Carbon Dioxide Capture for Storage in Deep Geologic Formations – Results from the CO_2 Capture Project

Capture and Separation of Carbon Dioxide from Combustion Sources

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Chapter 5

CO_2 REMOVAL FROM POWER PLANT FLUE GAS–COST EFFICIENT DESIGN AND INTEGRATION STUDY

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ABSTRACT

Nexant Inc., an affiliate of Bechtel Corporation, was given the task to evaluate various engineering options to reduce the costs of amine-based carbon dioxide (CO_2) capture from flue gas generated by a 400 MW natural gas fired combined cycle (NGCC) power plant. ChevronTexaco, a member of the CO_2 Capture Project (CCP), was the project manager for the study.

The Nexant study consisted of three phases; Phase 1 involves technology survey and brainstorming to identify potential cost cutting ideas, and conducts tradeoff evaluations to quantify the potential cost reductions; Phase 2 consists of developing a base case CO_2 amine plant design and cost estimate for benchmarking, and implements Phase 1 ideas to develop a low-cost amine plant design as a stand-alone plant; Phase 3 consists of developing a stand-alone NGCC power plant design and cost estimate for benchmarking, and an integrated NGCC/amine plant design to explore further cost savings via process integration.

A total of 64 cost cutting ideas were identified during the Phase 1 study, of which 39 were considered unfeasible to evaluate in detail due to either insufficient performance or cost data. Tradeoff studies were performed on 18 of the remaining 25 ideas with eight being selected for final development of the Phase 2 low-cost amine plant design. The remaining seven ideas are related to the Phase 3 integrated NGCC/amine plant design, and two out of the seven were selected for implementation in the final integrated design.

By incorporating the eight cost cutting ideas, a low-cost amine plant design was developed at a reduced capital cost of about 40%. All of the eight cost-reduction ideas implemented are related to equipment design changes, and are deemed to be technically feasible with current commercially available equipments. Their

Abbreviations: ANSI, American National Standard Institute; API, American Petroleum Institute; BFW, boiler feedwater; BP, back pressure; CCP, CO_2 capture project; CW, cooling water; GT, gas turbine; HMB, heat and material balances; HRSG, heat recovery steam generator; ISO, International Standards Organization; LP, low pressure; M, thousand; MM, million; MEA, monoethanolamine; MMSCF, million standard cubic feet; MW, megawatt; NGCC, natural gas combined cycle; PFD, process flow diagram; P&F, plate and frame; S&T, shell and tube; SCR, selective catalytic reduction.

predicted performances (either via process simulation or from vendor quotes) will need to be verified via pilot plant testing.

Phase 3 integration of NGCC with the low-cost amine plant further reduced the capital cost of CO_2 removal by approximately 15% for a total cost reduction of about 55%. The integrated design incorporated ideas of reducing the gas turbine (GT) combustion air to half with flue gas recycle, and by relocating 75% of the amine reboiling duty directly into the HRSG (heat recovery steam generator) unit. These cost-reduction designs are considered technically possible. It is recommended that technology vendors to be funded for a preliminary engineering design to confirm the performance of low oxygen ($\sim 13\%$ O_2) combustion and the possibility of integrating an amine reboiler directly into a HRSG construction design.

INTRODUCTION

Chemical absorption with amines has been practiced as an acid gas (H_2S and CO_2) removal process in natural gas, refinery and chemical industries for decades and is currently the only commercially proven process for CO_2 capture from flue gas [1,2]. The CCP identified it as the best available technology for post-combustion CO_2 capture and they have requested Fluor to use their proprietary Econamine FG^{SM} process to produce a base case process design and cost estimate for CO_2 capture from gas-fired turbine exhaust [3]. Fluor's study is discussed in Chapter 7 of this volume.

The CCP recognizes the need to reduce the current costs of amine-based CO_2 capture and sequestration by at least 50–75% in order for the process to be economically viable and commercially competitive. This large cost reduction cannot be achieved without making fundamental changes to the conventional amine plant design. Thus, along with the development of a base case amine design, the CCP identified the need to explore new and innovative design ideas that would offer promise for cost reduction and to assess the economic impact of applying non-hydrocarbon design standards to amine CO_2 capture facilities. Nexant Inc., under contract from Statoil on behalf of the CCP, was given the task to evaluate various engineering options to reduce the costs for amine-based carbon dioxide capture and sequestration from flue gas generated by a 400 MW natural gas fired combined cycle power plant.

STUDY METHODOLOGY

The Nexant study consisted of three phases.

Phase 1—Idea Generation, Brainstorming and Preliminary Process Tradeoff Analysis

The Phase 1 scope of work focused on clearly defining the design basis, criteria to be used for the study and major cost and performance issues such as equipment, materials of construction, design codes and standards, engineering criteria and design philosophy, process integration, safety and operations, that are most important to the CCP assessment of how conventional amine systems can be modified to effectively capture CO_2 from power plant flue gas. Activities included consulting various amine technology vendors, engineering design and cost specialists, special equipment developers (e.g. engineered design assembly of package process unit, shop fabricators with reputation for compact systems, developers of new and specialized chemicals/catalysts and contact devices, etc.), current CO_2 capture plant operator (e.g. Bellingham [4]), as part of the overall technology survey and data collection process. A brainstorming session was held with representatives from the CCP team to collectively: (1) establish a common understanding of the technical issues at hand and agree on a firm design basis for the study; (2) generate cost-reduction ideas for design consideration and evaluation; and (3) categorize and prioritize all ideas for evaluations and final design implementation. Selected process tradeoff studies were conducted on various cost-reduction ideas generated prior to their final selection for a low-cost design implementation.

Phase 2—Development of a Low-Cost Amine CO_2 Capture Plant Design and Cost Estimate

The original plan was for Nexant to use the Fluor design (Chapter 7) to develop a base case cost estimate as a benchmark for cost comparison. It was deemed later that a parallel base case design by

Nexant would be needed in order to provide sufficient major equipment definitions to establish a base case amine CO_2 capture plant cost estimate. In developing its base case design, Nexant followed the published flow scheme of the Fluor Econamine FG^{SM} process, and relied on manufacturer's published data of CO_2 absorption by MEA (including those from the Fluor report) supplemented with in-house historical data.

