### Run: 2 - CO2 tax

**Summary of CO2 Options with CO2 Tax For Existing Coal Power Plant Baseline**

Natural gas price & CO2 tax set for triple point of same power costs for: Old PC & new NGCC without CCS + coal with CCS

<table>
<thead>
<tr>
<th>Case Number</th>
<th>CO2 Mitigation Options - all built at old PC site</th>
<th>Net MWe mid-2008</th>
<th>New Capital constant $/kWe mid-2008</th>
<th>Efficienc %</th>
<th>Net CO2 Emissions mt/MWe</th>
<th>Avoidance CO2 $/mt CO2</th>
<th>Power Cost $/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>O-PC</td>
<td>Baseline Paid-off Old Coal Power Plant</td>
<td>543 Paid off</td>
<td>Paid off</td>
<td>33.6%</td>
<td>0.95</td>
<td>$</td>
<td>$</td>
</tr>
<tr>
<td></td>
<td>sub PC with FGD size set to NGCC MW</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>O-PC-C1</td>
<td>Old PC &amp; ST with new Post CCS add-on</td>
<td>398 $ 528 $ 1,325</td>
<td>24.7%</td>
<td>0.13 $</td>
<td>0 $</td>
<td>$</td>
<td>$</td>
</tr>
<tr>
<td></td>
<td>new small BT ST + MH1 amine CO2 scrubber</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>O-PC-C2</td>
<td>Old PC + upgrade &amp; new Post CCS add-on</td>
<td>418 $ 755 $ 1,807</td>
<td>25.9%</td>
<td>0.12 $</td>
<td>5 $</td>
<td>$</td>
<td>$</td>
</tr>
<tr>
<td></td>
<td>rebuild SH/RH + sub ST/gen &amp; MH1 amine scrubber</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NGCC</td>
<td>Replacement NGCC - no CCS</td>
<td>543 $ 540 $ 993</td>
<td>50.7%</td>
<td>0.36 $</td>
<td>0 $</td>
<td>$</td>
<td>$</td>
</tr>
<tr>
<td></td>
<td>&quot;F&quot; class NGCC with SCR no CO2 Capture</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NGCC-C</td>
<td>Replacement NGCC with Post CO2 Capture</td>
<td>463 $ 836 $ 1,805</td>
<td>43.3%</td>
<td>0.06 $</td>
<td>15 $</td>
<td>$</td>
<td>$</td>
</tr>
<tr>
<td></td>
<td>&quot;F&quot; class GT with MH1 amine CO2 scrubber</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>N-PC</td>
<td>Rebuild SC-PC Power Plant - no CCS</td>
<td>630 $ 1,354 $ 2,151</td>
<td>39.0%</td>
<td>0.82 $</td>
<td>228 $</td>
<td>$</td>
<td>$</td>
</tr>
<tr>
<td></td>
<td>Super critical PC + FGD &amp; SCR - no CO2 Capture</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>N-PC-C</td>
<td>Rebuild SC-PC with Post CO2 Capture</td>
<td>499 $ 1,765 $ 3,537</td>
<td>30.9%</td>
<td>0.10 $</td>
<td>36 $</td>
<td>$</td>
<td>$</td>
</tr>
<tr>
<td></td>
<td>Super critical PC with MH1 amine CO2 Scrubber</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>N-OPC-C</td>
<td>Rebuild SC-PC with Oxyfuel CO2 Capture</td>
<td>485 $ 1,644 $ 3,389</td>
<td>30.1%</td>
<td>0.07 $</td>
<td>23 $</td>
<td>$</td>
<td>$</td>
</tr>
<tr>
<td></td>
<td>Super critical PC with oxygen &amp; flue gas recycle</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>IGCC-C</td>
<td>Repower H2-IGCC Pre-comb CO2 Capture</td>
<td>517 $ 1,667 $ 3,224</td>
<td>32.0%</td>
<td>0.08 $</td>
<td>20 $</td>
<td>$</td>
<td>$</td>
</tr>
<tr>
<td></td>
<td>HP GE Gasifier with quench, CO shift &amp; H2/N2-fired GE 7FB GT</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Does not account for power replacement of net drop from the original**

*543 MWe plus shorter remaining life of the old PC*

---

### Input Capital Cost Variables

<table>
<thead>
<tr>
<th>General Facilities for rebuild/retrofit at existing PC site</th>
<th>25% of New Installed Process unit capital</th>
</tr>
</thead>
<tbody>
<tr>
<td>Engineering, Startup &amp; Working Cap</td>
<td>15% of New Installed Process unit capital</td>
</tr>
<tr>
<td>Contingencies</td>
<td>10% of New Installed Process unit capital</td>
</tr>
<tr>
<td>Inflation adjustment from mid-2004 dollars</td>
<td>650 Ch. Eng. index for mid-2008 constant $</td>
</tr>
<tr>
<td>Location adjustment</td>
<td>115% of U.S. Gulf Coast costs to cover extra 10% for CCS risk</td>
</tr>
</tbody>
</table>

Note: this analysis does not include owner’s costs or allowance for funds during construction (AFDC) being capitalized

---

### Input Operating Cost Variables

- **Average annual capacity factor of all options at 85%**: NG can be lower due to its higher marginal dispatch cost
- **(if capitalize AFDC, lower for same return)**: 15.0%/yr of total capital or 6.67 yr capital payback
- **Non-Fuel O&M Costs**: 4.5%/yr of total capital less 1.0% for NGCC
- **Illinois Bit. coal price in Midwest min. shipping $2.00 per million Btu HHV or $48.43 per mt raw coal**
- **Same coal input for all coal cases set at O-PC = NGCC $174.5 m/t/hr raw coal design or 1,613 MWt HHV coal input**
- **Breakeven NG price NGCC wo CCS = O-PC-C1 = O-PC wo CCS $8.31 per million Btu HHV NG prices should go up if CO2 tax**
- **Breakeven NG price will likely change if high enough CO2 tax to make CO2 capture cost effective**

**Natural gas input set to fill 2-F7B GT NGCC at 3,654 million Btu/hr HHV 1,071 MWH HHV NG input**

**CO2 pipeline, injection & monitoring, high due to old PC locations $15.00 /mt CO2 or $0.79 per 1,000 scf HP CO2**

**Limestone minimal shipping $30 /mt**

**"what if" minimal gypsum or sulfur byproduct credits $5.00 /mt gypsum or $26.88 /mt sulfur equivalent**

**"what if" NOx emissions requires purchased credits at $2,000 /mt as NO2**

**"what if" SO2 emissions requires purchased credits at $1,000 /mt SO2**

**"what if" Hg emissions requires purchased credits at $20,000 /lb Hg**

**Lowest CO2 avoidance costs (O-PC-C1) entered as a CO2 tax $74.20 /mt CO2 or $272.07 per mt carbon equivalent**

**CO2 avoidance cost for O-PC-C1 is the lowest CO2 tax where added CCS is the same power cost as O-PC just paying the CO2 tax**

---

Source: SFA Pacific, Inc.  
Client Private  
March 3, 2009
Case: O-PC
Mass & Energy Flow Diagram of Baseline Existing Old Subcritical PC Boiler with Bit Coal

Basis: 600 feet elevation of U.S. Midwest to 1.00 bar (14.5 psia), 15°C (59°F), recycle cooling tower water - 57 mbar (1.7 inch Hg or 96°F) condenser
Assume typical 400-600 MWe gross old PC units build in the early 1970s with old ESP & wet FGD to sludge

Net Water Use
5,933 gpm or
1,346 m³/h
10.9 pgm/MWe net

Limestone
503 mt/d 90.0% sulfur capture

Flue Gas
2,413 mt/h including
518 mt/h CO2
0.95 mt CO2/MWh

Sludge goes with ash
865 mt/d dry basis

Subcritical Steam
6.75 lb total steam/kWh ST
6 lb steam to condenser/kWh ST

Sup Ctr
ST/Gen
42.4% 1

2.400psig/1,000°F

Electric Power
593 MW gross
50 MW Aux

807 MWt cooling loses
1,032.0 Btu/MM Btu HHV

Aux power as % of Gross ST MWe
5.5% 33

MWt

34.9% LHV

543 MW net

Illinois Bit Coal
5,458 mt/d raw coal
10,982 Btu/lb raw HHV

Raw Coal
To Boilers
wt% mt/h kg mol/h
C 61.0% 138.7 115.50
H 4.3% 9.7 6.335
O 7.0% 15.8 60.522
N 1.3% 2.8 15.8
S 3.3% 7.5 2.327

