

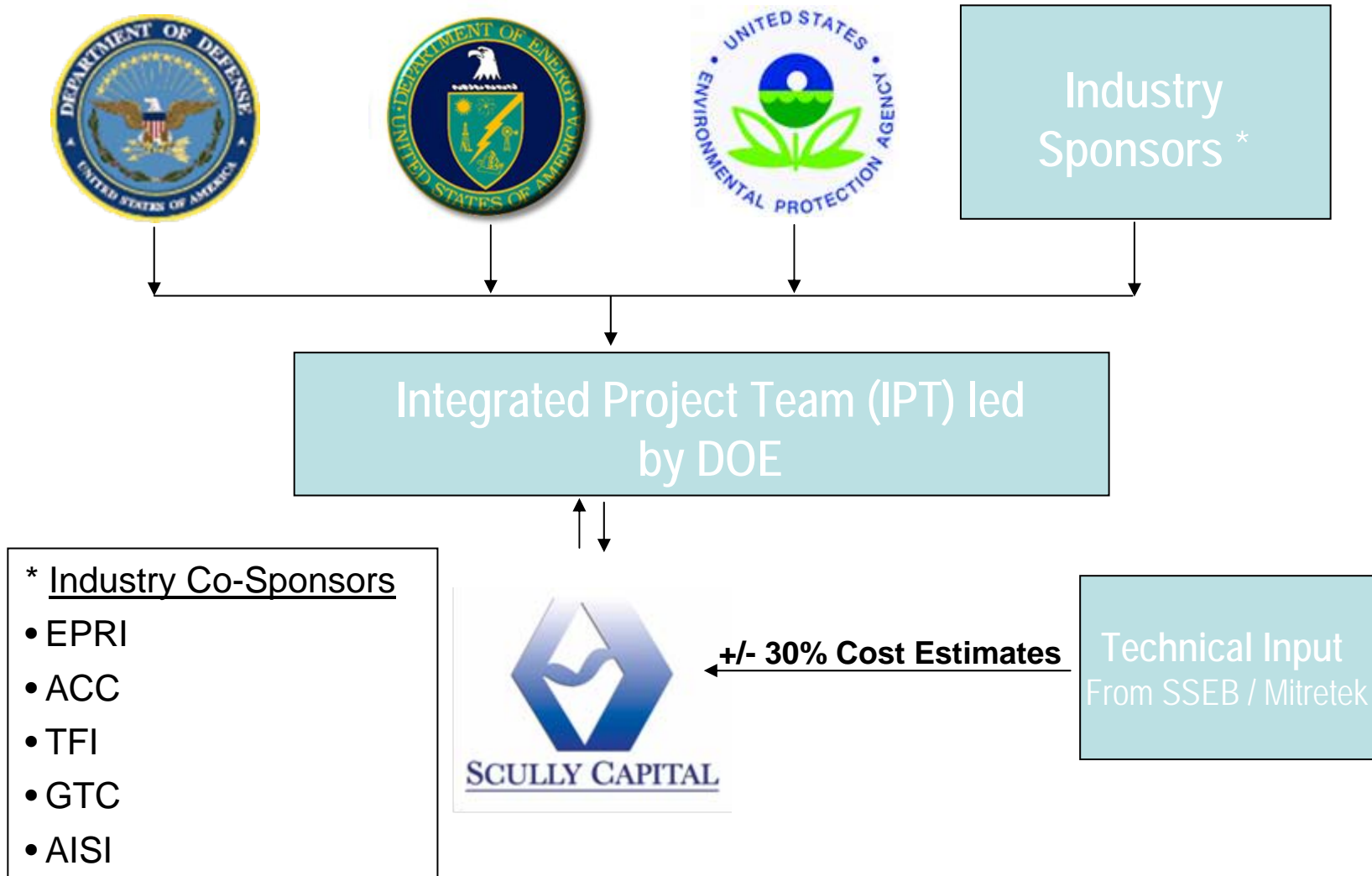
# ***The Business Case for Coal Gasification with Co-Production***

**An Evaluation of Business Risks and Potential Incentives  
for Early Commercial Coal Gasification with  
Co-Production Projects**

***Briefing for GTC  
David Berg, DOE/Policy  
June 13, 2007***



# Study Sponsors



- Determine “Reference Plant” and alternative configurations
  - Coal types
  - \* Degrees of carbon management
  - \* Doubled power production
- Financial modeling
  - “Base case” financial results
  - Sensitivity testing
  - Analysis of the impact of various incentives
- Assessment of business risks
- Interviews
- \* Production of final report

# REFERENCE PLANT AND FINANCIAL FRAMEWORK



- Coal gasification with co-production of transportation fuels is known as “coal-to-liquids (CTL)”. CTL plants integrate coal gasification with Fischer-Tropsch (FT) units.
- Coal gasification process can be linked with several other unit operations in co-production plants, including:
  - Electricity generation (IGCC plants)
  - Synthetic natural gas (SNG plants)
  - Ammonia / urea
  - Methanol
  - Hydrogen
  - Steam production
- Coal gasification offers easier and less costly capture and compression of CO<sub>2</sub>, facilitating CO<sub>2</sub> sales and sequestration.
- FT fuels can be carbon neutral compared with oil-based fuels (if CO<sub>2</sub> from gasifiers and FT units is used or sequestered).

Input Characteristics	
Tons of Coal Per Day	17,987
BTU Value of Bituminous Coal	11,800
Price of Coal Delivered	\$36 / Short Ton
Output Characteristics @ Capacity	
FT Liquids (bpd)	
FT Diesel	24,359
Naptha	11,398
Total: FT Diesel Equivalent	32,502
Electricity Production	
Gross (MWe)	725
Net (MWe)	257
Net (MWe) with Sequestration	205
Plant Characteristics	
Efficiency (HHV)	48%
Gasifier Trains	6
Spare Gasifier	No
FT Reactors	6
Other Characteristics	
Construction Time	3 Years
Availability	
1 <sup>st</sup> Year	51%
2 <sup>nd</sup> Year	81%
3 <sup>rd</sup> + Year	90%

- Primary outputs: FT diesel and/or aviation fuel, naphtha, electricity (@ \$58/MWh)
- ~30,000 bpd of liquid fuel outputs: 75% FT fuels, 25% naphtha (@ \$30/bbl)
- Most of the electricity produced is used internally for plant load
- The parasitic load to capture and compress CO<sub>2</sub> is ~52 MWe
- Overnight capital cost: \$2.6 B
- Total plant cost: \$3.2–3.6 B
- Annual operating cost: \$0.4 B

- Capital structure: 30% equity – 70% debt
- Interest rate: 8% annual
- Amortization: 15 years with mortgage-style debt amortization. Debt matches off-take agreement with creditworthy counterparty. Depreciation over 15 – 20 years.
- Reserves: Debt service reserves capitalized at 50% of maximum annual debt service.
- Interest capitalization: Capitalized during construction and 1st year of operation (during ramp-up).
- Marginal income tax rate: 40% (Federal and state)
- Tax loss benefits: Utilized currently
- Other costs:
  - Development costs: 2.5% of EPC
  - Financial closing costs: \$50 million.
- After-tax equity internal rate of return range: 17%–19%

- **“Project finance”** refers to a wide range of financing structures that have one feature in common: The financing is “off balance sheet,” i.e., not primarily dependent on the credit support of the sponsors or the value of the physical assets involved.
- **Weighted average cost of capital (WACC)** achieved under financing assumptions in the high IRR reference case =

$$(70\% * 8\%) * (1-40\%) + (30\% * 19\%) = 9.1\%$$

- Comparison: Weighted average cost of capital for selected oil and gas companies = 10.1% (see table):
- Risk-adjusted “hurdle rates” may be higher than WACC in unconventional investments (e.g., first-of-a-kind commercial plants).

Company Name	Post Tax WACC*
Amerada Hess	9.2%
Anadarko	10.4%
Apache	10.6%
Burlington Resources	10.0%
Chevron	10.7%
Conoco Phillips	10.4%
Exxon Mobil	11.4%
Kerr-McGee	10.3%
Marathon	10.0%
Murphy	11.2%
Occidental	5.8%
Unocal	10.4%
<b>AVERAGE</b>	<b>10.1%</b>

\* Source: Texas comptroller of Public Accounts. 2005.

