POST-COMBUSTION CO_2 CAPTURE SCALE-UP STUDY

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POST-COMBUSTION CO_2 CAPTURE
SCALE-UP STUDY

Key Messages

- Scale up of CO_2 post combustion capture process is possible without significant development and cost. Although process performance could be improved further by additional research and development identified from this study.

- Process integration and improved amine based solvent formulations will help in reducing the energy requirement for the post combustion capture process.

- Focus should be given on improving the amine based solvents on their CO_2 absorption rate, CO_2 absorption capacity, reduction in sensible heat requirement for solvent regeneration and waste generation.

- Further work should be performed on improving process equipment (e.g. heat exchangers), process heat integration and operational flexibility of the process.

- IEAGHG would like to encourage equipment developers and suppliers to have improved interaction to address issues identified in this study.

POST-COMBUSTION CO_2 CAPTURE
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Introduction

Several government and international organisations have set 2020 as a target for commercial deployment of CCS. In order to keep this target, it is clear that the initial CCS demonstration projects and full scale CO_2 capture plants will have to be based on currently available technologies. These commitments and agreed targets give an important role for the solvent based post-combustion capture technology, which is considered to be the most mature of all the capture technologies available today. This technology provides a retrofit possibility and is already available on relatively small industrial scale; this makes it one of the most viable options for large scale CCS deployment.

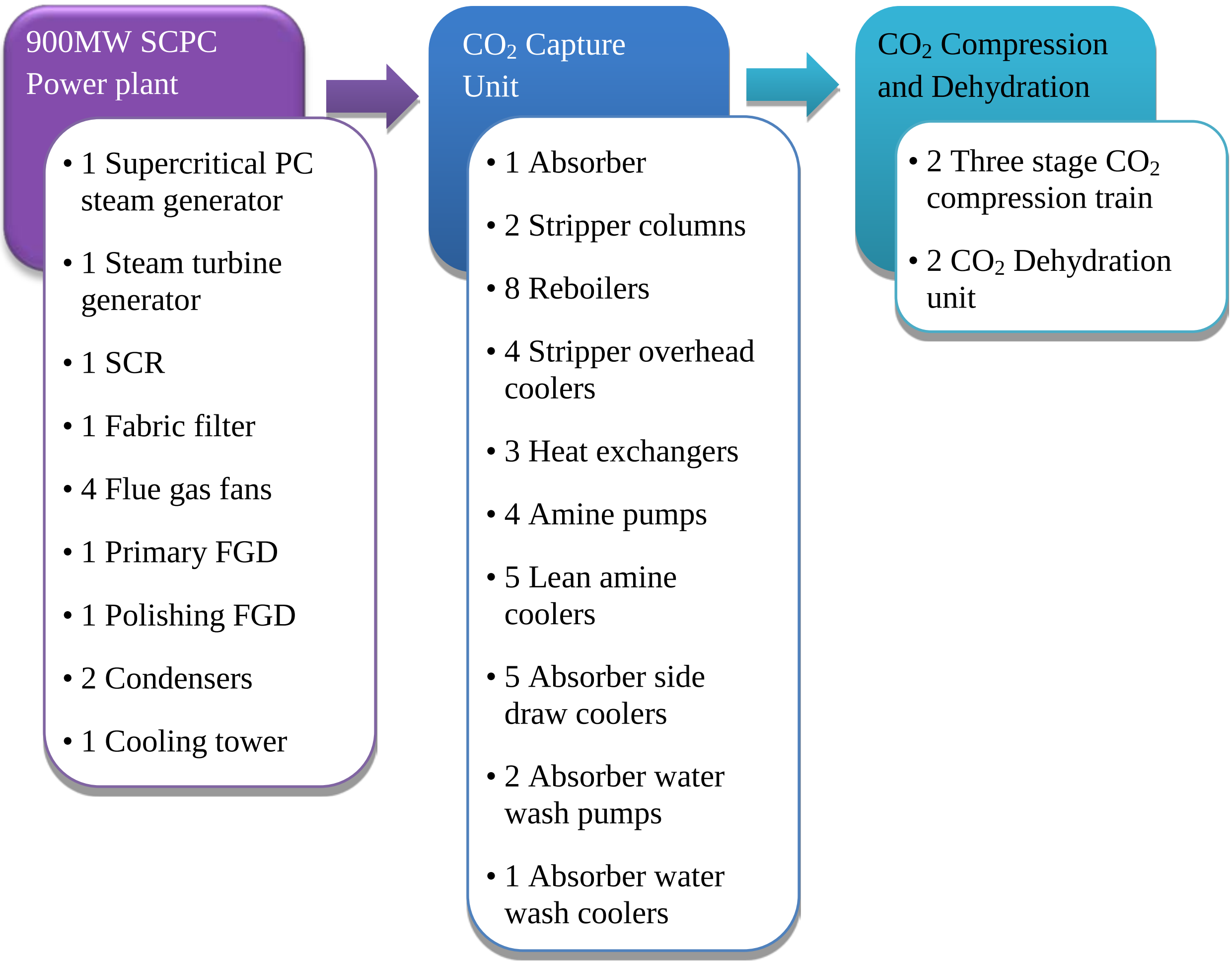
However, the conventional solvent based post-combustion CO_2 capture technology are facing a number of challenges, which need to be addressed before full scale deployment. Major challenges are related to the high energy requirement, high capture cost and the uncertainties of the environmental impact from the capture technology and very important the challenge related to the scale. Therefore, IEAGHG has commissioned this study to define the different technical challenges associated to the conventional post-combustion capture technology with a special focus on those risks related to scale-up and full scale operational requirements.

Approach

This study was awarded to Black & Veatch, USA, on the basis of competitive tender. This study assess the technical challenges associated with full-scale design and operation of conventional post-combustion capture technologies for supercritical pulverized coal (SCPC) and natural gas fired combined cycle (NGCC) power plant. In this study technical and operational risks, performance gaps, technical challenges and sensitivity to several process variables are evaluated. Finally, a suggested scale-up strategy was developed with a focus on specific areas for development in future.

To accomplish the project objectives, Black & Veatch developed a full scale conceptual design of a 900 megawatt (MW) supercritical pulverized coal (SCPC) and an 800 MW natural gas fired combined cycle (NGCC) power plant without and with a solvent based CO_2 post combustion capture process, in order to serve as a basis for discussion of the issues associated with the scale-up. A low sulphur Australian coal was used for SCPC case. The design of the selected power plant was based on conservative supercritical conditions and hence a conservative assessment of flows and equipment sizes. Black & Veatch has reviewed the post-combustion CO_2 capture technologies currently available and amine-based absorption process was selected as the most developed technology for both power plants. In this study a CO_2 capture efficiency of 90% was selected.

NOx reduction in the flue gas was achieved by Selective Catalytic Reduction (SCR) technology for both SCPC and NGCC power plants with 80-84% NOx removal efficiency. In the SCPC power plant SCR is located between the economizer outlet and the air preheater inlet whereas in the NGCC power plant SCR is situated in the exhaust gas path and is integral with the HRSG. An oxidation catalyst was selected for carbon monoxide (CO) reduction in NGCC power plant which is located upstream of SCR. Mercury reduction in the SCPC power plant was achieved by Powdered Activated Carbon (PAC) injection upstream of the particulate matter reduction. Particulates were removed from the SCPC power plant exhaust stream by Pulse Jet Fabric Filter (PJFF) as this technology is able to meet low particulate emissions for a wide range of fuel and operations. The particulate removal efficiency was specified as 99.9%. Major equipment lists for SCPC and NGCC with CO_2 capture cases (Case 2 and 4) are presented in Figure 1 and 2 respectively.



900MW SCPC Power plant

- 1 Supercritical PC steam generator
- 1 Steam turbine generator
- 1 SCR
- 1 Fabric filter
- 4 Flue gas fans
- 1 Primary FGD
- 1 Polishing FGD
- 2 Condensers
- 1 Cooling tower

CO_2 Capture Unit

- 1 Absorber
- 2 Stripper columns
- 8 Reboilers
- 4 Stripper overhead coolers
- 3 Heat exchangers
- 4 Amine pumps
- 5 Lean amine coolers
- 5 Absorber side draw coolers
- 2 Absorber water wash pumps
- 1 Absorber water wash coolers

CO_2 Compression and Dehydration

- 2 Three stage CO_2 compression train
- 2 CO_2 Dehydration unit

Figure 1, Major equipment list of 900MW SCPC with 90% CO_2 capture case (Case 2).

A Wet Flue Gas Desulphurisation (WFGD) with Limestone Forced Oxidation (LSFO) was selected for the SCPC power plant with SO_2 removal efficiency of 97.5%. A low level of SO_2 is required in the flue gas for amine based CO_2 capture systems. Since LSFO WFGD would likely not be able to achieve the low level required, a SO_2 polishing scrubber was selected for the SCPC power plant with CO_2 capture (Case 2). The SO_2 concentration in the flue gas for SCPC CO_2 capture process (Case 2) was assumed to be 10ppm.

The flue gas entering the CO_2 Capture process had CO_2 concentrations of 11.8mole% and 4.1mole% for SCPC and NGCC power plant cases respectively. The oxygen concentration in flue gas was 5mole% and 12mole% for SCPC and NGCC power plants respectively. Flue gas flow rate was 3989tonne/h and 4362tonne/h for SCPC (Case 2) and NGCC (Case 4) CO_2 capture cases respectively.

The CO_2 recovery process consists of three main sections: CO_2 absorption, solvent stripping, and CO_2 compression. The CO_2 absorber is a rectangular concrete column with stainless steel internals that divide the column into six parallel sections. Each parallel section of the CO_2 absorber has a cross section of approximately 7 meter (m) by 7 m. In the SCPC CO_2 case (Case 2) the absorber has three main vertical segments: the CO_2 absorption segment, the overhead cooling segment, and the water wash segment. Whereas in the NGCC CO_2 capture case (Case 4) the absorber has four main vertical segments: the quench cooler segment, the CO_2 absorption segment, the overhead cooling segment, and the water wash segment. A demister is used at the exit of the overhead segment of the absorber column to remove water droplets that may have been entrained with the flue gas for both Cases 2&4. The clean flue gas is vented to the atmosphere through a stack at the top of the absorption column. Table 1 gives the summary of electricity generation and CO_2 capture process specific utility requirements for SCPC and NGCC power plants.

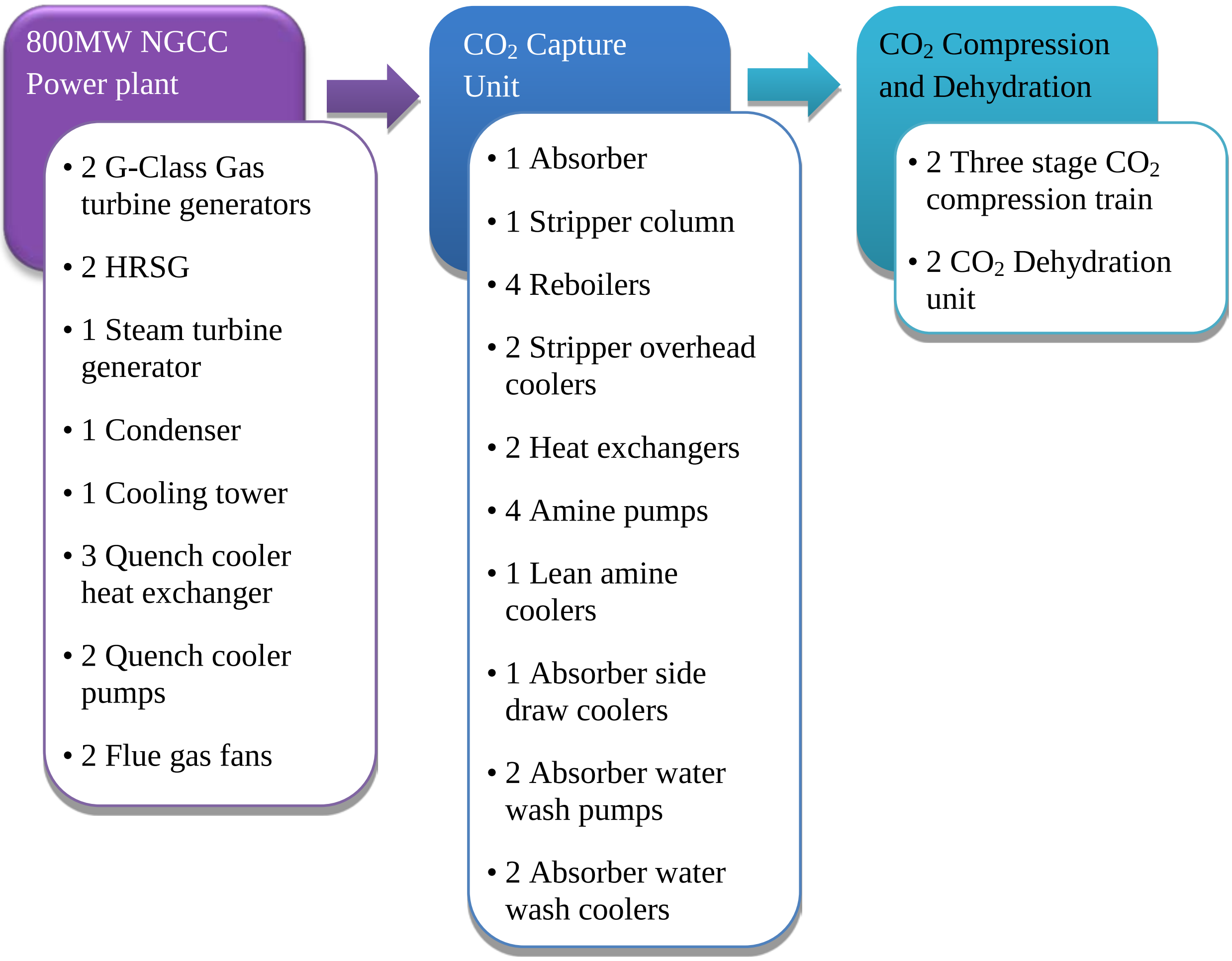


Figure 2, Major equipment list for 800MW NGCC with 90% CO_2 capture case (Case 4).

The rich solvent from the bottom of the CO_2 absorber is sent to two parallel stripper columns by a rich solution pump through three plate and frame rich/lean solvent heat exchangers for the SCPC case (Case 2) and two plate and frame rich/lean solvent heat exchangers for the NGCC case (Case 4). The strippers used were cylindrical packed columns with the main shells made of carbon steel where the rich solvent is heated to liberate the CO_2.

Table 1, Electrical generation and utility requirements summary for SCPC and NGCC cases.

	UNIT	CASE 1	CASE 2	CASE 3	CASE 4
Reference Case Description		Supercritical Pulverized Coal Rankine Cycle		2-on-1 G-Class Gas Turbine Combined Cycle	
Fuel Type		Low Sulfur Australian Coal	Low Sulfur Australian Coal	Natural Gas	Natural Gas
Net Plant Thermal efficiency	%	40.4	28.3	58.0	49.6
CO_2 Capture	%	No	90	No	90
ELECTRICAL OUTPUT					
STG	MW	-	-	280.4	223.7
Gas Turbine Generators	MW	-	-	529.5	529.5
Total Gross Output	MW	900.1	756.6	809.9	753.2
Auxiliary Electric Load					
Power Block	MW	35.5	35.1	19.6	22.1
Flue Gas Fans	MW	17.2	44.0	N/A	26.1
Air Quality Systems	MW	5.8	8.5	-	-
CO_2 Capture	MW	N/A	5.2	N/A	3.6
CO_2 Compression	MW	N/A	75.0	N/A	25.5
Total Auxiliary Electric Load	MW	58.5	167.8	19.6	77.3
Net Plant Output	MW	841.6	588.8	790.3	675.9
Energy Penalty	%	N/A	-30.0	N/A	-14.5
CO_2 for Transport	t/h	N/A	629	N/A	250
CO_2 to Atmosphere	t/h	702	73	276	28
PLANT UTILITY CONSUMPTION					
Makeup Water					
Cooling Tower	m^3/h	9,600	12,500	4,400	6,400
Cycle Makeup	m^3/h	25.9	26.1	7.7	8.1
Advanced Amine Solvent$^{(1)}$	kg/h	N/A	283	N/A	210
CO_2 Dehydration Adsorbent$^{(2)}$	kg/h	N/A	16	N/A	7
PLANT WASTE PRODUCTION					
Wastewater					
Cooling Tower Blowdown	m^3/h	1,900	2,300	880	1,300
CO_2 Capture Wastewater$^{(3)}$	m^3/h	N/A	(Note 3)	N/A	(Note 3)
Amine Waste	kg/h	N/A	146	N/A	108

Notes:

1 Amine degradation includes degradation from oxygen and sulfur, but excludes NO_x.
2 Bed replacement every 3 to 5 years.
3 Minimal wastewater discharge. Water condensed from flue gas and CO_2 streams are used for cooling tower makeup.

There are two strippers with eight reboilers for SCPC CO_2 capture Case 2, whereas for NGCC CO_2 capture Case 4, single stripper column with four reboiler at the bottom of the stripper was used. Water is separated from the CO_2 stream in a knockout drum and CO_2 is relatively free of water vapour with a pressure of 1.7bara. This CO_2 stream is send to a three stage compressor and the dehydration unit. The final CO_2 stream has a purity of greater than 99.5% at 110bara and 38°C. While compression from 1.72 to 110 bara can be reached by three stages, this pushes the desirable limits, four or more stages of compression could also be used.

The cooling requirements for the CO_2 capture cases for SCPC and NGCC (cases 2 & 4) are approximately 20 and 40 percent higher respectively when compared to their non CO_2 capture cases 1 & 3. This study assumes that the use of a closed circulating cooling water systems utilizing wet mechanical-draft cooling towers for heat rejection from the condensers and other plant cooling systems.

In this work the focus is on the evaluation of the technical and operational issues related to the scale-up of post combustion capture technology for SCPC and NGCC power plants. Main operational issues associated with flexibility identified in this work were not investigated in further detail as IEAGHG study 2012-06, Operating Flexibility of Power Plants with Carbon Capture and Storage evaluates this issue much in detail.

Results and discussion

CO_2 post combustion capture design cases for SCPC and NGCC were reviewed to identify the major issues that will likely be faced when moving from the current pilot scale demonstration plants to constructing and operating large commercial scale units. In general, there appear not to be any major risks which have not been addressed either in power generation or elsewhere in the heavy industrial sector. Integration of the each component of the CO_2 capture facility at large scale and incorporation into existing power plant designs may represent the largest challenge. The following section discusses the main issues related to the scale up for post combustion capture process which have emerged in this study.

New Insights

Size and construction of absorber and stripper unit

In this study for the reference cases (2 & 4), single rectangular concrete absorber structures with multiple parallel sections were selected. Such a design should be technically feasible for design and construction. The construction of such a large concrete structure will not be simple, but the same techniques used to build large stacks can be used. More precision would be required to get internal dimensions and feeds connections for the absorber, but still its construction would not pose inordinate challenges to a competent construction company. The absorber required for large-scale CO_2 capture is the single largest technical challenge for designing and constructing a full scale CO_2 capture facility.

The size of strippers for SCPC and NGCC cases (2 & 4) studied are quite large for typical amine stripping technology require 2x7.2m and 1x7.0m columns respectively and approximately 23 meters length for both cases. However this size vessel is not outside what is considered to be normal and practical for construction. Similar to the absorber, liquid and vapour distribution in the stripper is important, but certainly within the range of existing, proven technology. The main challenge associated with the strippers is the transportation to the capture site due its large size. This issue is very site specific and may not pose a challenge where there is water access. In other locations local stick build fabrication may be necessary.

Plant stiffening requirements

Addition of CO_2 capture equipment to large-scale power plants results in a larger pressure drop associated with the CO_2 capture equipment compared to that across conventional air quality control (AQC) equipment. Also the natural stack draft will be reduced. This can be overcome by the use of fans with significantly higher head. To protect against the increased under and over pressures which can occur additional stiffening for boiler, ductwork and flue gas equipment will be required.

Applying stiffening of this type is an expensive and time intensive process when considered for a retrofit case. It may be possible to reduce the extent of stiffening needed by use of optimized control systems to limit pressure excursions during upset conditions. However, stiffening of the steam generator, flue gas equipment, and flue gas ducts should not pose a significant technical challenge to the design and construction of the new power plant but will result in some changes to standard design.

Flue gas bypass

During start-up, shutdown, and other upset conditions there is likely to be increased acid gas concentrations in the flue gas, primarily NO_2 and SO_2. This could result in the formation of excessive amounts of nitrous amines and Heat Stable Salts (HSS) in amine based solvents. For this reason a bypass around the CO_2 capture process is considered desirable. This would also allow the power plant to continue operating when the CO_2 capture process is unavailable for planned or unplanned maintenance activities.

Construction and operation of a flue gas bypass arrangement is not considered to be a technical risk at the scales presented. However the addition of a bypass system around the absorber, diverter dampers and transition piece is complicated. Especially when it is desired to access and service absorber column in the power plant operation. Special consideration should be given to the transition of the operation in and out of bypass mode to establish normal operating pressure loss in the absorber column. Moreover, coordination of the flue gas and boiler draft pressure during transition should be properly coordinated by flue gas fans and bypass damper controls.

Gas Turbine back pressure

In this study for NGCC with CO_2 capture (reference case 4) currently available gas turbine and HRSG product offerings are incorporated. Flue gas exhausted from each gas turbine and HRSG is at 3.7kPa(g) and atmospheric pressure respectively and at 97°C. Flue gas booster fans and structured packing flue gas coolers are required to boost the pressure to approximately 13.8kPa(g) and reduce the temperature to approximately 32.2°C appropriate for the CO_2 capture process.

In the situation when flue gas is exhausted from gas turbine at approximately 18 kPa(g) and cooled further in the HRSG this could eliminate the need for separate flue gas booster fans and will result in a smaller footprint, a less complex flue gas path and possibly a slight improvement in the overall power plant efficiency. These changes would require research and development to produce gas turbines designed for a higher backpressure. Even though a relatively minor change is costly and could add considerably to unit costs, especially if the market for such machines were small.

Flue gas fan size

In order to overcome the pressure drop associated with AQC system and absorber, four axial induced draft (ID) fans with two fans placed in a series and each series operated in a parallel (2-by-2 arrangement) were used for the SCPC Case 2. For the NGCC Case 4, only two axial fans were selected. Incorporating fans to handle higher flows and pressure differentials will result in fewer units and thus results in a less expensive and more compact solution. It was found that the additional flue gas draft fans are not a technical challenge to the scale-up of CO_2 capture process. Nor is the development of larger head units, although the same considerations of market size apply as that for the modified gas turbines. If the number of units which can be sold is small the development cost would not be justified.

Emission Issues

Emission concentrations associated with the power plants with CO_2 capture are not particularly related to the scale of the plant, but there are some significant issues related to environmental regulations for these types of plants. The potential emissions from these plants are unique to the amine-based post-combustion capture plants and include Amines, Nitrosamines, Nitramines and potentially hazardous sludge/liquids produced from amine based solvent reclaiming process. Regulations are still in process of formulation in many countries and the environmental effect of the airborne contaminants is not defined, so further research is required on the long-term health effects of Amines, Nitrosamines, and Nitramines. Moreover emission limitations for such process need to be established. In IEAGHG study 2012/07 on ‘Gaseous emission from amine based post combustion CO_2 capture process and methods for deep removal’ shows that the application of an additional acid wash on top of the absorber is one effective way of eliminating emissions of the lighter components. The study considers that addition of further amine emission reduction equipment like demister, after the main absorber can easily be incorporated in the absorber design. However development of the technology required for any further reduction in emissions would require “bleeding edge” advances.

The quantity of wastes will be larger for large scale plants when compared to that of the small-scale plants as for Case 2 and 4, 146 and 108 kg/h respectively amine waste was generated. Therefore, sustainable amine waste disposal techniques should be further developed and it may no longer be possible to rely solely on solvent suppliers or waste disposal companies to handle the increased waste quantities. IEAGHG has commissioned study on ‘Reclaimer waste disposal from amine based CO_2 post Combustion capture plants’ in which different sustainable disposal techniques for amine waste will be investigated.

Plume visibility may be an issue because of the much lower release temperature. Addition of a superheater to the vent stream is an option. Available heat from the air quality control system can be used for such a superheater. However, such an arrangement will add further complexity and a small efficiency penalty due to the increase in pressure drop.

Steam system, turbine, condenser

Saturated steam required by the CO_2 stripper reboilers to achieve 90% CO_2 capture was 821t/h and 330t/h for SCPC and NGCC cases (Case 2&4) respectively and at 4.5 bara, which is a considerable amount. In SCPC Case 2 the required steam is extracted from the cross-over piping and de-superheated to saturation before being sent to the amine stripping process whereas in a fully optimized design non-condensing turbines would be used to recover some of the energy lost to let down the steam to the required process conditions. These could be coupled to the CO_2 compressors. In NGCC Case 4, a quarter of the steam is taken from HRSG and the rest is taken from the LP turbine. While the conditions are quite suitable still the low flow rate of the steam from the HRSG is found to be inadequate to meet the requirement of the CO_2 capture plant.

The major original equipment manufacturers (OEMs) of large steam turbines are able to modify their standard steam turbine design to accommodate a CO_2 capture process. The combined cycle heat recovery steam generator (HRSG) and steam turbine do not require any major modifications from the standard industry design for this application, although there are opportunities for optimization of the steam extraction points and condensate return. IEAGHG study 2011-02 on ‘Retrofitting CO_2 capture to existing power plants’ concluded that the choice of CO_2 capture retrofit related to steam extraction is wider and other factors such as the size and age of the existing power plant may be more important in determining the steam extraction potential.

Secondary Issues

Post combustion capture will have some secondary issues when considering scale up which are still noteworthy. The following are some of these:

- **Increase in cooling water**

  The cooling requirements for the CO_2 capture reference cases, compared to the non-capture reference cases, are approximately 20% higher for the SCPC case (Case 2) and approximately 40% higher for the NGCC case (Case 4). However cooling system design is very site specific and the economics related to cooling system is very much dependent on the price of the available water, as this was one of the main outcomes from IEAGHG study 2010/05 on ‘Water Usage and Loss Analysis of Bituminous Coal Fired Power Plants with CO_2 Capture’. Therefore, in the dry location where water is scarce alternative cooling systems like air cooling will become more economical.

- **Flue Gas Desulphurization**

  In this study WFGD and a polishing scrubber system were used to reduce SO_2 to the level necessary to minimize amine based solvent degradation for SCPC reference case (Case 2). However in future integration of primary and polishing flue gas desulfurization (FGD) stages into a single SO_2 absorber system would reduce the footprint of the flue gas cleaning.

Other points

- CO_2 Compression issues are mainly related to the availability of the plant and its start-up requirements. IEAGHG study 2010/07 on Rotating equipment for Carbon dioxide Capture and Storage concluded that integration of heat of compression into the power plant is essential to maximise the efficiency. Therefore, waste heat from the inter-stage heat exchangers can be used to achieve potential optimization.
- CO_2 drying requirement for suitable CO_2 compositions for its transportation by pipeline or ship is achievable by solid adsorbent technology.
- The size of the heat exchangers required for large scale power plant CO_2 capture will be quite large compared to the commercially available heat exchangers and multiple units will be needed.
- The CO_2 capture process controls could be integrated with the main power plant distributed control system or a separate system could be utilized with a communication interface.

Size Breakpoints

No significant size breakpoints were found for post combustion capture technology scale up. The main issues identified from this study are as follows:

- Above 1000-1200MW the construction of a single absorber may no longer be reasonable because of the increasing number of compartments.

- Above 1000MW a second stripper would be required for a NGCC plant with capture

- Above 1200MW a third stripper would be required for a SCPC plant with capture

- CO_2 compressors are limited to around 75,000kW; so this could become a limitation if single trains were used for SCPC plants of more than the reference case size. However for reliability reasons two 50% trains were selected and available compressor size is not likely to be a break point issue.

Future Evaluation

Analysis of the CO_2 post combustion capture technology on the basis of technical risk, operational risk, gaps, challenges and design sensitivities was performed. From this evaluation some important areas for future research and development were identified and are presented in Table 2 for post combustion CO_2 capture process large scale application.

Table 2, Future research and development required for large scale CO_2 post combustion capture for coal and natural gas based power plants.

FUTURE RESEARCH & DEVELOPMENT	
PROCESS UNIT	
NGCC power plant	• Evaluation of the design change in gas turbine with an increased exhaust pressure up to 18kPa (g). • Evaluation of the design changes in HRSG based on gas turbine increased pressure.
Steam extraction	• Evaluation of non-condensing turbine use for additional energy generation for CO_2 compression in SCPC power plant. • Evaluation of the dispatch model for LP turbine, generator, downstream electrical equipment and heat rejection system.
Flue gas bypass	• Evaluation of the cost, safety and permit issues for CO_2 stack discharge for extended period of time for large scale post combustion CO_2 capture system.
Cooling system	• Evaluation of large scale CO_2 post combustion capture process cooling water system for low water available site.
Water / Wastewater impacts	• Evaluation of site specific water usage and waste water impacts for large scale CO_2 post combustion capture process.
Fans	• Development of axial fans with an increased head/flow capacity. • Evaluation of the optimal draft fan arrangement for specific project based on the technical design requirements for CO_2 capture process requirement and WFGD with polishing scrubber systems.
Flue gas cleanup	• Evaluation and optimization of the integrated primary and polishing FGD stages into single SO_2 absorber system.
Absorber	• Investigate effect of rectangular shape absorber on its hydrodynamics.
Stripper	• Development of the site specific transportation strategy for stripper columns.
CO_2 compressor	• Evaluation of the heat recovery from CO_2 compressor by heating condensate or feedwater into the intercoolers and aftercoolers of the CO_2 compressor. • Feasibility investigation of the power plant Rankine cycle and main steam turbine generator design integrated with direct steam turbine drive of CO_2 compressors.
CO_2 Drying	• Investigation of glycol solubility in supercritical CO_2 and glycol loss in the CO_2 glycol drying process.

Process Control System	• Evaluation of the CO_2 capture plant control system integration to the main power plant DCS system. • Evaluation of the optimized control system for CO_2 capture plant during power plant upset conditions.
PROCESS ISSUES	
Environmental	• Evaluation of the required technology for amine emission reduction and amine waste disposal.
Capture plant Startup and Shutdown	• Operational requirement during startup and shutting down of highly integrated power plant with CO_2 capture.
Operational Flexibility	• Evaluation of the operation flexibility for large scale CO_2 post combustion capture plant application in power plants.

Strategy for Commercialization

Application of the CCS technology is influenced by factors like environmental policy, research support and economics. Policy incentives that could be provided for CCS technology developers can include bonus carbon allowances for power that use CO_2 capture, tax credits, obligations for power that utilizes CO_2 capture, or a feed-in tariff would give a clear incentive for the use of CCS technology. In the near future use of CO_2 for enhanced oil recovery (EOR) might be one of the most attractive business option and hence can act as a strong economic driver for several future CCS projects. Therefore, while the post combustion capture technology commercialization will be driven principally by policy and market there are still some important technological improvements required as shown in Figure 4.

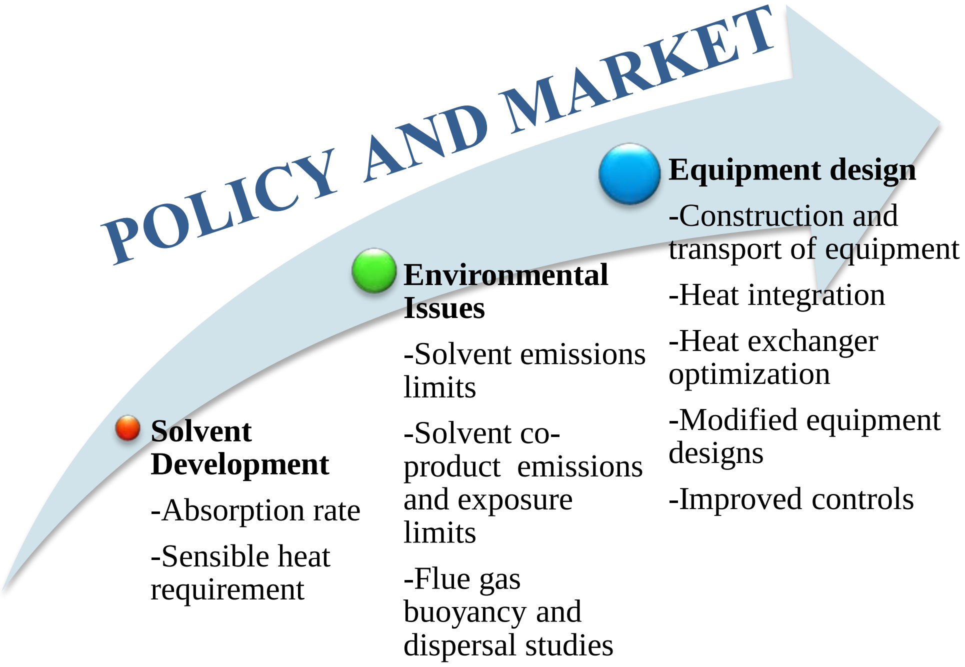


Figure 4, Strategy for scale-up of post combustion capture technology.