MAF 76.7% 174.5 2.9% vol wet
Ash 11.1% 25.2 25.2
Water 12.2% 27.7 27.7

Total 100.0% 227.4 227.4 same feedrated

Ash/carbon NA 25 for all cases

Clean Flue Gas
kg mol/h mt/h
CO2 11,550 508
H2O 6,335.42 114
SO2 232 15
N2 60,522 1,706
O2 2.327 74

2.9% vol wet

Total 80,966 2,443

Assume 100% carbon conversion

3.1% O2 by vol dry

Source: SFA Pacific, Inc. March 3, 2009
## Case: O-PC Continued

### Economic Estimate of Baseline Old Exiting Paid-off Subcritical PC Boiler with Bit Coal

<table>
<thead>
<tr>
<th>Capital Cost Estimates</th>
<th>Units of Flow</th>
<th>Flow Rates</th>
<th>Baseline Unit Capital</th>
<th>Multi train or unit capital costs</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Actual</td>
<td>ISOdesign</td>
<td>Trains</td>
</tr>
<tr>
<td>Coal &amp; limestone handling &amp; storage</td>
<td>mt/d coal &amp; limestone</td>
<td>5,961</td>
<td>7,153</td>
<td>1</td>
</tr>
<tr>
<td>Flue gas dry milling dilute pneumatic feed</td>
<td>mt/d raw coal</td>
<td>5,458</td>
<td>7,096</td>
<td>4</td>
</tr>
<tr>
<td><strong>Sub-critical PC Boilers</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bit.</td>
<td>kWt heat exchange</td>
<td>1,400,624</td>
<td>1,540,686</td>
<td>1</td>
</tr>
<tr>
<td>Selective Cat. Reduction NOx control</td>
<td>kg mol/h raw flue gas</td>
<td>80,966</td>
<td>89,063</td>
<td>1</td>
</tr>
<tr>
<td>FGD - wet limestone absorber</td>
<td>kg mol/h raw flue gas</td>
<td>80,966</td>
<td>89,063</td>
<td>1</td>
</tr>
<tr>
<td>FGD - forced oxidation to gypsum</td>
<td>mt/d gypsum</td>
<td>865</td>
<td>1,038</td>
<td>1</td>
</tr>
<tr>
<td>ESP</td>
<td>kg mol/h raw flue gas</td>
<td>80,966</td>
<td>89,063</td>
<td>1</td>
</tr>
<tr>
<td>Subcritical reheat steam turbine &amp; gen</td>
<td>kWe ST gross</td>
<td>593,314</td>
<td>622,980</td>
<td>1</td>
</tr>
</tbody>
</table>

### Installed process unit costs

- 401
- 738
- 100
- 185
- 60
- 111
- 40
- 74

### U.S. Gulf Coast Reference $2004 Baseline Unit Capital Cost

- 601
- 1,107

### Inflation adjustment to Ch.E index change for mid-2008 from Ch.E index mid 2004

- 444
- 1,621

### Location adjustment to 115% of U.S. Gulf Coast Construction costs for Total Site Specific Capital Costs

- 1,012
- 1,865

### Product Cost Estimate

<table>
<thead>
<tr>
<th>Capital charges</th>
<th>Assume-paid-off</th>
<th>Average annual capacity factor of</th>
<th>85% or 4.0E+06 MWh per year</th>
<th>$ Million/yr</th>
<th>$/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Non-Fuel O&amp;M Costs</td>
<td>Assume-paid-off</td>
<td>$2.00 per million Btu HHV of 48.43 /mt raw coal</td>
<td>82.0</td>
<td>20.3</td>
<td></td>
</tr>
<tr>
<td>Limestone minimal shipping</td>
<td>$30 /mt</td>
<td>4.7</td>
<td>1.2</td>
<td></td>
<td></td>
</tr>
<tr>
<td>&quot;what if&quot; minimal gypsum byproduct credits</td>
<td>$5.00 /mt gypsum or (26.88) /mt sulfur equivalent</td>
<td>(1.3)</td>
<td>(0.3)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>&quot;what if&quot; NOx emissions requires purchased credits at</td>
<td>$2.00 /mt as NO2</td>
<td>8.9</td>
<td>2.2</td>
<td></td>
<td></td>
</tr>
<tr>
<td>&quot;what if&quot; SO2 emissions requires purchased credits at</td>
<td>$1.00 /mt SO2</td>
<td>6.4</td>
<td>1.6</td>
<td></td>
<td></td>
</tr>
<tr>
<td>&quot;what if&quot; Hg emissions requires purchased credits at</td>
<td>$20,000 /lb Hg or</td>
<td>2.5</td>
<td>0.6</td>
<td></td>
<td></td>
</tr>
<tr>
<td>&quot;what if&quot; CO2 emissions requires purchased credits at</td>
<td>$74.20 /mt CO2 or $272.07 per mt carbon equivalent</td>
<td>285.9</td>
<td>70.7</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Net revenues required at above assumptions

- 434.6
- 107.5

*Can vary the above CO2 tax to calculate at what carbon tax it becomes cheaper to do something*

Source: SFA Pacific, Inc.  
Client Private  
March 3, 2009
Case: O-PC-C1
Mass & Energy Flow Diagram of old PC Boiler & St/gen with just add-on CO2 Post Combustion CO2 Capture

Basis: 600 feet elevation of U.S. Midwest to 1.00 bar (14.5 psia), 15°C (59°F), recycle cooling tower water - 57 mbar (1.7 inch Hg or 96°F) condenser

Net Water Use
5,298 gpm or 1,202 m³/h
13.3 gpm/MWt net

Limestone
559 m³/d or 100% sulfur capture

CO2
1,200 Blub/lb CO2 or
1.3 ton steam/ton CO2

HP CO2 to Pipeline
467 m³/h

Gypsum
530 MW gross
48 MW Aux
28 CO2 scrubber
56 CO2 compressor

Electric Power
52 m³/h CO2
0.13 m³ CO2/2MWh

Air
92.0% LHV effic

Water
12.2% MAF

Illinois Bit Coal
5,458 m³/d raw coal
10,962 Blub/lb raw HHV

16 MWi sub-PC Boilers
2,195 m³/h heat of flue gas to dry feed coal water

18 MWi net
Subcritical Steam
2,400psi 000/1,000°F + added MP to 50 psi back-pressure ST

Subcritical Steam
1,401 MWt
LHV effic
1,817 m³/h total
after heat losses & coal drying

Gypsum
loses in boiler 5.04 lb/h steam to both condensers per Kwe

25.6% LHV

Raw Coal

C 61.0% 138.7 138.7
H 4.3% 9.7 9.7
O 7.0% 15.8 15.8
N 1.3% 2.8 2.8
S 3.3% 7.5 7.5

MAF 76.7% 174.5
Ash 11.1% 25.2 25.2
Water 12.2% 27.7 27.7

Total 100.0% 227.4

CO2 11,550 508
H2O 6,335 42
6,335 114

Theoretical O2 for combustion 11,686 438

N2 in air for combustion 51,641 1,454

O2 in excess air 2,190 70

Ash/carbon NA 25

Total 80,313 2,424

Assume 100% carbon conversion

CO2
11,550 508

Theoretical O2 for combustion 11,686 438

N2 in air for combustion 51,641 1,454

O2 in excess air 2,190 70

Assume 100% carbon conversion

3.0% O2 by vol dry

NOx SO2 Hg

lbs/MM Btu 0.060 - 2.00E-06

Source: SFA Pacific, Inc.