# HIGHLIGHTS OF FINDINGS

- Overall, the analysis suggests that FT fuel could be a competitive and assured source of transportation fuels, *but industry requires purchase agreements + incentives for first few plants (type, level depend on project characteristics)*.
- A mid-size plant requires investment in the range of \$3.3 – \$3.7 billion, depending on type of coal and the use of carbon handling equipment.
- Crude-equivalent price for bituminous FT fuels *without* carbon compression (CC) and sequestration is \$52 – \$56 per barrel (\$68 – \$73 for FT fuels). CC adds 5% – 6% to the price.
- Very large scaling benefits arise over the plant size range 10,000 bpd to 30,000 bpd. The increase in benefits from size tapers over the range 30,000 bpd to 60,000+ bpd.

- Key concerns among industry players: Market risk, high capital cost, potential cost overruns, and lack of construction / completion certainty. Excessive downtime?
- Purchase agreement (PA): A flexible tool needed to address certain project risks (e.g., *market*, inputs, performance), enhancing financial feasibility. PAs pose budget challenges, however.
- Tax incentives can reduce output pricing and may positively impact project creditworthiness. Budget cost, however, varies directly with degree of financial “lift”.
- Loan guarantees can provide a big (14% – 30%) reduction in FT fuel price, depending on their structure. Budget cost can be zero, depending on terms.
- Skepticism exists about resolving national policy on CO<sub>2</sub>.

**REFERENCE PLANT & SENSITIVITY  
TESTING RESULTS  
(BASED ON FINANCIAL MODELING)**



SCULLY CAPITAL

**EXHIBIT 1: SOURCE AND USES OF FUNDS (\$000)**  
**PROJECT: Coal Gasification with Co-Production Plant Study**  
 Scenario Number: 1 - Reference Case: 30,000 bpd plant w/ Bituminous coal

**USES**

**Facility Costs**

Solids Handling	\$ 166,616
Air Separation Unit	261,673
Gasification	470,533
F-T Liquids Area + refining	369,650
Power Block	296,650
Gas cleanup/polishing	300,197
Carbon Sequestration Equipment	-
Balance of Plant	352,601
Owner's Contingency	110,896
License Fees & Startup Costs	92,209
Design Costs	190,891
Subtotal - Facility Costs	<u>2,611,915</u>

**Financing Costs**

Development Costs	54,248
Closing Costs	50,000
Debt Service Reserve Fund	129,840
Capitalized Interest	423,059
Subtotal - Financing Costs	<u>657,147</u>

**Gross Funding Requirements**      **\$ 3,269,062**

**SOURCES**

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Equity	980,719
Equity %	30.0%
Debt	2,288,343
Debt %	70.0%

Tranche A      2,288,343  
70%

Tranche B      0  
0%

Tranche C      -  
0%

**Total Funds Drawn**      **\$ 3,269,062**

- Output pricing (+/- 30%)
  - FT fuel: \$72.83 per barrel
  - (Crude equivalent: \$56.02 per barrel)
- Pre-tax minimum DSCR is 1.67x (debt service)
- Average DSCR is 2.16x
- Internal Rate of Return (IRR) = 19%, after tax
- Cost of debt = 8%
- D/E ratio = 70:30

# Sensitivity Testing: Key Results

Sensitivity Test	Value Change	Percentage Change in Price from Reference Case
<b>Base Case: FT Diesel Value = \$72.83, Crude Equivalent Price = \$56.02</b>		
EPC Cost	+/- 25%	+/- 18.7%
Coal Cost	+/- 33%	+/- 12.5%
Interest Rates	+/- 200 bps	+6.1% / -5.5%
Price of Electricity Sold	+/- 15%	-/+ 2.8%
Construction Time	+ 1year / - 6 months	+13.0% / -7.8%
Debt Amortization Period	+/- 5 years	-5.1% / 9.6%
Final Availability	+/- 5%	-5.4% / 7.6%
Reduced Naphtha Output	15% of output	-5.0%
Higher Naphtha Price	+ 100%	-19.3%
Capital Structure (Debt Percentage)	+/- 10%	-8.6% / 10.8%
Faster Ramp-up	75%, 85%, and 90%	-3.6%
Plant Size	10,000 bpd / 60,000 bpd	+37.2% / -5.2%
Use of CO <sub>2</sub> for EOR	\$12/ton CO <sub>2</sub>	-4.2%

- Output of smaller plants will be more costly.
- Naphtha product pricing & coal input cost will significantly affect economics.
- Construction timeline and budget plus plant performance combined play a key role in final plant economics.
- Greater leverage in capital structure will reduce fuel price.

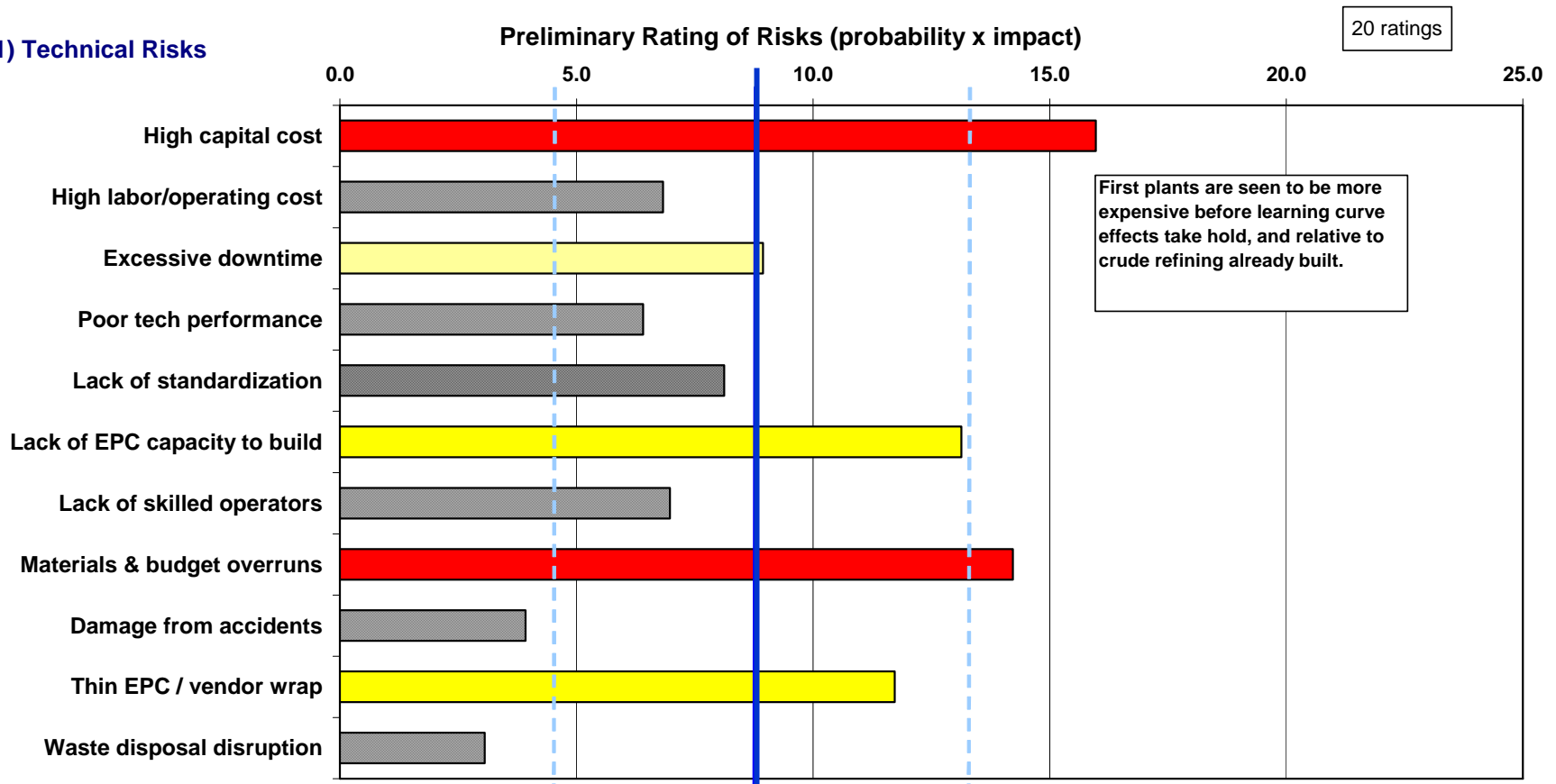
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- **Chemical / Fuel Manufs.**
  - Eastman Chemical
  - SASOL
  - Rentech
  - The Fertilizer Institute
- **EPC Firms**
  - Bechtel
  - Fluor / Hensley
  - Burns & McDonnell
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  - Air Force, DOE/FE
- **Project Developers**
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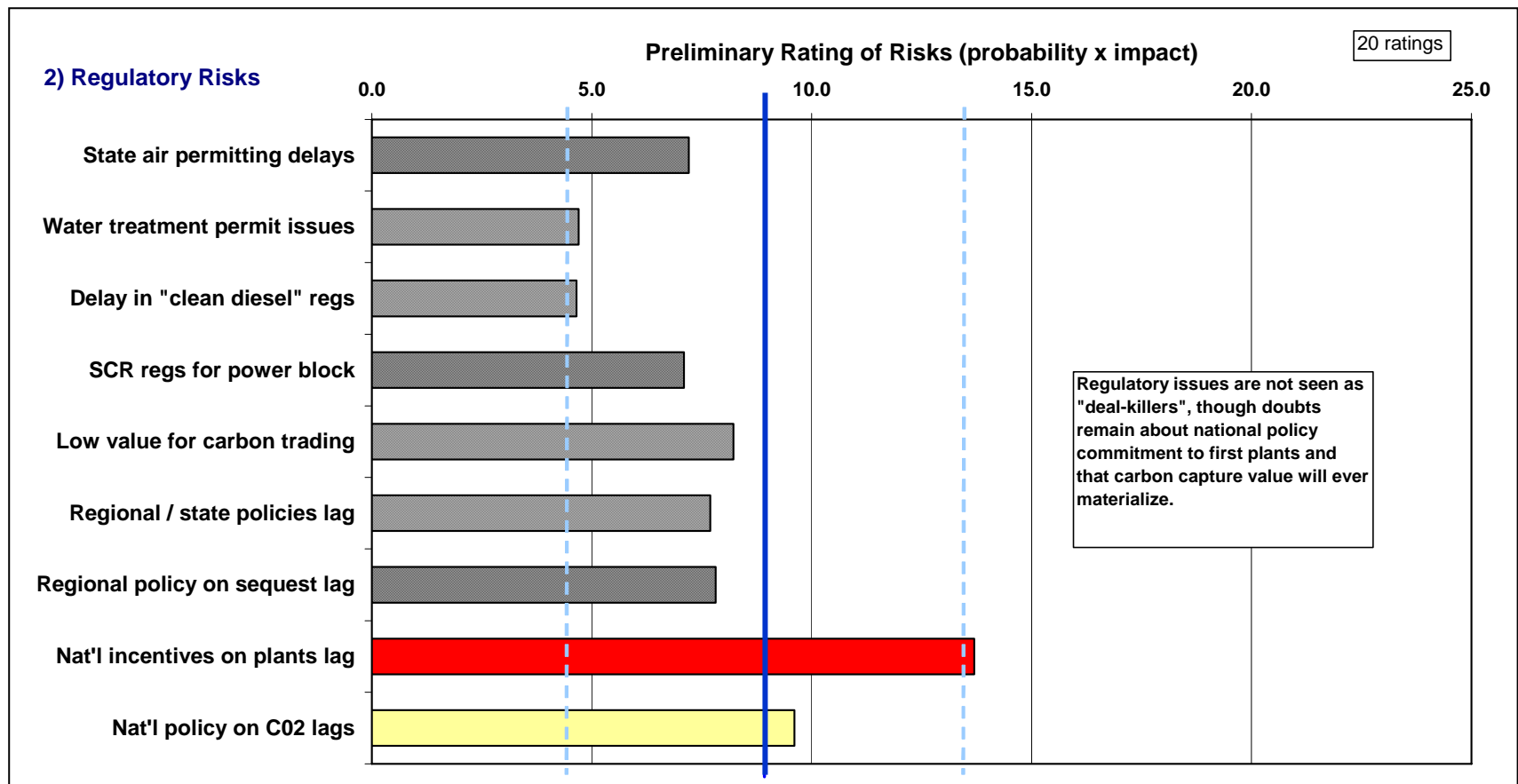
- Among 33 risks in 3 categories (technical, regulatory & policy, market), 3 *project* risks rate highest:
  - **High capital cost**
  - **Tightness in construction sector (in EPC capacity, warranties)**
  - **Price increases in materials & equipment (risk of budget overrun)**
- Respondents also expressed a similarly high level of concern about two other important uncertainties:
  - **Availability of off-take agreements to help contain *market* risk**
  - **Availability of *incentives* to address project risks**
- **Taken together, these key risks make financing problematic.**
- Risk rating results conform with interview observations.
- Concerns also persist about lack of resolution about – and impact of – carbon policy.