Another impetus for Nexant to develop a parallel base case design is to provide a consistent basis for Nexant to benchmark with the low-cost amine CO_2 capture plant design developed in Phase 2, allowing transparency in identifying areas of cost savings. Both the base case and the low-cost designs were developed with the same level of engineering details, which include:

- design basis document,
- process flow diagrams (PFD),
- detailed heat and material, and utility balances,
- sized equipment with data sheet including types, dimensions and weights, materials of construction, internals, operation conditions, applicable codes and standards, etc. as needed by vendor to provide price quotations,
- preliminary plant layout,
- estimated catalyst/chemical and utility consumptions for operating cost comparison.

Plant capital costs were factored from major equipment costs, with an estimated accuracy range of $\pm 30\%$. Factored costs included bulk materials, direct and indirect labors for installation. Allowance was included for home office/engineering charges, but not escalation and contingency. Most of the major equipment costs (e.g., flue gas cooler and blower, absorber and stripper vessel and internals, plate and frame heat exchanger, CO_2 product dryer and compressor, etc.,) were obtained as budgetary quotes from vendors. Other equipment costs were estimated from in-house database.

With the base case amine plant, equipments were designed to meet refinery codes and specifications (API standards). Whereas for the low-cost amine design, equipments were designed to meet minimum code requirement (ANSI or vendor's standards) to reflect the minimal hazardous conditions expected in a typical power plant flue gas treatment facility.

Phase 3—Development of an Integrated Power Plant and Amine CO_2 Capture Design for Further Cost Reduction

Cost-reduction ideas relating to integration of a CO_2 capture amine plant into a new natural gas combined cycle (NGCC) plant were implemented in this phase of the study. A base case NGCC plant design was generated to establish sufficient major equipment definitions and details to develop a reference power plant cost which, together with the stand-alone low-cost amine plant from Phase 2, provides a platform to evaluate integration cost-saving options. Overall design and cost estimation were developed using the same methodology as with the Phase 2 stand-alone amine plants.

RESULTS AND DISCUSSION

Nine stand-alone reports [5–13] were issued to the CCP during the course of the project, in which the study objective, methodology, process design and cost estimate information are presented in more detail.

Design Basis and Criteria

The stand-alone base case amine plant was designed as an add-on to an existing 400 MW NGCC power plant in accordance with the following design basis and criteria.

Site conditions

At a typical Norwegian location with climatic and site conditions similar to those specified for the Fluor base case design.

Elevation above sea level	< 30 m
Atmospheric pressure (barg)	1.013
Ambient dry bulb temperatures (°C)	
Summer maximum (for critical services)	21
Summer design	19
Winter minimum (for winterization)	−10
Winter design	−2
Annual average	10
Ambient air composition (vol%)	
Nitrogen	77.4
Argon	0.9
Oxygen	20.7
Water (at 10 °C)	1.0
Carbon dioxide	–
Total vol%	100.00
Relative humidity, % saturation	85

Design flue gas feed
From a single GT driven nominal 400 MW NGCC power plant without SCR, having the following composition, flow rate and properties:

Composition (vol%)	
Nitrogen	74.39
Argon	0.89
Oxygen	12.40
Carbon dioxide	3.98
Water	8.34
SO_x	< 1 ppm
NO_x	< 10 ppm
Carbon monoxide	−ppm
Total vol%	100.00
Flow rate (kg mol/hr)	78,912
Temperature (°C)	80
Pressure (barg)	1.01
CO_2 product specification	
Minimum vol% CO_2 (dry basis)	97.0
NO_x, SO_x, CO, O_2, etc.,	< 3.0
Maximum vol% H_2O	50 ppm
B/L pressure (barg)	220
B/L temperature (°C, maximum)	60
Seawater for cooling	
Supply temperature (°C)	11
Supply pressure (barg)	5.3
Max return temperature (°C)	22
Min return pressure (barg)	3.3

Utility and other design specifications are presented in various Nexant reports [5–13].

Additional design considerations

Plant is to be located at a typical Norwegian coastal site accessible from the ocean so that large diameter vessels can be shop-fabricated and shipped to site for installation.
Number of parallel trains. Typical commercial trayed and packed fractionation/absorption column diameters generally do not exceed 35–40 feet (11.5–13.1 m) to minimize potential flow mal-distribution problems. To keep the absorber diameter within this limitation, two identical and parallel trains are provided to recover CO_2 in the flue gas from the 400 MW NGCC Power Plant. Each train is sized to process half of the flue gas. Option of a single regeneration train common to both absorbers was also considered.
30 wt% MEA process performance basis. The amine plant was designed based on published information on the Fluor Econamine FG^{SM} process, with proprietary additives to inhibit solution degradation and corrosion. Estimated MEA absorption and regeneration performances were predicted using commercial simulators ignoring any potential effect of the Econamine additives. Overall plant process and utility heat and material balances were developed and major equipment sized using an in-house plant design simulation model.
Base case design is representative of a typical ‘conventional’ amine plant based on refinery practices and standards.
The addition of the amine plant will not affect the availability of the existing NGCC power plant. The design on-stream factor for each amine train, including CO_2 compression, is 94% based on a NGCC on-stream factor of 96%. Scheduled shutdowns for the amine plant are assumed to coincide with the NGCC annual scheduled shutdown to avoid additional time loss due to NGCC scheduled outages. A feed bypass seal drum is provided in the amine plant design to divert the NGCC flue gas to the existing vent stack in case of amine plant outages.

Ideas for Cost Reduction and Tradeoff Evaluation

A total of 64 cost-reduction ideas were generated in the brainstorming meeting. They were categorized into the following headings: process scheme, solvent, feed cooler, absorber, stripper, exchanger, pump, blower, construction technique, ducts and piping, CO_2 compression, and miscellaneous. The ideas were then analyzed, sorted and ranked according to the following criteria:

Park—Ideas that are deemed relevant but not defined clearly enough for engineering evaluation.
Long term—Ideas that are still in early technological development and lack of sufficient performance and design information; extensive feasibility assessments are beyond the current work scope. Most are recommended for future study.
Short term—Ideas that are deemed either technically feasible to evaluate, demonstrated or pilot tested for other applications, or commercially available.

The ‘short term’ items were the primary focus of the Phase 1 evaluation study. Eighteen ideas were subjected to more detailed techno-economic tradeoff evaluation. Individual reports are prepared for each of these studies [7], and a summary of the results is presented in Table 1.

