Economic Analysis For Conceptual Design of Supercritical O_2-Based PC Boiler

Topical Report

Andrew Seltzer
Archie Robertson

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Foster Wheeler Power Group, Inc.
12 Peach Tree Hill Road
Livingston, New Jersey 07039

Disclaimer

Abstract

This report determines the capital and operating costs of two different oxygen-based, pulverized coal-fired (PC) power plants and compares their economics to that of a comparable, air-based PC plant. Rather than combust their coal with air, the oxygen-based plants use oxygen to facilitate capture/removal of the plant CO_2 for transport by pipeline to a sequestering site. To provide a consistent comparison of technologies, all three plants analyzed herein operate with the same coal (Illinois No 6), the same site conditions, and the same supercritical pressure steam turbine (459 MWe).

In the first oxygen-based plant, the pulverized coal-fired boiler operates with oxygen supplied by a conventional, cryogenic air separation unit, whereas, in the second oxygen-based plant, the oxygen is supplied by an oxygen ion transport membrane. In both oxygen-based plants a portion of the boiler exhaust gas, which is primarily CO_2, is recirculated back to the boiler to control the combustion temperature, and the balance of the flue gas undergoes drying and compression to pipeline pressure; for consistency, both plants operate with similar combustion temperatures and utilize the same CO_2 processing technologies

The capital and operating costs of the pulverized coal-fired boilers required by the three different plants were estimated by Foster Wheeler and the balance of plant costs were budget priced using published data together with vendor supplied quotations. The cost of electricity produced by each of the plants was determined and oxygen-based plant CO_2 mitigation costs were calculated and compared to each other as well as to values published for some alternative CO_2 capture technologies.

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1.0 Introduction

This report describes the results and conclusions of Task 4, Economic Analysis of the Conceptual Design of Supercritical Oxygen-Based PC Boiler Study. The objective of the study is to develop a conceptual design of a pulverized coal-fired power plant that facilitates the practical capture of carbon dioxide for subsequent sequestration. The economic analysis is based on the results of System Analysis and Design (Task 1), Advanced O_2 Separation System Integration (Task 2), and Furnace Design and Analysis (Task 3).

2.0 Executive Summary

The objective of this study is to develop a conceptual design of a pulverized coal-fired power plant that facilitates the practical capture/removal of carbon dioxide for subsequent sequestration. Two oxygen-based/O_2-fired plant arrangements were studied: in the first arrangement the oxygen was supplied by a conventional, cryogenic air separation unit (ASU) and in the second arrangement, the oxygen was supplied via an oxygen ion transport membrane (OITM). Since these plants are operated with oxygen rather than air, flue gas from the back end of the plant is recirculated back to the boiler to keep their combustion temperatures at levels that are compatible with conventional boiler tube materials. In both cases the carbon dioxide rich exhaust gas from the plant is dried and compressed to 3000 psia for pipeline transport to an off-site sequestering location. With virtually no combustion exhaust gases being released to the atmosphere, the plants do not incorporate flue gas desulfurization or NOx control. The objective of the economic analysis is to prepare a budgetary estimate of the capital and operating costs of the O_2-fired PC power plants to permit comparison to an equivalent, conventional, air-fired power plant (e.g. the reference plant) as well as other CO_2 capture technologies.

The reference plant has a net power output of 430.2 MWe, incorporates a supercritical pressure boiler firing 2.5 per cent sulfur Illinois No 6 coal with air, and operates with an efficiency of 39.5 per cent. To control its emissions, the PC boiler is provided with low NOx burners, an SCR system, a baghouse filter, and a flue gas desulfurization system.

To provide a consistent comparison of technologies, all three plants were designed to operate with the same supercritical pressure 459 MWe steam turbine with identical steam conditions (4020 psig/1076ºF/1112ºF) and identical superheat and reheat steam flow rates. Since the oxygen supply systems have different parasitic power requirements, and with the OITM based plant incorporating a hot gas expander and heat recovery steam generator (HRSG) for additional power generation, the O_2-fired plants have efficiencies and net power outputs that are significantly different than the air-fired reference plant. The ASU oxygen-based plant operates with an efficiency of 33.0 per cent at a net output of 347.0 MWe, whereas, the OITM oxygen-based plant has an efficiency of 36.1 per cent at a net power output of 463.3 MWe.

The economic analyses of the plants were carried out based on the EPRI Technical Assessment Guide (TAG) methodology. Plant capital costs were compiled under the Code of Accounts developed by EPRI. The estimate basis is year 2006 dollars, a 20-year life, and an 85 per cent capacity factor. Table 2.1 summarizes the performance and economics of the plants.

Table 2.1 - Summary of Plant Performance and Economics

	Reference Air-Fired Plant	ASU Based Plant	OITM Based Plant
Net Power Output, MWe	430.2	347.0	463.3
Efficiency, % (HHV)	39.5	33.0	36.1
Coal Flow, Klb/hr	319.0	308.0	375.4
Total Plant Cost			
Millions of Dollars	633.0	723.3	953.0
$/kW	1,471	2,084	2,057
Levelized COE, $/MWhr	50.41	66.17	63.48
CO2 Mitigation Cost, $/tonne		20.23	16.77

Total plant costs are \$633 million (1471 \$/kW) for the air-fired reference plant, \$723 (2084 \$/kW) million for the cryogenic ASU O_2-PC, and \$953 (2057 \$/kW) million for the OITM O_2-PC. Even though the OITM O_2-PC has a total plant cost that was 32 per cent higher than the ASU O_2-PC, its higher power output results in a slightly lower \$/kW cost of \$2,057/kW versus \$2,084/kW.

The levelized cost of electricity (COE) was calculated for each of the plants assuming an 85 per cent capacity factor. The COE value is made up of contributions from capital cost, operating and maintenance costs, consumables, and fuel costs. The levelized COE was calculated to be \$50.41/MWhr for the reference plant, \$66.17/MWhr for the cryogenic ASU O_2-PC, and \$63.48/MWhr for the OITM O_2-PC. Again, because of its higher output, the OITM O_2-PC has a lower levelized cost of electricity (\$63.48/MWhr versus \$66.17/MWhr) and a lower CO_2 mitigation cost (MC) (\$16.77/tonne versus \$20.23/tonne) than the ASU O_2-PC.

Compared to the COE of the supercritical cryogenic O_2 PC, the COE for the other technologies is 52% higher for Air PC, 35% higher for NGCC, 15% higher for IGCC, and 5% higher for the subcritical O_2PC, and 4% lower for the supercritical O_2PC with OITM. Compared to the MC of the supercritical cryogenic O_2 PC, the MC for the other technologies is 238% higher for NGCC, 192% higher for Air PC, 25% higher for IGCC, 5% higher for the subcritical O_2PC, and 17% lower for the supercritical O_2PC with OITM.

3.0 Experimental

No experimental work or test equipment was needed or used in the performance of this task.

4.0 Results and Discussion

4.1 Main Assumptions

The economic analysis was performed based on the DOE/NETL guidelines [1] using the EPRI Technical Assessment Guide (TAG) methodology. Plant capital costs were compiled under the Code of Accounts developed by EPRI.