Respondents consider first plants to be more expensive (before learning curve effects take hold and relative to crude refineries). Today's tight EPC market has increased key ratings. Materials costs are also elevated.

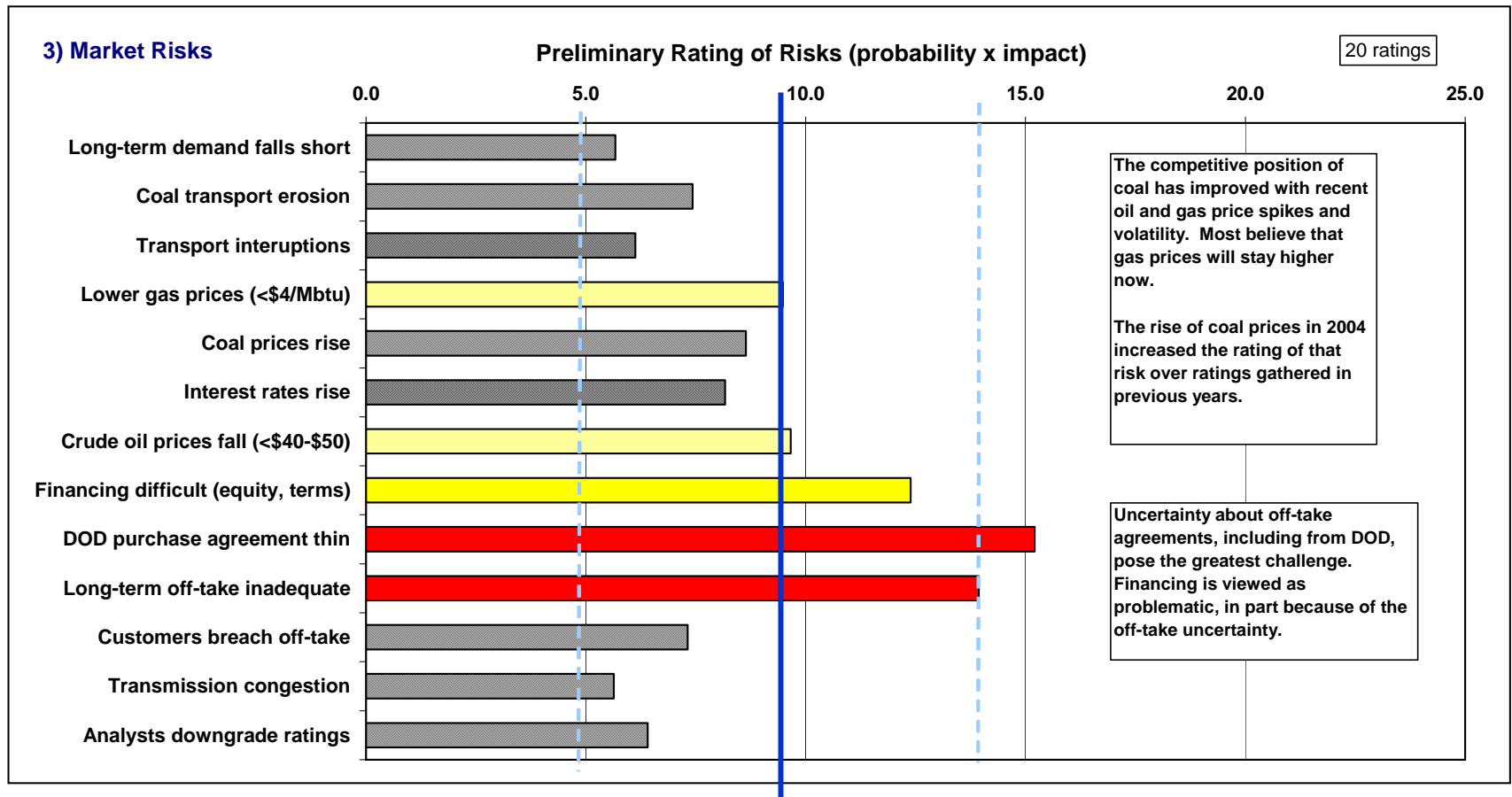
## 1) Technical Risks



Respondents do not consider regulatory issues "deal-killers", but doubts remain about the Nation's policy commitment to first plants and about whether carbon capture value will materialize.



Respondents' uncertainty with off-take agreements, including potentially from DOD, poses the greatest challenge among market risks. Financing, a derivative risk, is problematic, in part because of off-take uncertainty.