Another seven of the cost-reduction ideas are related to integration with the NGCC. They were evaluated as part of Phase 3 integration study.

Base Case Amine CO_2 Capture Design

Process flow diagram

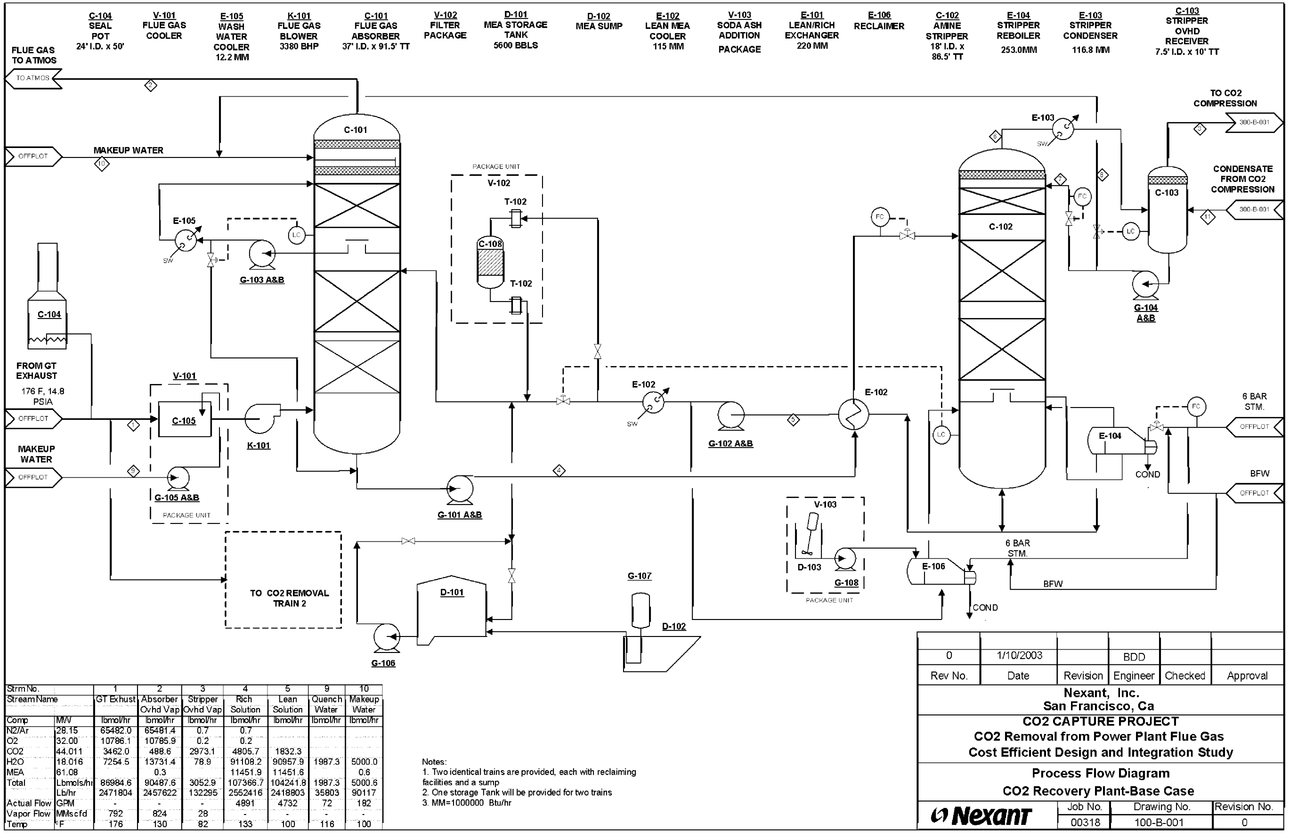
Figure 1 shows the PFD for the base case amine CO_2 capture plant, and Figure 2 the PFD for the product CO_2 dehydration and compression facility. The amine absorption and regeneration process is similar to most conventional acid gas treatment processes, except for adding a cooler and a blower to cool and pressurize the incoming flue gas from the NGCC HRSG unit. The 400 MW NGCC power plant produces roughly 1580 MMSCFD (1,769,500 Nm^3/hr) of flue gas, and base case amine plant is designed to recover 86% of the produced CO_2 or roughly 3140 ton (2850 ton) per day of 99.97% purity CO_2. The recovered CO_2 is dried and compressed to 3190 psig (220 barg) for pipeline transport and sequestration. Two separate processing trains are required to recover and compress the produced CO_2 for delivery to the pipeline for sequestration.

TABLE 1
PHASE 1 TRADE-OFF EVALUATION SUMMARY

No.	Description	Estimated installed capital cost savings (MM$)	Estimated 4 years of operating costs savings (MM$)	Capital + 4 years operating costs savings (MM$)	Recommended for low-cost design
PS-8	Look at lean solution let down at bottom of regenerator and flash it and educt the flashed vapor with steam back to the regenerator as live stripping steam	0.70	6.68	7.42	Yes
PS-9	Refrigerate lean amine to improve absorption of CO_2 or get maximum cooling with the once-through 11 °C seawater	No savings	No savings	No savings	No
SO3	Increase MEA concentration to above 30 wt %	1.14	3.3	4.45	No
FC-2	Eliminate cooler and enter absorber hot	3.35	−0.14	3.2	Yes
A-3	Use plastic fill or packing in the absorber to reduce cost	0.18	0.09	0.27	No
A-8	Spray absorber: extend HSRG ducting; use plastic material in construction; Hang plastic netting or screen to improve contact efficiency				
A-9	Add intercooler to absorber to increase loading (increase solvent loading)	No savings	No savings	No savings	No
A-13	Use column packing internals that reduces absorber diameter	1.37	1.06	2.43	Yes
S-3	Optimize lean loading from the stripper bottoms to minimize plant utilities and cost				Base case is close to optimum lean loading
S-4	Can we utilize the heat coming from the top of the regenerator for other uses? Producing electricity, for example	−5.49	1.19	−4.30	No there is no capital savings