The estimate basis and major assumptions are listed below:

- Total plant costs were estimated in January 2006 dollars.
- Plant book life was assumed to be 20 years.
- The net power output of the reference air-fired plant is 430.2 MWe versus 347.0 MWe for the ASU oxygen-based plant and 463.3 MWe for the OITM oxygen-based plant.
- The plants operate with a capacity factor of 85 per cent (Plant operates at 100 per cent load 85 per cent of the time).
- Cost of electricity (COE) was determined on a levelized constant dollar basis.
- Average annual ambient air conditions for material balances, thermal efficiencies and other performance related parameters are at a dry bulb temperature of 60ºF and an air pressure of 14.7 psia.
- The coal is 2.5 per cent sulfur Illinois #6 coal (see Table 4.1 for analysis).
- Design CO_2 effluent purity is presented in Table 4.2
- Terms used are consistent with the EPRI TAG.

Economic study assumptions are detailed in Table 4.3.

Table 4.1 - Coal Properties

Illinois No. 6 Coal		
C	%	63.75%
H	%	4.50%
O	%	6.88%
N	%	1.25%
Cl	%	0.29%
S	%	2.51%
Ash	%	9.70%
H2O	%	11.12%
Total	%	100.00%
LHV	Btu/lb	11,283
HHV	Btu/lb	11,631

Table 4.2 - CO_2 Effluent Purity Design Conditions

Constituent	Units	Value
N2	vppm	< 300
H2O	vppm	< 20
O2	vppm	< 50

Table 4.3 – Economic Study Assumptions

GENERAL DATA/CHARACTERISTICS			
Levelized Capacity Factor / Preproduction (equivalent months):	85%		
Capital Cost Year Dollars (Reference Year Dollars):	2006 (January)		
Design/ Construction Period:	4	years	
Plant Start-up Date (1st year Dollars):	2010 (January)		
Land Area/Unit Cost:	100	acres	$1,600 / Acre
FINANCIAL CRITERIA			
Project Book Life:	20	years	
Book Salvage Value:	0	%	
Project Tax Life:	20	years	
Tax Depreciation Method:	Accel. Based on ACRS Class		
Inflation Rate	3.0	%	
Property Tax Rate:	1.0	%	
Insurance Tax Rate:	1.0	%	
Federal Income Tax Rate:	35.0	%	
State Income Tax Rate:	4.0	%	
Investment Tax Credit/% Eligible	0	%	
Economic Basis:	Over Book	Constant Dollars	
Capital Structure	% of Total		Cost (%)
Common Equity	20		12
Preferred Stock	0		
Debt	80		6.5
Weighted Cost of Capital: (after tax)		5.57%	
Coal Price Escalation Rate	3.0%		(same as general escalation)
Total Capital Requirement			
Initial Chemical Inventory	30	days	
Startup Costs	2% TPI 30 days of fuel and chemicals labor and miscellaneous items		
Spare Parts	0.5% TPC		
Working Capital	30 days fuel and consumables 30 days direct expenses		
Consumable Costs			
Coal, $/MMBtu	$1.34		
Limestone, $/ton	$15.00		
Water, $/kgal	$1.00		
Water Treatment Chemicals, $/kgal	$0.50		
Ash/Slag Disposal, $/ton	$10.00		
Plant Labor			
Operating labor			
Labor Rate	42.25	$/hr	(includes labor burden)
personnel	14	per shift	
Supervisory/clerical	30% of operating + maintenance labor cost		
Maintenance Costs			
Labor	0.88% TPC		
Materials	1.32% TPC		

4.2 Plant Cost Basis

Heat and material balances (Aspen simulations) were prepared for each of the plants that identified the flow rates and operating conditions of all their major flow streams ([6] and [7]). These balances also identified each boiler's operating requirements and enabled design calculations to be performed that established the overall boiler dimensions, tube surface areas, materials of construction, weights, and auxiliary equipment requirements. With this information defined, the cost of each boiler, which together with its auxiliary equipment constitutes the plant "boiler island", was determined from Foster Wheeler's cost estimating database.

4.2.1 Air-Fired Reference Plant Cost

In [2] Parsons presents a conceptual design of a supercritical pressure PC plant with a net power output of 550.2 MWe. Similar to the air-fired reference plant of this study, the Parsons plant burned 2.5 per cent sulfur Illinois No. 6 coal with air and, to control emissions, the boiler was provided with low NOx burners, SCR, wet flue gas desulfurization, and a baghouse filter. A detailed EPRI TAG cost estimate of the plant totaled $745.7 million or $1355/kW in year 2006 dollars and was broken down into 14 accounts, one of which (Account 4 entitled, "PC Boiler and Accessories") included the cost of the PC boiler and its auxiliaries. Since the primary difference between the Parsons and the FW air-fired reference plant is size, the Parsons balance of plant costs (excluding the boiler island) were scaled down on an account-by-account basis to obtain the reference plant balance of plant costs. As recommended in [3] a scaling exponent of 0.65 applied to flow rate/output was used and a small adjustment to the PC plant's feedwater and steam turbine accounts was made for the slightly higher operating pressure. Boiler island costs were estimated directly by FW based on designs generated in Task 3 [8]. To validate the scaling process, Parsons Account 4 boiler costs were scaled down and determined to be within 6 per cent of Foster Wheeler's directly estimated costs. The results of the scaling, together with Foster Wheeler's determined Account 4 (boiler island) costs, yielded a total plant cost of $633.0 million or $1471/kW for the 430.2 MWe reference plant. The account-by-account costs of the reference plant are presented in Table 4.2.1.

The total plant cost (TPC), also referred to as the plant capital cost is comprised of the following elements:

1. Bare erected plant cost (includes equipment supply and erection)
2. Architect engineering, construction management, and fee
3. Project and process contingencies

The reference plant estimate uses the same erection factors, fees, and contingencies as the Parsons plant estimate (i.e. boiler erection at 80 per cent of equipment supply costs, architect engineering/construction management/home office/fees at 10 per cent of bare erected costs, and contingency, totaling 10 per cent, applied to the sum of items 1 and 2).

4.2.2 Oxygen Based PC Plant Costs

In [4] Parsons presents conceptual designs of two plants that burned 2.5 per cent sulfur Illinois No. 6 coal with oxygen to facilitate CO_2 capture/removal for pipeline transport to a sequestering site. Both plants used flue gas recirculation to control their boiler combustion temperatures and their CO_2 rich exhaust gases were dried and compressed for pipeline transport.

The first plant had a net power output of 132.2 MWe, its oxygen was supplied by a conventional, cryogenic ASU, and the gas flow to the CO_2 processing unit totaled 422.3 Klb/hr. The oxygen was 99 per cent pure and it was delivered to an "air heater" at the boiler where 660ºF flue gas heated the oxygen to 610ºF for delivery to the boiler at a rate of 327.1 Klb/hr. In the FW study's ASU based plant, the oxygen from the ASU is also heated by an "air heater" at the boiler but to 625ºF with 695ºF flue gas; aside from some slight temperature differences, the plant arrangements are similar and their ASUs differ primarily in size/through put.

The second Parsons plant had a net output of 197.4 MWe, its oxygen was supplied at a rate of 398.8 Klb/hr by an ion transport membrane, and the gas flow to CO_2 processing was 515.8 Klb/hr. The OITM operated with 200 psia air that was heated to 1652ºF via heat transfer surface placed in the boiler; the hot air was then delivered to the OITM for separation of the oxygen and nitrogen. The oxygen, with a purity of 100 per cent, was then delivered to the boiler, whereas, the nitrogen was passed through a hot gas expander followed by a heat recovery steam generator for power recovery. Excepting for differences in flow rates, the operating conditions of the Parsons OITM plant are essentially identical to the OITM based plant of the FW study.