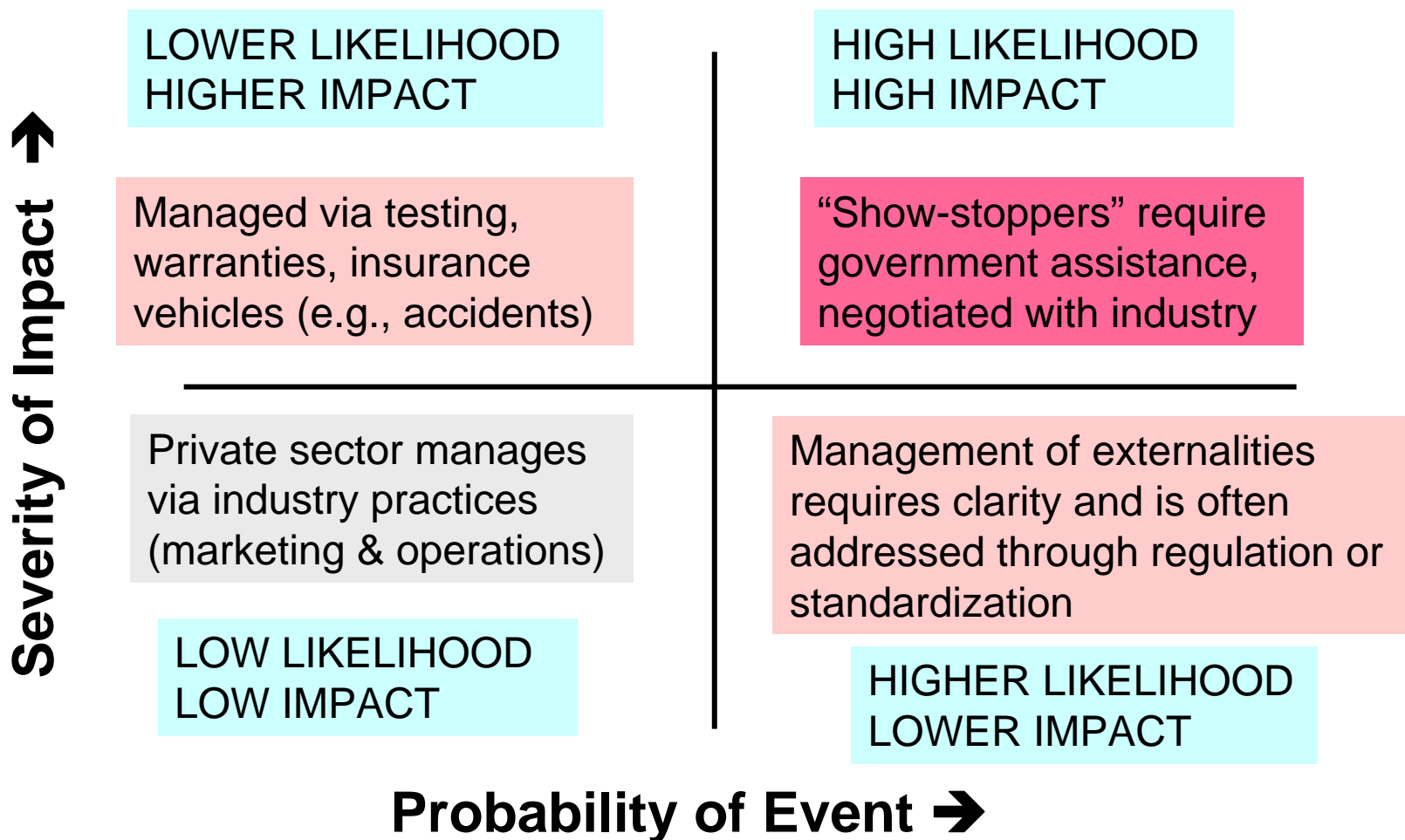


## Summary: Highest Risk Ratings

	25 pt. scale (5 x 5 = 25)	Co-Prod'n	Co-Prod'n	20		50Rs
	Risk Area for IGCC	A	B	2006		2005
Q#	Highest Risks	Probability	Severity	Rating		IGCC
1	High capital cost	3.6	4.5	<b>16.0</b>		<b>14.9</b>
3*	Excessive downtime	2.5	3.7	8.9		<b>13.1</b>
6	Lack of EPC capacity to build	3.6	3.7	<b>13.1</b>		6.5
8	Materials & budget overruns	3.6	4.0	<b>14.2</b>		10.9
10	Thin EPC / vendor wrap	3.4	3.5	11.7		9.5
12*	State air permitting delays	2.2	3.4	7.2		<b>13.0</b>
18*	Regional policy on sequest lag	3.0	2.7	7.8		11.4
19	Nat'l incentives on plants lag	3.3	4.2	<b>13.7</b>		11.8
28	Financing difficult (equity, terms)	3.0	4.2	<b>12.4</b>		<b>13.0</b>
29	DOD purchase agreement thin	4.0	3.9	<b>15.2</b>		<b>NR</b>
30	Long-term off-take inadequate	3.4	4.1	<b>13.9</b>		<b>NR</b>
	<b>Overall Average</b>	<b>2.6</b>	<b>3.3</b>	<b>8.7</b>		<b>9.0</b>

- Concerns about high capital cost rate highest for co-production plants.
- Concerns about cost overruns and tight EPC capacity also are elevated.
- Uncertainties about off-take and incentives add to financing challenges.
- Combined, these risks explain why plants are not being built, unaided.

Framework for plotting questionnaire results facilitates risk-informed government participation:



# **RESULTS OF ANALYSIS OF INCENTIVES (BASED ON FINANCIAL MODELING)**

- Incentives analyzed separately and in (limited) combinations:
  - **Purchase (off-take) agreements (PA);**
  - **Tax incentives** (accelerated depreciation / expensing, investment tax credits, excise tax credits, & tax exempt bonds);
  - Credit incentives in the form of **loan guarantees;**
  - **Grants;** and
  - **Combination case.**
- Some potential incentives were also analyzed as part of sensitivity testing, e.g., reduced coal cost.
- States may be able to provide some of the same incentives as the Federal government, e.g.:
  - Investment tax credits, grants;
  - Small project development grants of \$5 million; and
  - Improved permitting or other regulatory processes (which do not have an explicit monetary value).

- **Definition:** Off-taker agrees to purchase a portion of plant output under pre-defined terms, which may involve:
  - Capacity payments
  - Fuel price adjustments / cost pass through
  - *Force majeure* “outs”
  - Price floors / ceilings
  - Liquidated damage / cure rights
  - Fixed start dates
  - Offer value for carbon capture
- But, the budget requirements for a 15-year purchase agreement (PA) for all of a reference plant’s output = \$10 billion.
- PAs more flexibly address project risks than other incentives, but budget scoring is “front loaded”.
- PAs complement other incentives very well. A strong PA can assure a project’s revenue stream, for example, reducing the credit subsidy cost of a loan guarantee.

# Results: Tax Incentives

Type of Tax Incentive	FT Diesel/ Crude Equivalent Price per Barrel	Percentage Change from Reference Case	Budget Impact (\$ millions)	Total Cost (\$ millions)
<b>Investment Tax Credit</b>				
20%	\$ 67 / \$ 52	8%	\$ 129	\$ 109
20% + Expensing	62 / 48	15%	194	87
<b>Excise Tax Credit</b>				
5 Years Production				
10 cent	70 / 54	4%	150	150
25 cent	65 / 50	11%	375	375
50 cent	57 / 44	22%	751	751
10 Years of Production				
10 cent	68 / 52	6%	318	318
25 cent	61 / 47	16%	795	795
50 cent	54 / 42	26%	1,591	1,591
<b>50% Expensing of FT Equip.</b>	72 / 55	1%	20	-
<b>Tax Exempt Debt</b>	\$ 71 / \$ 55	3%	\$ 325	\$ 643

- Cost of tax incentives tends to move directly with benefit, and money is fungible...
- Utilizing tax incentives to enhance creditworthiness may result in little to no impact on price – and may not target key first-plant risks.

## Results: Credit Incentives

Type of Loan Guarantee				Price Analysis			
Option	Government / Self-Pay Credit Subsidy	Total Debt (\$ millions)	Debt Guarantee Percentage	FT Diesel Price per Barrel	Crude Equivalent Price per Barrel	Change from Reference Case	Budget Impact* (\$ millions)
Option A	Government	\$ 2,536	100%	\$ 51	\$ 39	30%	\$ 188
Option B	Self-Pay	2,536	100%	60	46	18%	-
Option C	Self-Pay	\$ 2,644	80%	\$ 63	\$ 48	14%	\$ -

\*For credit incentives, budget impact is equal to the total cost to taxpayers.