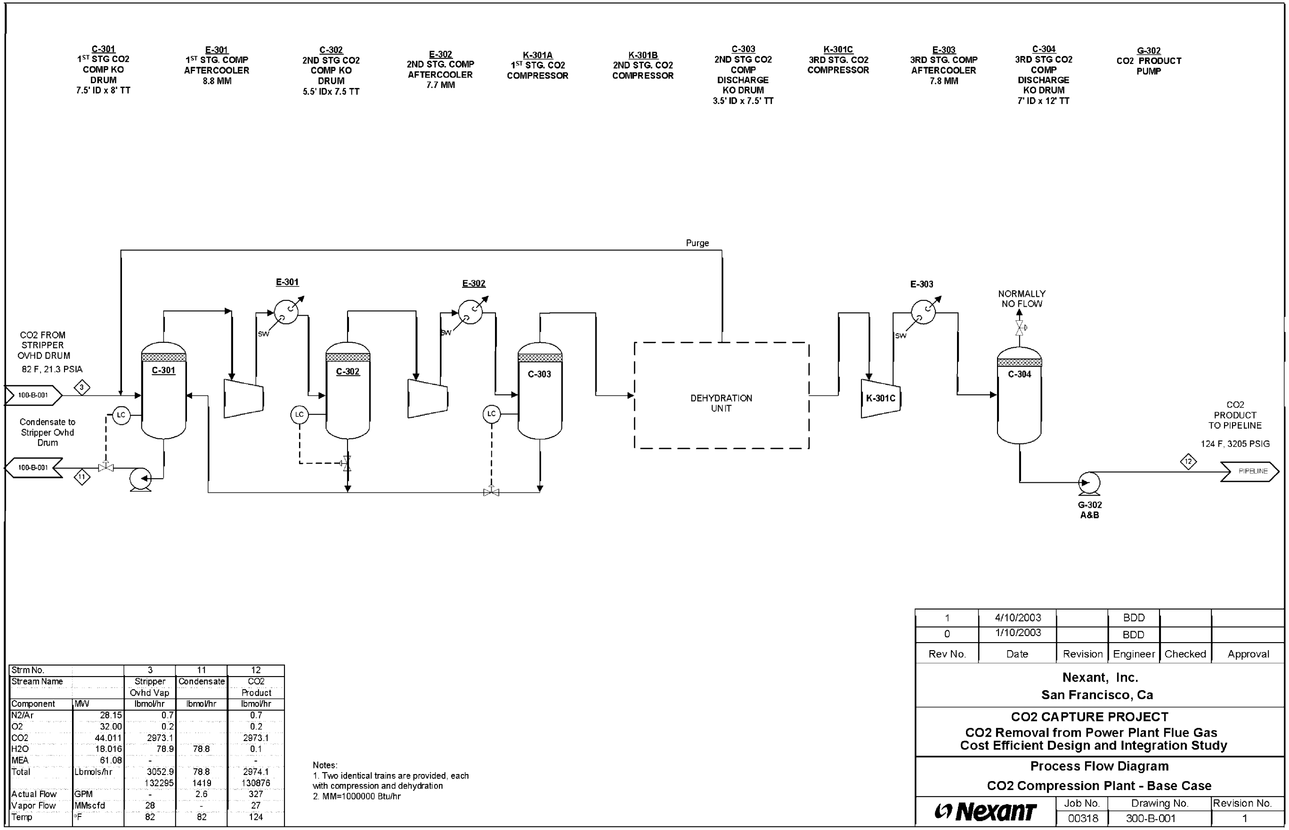
S-12	Optimize temperature approach of lean/rich heat exchanger				Base case 19 °F temperature approach is close to optimum
E-1	Use plate and frame exchanger for liquid–liquid heat exchangers	7.4	None	7.4	Yes
E-2	Place tube bundles directly in regenerator bottom-saving kettle costs	−0.014	None	−0.014	No
E-3	Reheat flashed rich MEA. Separate flashed rich MEA after R/L exchange. Send cooled liquid to exchange against reboiler steam condensate	−0.08	−1.08	−1.16	No
P-2	Lower pump design standards. Go from API to ANSI	1.83	None	1.83	Yes
CT-3	Investigate if modularized design can reduce costs	<0.4	None	<0.4	No way to estimate true savings at this time
CC-1	Pump CO_2 liquid and use ambient air to raise pressure	No savings	No savings	No savings	Base case uses a pump on last stage
CC-3	Use CO_2 compression interstage cooling to reboil stripper	0.04	−0.54	0.5	No Increases complexity

Note: a cost of $40/MW-h for power was used for all trade-off evaluations.



Strm No.		1	2	3	4	5	9	10
Stream Name		GT Exhust	Absorber Ovhd Vap	Stripper Ovhd Vap	Rich Solution	Lean Solution	Quench Water	Makeup Water
Comp	MW	lbmol/hr	lbmol/hr	lbmol/hr	lbmol/hr	lbmol/hr	lbmol/hr	lbmol/hr
N2/Ar	28.15	65482.0	65481.4	0.7	0.7			
O2	32.00	10786.1	10785.9	0.2	0.2			
CO2	44.011	3462.0	488.6	2973.1	4805.7	1832.3		
H2O	18.016	7254.5	13731.4	78.9	91108.2	90957.9	1987.3	5000.0
MEA	61.08		0.3		11451.9	11451.6		0.6
Total	Lbmols/hr	86984.6	90487.6	3052.9	107366.7	104241.8	1987.3	5000.6
	Lb/hr	2471804	2457622	132295	2552416	2418803	35803	90117
Actual Flow	GPM	-	-	-	4891	4732	72	182
Vapor Flow	MMscfd	792	824	28	-	-	-	-
Temp	°F	176	130	82	133	100	116	100

Figure 1: Simplified process flow diagram of base case amine CO_2 plant.



Strm No.		3	11	12
Stream Name		Stripper Ovhd Vap	Condensate	CO2 Product
Component	MW	lbmol/hr	lbmol/hr	lbmol/hr
N2/Ar	28.15	0.7		0.7
O2	32.00	0.2		0.2
CO2	44.011	2973.1		2973.1
H2O	18.016	78.9	78.8	0.1
MEA	61.08	-		-
Total	Lbmols/hr	3052.9	78.8	2974.1
		132295	1419	130876
Actual Flow	GPM	-	2.6	327
Vapor Flow	MMscfd	28	-	27
Temp	°F	82	82	124

Figure 2: Simplified process flow diagram of product CO_2 dehydration and compression.