Client Private

March 3, 2009
## Case: O-PC-C1 Continued

**Economic Estimate of Old PC Boiler & st/gen with just Add-on Post Combustion CO2 Capture**

<table>
<thead>
<tr>
<th>Capital Cost Estimates</th>
<th>Units of Flow</th>
<th>Flow Rates</th>
<th>Baseline Unit Capital</th>
<th>Multi train or unit capital costs</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Actual ISODEsign Trains</td>
<td>Unit cost</td>
<td>Train Size</td>
<td>Size/cost exp factor</td>
</tr>
<tr>
<td><strong>Coal &amp; limestone handling &amp; storage</strong></td>
<td>mt/d coal &amp; limestone</td>
<td>6,017 7,220 1</td>
<td>$0</td>
<td>10,000 0.70</td>
</tr>
<tr>
<td><strong>Flue gas dry milling dilute pneumatic feed</strong></td>
<td>mt/d raw coal</td>
<td>5,458 7,096 4</td>
<td>$0</td>
<td>1,774 0.85</td>
</tr>
<tr>
<td><strong>Sub-critical PC Boilers</strong></td>
<td>Bit. kWt heat exchange</td>
<td>1,400,624 1,540,686 1</td>
<td>$0</td>
<td>1,400,000 0.85</td>
</tr>
<tr>
<td><strong>Selective Cat. Reduction NOx control</strong></td>
<td>kg mol/hr raw flue gas</td>
<td>80,313 88,344 1</td>
<td>$0</td>
<td>80,000 0.70</td>
</tr>
<tr>
<td><strong>max recovery FGD - wet limestone absorbe</strong></td>
<td>kg mol/hr raw flue gas</td>
<td>80,313 88,344 1</td>
<td>$0</td>
<td>80,000 0.70</td>
</tr>
<tr>
<td><strong>Caustic trace SO2 removal</strong></td>
<td>kg mol/hr raw flue gas</td>
<td>80,313 88,344 1</td>
<td>$200</td>
<td>80,000 0.70</td>
</tr>
<tr>
<td><strong>FGD - gypsum oxidizer &amp; handling</strong></td>
<td>mt/d gypsum</td>
<td>961 1,153 1</td>
<td>$0</td>
<td>750 0.70</td>
</tr>
<tr>
<td><strong>Bag house</strong></td>
<td>kg mol/hr raw flue gas</td>
<td>80,313 88,344 1</td>
<td>$0</td>
<td>80,000 0.70</td>
</tr>
<tr>
<td><strong>CO2 scrubber</strong></td>
<td>kg mol/hr CO2 stripped</td>
<td>10,395 11,435 1</td>
<td>$1,500</td>
<td>5,717 0.80</td>
</tr>
<tr>
<td><strong>CO2 compressor</strong></td>
<td>kWe driver</td>
<td>56,002 61,603 4</td>
<td>$1,050</td>
<td>15,401 0.85</td>
</tr>
<tr>
<td><strong>old ST/gen + new MP to BP-LP ST/gen</strong></td>
<td>kWe ST no extraction</td>
<td>529,897 622,980 1</td>
<td>$550</td>
<td>500,000 0.80</td>
</tr>
</tbody>
</table>

**Installed process unit costs**
- General Facilities: 25% of Installed Process unit capital
- Engineering, Startup & Working Cap: 15% of Installed Process unit capital
- Contingencies: 10% of Installed Process unit capital

**U.S. Gulf Coast Reference $2004 Baseline Unit Capital Cost**
- 313 787

<table>
<thead>
<tr>
<th>Location adjustment to</th>
<th>115% of U.S. Gulf Coast Construction costs for</th>
<th>Total Site Specific Capital Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Inflation adjustment to</strong></td>
<td>650 Ch.E. index change for mid-2008 from 444 Ch.E index mid 2004 $ baseline</td>
<td>528 1,325</td>
</tr>
</tbody>
</table>

**Product Cost Estimate**
- average annual capacity factor of 85% or 3.0E+06 MWh per year

<table>
<thead>
<tr>
<th>Capital charges Key variable</th>
<th>15.0% or 6.67 yr capital payback</th>
<th>79.2 26.7</th>
</tr>
</thead>
<tbody>
<tr>
<td>Non-Fuel O&amp;M Costs</td>
<td>4.5% yr of total new capital + 100% of old PC capital</td>
<td>69.3 23.4</td>
</tr>
</tbody>
</table>
| Fuel | $2.00 per million Blu HHV of | $48.43 /
| HP CO2 pipeline & injection costs (or credit if for EOR) | $15.00 mt ton CO2 or | $0.79 per 1,000 scf | $52.1 17.6 |
| Limestone | minimal shipping | | |
| "what if" minimal gypsum byproduct credits | $(5.00) mt gypsum or | $(26.88) mt sulfur equivalent | (1.5) (0.5) |
| "what if" NOx emissions requires purchased credits at | $(2,000) mt as NOx2 | | |
| "what if" SO2 emissions requires purchased credits at | $(1,000) mt SO2 | | |
| "what if" Hg emissions requires purchased credits at | $(20,000) lb Hg or | $44 million per mt mercury emissions | 1.6 0.6 |
| "what if" CO2 emissions requires purchased credits at | $(74) mt CO2 or | $272.07 per mt carbon equivalent | 28.6 9.7 |

**CO2 avoidance cost**
- $0 /mt CO2 or $0 /mt C equiv from old PC baseline - ($/MWh ccs - $/MWh b) / (mt CO2/MWh b - mt CO2/MWh ccs)

## Case: O-PC-C2

### Energy Flow Diagram of old PC Boiler with new ST/gen for add-on CO2 Post Combustion CO2 Capture plus steam upgrade

### Basis:
- 600 feet elevation of U.S. Midwest to 1.00 bar (14.5 psia), 15°C (59°F), recycle cooling tower water - 57 mbar (1.7 inch Hg or 96°F) condenser

### Net Water Use
- **5,486 gpm or 1,245 m³/h net**
- **13.1 gpm/MWe net**

### Carbon Capture
- **1,200 Blubt CO2 or 1.2 ton steam/ton CO2**
- **56 MWe HP CO2 to Pipeline 467 m³/h**

### Flue Gas
- **1,928 m³/h including 0.12 m³ CO2/MWh**

### Electric Power
- **549 MW gross**
- **47 MW Aux**
- **28 CO2 scrubber**
- **56 CO2 compressor**

### New Steam
- **4.77 lb/h steam to both condensers per KWe**

### BFW & recycle cooling water
- **5.0%**

### Coal Handling, Dry Feed, Prep
- **5,458 m³/d raw coal**
- **10,362 Blubt raw HHV**

### Air
- **2,195 m³/h**
- **92.0% LHV effic**
- **9.7% N2 in air for combustion**

### Illinois Bit Coal
- **% MAF 76.7%**
- **% Ash 11.1%**
- **% Water 12.2%**

### CO2
- **138.7 m³/h**
- **13.1% CO2**
- **2,190 m³/h O2**

### CO2 Scrubber Stripper
- **2,190 m³/h O2**

### SCR + 2-FGD baghouse
- **1,401 MWe**

### Subcritical Steam
- **2,050/1,050°F upgraded SH/RH + rebuild ST/gen**
- **1,556 kg mol/h CO2**

### BOILERS
- **174.5 MAF**
- **174.5 Ash/Carbon**
- **227.4 Water**

### Coal (wt)
- **C 61.0%**
- **H 4.3%**
- **O 7.0%**
- **N 1.3%**
- **S 3.3%**

### Total
- **100.0%**

### MWe HHV
- **1,613 kg mol/h CO2**
- **1,484 kg mol/h CO2 in air for combustion**

### MWe LHV
- **1,556 kg mol/h CO2**
- **1,454 kg mol/h CO2 in air for combustion**

### Assumptions
- **100% carbon conversion**
- **3.0% O2 by vol dry**

### Source:
- SFA Pacific, Inc.
- Client Private
- March 3, 2009
**Case: O-PC-C2 Continued**

Economic Estimate of Old PC Boiler with Add-on Post Combustion CO2 Capture Pus steam upgrades