- Loan guarantees can price reduce significantly (14% – 30%) compared with Reference Case results.
- Self-pay loan guarantees are somewhat less powerful, but they offer a zero-budget impact if government correctly assesses risk, making a basket of them revenue and budget neutral.
- **Equal “lift” from self-pay loan guarantee costs government ~\$800 million less than excise tax credit (25¢/gal for 10 years).**

## ***Results: Grants (Cost-Sharing)***

- Provide direct funding to project.
- Are particularly well-suited for early development expenses (pre-financing), such as to help pay for FEED, which helps reduce risk by improving construction cost estimates.
- A \$200 million grant results in a 6% – 7% decrease in FT fuel price, but it is scored in the year it is awarded.
- A \$1.3 billion grant (50% of the facility's hard costs) results in a 32% – 36% decrease in FT fuel price depending on whether the grant is repaid.

## Results: Combination Case

Type of Incentive	FT Diesel Price Per Barrel	Crude Equivalent Price per Barrel	% Change from Reference Case	Budget Impact (\$ millions)	Total Cost (\$ millions)
Combination Case	\$ 43.29	\$ 33.30	41%	\$ 751	\$ 751

- The Combination Case includes:
  - Loan guarantee (100% of project debt, self-pay)
  - 5-year, \$0.50 excise tax credit (= \$21 per barrel)
  - \$20 million state grant (pre-financial close)
- The Combination Case reduces crude-equivalent price to within the floor price for petroleum, although...
- At a cost of ~\$750 million to the government.

# INSIGHTS FROM INTERVIEWS WITH FINANCIAL COMMUNITY & INDUSTRY

- **Banks / Financial Firms**

- Credit Suisse
- UBS
- GE Capital
- Hudson United
- CIFG
- New York Life
- EEA Fund Management
- Standard & Poor's

- **EPC Firms**

- WorleyParsons
- Fluor

- **Developers**

- Baard Energy
- Leucadia
- Agrium
- Excelsior

- **Technology Providers**

- Shell
- ConocoPhillips
- Econo-Power International

Industry interviews confirm sensitivity testing & “Q” results:

- **Capital Cost:** In general, developers find plant cost estimates high, EPC contractors find the plant cost used low, and others find it to be approximately in the right range.
- **Purchase Agreement/Off-take Agreement:** A long term, creditworthy off-taker was mentioned uniformly as a key requirement to offsetting price volatility in energy markets.
- **Volatility of Oil Markets:** Energy price volatility is seen as a key obstacle to financing CTL plants. Lenders mentioned the cost of FT diesel needed to service debt as a key benchmark in determining the ability of a project to withstand price volatility.
- **Length of Debt:** While lenders mentioned that, in certain project finance deals, the length of amortization can be longer than the purchase agreement, they doubt that it can be done for the first co-production plant.

Important observations include:

- **Internal Rate of Return (IRR):** Most interviewees express comfort with IRRs of 17% – 19%. Many specifically offer that the IRR requirement could increase unless the off-take agreement has sufficient length and quality. *The resulting cost of capital fits well with the WACC range for oil and gas companies.*
- **Technology Risk/Completion Risk:** Lenders & investment bankers uniformly mention the likely lack of EPC wraps with performance guarantees on CTL plants as a key obstacle to arranging financing for projects.
- **Project Finance Structure:** Some interviewees believe a project finance structure is possible, but cite as keys to completing non-recourse financings (a) the apparent lack of EPC wraps and (b) the need for a long-term, creditworthy off-taker. Others indicated that a limited recourse structure might be better for the first plants.

	Task	Sponsor	Status
I	Define a Reference Case coal gasification with co-production plant	DOE	Complete
II	Develop Reference Case co-production plant and populate DOE's financial model; perform sensitivity testing	DOD	Complete
III	Analyze sensitivities for alternate plant configurations and product mixes	EPRI	Underway
IV	Assess business risks and financing challenges for development of coal gasification with co-production plants	Industry Groups	Draft Report
V (A)	Analyze the impact of various incentives on the Reference Case coal gasification with co-production plant	EPRI	Final Draft Report
V(B)	Analyze incentives directed towards the environmental benefits of co-production.	EPA	Underway
VI	Integrate findings in a summary report	DOE	Pending

- Analysis of an *alternative plant configuration* (high power production case) to broaden the study: Underway.
- Analysis of the cost impacts of sequestration (Task V.B.): Underway.
- Preparation of reports & reviews of reports: Underway.
- Sponsor briefings on results and, later, public presentations.
- Design project scenarios that may be able to meet DoD objectives in terms of fuel price and attendant risks (New Task TBD).
- Continue monitoring availability of purchasing authorities, loan guarantees, and tax incentives.

# QUESTIONS & ANSWERS and DISCUSSION

# TASK V.B. ANALYSIS

- Aim of Task V.B. is to understand the costs associated with transportation and sequestration of carbon dioxide and the impact of these costs on a Reference Plant's prospects.
  - What level of incentive would be required to offset these costs?
  - What is the impact of enhanced oil recovery on project economics?
  - What is the effect of different types of coal (bituminous, sub-bituminous, lignite) on a project with sequestration?

- Research costs to construct pipeline, inject CO<sub>2</sub>, and monitor and verify CO<sub>2</sub> sequestration.
- Use AES study engineering cost estimates for plants using bituminous, sub-bituminous, and lignite coals.
- Determine incremental cost for each step:
  - Reference Case -> Reference Case with carbon capture & compression
  - Reference Case with carbon capture & compression -> Reference Case with sequestration
  - Reference Case with sequestration -> Reference Case with EOR

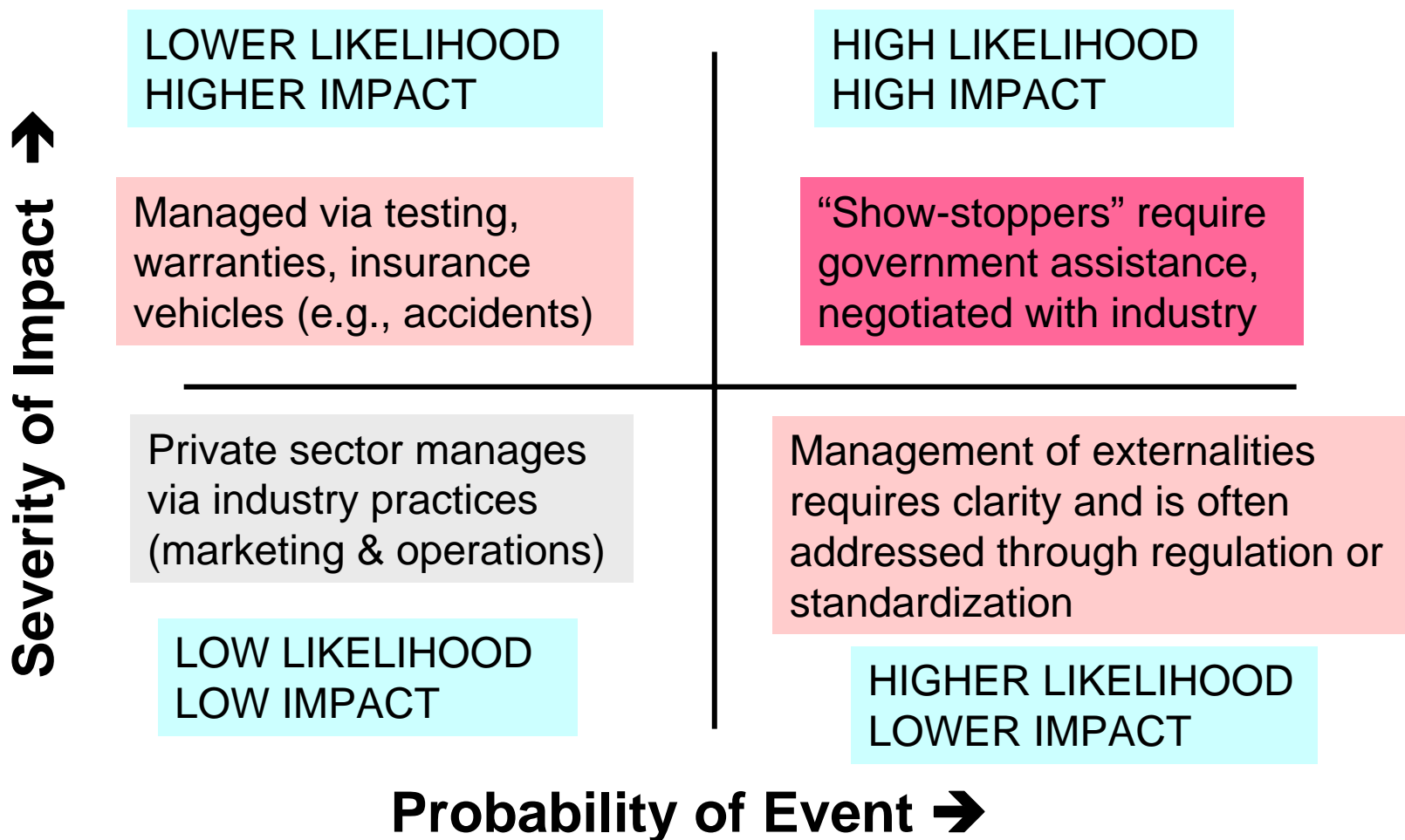
- Model value of CO<sub>2</sub> as a 10-year, level-amount tax credit per ton of CO<sub>2</sub> sequestered.
- Apply this tax credit to Reference Case with sequestration to obtain price at Reference Case.
- Apply same level of tax credit to Reference Case with EOR to determine what additional benefit EOR applications would receive.
- Conduct sensitivity tests on:
  - Cost of injecting;
  - Price of CO<sub>2</sub> in EOR applications; and
  - Length of incentive.
- Develop summary and conclusions based on analysis.