The amine plant includes of the following major equipment, as shown in Figure 1.

Feed gas seal drum (C-102)—Common to Trains 1&2,
Feed gas cooler (V-101) and feed blower (K-101),
Amine absorber (C-101),
Amine stripper or regenerator (C-102),
Heat exchangers and reboiler (E-101 to 105),
MEA filtration (V-102) and reclaiming (E-106),
MEA storage facility (D-101, 102).

Product CO_2 compression consists of the following as shown in Figure 2.

CO_2 compression with interstage cooling,
CO_2 dehydration, and
CO_2 supercritical product pump.

Process descriptions
Flue gas is diverted equally from the existing NGCC HRSG outlet to the two parallel stand-alone amine plants.

Feed gas water seal drum (C-104). A water seal drum, common to both amine plants, is included to the bottom of the existing NGCC exhaust stack. It is provided to limit the GT/HRSG to not more than 10 in., or 18 mm Hg, in back pressure (BP). Pressure exceeding 10 in. will blow the water seal and divert the flue gas to the vent stack.

Feed gas cooler (V-101). A direct contact water evaporation spray cooler is provided to lower the temperature of the flue gas from the HRSG prior to entering the flue gas absorber (C-101). The cooled flue gas, at approximately 116 °F (47 °C), is sent to the feed gas blower (K-101).

Feed gas blower (K-101). A feed gas blower is included to overcome the pressure drop in the feed gas cooler (V-101) and to provide the needed inlet pressure to the amine plant without raising the BP on the GT and HRSG in the existing NGCC power plant. NGCC plant operation is sensitive to GT BP; a small increase in BP will reduce the GT power output and changes the HRSG steam output, while a large increase will effectively shut down the NGCC plant.

Amine absorber (C-101). The compressed gas feed is sent to the flue gas absorber (C-101). The absorber is designed to recover 86% of the flue gas CO_2. The column has an absorber section and a wash section. The bottom absorption section consists of two packed beds where the flue gas is contacted with the lean MEA solution. Because of the low operating pressure of the absorber and the high vapor pressure of MEA, there is a significant amount of MEA (in excess of 500 ppmv) leaving the absorption section with the clean flue gas. A wash section is required to recover the MEA and meet air quality standards.

The wash section consists of a top wash tray followed by a packed wash section. Most of the MEA in the absorber overhead gas is removed in the packed section just below the top wash tray through washing with cooled recirculating water. The recirculation water is cooled with seawater in the wash water cooler (E-105). Makeup water is sent to the top tray to remove residual MEA in the exhaust flue gas down to 3 ppmv.

Because of the lower absorber operating pressure, rich MEA solution from the bottom of C-101 has to be pumped, via G-101 A/B, through the rich/lean exchanger (E-102) where it is preheated against the hot lean amine, before returning to the amine stripper (C-102) for regeneration.

Amine stripper (C-102). The rich solution is stripped of CO_2 in a reboiled amine stripper to yield a lean solution with about 0.16 mole CO_2/mole MEA. The reboilers are kettle type. The amine stripper consists of two packed stripping sections and a wash section to remove entrained and volatized MEA. The stripper overhead vapors are cooled by seawater to 82 °F (28 °C) in E-103 and sent to the stripper overhead receiver (C-103). The vapor from the receiver is the recovered CO_2 and it is sent to the CO_2 compression section where it is compressed, dried and delivered to the CO_2 product pipeline.

Most of the condensed liquid from the overhead receiver (C-103) is returned to the stripper as reflux and any excess is sent to the wash section of the amine absorber (C-101) as makeup water. The lean solution from the stripper is first cooled by rich MEA solution in E-101 and then pumped and further cooled in lean solution cooler (E-102) to 100 °F (38 °C) before returning to C-101.

Amine solution treating, preparation and storage. The amine solution will be continuously cleaned by taking a slip stream from E-102 outlet and circulating it through a cartridge filter (T-102) to remove rust and solids, then through a carbon drum (T-101) to remove degradation products followed by another cartridge filter (T-103) to remove any entrained carbon filter particles. An amine sump (D-102) is provided to collect drainage for recovery of amine and for preparation of MEA makeup solution. A MEA storage tank (D-101) is provided for each train to store the system inventory in the event of a plant shutdown. The sump and the tank are gas blanketed to keep air from contact with MEA.

MEA reclaiming facilities. A reclaiming facility is provided for each train to remove heat stable salts formed from decomposition and degradation of MEA. This is done by batch distillation. Periodically part of the lean MEA solution is pumped (G-102 A/B) to the reclaimer E-106, where steam is introduced to heat and vaporize the MEA solution. The MEA/water vapors are returned to the amine stripper (C-102). The remaining stable salt sludge is cooled and disposed as a solid waste. A soda ash addition system is included to promote MEA recovery by neutralizing some of the acidic degradation byproducts. It consists of a mix drum (D-103), a mixer (V-103) and an addition soda ash pump (G-108).

CO_2 compression and dehydration. CO_2 needs to be delivered to the pipeline at a pressure of 3190 psig (220 barg). This is accomplished first by compressing the CO_2 vapor to 1100 psig (76 barg) in a 3-stage centrifugal CO_2 compressor (K-301) with intercoolers. It is followed by pumping the cooled liquid CO_2 from the 3rd stage compressor to 3190 psig (220 barg) with a proprietary supercritical liquid pump. To meet the 50 ppm water specification for the CO_2 product, the CO_2 is dried in a proprietary packaged heatless drying unit located after the second compression stage at approximately 350 psig (24 barg). To maximize the availability of the base case CO_2 recovery scheme, two 50% CO_2 compression trains were provided.

Base Case Amine CO_2 Capture Plant Performance and Cost

Details of the base case design and its cost estimation are the subject of Nexant report #2 and #4 [6,8], respectively. A summary of the base case design performance, cost estimates and utility consumptions is presented in Table 2. Costs shown are for 1st quarter, 2003 without any escalation allowance, and with an estimated accuracy range of $\pm 30\%$. Two separate amine and CO_2 compression trains are provided to produce the 2850 ton per day of CO_2. Amine train #1 costs more than train #2 because the common flue gas seal drum cost is included under train #1.