Praxair Inc, a developer of oxygen transport membranes, participated in the detailed Alstom/Parsons study [4] and, per the Acknowledgement section of their study report, provided detailed design, performance, and cost information on the OITM system. Aside from a difference in flow rate, the FW OITM operates at essentially the same pressure and temperature as that used in the Alstom/Parsons study and, hence, the FW system cost estimate was obtained by scaling their system capital costs. Consequently, individual OITM component designs were not developed in the FW study. It is assumed that Parsons/Praxair selected the operating conditions of the OITM to minimize the overall system cost. Such a sensitivity/optimization cost evaluation of the OITM plant design is beyond the scope of the FW study. Note that there are several variables, which have direct influence on the OITM plant cost and performance (see [7] for more details). These variables include

1. **O_2 Recovery Percentage**: CO_2 removal power penalty is minimum at an O_2 recovery of 86% (The Alstom/Parsons study uses a O_2 recovery of 85%).

2. **Air Pressure**: Increasing air pressure reduces OITM size, but also reduces system efficiency. Optimum pressure depends on the relative cost of the OITM.

3. **OITM Temperature:** Increasing OITM operating temperature will increase system efficiency, but will increase boiler air heater cost and presumably OITM cost.

A detailed 14 account EPRI TAG cost estimate in year 2003 dollars was prepared by Parsons for each of the two plants; in these estimates the oxygen (ASU or OITM) and CO_2 processing system costs appear, respectively, as separate subaccounts under the Boiler and Accessories and Flue Gas Clean Up Accounts. Since the arrangement and scope of supply of these systems is essentially identical to that of the FW study's O_2-fired plants, the Parsons costs were used to estimate the costs of Foster Wheeler's two plants. The Parsons ASU system costs were scaled up based on oxygen flow rate raised to the 0.65 exponent and escalated to year 2006 dollars; comparison of the scaled up costs with a vendor supplied budget price yielded good agreement further validating the scale up exponent. Comparison of the gas processing system costs given for Parsons' two plants, however, revealed a greater sensitivity to flow rate and resulted in a scaling exponent of 0.87; this exponent was then used to calculate the CO_2 gas processing system costs of Foster Wheeler's plants.

The Table 4.4 air-fired reference plant cost estimate served as a starting point for the determination of O_2 based plant costs. The cost of the air-fired PC boiler package was removed from the Parsons cost estimate and the new value, determined by Foster Wheeler for the particular plant configuration under study, was inserted. Then each balance of plant account and or component was individually scaled based on flow rate/output and adjusted, where necessary, to reflect design differences. Some examples of the changes that were made are removal of SCR systems, limestone systems, flue gas desulfurization systems, etc. and elimination of the stack from the ASU based plant.

Table 4.5 and Table 4.6 present a detailed cost breakdown of the ASU and OITM based O_2-PC plants and Table 4.7 compares the total costs of all three plants. Although the oxygen-based plants use flue gas recirculation to control the boiler combustion temperature, they operate with higher oxygen concentrations than the air-fired reference plant boiler. As a result they produce a higher combustion temperature and a lower flue gas flow rate, which reduce the size of the boiler and its downstream flue gas components. With the SCR eliminated and the flue gas flow rate reduced, the PC boiler cost of the ASU based plant is about $32 million less than that of the air-fired case. Despite additional savings associated with elimination of some systems/components (e.g. SCR, limestone, FGD, and stack plus a reduction in size of other components, i.e. baghouse filter, ducting, foundations, etc.), the total cost of the ASU based plant is approximately $91 million higher than the air-fired plant because of the high cost of the ASU ($115.0 million) and CO_2 processing systems ($111.5 million).

In the OITM based plant, the PC boiler not only meets the steam generation and heating needs of the steam cycle, but it also contains tubing that heats air to 1600ºF for delivery to the OITM. Although the boiler flue gas flow rate of the OITM based plant is about 25 per cent less than the air-fired plant, the cost savings it provides is more than negated by the high cost of the air heater tubing; as a result, the OITM based PC boiler costs $18 million more than that of the air-fired plant. The compressor required to pressurize OITM air to 200 psia, the OITM, the OITM associated heat exchangers and piping, the OITM power recovery system (hot gas expander and HRSG), and a larger CO_2 gas processing system add additional costs to the plant; as a result, the OITM plant costs approximately 50 per cent more than the air-fired reference plant ($953.0 million versus $633.0 million) and approximately 32 per cent more than the ASU based plant ($953.0 million versus $723.3 million). Since the OITM based plant operates with a higher electrical output than the ASU based plant (463.3 MWe versus 347.0 MWe), its total plant costs on a dollar per kilowatt basis are slightly lower ($2.057/kW versus $2,084/kW) but much higher than the air-fired plant ($2,057/kW versus $1,471/kW).

Table 4.4 - Cost of 430.2 MWe Air-Fired Supercritical PC Plant ($1000 Yr 2006)

Account #	Account Title	Bare Erected Costs	Engr, C.M. H.O. & Feee at 10%	Contingency at 10%	Total Plant Costs
1	**Coal & Sorbent Handling**				
	Coal	12,985	1,299	1,428	**15,712**
	Limestone	3,114	311	343	**3,768**
2	**Coal and Sorbent Prep & Feed**				
	Coal	2,599	260	286	**3,145**
	Limestone	6,934	693	763	**8,390**
3	**Feedwater & Misc BOP Systems**	47,879	4,788	5,267	**57,933**
4	**Boiler and Accessories**				
	Boiler with SCR, Air Heater, Fans, Ducts, etc	155,621	15,562	17,118	**188,301**
	Oxygen Supply; None				**0**
5	**Flue Gas Clean Up**				
	Baghouse & Accessories	17,111	1,711	1,882	**20,705**
	FGD	58,705	5,871	6,458	**71,033**
	CO2 Processing	0	0	0	**0**
6	**Combustion Turbine & Accessories**				**0**
7	**HRSG, Ducting, & Stack**				
	Duct Work	9,094	909	1,000	**11,004**
	Stack	9,774	977	1,075	**11,827**
	Foundations	1,456	146	160	**1,762**
8	**Steam Turbine Generator**	88,706	8,871	9,758	**107,334**
9	**Cooling Water System**	24,540	2,454	2,699	**29,693**
10	**Slag/Ash Handling Systems**	7,746	775	852	**9,373**
11	**Accessory Electric Plant**	27,500	2,750	3,025	**33,275**
12	**Instrumentation & Control**	12,237	1,224	1,346	**14,807**
13	**Improvements to Site**	7,773	777	855	**9,405**
14	**Buildings & Structures**	29,353	2,935	3,229	**35,517**
	Totals	523,126	52,313	57,544	**632,984**
	$/kW				**1,471**

Table 4.5 - Cost of 347.0 MWe ASU Based Supercritical PC Plant ($1000 Yr 2006)