# BACK – UP SLIDES

# RISK RATING QUESTIONNAIRE RESULTS

- **Banks/Financial Firms**
  - Credit Suisse
  - Bank of America Securities
  - Standard & Poor's
- **Chemical / Fuel Manufs.**
  - Eastman Chemical
  - SASOL
  - Rentech
  - The Fertilizer Institute
- **EPC Firms**
  - Bechtel
  - Fluor / Hensley
  - Burns & McDonnell
- **Feds (DOD, DOE):**
  - Air Force, DOE/FE
- **Project Developers**
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  - E3 Gasification
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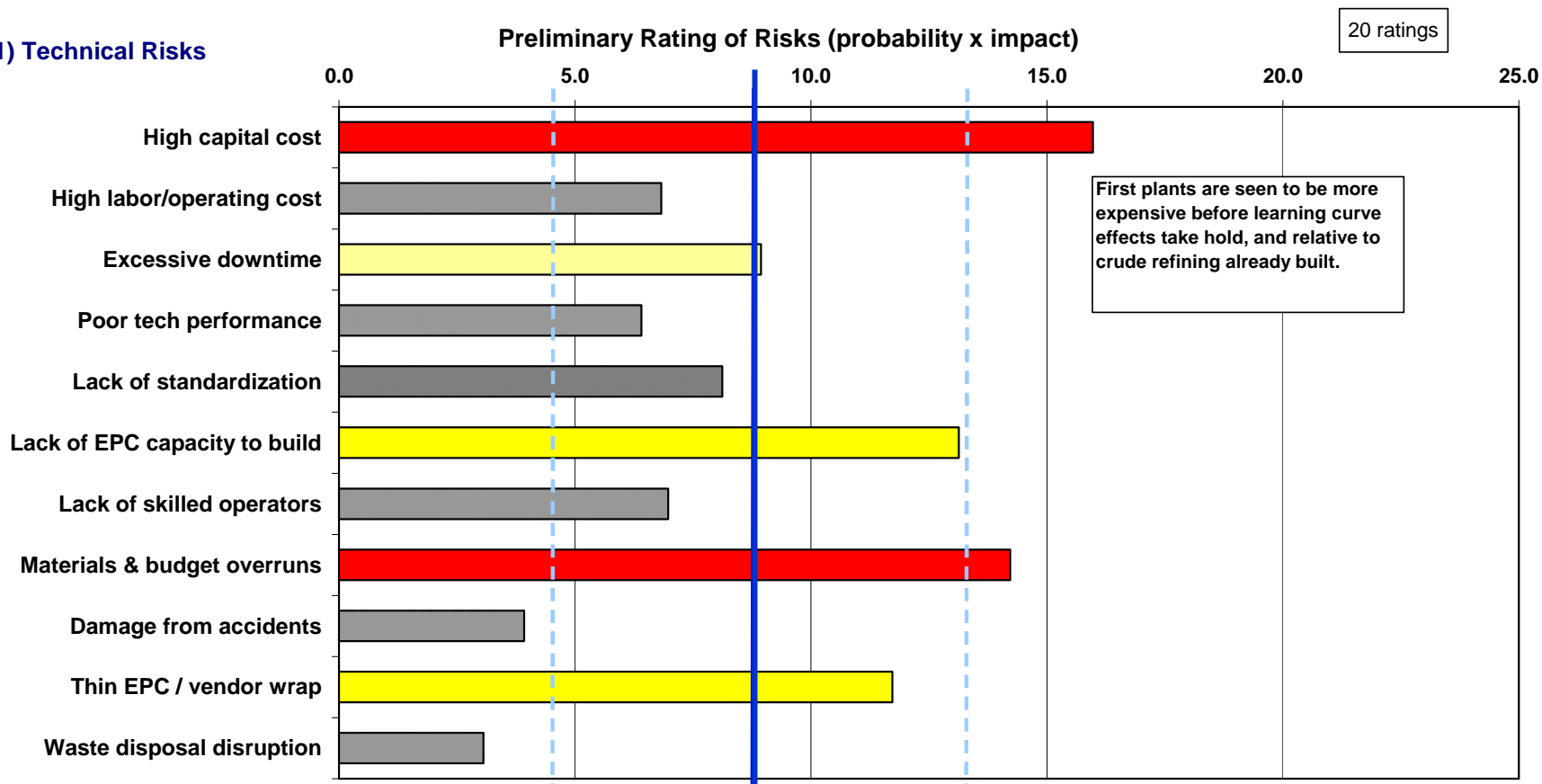
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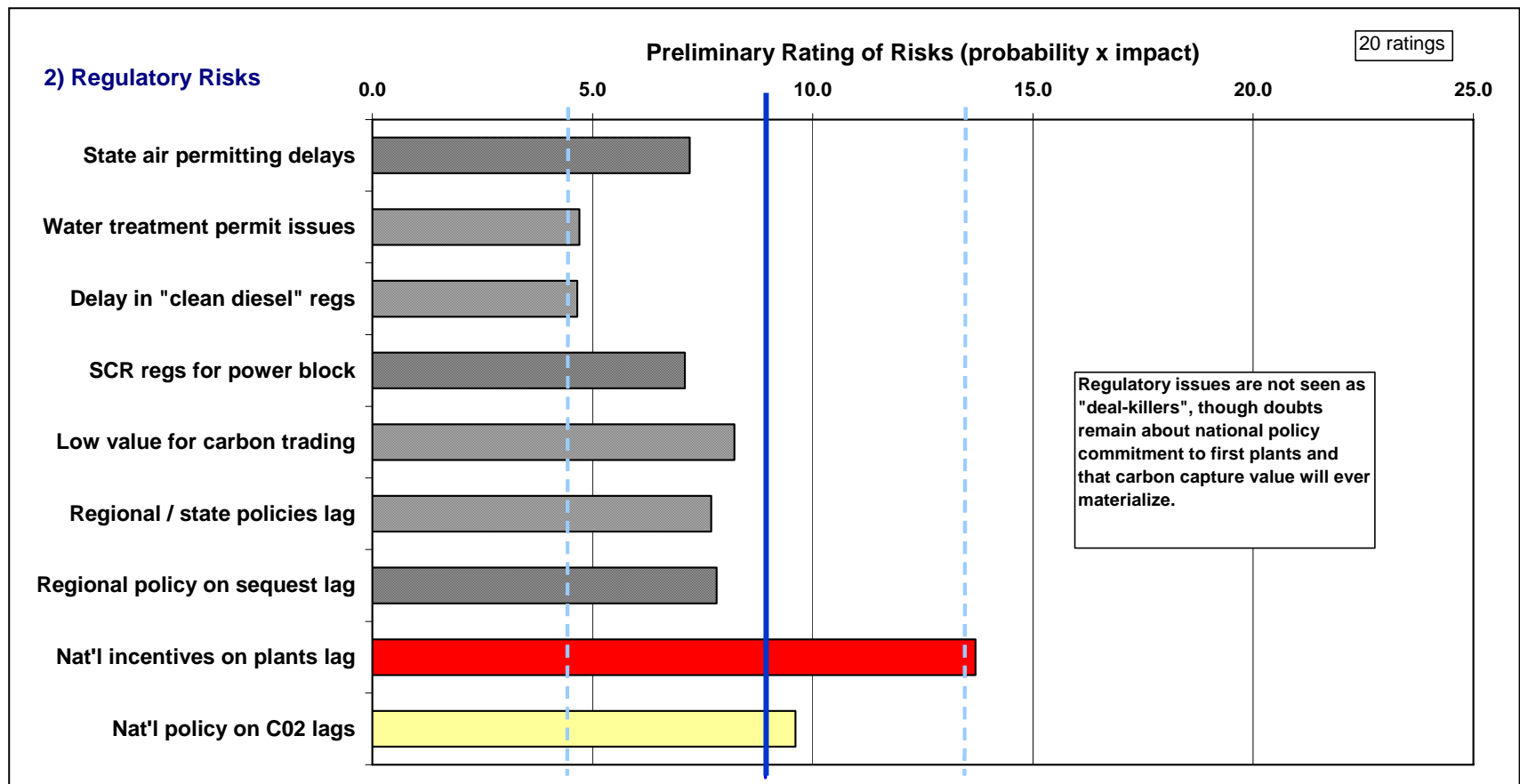
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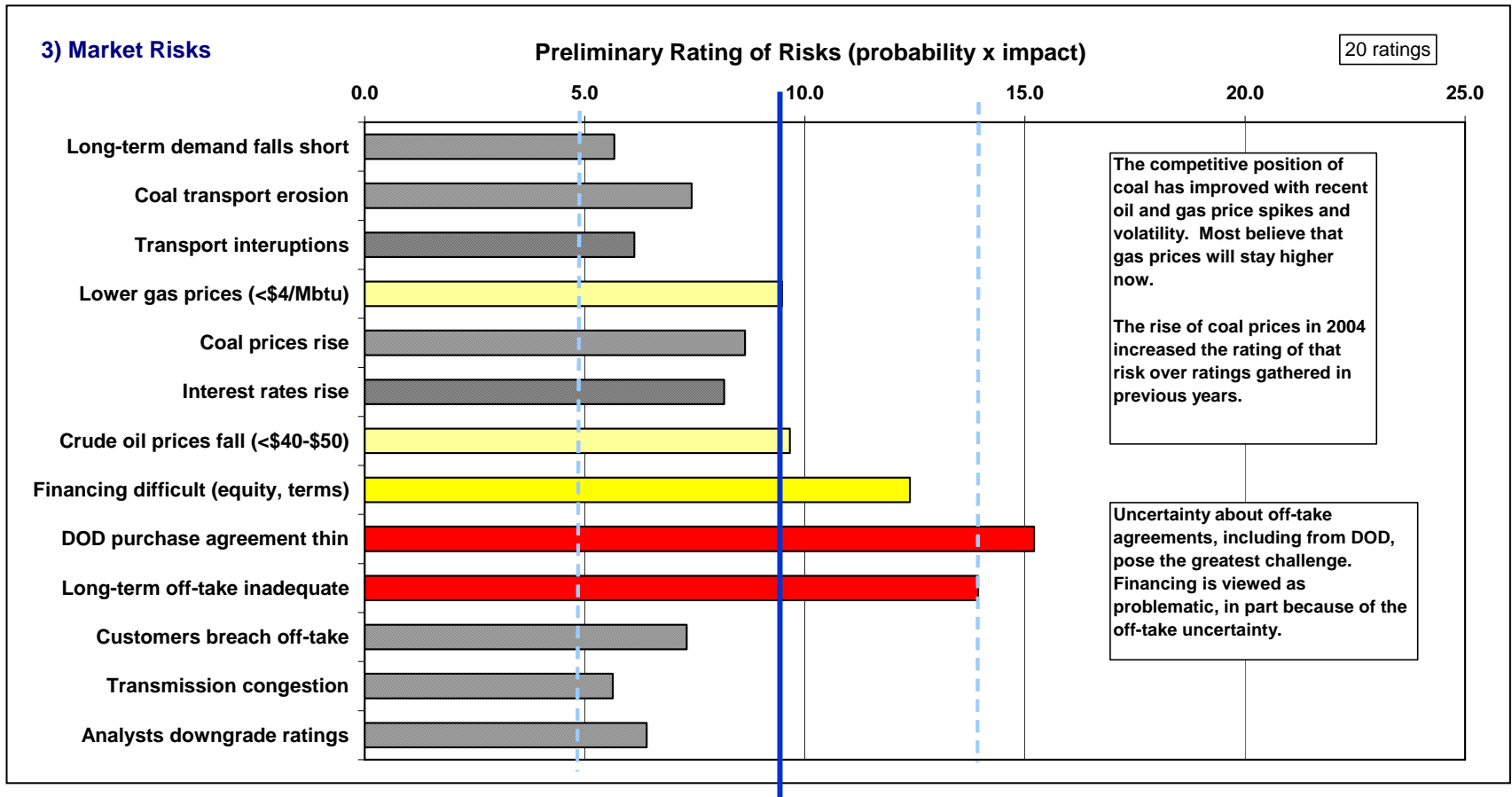
## 1) Technical Risks