### Capital Cost Estimates

<table>
<thead>
<tr>
<th>Units of Flow</th>
<th>Flow Rates</th>
<th>Multi train or</th>
<th>Baseline Unit Capital</th>
<th>Unit capital costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal &amp; limestone handling &amp; storage</td>
<td>mtd coal &amp; limestone</td>
<td>6,017 7,220 1</td>
<td>$0 10,000 0.70</td>
<td>0 0 0 old</td>
</tr>
<tr>
<td>Flue gas dry milling dilute pneumatic feed</td>
<td>mtd raw coal</td>
<td>5,458 7,096 4</td>
<td>$0 1,774 0.85</td>
<td>0 0 0 old</td>
</tr>
<tr>
<td>Old PC Boilers + new SH/RH Bit.</td>
<td>kWt heat exchange</td>
<td>1,400,624 1,540,686 1</td>
<td>$20 1,400,000 0.85</td>
<td>20 73 upgrade</td>
</tr>
<tr>
<td>Selective Cat. Reduction NOx control</td>
<td>kg mol/h raw flue gas</td>
<td>30,313 88,344 2</td>
<td>$400 80,000 0.70</td>
<td>388 82 new</td>
</tr>
<tr>
<td>max recovery FGD - wet limestone absorber</td>
<td>kg mol/h raw flue gas</td>
<td>80,313 88,344 2</td>
<td>$200 80,000 0.70</td>
<td>194 41 new</td>
</tr>
<tr>
<td>Bag house</td>
<td>kg mol/h raw flue gas</td>
<td>80,313 88,344 2</td>
<td>$0 80,000 0.70</td>
<td>0 0 0 old</td>
</tr>
<tr>
<td>CO2 scrubber</td>
<td>kg mol/h raw flue gas</td>
<td>80,313 88,344 2</td>
<td>$750 64,400 0.70</td>
<td>682 144 new</td>
</tr>
<tr>
<td>CO2 stripper</td>
<td>kg mol CO2 stripped</td>
<td>10,395 11,435 2</td>
<td>$1,500 5,717 0.80</td>
<td>1,306 36 new</td>
</tr>
<tr>
<td>CO2 compressor</td>
<td>kWe driver</td>
<td>58,002 61,603 4</td>
<td>$1,050 15,401 0.85</td>
<td>853 126 new</td>
</tr>
<tr>
<td>Rebuild reheat extraction ST &amp; gen</td>
<td>kWe ST no extraction</td>
<td>548,568 622,980 2</td>
<td>$150 500,000 0.80</td>
<td>144 214 rebuild</td>
</tr>
</tbody>
</table>

Total site specific capital costs = 755 1,807

### Product Cost Estimate

- **Capital charges**
  - **Key variable**
    - 15% of total capital or 6.67 yr capital payback
  - 85% or 3.1E+06 MWh per year

- **Non-Fuel O&M Costs**
  - Illinois Bit in midWest min. shipping
  - Fuel

- HP CO2 pipeline & injection costs (or credit if for EOR)
  - \(\text{CO}_2\) avoidance cost

- Limestone
  - minimal shipping

- "what if" minimal gypsum byproduct credits

- "what if" NOx emissions require purchased credits at

- "what if" SO2 emissions require purchased credits at

- "what if" \(\text{Hg}\) emissions require purchased credits at

- "what if" \(\text{CO}_2\) emissions require purchased credits at

- \(\text{CO}_2\) avoidance cost

- Net revenues required at above assumptions

**Source:** SFA Pacific, Inc.  
**Client Private**  
**March 3, 2009**
Case: NGCC
NGCC Replacement Repowering of Old PC at Existing Site for CO2 Reduction

Basis: 600 feet elevation of U.S. Midwest to 1.00 bar (14.5 psia), 15°C (59°F), recycle cooling tower water - 57 mbar (1.7 inch Hg or 96°F) condenser
Elevation is 2% GT ISO capacity derating but no efficiency loses plus additional 0.42% capacity & 0.42% efficiency loses from SCR back pressure
Recycle cooling tower water increases internal power, SCR slightly reduces HRSG heat recovery efficiency

Natural Gas

<table>
<thead>
<tr>
<th>GT-specific power</th>
<th>Natural Gas</th>
<th>GT exhaust flue gas assuming</th>
<th>NOx Emissions of ppmv NOx in dry gas @</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>excess dry air</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>kg mol/h</td>
<td>mth/h</td>
</tr>
<tr>
<td></td>
<td>CH4</td>
<td>86.25%</td>
<td>3,625</td>
</tr>
<tr>
<td></td>
<td>C2H6</td>
<td>9.75%</td>
<td>401</td>
</tr>
<tr>
<td></td>
<td>CO2</td>
<td>1.00%</td>
<td>41</td>
</tr>
<tr>
<td></td>
<td>N2</td>
<td>1.00%</td>
<td>41</td>
</tr>
<tr>
<td>Total</td>
<td>100.00%</td>
<td>4,107.8</td>
<td>73</td>
</tr>
</tbody>
</table>

相同气流率

<table>
<thead>
<tr>
<th>MWh HHV</th>
<th>MWh LHV</th>
<th>same feedrate: 2% of GT exhaust mass low</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.108</td>
<td>1,070.6</td>
<td></td>
</tr>
<tr>
<td>HHV/LHV</td>
<td>966.4</td>
<td></td>
</tr>
</tbody>
</table>

Capital Cost Estimate

<table>
<thead>
<tr>
<th>Units of Flow</th>
<th>Flow Rates</th>
<th>Baseline Unit Capital</th>
<th>Multi train &amp; Size/cost</th>
<th>Adjusted unit cost</th>
<th>$ Million</th>
<th>$/kWe net</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Actual</td>
<td>ISO design</td>
<td>Trains</td>
<td>Unit cost</td>
<td>Train Size</td>
<td>exp factor</td>
</tr>
<tr>
<td>Gas turbines &amp; gen - dry Low-NOx</td>
<td>kWe GT gross</td>
<td>357,553</td>
<td>366,300</td>
<td>2</td>
<td>$300</td>
<td>183,150</td>
</tr>
<tr>
<td>HRSG installed</td>
<td>kW heat to steam</td>
<td>529,662</td>
<td>556,145</td>
<td>2</td>
<td>$90</td>
<td>278,072</td>
</tr>
<tr>
<td>SCR NOx control in HRSG</td>
<td>kg mol/h raw flue gas</td>
<td>112,924</td>
<td>124,217</td>
<td>2</td>
<td>$150</td>
<td>62,108</td>
</tr>
<tr>
<td>Subcritical reheat steam turbine &amp; gen kW ST gross</td>
<td>198,623</td>
<td>214,200</td>
<td>1</td>
<td>$210</td>
<td>500,000</td>
<td>0.80</td>
</tr>
</tbody>
</table>

General Facilities: 25% of Installed Process unit capital
Engineering, Startup & Working Cap: 15% of Installed Process unit capital
Contingencies: 10% of Installed Process unit capital

Installed process unit costs

<table>
<thead>
<tr>
<th>General Facilities</th>
<th>Engineering, Startup &amp; Working Cap</th>
<th>Contingencies</th>
<th>Saving due to exising PC site</th>
<th>U.S. Gulf Coast Reference 2004 Baseline Unit Capital Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>214 Facilites</td>
<td>359</td>
<td>32</td>
<td>53</td>
<td>320</td>
</tr>
</tbody>
</table>

Inflation adjustment to: 650 Ch.E. index change for mid-2008 from 444 Ch.E index mid 2004$ baseline

Location adjustment to: 115% of U.S. Gulf Coast Construction costs for Total Site Specific Capital Costs

Product Cost Estimate

<table>
<thead>
<tr>
<th>Product Cost Estimate</th>
<th>average annual capacity factor of</th>
<th>See notes below</th>
<th>4.05E+06 MWh/yr</th>
<th>80.9</th>
<th>20.0</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital changes assuming</td>
<td>15.0% of total capacity or</td>
<td>$/yr of total capacity or</td>
<td>6.67 $/yr payback</td>
<td>8.09</td>
<td>20.0</td>
</tr>
<tr>
<td>Non-Fuel O&amp;M Costs</td>
<td>4% of total capacity (use higher % for coal units)</td>
<td>$/yr of total capital</td>
<td>18.9</td>
<td>4.7</td>
<td></td>
</tr>
<tr>
<td>Fuel Natural gas</td>
<td>Key variable</td>
<td>$ 8.31</td>
<td>per million Btu HHV</td>
<td>226.2</td>
<td>55.9</td>
</tr>
<tr>
<td>&quot;what if&quot; NOx emissions requires purchased credits at $ 2,000</td>
<td>as NO2</td>
<td>See notes below</td>
<td>$4.0</td>
<td>0.1</td>
<td></td>
</tr>
<tr>
<td>&quot;what if&quot; CO2 emissions requires purchased credits at $ 74.20</td>
<td>as CO2</td>
<td>272.07</td>
<td>per mt carbon equivalent</td>
<td>108.6</td>
<td>26.9</td>
</tr>
</tbody>
</table>