The most challenging part will be to reduce the cost of amine based solvent post combustion capture technology. Process integration and improved amine based solvents formulations may be able to reduce the energy requirement from the capture unit. Hence the main focus should be on improving the amine based solvents CO_2 absorption rate, absorption capacity and reduction in sensible heat requirement. The development of a large scale CO_2 capture unit evaluated in this work does not create a set of novel challenges from an equipment design viewpoint. Large-scale stripping of impurities in gas by liquid solvents in large vessels has been accomplished in the petrochemical industry for decades. Therefore, in CO_2 post combustion capture processes, issues related to appropriate liquid/gas distribution, maintaining required residence time and handling large quantities of solvent should not create major problems during operation. However, focusing on improving specific areas in equipment design should be beneficial as shown in Figure 4.

Large scale post combustion capture units present special concern for the environment and this area should be more thoroughly investigated prior to widespread commercialization. Many of these concerns involve the permissible exposure level for the solvents and impurities that are entrained in the treated flue gas emissions. Figures 4 shows the environmental issues to be focused on for safe application of post combustion capture process.

Expert reviewer’s comments

Most reviewers felt that the key message from the report is that there are no major issue related to the scale-up of post combustion capture technology and that the required skills exists to build the process. They were largely happy with this conclusion.

One reviewer commented that the true issue in “Scale Up” is dealing with the uncertainties associated with going from current experience base to understanding what may happen in a commercial application. In his view point, this study is a quantitative assessment of specific uncertainties which underpins a “go/no-go” decision on commercial development. If the uncertainties are considered as a barrier, then further R&D should be indicated in this study. This suggestion was incorporated in the report and also an overview list for future R&D areas is presented in Table 2.

Another reviewer commented that it would be helpful if for each element of the post combustion capture technology chain an assessment and classification was made of whether what is being proposed is commonplace, “leading” edge, or “bleeding” edge. This was incorporated in the report in section 5. Another reviewer recommended that more should be said about the technical challenges and limitations related to the absorber size. This section of the report was expanded.

Conclusions

A summary of the process unit and operational issues related to post combustion capture unit scale up for SCPC and NGCC power plant cases (Case 2 and 4) are presented in Table 3.

Table 3, Summary of challenges related to different process units and operational issues for scale up of post combustion capture technology. Standard +; Moderate ++; Complex +++.

BARRIER	TECHNICAL BREAKTHROUGH	COMPLEXITY OF DEVELOPMENT	COST
PROCESS UNIT			
Steam Generation	🟩 +	🟩 +	🟥 +
Steam Extraction	🟨 +	🟨 +	🟩 +
Flue gas bypass	🟩 +	🟩 +	🟩 +
Cooling	🟨 +	🟨 +	🟩 +
ID Fans	🟨 +	🟩 +	🟩 +
Absorber	🟨 +	🟩 +	🟨 +
Heat exchanger	🟨 +	🟩 ++	🟨 +
Stripper	🟨 +	🟩 ++	🟨 +
CO_2 Compression	🟨 +	🟨 +	🟨 +
CO_2 Drying	🟨 +	🟩 +	🟩 +
PROCESS ISSUES			
Amine Emission	🟨 +	🟩 +	🟩 +
Capture plant Startup & Shutdown	🟨 +	🟩 +	🟩 +
Retrofit	🟨 +	🟩 +	🟩 +
Advanced Control System	🟨 +	🟩 +	🟨 +

This evaluation is based on the main barriers:- technical breakthrough, complexity of development and cost. In this evaluation process units and operational issues were evaluated at three different level Standard +; Moderate ++; Complex +++. Also the cells are highlighted in traffic sign colors of Green, Yellow and Red representing the level of further research and development required in that particular area. The evaluation presented above in Table 3 shows that there are no major scale-up issues related to the CO_2 post combustion capture application in coal and gas based power plants. Although there are some areas of further research and development required in the technology development for units like steam extraction, cooling system, absorber, stripper, CO_2 compression and issues like environmental, retrofit and advanced control system. Whereas, construction of stripper and heat exchanger can be an issue which is site specific. Moreover stiffening will be required for process units like boiler, ductwork, and flue gas equipment to overcome pressure increase by large size ID fans.

Recommendations to Executive Committee

Several areas where engineering and equipment development is required have been identified in this study. This study has mainly concentrated on the designs of the major equipment required for the CO_2 capture system. A major challenge for designing a system, especially when considering the eventual disposal of the captured CO_2, would be the design of the instrumentation and controls for this system. Although scale up of CO_2 capture process is possible without significant development, cost and performance, still these areas could be improved further by additional R&D. The IEAGHG programme should encourage equipment developers and suppliers to address issues identified in this study. This could be best done by improved interaction of different parties working in the engineering community. IEAGHG is not in a position to undertake the necessary development but could provide some guidance to those who are.

- Amine emission issue is significant environmental concern and disposal of amine based waste generated by large scale should be investigated in more depth.
- Important operational issues like cycling, part-load, intermittent operation, start-up, shut-down issues need to be looked more in detail at large scale.
- CO_2 large scale venting or depressurizing HP pipeline issues related to safety and permits should be further evaluated.
- Gaps and technical challenges should be evaluated further to include other elements that may constrain the operation flexibility of the power plants with CCS. In particular, evaluation of the possibility of operation of these plants in the mid and peak merit market, following a specific weekly demand curve should be performed. Attention should also be focused on identifying the capacity limits and ramping capabilities of equipment like the stripper and reboiler. To make frequent and fast start-ups/shut-downs will be difficult due to the time required to pre-heat the regeneration column. Therefore, ways to overcome these limitations should be investigated further.

FINAL REPORT

POST-COMBUSTION CO_2 CAPTURE SCALE-UP STUDY

BLACK & VEATCH PROJECT NO. 175185
BLACK & VEATCH FILE NO. 41.0809

PREPARED FOR

IEA Environmental Projects Ltd.

OCTOBER 2012

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Rev.	Date	Issue Status	Revisions and Record of Issue
0	04/17/2012	Review	Initial Issue for Client Review
1	08/03/2012	Final Draft	Incorporated Client Comments
2	10/02/2012	Final Report	Incorporated Client Comments

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List of Acronyms

°C	Degrees Celsius
°F	Fahrenheit
AQC	Air Quality Control
AQCS	Air Quality Control System
bar(a)	100 Kilopascals-Absolute
C_2H_6	Ethane
C_3H_8	Propane
CCS	Carbon Dioxide Capture and Storage
CDM	Clean Development Mechanism
CDS	Circulating Dry Scrubbers
CES	Clean Energy Standard
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COP	Conference of the Parties
CRH	Cold Reheat
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CTG	Combustion Turbine Generators
DLN	Dry Low NO_x
DCS	Distributed Control System
EOR	Enhanced Oil Recovery
ESP	Electrostatic Precipitator
EU	European Union
FGD	Flue Gas Desulfurization
GCV	Gross Calorific Value
GHG	Greenhouse Gas
GJ/h	Gigajoule per Hour
H_2S	Hydrogen Sulfide
Hg	Mercury
HP	High Pressure
HRH	Hot Reheat
HRSG	Heat Recovery Steam Generator
HSS	Heat Stable Salts
Hz	Hertz
ID	Induced Draft
IEA EPL	IEA Environmental Projects Ltd.
IEAGHG	IEA Greenhouse Gas
in. wg	Inches of Water Gauge

IP	Intermediate Pressure
kcal/kg	Kilocalories per Kilogram
kg	Kilogram
kg/h	Kilogram per Hour
kg/s	Kilograms per Second
kJ	Kilojoule
kmol/h	Kilomoles per Hour
kPa	Kilopascals-Absolute
kPa(g)	Kilopascal Gauge
kW	Kilowatt
kWh	Kilowatt-Hour
LNB	Low NO_x Burners
LP	Low Pressure
LSFO	Limestone Forced Oxidation
m	Meter
m^2	Square Meters
m^3/h	Cubic Meters per Hour
MEA	Monoethanolamine
MHI	Mitsubishi Heavy Industries
MMscf	Million Standard Cubic Feet
MOF	Metal Organic Frameworks
MS	Main Steam
MW	Megawatt
MWh	Megawatt-Hour
MWh-net	Net Megawatt-Hour
N_2	Nitrogen
NaOH	Sodium Hydroxide
NCSTG	Non-Condensing Steam Turbine Generator
NCV	Net Calorific Value
NGCC	Natural Gas Fired Combined Cycle
Nm^3/min	Normal Cubic Meter per Minute
NO_x	Nitrogen Oxide
NO_2	Nitrogen Dioxide
OEM	Original Equipment Manufacturer
OFA	Overfire Air
PAC	Powdered Activated Carbon
PFD	Process Flow Diagram
PJFF	Pulse Jet Fabric Filter
ppm	Parts per Million
ppmw	Parts per Million by Weight

psia	Pounds per Square Inch-Absolute
psig	Pounds per Square Inch Gauge
R&D	Research and Development
RPS	Renewable Portfolio Standards
SCPC	Supercritical Pulverized Coal
SCR	Selective Catalytic Reduction
SNCR	Selective Noncatalytic Reduction
SO_x	Sulfur Oxide
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
STG	Steam Turbine Generator
t/h	Metric Tonnes per Hour
USDOE	US Department of Energy
USEPA	US Environmental Protection Agency
vol%	Volumetric Percentage
WFGD	Wet Flue Gas Desulfurization
wt%	Weight Percentage

1.0 Executive Summary

1.1 INTRODUCTION

Black & Veatch was retained by IEA Environmental Projects Ltd. (IEA EPL) to prepare a study addressing the challenges associated with scale-up of post-combustion carbon dioxide (CO_2) capture. The objective of the study is to define and discuss the technical challenges associated with conventional post-combustion capture technologies as they relate to full-scale design and operation. Both supercritical pulverized coal (SCPC) and natural gas fired combined cycle (NGCC) power plant technologies are addressed.

To accomplish the project objective, Black & Veatch first developed full-scale conceptual designs to serve as a basis for discussion of the issues associated with scale. The conceptual designs include both a 900 megawatt (MW) SCPC power plant and an 800 MW NGCC power plant. Conceptual designs for both plants were completed with and without CO_2 capture. Black & Veatch reviewed the CO_2 capture technologies currently available and selected amine-based absorption as the most developed technology for each plant. Optimization of the conceptual designs was not a prime consideration for this study.

On the basis of the full-scale reference designs, the technical and operational risks, performance gaps, technical challenges, and sensitivity to several variables are discussed. Finally, a suggested scale-up strategy and roadmap are included with suggested areas for future focus.

1.2 REFERENCE PLANT DESIGN BASIS

Two reference cases were developed for each power plant type. The first reference case is representative of a power plant built without CO_2 capture. The second reference case is representative of a power plant constructed with integral post-combustion CO_2 capture and compression facilities. A summary of the four cases is presented in Table 1-1. A CO_2 capture efficiency of 90 percent was selected for the CO_2 capture reference cases.

Table 1-1 Power Plant Design Case

	DESIGN CASE 1 SCPC WITHOUT CAPTURE	DESIGN CASE 2 SCPC WITH CO_2 CAPTURE	DESIGN CASE 3 NGCC WITHOUT CAPTURE	DESIGN CASE 4 NGCC WITH CO_2 CAPTURE
CO_2 Capture, % of Gross	N/A	90	N/A	90
Technology Description	Supercritical pulverized coal Rankine cycle with 1 two-pass tangential or wall-fired boiler and 1 reheat condensing steam turbine.		Natural gas combined cycle with 2x G-Class gas turbines, 2 x three-pressure heat recovery steam generators, and 1 x reheat steam turbine.	
Nominal Gross Output, MW	900	TBD(1)	810	TBD(1)
Unit Output Frequency, Hz	60	60	60	60
Fuel	Australian Low-Sulfur	Same as Case 1	Natural Gas	Same as Case 3
Fuel Quantity	Note 1	Same as Case 1	Note 1	Same as Case 3
Throttle Conditions (MS temperature, HRH temperature, MS pressure) ° C / ° C / bar(a) (° F / ° F / psia)	582 / 582 / 254.4 (1,080 / 1,080 / 3,690)		565.6 / 565.6 / 124.1 (1,050 / 1,050 / 1,800)	
Supplemental Firing	N/A	N/A	No	No
Heat Rejection	Wet mechanical draft cooling tower			
Air Quality Control Systems	Selective Catalytic Reduction, PAC Injection, Fabric Filter, Wet Flue Gas Desulfurization		Dry Low NO_x Combustion, Selective Catalytic Reduction, Oxidation Catalyst	
CO_2 Export Pressure, bar(a) (psia)	N/A	110 (1,600)	N/A	110 (1,600)

Notes:

(1) Fuel quantity to be determined as part of the study. As a basis of design, the CO_2 capture case will use the same amount of fuel as the non-capture case. Calculated values are presented in Section 4.0.

°C - Degrees Celsius
°F – Degrees Fahrenheit
bar(a) – 100 Kilopascals-absolute
HRH – Hot reheat
Hz –Hertz
MS – Main steam
MW – Megawatt
PAC – Powdered activated carbon
psia – Pounds per square inch-absolute

1.3 PERFORMANCE SUMMARIES

A summary of power plant performance for Cases 1 through 4 is presented in Table 1-2. Integration of 90 percent CO_2 capture and compression processes is expected to reduce the net electrical export capability of an SCPC power plant by about 30 percent. Integration of 90 percent CO_2 capture and compression processes is expected to reduce the net electrical export capability of a NGCC power plant by about 14.5 percent.

Table 1-2 Electricity Generation Performance Summary

		CASE 1	CASE 2	CASE 3	CASE 4
Reference Case Description		Supercritical Pulverized Coal Rankine Cycle		2-on-1 G-Class Gas Turbine Combined Cycle	
Fuel Type		Coal	Coal	Natural Gas	Natural Gas
CO_2 Capture		None	90%	None	90%
ELECTRICAL OUTPUT					
Total Gross Output	MW	900.1	756.6	809.9	753.2
Total Auxiliary Electric Load	MW	58.5	167.8	19.6	77.3
Net Plant Output	MW	841.6	588.8	790.3	675.9
Energy Penalty (Net output)	%	N/A	-30.0	N/A	-14.5
Energy Penalty (Net output reduction per tonne-CO_2 to pipeline)	MW/(t-CO_2 captured)	N/A	0.40	N/A	0.46
ELECTRICAL PRODUCTION EFFICIENCY					
Net Plant Heat Rate (NCV)	kJ/kWh	8,912	12,738	6,208	7,259
Net Plant Heat Rate (GCV)	kJ/kWh	9,285	13,272	6,874	8,038
Net Plant Thermal Efficiency (NCV)	%	40.4	28.3	58.0	49.6
Net Plant Thermal Efficiency (GCV)	%	38.8	27.1	52.4	44.8
CO_2 EMISSIONS					
CO_2 for Transport	t/h	N/A	629	N/A	250
CO_2 to Atmosphere	t/h	702	73	276	28
CO_2 to Atmosphere	kg/MWh-net	834	124	349	41
GCV - Gross calorific value kg - Kilogram kJ - Kilojoule kWh - Kilowatt-hour MWh - Megawatt-hour NCV - Net calorific value					

1.4 TECHNICAL AND OPERATIONAL RISK ANALYSIS

After completion of the CO_2 capture reference cases, each design was reviewed to identify the major issues that would likely be faced when the current demonstration scale was moved to operating commercial-scale units. The key technical and operational issues are highlighted below; the next section focuses on design challenges.

1.4.1 Steam Extraction

The CO_2 stripper reboilers require a considerable amount of saturated steam, which can be sourced from the power plant of either design. To achieve 90 percent CO_2 capture, saturated steam at 4.5 bar(a) is required. Based on Black & Veatch experience in this area, the major original equipment manufacturers (OEMs) of large steam turbines for SCPC plants are able to modify their standard steam turbine designs to fit into a CO_2 capture process. The combined cycle heat recovery steam generator (HRSG) and steam turbine do not require any major modifications from the standard industry design for this application. Black & Veatch does not expect difficulties in procurement of major equipment for the power plant. Opportunities will be available for optimization of steam extraction points and condensate return.

1.4.2 Flue Gas CO_2 Capture Process Bypass

During startup, shutdown, and other upset conditions, increased acid gas concentrations in the flue gas, primarily nitrogen dioxide (NO_2) and sulfur dioxide (SO_2), could result in the formation of excessive amounts of nitrous amines and heat stable salts (HSS). Bypassing the absorption column under these conditions would minimize these issues. Having a bypass around the CO_2 capture process could also allow the power plant to continue operating when the capture process is unavailable for planned or unplanned maintenance activities. Black & Veatch does not consider the construction and operation of a flue gas bypass arrangement to be a significant technical risk at the scales presented. However, the cost to construct and maintain a flue gas bypass system would be significant. The addition of a bypass system would also increase flue gas pressure losses, adversely affecting plant performance. Special consideration of how to transition into and out of bypass mode would also be warranted, as the normal operating pressure losses across the absorption column would be high. Maintaining flue gas and boiler draft pressure during transition would require coordination of flue gas fans and bypass damper operation.

1.4.3 Compression

For the CO_2 capture and compression reference cases, Black & Veatch has used three stages of electric motor-driven compression to go from 1.72 to approximately 110 bar(a) (25 - 1,600 psia). Other configurations, including the use of a pump in the final stages to optimize compression power, or integral gear compressors, are possible, but should not affect scale up. The issues examined on CO_2 compression are rather minor and are mainly related to availability of the plant and startup requirements. Even though the CO_2 compressors are large compressors, units of this size are not uncommon, and Black & Veatch does not believe that the CO_2 compression train carries significant technical risk. Use of waste heat from the inter-stage heat exchangers represents a potential area of optimization.

1.4.4 Cooling

The cooling requirements for the CO_2 capture reference cases, compared to the non-capture reference cases, are approximately 20 percent higher for the SCPC cases and approximately 40 percent higher for the NGCC cases. These cooling requirements are well within the capabilities of modern cooling equipment (cooling towers, pumps, piping, etc.) and do not represent an impediment to the scalability of CO_2 capture and storage (CCS) for either case. In general, Black & Veatch does not expect the design of an appropriate cooling system to be a problem with regard to the scale of CCS. However, barriers to gaining access to cooling water could depend on site specific conditions.

1.4.5 Environmental

The risks related to the environmental aspect of power plants with CO_2 capture are not necessarily related to scale, but there are some significant risks related to the process and the regulations for these types of plants. One of the foremost risks is the regulations on CO_2 emissions are still being developed in many countries, and the potential environmental impacts of capture technologies are largely undefined. In addition, the regulation of CO_2 after it is captured and compressed (outside the scope of this study) is not fully defined in most countries. Black & Veatch considers the environmental risk to be a bleeding edge risk.

For large-scale plants, the quantity of contaminants emitted is larger than for small-scale plants, and better dispersion is usually required. This issue is addressed in an IEA Greenhouse Gas (IEAGHG) study performed by Commonwealth Scientific and Industrial Research Organisation (CSIRO) in Australia. Currently, regulations are in the formative stage because health consequences are not well understood for some of the potential emissions. Black & Veatch included a fresh water wash above an amine water wash section of the absorber. This wash consists of a once-through section that is fed by water derived from flue gas condensation not contaminated with trace amounts of amine. Preliminary modeling shows that the concentration of amine in the overhead flue gas vented to the atmosphere is quite low. This two stage approach is useful in maintaining a system water balance and should result in extremely low levels of amine in the vent. Further work is needed to understand the potential health impacts, if any, of amine emissions from post-combustion capture. It is believed that measures to minimize health impacts can be accommodated in the absorber design without significant impact due to scale. While the requirements and regulations for emissions of amine compounds are considered bleeding edge, the technology required for amine emissions reduction specifically related to amines and amine compounds is considered leading edge.

Estimates of the amount of solvent degradation products are provided in Table 4-4 and Table 4-7. It should be noted that these estimates are only approximate, as solvent degradation will be very solvent specific. Some process vendors may arrange for disposal as part of their services, and the disposal method will vary greatly from one jurisdiction to another and one solvent to another.

1.4.6 Capture Plant Startup and Shutdown Issues

Because the CO_2 will need to be vented until significant flow is established through the capture plant, some method of dispersing the CO_2 will be needed to avoid accumulation and potentially hazardous conditions on the ground beneath the vent. The best method for dispersing this stream is to return it to the absorber stack where it can be safely entrained with the flue gas. An alternative method could be a dedicated CO_2 purge stack, high enough to sufficiently disperse the CO_2 stream into the atmosphere during startup.

1.4.7 Retrofit Issues

With the high capital cost of capture, it is expected that most full scale capture facilities will be incorporated into new plants to amortize the capital costs over maximum plant life. Older, less efficient plants are more likely to simply shut down rather than retrofit expensive CO_2 capture equipment. However, it is still likely that some existing facilities, particularly newer facilities, will choose to retrofit CO_2 capture to meet greenhouse gas (GHG) emissions targets. Issues associated with the retrofit of CO_2 capture, particularly on a large scale, include plot space, steam generator/flue gas path design, ductwork, air quality control (AQC) system modifications, steam cycle modifications, water/wastewater impacts, electrical interconnection, and constructability. Although there are challenges associated with the retrofit of an older plant, the engineering design requirements are known and can be addressed in the normal course of project execution.

1.5 GAPS AND TECHNICAL CHALLENGES

A commercial CO_2 capture unit will require unique equipment and controls that have not been widely operated at the scale discussed herein. No real technical gaps were identified. However, Black & Veatch did identify a number of areas in which further development efforts could result in improvements. This section highlights the major technology design challenges identified in each of the capture cases.

1.5.1 Absorber

The absorber required for large-scale CO_2 capture is the single largest technical challenge for designing and constructing a full-scale CO_2 capture facility. For the reference cases, Black & Veatch selected a single rectangular concrete absorber structure with multiple parallel sections, which should be technically feasible to design and construct. The construction of such a large concrete structure will not be simple, but the same techniques used to build large stacks can be used to construct the absorber concrete structure. More precision would be required to get internal dimensions and feeds correct for the absorber, but Black & Veatch believes that the absorber construction would not pose inordinate challenges to a competent construction company.

An additional challenge related to large absorbers (and strippers) is that as new, advanced amines are developed, physical property information will have to be collected to allow the appropriate design and construction of these large units. While these challenges are manageable, it will perhaps require additional engineering time to manage the risks associated with design of these large mass transfer devices.

1.5.2 Stripper

The stripper technology required for the power plant with CO_2 capture is considered commonplace. The strippers are quite large for typical amine stripping technology. However, they are not outside of what is considered normal, and Black & Veatch believes that there will not be significant technological challenges with this part of the CO_2 capture plant. Similar to the absorber, liquid and vapor distribution in the stripper is important, but certainly within the range of existing, proven technology. The main challenge associated with the stripper is transportation due to size.

1.5.3 Steam Generator

Given the larger pressure drops associated with the CO_2 capture equipment compared to conventional AQC equipment, additional steam generator, flue gas equipment, and duct stiffening may be necessary beyond what is typically utilized for SCPC and NGCC units. However, stiffening of the steam generator, flue gas equipment, and flue gas ducts should not pose a significant technical challenge to the design and construction of a power plant.

1.5.4 Fans

The fan technology required for power plants with CO_2 capture is fairly commonplace, but could be considered leading edge in some aspects. For the reference case SCPC with CO_2 capture, four axial induced draft (ID) fans, with two fans in series and each series operating in parallel (2-by-2 arrangement), were selected to overcome the larger pressure drops associated with the AQC systems and absorber. It is possible that development of fans capable of handling higher power and pressure differentials will result in a less expensive and more compact solution. Two axial fans (one per HRSG) were selected for the NGCC with CO_2 capture reference case. Flue gas draft fans should not be considered a technical impediment to scaling up CO_2 capture processes.

1.5.5 Flue Gas Cleanup

The flue gas cleanup technology required for a power plant with CO_2 capture is considered commonplace. The SCPC reference case incorporates separate wet flue gas desulfurization (WFGD) and polishing scrubber systems to reduce SO_2 to levels necessary to minimize amine solvent degradation. Less costly solutions, requiring a smaller overall footprint, could be available now or in the near term. One possible solution would be to integrate the primary and polishing flue gas desulfurization (FGD) stages into a single SO_2 absorber system in future optimization. Black & Veatch does not consider this a technical impediment to scaling up the CO_2 capture process.

1.5.6 Heat Exchangers

While the scale of large power plants with CO_2 capture requires the use of multiple trains of heat exchangers in some services, the technology is generally considered to be commonplace. Because heat transfer is a function of surface area, the scale of the heat exchangers needed for the large-scale power plant CO_2 capture is quite large compared to what is currently commercially available. However, it is common practice and relatively straightforward to use multiple heat exchangers in parallel to obtain the required heat transfer area. Most of the heat exchangers selected for the CO_2 capture plants are plate and frame type of exchangers.

1.5.7 Heat of Compression

Heat of compression could potentially be used to heat condensate in the power cycles. In an SCPC plant of about 900 MW, this could potentially eliminate enough low-pressure (LP) extraction steam for condensate heating to increase power production by up to 5 MW. Given the small incremental energy savings and increased capital cost and complexity of such a system, this option is likely to be considered only for large-scale capture facilities.

In an NGCC plant, the temperatures for heat recovery from the CO_2 compressor coolers would approximately correspond to the low temperature economizer. Because eliminating this section of the HRSG would simply result in heat not recovered from the flue gas that would need to be removed in the quench cooler, Black & Veatch does not believe that recovery of the heat of CO_2 compression in an NGCC plant is a beneficial option.

1.5.8 CO_2 Drying

The technology required for CO_2 drying is commonplace. CO_2 drying can be accomplished by a solid adsorbent or by liquid glycerol or triethylene glycol. On the basis of previous comparisons, Black & Veatch generally favors the use of a solid bed adsorbent system to eliminate the issues associated with handling and disposal of glycol solutions. This technology is widely available, understood, and scalable.

1.5.9 Advanced Controls

The controls required for integrated operation of a power plant with CO_2 capture are generally available, but should be well proven at a small scale before use in a large-scale plant. This is not a scale-up issue, and Black & Veatch believes that the technology should be considered commonplace. The controls required for a power plant with CO_2 capture are not expected to be significantly different from the controls required for other process plants of this scale. Black & Veatch expects that a full distributed control system (DCS) would be required, but that scale will not have an impact on the required controls; any plant of this size, with or without CO_2 capture, would have advanced controls. The CO_2 capture plant controls could be integrated with the main power plant DCS system, or separate systems could be utilized with a communication interface. An operational learning curve would exist when plants of this size are first placed in operation.

1.5.10 Operating Flexibility

It is expected that in the early stages of carbon capture deployment, new power plants that have been designed and equipped with CO_2 capture will generally operate as baseload units. Nevertheless, there may be situations where power plants with carbon capture may need to start and stop or ramp up or down to meet system demand. In addition, if carbon capture ever develops to the point that most plants include it, some of the plants will be required to operate in a load-following mode. No issues related to scale and load following were identified, but further research in this area could be beneficial to determine whether operating flexibility is a concern going forward.

1.5.11 Additional NGCC Considerations

The current NGCC reference plant with CO_2 capture incorporates currently available gas turbine and HRSG product offerings. However typical gas turbine and HRSG designs would require the use of flue gas booster fans to boost the flue gas pressure at the outlet of the HRSG to a pressure suitable for the CO_2 capture process. Exhausting the flue gas from the gas turbine at a higher pressure would eliminate the need for separate flue gas booster fans, resulting in a smaller footprint and cost savings. However, further extensive development of gas turbine package designs would be required. This is considered to be a subject of optimization and is not related to scaling.

1.6 DESIGN SENSITIVITIES

1.6.1 Break Points

Break points for absorber and stripper designs are highly vendor specific. The absorber proposed for both the SCPC and NGCC cases is near the limit of what is considered reasonable, but could be increased to accommodate plants of approximately 1,000 MW to 1,200 MW.

The SCPC case requires two strippers, and the NGCC case requires one stripper. Based on expected vapor and liquid loadings and a typical maximum column diameter of approximately 7 meters (m) to 8 m, Black & Veatch estimates that an additional stripper would be required for an SCPC plant larger than about 1,200 MW operating on the design coal and for an NGCC plant larger than about 1,000 MW. The sizes used in this report were calculated from industry standard methods.

CO_2 compressors are currently limited in size to 75,000 kilowatt (kW). If a single compressor train were used for the SCPC reference case with CO_2 capture, the train would be near the limit of what is currently available. However, two CO_2 compressor trains were selected for the SCPC reference case for reliability and turndown reasons. The NGCC reference case with CO_2 capture also utilizes two CO_2 compressor trains for these reasons. Electrical drives, such as variable frequency drives, are available at the motor sizes considered. Because of this, Black & Veatch has not identified a definitive break point for CO_2 compression design sensitivities.

1.6.2 Fuel Type

The CO_2 capture plant design sensitivity to the fuel choice largely depends on the weight percent of carbon in the fuel and the amount of moisture in the fuel. Impacts to the SCPC plant due to fuel type should be manageable at scale. Particulates are expected to be reduced to similar levels in appropriately designed particulate reduction equipment (e.g., electrostatic precipitator and/or fabric filter) and not affect CO_2 capture plant design. The amount of sulfur in the fuel will dictate the amount of scrubbing required upstream of the CO_2 capture plant but will not necessarily change the design of the CO_2 capture plant itself.

In the NGCC case, these parameters change very little, and there will be no changes in the design because of slightly different fuels although high sulfur fuels could impact post-combustion emission control equipment selection.

1.6.3 Capture Percentage

Most studies propose 85 to 90 percent capture as an upper reasonable level of capture efficiency. The physically limiting factor on the maximum amount of CO_2 that can be captured is the concentration of CO_2 in the flue gas exiting the absorber. Less than 90 percent CO_2 capture is best achieved by designing the plant for high CO_2 capture (80 to 90 percent) and bypassing a fraction of the flue gas to achieve the desired capture amount. This would generally shrink the diameter of the absorber proportionally to the reduced flue gas flow through the CO_2 capture plant for both SCPC and NGCC plants. It is often suggested that lower capture percentages can be obtained by lowering the amine circulation rate. This, however, would result in higher rich amine loading and increased potential for corrosion and foaming and generally unstable operation. Black & Veatch does not recommend this approach for a long-term operation.

1.6.4 Low Load/Cycling

For low load and power plant turndown, the capture plant would have to be designed to consider any reduction in steam pressure associated with operation of the power plant. A preliminary analysis of this case indicates that the equipment design for this operation would be within the normal scope of a plant design and may not require significant modifications to the CO_2 capture plant amine system.

1.7 STRATEGY FOR COMMERCIALIZATION

Drivers for the use of CCS technology come from three areas, all of which are related: environmental policy, research support, and economics. Currently, most work in CCS is based on funding provided for research, since government policy and economic drivers are insufficient to stimulate large-scale or wide deployment. While some small-scale CCS projects are economical (namely, for the food and beverage industry), these are largely niche opportunities that will not be sufficient to promote greater use of the technology. In the future, the use of CO_2 for enhanced oil recovery (EOR) may act as a strong economic driver for future CCS projects if oil prices remain high and natural CO_2 sources are limited.

While some improvements in the technology are possible, it will be a challenge to greatly reduce the cost of CCS through the use of amines. The main reason for this is that the reaction heat needed to break the bond between amine and CO_2 is relatively fixed, with little room for improvement. Improved amine formulations may be able to reduce this, but the improvements will likely be incremental only.

From an equipment design standpoint, the development of a large CO_2 capture units such as those outlined in this study does not create a set of novel challenges. Large-scale stripping of impurities using liquid solvents in large vessels has been accomplished in the petrochemical industry. Items such as appropriate liquid/gas distribution, maintaining required residence times, and handling large quantities of solvent should not create major problems during operation. However, specific areas of focus could be beneficial, including the following:

- Construction and transport of equipment.
- Heat integration.
- Heat exchanger optimization.
- Modified equipment designs.
- Improved controls.
- Additional research on CO_2 removal from natural gas-derived flue gas.

Finally, there are a number of environmental concerns that may be present in large-scale CCS units that should be investigated more thoroughly prior to widespread commercialization. Many of these concerns involve the permissible exposure level for the solvents and impurities that are entrained in the flue gas emissions. Investigating these items now to the extent possible will smooth the transition and acceptance of CCS technology. Major environmental research and development (R&D) areas include the following:

- Establishment of solvent emissions limits.
- Establishment of co-product emissions and exposure limits.
- Flue gas buoyancy and dispersion studies.
- Handling of waste products, such as materials from solvent degradation.