Respondents do not consider regulatory issues "deal-killers", but doubts remain about the Nation's policy commitment to first plants and about whether carbon capture value will materialize.



Respondents' uncertainty with off-take agreements, including potentially from DOD, poses the greatest challenge among market risks. Financing, a derivative risk, is problematic, in part because of off-take uncertainty.

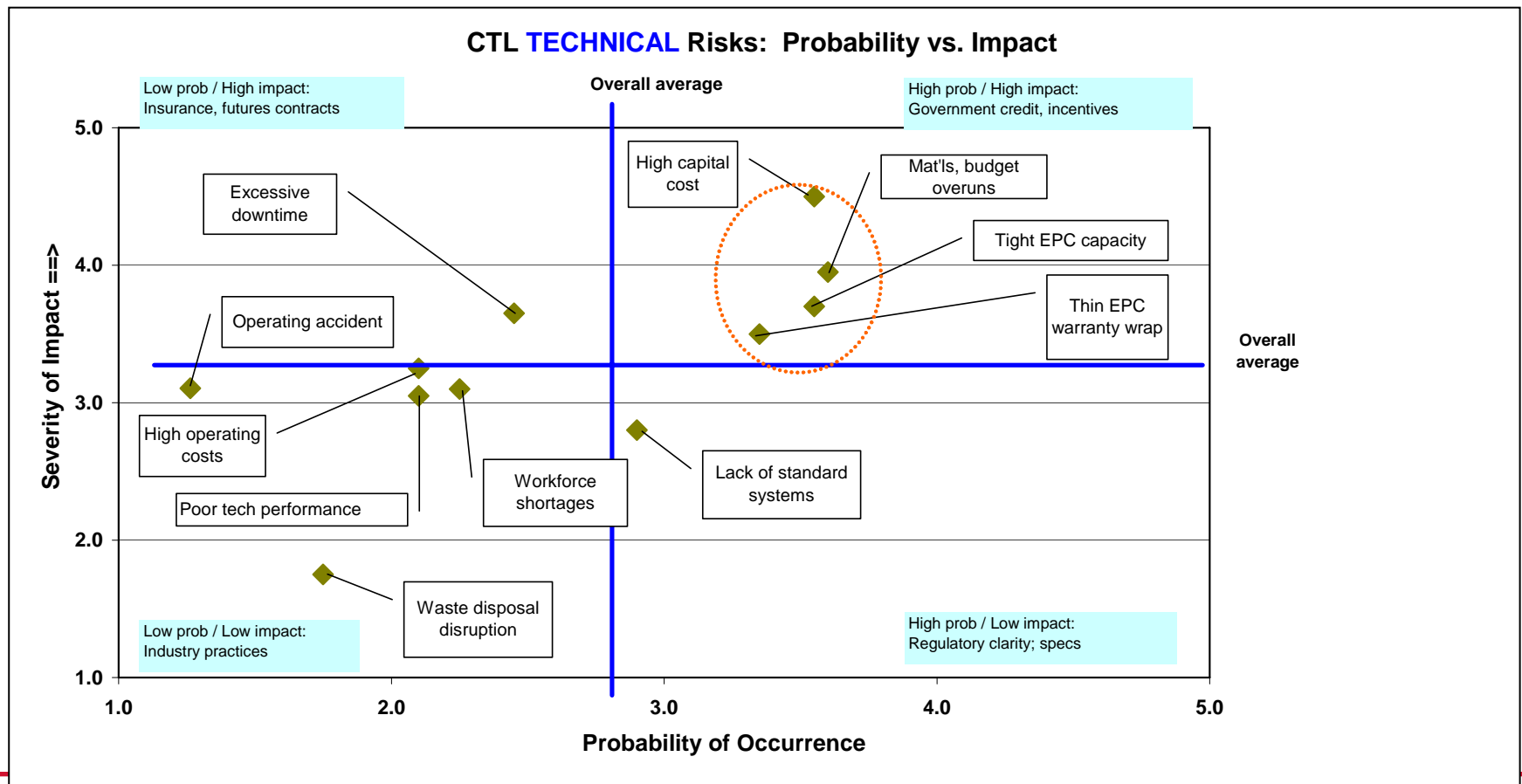


High ratings on capital costs match those for IGCC, but concerns about excessive downtime are muted, in part because chemicals or fuels can be stored (unlike electricity). In addition, chemical firms have more operating confidence. The “EPC wrap” is seen as more problematic in co-production.

