/01	73	Belfer Center for Science and International Affairs Harvard Kennedy School, Harvard University	Costs for pre-combustion capture with compression are examined in this discussion paper for First-of-a-Kind (FOAK) plant and for more mature technologies, or Nth-of-a-Kind plant (NOAK). Estimates for both FOAK and NOAK are mainly based

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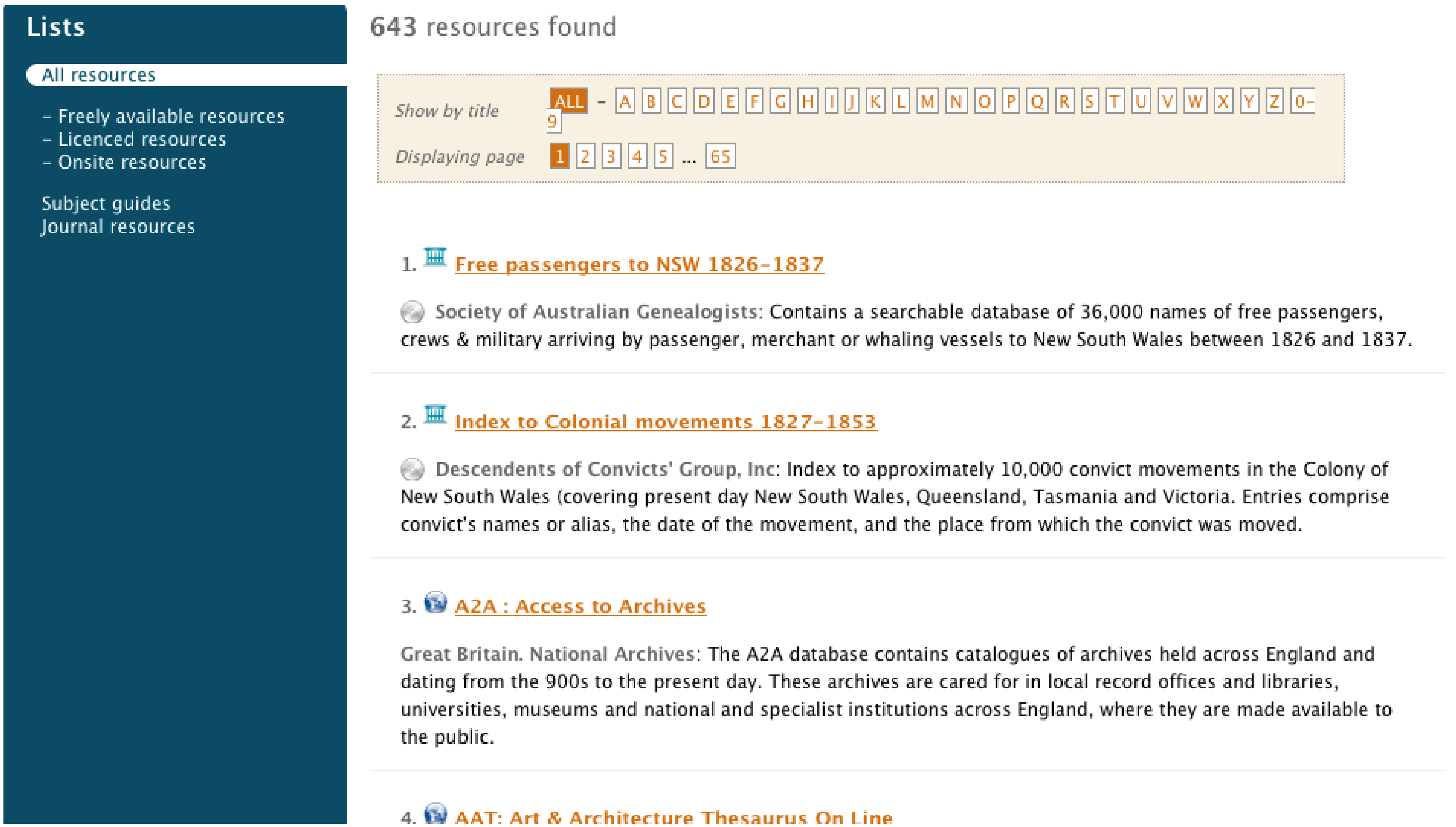