2.0 Introduction

2.1 BACKGROUND

The IEAGHG R&D Programme is an international organization established in 1991 to evaluate technologies that could be used to avoid emissions of GHGs, particularly from the use of fossil fuels. IEAGHG has undertaken numerous studies on CCS, which is one of the main potential methods of reducing emissions of CO_2 from the use of fossil fuels.

Several governments and international organizations have set 2020 as the target for broad commercial deployment of CCS. With this target in mind, it is clear that the initial commercial and full scale capture plants will have to be based on currently available technologies. These commitments and agreed targets create an important role for the solvent-based post-combustion capture technologies, which are considered to be the most mature of the capture technologies available today. These technologies provide a retrofit possibility and are already available on relatively small industrial scale, which makes them the most viable options for near term large-scale deployment.

However, the conventional solvent-based technologies face a number of challenges that must be addressed before commercial full-scale deployment is viable. These challenges include high capital costs, high parasitic energy requirements, uncertain environmental impacts, and the challenges of scale.

2.2 OBJECTIVE

This report defines and discusses the technical challenges associated with conventional post-combustion capture technologies as they relate to full-scale design and operation. Both SCPC and NGCC power plant technologies are addressed.

2.3 APPROACH AND METHODOLOGY

To accomplish the project objectives, Black & Veatch first developed full-scale conceptual designs to serve as a reference for discussion of the issues associated with scale. The conceptual designs include both a 900 MW SCPC power plant and an 800 MW NGCC power plant. Conceptual designs for both plants were completed with and without CO_2 capture. Black & Veatch reviewed the CO_2 capture technologies currently available and selected the most developed technology for each plant.

On the basis of the full scale reference designs, Black & Veatch investigated the technical and operational risks, performance gaps, technical challenges, and sensitivity to several variables. Finally, a suggested scale-up strategy and roadmap with suggested areas of focus was developed.

3.0 Reference Plant Design Basis

To provide a frame of reference for discussion of the scale-up issues associated with the post-combustion CO_2 capture, full scale conceptual designs were developed. This section provides the design basis for the conceptual designs. Reference plant designs were selected on the basis of recent trends in the power generation industry. Power plant designs chosen for this study are typical of modern day large-scale commercial power plants.

3.1 POWER PLANT DESIGNS

Power plant designs for a large SCPC and a large NGCC were selected to represent modern day power plants typical of those currently being constructed around the world. Two reference cases were developed for each design. The first reference case is representative of a power plant built without CO_2 capture. The second reference case is representative of a power plant constructed with integral post-combustion CO_2 capture and compression facilities. A summary of the four cases is presented in Table 3-1. The basis for the post-combustion CO_2 capture technology is discussed in Section 3.2.

A CO_2 capture efficiency of 90 percent was selected for the CO_2 capture reference cases. This percentage was selected because industry experience suggests that attempting to achieve capture rates much higher than this would result in diminishing returns. Therefore, 90 percent is generally considered an optimum level of CO_2 capture.

The power plant reference cases were evaluated at a barometric pressure of 101.325 kilopascals-absolute (kPa), temperature of 15 degrees Celsius (°C), and relative humidity of 60 percent. The two SCPC cases were developed assuming the use of low sulfur Australian coal. Representative coal properties are presented in Table 3-2. The two NGCC cases were developed assuming natural gas with the properties presented in Table 3-3.

Table 3-1 Power Plant Design Cases

	DESIGN CASE 1 SCPC WITHOUT CAPTURE	DESIGN CASE 2 SCPC WITH CO_2 CAPTURE	DESIGN CASE 3 NGCC WITHOUT CAPTURE	DESIGN CASE 4 NGCC WITH CO_2 CAPTURE
CO_2 Capture, % of Gross	N/A	90	N/A	90
Technology Description	Supercritical pulverized coal Rankine cycle with 1 two-pass tangential or wall-fired boiler and 1 reheat condensing steam turbine.		Natural gas combined cycle with 2x G-Class gas turbines, 2x three-pressure heat recovery steam generators, and 1x reheat steam turbine.	
Nominal Gross Output, MW	900	TBD(1)	810	TBD(1)
Unit Output Frequency, Hz	60	60	60	60
Fuel	Australian Low-Sulfur	Same as Case 1	Natural Gas	Same as Case 3
Fuel Quantity	Note 1	Same as Case 1	Note 1	Same as Case 3
Throttle Conditions (MS temperature, HRH temperature, MS pressure) ° C / ° C / bar(a) (° F / ° F / psia)	582 / 582 / 254.4 (1,080 / 1,080 / 3,690)		565.6 / 565.6 / 124.1 (1,050 / 1,050 / 1,800)	
Supplemental Firing	N/A	N/A	No	No
Heat Rejection	Wet mechanical draft cooling tower			
Auxiliary Boiler During Normal Operations	No	No	No	No
Air Quality Control Systems	Selective Catalytic Reduction, PAC Injection, Fabric Filter, Wet Flue Gas Desulfurization		Dry Low NO_x Combustion, Selective Catalytic Reduction, Oxidation Catalyst	
CO_2 Export Pressure, bar(a) (psia)	N/A	110 (1,600)	N/A	110 (1,600)

Notes:

(1) Fuel quantity to be determined as part of the study. As a basis of the design, CO_2 capture case will use the same amount of fuel as the non-capture case. Calculated values are presented in Section 4.0.

Table 3-2 Study Design Coal: Low Sulfur Australian

As-Received Proximate Analysis, wt%			**Ash Analysis, wt%**		
Gross Calorific Value	6,270	kcal/kg	Silica	46.8	%
Hardgrove Grindability Index	50		Aluminum	26	%
Moisture	9	%	Iron	11	%
Ash	13.5	%	Calcium	5.6	%
Volatiles	25.2	%	Magnesium	1.5	%
Fixed Carbon	52.3	%	Sodium	0.4	%
			Potassium	0.7	%
As-Received Ultimate Analysis, wt%			Sulfur Trioxide (SO_3)	4.1	%
Carbon	65.3	%	Phosphorus	1.1	%
Hydrogen	3.9	%	Titanium	1	%
Oxygen	6.3	%	Manganese	0.3	%
Nitrogen	1.3	%	Other	1.5	%
Sulfur	0.7	%			
Ash	13.5	%	**Other Properties**		
Moisture	9	%	Initial Deformation	1,200	° C
Chlorine	0.07	%	Hemi	1,240	° C
			Flow	1,300	° C
Notes: wt% - Weight percentage kcal/kg – Kilocalories per kilogram					

Table 3-3 Study Design Natural Gas

Methane (CH_4), vol%	92
Ethane (C_2H_6), vol%	6
Propane (C_3H_8), vol%	1
CO_2, vol%	0.5
Nitrogen (N_2), vol%	0.5
Total Sulfur	8 ppmw
Hydrogen Sulfide (H_2S)	3 ppmw
Notes: vol% – Volumetric percentage ppmw – Parts per million by weight	

3.2 CO_2 CAPTURE TECHNOLOGIES

Amine-based post-combustion CO_2 capture technology was selected for both the SCPC and NGCC reference plant cases with CO_2 capture. Amine-based technology was selected primarily because of its relative maturity level, but also because of the availability of data and projected performance compared to competing technologies. Currently, there are at least six companies actively developing and marketing amine-based CO_2 capture technologies. A memorandum presenting the two-step analysis in which post-combustion CO_2 capture technologies were reviewed and qualitatively compared is included in Appendix A of this report.

4.0 Reference Power Plant Designs

4.1 COAL FUELED PLANTS

4.1.1 Main Power Block Description

SCPC power plants utilize proven technology with high reliability and are relatively easy to operate and maintain. Various designs and configurations exist that offer flexibility to match electrical system demands and type(s) of fuel available.

The function of the steam generator of an SCPC power plant is to provide the controlled release of heat in the fuel and the efficient transfer of heat to the feedwater and steam. The transfer of heat produces main steam (MS) at the pressure and temperature required by the high-pressure (HP) turbine. Heat is also transferred through the reheater to increase the temperature of the HP turbine exhaust, or cold reheat (CRH) steam, to the conditions required by the intermediate-pressure (IP) turbine as hot reheat (HRH) steam. Exhaust from the IP turbine is admitted to the LP turbine. The MS and HRH steam drive a steam turbine generator (STG) to produce rotational mechanical energy. The rotational mechanical energy is converted to electrical energy by a statically excited electric generator coupled to the turbine.

Waste heat from the condensing of LP steam in the condenser is typically rejected to either an open or closed cycle cooling water system. Selection of the cooling water system is location-specific and dependent on several factors, including the availability of raw water and suitable discharge location. This study assumes the use of a closed circulating cooling water system utilizing a wet mechanical-draft cooling tower for heat rejection from the condenser and other plant cooling needs. A high-level block flow diagram for an SCPC power plant is illustrated on Figure 4-1.

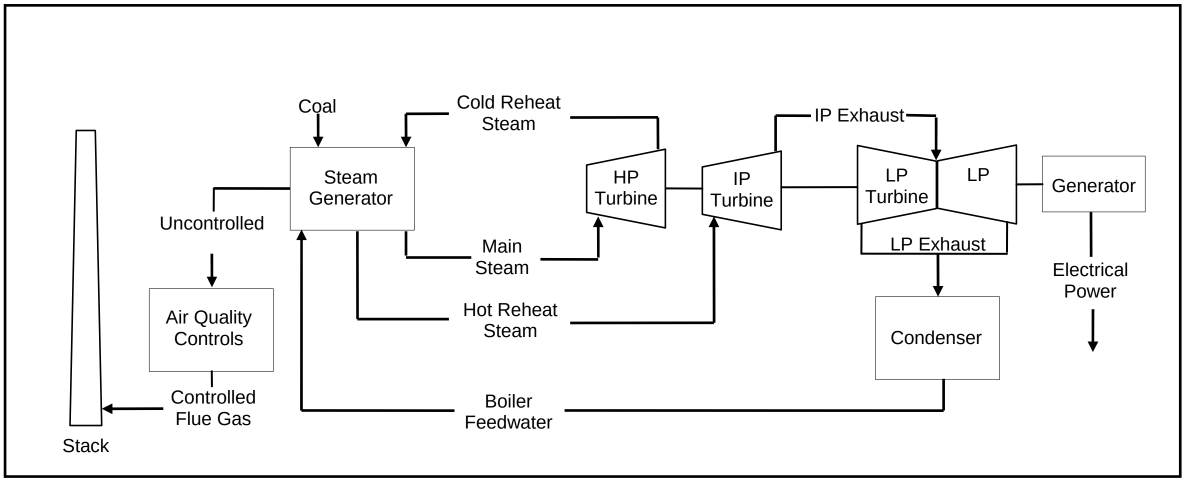

Figure 4-1 Typical SCPC Power Plant

After being heated by the LP and HP feedwater heaters, boiler feedwater is fed through the steam generator's economizer, where initial heat transfer from the flue gas to the working fluid takes place. Feedwater is supplied to the bottom header of the economizer, flows upward and absorbs heat within the economizer, then enters the economizer outlet header. Feedwater exits the economizer and is supplied to headers at the bottom of the furnace walls. Feedwater in the headers flows upwards by forced circulation through the furnace waterwall tubes in a once-through operation (i.e., no boiler drum). Because the pressure of the feedwater is above the critical point of water, the feedwater does not boil. However, it increases in specific volume as its enthalpy increases. A "fluid" above the critical point of water, often referred to as supercritical steam, is produced in the waterwalls of an SCPC steam generator, which is supplied to the primary superheater in the convective pass of the boiler.

With SCPC technology, coal is pulverized then suspended in a primary air stream and conveyed to coal burners. At the burners, this mixture of primary air and coal is further mixed with secondary air and, with the presence of sufficient heat for ignition, the coal combusts in suspension. The furnace enclosure is constructed of membrane waterwalls that absorb the radiant heat of combustion produced by the high combustion temperatures at the burners and produce steam. Current pulverized fuel combustion technology also includes features to minimize unintended products of combustion. For the reference SCPC plant, low nitrogen oxide (NO_x) burners (LNBs) and overfire air (OFA, staged combustion) are used to reduce NO_x formation. Carbon monoxide (CO) emissions are minimized by carefully controlling air-fuel ratios.

Once the products of coal combustion (ash and flue gas) have been cooled sufficiently by the waterwall surfaces so that the ash is no longer molten but in solid form, convective heat transfer surfaces absorb most of the remaining heat of combustion. These convective heat transfer surfaces include the superheaters, reheaters, and economizers located within the steam generator enclosure downstream of the furnace. The final section of boiler heat recovery is in the air preheater, where the flue gas leaving the economizer surface is further cooled by regenerative or recuperative heat transfer to the incoming combustion air.

With SCPC combustion technology, the majority of the solid ash components in the coal will be carried in the flue gas stream all the way through the furnace and convective heat transfer components to enable collection with particulate removal equipment downstream of the air pre-heaters. Typically, no less than 80 percent of the total ash will be carried out of the steam generator for collection downstream. Approximately 15 percent of the total fuel ash is collected wet from the furnace as bottom ash, and 5 percent is collected dry in hoppers located below the steam generator economizer and regenerative air heaters.

For the reference plant, a balanced draft configuration was assumed, as is typical for most modern SCPC units. In this configuration, the boiler operates under slightly negative pressure, and all draft pressure conveying the flue gas is supplied by ID fans that are located downstream of the air preheater. For the CO_2 capture case, the ID fan must be large enough to push the flue gas through the absorber and out the absorber stack.

4.1.2 Post-Combustion Emissions Control Description (Excluding CO_2 Capture)

The following AQC equipment and systems are included in the reference SCPC power plant: selective catalytic reduction (SCR), powdered activated carbon (PAC), pulse jet fabric filter (PJFF), and WFGD. A caustic polishing scrubber is also included for the CO_2 capture case. These systems are discussed later in this section.

Note that the post-combustion AQC equipment and systems assumed for the reference SCPC power plant are representative of a modern power plant design with a comprehensive suite of air emissions control equipment. However, because of the generic nature of the study and nonspecific location of the power plant, no specific power plant stack emissions targets were selected. The reference SCPC plant flue gas configuration is presented on Figure 4-2.

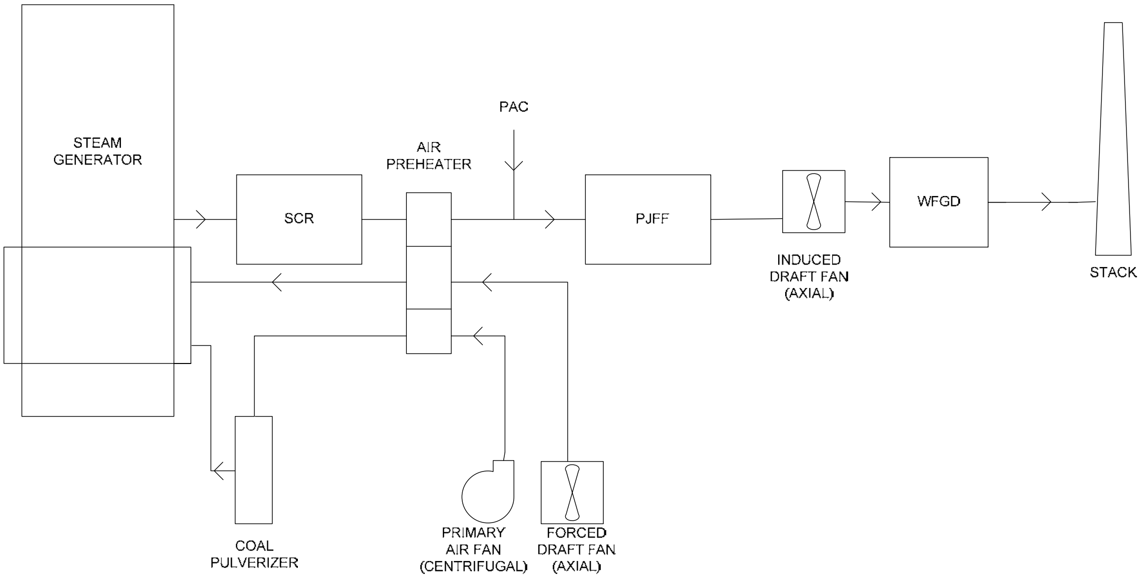

Figure 4-2 Reference SCPC Plant Flue Gas Configuration (polishing scrubber not shown)

4.1.2.1 NO_x Reduction

An SCR system was selected for the reference SCPC power plant. Electric utilities frequently use SCR systems for the reduction of NO_x. A selective noncatalytic reduction (SNCR) system could have been chosen as well, but SCR systems are more efficient at NO_x reduction and can generally achieve lower outlet NO_x concentrations, which is beneficial to the CO_2 capture process.

SCR systems utilize ammonia as a reagent and a catalyst (typically vanadium-based) for NO_x removal. Ammonia is injected into the SCR where it reacts with NO_x to create nitrogen and water. The SCR for the SCPC reference plant is located between the economizer outlet and the air preheater inlet because the ammonia needs to be injected at temperatures between about 315 and 425° C (600 and 800° F). It is possible to locate the SCR downstream of all post-combustion emissions control equipment, but the gas-to-gas reheat needed to obtain the necessary temperature is expensive.

4.1.2.2 Mercury Reduction

A PAC injection system was selected for the reference SCPC power plant. This system injects powdered activated carbon, often lignite based, into ductwork upstream of a particulate removal device. Elemental and oxidized forms of mercury (Hg) are adsorbed onto the carbon surfaces.

4.1.2.3 Particulate Matter Reduction

A PJFF was selected for the reference SCPC power plant. PJFFs are common particulate removal devices for meeting particulate matter emissions requirements. Fabric filters essentially act as industrial-scale vacuum cleaners, with the particulate-laden flue gas passing through fabric bags. As the flue gas passes through the bags, the particulate collects on the bag surface as a filter cake, and the clean air passes through.

An electrostatic precipitator (ESP) was not selected for this study for two primary reasons. First, a PJFF can aid Hg removal by allowing more contact opportunities between the PAC and Hg on the bags' filter cakes. Second, PJFFs are able to meet low particulate emissions for a wide range of fuels and operations.

4.1.2.4 Sulfur Dioxide Reduction

Selection of the SO_2 reduction system for the reference plant is important because SO_2 is a contaminant for amine-based CO_2 capture systems, causing the formation of heat stable salts and degradation of the amine solvent. A WFGD system was selected for the reference SCPC power plant. WFGD is recommended because of its superior SO_2 removal capabilities compared to a dry or semi-dry FGD. Circulating dry scrubbers (CDS) are able to achieve similar SO_2 removal rates, but they use lime as their reagent, which is much more expensive than limestone.

Several types of WFGDs exist, but this study assumes a limestone forced oxidation (LSFO) type. There are several different types of absorbers that might achieve similar performance. In all cases, a limestone slurry is contacted with the flue gas by sprays, gas contact devices such as dual flow trays, or bubbling the gas through a tank of the slurry. Oxidation air is introduced into the processed slurry pool at the bottom of the tower. The oxidation air converts all of the calcium sulfite into sulfate form, which is commonly known as gypsum. Depending on the technology/equipment vendor, various methods are used to increase the liquid-to-gas contact, such as contact trays, absorber rings, etc. The gypsum byproduct is potentially marketable.

4.1.2.5 SO_2 Polishing (SCPC Power Plant with CO_2 Capture Only)

Amine-based CO_2 capture systems require low levels of SO_2 in the inlet flue gas because SO_2 reacts with the amine solvent to produce heat stable salts that degrade the amine solvent. Different technology vendors will require different levels of SO_2 in the inlet flue gas, so a typical value of 10 parts per million (ppm) SO_2 was assumed for this study. While WFGD systems have recently demonstrated SO_2 outlet concentrations as low as 10 ppm with low-sulfur fuels similar to the study design low-sulfur Australian coal, WFGD vendors generally do not guarantee this degree of sulfur removal. Therefore, a polishing scrubber downstream of the WFGD was selected for the SCPC power plant reference design case with post-combustion CO_2 capture. As WFGD and other SO_2 reduction technologies are operated more aggressively, consistently achieving higher sulfur removal rates, vendors might eventually guarantee a maximum SO_2 outlet concentration of 10 ppm.

The polishing scrubber uses a sodium hydroxide (NaOH) caustic reagent. As an alkali metal, sodium is much more reactive with acidic compounds, such as SO_2, than calcium, so caustic scrubbers are capable of achieving very low SO_2 emissions rates. However, caustic solutions are more expensive than calcium-based reagents, so maximum SO_2 removal should be achieved in the WFGD and the caustic scrubber only used for "polishing" the flue gas.

4.1.3 Post-Combustion CO_2 Capture Description

Black & Veatch modeled a generic process for CO_2 capture from the SCPC power plant. The CO_2 capture process was modeled using Bryan Research and Engineering, Inc. ProMax 3.2 software and a solvent with the properties of monoethanolamine (MEA). The property package used for the simulations was "Amine Sweetening – PR," which uses the Peng-Robinson equation of state for the vapor properties and the Electrolytic ELR package for the liquid properties. The column type was TSWEET Kinetics, with a VLE flash, and the convergence was based on the Composition Dependent Enthalpy Model and Boston-Sullivan Non-Ideal Inner Loop Model.

The data from the simulation were adjusted to reflect published information for various enhanced amines to provide a more accurate picture of the performance of state-of-the-art CO_2 capture technologies. The main adjustment to the simulation was the solvent regeneration duty, which was assumed to be the same on a CO_2-mass specific basis for both SCPC and NGCC cases. The rich and lean stream flow rates in the simulation were 8.2 million kilogram per hour (kg/h) and 7.5 million kg/h, respectively. Additional data from the simulation, including temperature and stream information, are provided in Appendix B. While additional optimizations may be performed that would improve the design and performance of the system and potentially reduce its cost, the design envisioned serves as a good basis for discussion of the technology requirements that will be necessary for scaling up CO_2 capture systems for large coal fired power plants. Optimization of the CO_2 capture process was not a primary goal of this study.

The CO_2 capture process flow schematic is presented in the simplified process flow diagram (PFD) in Appendix C of this report. The CO_2 recovery plant consists of three main sections: CO_2 absorption, solvent stripping, and CO_2 compression. The major pieces of equipment include an absorption column, stripper column, and CO_2 compressor.

The flue gas is directed from the polishing scrubber to the CO_2 absorber column which has a footprint of approximately 18 m by 18 m. The CO_2 absorber is a rectangular concrete column with stainless steel internals that divide the column into six parallel sections. Each parallel section of the CO_2 absorber has a cross section of approximately 7 m by 7 m and three main vertical segments: the CO_2 absorption segment, the overhead cooling segment, and the water wash segment. The absorber would likely have to be lined either with a thin corrosion-resistant steel alloy material or a polymer. The exact nature of the lining would be dictated by the amine selected.

The flue gas is introduced into the bottom of the absorber and moves upward through the lower CO_2 absorption segment of the column. As the flue gas ascends through the column packing, it comes into contact with amine solvent that is introduced at the top of the CO_2 absorption segment of the column and descends countercurrent to the flue gas flow. As the lean solvent comes into contact with the flue gas, it absorbs the CO_2 in the flue gas and reacts to form amine salts. The absorption process is driven by the difference in the partial pressures of the CO_2 in the flue gas and the solution, and the reaction of the CO_2 in the amine solution reduces its partial pressure in the solution. The reaction of amine with CO_2 is shown in Equation 4-1.

$$RNH_2 + CO_2 \leftrightarrow RNHCOO^- + H^+ \qquad \text{Equation 4-1}$$

Lower temperatures enhance the amine/CO_2 reaction, so it is important that the solvent be kept at a low temperature (usually between 32° and 55° C). However, the reaction of amine with CO_2 is exothermic, and it raises the temperature of the solution. A side draw is often necessary in the CO_2 absorption segment to remove some of the solvent, cool it, and return it to the absorption segment. For the purposes of this study, Black & Veatch has assumed that the entire solvent stream is withdrawn and cooled.

The flue gas leaving the CO_2 absorption segment has had 90 percent of the CO_2 removed and is almost totally free of sulfur oxide (SO_x) and NO_2. However, a significant amount of amine solvent and moisture is carried in the flue gas from the CO_2 absorption segment. Therefore, as the flue gas leaves the absorption segment, it moves upward into the cooling segment in the middle part of the absorption column, where the treated flue gas is cooled and washed by water flowing countercurrent to the flue gas stream. Because amine is more readily dissolved in cool water, the water that is used to wash the amine from the flue gas is cooled in a plate-and-frame heat exchanger before it is recycled to the top of the segment. To prevent the wash water from becoming too concentrated with amine, excess wash water is mixed with lean amine and sent to the top of the CO_2 absorption segment.

Although cooling the treated flue gas will condense some water, amine-free water from elsewhere in the capture process is added to maintain a water balance in the amine absorber. This water is introduced into the overhead segment of the column, where the fresh water reduces the amine in the flue gas down to a few parts per million. A demister is used at the exit of the overhead segment of the column to remove water droplets that may have been entrained with the flue gas. The clean flue gas leaving the demister in the overhead segment of each parallel section is combined into one stream and vented to the atmosphere through a stack at the top of the absorption column.

The rich solvent from the bottom of the CO_2 absorber is sent to two parallel stripper columns by a rich solution pump through three plate-and-frame rich/lean solvent heat exchangers. The strippers are cylindrical, packed columns where the rich solvent is heated to liberate the CO_2. After leaving the rich/lean heat exchanger, the pre-heated rich solvent is introduced into the upper sections of the strippers, where it contacts stripping steam. The steam in the strippers is produced by eight reboilers (four per stripper column) at the bottom of each stripper which use LP steam from the power plant to boil the solvent. As the amine solution is heated, the reaction between amine and CO_2 is reversed, causing a higher CO_2 partial pressure in the solution, which results in CO_2 desorption into the vapor phase.

Water/CO_2 vapor exits the top of each stripper and is cooled by five shell and tube heat exchangers to condense the water. The water is separated from the CO_2 stream in two dedicated knockout drums and returned to each stripper column. The CO_2 is relatively free of water vapor and is at a pressure of about 1.7 bar(a) (25 psia). Before being sent to the pipeline, the CO_2 needs to be compressed to 110 bar(a) (1,600 psia), which puts it in a supercritical phase and facilitates transportation by pipeline. The CO_2 from each knockout drum is combined into one stream for compression. Compression from 1.7 bar(a) to 110 bar(a) is accomplished with three stages of compression. The first and second intercooler stages have five and two shell and tube heat exchangers, respectively. After the first stage of compression and cooling, water is condensed from the CO_2 stream and removed in a knockout drum. Although not considered in this study, a pump could be used in the last stage of compression to optimize compression power. At high pressures, the water in the CO_2 stream dissolves more CO_2 and becomes acidic. To avoid corrosion, two adsorbent beds are used to dehydrate the CO_2 stream after the second stage of compression. Only one adsorbent bed is dehydrating at any given time, while the other is being regenerated. The final CO_2 stream has a purity of greater than 99.5 percent.

The lean solvent from each stripper reboiler is cooled in the rich/lean heat exchangers and then further cooled to a temperature suitable for absorption by five lean solution plate and frame coolers prior to being introduced back into the CO_2 absorber through a lean solution pump.

Oxygen, SO_2, and NO_2 react with primary amine solvents in the CO_2 absorber, and these reactions form heat stable salts. Primary amines can also degrade to secondary amines, which would then react with other NO_x compounds. The accumulation of heat stable salts can cause corrosion and solution foaming. Reclamation (not discussed in this study) will be necessary to remove the heat stable salts accumulated in the solvent. Each technology vendor will have its own method of reclaiming solvent, but will typically use a distillation or ion exchange process.

4.1.4 Electricity Generation Performance Summaries

A summary of power plant performance for Cases 1 and 2 is presented in Table 4-1. Integration of 90 percent CO_2 capture and compression processes is expected to reduce the net electrical export capability of an SCPC power plant by about 30 percent. CO_2 emissions to atmosphere, on an absolute metric tonnes per hour (t/h) basis, were reduced from 702 t/h to 73 t/h, a reduction of about 90 percent. CO_2 emissions to the atmosphere, on a net megawatt-hour (MWh-net) basis, were reduced from 834 kg/MWh-net to 124 kg/MWh-net, a net reduction of about 85 percent. A side-by-side comparison of the SCPC power plant reference cases to the NGCC power plant reference cases is presented in Appendix D.

4.1.5 Mass and Energy Balances

Table 4-2 shows the main stream information for the Case 2 CO_2 capture process. The steam use in the stripper reboilers is about 1,740 gigajoule per hour (GJ/h) or 821 t/h of 4.5 bar(a) saturated steam. A simplified PFD of the overall reference SCPC power plant with integral CO_2 capture and compression processes is presented in Appendix C.

Table 4-1 Electricity Generation Performance Summary – Cases 1 and 2

	UNIT	CASE 1	CASE 2
Reference Case Description		Supercritical Pulverized Coal Rankine Cycle	
Fuel Type		Coal	Coal
CO_2 Capture	%	None	90
ELECTRICAL OUTPUT			
Total Gross Output	MW	900.1	756.6
Auxiliary Electric Load			
Power Block	MW	35.5	35.1
Flue Gas Fans	MW	17.2	44.0
Air Quality Systems	MW	5.8	8.5
CO_2 Capture	MW	N/A	5.2
CO_2 Compression	MW	N/A	75.0
Total Auxiliary Electric Load	MW	58.5	167.8
Net Plant Output	MW	841.6	588.8
Energy Penalty (Net output)	%	N/A	-30.0
Energy Penalty (Net output reduction per tonne-CO_2 to pipeline)	MW/(t-CO_2 captured)	N/A	0.40
ELECTRICAL PRODUCTION EFFICIENCY			
Fuel Input (NCV)	GJ/h	7,500	7,500
Fuel Input (GCV)	GJ/h	7,815	7,815
Net Plant Heat Rate (NCV)	kJ/kWh	8,912	12,738
Net Plant Heat Rate (GCV)	kJ/kWh	9,285	13,272
Net Plant Thermal Efficiency (NCV)	%	40.4	28.3
Net Plant Thermal Efficiency (GCV)	%	38.8	27.1
CO_2 EMISSIONS			
CO_2 for Transport	t/h	N/A	629
CO_2 to Atmosphere	t/h	702	73
CO_2 to Atmosphere	kg/MWh-net	834	124

Table 4-2 Case 2 CO_2 Capture Process Major Stream Information

MEDIUM:		FLUE GAS	FLUE GAS	CO_2	CO_2
FROM:		POLISHING SCRUBBER	ABSORBER	STRIPPER	COMPRESSION
TO:		ABSORBER	ATMOSPHERE	COMPRESSION	STORAGE
Mole-flow	kmol/h	135,350	117,802	15,021	14,297
Mass-flow	kg/s	1,083	891	178	175
Mass-flow	t/h	3,898	3,209	642	630
Vol.-flow, gas	Nm^3/min	50,562	44,007	5,611	5,341
Pressure	kPa	115.51	108.61	186.16	11,032
Temperature	°C	54	51	48	38
COMPOSITION					
N_2	%mole	70.22	80.68	0.01	0.02
CO_2	%mole	11.78	1.35	95.18	99.98
O_2	%mole	5.03	5.78	0.00	0.00
H_2O	%mole	12.97	12.19	4.80	0.00
NO_2	%mole	0.00	0.00	0.00	0.00
CO	%mole	0.00	0.00	0.00	0.00
SO_2+SO_3	%mole	0.00	0.00	0.00	0.000
Total	%mole	100.00	100.00	100.00	100.00
MOLAR FLOW					
N_2	kmol/h	95,041.37	95,039.12	2.21	2.21
CO_2	kmol/h	15,943.99	1,591.21	14,297.47	14,294.39
O_2	kmol/h	6,808.00	6,809.98	0.30	0.30
H_2O	kmol/h	17,554.64	14,361.01	720.82	0.00
NO_2	kmol/h	0.00	0.00	0.00	0.00
CO	kmol/h	0.00	0.00	0.00	0.00
SO_2+SO_3	kmol/h	2.17	0.00	0.00	0.00
Total	kmol/h	135,350.17	117,801.32	15,020.80	14,296.90
MASS FLOW					
N_2	kg/s	739.74	739.72	0.02	0.02
CO_2	kg/s	194.92	19.45	174.79	174.75
O_2	kg/s	60.52	60.53	0.00	0.00
H_2O	kg/s	87.85	71.87	3.61	0.00
NO_2	kg/s	0.00	0.00	0.00	0.00
CO	kg/s	0.00	0.00	0.00	0.00
SO_2+SO_3	kg/s	0.04	0.00	0.00	0.00
Total	kg/s	1,083.06	891.58	178.41	174.77

kg/s - Kilograms per second.
kmol/h - Kilomoles per hour.
Nm^3/min - Normal cubic meter per minute.

4.1.6 Equipment

Preliminary major equipment lists and site arrangement drawings were developed for each of the reference power plant cases. Both the major equipment lists and site arrangement drawings illustrate the differences between a conventional large-scale modern power plant and a similar power plant constructed with integrated 90 percent CO_2 capture and compression processes. Key information on the SCPC plant with capture is provided in Table 4-3.