Account #	Account Title	Bare Erected Costs	Engr, C.M. H.O. & Feee at 10%	Contingency at 10%	Total Plant Costs
1	**Coal Handling**	12,692	1,269	1,396	**15,357**
2	**Coal Prep & Feed**	2,540	254	279	**3,074**
3	**Feedwater & Misc BOP Systems**	47,879	4,788	5,267	**57,933**
4	**Boiler and Accessories**				
	Boiler with Air Heater, Fans, Ducts, etc	129,052	12,905	14,196	**156,153**
	Oxygen Supply: ASU				**115,005** *
5	**Flue Gas Clean Up**				
	Baghouse & Accessories	12,102	1,210	1,331	**14,643**
	FGD				**0**
	CO2 Processing				**111,493** *
6	**Combustion Turbine & Accessories**				**0**
7	**HRSG, Ducting, & Stack**				
	Duct Work and Foundations	6,432	643	707	**7,782**
	Stack				**0**
	HRSG				**0**
8	**Steam Turbine Generator**	88,706	8,871	9,758	**107,334**
9	**Cooling Water System**	25,966	2,597	2,856	**31,419**
10	**Slag/Ash Handling Systems**	7,281	728	801	**8,810**
11	**Accessory Electric Plant**	27,885	2,789	3,067	**33,741**
12	**Instrumentation & Control**	12,408	1,241	1,365	**15,014**
13	**Improvements to Site**	7,882	788	867	**9,537**
14	**Buildings & Structures**	29,764	2,976	3,274	**36,014**
	Totals		41,059	45,165	**723,310**
	$/kW				**2,084**

*Values Scaled from Parsons /Alstom Year 2003 Study and Escalated to 2006 at 5% per Year

Table 4.6 - Cost of 463.3 MWe OITM Based Supercritical PC Plant ($1000 Yr 2006)

Account #	Account Title	Bare Erected Costs	Engr, C.M. H.O. & Feee at 10%	Contingency at 10%	Total Plant Costs
1	**Coal Handling**	14,434	1,443	1,588	**17,465**
2	**Coal Prep & Feed**	2,889	289	318	**3,496**
3	**Feedwater & Misc BOP Systems**	47,879	4,788	5,267	**57,933**
4	**Boiler and Accessories**				
	Boiler, Air Heater, Fans, Ducts, etc	170,902	17,090	18,799	**206,791**
	Oxygen Supply: OTM				**188,031** *
5	**Flue Gas Clean Up**				
	Baghouse & Accessories	14,113	1,411	1,552	**17,077**
	FGD				**0**
	CO2 Processing				**131,662** *
6	**Combustion Turbine & Accessories**				**48,627** *
7	**HRSG, Ducting, & Stack**				
	Duct Work	7,501	750	825	**9,076**
	Stack				**2,680** *
	Foundations				**205** *
	HRSG				**18,420** *
8	**Steam Turbine Generator**	88,706	8,871	9,758	**107,334**
9	**Cooling Water System**	29,489	2,949	3,244	**35,682**
10	**Slag/Ash Handling Systems**	8,344	834	918	**10,097**
11	**Accessory Electric Plant**	29,101	2,910	3,201	**35,212**
12	**Instrumentation & Control**	12,949	1,295	1,424	**15,668**
13	**Improvements to Site**	8,225	823	905	**9,953**
14	**Buildings & Structures**	31,061	3,106	3,417	**37,584**
	Totals		46,559	51,215	**952,993**
	$/kW				**2,057**

*Values Scaled from Parsons /Alstom Year 2003 Study and Escalated to 2006 at 5% per Year

Table 4.7 - Comparison of Total Plant Costs ($1000 Yr 2006)

		Reference Air-Fired Plant	ASU Based Plant	OITM Based Plant
	Net Power Output, MWe	430.2	347.0	463.3
	Flow Rates, Klb/hr			
	Coal	319.0	308.0	375.4
	Limestone	26.0	0.0	0.0
	Ash	33.0	30.0	37.0
	Boiler Flue Gas	3556.0	2087.0	2644.0
	Gas to CO_2 Processing	0.0	774.0	936.0
	Condenser Duty, MMBtu/hr	1696.0	1850.0	2250.0

Account #	Account Title	**Plant Costs by Account**		
1	Coal and Limestone Handling			
	Coal	15,712	15,357	17,465
	Limestone	3,768	0	0
2	Coal and Limestone Prep & Feed			
	Coal	3,145	3,074	3,496
	Limestone	8,390	0	0
3	Feedwater & Misc BOP Systems	57,933	57,933	57,933
4	Boiler and Accessories			
	Boiler, SCR*, Air Heater, Fans, Ducts, etc	188,301	156,153	206,791
	Oxygen Supply		115,005	188,031
5	Flue Gas Clean Up			
	Baghouse & Accessories	20,705	14,643	17,077
	FGD	71,033	0	0
	CO_2 Processing	0	111,493	131,662
6	Combustion Turbine & Accessories	0	0	48,627
7	HRSG, Ducting, & Stack			
	Duct Work	11,004	7,782	9,076
	Stack	11,827	0	2,680
	Foundations	1,762	in duct work	205
	HRSG	0	0	18,420
8	Steam Turbine Generator	107,334	107,334	107,334
9	Cooling Water System	29,693	31,419	35,682
10	Slag/Ash Handling Systems	9,373	8,810	10,097
11	Accessory Electric Plant	33,275	33,741	35,212
12	Instrumentation & Control	14,807	15,014	15,668
13	Improvements to Site	9,405	9,537	9,953
14	Buildings & Structures	35,517	36,014	37,584
	Totals	**632,984**	**723,310**	**952,993**
	$/kW	**1,471**	**2,084**	**2,057**

4.3 Total Plant Investment (TPI)

The TPI at date of start-up includes escalation of construction costs and allowance for funds used during construction (AFUDC). AFUDC includes interest during construction as well as a similar concept for timing of equity funds over the construction period. TPI is computed from the TPC based on a linear draw down schedule and the compounded interest (or implied equity rate) in the percentages of debt and equity. Draw down was over the assumed 48-month construction schedule for all three plants. As the analysis is done in constant 2006 dollars, no escalation was applied. The full AFUDC is used in calculating returns on debt and equity, but only the interest during construction is included in the depreciation base.

4.4 Total Capital Requirement (TCR)

The TCR includes all capital necessary to complete the entire project. TCR consists of TPI, prepaid royalties, pre-production (or start-up) costs, inventory capital, initial chemical and catalyst charge, and land cost:

- Royalty Costs have been assumed to be zero, as none apply.
- Start-Up/Pre-Production Costs are intended to cover operator training, equipment checkout, extra maintenance, and use of fuel and other materials during plant start-up. They are estimated as follows:
  - Hiring and phasing-in prior to and during start up of operating and maintenance labor, administrative and support labor, variable operating costs ramped up to full capacity (including fuel, chemicals, water, and other consumables and waste disposal charges. These variable costs are assumed to be compensated by electric energy payments during the start up period.
  - Costs of spare parts usage, and expected changes and modifications to equipment that may be needed to bring the plant up to full capacity.
- Inventory capital is the value of inventories of fuel, other consumables, and by-products, which are capitalized and included in the inventory capital account. The inventory capital is estimated as follows:
  - Fuel inventory is based on full-capacity operation for 30 days.
  - Inventory of other consumables (excluding water) is normally based on full-capacity operation for the same number of days as specified for the fuel.
  - ½ percent of the TPC equipment cost is included for spare parts.
- Initial catalyst and chemical charge covers the initial cost of any catalyst or chemicals that are contained in the process equipment (but not in storage, which is covered in inventory capital). No value is shown because costs are assumed to have been included in the component equipment capital cost.
- Land cost is based on 100 acres of land at $1,600 per acre.

4.5 Operating Costs And Expenses

Operating costs were expressed in terms of the following categories:

- Operating Labor
- Maintenance Cost
    - Maintenance labor
    - Maintenance materials
- Administrative and Support Labor
- Consumables
- Fuel Cost

These values were calculated consistent with EPRI TAG methodology. All costs were based on a first year basis in January 2006 dollars. The first year costs do not include start-up expenses, which are included in the TCR.