An additional $4,000,000 to cover the Combined Cycle Power Plant retrofit modification needs is added to the above installed cost. The modification costs are required to cover Combined Cycle Power Plant new demineralizer capacities, and new extraction steam and condensate piping. Details are shown in the 400 MW Natural Gas Combined Cycle Power Plant Design and Cost Estimate Specifications of Nexant report #6 [10].

Low-Cost Amine CO_2 Capture Design

The low-cost amine design incorporates all the ideas from the Phase 1 cost-reduction tradeoff studies that showed significant cost savings without adding excessive complexity to overall plant operation. The design details, equipment descriptions and cost estimates are documented in Nexant report #5 [9]. The low-cost amine plant is similar to the base case design except for the following cost-reduction design/equipment changes.

- Eliminate the feed gas cooler package;
- Relax flue gas blower metallurgy from stainless to carbon steel;

TABLE 2
BASE CASE AMINE PLANT DESIGN SUMMARY

Installed cost ($US, 1st quarter 2003)	
Direct cost	
Amine absorption train #1	$30,446,000
Amine absorption train #2	$30,136,000
CO_2 compression and dehydration (total two trains)	$23,370,000
Construction indirect costs	$17,373,000
Vendor representative costs	$356,000
Home office costs	$12,593,000
Total installed cost	$114,274,000
Plant utility consumptions	
Steam (6 barg) import (kg/h)	238,200
Electric power (kW)	20,350
Seawater cooling duty (10^6 kJ/h)	623
Condensate export (kg/h)	177,200
Catalyst and chemical consumptions	
85 wt% MEA (kg/h)	220
Activated carbon (amine grade) (kg/day)	114
Inhibitor consumption (kg/day)	157
Anhydrous Na_2CO_3 (kg/h)	168

- Replace random packing with more efficient structured packing for Absorber C-101;
- Replace the shell and tube (S&T) heat exchangers for rich/lean amine heat exchange, lean amine cooling, and wash water cooling services with lower-cost, non-hydrocarbon application, plate and frame (P&F) heat exchangers,
- Replace the S&T stripper overhead condenser with lower cost welded P&F exchanger,
- Reduce overall reboiler steam demand by adding a lean solution flash drum and ejector system to recover part of the lean solution heat as flashed steam back to the stripper,
- Replace API-610 pumps with less costly ANSI pumps where applicable, and
- Replace the two 50% trains CO_2 compression plant with a single 100% train; availability analysis shows that additional plant availability gained from using two 50% CO_2 compression trains versus a single 100% compression train is less than an hour per year.

The above cost-reduction ideas are considered technically viable, with performances either predicted with commercial process simulators or provided directly by technology vendors. Many of the predicted performances, however, would need to be verified with either pilot or demonstration plant testing.

The low-cost amine plant uses approximately 15% less steam, 7% less power, and 12% less cooling seawater than the base case design. Reduction in steam consumption mainly comes from lower stripper reboiler duty. Reduction in power consumption is attributed to lower flue gas blower head and slightly higher efficiency for larger CO_2 compressor. Reduction in cooling load is attributed to lower stripper condenser duty and smaller return condensate cooler duty.

A summary of the low-cost amine design performance, equipment descriptions, cost estimates and utility consumption requirements is shown in Table 3. Total installed capital cost for the low-cost amine plant is approximately US$70 million (including estimated $3,765,000 NGCC modification cost), comparing to US$118 million for the base case amine plant. It represents a total capital saving of approximately 40%. The two-train low cost amine plant requires a total plot area of approximately 54,700 ft^2 (5080 m^2).

The $3,765,000 includes retrofit modification costs for items such as new demineralizer capacities and additional extraction steam and condensate piping.

TABLE 3
LOW-COST AMINE PLANT DESIGN SUMMARY

Installed cost ($US, 1st quarter 2003)	
Direct cost–Amine absorption train #1	$16,014,000
Direct cost–Amine absorption train #2	$15,700,000
Direct cost–CO_2 compression and dehydration (total two trains)	$16,886,000
Construction indirect costs	$10,114,000
Vendor representative costs	$210,000
Home office costs	$7,290,000
Total installed cost	$66,214,000
Plant utility consumptions	
Steam (6 barg) import (kg/h)	201,200
Electric power (kW)	18,940
Seawater cooling duty (10^6 kJ/h)	550
Condensate export (kg/h)	147,500
Catalyst and chemical consumptions	
85 wt% MEA (kg/h)	220
Activated carbon (amine grade) (kg/day)	114
Inhibitor consumption (kg/day)	157
Anhydrous Na_2CO_3 (kg/h)	168

Base Case NGCC Power Plant Design

This stand-alone power train is based on Bechtel's standard PowerLine 350 MW NGCC Power Plant design [13], modified to use once through seawater for cooling. It is a bare-bone version of the single shaft GE 9F-based NGCC with a net power output of 385 MW. Figure 3 shows a typical heat and material flow diagram.

The NGCC facility will include a 254 MW (nominal) combustion turbine exhausting to an unfired HRSG. Steams from the HRSG are fed to a 140 MW (nominal) steam turbine. The combustion turbine, steam turbine, and their common generator are designed to be located in a single-shaft arrangement. The estimated facility net output at 15 °C (ISO conditions) is approximately 384 MW when burning natural gas. The DLN combustor will operate dry during natural gas firing. An inlet air filtration system is included to provide suitably filtered combustion air to the combustion turbine.

The NGCC base case design is the subject of Nexant report #6 [10]. Plant capital cost and utility summary are presented in Table 4.

Integrated NGCC Power Plant and Low-Cost Amine CO_2 Capture Design

Seven of the 64 cost cutting ideas generated from brainstorming were related to integration:

PS-4	Integrate stripper reboiler into the tail end of the HRSG;
PS-5	Recycle part of the HRSG flue gas back to the GT air compressor inlet;
PS-7	Eliminate the flue gas blower;
S-1	Optimize LP steam from NGCC to match stripper reboiler requirement;
S-9	Maximize stripper pressure levels;
CC-2	Use turbine-driven CO_2 compressor to provide speed control.
CC-5	Use backpressure turbine-driven CO_2 compressor with exhaust being used to heat stripper reboiler.