Table 4-3 Key Equipment Information for SCPC Plant with Capture

FEATURE	VALUE
Number of Absorbers	1
Absorber Cross-Sectional Area, m^2	317
Absorber Height, m	28
Number of Strippers	2
Stripper Diameter, m	7.2
Stripper Height, m	23
Number of Stripper Reboilers	8
Number of Rich/Lean Exchangers	3
Number of Stripper Overhead Coolers	5
Number of Lean Amine Coolers	5
Number of CO_2 Compressor Trains	2

The preliminary major equipment lists (Appendix E) provide the description, type, quantity installed, key design parameters, and other information for each piece of equipment listed.

The preliminary site arrangement drawings (Appendix F) for the reference cases serve as a good comparison tool to show the relative scale of the CO_2 capture and compression equipment and structures compared to the remainder of the power plant.

The layout of the SCPC plant with CO_2 capture took into account the following objectives:

- Minimize the distance between the polishing scrubber and absorber in order to minimize flue gas duct length/cost.
- Minimize the distance between the power plant's Rankine steam cycle and stripper reboilers in order to minimize the steam and return condensate piping length/cost.
- Minimize the distance between the stripper reboilers and stripper columns.
- Minimize the distance between the stripper columns and CO_2 compression in order to minimize LP CO_2 piping length/cost.
- Minimize the distance between CO_2 compression and high-voltage electrical systems.
- Maintain access to AQC equipment, flue gas fans, stripper reboilers, process pumps, and other process heat exchangers.

The balance of the process equipment, composed primarily of heat exchangers and pumps, was placed on a multi-tiered steel structure situated between the absorber and stripper columns. The location of the balance of the process equipment is considered less critical than the location of the absorber, strippers, reboilers, and CO_2 compression.

4.1.7 Utility Requirements

A summary of utility consumption and waste production for Reference Cases 1 and 2 is presented in Table 4-4. In accordance with the reference case design basis, the fuel requirements for both cases are the same. Because of this, makeup requirements for most of the AQC systems chemicals and waste streams for bottom ash, fly ash, and FGD gypsum byproduct remain unchanged. Case 2 does have additional chemical requirements in the form of sodium hydroxide for the polishing scrubber, advanced amine solvent, and adsorbent for CO_2 dehydration. Case 2 will also have an additional waste stream composed in part of spent amine solvent. Water requirements for Case 2 are markedly greater, with a total makeup water requirement of about 12,600 m^3/h compared to the Case 1 total makeup flow of 9,900 m^3/h. Most of the difference is in the cooling tower makeup requirements. It is expected that about 80 percent of the FGD makeup water requirement can be met by the cooling tower blowdown stream. The 58 m^3/h of water condensed from the CO_2 capture process can also be used as cooling tower makeup.

Table 4-4 Utility Requirements and Waste Summary – Cases 1 and 2

	UNIT	CASE 1	CASE 2
Reference Case Description		Supercritical Pulverized Coal Rankine Cycle	
Fuel Type		Coal	Coal
CO_2 Capture	%	None	90
PLANT UTILITY CONSUMPTION			
Fuel	kg/h	293,300	293,300
Makeup Water			
FGD(s)	m^3/h	295	59
Cooling Tower	m^3/h	9,600	12,500
Cycle Makeup	m^3/h	25.9	26.1
29% Aqueous Ammonia	kg/h	960	960
Powdered Activated Carbon	kg/h	350	350
Limestone	kg/h	7,600	7,600
Sodium Hydroxide Granules (NaOH)	kg/h	N/A	32
Advanced Amine Solvent(1)	kg/h	N/A	283
CO_2 Dehydration Adsorbent(2)	kg/h	N/A	16
PLANT WASTE PRODUCTION			
Wastewater			
Cooling Tower Blowdown	m^3/h	1,900	2,300
FGD Bleed Streams	m^3/h	100	100.5
CO_2 Capture Wastewater	m^3/h	N/A	(Note 3)
Bottom Ash	kg/h	4,000	4,000
Fly Ash/PJFF Solids	kg/h	36,700	36,700
Gypsum (10% moisture)	kg/h	13,100	13,100
Amine Waste	kg/h	N/A	146

Notes:
1. Amine degradation includes degradation from oxygen and sulfur, but excludes NO_2.
2. Bed replacement every 3 to 5 years.
3. The CO_2 capture plant is expected to have minimal wastewater discharge. The water condensed from flue gas and CO_2 streams is used for cooling tower makeup.

4.2 NATURAL GAS PLANTS

4.2.1 Main Power Block Description

NGCC power plants are mature designs that have been used to produce electricity from natural gas since the 1960s. NGCC power plants are considered to be highly reliable and efficient. Various designs and configurations of this technology exist that offer flexibility to match electrical system demands and type(s) of fuel available.

The selected NGCC reference configuration is designed around two Mitsubishi Heavy Industries (MHI) 501GAC combustion turbine generators (CTGs). The 501GAC has just recently been made available commercially. The 501GAC is a large advanced class, heavy frame, single-shaft, single casing machine with a 17 stage axial flow compressor, a four stage turbine, and 16 can-annular-type combustors. The compressor operates at a 20:1 compression ratio. The baseload turbine inlet temperature is approximately 1,500° C (2,732° F). The generator is driven at the compressor end to allow for axial exhaust to the HRSG. Modulating inlet guide vanes are used to maintain high exhaust temperatures for combined cycle operation at part-load conditions. The MHI 501GAC is fully air cooled in lieu of steam cooling as found on the MHI 501G1 (60 Hz) and 701G2 (50 Hz).

The CTG produces electricity and high temperature exhaust by compressing large volumes of air, adding heat to the compressed air through combustion of natural gas, and expanding the hot air to drive a turbine coupled to a generator to produce electricity. Approximately two-thirds of the electricity generated by a heavy frame CTG-based combined cycle is produced by the CTGs (excluding supplemental firing in the HRSGs, if used).

Additional electricity is produced using two triple pressure reheat HRSGs, which utilize the thermal energy from the hot CTG exhaust gases to generate steam. The HRSGs supply HP, IP, and LP steam to a single reheat STG. A schematic of a combined cycle power plant is shown on Figure 4-3. The HRSG configuration depicted on Figure 4-3 is a horizontal flue gas flow design. A vertical flue gas flue design is also commonly used. A number of power augmentation options are available for combined cycle power plants, such as CTG inlet air cooling and HRSG supplemental duct firing. These options have not been included in this study.

Waste heat from the condensing of LP steam in the condenser is typically rejected to an open cooling water system, a closed cycle cooling water system, or an air cooled condenser is used. Selection of the cooling water system is location-specific and dependent on several factors, including the availability of raw water and suitable discharge location. This study assumes the use of a closed circulating cooling water system utilizing a wet mechanical-draft cooling tower for heat rejection from the condenser and other plant cooling needs.

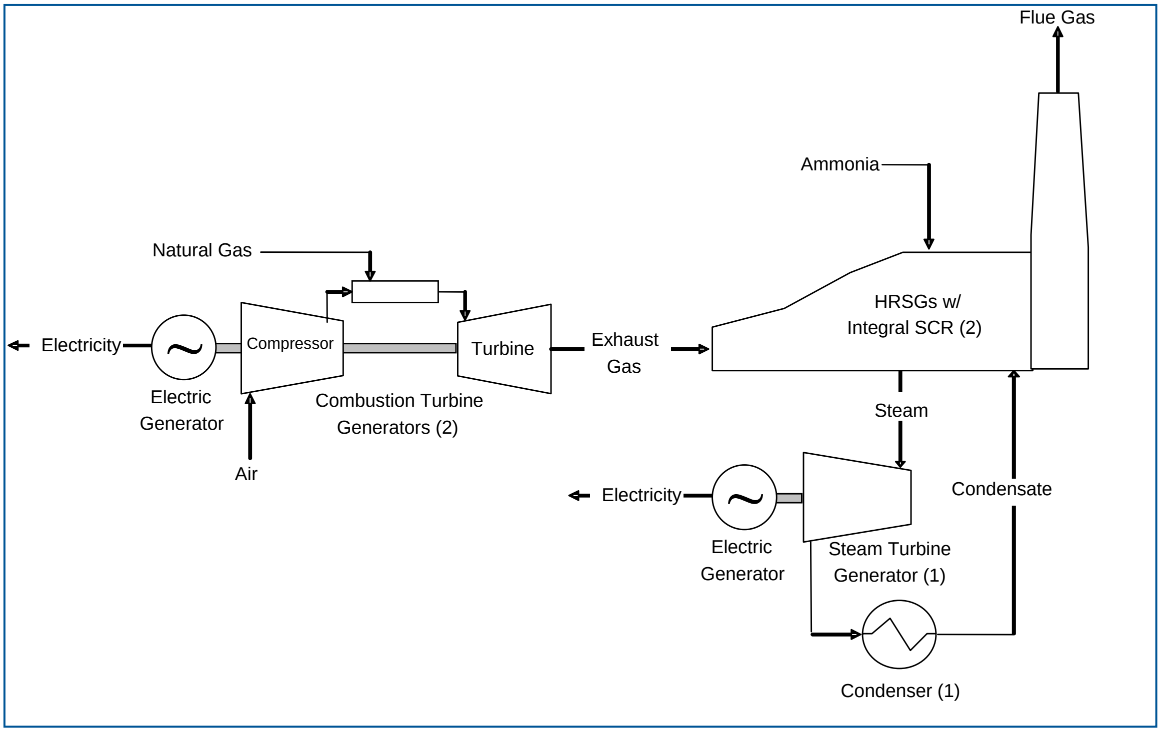

Figure 4-3 **Typical NGCC Plant**

4.2.2 Post-Combustion Emissions Control Description (Excluding CO_2 Capture)

An oxidation catalyst and SCR system were selected for the NGCC reference plant design cases.

4.2.2.1 Carbon Monoxide Reduction

An oxidation catalyst was selected for the reference NGCC power plant. An oxidation catalyst, often referred to as a CO catalyst, oxidizes CO and unburned hydrocarbons in the exhaust gases to form CO_2. The use of an oxidation catalyst is a proven post-combustion control technology widely used to abate CO emissions. No reagent injection is necessary. The oxidation catalyst reactor housing is situated in the exhaust gas path and is integral to the HRSG, located upstream of the SCR system.

4.2.2.2 NO_x Reduction

The gas turbines selected for the reference NGCC power plant minimize NO_x emissions using dry low NO_x (DLN) combustion systems. In addition, an SCR system was selected to further reduce NO_x emissions. The SCR reactor housing and ammonia injection grid are situated in the exhaust gas path and are integral to the HRSG, located downstream of the oxidation catalyst in an area of the HRSG where temperatures are between about 315 and 425° C (600 and 800° F). Ammonia is injected into the SCR, where it reacts with NO_x to create nitrogen and water. Ammonium bisulfate and ammonium sulfite could form and foul surfaces downstream of the ammonia injection grid for higher sulfur fuels. However, for natural gas with a sulfur concentration of 8 ppm, ammonium bisulfate and ammonium sulfite formation is not a concern.

4.2.3 Post-Combustion CO_2 Capture Description

Black & Veatch modeled a generic process for CO_2 capture from the combined cycle power plant. The CO_2 capture process was modeled using Bryan Research and Engineering, Inc. ProMax 3.2 software and properties of a generic MEA and using the same thermodynamic property package as settings as described in Section 4.1.3. The data from the simulation were adjusted to reflect published information for various enhanced amines to provide a more representative picture of the performance of state-of-the-art CO_2 capture technologies. The main adjustment to the simulation was the solvent regeneration duty, which was assumed to be the same on a CO_2-mass specific basis for both SCPC and NGCC cases. The rich and lean stream flow rates in the simulation were 3.3 million kg/h and 3.2 million kg/h, respectively. Additional data from the simulation, including temperature and stream information, is provided in Appendix B. While additional optimizations may be performed that would improve the design and performance of the system and potentially reduce its cost, the design envisioned serves as a good basis for discussion of the technology requirements that will be necessary for scaling up CO_2 capture systems for large combined cycle power plants.

The CO_2 capture process flow schematic is presented in the simplified PFD in Appendix C of this report. The CO_2 recovery plant consists of three main sections: CO_2 absorption, solvent stripping, and CO_2 compression. The major pieces of equipment are an absorption column, stripper column, and CO_2 compressor.

The flue gas is directed from each HRSG outlet to the CO_2 absorber column by a flue gas fan. The CO_2 absorber is a rectangular concrete column with stainless steel internals that divide the column into six parallel sections. Each parallel section of the CO_2 absorber has a cross section of approximately 7 m x 7 m and has four main vertical segments: the quench cooler segment, the CO_2 absorption segment, the overhead cooling segment, and the water wash segment.

The absorption process is driven by the difference in the partial pressures of the CO_2 in the flue gas and the solution, and the reaction of the CO_2 in the amine solution reduces its partial pressure in the solution. Lower temperatures enhance the amine/CO_2 reaction (refer to Equation 4-1), so it is important that the solvent be kept at a low temperature (usually between 32 and 55° C). In the combined cycle application, it is particularly important that the low temperature be maintained because of the lower partial pressure of CO_2 in the flue gas. For the purposes of this study, Black & Veatch has assumed that the entire solvent stream is withdrawn and cooled at a suitable point in the absorber column. Additionally, the pressure drop through the absorber and out of the absorber vent is expected to be about 13.8 kilopascals gauge (kPa[g]) (2 pounds per square inch gauge [psig]). The flue gas exiting the HRSG is at a temperature of approximately 100° C and at a pressure near atmospheric. This means that the flue gas must be cooled and slightly pressurized before entering the CO_2 absorption segment of the absorber. The flue gas pressure is increased by two parallel fans located upstream of the absorber. Because of the large volume of the flue gas, the fans consume a significant amount of power.

The hot, pressurized flue gas is introduced into the bottom of the absorber and moves upward through the quench cooler segment of each parallel section. Cold water descends through packing to enhance contact between the flue gas and the cold water. The water is heated as it descends through the cooler, and part of it evaporates into the flue gas stream. This evaporation is more than offset by the water in the flue gas that condenses as it cools. The hot water exits the bottom of the absorber and is cooled in three plate-and-frame quench water coolers before it is recycled back to the top of the quench cooler segment of the absorber. The cool flue gas (approximately 32° C) then enters the lower CO_2 absorption segment of the column. As the flue gas ascends through the column packing, it comes into contact with amine solvent that is introduced at the top of the CO_2 absorption segment and descends countercurrent to the flue gas flow. As the lean solvent comes into contact with the flue gas, it absorbs the CO_2 in the flue gas and reacts to form amine salts. However, the reaction of amine with CO_2 is exothermic, so it raises the temperature of the solution. This means that a side draw is necessary at some point in the CO_2 absorption segment to remove some of the solvent, cool it down, and return it to the absorption segment.

The flue gas leaving the CO_2 absorption segment has had 90 percent of the CO_2 removed and is almost totally free of NO_2. However, a significant amount of amine solvent and moisture is carried in the flue gas from the CO_2 absorption segment. Therefore, as the flue gas leaves the absorption segment, it moves upward into the cooling segment in the absorption column, where the treated flue gas is cooled and washed by water flowing countercurrent to the flue gas stream. Because amine is more readily dissolved in cool water, the water used to wash the amine from the flue gas is cooled in a plate-and-frame heat exchanger before it is recycled to the top of the segment. To prevent the wash water from becoming too concentrated with amine, excess wash water is mixed with lean amine and sent to the top of the CO_2 absorption segment.

Although cooling the treated flue gas will condense some water, amine-free water from elsewhere in the capture process is added to maintain a water balance in the amine absorber. This water is introduced into the overhead segment of the column, where the fresh water reduces the amine in the flue gas to a few parts per million. A demister is used at the exit of the overhead segment of the column to remove water droplets that may have been entrained with the flue gas. The clean flue gas leaving the demister in each parallel section is combined into one stream and vented to the atmosphere through a stack at the top of the absorption column.

The rich solvent from the bottom of the CO_2 absorber is sent to a single stripper column by a rich solution pump through two plate-and-frame rich/lean solvent heat exchangers. The stripper is a cylindrical, packed column, where the rich solvent is heated to liberate the CO_2. After leaving the rich/lean heat exchangers, the pre-heated rich solvent is introduced into the upper sections of the stripper, where it contacts stripping steam. The steam in the stripper is produced by four reboilers at the bottom of the stripper, which use LP steam from the power plant to boil the lean solvent. As the rich amine solution is heated, the reaction of amine and CO_2 moves to the left, causing a higher CO_2 partial pressure in the solution, which results in CO_2 desorption into the vapor phase.

Water/CO_2 vapor exits the top of each stripper and is cooled by two shell-and-tube heat exchangers to condense the water. The water is separated from the CO_2 stream in a knockout drum and returned to the stripper column. The CO_2 is relatively free of water vapor and is at a pressure of about 1.7 bar(a). Before being sent to the pipeline, the CO_2 needs to be compressed to about 110 bar(a), which puts it in a supercritical phase and facilitates transportation by pipeline. Compression from 1.7 bar(a) to 110 bar(a) is accomplished with three stages of compression. After the first stage of compression and cooling, water is condensed from the CO_2 stream and removed in a knockout drum. At high pressures, the water in the CO_2 stream dissolves more CO_2 and becomes acidic. To avoid corrosion, adsorbent beds are used to dehydrate the CO_2 stream after the second stage of compression and intercooling. Only one bed is dehydrating at any given time, while the other is being regenerated. The final CO_2 stream has a purity of greater than 99.5 percent.

The lean solvent from each stripper reboiler is cooled in the rich/lean heat exchanger and then further cooled to a temperature suitable for absorption by one lean solution plate-and-frame cooler prior to being introduced back into the CO_2 absorber through a lean solution pump.

Oxygen and NO_2 react with primary amine solvents in the CO_2 absorber, and these reactions form heat stable salts. Primary amines can also degrade to secondary amines, which would then react with other NOx compounds. The accumulation of heat stable salts can cause corrosion and solution foaming. Reclamation (not discussed in this study) will be necessary to remove the heat stable salts accumulated in the solvent. Each technology vendor will have its own method of reclaiming solvent, but will typically use distillation or ion exchange processes.

4.2.4 Electricity Generation Performance Summaries

A summary of power plant performance for Cases 3 and 4 is presented in Table 4-5. Integration of 90 percent CO_2 capture and compression processes is expected to reduce the net electrical output capability of an NGCC power plant by about 14.5 percent. CO_2 emissions to atmosphere, on a t/h basis, were reduced from 276 t/h to 28 t/h, a reduction of about 90 percent. CO_2 emissions to atmosphere, on a MWh-net basis, were reduced from 349 kg/MWh-net to 41 kg/MWh-net, a net reduction of about 88 percent. A side-by-side comparison of the SCPC power plant reference cases to the NGCC power plant reference cases is presented in Appendix D.

4.2.5 Mass and Energy Balances

Table 4-6 shows the main stream information for the CO_2 capture process. The steam use in stripper reboilers is about 700 GJ/h or 330 t/h of 4.5 bar(a) saturated steam.

Table 4-5 Electricity Generation Performance Summary – Cases 3 and 4

	UNIT	CASE 3	CASE 4
Reference Case Description		2-on-1 G-Class Gas Turbine Combined Cycle	
Fuel Type		Natural Gas	Natural Gas
CO_2 Capture	%	None	90
ELECTRICAL OUTPUT			
Gross Output			
STG	MW	280.4	223.7
Gas Turbine Generators (total)	MW	529.5	529.5
Total Gross Output	MW	809.9	753.2
Auxiliary Electric Load			
Power Block	MW	19.6	22.1
Flue Gas Fans	MW	N/A	26.1
CO_2 Capture	MW	N/A	3.6
CO_2 Compression	MW	N/A	25.5
Total Auxiliary Electric Load	MW	19.6	77.3
Net Plant Output	MW	790.3	675.9
Energy Penalty (Net output)	%	N/A	-14.5
Energy Penalty (Net output reduction per tonne-CO_2 to pipeline)	MW/(t-CO_2 captured)	N/A	0.46
ELECTRICAL PRODUCTION EFFICIENCY			
Fuel Input (NCV)	GJ/h	4,906	4,906
Fuel Input (GCV)	GJ/h	5,433	5,433
Net Plant Heat Rate (NCV)	kJ/kWh	6,208	7,259
Net Plant Heat Rate (GCV)	kJ/kWh	6,874	8,038
Net Plant Thermal Efficiency (NCV)	%	58.0	49.6
Net Plant Thermal Efficiency (GCV)	%	52.4	44.8
CO_2 EMISSIONS			
CO_2 for Transport	t/h	N/A	250
CO_2 to Atmosphere	t/h	276	28
	kg/MWh-net	349	41

Table 4-6 Case 4 CO_2 Capture Process Major Stream Information

MEDIUM:		FLUE GAS	FLUE GAS	CO_2	CO_2
FROM:		FLUE GAS FANS	ABSORBER	STRIPPER	COMPRESSION
TO:		ABSORBER	ATMOSPHERE	COMPRESSION	STORAGE
Mole-flow	kmol/h	154,287	147,909	5,975	5,687
Mass-flow	kg/s	1,212	1,139	71	70
Mass-flow	t/h	4,362	4,098	255	250
Vol.-flow, gas	Nm^3/min	60,353	55,254	2,232	2,125
Pressure	kPa	117.21	108.61	186.16	11,032
Temperature	°C	109	51	43	38
COMPOSITION					
N_2	%mole	75.16	78.40	0.02	0.02
CO_2	%mole	4.09	0.42	95.18	99.97
O_2	%mole	11.99	12.51	0.01	0.01
H_2O	%mole	8.76	8.68	4.80	0.00
NO_2	%mole	0.00	0.00	0.00	0.00
CO	%mole	0.00	0.00	0.00	0.00
SO_2+SO_3	%mole	0.00	0.00	0.00	0.000
Total	%mole	100.00	100.00	100.00	100.00
MOLAR FLOW					
N_2	kmol/h	115,961.49	115,960.51	1.10	1.10
CO_2	kmol/h	6,312.99	614.00	5,687.00	5,685.77
O_2	kmol/h	18,502.25	18,503.42	0.34	0.34
H_2O	kmol/h	13,510.22	12,832.60	286.74	0.00
NO_2	kmol/h	0.00	0.00	0.00	0.00
CO	kmol/h	0.00	0.00	0.00	0.00
SO_2+SO_3	kmol/h	0.00	0.00	0.00	0.00
Total	kmol/h	154,286.95	147,910.53	5,975.18	5,687.21
MASS FLOW					
N_2	kg/s	902.57	902.56	0.01	0.01
CO_2	kg/s	77.18	7.51	69.52	69.51
O_2	kg/s	164.46	164.47	0.00	0.00
H_2O	kg/s	67.61	64.22	1.43	0.00
NO_2	kg/s	0.00	0.00	0.00	0.00
CO	kg/s	0.00	0.00	0.00	0.00
SO_2+SO_3	kg/s	0.00	0.00	0.00	0.00
Total	kg/s	1,211.82	1,138.76	70.97	69.52

4.2.6 Equipment

Preliminary major equipment lists and site arrangement drawings were developed for each of the reference power plant cases. Both the major equipment lists and site arrangement drawings illustrate the differences between a conventional large-scale modern power plant and a similar power plant constructed with integrated 90 percent CO_2 capture and compression processes.

The preliminary major equipment lists (Appendix E) provide the description, type, quantity installed, key design parameters, and other information for each piece of equipment listed. Key information on the NGCC plant with capture is provided in Table 4-7.

Table 4-7 Key Equipment Information for NGCC Plant with Capture

FEATURE	VALUE
Number of absorbers	1
Absorber Cross-Sectional Area, m^2	317
Absorber Height, m	28
Number of Strippers	1
Stripper Diameter, m	7
Stripper Height, m	23
Number of Stripper Reboilers	4
Number of Rich/Lean Exchangers	2
Number of Stripper Overhead Coolers	2
Number of Lean Amine Coolers	1
Number of CO_2 Compressor Trains	2

The preliminary site arrangement drawings (Appendix F) for the reference cases serve as a good comparison tool to show the relative scale of the CO_2 capture and compression equipment and structures compared to the remainder of the power plant.

The layout of the NGCC plant with CO_2 capture took into account the following objectives:

- Minimize the distance between the HRSGs and absorber in order to minimize flue gas duct length/cost.
- Minimize the distance between the power plant's Rankine steam cycle and stripper reboilers in order to minimize the steam and return condensate piping length/cost.
- Minimize the distance between the stripper reboilers and stripper column.
- Minimize the distance between the stripper column and CO_2 compression in order to minimize low pressure CO_2 piping length/cost.
- Minimize the distance between CO_2 compression and high voltage electrical systems.
- Maintain access to combustion turbines, HRSGs, steam turbine, flue gas fans, stripper reboilers, process pumps, and other process heat exchangers.

The balance of the process equipment, composed primarily of heat exchangers and pumps, was placed on a multi-tiered steel structure situated between the absorber and stripper columns. The location of the balance of the process equipment is considered less critical than the location of the absorber, stripper, reboilers, and CO_2 compression.

4.2.7 Utility Requirements

A summary of utility consumption and waste production for Reference Cases 3 and 4 is presented in Table 4-8. In accordance with the reference case design basis, the fuel requirements for both cases are the same. Because of this, makeup requirements for aqueous ammonia are unchanged. Case 4 does have additional chemical requirements in the form of advanced amine solvent and adsorbent for CO_2 dehydration. Case 4 will also have an additional waste stream composed in part of spent amine solvent. Water requirements for Case 4 are markedly greater, with a total makeup water requirement of about 6,400 m^3/h compared to the Case 3 total makeup flow of 4,400 m^3/h. Approximately 64 m^3/h of condensate from the flue gas quench segment of the absorber and CO_2 compression intercoolers is also used for cooling tower makeup.

Table 4-8 Utility Requirements and Waste Summary – Cases 3 and 4

	UNIT	CASE 3	CASE 4
Reference Case Description		2-on-1 G-Class Gas Turbine Combined Cycle	
Fuel Type		Natural Gas	Natural Gas
CO_2 Capture	%	None	90
PLANT UTILITY CONSUMPTION			
Fuel	kg/h	50,400	50,400
Fuel	NM^3/h	68,600	68,600
Makeup Water			
Cooling Tower	m^3/h	4,400	6,400
Cycle Makeup	m^3/h	7.7	8.1
29% Aqueous Ammonia	kg/h	200	200
Advanced Amine Solvent(1)	kg/h	N/A	210
CO_2 Dehydration Adsorbent(2)	kg/h	N/A	7
PLANT WASTE PRODUCTION			
Wastewater			
Cooling Tower Blowdown	m^3/h	880	1,300
CO_2 Capture Wastewater	m^3/h	N/A	(Note 3)
Amine Waste	kg/h	N/A	108

Notes:

1. Amine degradation includes degradation from oxygen and sulfur, but excludes NO_2.
2. Bed replacement every 3 to 5 years.
3. The CO_2 capture plant is expected to have minimal wastewater discharge. The water condensed from flue gas and CO_2 streams is used for cooling tower makeup.

5.0 Technical and Operational Risk Analysis

To date, the largest operational post-combustion CO_2 capture facility for a coal fired plant is on the order of 25 MW equivalent at Southern Company's Plant Barry, which uses MHI technology. The largest facility for a natural gas fired plant is the Florida Power & Light Bellingham plant, which captures the equivalent of approximately 35 MW. Larger facilities are at various states of design and construction, but are not yet operational. This section discusses the technical and operational risk factors associated with the design and operation of the full-scale facilities developed in the Reference Cases 2 and 4.

Black & Veatch has classified some of the major technical and operational risks as commonplace, leading edge, or bleeding edge. Commonplace means that there are potentially many vendors that could supply the required expertise and that the technology or operation, although possibly unique in a CO_2 capture setting, is frequently used in equivalent service. Leading edge means that there are likely only a few vendors that could supply the required expertise and that the technology or operation might require some modification to existing technologies with subsequent testing. Bleeding edge means that there are very few companies that could provide the required expertise, and the technology or operation would require extensive R&D.

Specific overall operational risks related to scale were not identified. Although extremely large and complex, the required systems are within the range of industrial experience. To ensure that operational considerations have been adequately addressed, it is likely that additional time will be required in the engineering and commissioning schedule for the first few large carbon capture plants. Also, the control systems for these plants will probably require more monitoring points and be more complex than typical power generation facilities. However, these risks are related more to the complexity of the systems than scale and, as such, are not expected to constitute an extraordinary operational risk.

5.1 STEAM EXTRACTION

The CO_2 stripper reboilers require a considerable amount of saturated steam, which can be sourced from the power plant of either configuration being considered in this study. The power plant would suffer a loss in the steam turbine output as a consequence. For the SCPC reference case, 821 t/h of 4.5 bar(a) saturated steam is required, and for the NGCC reference case, about 330 t/h of 4.5 bar(a) saturated steam is required. Approximately 23 percent of the Case 2 fuel heat input and 14 percent of the Case 4 fuel heat input (NCV basis) is used in the stripper reboilers. Design of the power plant Rankine cycle and stripper reboiler for a given project will require careful consideration to maximize efficiency and allow adequate flexibility to account for transient and upset conditions. Equipment sizing and details as to how to best integrate the systems are the subject of optimization.

The SCPC unit (Case 2) is composed of a steam turbine with several extractions at different pressure levels for regenerative feedwater heating. For optimization of the cycle, it is generally desirable to extract steam at conditions closest to those required by the steam use. The steam source with conditions closest to those required is the steam exhausting from the IP turbine casing and crossing over to the LP turbine for further expansion. In Black & Veatch's preliminary design of the steam turbine cycle, this occurs at a pressure of nearly 8.9 bar(a). The requisite quantity of steam is tapped off from the cross-over piping and desuperheated to saturation before being sent to the amine stripping process. In a fully optimized design, it may be desirable to include a non-condensing turbine to recover some of the energy lost to let down of the steam to the needed process conditions. Mechanical energy from the non-condensing turbine could be used to drive an additional generator or possibly a portion of the CO_2 compressor load. This decision would require a project-specific economic analysis to determine whether the cost and operation of the additional equipment is justified. There are other options, including a clutch between two LP cylinders and a partial arc valve arrangement at the LP inlet to optimize the cycle efficiency. The pressure of the IP-LP cross-over could also be reduced by modification of the IP and LP steam turbines. Steam turbine designs could be customized to some degree to accommodate specified steam extraction conditions.

The steam cycle of the combined cycle power plant in Case 4 is designed with the LP steam at a pressure level of about 4.9 bar(a). While the conditions are fairly suitable, the flow rate of steam from the HRSG at this pressure is inadequate to meet the requirements of the amine stripping. The Black & Veatch preliminary cycle design extracts the remainder of the steam from the LP steam turbine at this pressure. Approximately a quarter of the steam comes from the HRSG, and the rest is taken from the LP turbine.

The plant designs for Cases 2 and 4 are different from those in Cases 1 and 3, in which no CO_2 capture is planned. The continuous requirement of process steam dictates a modified steam turbine and heat rejection system design to achieve optimized results. As more steam is extracted from the steam turbine compared to the corresponding "no CO_2 capture" case, the amount of steam expanding in the last stages of the steam turbine and condensing in the condenser is reduced. Black & Veatch has, therefore, selected steam turbine last stage blades of lower sizes for these cases. This minimizes the associated leaving losses and optimizes the steam turbine output.

Black & Veatch experience in this area indicates that the major OEMs of large steam turbines are able to modify their standard steam turbine design to fit in to a CO_2 capture process. These suppliers are Hitachi, Toshiba, MHI, General Electric, Siemens, and Alstom. The combined cycle HRSG and steam turbine do not require any major modifications from the standard industry design for this application. Black & Veatch does not expect any difficulties in procurement of major equipment of the power plant for either of the CO_2 capture cases. Black & Veatch believes that the steam turbine and HRSG technology required for power plants with CO_2 capture at typical power plant scales is commonplace.

For Cases 2 and 4, the heat rejection system has been designed to also include the heat rejection load of the CO_2 capture compressors and other CO_2 capture cooling loads. The technology required for heat rejection in a power plant with CO_2 capture at any scale is commonplace.

The plant designs for Case 2 and Case 4 have been selected on the basis that the process steam demand is continuous or near continuous, which would be expected for a typical post-combustion amine capture plant. When the process steam demand is reduced for some reason, this steam continues to expand in the steam turbine. If the electric power load remains the same when there is no process steam demand, or if the last stage blade loading on the LP turbine is unable to handle additional flow, the steam turbine will have to be throttled to reduce the throttle steam flow. This will have a negative effect on the operating efficiency of the power plant; however, if this operating scenario is expected to happen frequently, an optimization can be performed to minimize the efficiency loss. If it is felt that there is sufficient demand for the additional power that can be generated, the LP turbine, generator, downstream electrical equipment, and the heat rejection system could be designed for higher capacity accordingly. Again, this needs to be evaluated with the dispatch model.