The cost categories listed above are calculated, on a dollars per year basis, as follows:

- <u>Operating labor</u> is calculated by multiplying the number of operating personnel with the average annual (burdened) compensation per person.

- <u>Maintenance costs</u> are estimated to be 2.2% of the TPC and are divided into maintenance labor and maintenance materials

    - <u>Maintenance labor</u> is estimated to be 40% of the total maintenance cost
    - <u>Maintenance materials</u> are estimated to be 60% of the total maintenance cost

- <u>Administrative and support labor</u> is estimated to be equal to 30% of the sum of operating and maintenance labor.

- <u>Consumables</u> are feedstock and disposal costs calculated from the annual usage at 100 per cent load and 85 per cent capacity factor. The costs is expressed in year 2006 dollars and levelized over 20 years on a constant dollar basis.

Fuel cost is calculated based on a coal delivered cost of $1.34/MMBtu. Fuel cost is determined on a first year basis and levelized over 20 years on a constant dollar basis. The calculation of first year fuel costs is done as follows:

Fuel (tons/day) = Full Load Coal Feed Rate (lb/hr) x 24 hr/day / 2000 lbs/ton

Fuel Unit Cost ($/ton) = HHV (Btu/lb) x 2000 lb/ton

Fuel Cost (1st year) = Fuel (tons/day) x Fuel Unit Cost ($/ton) x 365 day/yr x 0.85 (CF)

The operating and maintenance costs, excluding fuel and consumables, are combined and divided into two components: 1) 90 per cent for Fixed O&M, which is independent of power generation, and 2) 10 per cent for Variable O&M, which is proportional to power generation.

4.6 Cost Of Electricity (COE)

The COE value is made up of contributions from the capital cost (called the carrying charge), operating and maintenance costs, consumables, and fuel costs. The following relationship is used to calculate COE from these cost components:

COE = LCC + LFOM x 100/(8760 x CF) + LVOM + LCM +LFC

LCC = Levelized carrying charge, ¢/kWh
LFOM = Levelized fixed O&M, $/kW-yr
LVOM = Levelized variable O&M, ¢/kWh
LCM = Levelized consumables, ¢/kWh
LFC = Levelized fuel costs, ¢/kWh
CF = plant capacity factor (0.85)

The CO_2 mitigation cost (MC) shows the cost impact, in dollars per tonne of CO_2 that would otherwise be emitted, of a configuration that allows CO_2 capture relative to the air-fired reference plant.

The MC is calculated as follows:

$$MC = \frac{COE_{\text{with removal}} - COE_{\text{reference}}}{E_{\text{reference}} - E_{\text{with removal}}} \times 0.01\ \$/¢$$

COE = Cost of electricity in ¢/kWh
E = CO_2 emission in tonnes/kWh

The capital investment and revenue requirements of the three plants are presented in detail in Table 4.8 through Table 4.10 and summarized in Table 4.11.

With the oxygen based plants having higher total plant costs than the air-fired reference plant, their interest during construction is higher and they have higher total plant investment costs; start-up and working capital costs, which are somewhat related to total plant costs are also higher and yield total capital requirement costs that are 14 and 51 per cent higher than the air-fired plant.

The air-fired reference plant incorporates an ammonia based SCR and a limestone based scrubber to control its NOx and SOx emissions. Although these systems are not required with the oxygen based plants, the latter incorporate oxygen supply and CO_2

processing systems. Since the number of systems added equaled the number deleted, it was assumed, in the absence of a detailed staffing study, that all three plants required the same number of operating personnel. Although operator costs are identical, maintenance and administration costs, which key off of total plant costs, are higher for the oxygen based plants. The consumable requirements of the three plants are given in Table 4.12. With the SCR and scrubber systems deleted, the consumable costs of the oxygen-based plants are lower (ammonia and limestone costs are eliminated), but because of their lower efficiency, their fuel costs are higher (per net MWe). The higher fuel and higher operating and maintenance costs exceed the lower consumable cost savings and, as a result, the ASU and OITM plants have higher 20 year levelized production costs of $24.42/MWhr and $22.27/MWhr, respectively, versus $20.93/MWhr for the air-fired plant. When added to their respective higher capital carrying costs of $41.75/MWhr and $41.21/MWhr versus $29.48/MWhr, their costs of electricity of $66.17/MWhr and $63.48/MWhr are 31 and 26 per cent higher than the air-fired reference plant at $50.41/MWhr (see Figure 4.1).

The CO_2 mitigation costs of the ASU and OITM based plants were calculated to be $20.23 and $16.77 per tonne of CO_2 sent to the pipeline for sequestering. With the OITM based plant offering the promise of a lower CO_2 mitigation cost, this analysis has shown that reducing the costs of both the oxygen supply and the CO_2 processing systems are a key to reducing both the cost of electricity and CO_2 mitigation costs of these sequestration ready power plants.

Table 4.8 - Air Fired PC Plant Capital Investment & Revenue Requirement

TITLE/DEFINITION			
Case:	Air Fired	Steam Turbine:	4005psig/1076F/1112F
Plant Size:	430.2 MWe (net)	Net Efficiency:	39.5 % HHV
Fuel (type):	Illinois No 6 Coal	Fuel Cost:	$1.34/MMBtu
Design/Construction:	48 Months	Book Life:	20 Years
TPC (Plant Cost) Year:	Jan-06		
Capacity Factor:	85.0%		

CAPITAL INVESTMENT:		**$x1000**	**$/kW**
	TOTAL PLANT COST	**632,982**	**1,471**
	AFUDC	105,458	
	TOTAL PLANT INVESTMENT	**732,440**	**1,717**
Royalty Allowance		0	
Start Up Costs		16,458	
Working Capital		4,795	
Debt Service Reserve		0	
	TOTAL CAPITAL REQUIREMENT	**759,693**	**1,815**
OPERATING & MAINTENANCE COSTS (2006)			
Operating Labor		4,921	
Maintenance Labor		5,570	
Maintenance Material		8,355	
Administrative & Support Labor		3,147	
	TOTAL OPERATION & MAINTENANCE (2006)	21,994	
	FIXED O&M (2006)	**19,795**	
	VARIABLE O&M (2006)	**2,199**	
CONSUMABLE OPERATING COSTS, LESS FUEL (2006)			
Water and Treatment		1,297	
Limestone		1,452	
Ash Disposal		2,423	
Ammonia		1,768	
Other Consumables		1,005	
	TOTAL CONSUMABLES (2006)	**7,945**	
BY-PRODUCT CREDITS (2006)		0	
FUEL COST (2006)			
Coal	**FUEL COST (2006)**	**37,131**	

		1st Year (2010))	**20 Year Levelized**
PRODUCTION COST SUMMARY		**$/MWhr**	**$/MWhr**
	Fixed O&M	6.18	6.18
	Variable O&M	0.69	0.69
	Consumables	2.48	2.48
	By-Product Credit	0.00	0.00
	Fuel	11.59	11.59
	TOTAL PRODUCTION COST (2006)	**20.94**	**20.93**
	LEVELIZED 20 YEAR CARRYING CHARGES (Capital)*		**29.48**
	LEVELIZED 20 YEAR BUSBAR COST OF POWER		**50.41**