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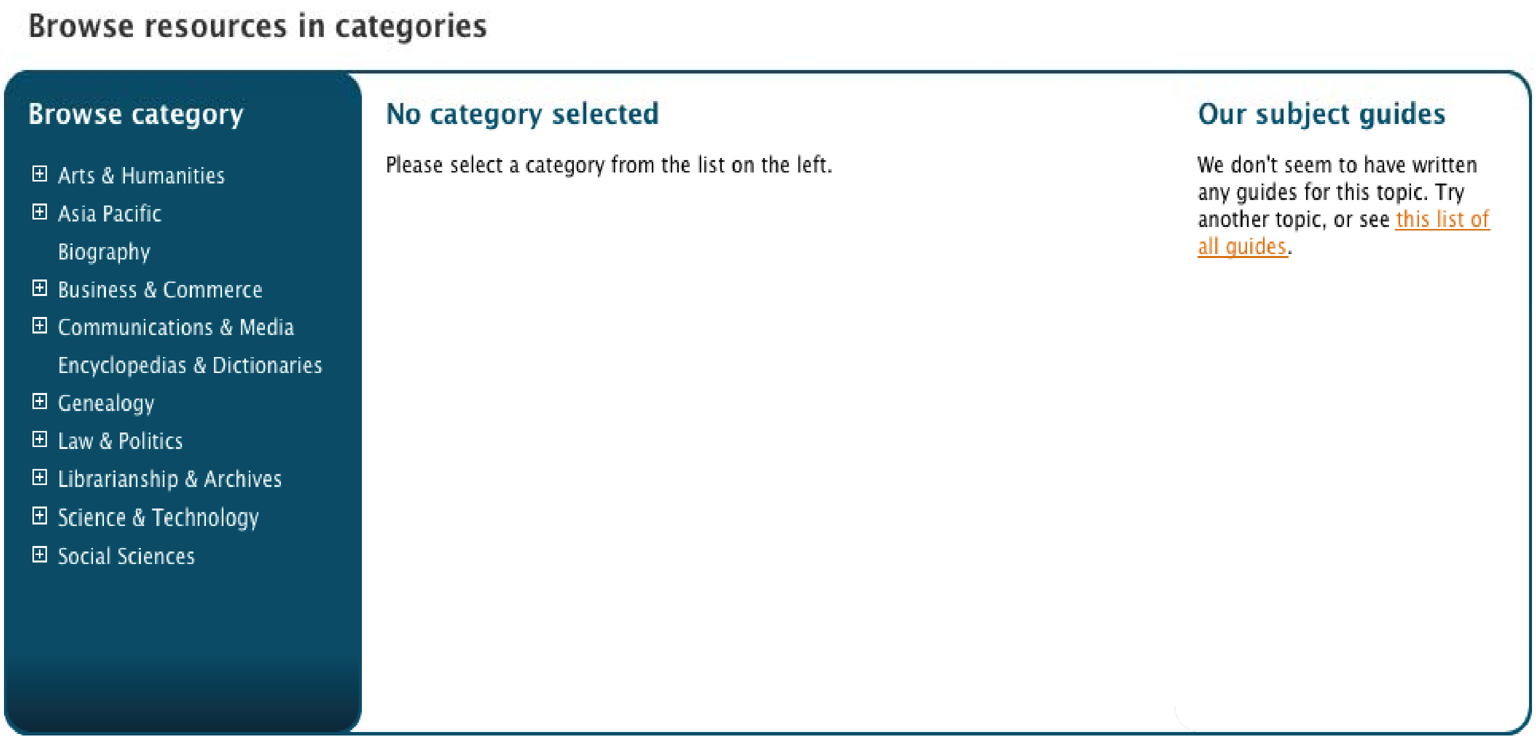

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