All of the process steam condensate from the amine process is available for re-use. In the reference designs, evaluated at study design conditions, it is available at a temperature of approximately 147° C. To conserve water and minimize the treatment of makeup water for the cycle, the process condensate is returned to the power plant cycle. Further study would be required to determine the optimum location for return of the condensate. In the SCPC case, if it is mixed with the steam turbine condensate (which is typically at a much lower temperature) before being routed to the steam generator, the higher temperature of the mixed condensate would reduce the amount of steam extracted from the steam turbine for regenerative heating while heating the condensate/boiler feedwater to the same final temperature. This would improve the plant efficiency. However, in a supercritical power cycle, concerns with even small contamination of the power plant condensate/feedwater may warrant return of the process condensate to the condenser so that it can be cooled and subsequently polished in the condensate polisher. Return of the process condensate to the condenser would eliminate the efficiency improvement previously stated. The technology required for treating condensate in a power plant with CO_2 capture would be considered commonplace.

In the HRSG, the higher temperature of the condensate reduces the amount of recirculation of condensate being utilized to maintain the condensate temperature at the HRSG inlet temperature sufficiently higher than the water dew point temperature. The auxiliary power of the plant is, therefore, reduced and overall plant efficiency improved.

5.2 FLUE GAS CO_2 CAPTURE PROCESS BYPASS

During startup, shutdown, and other upset conditions, increased acid gas concentrations in the flue gas, primarily NO_2 and SO_2, could result in the formation of excessive amounts of nitrous amines and HSS. Bypassing the absorption column (and hence the CO_2 capture process) under these conditions would minimize these issues. Having a bypass around the absorption column would also allow the power plant to continue operating when the capture process was unavailable because of planned or unplanned maintenance activities. In addition, a flue gas bypass around the absorption column would have benefits in terms of implosion protection, which could allow the use of reduced stiffening requirements for the steam generator and AQC systems and optimization of the draft fan controls.

However, the flue gas bypass duct around the absorber, diverter dampers, and transition pieces would be large, complicated, and costly. The cost and complexity of the bypass would be even greater if the ability to access and service the absorption column when the power plant is in operation is desired. Maintaining the flue gas bypass dampers would be critical to plant operations. In addition, a bypass system would also increase flue gas pressure losses, adversely affecting plant performance. Special consideration of how to transition into and out of bypass mode would also be warranted as the normal operating pressure losses across the absorption column would be high. Maintaining flue gas and boiler draft pressure during transition would require coordination of flue gas fans and bypass damper operation.

The air permits for a commercial power plant constructed with CO_2 capture and compression would likely make it difficult to operate the facility for extended periods of time without removal of CO_2 from the flue gas stream prior to stack discharge. The air permit would likely treat the CO_2 capture process in a manner analogous to other post-combustion AQC systems, such as FGD systems. The added cost, safety concerns, and permitting issues would need to be evaluated. However, Black & Veatch does not consider the construction and operation of a flue gas bypass arrangement to be a significant technical risk at the scales presented.

5.3 COMPRESSION

For the CO_2 capture and compression reference cases, Black & Veatch has used three stages of electric motor-driven compression to go from 1.72 to approximately 110 bar(a) (25 - 1,600 psia). Compression ratios in a single stage are typically limited by the discharge temperature, with the maximum desirable temperature being approximately 175° C (350° F). While compression from 1.72 to approximately 110 bar(a) can be accomplished in practice in three stages, it pushes the desirable limits; four or more stages of compression could also be used. The number of compressor stages to use would be subject to an economic evaluation, weighing the increased efficiency of the compressors to the costs. Other configurations (including the use of a pump in the final stages to optimize compression power, or integrally geared compressors) are possible, but should not affect scale up. The CO_2 compression technology for large-scale power plants is generally available, but could be improved for efficiency of operation. Turndown may ultimately dictate the number and type of compressors selected. For example, if integrally geared compressors are utilized, a larger number of units may be necessary to achieve the volumetric flow required. The maximum size of integrally geared compressors available varies by manufacturer but is in the range of 40 to 50 MW. Black & Veatch believes that the compression technology should be considered commonplace.

The configuration that Black & Veatch has chosen also uses multiple trains of CO_2 compression. This configuration still requires extremely large compressors and accompanying electric motors. Given that these compressors and their electric motors are relatively large, and equipment requirements for starting large electric motors are extensive, it might be desirable to go to more and smaller trains of compression. This option would also help plant availability because it would allow the plant to run at reduced capacity if one of the CO_2 compressor trains tripped or was otherwise offline for maintenance. The tradeoff would be increased capital cost. Variable frequency drives could also be used on a single train of compression, also with a tradeoff between the operational savings and capital costs associated with the variable frequency drive.

An alternative to using electric motors would be to use steam turbine drivers. Use of turbines using steam from the power plant's Rankine cycle would likely be the most efficient means of driving the CO_2 compressors. However, the complexity associated with integrating the steam turbine drivers with the Rankine cycle would complicate operations. Ability to integrate large steam turbines to drive the CO_2 compressors would require evaluation of the power plant's Rankine cycle and main steam turbine generator design to determine the feasibility of such a configuration.

The issues examined in the preceding paragraphs on CO_2 compression are rather minor and are mainly related to availability of the plant and startup requirements. Even though the CO_2 compressors are large, drivers of this size are not uncommon, and Black & Veatch does not believe that the CO_2 compression train carries significant technical risk.

5.4 COOLING

Table 5-1 shows the cooling requirements for each of the cases discussed.

Table 5-1 Cooling Requirements

CASE	COOLING TOWER HEAT LOAD, GJ/h	COOLING WATER FLOW, m^3/h	NUMBER OF COOLING TOWER CELLS
1 – SCPC, No Capture	3,600	96,600	16
2 – SCPC, 90% Capture	4,400	129,500	22
3 – NGCC, No Capture	1,600	43,300	8
4 – NGCC, 90% Capture	2,300	66,800	12

The cooling tower heat rejection duty requirements for the CO_2 capture cases are approximately 20 percent higher for the SCPC cases and approximately 40 percent higher for the combined cycle cases. These cooling requirements are well within the capabilities of modern cooling equipment (cooling towers, pumps, piping, etc.) and do not represent an impediment to the scalability of CCS for either case. In general, Black & Veatch does not expect cooling requirements to be an issue with regard to the scale of CCS. Cooling water requirements are site-specific, however, so it is possible that a specific site may not have adequate makeup water available to meet the cooling needs of a power plant with CCS.

5.5 ENVIRONMENTAL

The risks related to the environmental aspect of power plants with CO_2 capture are not necessarily related to scale, but there are some significant risks related to the processes and the regulations for these types of plants. One of the foremost risks is that regulations on CO_2 emissions are still being developed in many countries, and the potential environmental impacts of capture technologies are largely undefined. In addition, the regulation of CO_2 after it is captured and compressed (outside the scope of this study) is not fully defined in most countries. Recently, the United States Environmental Protection Agency (USEPA) has proposed New Source Performance Standards that would limit the CO_2 emissions for new, large facilities (>25 MW) to approximately the emissions of a natural gas combined cycle plant. Black & Veatch considers the environmental risk to be a bleeding edge risk.

A significant environmental concern related to power plants with CO_2 capture is the amine solvent that is vented to the atmosphere along with the flue gas. For example, MEA is a common chemical that in large doses can have adverse effects on the nervous system and digestive system. However, less is known about the impact of lower exposure over longer periods of time. Although the water wash, overhead, and demister on the absorber column are able to reduce the amine concentration to a few parts per million, it might be necessary to further reduce the concentration of the amine in the exiting flue gas with an additional wash, acid wash, or specialized mist elimination devices. Less is known about other, newer amines, and as these are developed, extensive environmental impact testing should be undertaken.

In addition to amine emissions, another significant concern is the formation of nitrosamines and nitramines, either directly in the capture plant flue gas or later in the environment. Various nitrosamines are known to be carcinogenic in animals and potentially in humans. Less is known about nitramines, but they also have the potential to be toxic and/or carcinogenic. Currently, Norway appears to be at the forefront of this issue and has performed a study investigating concerns associated with nitrosamine and nitramine emissions from CO_2 capture facilities. Emissions limits are recommended for both.[1]

More research is needed in the area of environmental impacts in order to reduce the environmental risks associated with CO_2 capture. While the requirements and regulations for emissions of amine compounds is considered bleeding edge, the technology required for amine emissions reduction specifically related to amines and amine compounds is considered leading edge.

When a flue gas is discharged, the factors that affect air quality are related to both the concentration of the contaminant in the flue gas and how far it is dispersed. In addition, for large-scale plants, the quantity of contaminants emitted is larger than for small-scale plants, and better dispersion is usually required. The dispersion of contaminants in a typical power plant is accomplished in large part by the buoyancy of the hot (usually 120° C or more) flue gas as it exits

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[1] Health Effects of Amines and Derivatives Associated with CO_2 Capture. Norwegian Institute of Public Health, April 2011.

the stack. Because amines need to be cool in order to obtain good CO_2 absorption, the flue gas that exits the stack does not have as much buoyancy and will not disperse as well as a hot flue gas. Detailed study will be required on a plant-specific basis to determine whether a given plant will have emissions issues, and the risks will depend heavily on the emissions regulations for the specific location. Larger plants will likely have greater risks than smaller plants because of the larger quantity of emissions for which there is currently limited experience (e.g., amines, nitrosamines, nitramines).

If plume visibility is an issue and education of the affected parties is not viable, one option would be to add superheat to the vent stream. With some amount of additional complexity in the absorber, superheat could be added to the vent stream using heat available from the air quality control system (AQCS) and capture systems. While there would be a small penalty related to the higher pressure drop from the heater, this would allow plume abatement with minimal additional energy penalty and would not be a function of scale, since the heat exchange equipment would be part of the base design.

The amine capture system may produce waste streams such as reclaimer bottoms that should be disposed of offsite, but no liquid wastewater stream is expected apart from the typical wastewaters generated from power plants with WFGD systems (e.g., cooling tower blowdown, FGD bleed streams). Excess water from the capture and compression process would be used as cooling tower makeup. The predicted excess water volumes are very small compared with cooling tower needs and the associated risks are not affected by scale.

In addition to the air emissions, the CO_2 capture power plant will have to dispose of spent amine products and solid HSS that are formed from the reaction of oxygen, SO_2, and NO_2 with the amine. These are typically reclaimed from the solvent using a vendor-specific process such as ion exchange or distillation. The resulting waste, either a liquid or sludge with heavy concentration of the HSS, would likely be classified as a hazardous waste, depending on local regulations, and would need to be disposed of in an appropriate landfill. While disposal of this waste is manageable for small demonstration facilities, it may be more problematic with large-scale facilities. Black & Veatch has estimated that the spent amine/HSS waste from the SCPC and NGCC reference cases is approximately 146 and 108 kg/h, respectively. Disposal of this quantity of hazardous waste will be expensive on a large scale and may be difficult, depending on the capacity of nearby disposal facilities. More investigation is recommended into the properties and quantities of wastes generated by the various technologies and acceptance of this waste by waste disposal facilities.

5.6 CAPTURE PLANT STARTUP AND SHUTDOWN ISSUES

The operational requirements for starting up or shutting down a power plant that is highly integrated with a CO_2 capture plant is considered leading edge. The capture plant will be started in sequence with the power plant. The amine circulation pumps will need to be started first to wet the packing in the absorber and stripper. After the amine is circulating, flue gas can be introduced into the absorber. The cold amine will immediately start absorbing CO_2 from the flue gas stream, and the amine will begin to heat up because of the heat of reaction of amine with CO_2. Part of the CO_2 will be driven off from the amine when it is flashed going into the stripper, but the return amine stream will still contain a larger than desirable fraction of CO_2 until steam is introduced into the stripper reboiler to bring the amine up to temperature and drive off the CO_2. The CO_2 that is driven off in the stripper will need to be vented to atmosphere until there is enough volume to start the first CO_2 compressor. The CO_2 compressors can be started up in sequence, with the CO_2 being vented from the discharge of each compressor as they are started until the dehydration can be started and reduce the moisture in the CO_2 to a level that is adequate for introduction into the pipeline. Vented CO_2 will need to be warm enough and/or discharged at a high enough velocity to provide good dispersion. Otherwise, the CO_2 could accumulate and cause a suffocation hazard.

Because the CO_2 must be vented until significant forward flow is established, some method of dispersing the CO_2 is needed to avoid accumulation and potentially hazardous conditions on the ground beneath the vent. The best method for dispersing this stream is to return it to the absorber stack where it can be safely entrained with the flue gas. An alternative method could be a dedicated CO_2 purge stack, high enough to sufficiently disperse the CO_2 stream into the atmosphere during startup; this option would add significantly to capital cost.

Shutdown procedures for the plant would be almost the reverse order of steps as those for startup, starting with venting CO_2 from the regenerator to the atmosphere (through the stack) and reducing the steam. The power plant could potentially be run with only amine circulation, but the CO_2 capture plant should not be run dry for long periods. Only after the flue gas to the absorber is discontinued should the amine circulation be discontinued.

Another effect of operation of the CO_2 capture plant during shutdown and startup conditions is the increased degradation of the amine from potentially higher NO_2 and SO_2 in the flue gas. Because the WFGD and polishing scrubber take time to start up and shut down, the SO_x emissions during startup and shutdown are expected to be higher than during normal operation. The NO_x would also be higher because the low NO_x burners are tuned to emit the minimum NO_x during normal operation, and off-design operation produces higher concentrations of NO_x. In addition, the SCR system would take some time to reach temperature. The consideration of these contaminants would indicate that the plant should be ideally operated as a baseload plant.

If a CO_2 export pipeline outage occurred, the CO_2 would have to be vented. For short pipeline outages, it can be vented to the absorber stack from the compressor discharge. For longer or planned outages, it would be desirable to vent upstream of the compressors, but this would require large, LP piping from the stripper overhead to the absorber vent stack. Further optimization of this operating condition must be performed during detailed engineering. Because of the potential for large, HP piping and large compressors operating in different modes, this scenario must be considered when designing CO_2 delivery systems of this scale.

5.7 RETROFIT ISSUES

With the high capital cost of capture, it is expected that most full-scale capture facilities will be incorporated into new plants to amortize the capital costs over a maximum plant life. Older, less efficient plants are more likely to simply shut down rather than retrofit expensive CO_2 capture equipment, which must be amortized over a shorter time scale. However, it is still likely that some existing facilities, particularly newer facilities, will choose to retrofit CO_2 capture in order to meet GHG emissions targets. Issues associated with the retrofit of CO_2 capture, particularly on a large scale, are discussed below. It should be noted that although there are challenges associated with the retrofit of an older plant, there are no engineering design requirements known that cannot be addressed in the normal course of project execution.

5.7.1 Plot Space

In general, the plot space required for a retrofit CO_2 capture installation should be the same as for a new installation, assuming plants with similar heat rates burning similar fuel. Major equipment such as absorbers, strippers, CO_2 compressor(s), heat exchangers, and pumps would not be different in size simply because the facility is a retrofit application. However, most existing power plants were not designed with CO_2 capture in mind and may have limited space available close to the plant back end. This will result in layouts that are not optimized and will require more plot space than an optimized layout. In particular, plot space required for ductwork runs, pipe racks interfacing with the existing plant, and cooling water piping may be greater than for an optimized design. Some retrofit applications may necessitate separation of the capture equipment into more than one area (for example, absorption and regeneration equipment), further increasing plot space requirements. In addition, retrofit applications may require somewhat more room for cooling equipment, flue gas fan(s), and polishing scrubber equipment than greenfield applications where this equipment is integral to the original design.

Retrofit of CO_2 capture equipment to large-scale power plants, such as the reference case 900 MW coal fired SCPC and 800 MW NGCC plants, is not expected to present additional issues compared to non-retrofit applications, other than somewhat larger space requirements in some cases.

In addition to higher capital costs and design challenges, a retrofit installation will probably result in higher operating and repair costs because of more difficult access to equipment for maintenance.

5.7.2 Steam Generator/Flue Gas Path Design

The flue gas path design, particularly the fans and gas path wall strength, is considered to be commonplace. The large system resistance needed for the CO_2 capture equipment causes increased costs for the draft fans required. Additional pressure capability of approximately 13.8 kPa(g) (55 inches of water gauge [in. wg]) at the CO_2 capture inlet will more than double the flue gas system resistance in most units. In addition to the very large ID fans required to overcome this system resistance, it is likely that the boiler, ductwork, and flue gas equipment will need to be stiffened to withstand the increased implosion potential created by the large ID fans. Stiffening of the boiler, ductwork, and flue gas equipment is an expensive, time intensive, and labor intensive process. Stiffening involves stripping off all lagging and insulation, adding structural members, and installing new insulation and lagging. This process is estimated to require approximately a 12 week unit outage. This process is also challenging because the existing design might not be conducive to stiffening, which would require significant modifications to implement.

Ideally, if a plant is designed and constructed with consideration for the future addition of CO_2 capture equipment, the plant would be designed for explosion/implosion structural rating associated with the CO_2 capture equipment. Although this will increase the facility's initial cost, it would avoid the long outage for stiffening. Stiffening can also be minimized, and possibly eliminated, through the use of controls optimization during upset conditions. In this case, an emergency bypass to the existing stack might help to minimize the stiffening required.

5.7.3 Ductwork

Retrofit applications will require that the existing flue gas ductwork be modified to allow connection of new ductwork to route flue gas to the new CO_2 capture equipment. For full flow CO_2 capture, the modifications would require the addition of a damper in the existing ductwork to block flue gas flow to the existing stack, as well as a bypass damper to allow flue gas flow to the new capture equipment (assuming the facility may want to operate without the capture plant in service). A second connection to the existing ductwork would also be required if the treated flue gas is to be directed back to the existing stack (as opposed to venting from the top of the absorber, which may be feasible depending on permitting requirements). These modifications would not be unlike the modifications required to retrofit a full flow FGD system and are not anticipated to be an issue associated with scale. Space availability in the existing flue gas ductwork for the tie-in and dampers could be an issue at some facilities.

Depending on space available for the new CO_2 capture equipment, longer runs of new flue gas ductwork may be necessary. The length of the longer duct would be site-specific; however, longer ductwork can significantly increase capital costs for the new ductwork and larger flue gas fan, as well as significantly increase operating costs in the form of fan power to overcome the increased pressure loss in the longer ductwork.

5.7.4 AQCS Modifications

The AQCS technology required for a power plant with CO_2 capture is considered commonplace. SO_2, NO_2, and particulates are absorbed by the amine-based solvents and can degrade them. For most installations, it makes economic sense to reduce SO_2 concentrations below 10 to 20 ppm to minimize solvent reclamation and/or replacement costs. Since most existing plants do not reduce SO_2 to these levels, even with full FGD systems, this necessitates either the addition of a polishing scrubber, modification of the existing FGD system, or a completely new WFGD system, although even the most efficient WFGD systems are not always able to achieve the levels required to minimize solvent degradation. The polishing scrubber can also be incorporated into the flue gas cooling system, which would not affect the existing plant equipment. Modifications to an existing WFGD to lower outlet SO_2 concentrations could potentially include addition of a perforated tray, modification of headers or upgrade of pump capacity, addition of a new spray header, or addition of dibasic acid injection. Additional fan power may be necessary if the pressure drop through the FGD system is increased. The issues associated with AQC equipment modifications are site-specific, but are not a function of scale and are not expected to prevent the retrofit of CO_2 capture to large power generating facilities.

It should be noted that after removal of CO_2 from the flue gas, the concentration of NO_x in the flue gas may actually increase at the stack, even though the mass quantity of NO_x has remained the same or even decreased because of the reduction of CO_2 as a diluent in the stack gas. This effect may require a revision of the NO_x emissions limits in the existing permit.

5.7.5 Steam Cycle Modifications

As explained in Section 5.1, steam is required by the amine-based capture systems to heat the CO_2-rich solvent in the stripper, liberating it from the solvent for compression and transport to sequestration. For new installations, it is anticipated that the steam cycle, and in particular the steam turbine, will be designed assuming the CO_2 capture equipment will be in service essentially at all times. Stated another way, if the CO_2 capture plant is not in service, the power plant would not be capable of generating more power with the steam not being used by the capture plant.

This is in stark contrast to retrofit applications, where the steam cycle is most likely not designed for CO_2 capture, and where the addition of CO_2 capture will likely strand a portion of the steam turbine generator output because of the use of steam from the cycle for solvent regeneration.

A commonly selected practice when studying the impacts of CO_2 capture on an existing facility is to assume that LP steam for regeneration is taken from the IP/LP crossover of the existing steam turbine. This generally results in the least impact to the overall cycle (compared with use of steam from a higher pressure location in the cycle, such as hot reheat), but can result in a host of operational issues. In particular, with sliding pressure operation, steam may not be available at sufficient pressure when the main plant is operating at reduced load. These issues are not necessarily a function of power plant scale, but do increase in severity as a function of the percentage of overall CO_2 generation that is removed in the capture plant. These issues are highly plant-specific. The turbine generator OEM should be consulted in each case and may have specific recommendations with regard to design and operation. LP turbine de-blading, or even removal of a complete LP turbine, may be required.

Another option would be to take steam from a higher pressure location, such as hot reheat, and add a non-condensing steam turbine generator (NCSTG) to let the steam down to the conditions needed by the CO_2 capture system. This would improve operating flexibility of the unit, at the expense of the capital cost and space requirements for the additional steam turbine generator and associated balance-of-plant equipment. This option is likely to make more sense at a larger scale installation to take advantage of the economies of scale in the capital cost of the additional equipment. At smaller scale, a throttling valve/desuperheater could be used in place of a NCSTG, which would be much less efficient but would have a lower capital cost.

In all cases, steam piping must be routed from the main plant area to the CO_2 capture area and the resulting condensate returned to the main plant area. Retrofit applications will likely require longer runs of this piping, but this is not expected to be an issue associated with scale.

5.7.6 Water/Wastewater Impacts

The technology and operation required for water and wastewater treatment in a power plant with CO_2 capture is considered commonplace. The water needs and wastewater generated by a retrofit CO_2 capture plant will generally be similar to a non-retrofit plant, all else being equal, but may be marginally higher because of inefficiencies associated with retrofit designs compared to new plant designs. The primary water usage will be for cooling purposes, whether a cooling tower or once-through cooling system is employed. Water will also likely be generated from cooling of the flue gas. This water should be reusable on the site, since it would be of reasonably good quality and might be used, for example, as makeup to the cooling tower, makeup to the FGD, or for ash handling. With the diversion of a significant amount of steam from the condenser for use in the capture plant, a significant fraction of the main plant cooling capacity will be freed for potential use by the capture plant. Water usage and wastewater discharge limitations are highly site-specific, so any detailed analysis of water and wastewater impacts would be site-specific as well.

5.7.7 Electrical Interconnection

The electrical power requirements for a retrofit CO_2 capture system will generally be the same as for a new plant design, although they could be slightly higher because of inefficiencies associated with retrofit. A new auxiliary power transformer and switchgear will likely be required for a retrofit application; whereas CO_2 capture power needs can be designed into the main plant auxiliary power design for a new plant installation. Electrical power requirements will not be limited by scale for retrofit applications any more than they would for new plant installations.

5.7.8 Constructability

Because of the size and complexity of CO_2 capture equipment, careful planning will be required in a retrofit installation to allow construction to proceed at a reasonable pace while minimizing impact to the operating power plant. In addition to the plot area needed for the new equipment, significant area will be needed for crane placement to erect the absorber and stripper columns and for equipment laydown. Most of the equipment can be erected while the main unit is still operating, but one or two outages of 2 to 3 weeks each will be required to make connections to the existing plant for flue gas, steam, condensate return, etc. Constructability of a retrofit plant is not a function of scale, but may be site-specific to the extent that a given power plant simply does not have enough available space to allow for crane placement and laydown.

6.0 Gaps and Technical Challenges

In the following sections, gaps and areas for technical development of large-scale CO_2 capture are addressed. A summary of suggested areas of focus and potential improvements is presented in Table 6-1. No real technical gaps were identified. However, Black & Veatch did identify a number of areas in which further development efforts could result in improvements. Challenges of large-scale CO_2 capture related to policy and economics are addressed in Section 8.0.

Table 6-1 Summary of Potential Areas of Improvement

AREA OF FOCUS	POTENTIAL IMPROVEMENTS
Absorber	• Further research into methods of construction and transport could be explored.
Stripper	• Use of a lean/semi-lean stripper has the potential to reduce the amine circulation rate and the steam requirement, but may not be economical. • Further research into methods of construction and transport could be explored.
Steam Generator	• Stiffening beyond what is typically utilized for both SCPC and NGCC units would be required because of the higher operating pressure requirements. Development of less expensive means of stiffening could reduce cost.
Fans	• The flue gas pressure might require two flue gas fans in series. New fan designs with increased pressure and flow rate capabilities would allow for a potential reduction in the number of fans required and could reduce overall footprint and cost.
Flue Gas Cleanup	• SO_2 removal efficiencies necessary to minimize amine solvent degradation push the limits of current offerings and could potentially necessitate the use of two desulfurization stages. Commercial development and demonstration of more efficient desulfurization systems could reduce footprint and cost.
Heat Exchangers	• Larger heat exchangers would simplify layout and construction. • Further study of process temperatures to optimize heat transfer surface, amine degradation, and process steam requirements could improve project economics.
Heat of Compression	• In an SCPC plant, the heat of compression from the CO_2 compressor coolers could potentially be used to heat condensate to increase steam turbine output. However, the added cost and complexity may not be economical. • In an NGCC plant, use of heat from the CO_2 compressor coolers would likely not be beneficial and could increase flue gas temperature at the quench cooler, which would adversely affect plant performance.
CO_2 Drying	• The technology required for CO_2 drying is commonplace. No significant improvements are expected for this process. However, research into the water-carrying capacity of CO_2 steams with small amounts of various impurities has the potential to allow further optimization of these systems.
Advanced Controls	• The controls required for integrated operation of a power plant with CO_2 capture are available, but need to be demonstrated in a large-scale plant.
Operating Flexibility	• Research the effectiveness and costs associated with carbon capture processes on plants operating in load following mode. This might include dynamic modeling of the systems to determine reaction times to operational changes.
Additional NGCC Considerations	• Exhausting the flue gas from the gas turbine at a higher pressure would eliminate the need for separate flue gas booster fans, resulting in a smaller footprint and cost savings. However, further extensive development of gas turbine package designs would be required.

6.1 ABSORBER

The absorber required for large scale CO_2 capture is the single largest technical challenge for designing and constructing a full-scale CO_2 capture facility. However, the technology required is likely available from several vendors with large scale absorption tower experience. Absorbers used in the hydrocarbon processing and chemical industries are typically not more than about 7 m to 8 m in diameter and use cylindrical construction. A span of about 7 m to 8 m is a practical limit for absorber column design based on support of the column internals. The required theoretical diameter of the absorber in both the SCPC and NGCC capture cases is approximately the same, and is calculated based on the vapor and liquid loadings. Although the liquid loading is much larger in the SCPC case than the NGCC case, the theoretical diameter is primarily determined by the vapor loading, which is slightly larger for the NGCC case. Black & Veatch considers large scale absorption technology for carbon capture to be leading edge.

Because of the large amount of flue gas that needs to be processed in both the SCPC and NGCC cases, the necessary cross-sectional area is much greater than can typically be provided by a single absorber of this size. Full-scale CO_2 capture will require the use of either a single rectangular absorber with multiple parallel sections or multiple cylindrical absorbers. Multiple absorbers can result in piping, ductwork, and layout requirements that are complicated and expensive. The specific absorber design will vary by technology provider, but many proposals for large-scale CO_2 capture absorbers use a rectangular design with the exterior structure made of concrete or steel, and the internal support structure made of stainless steel. For the reference cases, Black & Veatch has selected a single rectangular concrete absorber structure with multiple parallel sections, which should be technically feasible to design and construct. Although traditional round absorbers could theoretically be constructed at the required very large scale, the field construction cost would be more expensive. Until full-scale CO_2 capture is well developed, it is unlikely that the required investment in engineering and construction techniques will be sufficient to consider developing those types of absorbers. Even then, a compelling case would have to be made to motivate engineers to develop such technology. The choice of liner material is not considered an important parameter (lined and clad vessels are common in industry) and is not a challenge related to the scale of the absorber.

While this type of construction for an absorber is not unprecedented, the use of rectangular cross sections instead of circular requires that special care be taken to account for the unique hydrodynamics related to the rectangular shape. In particular, the shear stress at the corners will be greater than the shear stress at the wall away from the corners. Although these effects must be accounted for, the effects are well characterized and do not present a special problem to the design of a rectangular cross section. Although using fewer sections would decrease wall effects at the corners, the practical limit of the span length is approximately 7.5 m, as previously explained. Also, because there are multiple side draws and feeds along the vertical dimension of the absorber, the parallel sections of the absorber should have at least one wall in common with the concrete structure exterior.

The construction of such a large concrete structure will not be simple, but the same techniques used to build large stacks can be used to construct the absorber concrete structure. More precision will be required to achieve the correct internal dimensions and feeds for the absorber, but Black & Veatch does not believe that its construction will pose inordinate challenges to a competent construction company. The internal support structure and tolerances will also be feasible for a competent construction company. The construction of the internal packing will be similar to the construction and installation of typical absorbers because of the parallel sections.

One additional challenge related to large absorbers (and strippers) is that as new, advanced amines are developed, physical property information will have to be collected to allow the confident design and construction of these large units. While these gaps and challenges are manageable, it will perhaps require additional engineering time to manage them.

6.2 STRIPPER

The stripper technology required for the power plant with CO_2 capture is considered commonplace. The stripper for the NGCC case and the two strippers for the SCPC case are quite large for typical amine stripping technology. However, they are not outside of what is considered normal, and Black & Veatch does not believe that there will be significant technological challenges with this part of the CO_2 capture plant. If a single stripper were used for the coal case, the diameter would need to be much larger, but it is not unreasonable to use two strippers to avoid the large diameter requirement with its attendant engineering and construction requirements. A span of 7.5 m is a practical limit to absorber column size because of the requirements for support of the column internals. Each stripper in the reference cases will be about 7 m in diameter and 23 m high.

One proposed advancement to the stripping process that deserves some discussion is the use of a lean/semi-lean stripper configuration, in which a semi-lean stream is taken from the stripper mid-point and introduced into the absorber at an intermediate stage. The semi-lean draw location on the stripper is chosen so that the heat from the rich/lean heat exchanger is sufficient to provide the separation of CO_2 to that location. This has the potential to reduce the amine circulation rate and the steam requirement, but at the low pressure existing in the CO_2 absorber, the difference in CO_2 loading in the amine from the bottom of the absorber compared to the CO_2 loading in the stripper draw location would be so small that it may not be economical.

Depending on the cost of local site labor and the availability and cost for transport of large vessels, the construction of large strippers like those anticipated for the reference cases would likely be done on the site, with transportation of smaller components by truck, rail, or barge. For locations near waterways, it might be possible to build the stripper in multiple vertical segments and transport them via barge for assembly at the site.

Like the absorber, liquid and vapor distribution in the stripper is important, but certainly within the range of existing, proven technology. The main challenge associated with the stripper is transportation because of size. This is very site-specific and may or may not pose a challenge, depending on location.

6.3 STEAM GENERATOR

The steam generator in a power plant with CO_2 capture is considered commonplace, although the walls may require increased stiffening over the non-capture case. A steam generator operating upstream of CO_2 capture equipment will operate in much the same way as it would without CO_2 capture. Coal will still be combusted in suspension, and LNB and OFA systems will remain in operation to reduce NO_x upstream of an SCR system. The plant would likely maximize operating efficiency to the full extent of current state-of-the-art combustion and heat recovery technologies, as the CO_2 removal equipment will add substantial auxiliary power consumption compared to other AQC equipment typically used on an SCPC unit.

Given the larger pressure drops associated with the CO_2 capture equipment compared to conventional AQC equipment, additional steam generator, flue gas equipment, and duct stiffening will be necessary beyond what is typically included for both SCPC and NGCC units because of the high operating pressure requirements.

Stiffening of the steam generator, flue gas equipment, and flue gas ducts should not pose a significant technical challenge to the design and construction of a power plant.

6.4 FANS

The fan technology required for power plants with CO_2 capture is fairly commonplace, but could be considered leading edge in some aspects. Axial ID fans were selected for the reference SCPC plant rather than centrifugal fans because of the lower expected installed cost and higher operating efficiency compared to centrifugal type fans.

The flue gas draft system for the SCPC reference plant with CO_2 capture consists of four axial ID fans located downstream of the PJFF and upstream of the WFGD, with two fans in series and each series pair operating in parallel (2-by-2 arrangement). The CO_2 capture process for the SCPC reference plant requires approximately 13.8 kPa(g) (55 in. wg) of flue gas pressure during normal operation, in addition to the typical SCPC unit flue gas draft pressure losses. The fans are located downstream of the PJFF because the cleaner environment (less particulate) will allow for a more efficient fan design, and upstream of the WFGD and polishing scrubber to avoid operation in a saturated flue gas stream, which would require the use of special corrosion-resistant alloys. The electric auxiliary load required to operate the four axial ID fan motors in the SCPC reference plant with CO_2 capture is about 44 MW compared to approximately 17 MW required to operate the two axial ID fans for the SCPC reference plant without CO_2 capture.