***Levelized Fixed Charge Rate = 12.5%**

Table 4.9 - ASU Based PC Plant Capital Investment & Revenue Requirement

TITLE/DEFINITION			
Case:	Oxygen by ASU	Steam Turbine:	4005psig/1076F/1112F
Plant Size:	347.0 MWe (net)	Net Efficiency:	33.0 % HHV
Fuel (type):	Illinois No 6 Coal	Fuel Cost:	$1.34/MMBtu
Design/Construction:	48 Months	Book Life:	20 Years
TPC (Plant Cost) Year:	Jan-06		
Capacity Factor:	85.0%		

CAPITAL INVESTMENT:		**$x1000**	**$/kW**
	TOTAL PLANT COST	**723,310**	**2,084**
	AFUDC	120,507	
	TOTAL PLANT INVESTMENT	**843,818**	**2,432**
Royalty Allowance		0	
Start Up Costs		18,806	
Working Capital		5,480	
Debt Service Reserve		0	
	TOTAL CAPITAL REQUIREMENT	**868,103**	**2,502**
OPERATING & MAINTENANCE COSTS (2006)			
Operating Labor		4,921	
Maintenance Labor		6,365	
Maintenance Material		9,548	
Administrative & Support Labor		3,386	
	TOTAL OPERATION & MAINTENANCE (2006)	24,220	
	FIXED O&M (2006)	**21,798**	
	VARIABLE O&M (2006)	**2,422**	
CONSUMABLE OPERATING COSTS, LESS FUEL (2006)			
Water and Treatment		898	
Limestone		0	
Ash Disposal		1,111	
Ammonia		0	
Other Consumables		1,005	
	TOTAL CONSUMABLES (2006)	**3,014**	
BY-PRODUCT CREDITS (2006)		0	
FUEL COST (2006)			
Coal	**FUEL COST (2006)**	**35,851**	
		1st Year (2010))	**20 Year Levelized**
PRODUCTION COST SUMMARY		**$/MWhr**	**$/MWhr**
	Fixed O&M	8.43	8.43
	Variable O&M	0.94	0.94
	Consumables	1.17	1.17
	By-Product Credit	0.00	0.00
	Fuel	13.88	13.88
	TOTAL PRODUCTION COST (2006)	**24.42**	**24.42**
	LEVELIZED 20 YEAR CARRYING CHARGES (Capital)*		**41.75**
	LEVELIZED 20 YEAR BUSBAR COST OF POWER		**66.17**

***Levelized Fixed Charge Rate = 12.5%**

Table 4.10 - OITM Based PC Plant Capital Investment & Revenue Requirement

TITLE/DEFINITION			
Case:	Oxygen by Ion Transport Membrane	Steam Turbine:	4005psig/1076F/1112F
Plant Size:	463.3 MWe (net)	Net Efficiency:	36.1 % HHV
Fuel (type):	Illinois No 6 Coal	Fuel Cost:	$1.34/MMBtu
Design/Construction:	48 Months	Book Life:	20 Years
TPC (Plant Cost) Year:	Jan-06		
Capacity Factor:	85.0%		

CAPITAL INVESTMENT:		**$x1000**	**$/kW**
	TOTAL PLANT COST	**952,993**	**2,057**
	AFUDC	158,774	
	TOTAL PLANT INVESTMENT	**1,111,767**	**2,400**
Royalty Allowance		0	
Start Up Costs		24,778	
Working Capital		7,220	
Debt Service Reserve		0	
	TOTAL CAPITAL REQUIREMENT	**1,143,764**	**2,469**
OPERATING & MAINTENANCE COSTS (2006)			
Operating Labor		4,921	
Maintenance Labor		8,386	
Maintenance Material		12,579	
Administrative & Support Labor		3,992	
	TOTAL OPERATION & MAINTENANCE (2006)	29,879	
	FIXED O&M (2006)	**26,891**	
	VARIABLE O&M (2006)	**2,988**	
CONSUMABLE OPERATING COSTS, LESS FUEL (2006)			
Water and Treatment		899	
Limestone		0	
Ash Disposal		1,356	
Ammonia		0	
Other Consumables		1,005	
	TOTAL CONSUMABLES (2006)	**3,259**	
BY-PRODUCT CREDITS (2006)		0	
FUEL COST (2006)			
Coal	**FUEL COST (2006)**	**43,696**	
		1st Year (2010))	**20 Year Levelized**
PRODUCTION COST SUMMARY		**$/MWhr**	**$/MWhr**
	Fixed O&M	7.79	7.79
	Variable O&M	0.86	0.86
	Consumables	0.94	0.94
	By-Product Credit	0.00	0.00
	Fuel	12.67	12.67
	TOTAL PRODUCTION COST (2006)	**22.27**	**22.27**
	LEVELIZED 20 YEAR CARRYING CHARGES (Capital)*		**41.21**
	LEVELIZED 20 YEAR BUSBAR COST OF POWER		**63.48**

***Levelized Fixed Charge Rate = 12.5%**

Table 4.11 - Summary of Plant Economics and CO_2 Mitigation Costs

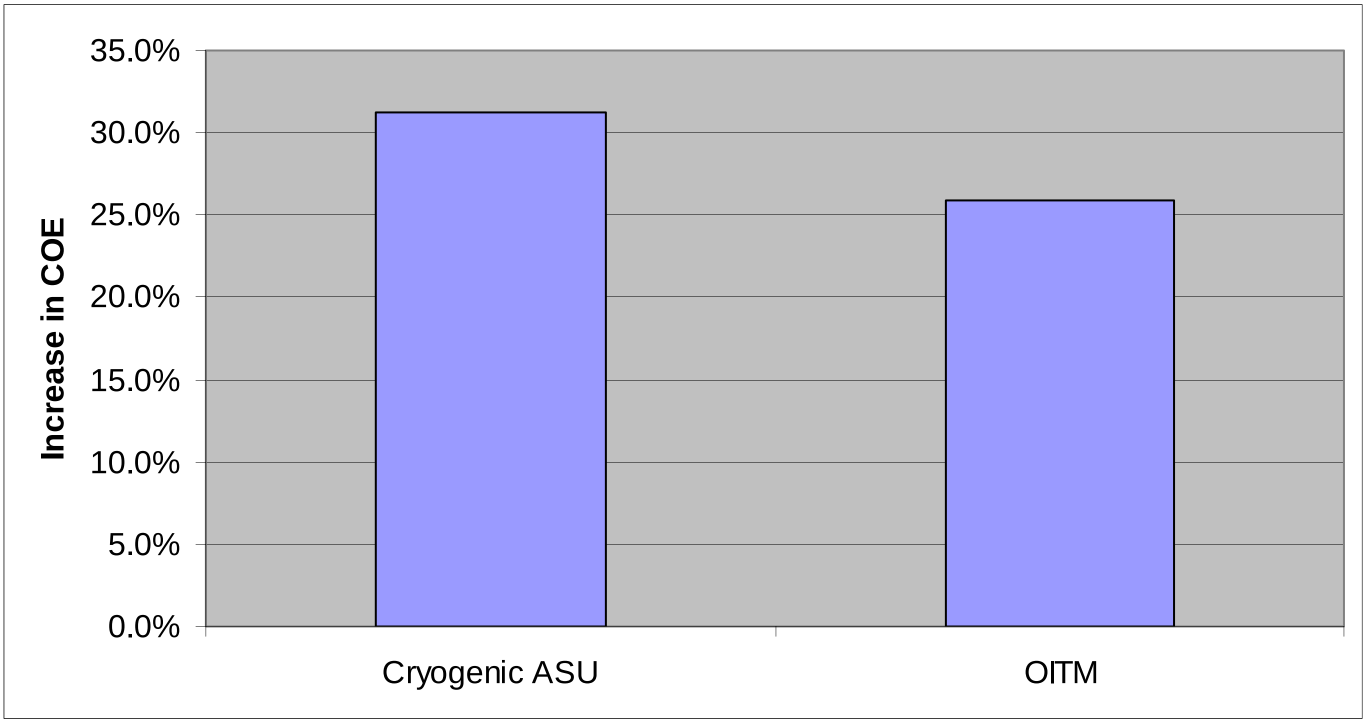
	Reference Air-Fired Plant	ASU Based Plant	OITM Based Plant
Net Power Output, MWe	430.2	347.0	463.3
Efficiency, % (HHV)	39.5	33.0	36.1
Coal Flow, Klb/hr	319.0	308.0	375.4
CO2 to Stack			
Klb/hr	739.0		
Tonnes/MWhr	0.779		
CO2 to Pipe Line			
Klb/hr		718.0	866.0
Tonnes/MWhr		0.939	0.848
Total Plant Cost			
Millions of Dollars	633.0	723.3	953.0
$/kW	1,471	2,084	2,057
Total Capital Requirement in Millions of Dollars	760.0	868.1	1143.8
Levelized Production Costs, $/MWhr			
Operating & Maintenance	6.86	9.37	8.66
Consummables	2.48	1.17	0.94
Fuel	11.59	13.88	12.67
Total	20.93	24.42	22.27
Levelized Capital Carrying Charges, $/MWhr	29.48	41.75	41.21
Levelized COE, $/MWhr	50.41	66.17	63.48
CO2 Mitigation Cost, $/tonne		20.23	16.77