Gross revenues required at above assumptions 435.0 | 107.5 |

NG price so no CCS NGCC CO2 avoided cost is same as lowest CCS

<table>
<thead>
<tr>
<th>CO2 avoidance cost</th>
<th>$0</th>
<th>$0</th>
<th>$0</th>
</tr>
</thead>
</table>

Source: SFA Pacific, Inc.
Client Private
March 3, 2009
Case: NGCC-C
NGCC Replacement Repowering of Old PC at Existing Site with Post CO2 Capture

Basis: ISO conditions of sea level (1,013 bar), 15°C, LHV with recycle cooling tower - 76 mbar (2.25 inch or 105°F) condenser

- Natural Gas
  - 1,071 MWe, HHV
  - 1,804 MWe, HHV
  - 72.3 MWe NG
  - 22.654 Btu/lb HHV
  - 20.448 Btu/lb HHV

- Capital Cost Estimate
  - Units of Flow
  - Flow Rates
  - Baseline Unit Capital
  - Multi train & Size/cost
  - Adjusted unit cost
  - $ Million
  - $/kWe net

- General Facilities
- Engineering, Startup & Working Cap
- Contingencies
- U.S. Gulf Coast Reference: 2004 Baseline Unit Capital Cost
- Inflation adjustment to Ch. E. index change for mid-2008
- Location adjustment to 15% of U.S. Gulf Coast Construction costs

- Product Cost Estimate
  - average annual capacity factor of 85%
  - See notes below: 3.45E+06 MWh/yr
  - $ Million/yr
  - $/MWh

- CO2 avoidance cost: $15/mt CO2 or $54/mt C equiv from old PC baseline - ($/MWh ccs - $/MWh b) / (mt CO2/MWh b - mt CO2/MWh ccs)

Assuming the same annual load factor for NGCC and coal-based power is questionable due to the much higher marginal load dispatch costs of NGCC. Was only done here to show relative "break-even" capital loaded economics for the NG price at which new baseload coal & NGCC power costs are the same.
Case: N-PC
Mass & Energy Flow Diagram Replacement Supercritical PC Boiler at Old PC Site for CO2 Reduction

Basis: 600 feet elevation of U.S. Midwest to 1.00 bar (14.5 psia), 15°C (59°F), recycle cooling tower water - 57 mbar (1.7 inch Hg or 96°F) condenser

Net Water Use
- 6,844 gpm or 1,553 mt/h
- 10.9 gpm/MWe net

Limestone
- 559 mt/d
- 95.0% sulfur capture

Flue Gas
- 2,294 mt/h including 518 mt/h CO2
- 0.82 mt CO2/MWh

Electric Power
- 684 MW gross
- 55 MW Aux
- 40.5% HHV

Gypsum
- 913 mt/d

Fuels
- Illinois Bit Coal
  - 5,458 mt/d raw coal
  - 10,982 But/lb raw HHV

Raw Coal
- Coal
  - wt% C: 61.0%, H: 4.3%, O: 7.0%, N: 1.3%, S: 3.3%
  - MAF: 76.7%, Ash: 11.1%, Water: 12.2%

To Boilers
- 1,406 MWt
- Supercritical Steam
  - 1,056 mt/h cond
  - LHV effic: 1,520 mt/h total: 48.6%
  - 34.8% non-flue gas heat losses in boiler

Air
- 2,195 m³/h

Coal Handling
- Dry Feed Prep

18 MWt
- heat of flue gas to dry feed coal water

SCR
- 1,032 Btu/lb steam condensed

FGD
- 1,150 Btu/lb steam to condenser/kW ST

Flue Gas baghouse
- 2,394 mt/h including 518 mt/h CO2
- 1.5% non-flue gas heat energy

Heat ash/carbon
- 25.2 NA

Sup Flue Gas
- 3.50 lb steam to condenser/kW ST
- 724 MWt cooling losses

Mantle
- 70 kg/MWhe

Coal
- 11.1% 25.2 25.2

Water
- 12.2% 27.7 27.7

Nitrogenous Pollutants
- NOx
- SO2
- Hg

16.0% excess dry air

Water
- 12.2% 27.7 27.7

Oxygen
- 100.0% 227.4 227.4

Total dry air feed
- 75,779 2,195 3.0% O2 by vol dry

Assume 100% carbon conversion

18.0% excess dry air

Oxygen
- 100.0% 227.4 227.4

Total dry air feed
- 75,779 2,195

Assume 100% carbon conversion

O2 by vol dry
- 3.0%

Source: SFA Pacific, Inc.
Client Private
March 3, 2009
# Case: N-PC Continued

## Economic Estimate of Baseline Replacement Supercritical PC Boiler at Old PC Site for CO2 Reduction

### Capital Cost Estimates

<table>
<thead>
<tr>
<th>Units of Flow</th>
<th>Flow Rates</th>
<th>Baseline Unit Capital</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Actual ISO design</td>
<td>Trains</td>
</tr>
<tr>
<td>Coal &amp; limestone handling &amp; storage</td>
<td>6,017 7,220</td>
<td>1</td>
</tr>
<tr>
<td>Flue gas dry milling dilute pneumatic feed</td>
<td>5,458 7,096</td>
<td>4</td>
</tr>
<tr>
<td>Supercritical PC Boilers Bit.</td>
<td>1,408,236 1,549,060</td>
<td>1</td>
</tr>
<tr>
<td>Selective Cat. Reduction NOx control</td>
<td>80,313 88,344</td>
<td>1</td>
</tr>
<tr>
<td>New FGD - wet limestone absorber</td>
<td>80,313 88,344</td>
<td>1</td>
</tr>
<tr>
<td>New FGD - gypsum oxidizer &amp; handling</td>
<td>913 1,096</td>
<td>1</td>
</tr>
<tr>
<td>New Bag house</td>
<td>80,313 88,344</td>
<td>1</td>
</tr>
</tbody>
</table>

### General Facilities
- 25% of Installed Process unit capital: Saving due to existing PC site = 134 $ 213 saving?
- 15% of Installed Process unit capital: Engineering, Startup & Working Cap = 80 128
- 10% of Installed Process unit capital: Contingencies = 54 85

### Inflation adjustment to U.S. Gulf Coast Reference $2004 Baseline Unit Capital Cost
- 650 Ch.E. index change for mid-2008 from baseline 1,178 1,870

### Location adjustment to 115% of U.S. Gulf Coast Construction costs for Total Site Specific Capital Costs 1,354 2,151

### Product Cost Estimate

<table>
<thead>
<tr>
<th>Capital charges</th>
<th>Key variable</th>
<th>$/yr of total capital or $/MWh</th>
<th>$/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Non-Fuel O&amp;M Costs</td>
<td>15.0%</td>
<td>4.7E+06 MWh per year</td>
<td>6.67 yr capital payback</td>
</tr>
<tr>
<td>Illinois Bit in MIdWest min. shipping</td>
<td>4.5%</td>
<td>60.9</td>
<td>13.0</td>
</tr>
<tr>
<td>Limestone minimal shipping</td>
<td>2.00 per million Btu HHV of</td>
<td>6.48</td>
<td>17.5</td>
</tr>
<tr>
<td><em>what if</em> minimal gypsum byproduct credits</td>
<td>$5.00</td>
<td>1.4 (0.3)</td>
<td></td>
</tr>
<tr>
<td><em>what if</em> NOx emissions requires purchased credits at</td>
<td>$2,000</td>
<td>(26.86) /mt sulfur equivalent</td>
<td>2.7</td>
</tr>
<tr>
<td><em>what if</em> SO2 emissions requires purchased credits at</td>
<td>$1,000</td>
<td>(1.4) (0.3)</td>
<td></td>
</tr>
<tr>
<td><em>what if</em> Hg emissions requires purchased credits at</td>
<td>$20,000</td>
<td>3.2</td>
<td>0.7</td>
</tr>
<tr>
<td><em>what if</em> CO2 emissions requires purchased credits at</td>
<td>$74.20</td>
<td>272.07 per mt carbon equivalent</td>
<td>286.2</td>
</tr>
</tbody>
</table>