This configuration has the advantage of less expensive fan materials for construction. However, the disadvantages of this configuration are the requirement for unique high-pressure WFGD and polishing scrubber designs, increased implosion protection costs (stiffening of the steam generator and other flue gas equipment/components), and higher fan auxiliary power (caused by the relatively high temperature at the fan inlet).

Alternatives to this configuration could include placing two ID fans upstream of the WFGD and placing two ID fans downstream of the polishing scrubber. The different fan configurations would have slightly different auxiliary power consumption. Lower inlet temperature will reduce the specific volume and fan power requirements, but other difficulties (reheater, special material, etc.) would have to be taken into account to determine which arrangement would be preferable. This configuration allows for reduced fan auxiliary load because the inlet temperature of the two downstream ID fans is lower, which would reduce the specific volume of the flue gas. Another advantage of this design is that it would allow for relatively standard WFGD and polishing scrubber designs. However, disadvantages include the need for more expensive fan materials suitable for operating in a corrosive saturated flue gas environment and a higher flue gas temperature to the CO_2 capture process because of the heat of compression from the downstream ID fans. Use of a gas-to-gas heat exchanger or steam coils to heat the flue gas above saturated conditions upstream of the downstream ID fans would result in less expensive fan materials but would result in higher initial costs. All of these alternative methods would result in a higher flue gas temperature entering the CO_2 capture process.

Suppliers are developing new fan designs with increased pressure capabilities and sizes beyond those traditionally associated with axial fans. These new designs, which would allow a potential reduction in the number of axial fans required, should be investigated during detailed design. Some fans have been advertised as providing up to 29.9 kPa(g) (120 in. wg) static pressure rise.

Project economics, CO_2 capture process requirements, and the potential technical design limitations for the WFGD and polishing scrubber systems would need to be evaluated further on a project-specific basis to determine the optimal draft arrangement for a particular application.

Because of the relatively small footprint of the NGCC power plant, two axial fans were selected for the NGCC with CO_2 capture reference case. More discussion on NGCC flue gas fans is presented in Section 6.10.

Overall, flue gas draft fans should not be considered a technical impediment to scaling-up the CO_2 capture process.

6.5 FLUE GAS CLEANUP

The flue gas cleanup technology required for a power plant with CO_2 capture is considered commonplace. The SCPC reference case incorporates separate WFGD and polishing scrubber systems to reduce SO_2 to levels necessary to minimize amine solvent degradation. Less costly solutions requiring less overall footprint could be available now or in the near term. One possible solution would be to integrate the primary and polishing FGD stages into a single SO_2 absorber system. This option is a subject of optimization, not of scale. Black & Veatch does not consider flue gas cleanup to be a technical impediment to scaling up the CO_2 capture process.

6.6 HEAT EXCHANGERS

While the scale of large power plants with CO_2 capture requires the use of multiple trains of heat exchangers in some services, the technology is generally considered to be commonplace. Because heat transfer is a function of surface area, the scale of the heat exchangers needed for the large-scale power plant CO_2 capture is quite large compared to what is currently commercially available. However, it is common practice and relatively straightforward to use multiple heat exchangers in parallel to obtain the required heat transfer.

The stripper reboiler and overhead cooler have the largest duty of the heat exchangers in the CO_2 capture plant. The reboiler in the SCPC reference case requires several heat exchangers to accommodate the large heat transfer over a fairly tight temperature difference. The temperature difference could be increased by increasing the pressure of the steam used for stripping, but this would have an adverse effect on the efficiency of power generation and would increase the thermal degradation of the amine solvent.

The efficiency of the CO_2 capture plant could also be improved by narrowing the approach temperature in the rich/lean heat exchanger. However, this would increase the size (or number) of these heat exchangers. Also, it is considered good design practice to limit the velocity and temperature of the rich amine stream to minimize corrosion and erosion of piping and equipment. For example, if the stripper feed temperature were increased by the use of a lower approach, then release of the absorbed CO_2 would result. This would substantially increase the velocity and erosion potential for the piping, stripper feed nozzle, and feed distributors. For the purpose of this study, the stripper feed temperature has been limited to a value consistent with accepted industry practice for amine systems.

Most of the heat exchangers in the CO_2 capture plant are plate-and-frame exchangers. These were chosen because of the corrosive nature of amine, as well as the space requirements for the large-scale heat exchangers. The main exceptions to this type of exchanger are the stripper reboiler and overhead cooler, where boiling and condensing limit the application of plate-and-frame heat exchange. Additional heating of the stripper feed by even larger exchangers might lower steam requirements. However, for process reasons, the application of larger exchangers to lower the approach is not desirable.

6.7 HEAT OF COMPRESSION

The CO_2 compression technology for large-scale power plants is generally available, but could be improved for efficiency of operation. Black & Veatch believes that the technology should be considered leading edge. One potential improvement to the efficiency of an overall facility with carbon capture plant would be to incorporate heating of condensate or feedwater into the intercoolers and aftercooler of the CO_2 compressor to recover the heat of compression. Given that the maximum desirable temperature at the outlet of a compressor stage is about 175° C, and the compressor discharge must be cooled to about 40° C, Black & Veatch does not believe that preheating boiler feedwater with the heat of CO_2 compression is an economically desirable option. However, the heat of compression could potentially be used to heat condensate. In an SCPC plant of about 900 MW, this could potentially eliminate enough LP extraction steam for condensate heating to increase power production up to 5 MW. Given the small incremental energy savings and increased capital cost and complexity of such a system, this is likely to be considered only for large-scale capture facilities such as the reference case herein.

In an NGCC plant, the temperatures for heat recovery from the CO_2 compressor coolers would correspond approximately to the low temperature economizer. Because eliminating this section of the HRSG would simply result in heat not recovered from the flue gas that would need to be removed in the quench cooler, Black & Veatch does not believe that recovery of the heat of CO_2 compression in a NGCC plant is a beneficial option.

6.8 CO_2 DRYING

The technology required for CO_2 drying is commonplace. CO_2 drying is required in the CO_2 compressor above a pressure of about 34 bar(a). At higher pressures, the CO_2 concentration in the water will increase to the point where the water becomes very corrosive. CO_2 drying can be accomplished by a solid adsorbent or by liquid glycerol or triethylene glycol.

When an adsorbent is used for drying, at least two beds need to be in use; one bed will be in dehydration service, while the other is being regenerated. Regeneration of an adsorbent is accomplished by taking a small slip stream of the dry CO_2 and heating it up before it is passed through the offline adsorbent bed to regenerate it. Upon exiting the adsorbent bed, the moisture-laden CO_2 stream is then cooled to condense and knock-out the majority of the water before it is recycled to the inlet of the bed in dehydration service. The capacity for the CO_2 flows anticipated in a large SCPC or NGCC plant is typical of current commercial practice, and there are no new scale issues.

Glycols can be used in continuous operation, but a vessel for water absorption and a vessel for regeneration are still required. Glycol is circulated from the absorber, where it comes into contact with cool gas and absorbs the water, to the regenerator, where the glycol is heated to drive off the water. Although glycol requires heating similar to an adsorbent, the vent from the glycol will be almost pure water, and no CO_2 venting will be required. The principle disadvantage of glycols for this service is that they are soluble in supercritical CO_2, and glycol losses can be substantial.

Based on previous comparisons, Black & Veatch generally favors the use of a solid bed adsorbent system to eliminate the issues associated with handling and disposal of glycol solutions.

6.9 ADVANCED CONTROLS

The controls required for integrated operation of a power plant with CO_2 capture are generally available, but should be well proven at a small scale before use in a large-scale plant. This is not a scale-up issue, and Black & Veatch believes that the technology should be considered commonplace. The controls required for a power plant with CO_2 capture are not expected to be significantly different from the controls required for other hydrocarbon processing or chemical process plants of this scale. Black & Veatch expects that a full DCS would be required, but that scale will not have an effect on the required controls, as any plant of this size, with or without CO_2 capture, would have advanced controls. The CO_2 capture plant controls could be integrated with the main power plant DCS system, or separate systems could be utilized with a communication data interface.

6.10 OPERATING FLEXIBILITY

It is expected that in the early stages of carbon capture deployment (i.e., very few power plants include carbon capture), new power plants that have been designed and equipped with CO_2 capture will generally operate as baseload units, for two reasons: (1) the plants cannot contribute toward reducing GHG emissions unless they are operating and, (2) owners and developers will not go to the expense of including carbon capture equipment if they only expect to operate it infrequently. Nevertheless, there may be situations where power plants with carbon capture may need to start and stop or ramp up or down to meet local demand. In addition, if carbon capture ever develops to the point that the majority of plants include it, some of the plants will be required to operate in a load-following mode. Generally, the inclusion of carbon capture on a coal fired or combined cycle power plant will not preclude operation in a load-following mode; however, some reduction in carbon capture can be expected during ramp up and, especially, startup while the carbon capture process adjusts to the changing load. It is not entirely clear whether this is an issue that is affected by scale. On the one hand, smaller capture plants may be able to adjust more quickly to changing unit load, but on the other hand, larger units are more likely to be operated as baseload capacity and, therefore, operating flexibility is less of a concern. The inclusion of renewable sources and grid energy storage further complicates the situation. Further research in this area could be beneficial for determining whether operating flexibility is a concern going forward.

6.11 ADDITIONAL NGCC CONSIDERATIONS

The current NGCC reference plant with CO_2 capture incorporates currently available gas turbine and HRSG product offerings. Flue gas is exhausted from each gas turbine at 3.7 kPa(g) (0.5 psig) and leaves the HRSG at atmospheric pressure and 97° C (207° F). Flue gas booster fans boost the pressure to approximately 13.8 kPa(g) (2 psig), and structured packing flue gas coolers reduce the temperature to approximately 32.2° C (90° F) to condition the flue gas to conditions suitable for the CO_2 capture process.

Exhausting the flue gas from the gas turbine at a pressure of approximately 18 kPa(g) (2.6 psig) and cooling the flue gas further in the HRSG would eliminate the need for separate flue gas booster fans, resulting in a smaller footprint, a less complex flue gas path, and, possibly, a slight improvement in the overall power plant efficiency. However, designing for these pressures would require a redesign of the gas turbine package and would result in a significant power generation penalty from the gas turbine. Current gas turbine designs are limited to a discharge pressure of about 6.2 kPa(g) (0.9 psig) or less. An advanced class gas turbine supplier contacted in support of this study said that, technically, there would be no reason why its F-Class turbine offering could not operate at an exhaust pressure of 18 kPa(g). However, due to the higher exhaust pressure, the turbine exhaust would have to be modified to keep exhaust gases from entering the gas turbine enclosure. This change would require a research and design program to develop and would likely require a first time engineering charge. The increase in exhaust pressure could also require redesign of the gas turbine thrust bearing. In addition to design changes required for the gas turbine, the HRSG would be a new design for the required pressures. Constructing a power plant incorporating these design changes is possible but would require additional research, design, and funding. In addition, the choice of suppliers might be limited.

7.0 Design Sensitivities

On the basis of the analysis performed for this project and previous studies, Black & Veatch believes that the design challenges associated with full-scale CO_2 capture systems are related to the maturity of the application. That is, the engineering required for these systems is not new or unknown, however any design at a new or large scale would require careful engineering.

7.1 BREAK POINTS

The rectangular concrete structure of the absorber would enable it to handle very large flows of flue gas from the power plant. However, there could be a point in the flue gas flow where its distribution to the different parallel sections would become onerous, and the associated coolers and pumps would become too tight to fit reasonably close to their associated internal sections. Because of the required side draws and feeds, it would not be desirable to have an internal section that did not have at least one wall in common with the exterior structure. Black & Veatch believes that the maximum number of internal sections that would be desirable is six to eight. This means that the absorber size for both the SCPC and NGCC cases is almost as large as is reasonable but could be increased to accommodate plants of approximately 1,000 to 1,200 MW. The sizes used in this report were calculated from industry standard methods (such as those used by Sulzer Chemtech) using flow rates as presented in Appendix B. The estimated plant size limit is based on expected vapor and liquid loadings scaled from the reference cases at the power output indicated and assumes a span of approximately 7.5 m.

The stripper size for the NGCC case could increase to about 7 m to 8 m and still be a reasonable column size, which means that an NGCC plant larger than about 1,000 MW would require an additional stripper. The 900 MW SCPC case already requires two strippers, and each of these could be slightly larger, but not significantly larger, before an additional stripper would be required. Black & Veatch estimates that an additional stripper would be required for a plant larger than approximately 1,200 MW operating on the design coal.

There are two components to the CO_2 compressor that should be considered in their sizing. The first is the compressor selected for any given stage, and the second is the motor required to drive the compressor. The maximum compressor size for many applications is about 75,000 kW. The maximum available motor size is similar to this figure and is suited to drive the large compressor. Multiple trains of CO_2 compression were selected for the reference cases. The SCPC reference case utilizes two compressor trains of about 37,500 kW each. The NGCC reference case utilizes two compressor trains of about 12,750 kW each. Multiple trains of CO_2 compression are preferred for reliability and turndown reasons, even if the maximum size limit of the compressor or motor is not reached. Electrical drives, such as variable frequency drives, are available at the motor sizes presented. Because of this, Black & Veatch has not identified a definite break point for CO_2 compression design sensitivities for typical power plant designs.

7.2 FUEL TYPE

The CO_2 capture plant design sensitivity to the fuel choice depends largely on the weight percent of carbon in the fuel, the amount of sulfur in the fuel, and the air required for complete combustion and good operation of the power plant. In the NGCC case, these parameters change very little, and there will be no changes in the design because of slightly different fuels.

The coal used in the SCPC case, however, can have an effect on the design of the CO_2 capture plant. Coal with higher fractions of carbon will produce a flue gas with a higher concentration of CO_2. This could improve the performance of the absorber and reduce its height. The size of the stripper and CO_2 compressors for a high carbon fuel are proportional to the CO_2 removed, so the impact on this equipment and steam consumption is minimal. In addition to the carbon, the quantity of air used for combustion will affect the diameter of the absorber. If the flue gas flow rate is higher for coal with a lower heating value, the absorber needs to be larger.

For coals with high moisture that results in a lower specific heating value, the coal boiler efficiency decreases, the fuel consumption and CO_2 generation rates increase, more flue gas is produced per unit of output, and the flue gas has higher concentrations of moisture. The higher flue gas and CO_2 flow rates mean that more CO_2 is produced per unit of power, and the CO_2 capture equipment will increase in size. In addition, the higher concentration of moisture in the flue gas means that the temperature of the flue gas is not cooled as much in the polishing scrubber as water is added to the saturation point. This means that a quench cooler will likely be required for coals with high moisture; whereas, a quench cooler could be optional for coals with lower moisture.

Black & Veatch has performed an alternative summary analysis for a 900 MW coal plant using a typical German brown coal. Key information on the coal and the resulting changes in the equipment are shown in Table 7-1.

Regarding the sulfur in the fuel, a fuel with higher sulfur will require more scrubbing upstream of the CO_2 capture plant, but it will not necessarily change the design of the CO_2 capture plant itself. Likewise, particulates are expected to be reduced to similar levels in appropriately designed particulate reduction equipment (e.g., electrostatic precipitator and/or fabric filter) and not affect the CO_2 capture plant design.

Table 7-1 Comparison of High Heating Value and Low Heating Value SCPC Units

	UNIT	CASE 2	CASE 2A
Fuel Type		Low Sulfur Australian	German Brown Coal
CO_2 Capture	%	90	90
Fuel Input (GCV)	GJ/h	7,815	8,975
Fuel Properties			
Carbon	AR wt%	65.3	31.3
Hydrogen	AR wt%	3.9	2.3
Sulfur	AR wt%	0.7	0.22
Nitrogen	AR wt%	1.3	0.36
Chlorine	AR wt%	0.07	0.02
Oxygen	AR wt%	6.3	11.6
Ash	AR wt%	13.5	3.5
Moisture	AR wt%	9.0	50.7
Gross Calorific Value	kcal/kg	6,270	2,870
Flue Gas Properties Upstream of Absorber			
Flue Gas Flow Rate	kg/h	3,898,000	5,076,000
Flue Gas Temperature	°C	54.0	66.3
CO_2 in Flue Gas	kg/h	702,000	847,500
CO_2 Captured	kg/h	629,000	764,000
Impacts			
Increase in Theoretical Absorber Cross-Sectional Area	%	N/A	30
Boiler Efficiency	% - GCV Basis	88.3	76.9
Flue Gas Fan Auxiliary Load	MW	44.0	58.8
AR wt% - Weight percentage on an as-received basis.			

7.3 CAPTURE PERCENTAGE

Most studies that Black & Veatch has reviewed or been involved with propose 85 to 90 percent capture as a reasonable upper level of capture. The physically limiting factor on the maximum amount of CO_2 that can be captured is the concentration of CO_2 in the flue gas exiting the absorber. The driving force for absorption in the amine is the pressure difference between the CO_2 in the gas and the concentration in the amine. Some additional absorption is possible by lowering the temperature of the flue gas and amine, but Black & Veatch believes that the limit to what is reasonably achievable is not much higher than 90 percent capture.

The percent capture is a key design consideration of the plant, and after the design is set, the percent capture cannot be changed significantly. The percent capture can be reduced by regenerating less in the stripper and returning an amine stream that is higher in CO_2 to the absorber; however, at stripper bottom temperature, higher CO_2 loading of the amine would likely be very corrosive. For this reason, Black & Veatch believes that less than 90 percent CO_2 capture is better achieved by designing the plant for high CO_2 capture (80 to 90 percent) and bypassing a fraction of the flue gas to achieve the desired percent capture. This would generally shrink the size of the absorber proportionally to the reduced flue gas flow through the CO_2 capture plant.

It is often suggested that lower capture percentages can be obtained by lowering the amine circulation rate. This, however, would result in higher rich amine loading and increased corrosion potential. Also, experience with amine units suggests that highly loaded solutions have an increased potential for foaming and generally unstable operation. While this might be possible for short durations with certain amine formulations, Black & Veatch does not recommend this approach for a long-term operation.

7.4 LOW LOAD/CYCLING

For this study, Black & Veatch has assumed that the CO_2 capture plant is an integral part of the power plant and not simply an add-on to an existing or separately designed power plant. The implication of this assumption to the overall plant operation is that if the CO_2 capture plant were to go offline, the steam turbine would not have the capacity to accept the steam that would otherwise be sent to the CO_2 capture process. The steam flow would need to be reduced, with a corresponding reduction in plant electrical output, or the excess steam would need to be dumped to the condenser, which implies that the condenser would be appropriately sized to accept the steam flow and duty. The cooling tower is designed for the heat rejection from the steam regardless of where the steam is condensed, so this should not affect cooling tower size. A comparison of cooling tower and condenser heat duties is presented in Table 7-2.

Table 7-2 Heat Rejection Duty Comparison (GJ/h Basis)

	CASE 1	CASE 2	CASE 2A	CASE 3	CASE 4	CASE 4A
	No Capture	**90% Capture**	**Bypass Capture**	**No Capture**	**90% Capture**	**Bypass Capture**
Cooling Tower Heat Duties						
Power Plant Condenser	3,600	1,700	1,700	1,600	1,000	900
CO_2 Process Heat Rejection	-	2,700	-	-	1,400	-
Process Steam Dump to Condensate	-	-	2,100	-	-	800
Total	***3,600***	***4,400***	***3,800***	***1,600***	***2,300***	***1,700***
Power Plant Condenser Heat Duties						
Power Plant Steam Turbine	3,500	1,600	1,600	1,600	900	900
Process Steam Dump to Condensate	-	-	2,100	-	-	800
Total	***3,500***	***1,600***	***3,700***	***1,600***	***900***	***1,800***

For low load and power plant turndown, the capture plant would have to be designed to consider any reduction in main steam pressure associated with operation of the power plant, which would result in a nearly proportional reduction in crossover steam pressure. During full load operation, as presented in Appendix C, the crossover pressure should be higher than the process steam pressure required for the CO_2 capture plant and sufficient to allow for low-load operation and line losses between the extraction point and stripper columns. A preliminary analysis of this case indicates that the equipment design for this operation would be within the normal scope of a plant design and may not require significant modifications to the CO_2 capture plant amine system. A NCSTG could be incorporated as a means of letting down the pressure from the crossover extraction during full-load operation and then be bypassed during low-load operation. However, there would be a tradeoff between cost and performance.

8.0 Strategy for Commercialization

This section outlines the main drivers for the use of CCS technology and the R&D areas that should be focused upon when developing future CCS units. Design recommendations from Sections 5.0 and 6.0 are incorporated in the discussion on R&D focus in Subsection 8.2.2.

8.1 DRIVERS FOR CAPTURE AND STORAGE USE AND TIMING

Drivers for the use of CCS technology come from three areas, all of which are related: environmental policy, research support, and economics. Currently, most work in CCS is based on funding provided for research, since government policy and economic drivers are insufficient to stimulate large-scale or wide deployment. While some small-scale CCS projects are economic (namely for the food and beverage industry), these are largely niche opportunities that will not be sufficient to promote greater use of the technology. In the future, the use of CO_2 for EOR may act as a strong economic driver for future CCS projects if oil prices remain high and natural CO_2 sources are limited.

8.1.1 Policy

Strong future policy drivers for reducing GHG emissions from the power sector will likely be necessary for there to be widespread adoption of CCS technology. Currently, Europe has the most aggressive GHG reduction targets, but even those are not sufficient to promote the use of CCS technology until after 2020. While some regions of the United States are developing strong GHG policies and the international community is attempting to strengthen binding targets, greater policy efforts in each of these regions will be required to drive widespread CCS use. Major policy initiatives and the effect on CCS timing are outlined below:

- **Europe:** The European Union (EU) is committed to reducing GHG emissions to 20 percent below 1990 levels by 2020. This goal may be increased if other developed and developing nations (largely, the United States and China) set comparable goals. While aggressive 2050 targets have been considered, no binding long-term targets have been set.
- **United States and Canada:** No binding national GHG reduction targets have been set in the United States. The most recent proposal for a national framework had targets for aggregate GHG emissions 3 percent below 2005 levels in 2012, 17 percent below in 2020, 42 percent below in 2030, and 83 percent below in 2050. Additionally, the USEPA has recently taken steps toward regulating GHG emissions through direct promulgation of regulations under authority of the current Clean Air Act. In March 2012, the USEPA set a proposed CO_2 emissions limit for new fossil plants of 455 kg/MWh, slightly higher than the CO_2 emissions from an efficient NGCC. Coal plants could average this amount over 30 years, allowing partial CO_2 capture from the outset or "full" capture later in the operational life. This proposal faces a number of hurdles before future implementation, including a set of legal challenges on the basis of the unusual step of regulating different types of power

plants (coal and gas) uniformly for pollutant emissions. On a regional basis, nine northeastern U.S. states are targeting a 10 percent GHG reduction in the power sector by 2018 relative to a 2009 baseline, and California has a goal to return to 1990 emissions levels by 2020.

Canada has set an emissions target similar to that proposed by the United States (17 percent below 2005 levels by 2020). However, this target is nonbinding and may be adjusted if the United States does not pursue similar emissions reductions.

- **International:** The international community has struggled to develop a set of binding, significant GHG reduction policies. Targets adopted under the Kyoto Protocol have been met with varying success among the signatories. More recently, the United Nations (UN) Conference of the Parties (COP) 17 talks in Durban, South Africa, extended the Kyoto compliance period and established a goal to set new binding emissions reduction targets by 2015. While CCS was included as an allowed technology under the Clean Development Mechanism (CDM) as a result of the Durban talks, it is unclear whether this inclusion will significantly stimulate new CCS projects.

In the absence of a broad carbon policy that sets a strong value on CO_2 to promote significant cuts in emissions, there are other types of policy mechanisms that can be used to stimulate the use of CCS technology. Policy incentives that could be provided for developers of CCS technologies include bonus carbon allowances for power that use CO_2 capture, tax credits, obligations for power that utilize CO_2 capture, or a feed-in tariff that would provide a clear incentive for use of CCS technology. With no strong market driver for the technology today, providing specific incentives in locations looking to stimulate CCS development could create one of the first true markets for the use of CO_2 capture technology.

Most CCS development today is driven by research funding, with additional funding proposed for the near future. In the EU, the legal framework necessary for large-scale capture and storage has been established. Funding has been made available to assist in research programs (such as the NER300 program), along with greater amounts for the development of a "network" of demonstration plants in the next 5 years, with a goal to have commercial plants in place by 2020. In the United States, the Department of Energy (USDOE) has established a number of research initiatives, with an R&D program for CO_2 capture since 1997. Resources have been spent to improve existing capture technologies and explore novel approaches. In 2010, the United States stated a target to have 5 to 10 commercial demonstration projects under way by 2016, although little has happened to make this goal a reality. Other nations, such as China, Japan, Norway, Australia, and Canada, also have research programs under way, some with similar commercial demonstration goals.

8.1.2 Markets

The current potential sources of value for CO_2 come from the sale of carbon credits, use in the food and beverage industry, and use for EOR. The value of carbon credits in the market today is currently too low to make CO_2 capture at fossil plants economical. Given the limited policy drivers expected this decade, relying on carbon market prices alone will likely not be enough to provide a sufficient driver for CO_2 capture until well into the next decade.

If carbon markets will not provide an economic driver, other uses for CO_2 should be considered. Both the food and beverage industry as well as oil and gas producers currently utilize CO_2. The market for the food and beverage industry is small, with an estimated worldwide demand in the 20 to 30 million tonne per year[2] range. To put this in perspective, the one large coal power station in this study could capture roughly 5.5 million tonnes per year, making this market much too small to support CO_2 capture on any significant scale.

A more attractive market would be the use of CO_2 for EOR. The use of mostly naturally occurring CO_2 for EOR is currently ongoing in the United States, with the current prices for oil providing some incentive for greater CO_2 use. U.S. oil exploration company Kinder Morgan has stated that West Texas EOR projects are willing to pay up to \$58 to \$77 per tonne when oil is priced at \$100/barrel[3], although pricing will vary greatly by location. This is approaching the price that would be required for CCS projects to be enacted on a large scale for coal fired power plants. Many of the announced projects in the United States, such as Summit Power's project in Texas, have made selling the captured CO_2 for EOR part of the overall project. Many international non-power based CCS projects, such as Weyburn in Canada, are also driven by the use of CO_2 for EOR or enhanced gas recovery. CO_2-Norway estimates that total North Sea EOR demand is in the 680 million tonne range[4], while the USDOE has estimated economic demand of CO_2 for EOR at nearly 20,000 million tonnes[5]. If crude oil prices remain high and market fundamentals support additional EOR projects, this could be a driver for CCS projects this decade, in lieu of government policy drivers.

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[2] http://www.globalccsinstitute.com/publications/accelerating-uptake-ccs-industrial-use-captured-carbon-dioxide/online/28461?1332447541.

[3] Fox, Charles, Kinder Morgan CO_2 Company, "Creating a Carbon Capture and Storage Business in a Carbon Unconstrained World," MIT Carbon Sequestration Forum VIII, 13 November 2007.

[4] Hustad, Carl, and Austell, J. Micael, "Mechanisms and Incentives to Promote the Use and Storage of CO_2 in the North Sea," *European Energy Law Report I*, pp. 355–380, 2004.

[5] Kuuskraa, V., Van Leewen, T., and Wallace, M., "Improving Domestic Energy Security and Lowering CO_2 Emissions with 'Next Generation' CO_2-Enhanced Oil Recovery (CO_2-EOR)," DOE/NETL-2011/1504, 2011.

A novel market for CO_2 that has not been commercially demonstrated to date is the use of solid carbonates as an aggregate material in cement. Companies in North America, the EU, and Australia are working on developing these processes, which involve CO_2 capture by bubbling flue gases through saline water. The global cement market is quite large, with roughly 3.5 billion metric tonnes used in 2011, and prices near US$100/tonne. Other novel markets for CO_2 capture, such as CO_2 to fuels or chemicals, are being studied, but these routes are too unproven to determine if they have real potential at this stage, and inherent energy requirements may make them unfeasible. The market for CO_2 may dictate the preferred capture technology method.

8.2 POST-COMBUSTION CAPTURE RESEARCH AND DEVELOPMENT

This study looked at the use of amine technology for removal of CO_2, because of its level of technical maturity versus other alternatives. Improvements are theoretically possible for amine-based CCS systems, and alternative post-combustion options exist that could have the potential to further improve CCS performance. This section highlights some of the R&D areas that should be focused on for full-scale post-combustion capture using advanced amines. At the end of this section, specific equipment and environmental research that may be beneficial is addressed.

8.2.1 Areas of Improvement for Amine Solvents

Amine solutions suffer from several operational disadvantages. Most amines are viscous and corrosive liquids that provide relatively limited absorption capacity (mass of CO_2 absorbed per mass of solution) and require a relatively large amount of heat to regenerate the lean solution. Amines also chemically degrade over time and require the addition of large quantities of replacement amine. These issues become even more important when amine technology is applied at scale. Suppliers of amine-based CO_2 capture systems have applied significant research efforts to developing improved amine formulations that minimize the problems associated with common amines such as MEA. Efforts to develop improved amines with higher absorption capacity, better chemical stability, and improved handling characteristics can be expected to continue and intensify as technology suppliers strive to bring improved CO_2 capture systems to the marketplace. Demonstration level tests on flue gases from coal and natural gas fired units have provided technical data to project what effect employing amine-based capture will have on commercial power stations with today's technology. The major concerns with today's post-combustion capture technologies can be organized into the following areas:

- **Absorption Capacity:** The ability of amines to absorb large amounts of CO_2 is fairly limited; absorption is limited to 0.05 to 0.1 kg CO_2 per kg of solution. Improving absorption capacity will allow smaller equipment to be utilized with lower operating costs since less solvent is required.

- **Speed of Absorption:** The rate of absorption is important to designing columns that can meet the level of removal desired at an acceptable unit size and cost. Since a post-combustion unit at a commercial power station will be handling very large amounts of gas, slow absorption rates would create unacceptably large contacting units. Additives have been evaluated to potentially increase the reaction rate and reduce the unit size.
- **Regeneration Energy:** The energy required to break the chemical bond between the solvent and CO_2 during regeneration is significant. Amine regeneration energy ranges from 2,800 to 3,500 kJ/kg CO_2.
- **Solvent Losses and Degradation:** In addition to solvent losses through the stack, the operating conditions present in capture units (such as the presence of oxygen and NO_2) will eventually cause molecular breakdowns, requiring fresh solvent to be added on a continual basis. This can be especially true with complicated amine molecules. In addition, impurities such as sulfur compounds and metals that are present in coal flue gases will lead to the creation of heat stable salts, which leads to additional solvent losses.

While some improvements in the technology are possible, it will be a challenge to greatly reduce the cost of CCS through the use of amines. The main reason for this is that the reaction heat needed to break the bond between amine and CO_2 is relatively fixed with little room for improvement. Improved amine formulations may be able to reduce the heat needed, but the improvements will likely be incremental only.

Besides the use of amines, other types of absorbents being investigated include ammonia, amino acid salts, potassium carbonate, ionic liquids, oligomeric solvents, and enzymes. While not a main part of this investigation, information on the potential of some of these technologies is presented in Appendix G.

8.2.2 Areas for Research and Development Focus

The USDOE outlined improvements[6] in post-combustion capture that have been evaluated in the last 10 years. None of these can be considered major breakthroughs, but combined they have the potential to provide a meaningful reduction in the cost of capture. The potential improvements include the following:

- **Heat Integration and Better Heat Utilization:** Utilizing waste heat or integrating the stripper reboiler into the steam cycle more effectively could reduce parasitic steam losses.
- **Simplification of Equipment:** Changing pump and heat exchanger types can maintain performance while reducing costs.

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[6] Ciferno, J., “Existing Coal Power Plants: CO_2 Retrofit Possibilities and Implications,” U.S. Department of Energy, National Energy Technology Laboratory, April 2008.

- **Reduced Number of Trains:** Having larger diameter equipment could potentially reduce the number of CO_2 removal trains needed, reducing capital cost.
- **Advanced Amine Solvents:** Additives and specialized amine blends can be used to improve performance and lower regeneration and replacement requirements.
- **Reducing Equipment Requirements:** Equipment items such as flue gas coolers could potentially be eliminated, taking advantage of economies of scale.