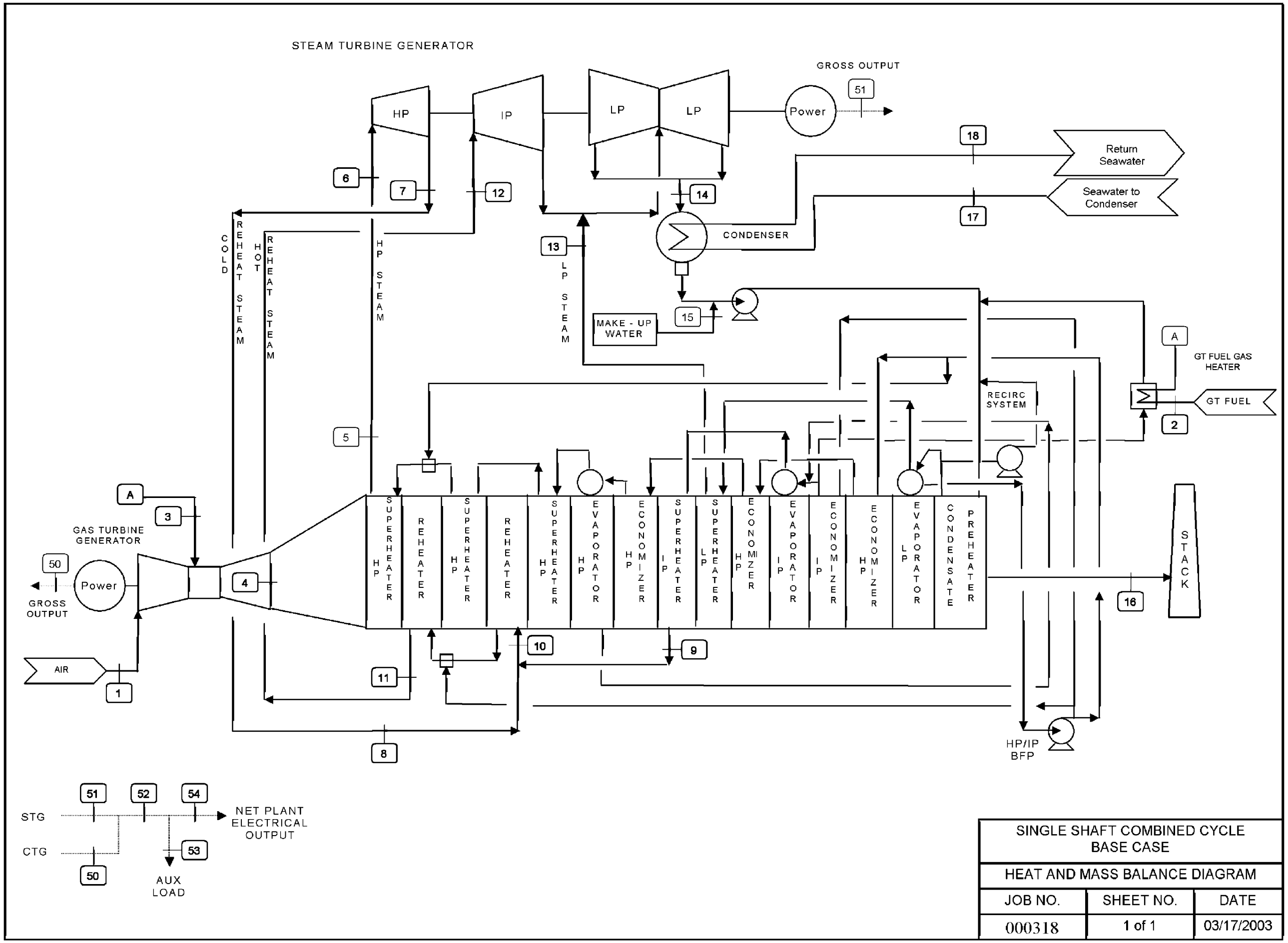


Figure 3: Simplified NGCC plant heat and mass balance diagram.

TABLE 4
BASE CASE NGCC DESIGN SUMMARY

Installed cost ($US, 1st quarter 2003)	
Direct cost	$102,594,000
Construction indirect costs	$17,266,000
Home office costs	$20,519,000
Total installed cost	$140,378,000
Plant performance summary	
Power generation (MW)	396
Power consumptions (MW)	
Parasitic loads	11
Amine plant loads	–
Net export to grid (MW)	385
Seawater cooling duty (10^6 kJ/h)	824
Catalyst and chemical consumptions, without amine CO_2 recovery	
Chlorine for CW injection (kg/day)	236
Sulfur dioxide for CW injection (kg/day)	272
BFW chemicals–Phosphate (kg/day)	9
BFW chemicals–Oxygen scavenger (kg/day)	14
BFW chemicals–Neutralizing amine (kg/day)	9
Demineralizer regeneration–Sulfuric acid (kg/day)	23
Demineralizer regeneration–Caustic (kg/day)	45

Only two of the above seven ideas (PS-4 and PS-5) were subjected to more detailed engineering calculation and assessment, and implemented in the integrated design. The remaining five were either rejected (after closer examination) or had already been included in the basic process design. For example, idea PS-7 of eliminating the flue gas blower at the expense of operating the NGCC power plant at a higher BP was deemed impractical due to turbine supplier's concern of unknown turbine aerodynamics and the associated increase in cost of designing for higher operating pressure.

The integrated design incorporated the following two cost cutting ideas for further CO_2 removal cost reduction:

PS-4—Integrate stripper reboiler into the HRSG
Integrating the reboiler tubes directly into the tail end of the HRSG would eliminate the reboiler shells and some of the steam generation tubes. A smaller steam heated kettle reboiler ($\sim 25\%$ of the total duty) is still required to control the heat input to the stripper in case of fluctuation in HRSG heat pickup. The smaller number of kettle reboiler needed also permits combining the stripping system into a single train design resulting in additional savings.

PS-5—Recycle part of the HRSG flue gas back to the GT inlet
Recycling flue gas to GT inlet has the effect of increasing the HRSG flue gas CO_2 concentration and decreasing the O_2 concentration. Both are positive effects for amine CO_2 recovery; higher feed CO_2 concentration reduces absorption stages required to recover a given tonnage of CO_2, and lower feed O_2 concentration reduces amine degradation losses. In addition, flue gas recycling decreases the quantity of flue gas flow to the amine absorber, hence resulting in a smaller diameter column.