Table 4.12 - Plant Daily Consumable Requirements

	Air-Fired	Cryogenic ASU	OITM
Water, 1000s gal/day	3,483	2,414	2,414
Water Treatment Chemicals, lbs/day	17,041	17,041	17,041
Limestone, tons/day	312	0	0
Ammonia (28% NH3), tons/day	25	0	0
Ash Disposal, tons/day	371	358	437
Fuel, tons/day	3,828	3,696	4,505

Fuel, lbs/hr/MWe	741.5	887.6	810.3
Fuel, Btu/hr/kWe	8625	10324	9424

Figure 4.1 – Increase in COE of O_2 Plant Above Air-Fired Reference Plant



4.3 Comparison with Other Technologies

An economic comparison was performed between the O_2 PC and other competing CO_2 removal technologies. For comparison the following alternate technologies were chosen:

Air PC:	Supercritical PC plant with post-combustion CO_2 mitigation (Ref. [2] case 12).
NGCC:	Natural Gas Combined Cycle with post combustion (Ref. [2] case 14).
IGCC:	Integrated Gasification Combined Cycle with pre-combustion CO_2 mitigation (Ref. [2] case 4).
SUB O_2PC:	Oxygen-fired subcritical PC (Ref. [5]).

The economics of these technologies were compared with the supercritical O_2 PC using both the levelized cost of electricity and the CO_2 mitigation cost as indexes. The CO_2 mitigation cost (MC) shows the cost impact, in dollars per tonne of CO_2 that would otherwise be emitted, of a configuration that allows CO_2 capture relative to the reference plant.

The COE and MC for the Air PC, NGCC, and IGCC were obtained from Ref. 2. Since the economic analysis of Ref. 2 were made for a larger power plant (480-550 MW net power) they were scaled to a 30% smaller power plant to be consistent with the supercritical O2 PC analyzed herein. The COE and MC for the subcritical O2 PC were obtained from Ref. 5 and adjusted from 2004 to 2006 dollars and from a coal cost of $1.14/MMBtu to $1.34/MMBtu.

Figure 4.2 and Figure 4.3 present a comparison of the COE and MC using an 85% capacity factor. Compared to the COE of the supercritical cryogenic O_2 PC, the COE for the other technologies is 52% higher for Air PC, 35% higher for NGCC, 15% higher for IGCC, and 5% higher for the subcritical O_2-PC, and 4% lower for the supercritical O_2-PC with OITM. Compared to the MC of the supercritical cryogenic O_2 PC, the MC for the other technologies is 238% higher for NGCC, 192% higher for Air PC, 25% higher for IGCC, 5% higher for the subcritical O_2-PC, and 17% lower for the supercritical O_2-PC with OITM. Since based on operating experience an 85% capacity factor for IGCC technology appears too optimistic, the COE and MC with a 70% capacity factor is also shown in Figure 4.2 and Figure 4.3 (COE is increased by 16% and MC by 18%).

Figure 4.2 - Comparison of Levelized Cost of Electricity Among Alternative Technologies