From an equipment design standpoint, the development of a large CO_2 capture unit, such as those outlined in this study, does not create a set of novel challenges. Large-scale absorbing of impurities using liquid solvents in large vessels has already been accomplished in the petrochemical industry. Items such as appropriate liquid/gas distribution, maintaining required residence times, and handling large quantities of solvent should not create major problems during operation. However, specific areas of focus, identified in Sections 5.0 and 6.0 as part of this analysis, that could be beneficial include the following:

- **Construction and Transport of Equipment:** As identified in Section 6.0, scaling CCS units to commercial scale will require the fabrication and transport of very large pieces of equipment, namely the absorbers and regenerators. Identifying ways to reduce costs associated with constructing and transporting this equipment in place will be helpful for future commercial efforts. Optimization of absorber and stripper design will be an important area that could reduce costs.
- **Heat Integration:** While this study did not attempt to identify and implement heat integration throughout the design, future designs could implement greater heat integration once experience with large-scale operation has been established. Major options for heat integration include the following:
  - Optimized steam extraction locations and conditions.
  - Recovery of energy lost during steam letdown (e.g., through use of a non-condensing steam turbine generator or steam drives for rotating equipment).
  - Optimum location for condensate return.
- **Heat Exchanger Optimization:** Both the rich/lean solvent heat exchanger and stripper reboiler have been identified as locations for potential optimization. The difference in stream temperature in the rich/lean solvent heat exchanger is low, creating a tight approach that will require a large surface area. The efficiency of the CO_2 capture plant could be improved by narrowing the approach temperature in the rich/lean heat exchanger, but the size or number of exchangers would need to be increased further for this to happen. On the stripper reboiler, using higher pressure steam would reduce the size of the exchanger, with the trade-off being lower overall power output. Each of these trade-offs would require techno-economic analysis to determine an optimized design.

- **Modified Equipment Designs:** Equipment that is required in a large-scale CCS facility, both in the power block and in the CCS unit, has not been optimized specifically for this service since no large scale facilities have been built to date. As identified in Sections 5.0 and 6.0, different designs and operating parameters for steam turbines, CO_2 compression (number of stages and number of trains), CO_2 strippers (incorporating a "semi-lean" stripper), and fans (location in the design) could all be potentially considered as ways to improve the overall design.
- **Improved Controls:** Control algorithms to optimize the operation of the power block and the CCS unit for large scale operation have not been demonstrated. These will need to be established for robust performance in large-scale CCS units.
- **Additional Research on CO_2 Removal from Natural Gas Derived Flue Gas:** Much of the development work that has been performed on CCS to date toward large-scale CO_2 capture has been on flue gases from coal power plants, which have a very different composition and greater CO_2 concentrations than natural gas-derived flue gases. Additional research on designs specific to large-scale natural gas units would help to optimize designs and lower costs.

8.2.3 Environmental Research and Development Focus

As mentioned in Section 5.5, there are a number of environmental concerns that may be present in large-scale CCS units that should be investigated more thoroughly prior to widespread commercialization. Many of these concerns involve the permissible exposure level for the solvents and impurities that are entrained in the flue gas emissions. Investigating these items now to the extent possible will smooth the transition and acceptance of CCS technology. Major environmental R&D areas include the following:

- **Establishment of Solvent Emissions Limits:** Any solvent that is being considered for CO_2 capture, be it some type of amine, ammonia, or specialty chemical, will have some level of air emissions due to flue gas entrainment. Since there is such a wide range of solvents being considered, adequate environmental and toxicological impact data do not exist to set permissible exposure levels for each solvent. Solvents being considered for commercial use require that studies performed to help to set these limits. Of particular importance are long-term exposure limits where data for most solvents is lacking.
- **Establishment of Co-Product Emissions and Exposure Limits:** As part of the capture process, co-products are formed such as nitrosamines, nitramines, and heat stable salts. The extent of the co-product production and permissible exposure limits, either as airborne emissions or handled in the waste streams, is not well established. R&D on acceptable levels of exposure to the range of chemicals that are produced in the process is needed to set policy and minimize negative impacts.

- **Flue Gas Buoyancy and Dispersal Studies:** Cooling and treating of flue gas as part of the amine process will change how the flue gas disperses once released into the atmosphere. This could have negative environmental impacts and may require a special stack design to maintain appropriate dispersion. Performing R&D in this area will help to design facilities that are environmentally compliant at the outset and avoid redesign.
- **Handling of Waste Products:** The degradation of solvents used in post-combustion capture creates waste products that must be removed from the solvent loop and properly disposed. Developing systems to efficiently remove waste products and dispose of them in an environmentally sound fashion should be a goal of environmental research.

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Appendix A. Post-Combustion CO_2 Capture Process Scale-Up Challenges Technology Selection

IEA Greenhouse Gas Program
Post-Combustion CO_2 Capture Scale Up Study
Technology Selection

INTRODUCTION AND SUMMARY

A range of different post-combustion capture technologies was considered for use in the IEA GHG Scale-Up Challenges study. The determination of the technology appropriate for detailed analysis was based on a two step analysis. First, Black & Veatch categorized different technologies available based on technical maturity level. Only technologies considered to be "near commercial" and those proposed to the IEA in the scope of work were evaluated further. Second, the selected technologies were evaluated in greater detail for the attributes of greatest importance for use in this study to determine which type should be selected. Key attributes included commercial readiness, cost, availability of data, energy consumption, plant footprint, and reliability.

The primary risk associated with all of the possible CO_2 capture technologies is the status of their development for large-scale, fossil fuel power plants. Several of the technologies have commercial applications in other industries, in particular, the technologies based on amine solvents. However, no CO_2 removal technology has been commercially demonstrated at a large coal or gas fired power plant. Amine technologies have been developed for other applications and for smaller-scale gas fired combined cycle applications. This experience suggests that their use on a larger scale for coal and gas applications is the most feasible at this time.

Taking into account the technical maturity along with other technical and process factors, Black & Veatch recommends the use of an amine solvent as the most appropriate technology for this analysis. Amine technology is suitable for both capture at natural gas and coal-fired power stations, so the same technology is proposed for each.

TECHNOLOGY REVIEW

For the initial technology screening analysis, Black & Veatch focused on a broad range of technologies to identify those with the potential for large-scale field testing on fossil fuel power plants in the near future. On the basis of this review, the technologies were placed in one of the following three categories:

- Research and Development
- Ready for Demonstration
- Near Commercial

The technology most widely available for "near commercial" use is amine. The use of amines for the removal of CO_2 from gas streams is a mature technology. The technology has been used on power plant flue gas streams at a small scale to produce CO_2 for industrial uses; however, the technology has not been applied at the scale of a major thermal power station. In the past the economic drivers may not have been sufficient to encourage further improvement in the technology, so some scope for improvement likely exists.

Currently, there are several companies continuing to develop and commercially market amine technologies. Efforts to improve the technology are primarily focused on reducing the amount of energy required to regenerate the amines, along with reducing the amount of solvent loss due to oxygen degradation and contamination from the formation of heat stable salts. Efforts to make these improvements are primarily focused on use of different amine blends and the use of additives. Some process changes may also improve energy use, including heat integration and better energy use.

The ammonia and amino acid salt technologies share some similarities with the amine technologies as far as the basic process (e.g. use of a stripper and absorber). The ammonia technologies are much less mature than the amine technologies and are being developed specifically for power plant CO_2 capture applications. The ammonia molecule theoretically has a lower regeneration energy requirement; however ammonia is much more volatile than the amines used for CO_2 capture and benefits from a lower operating temperature. Because the ammonia processes are not as mature as the amine processes, there exists a theoretically greater potential for improvement.

Use of a solid sodium carbonate sorbent in a fluidized bed to adsorb CO_2 from the flue gas stream is another option that was considered. The sorbent is regenerated by heating the sodium carbonate in a separate vessel. This technology is still in the research and development phase and is not seen as a viable option for this study.

Conclusions from the technology comparison include the following key items:

- Both amine and chilled ammonia have a significant auxiliary power demand and consume large amounts of steam. A significant portion of the auxiliary power in each case is needed for the additional booster fan and the CO_2 compression system. In addition, the chilled ammonia process requires a significant amount of power for the chillers used to cool the flue gas. The amino acid salt process has the potential to consume less energy than the amine or ammonia processes, but sufficient data is not available for this to be confirmed.

- Based on the current cost estimates, the installed cost for the chilled ammonia process system is believed to be lower than for amine processes. It is unclear what the costs would be for the amino acid salt or sodium carbonate designs without additional detail from the vendors and more detailed analysis.

- The chilled ammonia system has a higher O&M cost due to the usage rate of ammonia, caustic and acid. The O&M costs for the amine systems vary primarily due to the makeup solvent rates. The handling of the solids in the amino acid salt and carbonate cases has the potential to raise the O&M costs when compared to the ammonia and amine technologies.

- The reliability of the carbonate design is projected to be lower due to the current status of technology and the additional equipment required for solids handling.

- Chilled ammonia runs a greater risk of environmental impacts due to fugitive ammonia emissions. The amino acid salt and carbonate designs are likely to have fewer vapor emissions than the other technologies, but could have issues with particulate emissions and solid waste.

- The maturity of amine technology gives it a considerable advantage over the other technologies considered. It is likely that the technology will prove to be scalable to the extent necessary for large power plant application. It is also likely that the chilled ammonia process will also be scalable, though its economics compared to other processes and ultimate competitiveness in the market is still an unknown. The amino acid salt technology will likely have its first demonstration in the next five years, while the timetable for a demonstration of solid carbonate is unknown.

Based on the availability of data, commercial demonstration, and projected performance, Black & Veatch believes that an amine process should be used for the IEA Scale-Up Challenges study for both the coal and natural gas cases. Good data exists for the performance of amine technology, large-scale operational risks are lower due to the operations history, and the benefits of other solvents over amine have yet to be proven with certainty. While alternatives to amine processes are in development, none is yet known to be a superior choice to amine based processes, therefore using amine processes as baseline for this study is appropriate.

Appendix B. CO_2 Absorption Model Data

Reference Case 2 – SCPC, 90% CO_2 Capture

Reference Case 4 – NGCC, 90% CO_2 Capture

Bryan Research & Engineering, Inc.

ProMax® 3.2

with

TSWEET® & PROSIM®

Simulation Report

Project: 900MW Coal 90p Capture w Compression 120307_Promax.pmx

Licensed to Black & Veatch Pritchard, Inc. and Affiliates

Client Name:	**IEAGHG**
Location:	
Job:	
ProMax Filename:	**C:\Documents and Settings\bla49785\Desktop\900MW Coal 90p Capture w Compression 120307_Promax.pmx**
ProMax Version:	**3.2.11188.0**
Simulation Initiated:	**7/17/2012 8:29:46 AM**

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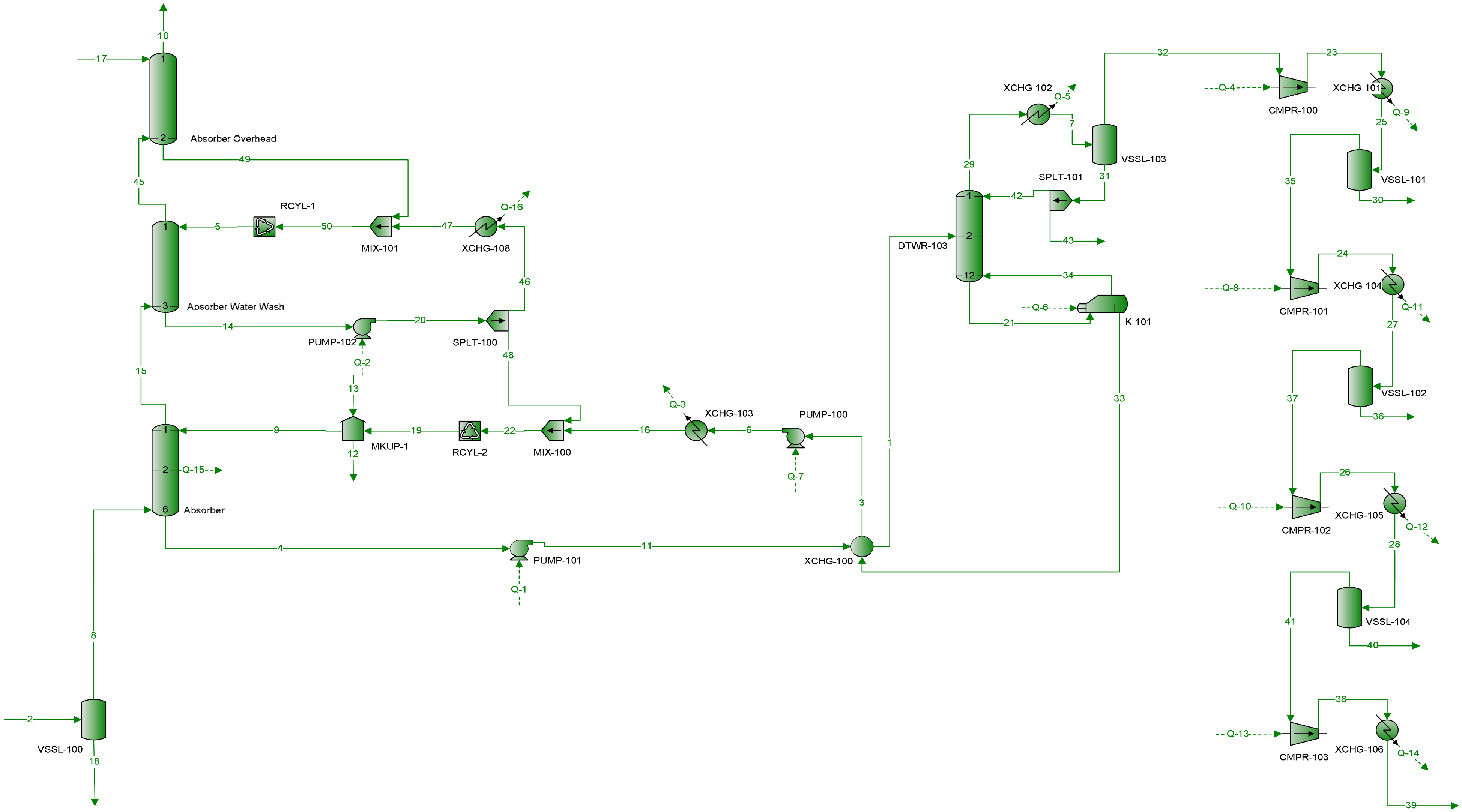
Report Navigator can be activated via the ProMax Navigator Toolbar.
An asterisk (*), throughout the report, denotes a user specified value.
A question mark (?) after a value, throughout the report, denotes an extrapolated or approximate value.


10
17
1
2
Absorber Overhead
49
45
RCYL-1
5
50
47
Q-16
MIX-101
XCHG-108
1
3
Absorber Water Wash
46
14
20
PUMP-102
SPLT-100
Q-2
48
15
13
Q-3
XCHG-103
PUMP-100
1
9
19
22
16
6
MKUP-1
12
RCYL-2
MIX-100
2
Q-15
Q-7
6
Absorber
3
4
11
PUMP-101
XCHG-100
Q-1
8
2
VSSL-100
18
XCHG-102
Q-5
7
32
23
Q-4
CMPR-100
XCHG-101
Q-9
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VSSL-103
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Q-8
CMPR-101
XCHG-104
Q-6
Q-11
K-101
21
27
33
VSSL-102
37
36
26
Q-10
CMPR-102
XCHG-105
Q-12
28
VSSL-104
41
40
38
Q-13
CMPR-103
XCHG-106
Q-14
39

Process Streams		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Composition	**Status:**	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved
Phase: **Total**	**From Block:**	XCHG-100	--	XCHG-100	Absorber	RCYL-1	PUMP-100	XCHG-102	VSSL-100	MKUP-1	Absorber Overhead	PUMP-101	MKUP-1	--
	To Block:	DTWR-103	VSSL-100	PUMP-100	PUMP-101	Absorber Water Wash	XCHG-103	VSSL-103	Absorber	Absorber	--	XCHG-100	--	MKUP-1
Mole Fraction														
Water		0.835774	0.129706*	0.870955	0.835774	0.965448	0.870955	0.812542	0.129706	0.871093	0.121851	0.835774	0.871104	0
Nitrogen		6.51067E-06	0.702195*	0	6.51067E-06	8.02097E-06	0	2.89227E-05	0.702195	1.16639E-08	0.806433	6.51067E-06	1.16640E-08	0
Hydrogen		0	0*	0	0	0	0	0	0	0	0	0	0	0
Carbon Monoxide		0	0*	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide		0.0550950	0.117767*	0.0137669	0.0550950	0.00862026	0.0137669	0.187396	0.117767	0.0137613	0.0139251	0.0550950	0.0137614	0
Methane		0	0*	0	0	0	0	0	0	0	0	0	0	0
Methanol		0	0*	0	0	0	0	0	0	0	0	0	0	0
Ethane		0	0*	0	0	0	0	0	0	0	0	0	0	0
Ethanol		0	0*	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Sulfide		0	0*	0	0	0	0	0	0	0	0	0	0	0
MDEA		0	0*	0	0	0	0	0	0	0	0	0	0	0
O2		8.75937E-07	0.0503164*	0	8.75937E-07	1.09646E-06	0	3.89147E-06	0.0503164	1.59928E-09	0.0577845	8.75937E-07	1.59930E-09	0
MEA		0.108600	0*	0.114725	0.108600	0.0259221	0.114725	2.85105E-05	0	0.114600	5.84982E-06	0.108600	0.114589	1
SO2		0.000523636	1.61643E-05*	0.000553172	0.000523636	0	0.000553172	6.05995E-11	1.61643E-05	0.000545540	0	0.000523636	0.000545546	0
Molar Flow		**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**
Water		78915.3	4876.53*	77846.1	78915.3	663.460	77846.1	17271.7	4876.53	77977.4	3988.96	78915.3	6.57526	0
Nitrogen		0.614748	26400.3*	0	0.614748	0.00551204	0	0.614791	26400.3	0.00104411	26399.7	0.614748	8.80421E-08	0
Hydrogen		0	0*	0	0	0	0	0	0	0	0	0	0	0
Carbon Monoxide		0	0*	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide		5202.16	4427.65*	1230.49	5202.16	5.92388	1230.49	3983.36	4427.65	1231.86	455.855	5202.16	0.103874	0
Methane		0	0*	0	0	0	0	0	0	0	0	0	0	0
Methanol		0	0*	0	0	0	0	0	0	0	0	0	0	0
Ethane		0	0*	0	0	0	0	0	0	0	0	0	0	0
Ethanol		0	0*	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Sulfide		0	0*	0	0	0	0	0	0	0	0	0	0	0
MDEA		0	0*	0	0	0	0	0	0	0	0	0	0	0
O2		0.0827075	1891.74*	0	0.0827075	0.000753495	0	0.0827184	1891.74	0.000143163	1891.65	0.0827075	1.20718E-08	0
MEA		10254.2	0*	10254.1	10254.2	17.8138	10254.1	0.606029	0	10258.6	0.191501	10254.2	0.864941	1.05948
SO2		49.4426	0.607728*	49.4426	49.4426	0	49.4426	1.28812E-06	0.607728	48.8349	0	49.4426	0.00411789	0
Mass Fraction														
Water		0.623498	0.0811308*	0.672271	0.623498	0.898582	0.672271	0.639555	0.0811308	0.672547	0.0805621	0.623498	0.672568	0
Nitrogen		7.55260E-06	0.682980*	0	7.55260E-06	1.16086E-05	0	3.53994E-05	0.682980	1.40031E-08	0.829075	7.55260E-06	1.40036E-08	0
Hydrogen		0	0*	0	0	0	0	0	0	0	0	0	0	0
Carbon Monoxide		0	0*	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide		0.100407	0.179951*	0.0259591	0.100407	0.0195999	0.0259591	0.360328	0.179951	0.0259551	0.0224907	0.100407	0.0259559	0
Methane		0	0*	0	0	0	0	0	0	0	0	0	0	0
Methanol		0	0*	0	0	0	0	0	0	0	0	0	0	0
Ethane		0	0*	0	0	0	0	0	0	0	0	0	0	0
Ethanol		0	0*	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Sulfide		0	0*	0	0	0	0	0	0	0	0	0	0	0
MDEA		0	0*	0	0	0	0	0	0	0	0	0	0	0
O2		1.16068E-06	0.0559021*	0	1.16068E-06	1.81266E-06	0	5.44049E-06	0.0559021	2.19319E-09	0.0678586	1.16068E-06	2.19326E-09	0
MEA		0.274697	0*	0.300252	0.274697	0.0818048	0.300252	7.60880E-05	0	0.3	1.31136E-05	0.274697	0.299978	1
SO2		0.00138914	3.59547E-05*	0.00151838	0.00138914	0	0.00151838	1.69618E-10	3.59547E-05	0.00149781	0	0.00138914	0.00149785	0
Mass Flow		**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**
Water		1421.68	87.8520*	1402.42	1421.68	11.9524	1402.42	311.154	87.8520	1404.78	71.8623	1421.68	0.118455	0
Nitrogen		0.0172212	739.562*	0	0.0172212	0.000154411	0	0.0172224	739.562	2.92491E-05	739.544	0.0172212	2.46636E-09	0
Hydrogen		0	0*	0	0	0	0	0	0	0	0	0	0	0
Carbon Monoxide		0	0*	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide		228.945	194.859*	54.1532	228.945	0.260707	54.1532	175.306	194.859	54.2137	20.0620	228.945	0.00457144	0
Methane		0	0*	0	0	0	0	0	0	0	0	0	0	0
Methanol		0	0*	0	0	0	0	0	0	0	0	0	0	0
Ethane		0	0*	0	0	0	0	0	0	0	0	0	0	0
Ethanol		0	0*	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Sulfide		0	0*	0	0	0	0	0	0	0	0	0	0	0
MDEA		0	0*	0	0	0	0	0	0	0	0	0	0	0
O2		0.00264654	60.5333*	0	0.00264654	2.41109E-05	0	0.00264689	60.5333	4.58103E-06	60.5306	0.00264654	3.86285E-10	0
MEA		626.356	0*	626.354	626.356	1.08812	626.354	0.0370181	0	626.626	0.0116975	626.356	0.0528332	0.0647164
SO2		3.16748	0.0389333*	3.16748	3.16748	0	3.16748	8.25221E-08	0.0389333	3.12855	0	3.16748	0.000263807	0

Process Streams		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Properties	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Total**	**From Block:**	**XCHG-100**	**--**	**XCHG-100**	**Absorber**	**RCYL-1**	**PUMP-100**	**XCHG-102**	**VSSL-100**	**MKUP-1**	**Absorber Overhead**	**PUMP-101**	**MKUP-1**	**--**
	To Block:	**DTWR-103**	**VSSL-100**	**PUMP-100**	**PUMP-101**	**Absorber Water Wash**	**XCHG-103**	**VSSL-103**	**Absorber**	**Absorber**	**--**	**XCHG-100**	**--**	**MKUP-1**
Property	**Units**													
Temperature	K	372.039*	327.2*	351.233	328.032	322.716	351.301	316.483*	327.2	316.595	324.463	328.052	316.597	316.483*
Pressure	Pa	189606*	115509*	186158	115509	109786	620528*	186158	115509	162027	108407	275790*	162027	620528*
Mole Fraction Vapor		0.00703567	1	0	0	0	0	0.196268	1	0	1	0	0	0
Mole Fraction Light Liquid		0.992964	0	1	1	1	1	0.803732	0	1	0	1	1	1
Molecular Weight	kg/mol	0.0241488	0.0288015	0.0233396	0.0241488	0.0193559	0.0233396	0.0228881	0.0288015	0.0233337	0.0272484	0.0241488	0.0233332	0.0610831
Mass Density	kg/m^3	177.958	1.22416	1021.72	1114.15	1000.53	1021.76	8.27936	1.22416	1039.65	1.09559	1114.16	1039.65	998.996
Molar Flow	mol/s	94421.7	37596.8	89380.2	94421.7	687.204	89380.2	21256.4	37596.8	89516.7	32736.3	94421.7	7.54819	1.05948
Mass Flow	kg/s	2280.17	1082.84	2086.09	2280.17	13.3014	2086.09	486.517	1082.84	2088.75	892.011	2280.17	0.176124	0.0647164
Vapor Volumetric Flow	m^3/s	12.8130	884.560	2.04174	2.04656	0.0132944	2.04166	58.7626	884.560	2.00909	814.180	2.04653	0.000169407	6.47814E-05
Liquid Volumetric Flow	m^3/s	12.8130	884.560	2.04174	2.04656	0.0132944	2.04166	58.7626	884.560	2.00909	814.180	2.04653	0.000169407	6.47814E-05
Std Vapor Volumetric Flow	m^3/s	2236.89	890.685	2117.46	2236.89	16.2802	2117.46	503.572	890.685	2120.69	775.538	2236.89	0.178820	0.0250996
Std Liquid Volumetric Flow	m^3/s	2.32028	1.29717	2.08687	2.32028	0.0133512	2.08687	0.526260	1.29717	2.08955*	1.06701	2.32028	0.000176191	6.34870E-05
Compressibility		0.00831777	0.998950	0.00145617	0.000917944	0.000791545	0.00485278	0.195573	0.998950	0.00138147	0.999423	0.00219154	0.00138145	0.0144189
Specific Gravity			0.994438	1.02269	1.11520	1.00147	1.02273		0.994438	1.04063	0.940812	1.11521	1.04063	0.999940
API Gravity				3.17748	-5.42139	8.04901	3.16941			3.18493		-5.42332	3.18525	6.32064
Enthalpy	J/s	-2.70461E+10	-2.88864E+09	-2.51097E+10	-2.74449E+10	-1.95755E+08	-2.51085E+10	-6.46943E+09	-2.88864E+09	-2.54187E+10	-1.11864E+09	-2.74444E+10	-2.14334E+06	-280781
Mass Enthalpy	J/kg	-1.18614E+07	-2.66764E+06	-1.20367E+07	-1.20363E+07	-1.47169E+07	-1.20361E+07	-1.32974E+07	-2.66764E+06	-1.21693E+07	-1.25406E+06	-1.20361E+07	-1.21695E+07	-4.33863E+06
Mass Cp	J/(kg*K)	3787.55	1076.52	3824.83	3497.53	4027.77	3824.40	2989.25	1076.52	3645.24	1100.37	3497.51	3645.28	4173.86
Ideal Gas CpCv Ratio		1.19335	1.36771	1.19395	1.20150	1.28328	1.19394	1.31476	1.36771	1.20050	1.38478	1.20149	1.20051	1.05101
Dynamic Viscosity	Pa*s		1.83221E-05	0.000748897	0.00144945	0.000670305	0.000748875		1.83221E-05	0.00155091	1.85646E-05	0.00144947	0.00155074	0.00900710
Kinematic Viscosity	m^2/s		1.49670E-05	7.32974E-07	1.30095E-06	6.69951E-07	7.32925E-07		1.49670E-05	1.49176E-06	1.69448E-05	1.30095E-06	1.49160E-06	9.01615E-06
Thermal Conductivity	W/(m*K)		0.0266275	0.472454	0.418007	0.573403	0.472485		0.0266275	0.456112	0.0273263	0.418017	0.456121	0.239656
Surface Tension	N/m			0.0575016	0.0859245?	0.0662620	0.0574895			0.0633871		0.0855240?	0.0633873	0.0463017
Net Ideal Gas Heating Value	J/m^3	6.53791E+06	0	6.90666E+06	6.53791E+06	1.56056E+06	6.90666E+06	1716.39	0	6.89913E+06	352.170	6.53791E+06	6.89850E+06	6.02020E+07
Net Liquid Heating Value	J/kg	4.56930E+06	-231311	5.03170E+06	4.56930E+06	-394628	5.03170E+06	-1.63750E+06	-231311	5.02542E+06	-202206	4.56930E+06	5.02488E+06	2.22944E+07
Gross Ideal Gas Heating Value	J/m^3	8.81626E+06	243133	9.29110E+06	8.81626E+06	3.54017E+06	9.29110E+06	1.52501E+06	243133	9.28301E+06	228800	8.81626E+06	9.28233E+06	6.67554E+07
Gross Liquid Heating Value	J/kg	6.80441E+06	-31323.2	7.45199E+06	6.80441E+06	2.02830E+06	7.45199E+06	-60804.5	-31323.2	7.44575E+06	-3587.51	6.80441E+06	7.44521E+06	2.48360E+07

Process Streams		1	2	3	4	5	6	7	8	9	10	11	12	13
Composition	Status:	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved
Phase: **Vapor**	From Block:	XCHG-100	--	XCHG-100	Absorber	RCYL-1	PUMP-100	XCHG-102	VSSL-100	MKUP-1	Absorber Overhead	PUMP-101	MKUP-1	--
	To Block:	DTWR-103	VSSL-100	PUMP-100	PUMP-101	Absorber Water Wash	XCHG-103	VSSL-103	Absorber	Absorber	--	XCHG-100	--	MKUP-1
Mole Fraction														
Water		0.476652	0.129706					0.0479879	0.129706		0.121851			
Nitrogen		0.000923367	0.702195					0.000147353	0.702195		0.806433			
Hydrogen		0	0					0	0		0			
Carbon Monoxide		0	0					0	0		0			
Carbon Dioxide		0.522042	0.117767					0.951845	0.117767		0.0139251			
Methane		0	0					0	0		0			
Methanol		0	0					0	0		0			
Ethane		0	0					0	0		0			
Ethanol		0	0					0	0		0			
Hydrogen Sulfide		0	0					0	0		0			
MDEA		0	0					0	0		0			
O2		0.000124059	0.0503164					1.98246E-05	0.0503164		0.0577845			
MEA		0.000258306	0					6.66570E-12	0		5.84982E-06			
SO2		3.82022E-08	1.61643E-05					0	1.61643E-05		0			
Molar Flow		**mol/s**	**mol/s**					**mol/s**	**mol/s**		**mol/s**			
Water		316.650	4876.53					200.203	4876.53		3988.96			
Nitrogen		0.613411	26400.3					0.614746	26400.3		26399.7			
Hydrogen		0	0					0	0		0			
Carbon Monoxide		0	0					0	0		0			
Carbon Dioxide		346.803	4427.65					3971.04	4427.65		455.855			
Methane		0	0					0	0		0			
Methanol		0	0					0	0		0			
Ethane		0	0					0	0		0			
Ethanol		0	0					0	0		0			
Hydrogen Sulfide		0	0					0	0		0			
MDEA		0	0					0	0		0			
O2		0.0824149	1891.74					0.0827069	1891.74		1891.65			
MEA		0.171598	0					2.78089E-08	0		0.191501			
SO2		2.53785E-05	0.607728					0	0.607728		0			
Mass Fraction														
Water		0.271677	0.0811308					0.0202181	0.0811308		0.0805621			
Nitrogen		0.000818372	0.682980					9.65363E-05	0.682980		0.829075			
Hydrogen		0	0					0	0		0			
Carbon Monoxide		0	0					0	0		0			
Carbon Dioxide		0.726880	0.179951					0.979671	0.179951		0.0224907			
Methane		0	0					0	0		0			
Methanol		0	0					0	0		0			
Ethane		0	0					0	0		0			
Ethanol		0	0					0	0		0			
Hydrogen Sulfide		0	0					0	0		0			
MDEA		0	0					0	0		0			
O2		0.000125595	0.0559021					1.48356E-05	0.0559021		0.0678586			
MEA		0.000499190	0					9.52213E-12	0		1.31136E-05			
SO2		7.74304E-08	3.59547E-05					0	3.59547E-05		0			
Mass Flow		**kg/s**	**kg/s**					**kg/s**	**kg/s**		**kg/s**			
Water		5.70453	87.8520					3.60671	87.8520		71.8623			
Nitrogen		0.0171837	739.562					0.0172211	739.562		739.544			
Hydrogen		0	0					0	0		0			
Carbon Monoxide		0	0					0	0		0			
Carbon Dioxide		15.2626	194.859					174.764	194.859		20.0620			
Methane		0	0					0	0		0			
Methanol		0	0					0	0		0			
Ethane		0	0					0	0		0			
Ethanol		0	0					0	0		0			
Hydrogen Sulfide		0	0					0	0		0			
MDEA		0	0					0	0		0			
O2		0.00263718	60.5333					0.00264652	60.5333		60.5306			
MEA		0.0104817	0					1.69865E-09	0		0.0116975			
SO2		1.62584E-06	0.0389333					0	0.0389333		0			