### Net revenues required at above assumptions 643.6 137.3

**CO2 avoidance cost** $228 /mt CO2 or $836 /mt C equiv from old PC baseline - ($/MWh ccs - $/MWh b) / (mt CO2/MWh b - mt CO2/MWh ccs)

Source: SFA Pacific, Inc.  
Client Private  
March 3, 2009
**Case: N-PC-C**

Mass & Energy Flow Diagram of Replacement Supercritical PC Boiler with CO2 Post Combustion CO2 Capture

**Basis:** 600 feet elevation of U.S. Midwest to 1.00 bar (14.5 psia), 15°C (59°F), recycle cooling tower water - 57 mbar (1.7 inch Hg or 96°F) condenser

---

### Net Water Use
- 6,266 gpm or 1,426 m/h
- 12.6 gpm/MWe net

### Limestone
- 559 m/ld
- 100% sulfur capture

### SCR
- 1,408 MWt
- 1.066 m/h cond

### Sup Crit ST/Gen
- 3.81 lb/m/h steam to both condensers per KWe

### Electric Power
- 629 MW gross
- 50 MW Aux
- 23 CO2 scrubber
- 56 CO2 compressor

### HP CO2 to Pipeline
- 467 m/h

### Supercritical Steam
- 1,928 mt/h including
- 1.90% non-flue gas heat loses in boiler
- 52 m/h CO2
- 0.10 m/t CO2/MWh

### Water 12.2% (27.7)

### Dry Feed Prep
- 11.1% (25.2)
- 3.3% (7.5)
- 76.7% (174.5)

### Air
- 2,195 m/h
- 92.5%
- 18 MWt heat of flue gas to dry feed coal water

### Illinois Bit Coal
- 5,458 mt/d raw coal (10,982 Bulb raw HLV)

### Raw Coal
- \( \text{wt\%} \)
- \( \text{m/ld} \)
- \( \text{m/h} \)

<table>
<thead>
<tr>
<th>C</th>
<th>61.0%</th>
<th>138.7</th>
<th>138.7</th>
</tr>
</thead>
<tbody>
<tr>
<td>H</td>
<td>4.3%</td>
<td>9.7</td>
<td>9.7</td>
</tr>
<tr>
<td>O</td>
<td>7.0%</td>
<td>15.8</td>
<td>15.8</td>
</tr>
<tr>
<td>N</td>
<td>1.3%</td>
<td>2.8</td>
<td>2.8</td>
</tr>
<tr>
<td>S</td>
<td>3.3%</td>
<td>7.5</td>
<td>7.5</td>
</tr>
<tr>
<td>MAF</td>
<td>76.7%</td>
<td>174.5</td>
<td>174.5</td>
</tr>
<tr>
<td>Ash</td>
<td>11.1%</td>
<td>25.2</td>
<td>25.2</td>
</tr>
<tr>
<td>Water</td>
<td>12.2%</td>
<td>27.7</td>
<td>27.7</td>
</tr>
<tr>
<td>Total</td>
<td>100.0%</td>
<td>227.4</td>
<td>227.4</td>
</tr>
</tbody>
</table>

---

### Coal Handling & Dry Feed

### Supercritical Steam
- 1,032.0 m/h steam to condenser

### Flue Gas
- 1,928 mt/h
- 1.0% non-flue gas heat

### CO2 Compressor
- 1,200 Btu/lb CO2 or 1.1 ton steam/ton CO2

### Net Water Use
- 559 mt/d
- 1.1 ton steam/ton CO2

### 2-FGD Scurbber
- 12.6 gpm/MWe net

### SCR
- 1,426 m/h SCR

### Flue Gas Baghouse Stripper
- 1,928 mt/h including
- 190% SO2

### Gypsum
- 961 mt/d

### Electric Power
- 52 MWe

### Gypsum
- 6,286 gpm or 100.0% sulfur capture

### BFW & recycle cooling water
- 4.5% BFW & recycle cooling water

### SCR & super FGD pumps & fans
- 1.5% SCR & super FGD pumps & fans

### Main fans, coal handling & dry coal milling conveying
- 2.0% main fans, coal handling & dry coal milling conveying

### Added load of CO2 capture system (fan, amine circ & CW)
- 0.05 Added load of CO2 capture system

### Auxiliary power as % of Gross ST MWe
- 32.1% LHV

### Btu/kWh HHV
- 30.9%

### Source: SFA Pacific, Inc. March 3, 2009

---

# Energy Flow Diagram

**Net Water Use**

**Limestone**

**SCR**

**Sup Crit**

**Electric Power**

**Coal Handling**

**Dry Feed Prep**

**Illinois Bit Coal**

**Raw Coal**

**To Boilers**

**Clean Flue Gas**

**Ash/Carbon**

**Total**

---

**Source:** SFA Pacific, Inc.

**Client Private**

**March 3, 2009**
Case: N-PC-C Continued

Economic Estimate of Replacement Supercritical PC Boiler with Post Combustion CO2 Capture

### Capital Cost Estimates

<table>
<thead>
<tr>
<th>Units of Flow</th>
<th>Flow Rates</th>
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<th>Multi train or Adjusted</th>
<th>unit capital costs</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Actual ISODesign</td>
<td>Trains</td>
<td>Size/cost</td>
<td>exp factor</td>
</tr>
<tr>
<td>Coal &amp; limestone handling &amp; storage</td>
<td>mtd coal &amp; limestone</td>
<td>6,017</td>
<td>7,220</td>
<td>1</td>
</tr>
<tr>
<td>Flue gas dry milling dilute pneumatic feed</td>
<td>mtd raw coal</td>
<td>5,458</td>
<td>7,086</td>
<td>4</td>
</tr>
<tr>
<td>Oxy Supercritical PC Boilers</td>
<td>Bt</td>
<td>kWt heat exchange</td>
<td>1,408,236</td>
<td>1,549,060</td>
</tr>
<tr>
<td>Selective Cat. Reduction NOx control</td>
<td>kg mol/h raw flue gas</td>
<td>80,313</td>
<td>88,344</td>
<td>1</td>
</tr>
<tr>
<td>max recovery FGD - wet limestone absorber</td>
<td>kg mol/h raw flue gas</td>
<td>80,313</td>
<td>88,344</td>
<td>1</td>
</tr>
<tr>
<td>Caustic trace SO2 removal</td>
<td>kg mol/h raw flue gas</td>
<td>80,313</td>
<td>88,344</td>
<td>1</td>
</tr>
<tr>
<td>FGD - gypsum oxidizer &amp; handling</td>
<td>mtd gypsum</td>
<td>961</td>
<td>1,153</td>
<td>1</td>
</tr>
<tr>
<td>Bag house</td>
<td>kg mol/h raw flue gas</td>
<td>80,313</td>
<td>88,344</td>
<td>1</td>
</tr>
<tr>
<td>CO2 scrubber</td>
<td>kg mol/h raw flue gas</td>
<td>80,313</td>
<td>88,344</td>
<td>1</td>
</tr>
<tr>
<td>CO2 stripper</td>
<td>kg mol/h CO2 stripped</td>
<td>10,395</td>
<td>11,435</td>
<td>1</td>
</tr>
<tr>
<td>CO2 compressor</td>
<td>kWe driver</td>
<td>56,002</td>
<td>61,603</td>
<td>4</td>
</tr>
<tr>
<td>Supercritical reheat extraction ST &amp; gen</td>
<td>kWe ST no extraction</td>
<td>629,586</td>
<td>710,623</td>
<td>1</td>
</tr>
</tbody>
</table>

### Installed process unit costs

- General Facilities: 25% of Installed Process unit capital
- Saving due to existing PC site: 175
- Engineering, Startup & Working Cap: 15% of Installed Process unit capital: 105
- Contingencies: 10% of Installed Process unit capital: 70

### Total Specified Capital Costs

U.S. Gulf Coast Reference $2004 Baseline Unit Capital Cost: 1,048

Inflation adjustment to Ch.E. index change for mid-2008 from 444 Ch.E index mid 2004 $ baseline: 1,535

Location adjustment to 115% of U.S. Gulf Coast Construction costs for Total Site Specific Capital Costs: 3,537