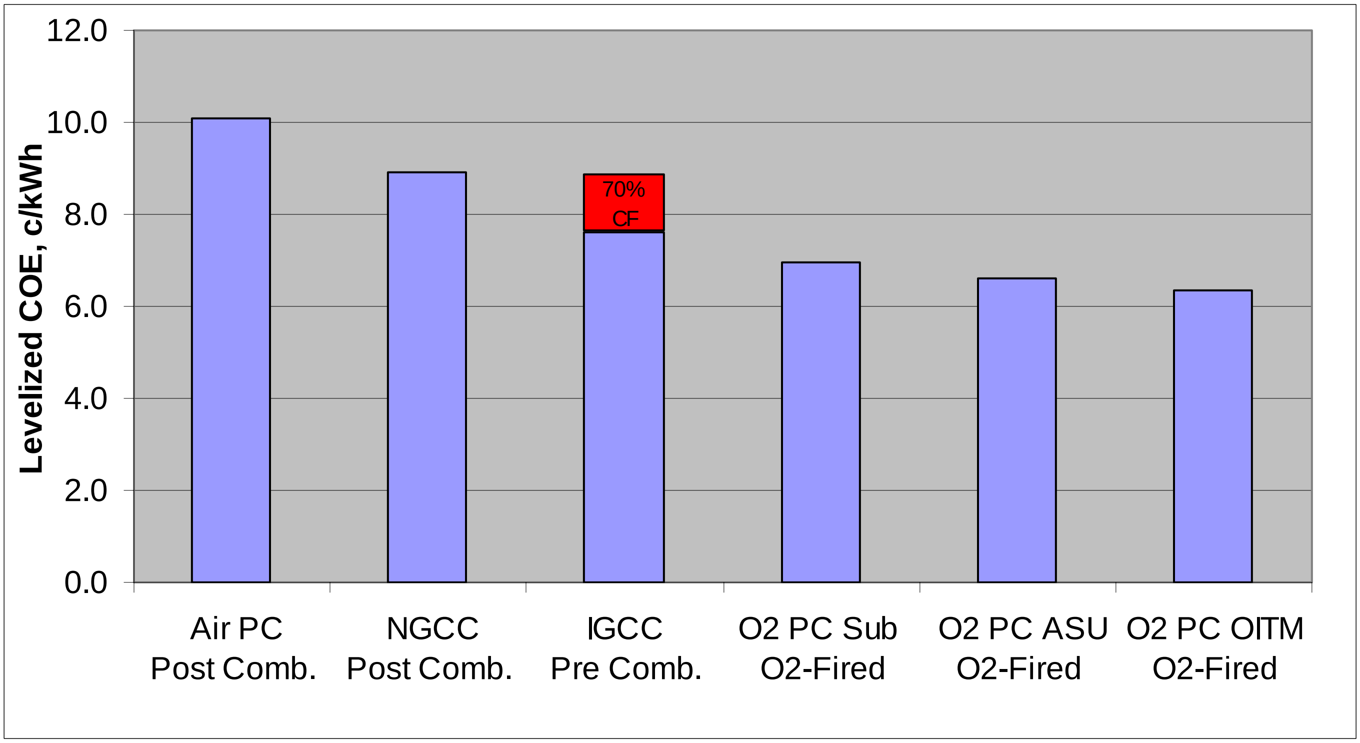
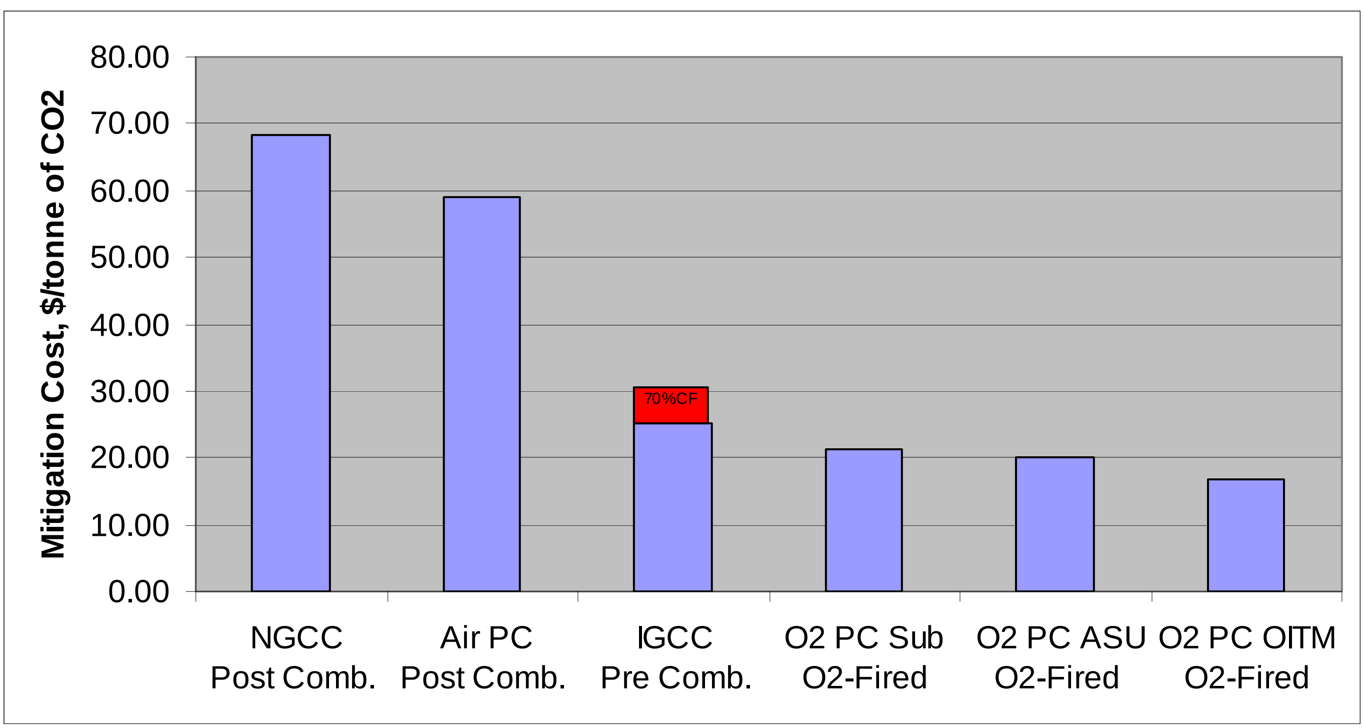


Figure 4.3 - Comparison of Mitigation Costs Among Alternative Technologies



5.0 Conclusion

To assure continued U.S. power generation from its abundant domestic coal resources, new coal combustion technologies must be developed to meet future emissions standards, especially CO_2 sequestration. Current conventional coal-fired boiler plants burn coal using 15-20 per cent excess air producing a flue gas, which is only approximately 15 per cent CO_2. Consequently, CO_2 sequestration requires removal/stripping of non-condensable gases, which is both expensive and highly power-consuming. Several different technologies for concentrating the CO_2 by removing the non-condensable gases have been proposed, including amine-based absorption and membrane gas absorption. However, these techniques require substantial energy, typically from low-pressure steam.

In the supercritical pressure, oxygen-based boilers studied herein, the “combustion air” is separated into O_2 and N_2 and only the O_2, mixed with recycled flue gas, is delivered to the boiler to support the combustion of pulverized coal. The products of oxy-fuel combustion are thus only CO_2 and water vapor. The water vapor is easily condensed, yielding a pure CO_2 stream ready for sequestration. The CO_2 effluent, after drying and pressurization, is in a liquid form that can be transported by pipeline to a sequestration site. An oxygen-based plant can thus be made into a truly zero emission stackless plant.

The levelized cost of electricity of the supercritical pressure, air-fired reference plant was calculated to be $50.41/MWhr and it operated with an efficiency of 39.5 per cent. The oxygen supply and CO_2 gas processing systems required by the oxygen-based plants significantly increase their plant costs and parasitic power requirements. The ASU based plant had a cost of electricity of $66.17/MWhr and an efficiency of 33.0 per cent.

The oxygen transport membrane of the OITM based plant operates at 200 psia with air heated to 1600ºF via tubes placed in the boiler. The high cost of this boiler tubing, together with piping, heat exchangers, and the oxygen transport membrane itself, add considerable costs to the plant. Since the nitrogen exhausting from the membrane is hot and at pressure, it can be used for power recovery via a hot gas expander and HRSG. Although addition of these components further increases plant costs, the added power they provide increases the plant efficiency to 36.1 per cent and enables the OITM based plant to operate with a cost of electricity that is less than that of the ASU based plant e.g. $63.48/MWhr versus $66.17/MWhr. As a result the CO_2 mitigation cost of the OITM based plant was calculated to be less than that of the ASU based plant e.g. $15.66/tonne versus $17.06/tonne, respectively.

The oxygen supply and the CO_2 gas processing systems have a major impact on the economics and efficiency of oxygen-based plants. Additional R&D aimed at improving these systems, especially OITMs, is necessary to improve both electricity costs and CO_2 mitigation costs.

6.0 References

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7.0 List of Acronyms and Abbreviations

ASU	Air Separation Unit
CF	Capacity Factor
COE	Cost of Electricity
E	Emission of CO_2
EPRI	Electric Power Research Institute
FGD	Flue Gas Desulfurization
HRSG	Heat Recovery Steam Generator
HHV	Higher Heating Value
LCC	Levelized Carrying Charge
LCM	Levelized Consumables
LFC	Levelized Fuel Costs
LFOM	Levelized Fixed O&M
LHV	Lower Heating Value
LVOM	Levelized Variable O&M
MC	Mitigation Cost (CO_2)
NOx	Nitrogen Oxides
OITM	Oxygen Ion Transport Membrane
O&M	Operation and Maintenance
PC	Pulverized Coal
SCR	Selective Catalytic Reactor
TCR	Total Capital Requirement
TPC	Total Plant Cost
TPI	Total Plant Investment