Risk Ratings for Co-Production		Co-Prod'n			IGCC	IGCC
		2006	2006	Total	2005	2004
				20	50Rs	33Rs
	Risk Area	A	B	A x B	A x B	A x B
	Technical	Probability	Severity	Rating	Rating	Rating
1	High capital cost	3.6	4.5	<b>16.0</b>	<b>14.9</b>	<b>19.2</b>
2	High labor/operating cost	2.1	3.3	6.8	7.4	7.9
3	Excessive downtime	2.5	3.7	8.9	<b>13.1</b>	<b>15.2</b>
4	Poor tech performance	2.1	3.1	6.4	8.1	9.7
5	Lack of standardization	2.9	2.8	8.1	9.8	<b>12.3</b>
6	Lack of EPC capacity to build	3.6	3.7	<b>13.1</b>	6.5	6.1
7	Lack of skilled operators	2.3	3.1	7.0	7.3	7.2
8	Materials & budget overruns	3.6	4.0	<b>14.2</b>	10.9	10.4
9	Damage from accidents	1.3	3.1	3.9	5.7	5.2
10	Thin EPC / vendor wrap	3.4	3.5	11.7	9.5	6.8
11	Waste disposal disruption	1.8	1.8	3.1	4.4	3.7

# Plot of Technical Risk Ratings

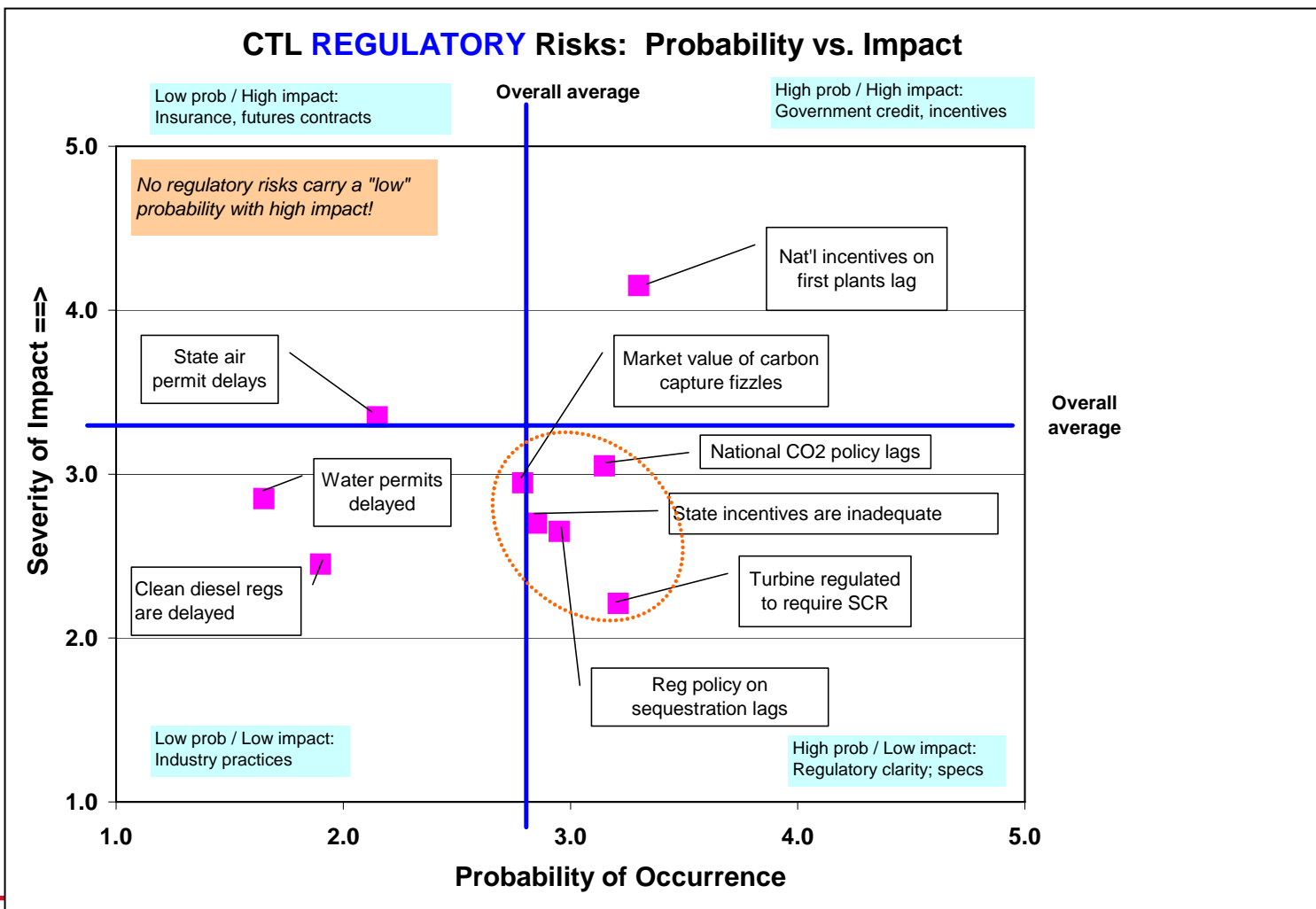
High capital costs, fear of budget overruns, tight EPC capacity, and lack of a real warranty wrap on CTL plants pose risks too great for the private sector to address without government support, particularly for “first mover” projects.



Respondents do not see regulatory issues as "deal-killers", but retain doubts about the Nation's policy commitment to first plants and about whether carbon capture value will materialize. Co-production investors and developers are not as concerned about CO<sub>2</sub> policy as power utilities. Competing fossil prices are a bigger issue for producers of FT fuels than regulatory issues because of market exposure.

	Risk Area			2006		2005	2004
	Regulatory	Probability	Impact	Rating		Rating	Rating
12	State air permitting delays	2.2	3.4	7.2		13.0	10.9
13	Water treatment permit issues	1.7	2.9	4.7		8.2	7.4
14	Delay in "clean diesel" regs	1.9	2.5	4.7		7.6	9.0
15	SCR regs for power block	3.2	2.2	7.1		8.7	11.1
16	Low value for carbon trading	2.8	2.9	8.2		10.3	10.8
17	Regional / state policies lag	2.9	2.7	7.7		6.6	6.7
18	Regional policy on sequest lag	3.0	2.7	7.8		11.4	11.7
19	Nat'l incentives on plants lag	3.3	4.2	13.7		NR	NR
20	Nat'l policy on C02 lags	3.2	3.1	9.6		11.8	13.7

Skepticism persists that national incentives on first plants will provide insufficient encouragement for early projects.



## Risk Ratings: Market

Recent oil and gas price spikes and price volatility improve the competitive position of coal, but respondents reflect their concerns about this market risk by seeking off-take agreements. Most observers expect gas prices to stay higher. Risk ratings for coal price increased after price rises in 2004.

				Co-Prod'n		IGCC	IGCC
	Risk Area	2006	2006	2006		2005	2004
	Market	Probability	Severity	Rating		Rating	Rating
21	Long-term demand falls short	2.1	2.7	5.7		8.0	7.7
22	Coal transport erosion	2.8	2.7	7.4		8.9	4.6
23	Transport interruptions	2.2	2.9	6.1		8.0	11.2
24	Lower gas prices (<\$4/Mbtu)	2.4	4.0	9.5		7.2	7.0
25	Coal prices rise	2.4	3.6	8.6		7.9	6.3
26	Interest rates rise	2.3	3.6	8.2		10.2	11.7
27	Crude oil prices fall (<\$40-\$50)	2.3	4.2	9.7		11.2	12.5
28	Financing difficult (equity, terms)	3.0	4.2	12.4		13.0	16.1
29	DOD purchase agreement thin	4.0	3.9	15.2		7.4	5.8
30	Long-term off-take inadequate	3.4	4.1	13.9		NR	7.6
31	Customers breach off-take	1.9	3.9	7.3		8.6	NR
32	Transmission congestion	1.9	2.9	5.6		6.8	NR
33	Analysts downgrade ratings	2.1	3.1	6.4		6.2	NR

The inadequacy of off-take agreements creates a clear market risk that hinders financing.