### Product Cost Estimate

<table>
<thead>
<tr>
<th>Capital charges</th>
<th>Key variable</th>
<th>average annual capacity factor of 85%</th>
<th>3.7E+06 MWh per year</th>
<th>$ Million/yr</th>
<th>$/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital charges</td>
<td>Key variable</td>
<td>average annual capacity factor of 85%</td>
<td>3.7E+06 MWh per year</td>
<td>$ Million/yr</td>
<td>$/MWh</td>
</tr>
<tr>
<td>Non-Fuel O&amp;M Costs</td>
<td>Key variable</td>
<td>average annual capacity factor of 85%</td>
<td>3.7E+06 MWh per year</td>
<td>$ Million/yr</td>
<td>$/MWh</td>
</tr>
<tr>
<td>Fuel</td>
<td>Illinois Blt in Midwest min. shipping</td>
<td>$2.00 per million Blu HHV of</td>
<td>48.43</td>
<td>$2.00 per million Blu HHV</td>
<td>48.43</td>
</tr>
<tr>
<td>HP CO2 pipeline &amp; injection costs (or credit if for EOR)</td>
<td>Key variable</td>
<td>average annual capacity factor of 85%</td>
<td>3.7E+06 MWh per year</td>
<td>$ Million/yr</td>
<td>$/MWh</td>
</tr>
<tr>
<td>Limestone</td>
<td>minimal shipping</td>
<td>$30</td>
<td>5.2</td>
<td>1.4</td>
<td></td>
</tr>
<tr>
<td>&quot;what if&quot; minimal gypsum byproduct credits</td>
<td>Key variable</td>
<td>average annual capacity factor of 85%</td>
<td>3.7E+06 MWh per year</td>
<td>$ Million/yr</td>
<td>$/MWh</td>
</tr>
<tr>
<td>&quot;what if&quot; NOx emissions requires purchased credits at</td>
<td>Key variable</td>
<td>average annual capacity factor of 85%</td>
<td>3.7E+06 MWh per year</td>
<td>$ Million/yr</td>
<td>$/MWh</td>
</tr>
<tr>
<td>&quot;what if&quot; SO2 emissions requires purchased credits at</td>
<td>Key variable</td>
<td>average annual capacity factor of 85%</td>
<td>3.7E+06 MWh per year</td>
<td>$ Million/yr</td>
<td>$/MWh</td>
</tr>
<tr>
<td>&quot;what if&quot; Hg emissions requires purchased credits at</td>
<td>Key variable</td>
<td>average annual capacity factor of 85%</td>
<td>3.7E+06 MWh per year</td>
<td>$ Million/yr</td>
<td>$/MWh</td>
</tr>
</tbody>
</table>

Net revenues required at above assumptions: 514.5

### CO2 avoidance cost

- $36 /mt CO2 or $134 /mt C equiv from old PC baseline - ($/MWh ccs - $/MWh b) / (mt CO2/MWh b - mt CO2/MWh ccs)

Source: SFA Pacific, Inc. Client Private

March 3, 2009
Case: N-OPC-C

Mass & Energy Flow Diagram of Replacement Oxyfuel Supercritical PC Boiler for CO2 Capture

Basis: 600 feet elevation of U.S. Midwest to 1.00 bar (14.5 psia), 15°C (59°F), recycle cooling tower water - 57 mbar (1.7 inch Hg or 96°F) condenser

Assume CO2 rich flue gas recycle to get the same mass flow through PC boiler as traditional air combustion (make heat transfer similar)

Net Water Use
6,955 gpm or 1,578 m³/h

High Pressure CO2 to pipeline
473 mt/h CO2

Gypsum
913 mt/d

CO2 rich flue gas recycle

1.578 mt/h CO2 dryer

62 MWe

Limestone + its CO2
531 mt/d

SO2 capture
111 mt/h

CO2 losses with impurities stripping gases
35 mt/h CO2

Net Flue Gas
5.0% CO2 loses with 35 mt/h CO2

Electric Power
696 MW gross
52 MW Aux
97 ASU
62 CO2 processing
485 MW net

Aux power as % of Gross ST
MWe
31.2% LHV
30.1% HHV

O2 by wt.

Acid water & Non-condensable gas impurities
95%
5.0%

Waste gas/acid process

Sup Crit ST/Gen
3,500psi/1,100/1,100°F

Air leakage

736 MWe cooling losses
1,034 Btu/lb steam condensed

O2 in excess
241
13
2.0% vol wet
411
13

80% vol CO2 dry basis

possible to boiler with recycle
65,265
2,197

if air total oxidant feed
75,779
2,195

N2 in O2 - mostly from air leakage

Recycle net flue gas to dilute oxygen
49,062
1,686

excess oxygen

2,208
62

BOF & recycle cooling water 4.5%
31

Waste gas FGD processing 1.0%
7
11,352 Btu/kWh HHV

Dry Feed main fans, coal handling & dry coal milling conveying 2.0% assume same as air PC

1,556
1,556

NOx SO2 Hg

MW t HHV
1,644
1,644

1,000
1,000

0.100
0.744
0.00E+00

lbs/MM Btu
0.040
0.298
0.00E+00

kg/MWhe
0.206
1.533
0.00E+00

% HHV
100%
100%

% LHV
100%
100%

CO2 vol % feed oxidant
22%

Potential Safety & Insurance Limits > 28% by vol

Recycle net flue gas to dilute oxygen
49,062
1,686

total oxidant to boiler with recycle
65,265
2,197

if air total oxidant feed
75,779
2,195

Source: SFA Pacific, Inc.
Client Private
March 3, 2009
**Case: N-OPC-C Continued**

**Economic Estimate of Replacement Oxyfuel Supercritical PC Boiler for CO2 Capture**

**Note:** Assumptions for special oxyfuel PC design and massive ASU can greatly impact results

100% $/kWt of conventional air PC boiler & same mass flow assuming (MWt = mass x cp x delta T)

### Capital Cost Estimates

<table>
<thead>
<tr>
<th>Units of Flow</th>
<th>Flow Rates</th>
<th>Baseline Unit Capital</th>
<th>Multi train or unit capital costs</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Unit cost</td>
<td>Train Size</td>
</tr>
<tr>
<td>Coal handling &amp; storage</td>
<td>mtd coal &amp; limestone</td>
<td>5,458</td>
<td>6,550</td>
</tr>
<tr>
<td>Flue gas dry milling dilute pneumatic feed</td>
<td>mtd raw coal</td>
<td>5,458</td>
<td>7,096</td>
</tr>
<tr>
<td>Special Oxyfuel Supercritical PC Boilers</td>
<td>kW heat exchange</td>
<td>1,431,072</td>
<td>1,574,180</td>
</tr>
<tr>
<td>New Bag house</td>
<td>kg mol/h raw flue gas</td>
<td>69,799</td>
<td>76,779</td>
</tr>
<tr>
<td>LP ASU air compressor</td>
<td>kW driver</td>
<td>96,756</td>
<td>101,594</td>
</tr>
<tr>
<td>Big LP ASU cold box</td>
<td>mtd O2</td>
<td>10,555</td>
<td>11,083</td>
</tr>
<tr>
<td>CO2 compressor with impurity stripper</td>
<td>kW driver</td>
<td>61,514</td>
<td>61,514</td>
</tr>
<tr>
<td>Impurity gas &amp; acid processing</td>
<td>kg mol/h raw gas</td>
<td>3,428</td>
<td>3,771</td>
</tr>
<tr>
<td>Gypsum reactors &amp; handling</td>
<td>mtd gypsum</td>
<td>913</td>
<td>1,096</td>
</tr>
<tr>
<td>Supercritical reheat steam turbine &amp; gen</td>
<td>kW ST gross</td>
<td>695,501</td>
<td>730,276</td>
</tr>
</tbody>
</table>

**Installed process unit costs**

- Total Site Specific Capital Costs: 1,644,389

### Product Cost Estimate

- **CO2 avoidance cost**:
  - $23 /mt CO2 or $85 /mt C equiv from old PC baseline

**Average annual capacity factor of 85% or 3.6E+06 MWh per year**

**Net revenues required at above assumptions**

- $462.5 128.0

**Source:** SFA Pacific, Inc.

**Client Private**

**March 3, 2009**
Case: IGCC-C
Mass & Energy Flow Diagram for Replacement GE-IGCC Precombustion for CO2 Capture

Basis: 600 feet elevation of U.S. Midwest to 1.00 bar (14.5 psia), 15°C (59°F), recycle cooling tower water - 57 mbar (1.7 inch Hg or 96°F) condenser
HP ASU - all N2 to GT syngas uprate 7FB to 232 MW ISO (-2% for 600 feet to 227 MWe) & reduce NOx without SCR to about 15 ppmv