Simulation shows that it is possible to recycle 50% of the flue gas and still maintain a minimum 13% oxygen concentration required for sustained GT combustor operation. The design change reduces the quantity of flue gas flow to the amine absorber by almost 50%. With it, it is possible to design a single train absorber that is less than 40 ft (12.189 m) in diameter.

The recycled flue gas from the HRSG is hot (~ 80 °C) and it must be cooled before mixing with air intake to the GT to maximize NGCC power output. This is done by indirectly cooled against seawater. The overall recycle process includes a condensate removal and treating facilities to collect and recycle the recovered water as water make-up. An adjustable vane-type louver is also used to control the recycle flow to maintain minimum oxygen content for GT combustion.

The Integrated NGCC/amine plant is designed to operate as a single 400 MW NGCC plant with 86% less CO_2 emission. The NGCC in the integrated scheme sends roughly 824 MNm^3/h (740 MMSCFD) of flue gas, containing 8.5 vol% CO_2 and 4.7 vol% oxygen, to the amine plant for CO_2 removal. The following major equipment had to be added to the NGCC and amine plant design to enable this integration:

- seawater-cooled indirect flue gas recycle cooler to maximize power generation,
- Louver-type recycle flow controller to maintain proper oxygen concentration in the GT combustor,
- pumps and storage to handle condensed water from the recycle cooler,
- circulation pumps to circulate the stripper bottoms to the new reboiler tubes in the HRSG.

The integrated plant is designed to operate as a single plant without any provision to allow isolated NGCC operation without the amine plant. Design and cost estimate details for the integrated NGCC/low-cost amine plant are documented in Nexant report #7 [11], and a plant summary is presented in Table 5. Overall plant utility consumptions are listed in Table 5. Steam and condensate are considered to be internal to the plant and are not shown. The integrated plant will have surplus water due to condensing moisture from the recycle flue gas.

Integrated NGCC/Amine CO_2 Capture Design—Cost and Economic Assessment

Table 6 summarizes and compares the capital costs developed for amine CO_2 capture from flue gas under the various design scenarios studied. Economic assessment of amine-based post-combustion CO_2 capture from flue gas is the subject of Chapter 5. The CCP chooses to evaluate all CO_2 capturing processes under a consistent set of economic parameters that is discussed in Chapter 4.

Table 6 shows the progressive reduction in overall plant capital between the base case, low-cost case, and the Integrated NGCC/amine CO_2 capture design. The integrated NGCC/amine CO_2 capture design has a total capital cost that is about 92% of the low-cost amine option, and 75% of the base case amine option. Ignoring the NGCC power plant cost, the amine absorption and compression cost for the integrated design is about 75% of the low-cost amine option, and about 45% of the base case amine option.

CONCLUSIONS AND RECOMMENDATIONS

The objective of this study is to cut the cost of a post-combustion amine-based CO_2 capture process by 50–70%. Results from this study indicate that capital investment for post-combustion CO_2 recovery from gas turbine (GT) exhaust by MEA can be reduced 40–55%.

For a near-term MEA plant designed as an add-on to existing power plant, the capital cost can be reduced by 40% through alternate equipment selections such as using P&F instead of S&T exchangers, elimination of the flue gas cooler, using ANSI instead of API pumps, using structured instead of random packing, and by combining two 50% trains into one 100% train CO_2 compression. In addition to the equipment selections changes, an ejector-assisted hot lean amine-flashing drum is added to reduce reboiling steam requirement by about 15%. All of the proposed changes are commercially demonstrated either for amine services or for other similar applications, and thus considered to have minimum risks. To further reduce the risk, Nexant recommends that some small pilot plant or intermediate demonstration plant be built to confirm the process performances before building full size commercial plants.

For a longer-term MEA plant designed as part of an integrated power/amine plant, the capital cost can be further reduced by another 15% for a total reduction of 55%. The additional reduction is achieved by recycling flue gas to the GT air compressor to cut the combustion air by 50%, and by relocating 75% of the stripper reboiling duty directly into the HRSG. Although these two options are considered to be technically

TABLE 5
INTEGRATED NGCC/AMINE CO_2 CAPTURE DESIGN SUMMARY

	Integrated NGCC/amine plant	**Stand-alone (NGCC + amine) plants**
Installed cost ($US, 1st quarter 2003)		
Amine CO_2 capture		
Direct cost-CO_2 capture	$21,092,000	$31,714,000
Direct cost-CO_2 dehydration and compression	$16,886,000	$16,886,000
Indirect costs	$7,571,000	$10,114,000
Vendor representative costs	$172,000	$210,000
NGCC plant		
Installed cost	$120,710,000	$119,860,000
Modification costs with added amine plant		$3,274,000
Home office costs	$27,469,000	$28,300,000
Total installed cost	$193,900,000	$210,358,000
Plant performance summary		
Power generation (MW)	355	353
Power consumptions (MW)		
NGCC parasitic loads	11	11
Amine plant loads	19	19
Net export to grid (MW)	325	323
Seawater cooling duty (10^6 kJ/h)	1122	982
Catalyst and chemical consumptions		
85% wt% MEA (kg/h)	220	220
Activated carbon (amine grade) (kg/day)	114	114
Inhibitor (kg/h)	157	157
Anhydrous Na_2CO_3 (kg/h)	168	168
Chlorine for CW injection (kg/day)	321	281
Sulfur dioxide for CW injection (kg/day)	370	324
BFW Chemicals-phosphate (kg/day)	7	9
BFW Chemicals-oxygen scavenger (kg/day)	11	14
BFW Chemicals-neutralizing amine (kg/day)	7	9
Demineralizer Regeneration-sulfuric acid (kg/day)	1038	1534
Demineralizer Regeneration-caustic (kg/day)	2031	3002

TABLE 6
INSTALLED CAPITAL COST SUMMARY AND COMPARISON (US$$10^6$)

	Base case amine	**Low-cost amine**	**Integrated NGCC/amine**
NGCC plant	140	140	141
NGCC modification	4	4	0
Amine plant	84	44	31
CO_2 dehydration/compression	30	22	22
Total installed costs	258	210	194

possible, it is recommended that GT vendors and HRSG vendor be funded to confirm the technical feasibility before commencing pilot or demonstration testing.

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