Net Water Use
- 5,630 gpm or 10
- 1,277 mt/h total ASU

14
- MW O2 compressor
- 3,146 mt/h total
- 0.052 lb/MM Btu
- 39% from GT
- 95%

42
- MW N2 compressor
- 90% of exhaust
- 1.45E-06 kg/MWe
- 12%

578
- mt/h HP N2 to syngas

2
- HP ASU impact on power/cost of compressors - increases air, reduces O2, added N2 NOx SO2 Hg

100%
- Air HP 36
- MW air compressor
- 0.130
- 0.074
- 7.49E-07

765
- mt/h total

14
- MW O2 compressor
- 3,146 mt/h total
- 0.130
- 0.074
- 7.49E-07

42
- MW N2 compressor
- 90% of exhaust
- 1.45E-06 kg/MWe
- 12%

4
- m/h LP O2 to Claus

100%
- Air HP 36
- MW air compressor
- 0.130
- 0.074
- 7.49E-07

95%
- Recycle cooling tower water - 57 mbar (1.7 inch Hg or 96°F) condenser

25%
- HP ASU - all N2 to GT syngas uprate 7FB to 232 MW ISO (-2% for 600 feet to 227 MWe) & reduce NOx without SCR to about 15 ppmv

Case: IGCC-CContinued
### Economic Estimate of Replacement GE IGCC Precombustion for CO2 Capture

#### Capital Cost Estimates

<table>
<thead>
<tr>
<th>Units of Flow</th>
<th>Flow Rates Actual</th>
<th>ISOdesign Trains</th>
<th>Baseline Unit Capital Size/cost</th>
<th>Multi train or Adjusted unit capital costs</th>
<th>unit capital costs</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Train Size</td>
<td>$/1000</td>
<td>0.70</td>
</tr>
<tr>
<td>Coal handling &amp; storage</td>
<td>mtd raw coal</td>
<td>5,458</td>
<td>6,550</td>
<td>1</td>
<td>$2,500</td>
</tr>
<tr>
<td>Wet coal milling &amp; slurry prepfeed</td>
<td>mtd raw coal</td>
<td>5,458</td>
<td>7,096</td>
<td>4</td>
<td>$430</td>
</tr>
<tr>
<td>HP ASU air compressor</td>
<td>kW driver</td>
<td>36,354</td>
<td>38,172</td>
<td>2</td>
<td>$10,850</td>
</tr>
<tr>
<td>HP ASU cold box</td>
<td>mtd C2</td>
<td>4,250</td>
<td>4,463</td>
<td>2</td>
<td>$1,400</td>
</tr>
<tr>
<td>HP ASU O2 compressors</td>
<td>kW driver</td>
<td>14,047</td>
<td>14,749</td>
<td>2</td>
<td>$450</td>
</tr>
<tr>
<td>GE Quench Gasifier @ 70 atm.</td>
<td>kg mol/h raw syngas</td>
<td>22,908</td>
<td>25,199</td>
<td>2</td>
<td>$3,000</td>
</tr>
<tr>
<td>Sour CO shift 2-stage</td>
<td>kg mol/h raw syngas</td>
<td>44,210</td>
<td>48,631</td>
<td>2</td>
<td>$700</td>
</tr>
<tr>
<td>Low T cooling, scrubbing &amp; CO2 convert.</td>
<td>kg mol/h dry syngas</td>
<td>27,166</td>
<td>29,883</td>
<td>2</td>
<td>$1,700</td>
</tr>
<tr>
<td>HP Selective AG Absorbers</td>
<td>kg mol/h dry feed gas</td>
<td>27,166</td>
<td>29,883</td>
<td>2</td>
<td>$2,250</td>
</tr>
<tr>
<td>Selective AG Stripper high CO2</td>
<td>kg mol/hr acid gas</td>
<td>10,720</td>
<td>13,936</td>
<td>2</td>
<td>$2,000</td>
</tr>
<tr>
<td>O2 Claus &amp; tail gas recycle</td>
<td>mtd/sulfur 20% feed</td>
<td>177</td>
<td>318</td>
<td>3</td>
<td>$75,000</td>
</tr>
<tr>
<td>CO2 compressor</td>
<td>kW driver</td>
<td>46,167</td>
<td>50,784</td>
<td>2</td>
<td>$1,000</td>
</tr>
<tr>
<td>H2 expander to 30 atm.</td>
<td>kW expander</td>
<td>8,005</td>
<td>8,405</td>
<td>2</td>
<td>$800</td>
</tr>
<tr>
<td>GT/gen if air extraction + 10%</td>
<td>kWt heat exchange</td>
<td>419,608</td>
<td>366,300</td>
<td>2</td>
<td>$360</td>
</tr>
<tr>
<td>HRSG &amp; superheater</td>
<td>kWt heat exchange</td>
<td>559,140</td>
<td>587,097</td>
<td>2</td>
<td>$100</td>
</tr>
<tr>
<td>Subcritical reheat steam turbine &amp; gen.</td>
<td>kWt ST gross</td>
<td>266,373</td>
<td>279,692</td>
<td>1</td>
<td>$210</td>
</tr>
</tbody>
</table>

#### General Facilities

- **25%** of Installed Process unit capital saving due to existing PC site: 165 / 319
- **15%** of Installed Process unit capital: 99 / 191
- **10%** of Installed Process unit capital: 66 / 128

#### Inflation adjustment to Ch.E. index mid-2004 to mid-2008: 650 / 444

#### Location adjustment to 115% of U.S. Gulf Coast Construction costs for total site specific capital costs: 1,667 / 3,224

#### Product Cost Estimate

<table>
<thead>
<tr>
<th>Capital charges</th>
<th>key variable</th>
<th>average annual capacity factor of 85% or 3.8E+06 MWh per year</th>
<th>$ Million/yr / $/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Non-Fuel O&amp;M Costs</td>
<td>key variable</td>
<td>15.0% yr of total capital or 6.67 yr capital payback</td>
<td>250.0 / 64.9</td>
</tr>
<tr>
<td>Fuel</td>
<td>Illinois Bit in MidWest min. shipping</td>
<td>key variable</td>
<td>4.5% yr of total capital</td>
</tr>
<tr>
<td>HP CO2 pipeline &amp; injection costs (or credit if for EOR)</td>
<td>key variable</td>
<td>$ 2.60/million Btu HHV of</td>
<td>$ 48.43 / lmt raw coal</td>
</tr>
<tr>
<td><em>what if</em> minimal sulfur byproduct credits</td>
<td>key variable</td>
<td>$ 15.00/lmt ton CO2 or $ 0.79 per 1,000 scf</td>
<td>51.6 / 13.4</td>
</tr>
<tr>
<td><em>what if</em> NOx emissions purchased credits at</td>
<td>key variable</td>
<td>$ 2.00/lmt as NO2 or ($ 5.00) lmt gypsum equivalent</td>
<td>(1.5) / (0.4)</td>
</tr>
<tr>
<td>*what if SO2 emissions purchased credits at</td>
<td>key variable</td>
<td>$ 1.00/lmt SO2</td>
<td>0.6 / 0.1</td>
</tr>
<tr>
<td><em>what if</em> Hg emissions purchased credits at</td>
<td>key variable</td>
<td>$ 20,000/lb Hg or $ 44 million per mt mercury equivalent</td>
<td>0.2 / 0.1</td>
</tr>
<tr>
<td><em>what if</em> CO2 emissions purchased credits at</td>
<td>key variable</td>
<td>$ 74.20/lmt CO2 or $ 272.07 per mt carbon equivalent</td>
<td>21.7 / 5.7</td>
</tr>
</tbody>
</table>

**Net revenues required at above assumptions:** 481.5 / 125.1

#### CO2 avoidance cost

- **$ 20/lmt CO2 or $ 74/lmt C equivalent** based on existing old coal power plants baseline

($/MWh ccs - $/MWh b) / (mt CO2/MWh ccs)