Process Streams		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Properties	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Vapor**	**From Block:**	**XCHG-100**	**--**	**XCHG-100**	**Absorber**	**RCYL-1**	**PUMP-100**	**XCHG-102**	**VSSL-100**	**MKUP-1**	**Absorber Overhead**	**PUMP-101**	**MKUP-1**	**--**
	To Block:	**DTWR-103**	**VSSL-100**	**PUMP-100**	**PUMP-101**	**Absorber Water Wash**	**XCHG-103**	**VSSL-103**	**Absorber**	**Absorber**	**--**	**XCHG-100**	**--**	**MKUP-1**
Property	**Units**													
Temperature	K	372.039	327.2					316.483	327.2		324.463			
Pressure	Pa	189606	115509					186158	115509		108407			
Mole Fraction Vapor		1	1					1	1		1			
Mole Fraction Light Liquid		0	0					0	0		0			
Molecular Weight	kg/mol	0.0316074	0.0288015					0.0427595	0.0288015		0.0272484			
Mass Density	kg/m^3	1.95425	1.22416					3.05193	1.22416		1.09559			
Molar Flow	mol/s	664.320	37596.8					4171.94	37596.8		32736.3			
Mass Flow	kg/s	20.9975	1082.84					178.390	1082.84		892.011			
Vapor Volumetric Flow	m^3/s	10.7445	884.560					58.4516	884.560		814.180			
Liquid Volumetric Flow	m^3/s	10.7445	884.560					58.4516	884.560		814.180			
Std Vapor Volumetric Flow	m^3/s	15.7380	890.685					98.8352	890.685		775.538			
Std Liquid Volumetric Flow	m^3/s	0.0244399	1.29717					0.217709	1.29717		1.06701			
Compressibility		0.991373	0.998950					0.991186	0.998950		0.999423			
Specific Gravity		1.09132	0.994438					1.47637	0.994438		0.940812			
API Gravity														
Enthalpy	J/s	-2.11339E+08	-2.88864E+09					-1.60850E+09	-2.88864E+09		-1.11864E+09			
Mass Enthalpy	J/kg	-1.00650E+07	-2.66764E+06					-9.01674E+06	-2.66764E+06		-1.25406E+06			
Mass Cp	J/(kg*K)	1196.46	1076.52					891.534	1076.52		1100.37			
Ideal Gas CpCv Ratio		1.28508	1.36771					1.28231	1.36771		1.38478			
Dynamic Viscosity	Pa*s	1.70324E-05	1.83221E-05					1.59294E-05	1.83221E-05		1.85646E-05			
Kinematic Viscosity	m^2/s	8.71553E-06	1.49670E-05					5.21946E-06	1.49670E-05		1.69448E-05			
Thermal Conductivity	W/(m*K)	0.0237942	0.0266275					0.0179288	0.0266275		0.0273263			
Surface Tension	N/m													
Net Ideal Gas Heating Value	J/m^3	15550.5	0					0.000401288	0		352.170			
Net Liquid Heating Value	J/kg	-785027	-231311					-220293	-231311		-202206			
Gross Ideal Gas Heating Value	J/m^3	910727	243133					89953.2	243133		228800			
Gross Liquid Heating Value	J/kg	-114073	-31323.2					-170455	-31323.2		-3587.51			

Process Streams		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Composition	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Light Liquid**	**From Block:**	**XCHG-100**	**--**	**XCHG-100**	**Absorber**	**RCYL-1**	**PUMP-100**	**XCHG-102**	**VSSL-100**	**MKUP-1**	**Absorber Overhead**	**PUMP-101**	**MKUP-1**	**--**
	To Block:	**DTWR-103**	**VSSL-100**	**PUMP-100**	**PUMP-101**	**Absorber Water Wash**	**XCHG-103**	**VSSL-103**	**Absorber**	**Absorber**	**--**	**XCHG-100**	**--**	**MKUP-1**
Mole Fraction														
Water		0.838319		0.870955	0.835774	0.965448	0.870955	0.999243		0.871093		0.835774	0.871104	0
Nitrogen		1.42606E-08		0	6.51067E-06	8.02097E-06	0	2.63378E-09		1.16639E-08		6.51067E-06	1.16640E-08	0
Hydrogen		0		0	0	0	0	0		0		0	0	0
Carbon Monoxide		0		0	0	0	0	0		0		0	0	0
Carbon Dioxide		0.0517864		0.0137669	0.0550950	0.00862026	0.0137669	0.000721163		0.0137613		0.0550950	0.0137614	0
Methane		0		0	0	0	0	0		0		0	0	0
Methanol		0		0	0	0	0	0		0		0	0	0
Ethane		0		0	0	0	0	0		0		0	0	0
Ethanol		0		0	0	0	0	0		0		0	0	0
Hydrogen Sulfide		0		0	0	0	0	0		0		0	0	0
MDEA		0		0	0	0	0	0		0		0	0	0
O2		3.12073E-09		0	8.75937E-07	1.09646E-06	0	6.76245E-10		1.59928E-09		8.75937E-07	1.59930E-09	0
MEA		0.109367		0.114725	0.108600	0.0259221	0.114725	3.54726E-05		0.114600		0.108600	0.114589	1
SO2		0.000527346		0.000553172	0.000523636	0	0.000553172	0		0.000545540		0.000523636	0.000545546	0
Molar Flow		**mol/s**		**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**		**mol/s**		**mol/s**	**mol/s**	**mol/s**
Water		78598.6		77846.1	78915.3	663.460	77846.1	17071.5		77977.4		78915.3	6.57526	0
Nitrogen		0.00133703		0	0.614748	0.00551204	0	4.49966E-05		0.00104411		0.614748	8.80421E-08	0
Hydrogen		0		0	0	0	0	0		0		0	0	0
Carbon Monoxide		0		0	0	0	0	0		0		0	0	0
Carbon Dioxide		4855.36		1230.49	5202.16	5.92388	1230.49	12.3206		1231.86		5202.16	0.103874	0
Methane		0		0	0	0	0	0		0		0	0	0
Methanol		0		0	0	0	0	0		0		0	0	0
Ethane		0		0	0	0	0	0		0		0	0	0
Ethanol		0		0	0	0	0	0		0		0	0	0
Hydrogen Sulfide		0		0	0	0	0	0		0		0	0	0
MDEA		0		0	0	0	0	0		0		0	0	0
O2		0.000292592		0	0.0827075	0.000753495	0	1.15532E-05		0.000143163		0.0827075	1.20718E-08	0
MEA		10254.0		10254.1	10254.2	17.8138	10254.1	0.606029		10258.6		10254.2	0.864941	1.05948
SO2		49.4426		49.4426	49.4426	0	49.4426	0		48.8349		49.4426	0.00411789	0
Mass Fraction														
Water		0.626768		0.672271	0.623498	0.898582	0.672271	0.998120		0.672547		0.623498	0.672568	0
Nitrogen		1.65790E-08		0	7.55260E-06	1.16086E-05	0	4.09088E-09		1.40031E-08		7.55260E-06	1.40036E-08	0
Hydrogen		0		0	0	0	0	0		0		0	0	0
Carbon Monoxide		0		0	0	0	0	0		0		0	0	0
Carbon Dioxide		0.0945843		0.0259591	0.100407	0.0195999	0.0259591	0.00175975		0.0259551		0.100407	0.0259559	0
Methane		0		0	0	0	0	0		0		0	0	0
Methanol		0		0	0	0	0	0		0		0	0	0
Ethane		0		0	0	0	0	0		0		0	0	0
Ethanol		0		0	0	0	0	0		0		0	0	0
Hydrogen Sulfide		0		0	0	0	0	0		0		0	0	0
MDEA		0		0	0	0	0	0		0		0	0	0
O2		4.14426E-09		0	1.16068E-06	1.81266E-06	0	1.19980E-09		2.19319E-09		1.16068E-06	2.19326E-09	0
MEA		0.277246		0.300252	0.274697	0.0818048	0.300252	0.000120139		0.3		0.274697	0.299978	1
SO2		0.00140205		0.00151838	0.00138914	0	0.00151838	0		0.00149781		0.00138914	0.00149785	0
Mass Flow		**kg/s**		**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**		**kg/s**		**kg/s**	**kg/s**	**kg/s**
Water		1415.98		1402.42	1421.68	11.9524	1402.42	307.548		1404.78		1421.68	0.118455	0
Nitrogen		3.74549E-05		0	0.0172212	0.000154411	0	1.26051E-06		2.92491E-05		0.0172212	2.46636E-09	0
Hydrogen		0		0	0	0	0	0		0		0	0	0
Carbon Monoxide		0		0	0	0	0	0		0		0	0	0
Carbon Dioxide		213.682		54.1532	228.945	0.260707	54.1532	0.542225		54.2137		228.945	0.00457144	0
Methane		0		0	0	0	0	0		0		0	0	0
Methanol		0		0	0	0	0	0		0		0	0	0
Ethane		0		0	0	0	0	0		0		0	0	0
Ethanol		0		0	0	0	0	0		0		0	0	0
Hydrogen Sulfide		0		0	0	0	0	0		0		0	0	0
MDEA		0		0	0	0	0	0		0		0	0	0
O2		9.36259E-06		0	0.00264654	2.41109E-05	0	3.69690E-07		4.58103E-06		0.00264654	3.86285E-10	0
MEA		626.345		626.354	626.356	1.08812	626.354	0.0370181		626.626		626.356	0.0528332	0.0647164
SO2		3.16748		3.16748	3.16748	0	3.16748	0		3.12855		3.16748	0.000263807	0

Process Streams		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Properties	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Light Liquid**	**From Block:**	**XCHG-100**	**--**	**XCHG-100**	**Absorber**	**RCYL-1**	**PUMP-100**	**XCHG-102**	**VSSL-100**	**MKUP-1**	**Absorber Overhead**	**PUMP-101**	**MKUP-1**	**--**
	To Block:	**DTWR-103**	**VSSL-100**	**PUMP-100**	**PUMP-101**	**Absorber Water Wash**	**XCHG-103**	**VSSL-103**	**Absorber**	**Absorber**	**--**	**XCHG-100**	**--**	**MKUP-1**
Property	**Units**													
Temperature	K	372.039		351.233	328.032	322.716	351.301	316.483		316.595		328.052	316.597	316.483
Pressure	Pa	189606		186158	115509	109786	620528	186158		162027		275790	162027	620528
Mole Fraction Vapor		0		0	0	0	0	0		0		0	0	0
Mole Fraction Light Liquid		1		1	1	1	1	1		1		1	1	1
Molecular Weight	kg/mol	0.0240959		0.0233396	0.0241488	0.0193559	0.0233396	0.0180356		0.0233337		0.0241488	0.0233332	0.0610831
Mass Density	kg/m^3	1092.18		1021.72	1114.15	1000.53	1021.76	990.513		1039.65		1114.16	1039.65	998.996
Molar Flow	mol/s	93757.4		89380.2	94421.7	687.204	89380.2	17084.4		89516.7		94421.7	7.54819	1.05948
Mass Flow	kg/s	2259.17		2086.09	2280.17	13.3014	2086.09	308.127		2088.75		2280.17	0.176124	0.0647164
Vapor Volumetric Flow	m^3/s	2.06849		2.04174	2.04656	0.0132944	2.04166	0.311078		2.00909		2.04653	0.000169407	6.47814E-05
Liquid Volumetric Flow	m^3/s	2.06849		2.04174	2.04656	0.0132944	2.04166	0.311078		2.00909		2.04653	0.000169407	6.47814E-05
Std Vapor Volumetric Flow	m^3/s	2221.15		2117.46	2236.89	16.2802	2117.46	404.737		2120.69		2236.89	0.178820	0.0250996
Std Liquid Volumetric Flow	m^3/s	2.29584		2.08687	2.32028	0.0133512	2.08687	0.308551		2.08955		2.32028	0.000176191	6.34870E-05
Compressibility		0.00135231		0.00145617	0.000917944	0.000791545	0.00485278	0.00128815		0.00138147		0.00219154	0.00138145	0.0144189
Specific Gravity		1.09322		1.02269	1.11520	1.00147	1.02273	0.991450		1.04063		1.11521	1.04063	0.999940
API Gravity		-4.89398		3.17748	-5.42139	8.04901	3.16941	9.95361		3.18493		-5.42332	3.18525	6.32064
Enthalpy	J/s	-2.68347E+10		-2.51097E+10	-2.74449E+10	-1.95755E+08	-2.51085E+10	-4.86093E+09		-2.54187E+10		-2.74444E+10	-2.14334E+06	-280781
Mass Enthalpy	J/kg	-1.18781E+07		-1.20367E+07	-1.20363E+07	-1.47169E+07	-1.20361E+07	-1.57757E+07		-1.21693E+07		-1.20361E+07	-1.21695E+07	-4.33863E+06
Mass Cp	J/(kg*K)	3811.64		3824.83	3497.53	4027.77	3824.40	4203.73		3645.24		3497.51	3645.28	4173.86
Ideal Gas CpCv Ratio		1.19291		1.19395	1.20150	1.28328	1.19394	1.32384		1.20050		1.20149	1.20051	1.05101
Dynamic Viscosity	Pa*s	0.000628377		0.000748897	0.00144945	0.000670305	0.000748875	0.000628953		0.00155091		0.00144947	0.00155074	0.00900710
Kinematic Viscosity	m^2/s	5.75340E-07		7.32974E-07	1.30095E-06	6.69951E-07	7.32925E-07	6.34977E-07		1.49176E-06		1.30095E-06	1.49160E-06	9.01615E-06
Thermal Conductivity	W/(m*K)	0.435408		0.472454	0.418007	0.573403	0.472485	0.628166		0.456112		0.418017	0.456121	0.239656
Surface Tension	N/m	0.0799090?		0.0575016	0.0859245?	0.0662620	0.0574895	0.0691357		0.0633871		0.0855240?	0.0633873	0.0463017
Net Ideal Gas Heating Value	J/m^3	6.58412E+06		6.90666E+06	6.53791E+06	1.56056E+06	6.90666E+06	2135.52		6.89913E+06		6.53791E+06	6.89850E+06	6.02020E+07
Net Liquid Heating Value	J/kg	4.61906E+06		5.03170E+06	4.56930E+06	-394628	5.03170E+06	-2.45799E+06		5.02542E+06		4.56930E+06	5.02488E+06	2.22944E+07
Gross Ideal Gas Heating Value	J/m^3	8.87228E+06		9.29110E+06	8.81626E+06	3.54017E+06	9.29110E+06	1.87545E+06		9.28301E+06		8.81626E+06	9.28233E+06	6.67554E+07
Gross Liquid Heating Value	J/kg	6.86871E+06		7.45199E+06	6.80441E+06	2.02830E+06	7.45199E+06	2677.60		7.44575E+06		6.80441E+06	7.44521E+06	2.48360E+07

Process Streams		**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Composition	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Total**	**From Block:**	**Absorber Water Wash**	**Absorber**	**XCHG-103**	**--**	**VSSL-100**	**RCYL-2**	**PUMP-102**	**DTWR-103**	**MIX-100**	**CMPR-100**	**CMPR-101**	**XCHG-101**	**CMPR-102**
	To Block:	**PUMP-102**	**Absorber Water Wash**	**MIX-100**	**Absorber Overhead**	**--**	**MKUP-1**	**SPLT-100**	**K-101**	**RCYL-2**	**XCHG-101**	**XCHG-104**	**VSSL-101**	**XCHG-105**
Mole Fraction														
Water		0.956087	0.120478	0.870955	1*		0.871104	0.956087	0.900664	0.871079	0.0479879	0.0100810	0.0479879	0.00302720
Nitrogen		8.01834E-06	0.807533	0	0*		1.16640E-08	8.01834E-06	0	1.16653E-08	0.000147353	0.000153237	0.000147353	0.000154340
Hydrogen		0	0	0	0*		0	0	0	0	0	0	0	0
Carbon Monoxide		0	0	0	0*		0	0	0	0	0	0	0	0
Carbon Dioxide		0.0113181	0.0139897	0.0137669	0*		0.0137614	0.0113181	0.0125197	0.0137633	0.951845	0.989745	0.951845	0.996798
Methane		0	0	0	0*		0	0	0	0	0	0	0	0
Methanol		0	0	0	0*		0	0	0	0	0	0	0	0
Ethane		0	0	0	0*		0	0	0	0	0	0	0	0
Ethanol		0	0	0	0*		0	0	0	0	0	0	0	0
Hydrogen Sulfide		0	0	0	0*		0	0	0	0	0	0	0	0
MDEA		0	0	0	0*		0	0	0	0	0	0	0	0
O2		1.09939E-06	0.0578634	0	0*		1.59930E-09	1.09939E-06	0	1.59941E-09	1.98246E-05	2.06162E-05	1.98246E-05	2.07645E-05
MEA		0.0325857	0.000135215	0.114725	0*		0.114589	0.0325857	0.0864073	0.114605	6.66570E-12	0	6.66570E-12	0
SO2		0	8.33977E-12	0.000553172	0*		0.000545546	0	0.000409073	0.000552367	0	0	0	0
Molar Flow		**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**
Water		622.517	3938.64	77846.1	174.849*	0	77984.0	622.517	108860	77970.6	200.203	40.4421	200.203	12.0575
Nitrogen		0.00522081	26399.7	0	0*	0	0.00104420	0.00522081	0	0.00104416	0.614746	0.614744	0.614746	0.614743
Hydrogen		0	0	0	0*	0	0	0	0	0	0	0	0	0
Carbon Monoxide		0	0	0	0*	0	0	0	0	0	0	0	0	0
Carbon Dioxide		7.36932	457.348	1230.49	0*	0	1231.97	7.36932	1513.21	1231.96	3971.04	3970.58	3971.04	3970.29
Methane		0	0	0	0*	0	0	0	0	0	0	0	0	0
Methanol		0	0	0	0*	0	0	0	0	0	0	0	0	0
Ethane		0	0	0	0*	0	0	0	0	0	0	0	0	0
Ethanol		0	0	0	0*	0	0	0	0	0	0	0	0	0
Hydrogen Sulfide		0	0	0	0*	0	0	0	0	0	0	0	0	0
MDEA		0	0	0	0*	0	0	0	0	0	0	0	0	0
O2		0.000715820	1891.65	0	0*	0	0.000143175	0.000715820	0	0.000143164	0.0827069	0.0827064	0.0827069	0.0827061
MEA		21.2168	4.42041	10254.1	0*	0	10258.4	21.2168	10443.8	10258.4	2.78089E-08	0	2.78089E-08	0
SO2		0	2.72641E-07	49.4426	0*	0	48.8390	0	49.4432	49.4426	0	0	0	0
Mass Fraction														
Water		0.873748	0.0795978	0.672271	1*		0.672568	0.873748	0.734829	0.672518	0.0202181	0.00415162	0.0202181	0.00124148
Nitrogen		1.13946E-05	0.829617	0	0*		1.40036E-08	1.13946E-05	0	1.40044E-08	9.65363E-05	9.81304E-05	9.65363E-05	9.84242E-05
Hydrogen		0	0	0	0*		0	0	0	0	0	0	0	0
Carbon Monoxide		0	0	0	0*		0	0	0	0	0	0	0	0
Carbon Dioxide		0.0252679	0.0225791	0.0259591	0*		0.0259559	0.0252679	0.0249529	0.0259583	0.979671	0.995735	0.979671	0.998645
Methane		0	0	0	0*		0	0	0	0	0	0	0	0
Methanol		0	0	0	0*		0	0	0	0	0	0	0	0
Ethane		0	0	0	0*		0	0	0	0	0	0	0	0
Ethanol		0	0	0	0*		0	0	0	0	0	0	0	0
Hydrogen Sulfide		0	0	0	0*		0	0	0	0	0	0	0	0
MDEA		0	0	0	0*		0	0	0	0	0	0	0	0
O2		1.78456E-06	0.0679030	0	0*		2.19326E-09	1.78456E-06	0	2.19331E-09	1.48356E-05	1.50805E-05	1.48356E-05	1.51256E-05
MEA		0.100971	0.000302899	0.300252	0*		0.299978	0.100971	0.239031	0.300007	9.52213E-12	0	9.52213E-12	0
SO2		0	1.95938E-11	0.00151838	0*		0.00149785	0	0.00118685	0.00151651	0	0	0	0
Mass Flow		**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**
Water		11.2148	70.9558	1402.42	3.14995*	0	1404.90	11.2148	1961.15	1404.66	3.60671	0.728576	3.60671	0.217219
Nitrogen		0.000146253	739.544	0	0*	0	2.92516E-05	0.000146253	0	2.92505E-05	0.0172211	0.0172211	0.0172211	0.0172210
Hydrogen		0	0	0	0*	0	0	0	0	0	0	0	0	0
Carbon Monoxide		0	0	0	0*	0	0	0	0	0	0	0	0	0
Carbon Dioxide		0.324320	20.1277	54.1532	0*	0	54.2183	0.324320	66.5955	54.2181	174.764	174.743	174.764	174.731
Methane		0	0	0	0*	0	0	0	0	0	0	0	0	0
Methanol		0	0	0	0*	0	0	0	0	0	0	0	0	0
Ethane		0	0	0	0*	0	0	0	0	0	0	0	0	0
Ethanol		0	0	0	0*	0	0	0	0	0	0	0	0	0
Hydrogen Sulfide		0	0	0	0*	0	0	0	0	0	0	0	0	0
MDEA		0	0	0	0*	0	0	0	0	0	0	0	0	0
O2		2.29054E-05	60.5306	0	0*	0	4.58142E-06	2.29054E-05	0	4.58108E-06	0.00264652	0.00264651	0.00264652	0.00264650
MEA		1.29599	0.270012	626.354	0*	0	626.614	1.29599	637.937	626.613	1.69865E-09	0	1.69865E-09	0
SO2		0	1.74664E-08	3.16748	0*	0	3.12881	0	3.16752	3.16748	0	0	0	0

Process Streams		**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Properties	**Status:**	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved
Phase: **Total**	**From Block:**	**Absorber Water Wash**	**Absorber**	**XCHG-103**	**--**	**VSSL-100**	**RCYL-2**	**PUMP-102**	**DTWR-103**	**MIX-100**	**CMPR-100**	**CMPR-101**	**XCHG-101**	**CMPR-102**
	To Block:	**PUMP-102**	**Absorber Water Wash**	**MIX-100**	**Absorber Overhead**	**--**	**MKUP-1**	**SPLT-100**	**K-101**	**RCYL-2**	**XCHG-101**	**XCHG-104**	**VSSL-101**	**XCHG-105**
Property	**Units**													
Temperature	K	325.584	326.774	316.483*	302.594*	327.2	316.597	325.591	398.621	316.597	453.849	453.468	310.928*	453.770
Pressure	Pa	111855	112062	599844	127553*	115509	162027	162027*	220632	162027	723950*	2.82685E+06*	689476	1.10661E+07*
Mole Fraction Vapor		0	1	0	0		0	0	0	0	1	1	0.961596	1
Mole Fraction Light Liquid		1	0	1	1		1	1	1	1	0	0	0.0384039	0
Molecular Weight	kg/mol	0.0197130	0.0272677	0.0233396	0.0180153		0.0233332	0.0197130	0.0220809	0.0233343	0.0427595	0.0437448	0.0427595	0.0439281
Mass Density	kg/m^3	1004.41	1.12530	1039.82	995.124		1039.65	1004.42	975.969	1039.66	8.28321	33.9957	12.2731	145.775
Molar Flow	mol/s	651.109	32691.7	89380.2	174.849	0	89523.2	651.109	120867	89510.4	4171.94	4011.72	4171.94	3983.05
Mass Flow	kg/s	12.8353	891.428	2086.09	3.14995*	0	2088.86	12.8353	2668.85	2088.66	178.390	175.492	178.390	174.968
Vapor Volumetric Flow	m^3/s	0.0127789	792.169	2.00620	0.00316538		2.00920	0.0127788	2.73456	2.00898	21.5364	5.16218	14.5351	1.20026
Liquid Volumetric Flow	m^3/s	0.0127789	792.169	2.00620	0.00316538		2.00920	0.0127788	2.73456	2.00898	21.5364	5.16218	14.5351	1.20026
Std Vapor Volumetric Flow	m^3/s	15.4251	774.482	2117.46	4.14224	0	2120.84	15.4251	2863.38	2120.54	98.8352	95.0395	98.8352	94.3601
Std Liquid Volumetric Flow	m^3/s	0.0128947	1.06644	2.08687	0.00315305	0	2.08966	0.0128947	2.67275	2.08945	0.217709	0.214803	0.217709	0.214276
Compressibility		0.000810954	0.999436	0.00511664	0.000917823		0.00138145	0.00117467	0.00150611	0.00138149	0.990366	0.964771	0.929187	0.883860
Specific Gravity		1.00536	0.941480	1.04081	0.996064		1.04063	1.00537	0.976891	1.04065	1.47637	1.51039		1.51672
API Gravity		7.33115		3.16979	10.0113		3.18525	7.33022	4.59014	3.18327				
Enthalpy	J/s	-1.85535E+08	-1.10570E+09	-2.53799E+10	-4.99154E+07	0	-2.54205E+10	-1.85534E+08	-3.35202E+10	-2.54170E+10	-1.58566E+09	-1.54945E+09	-1.61711E+09	-1.54905E+09
Mass Enthalpy	J/kg	-1.44551E+07	-1.24037E+06	-1.21662E+07	-1.58464E+07		-1.21695E+07	-1.44550E+07	-1.25598E+07	-1.21690E+07	-8.88875E+06	-8.82918E+06	-9.06499E+06	-8.85338E+06
Mass Cp	J/(kg*K)	3990.49	1100.36	3643.50	4133.63		3645.28	3990.43	4141.08	3645.17	1015.77	1043.71	947.621	1244.50
Ideal Gas CpCv Ratio		1.27408	1.38443	1.20044	1.32512		1.20051	1.27408	1.20690	1.20050	1.24110	1.23900	1.28462	1.23853
Dynamic Viscosity	Pa*s	0.000667814	1.86643E-05	0.00155840	0.000829453		0.00155074	0.000667807	0.000322953	0.00155091	2.18002E-05	2.22631E-05		2.50271E-05
Kinematic Viscosity	m^2/s	6.64880E-07	1.65861E-05	1.49871E-06	8.33517E-07		1.49160E-06	6.64869E-07	3.30905E-07	1.49174E-06	2.63185E-06	6.54881E-07		1.71683E-07
Thermal Conductivity	W/(m*K)	0.560660	0.0274889	0.455924	0.612417		0.456121	0.560666	0.512920	0.456098	0.0290745	0.0300986		0.0356422
Surface Tension	N/m	0.0652679		0.0633993	0.0719272		0.0633873	0.0652665	0.0498888?	0.0633859				
Net Ideal Gas Heating Value	J/m^3	1.96172E+06	8140.21	6.90666E+06	0		6.89850E+06	1.96172E+06	5.20189E+06	6.89947E+06	0.000401288	0	0.000401288	0
Net Liquid Heating Value	J/kg	92892.0	-193384	5.03170E+06	-2.46500E+06		5.02488E+06	92892.0	3.51291E+06	5.02563E+06	-220293	-183484	-220293	-176817
Gross Ideal Gas Heating Value	J/m^3	3.96745E+06	234863	9.29110E+06	1.87450E+06		9.28233E+06	3.96745E+06	7.45645E+06	9.28336E+06	89953.2	18896.8	89953.2	5674.47
Gross Liquid Heating Value	J/kg	2.50332E+06	3594.22	7.45199E+06	0		7.44521E+06	2.50332E+06	5.93181E+06	7.44591E+06	-170455	-173250	-170455	-173756

Process Streams	14	15	16	17	18	19	20	21	22	23	24	25	26
Composition Status:	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved
Phase: **Vapor** From Block:	Absorber Water Wash	Absorber	XCHG-103	--	VSSL-100	RCYL-2	PUMP-102	DTWR-103	MIX-100	CMPR-100	CMPR-101	XCHG-101	CMPR-102
To Block:	PUMP-102	Absorber Water Wash	MIX-100	Absorber Overhead	--	MKUP-1	SPLT-100	K-101	RCYL-2	XCHG-101	XCHG-104	VSSL-101	XCHG-105
Mole Fraction													
Water		0.120478								0.0479879	0.0100810	0.0100810	0.00302720
Nitrogen		0.807533								0.000147353	0.000153237	0.000153237	0.000154340
Hydrogen		0								0	0	0	0
Carbon Monoxide		0								0	0	0	0
Carbon Dioxide		0.0139897								0.951845	0.989745	0.989745	0.996798
Methane		0								0	0	0	0
Methanol		0								0	0	0	0
Ethane		0								0	0	0	0
Ethanol		0								0	0	0	0
Hydrogen Sulfide		0								0	0	0	0
MDEA		0								0	0	0	0
O2		0.0578634								1.98246E-05	2.06162E-05	2.06162E-05	2.07645E-05
MEA		0.000135215								0	0	0	0
SO2		8.33977E-12								0	0	0	0
Molar Flow		**mol/s**								**mol/s**	**mol/s**	**mol/s**	**mol/s**
Water		3938.64								200.203	40.4421	40.4421	12.0575
Nitrogen		26399.7								0.614746	0.614744	0.614744	0.614743
Hydrogen		0								0	0	0	0
Carbon Monoxide		0								0	0	0	0
Carbon Dioxide		457.348								3971.04	3970.58	3970.58	3970.29
Methane		0								0	0	0	0
Methanol		0								0	0	0	0
Ethane		0								0	0	0	0
Ethanol		0								0	0	0	0
Hydrogen Sulfide		0								0	0	0	0
MDEA		0								0	0	0	0
O2		1891.65								0.0827069	0.0827064	0.0827064	0.0827061
MEA		4.42041								0	0	0	0
SO2		2.72641E-07								0	0	0	0
Mass Fraction													
Water		0.0795978								0.0202181	0.00415162	0.00415162	0.00124148
Nitrogen		0.829617								9.65363E-05	9.81304E-05	9.81304E-05	9.84242E-05
Hydrogen		0								0	0	0	0
Carbon Monoxide		0								0	0	0	0
Carbon Dioxide		0.0225791								0.979671	0.995735	0.995735	0.998645
Methane		0								0	0	0	0
Methanol		0								0	0	0	0
Ethane		0								0	0	0	0
Ethanol		0								0	0	0	0
Hydrogen Sulfide		0								0	0	0	0
MDEA		0								0	0	0	0
O2		0.0679030								1.48356E-05	1.50805E-05	1.50805E-05	1.51256E-05
MEA		0.000302899								0	0	0	0
SO2		1.95938E-11								0	0	0	0
Mass Flow		**kg/s**								**kg/s**	**kg/s**	**kg/s**	**kg/s**
Water		70.9558								3.60671	0.728576	0.728576	0.217219
Nitrogen		739.544								0.0172211	0.0172211	0.0172211	0.0172210
Hydrogen		0								0	0	0	0
Carbon Monoxide		0								0	0	0	0
Carbon Dioxide		20.1277								174.764	174.743	174.743	174.731
Methane		0								0	0	0	0
Methanol		0								0	0	0	0
Ethane		0								0	0	0	0
Ethanol		0								0	0	0	0
Hydrogen Sulfide		0								0	0	0	0
MDEA		0								0	0	0	0
O2		60.5306								0.00264652	0.00264651	0.00264651	0.00264650
MEA		0.270012								0	0	0	0
SO2		1.74664E-08								0	0	0	0

Process Streams		**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Properties	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Vapor**	**From Block:**	**Absorber Water Wash**	**Absorber**	**XCHG-103**	**--**	**VSSL-100**	**RCYL-2**	**PUMP-102**	**DTWR-103**	**MIX-100**	**CMPR-100**	**CMPR-101**	**XCHG-101**	**CMPR-102**
	To Block:	**PUMP-102**	**Absorber Water Wash**	**MIX-100**	**Absorber Overhead**	**--**	**MKUP-1**	**SPLT-100**	**K-101**	**RCYL-2**	**XCHG-101**	**XCHG-104**	**VSSL-101**	**XCHG-105**
Property	**Units**													
Temperature	K		326.774								453.849	453.468	310.928	453.770
Pressure	Pa		112062								723950	2.82685E+06	689476	1.10661E+07
Mole Fraction Vapor			1								1	1	1	1
Mole Fraction Light Liquid			0								0	0	0	0
Molecular Weight	kg/mol		0.0272677								0.0427595	0.0437448	0.0437448	0.0439281
Mass Density	kg/m^3		1.12530								8.28321	33.9957	12.0761	145.775
Molar Flow	mol/s		32691.7								4171.94	4011.72	4011.72	3983.05
Mass Flow	kg/s		891.428								178.390	175.492	175.492	174.968
Vapor Volumetric Flow	m^3/s		792.169								21.5364	5.16218	14.5321	1.20026
Liquid Volumetric Flow	m^3/s		792.169								21.5364	5.16218	14.5321	1.20026
Std Vapor Volumetric Flow	m^3/s		774.482								98.8352	95.0395	95.0395	94.3601
Std Liquid Volumetric Flow	m^3/s		1.06644								0.217709	0.214803	0.214803	0.214276
Compressibility			0.999436								0.990366	0.964771	0.966103	0.883860
Specific Gravity			0.941480								1.47637	1.51039	1.51039	1.51672
API Gravity														
Enthalpy	J/s		-1.10570E+09								-1.58566E+09	-1.54945E+09	-1.57141E+09	-1.54905E+09
Mass Enthalpy	J/kg		-1.24037E+06								-8.88875E+06	-8.82919E+06	-8.95432E+06	-8.85338E+06
Mass Cp	J/(kg*K)		1100.36								1015.77	1043.71	894.268	1244.50
Ideal Gas CpCv Ratio			1.38443								1.24110	1.23900	1.28324	1.23853
Dynamic Viscosity	Pa*s		1.86643E-05								2.18002E-05	2.22631E-05	1.58668E-05	2.50271E-05
Kinematic Viscosity	m^2/s		1.65861E-05								2.63185E-06	6.54881E-07	1.31390E-06	1.71683E-07
Thermal Conductivity	W/(m*K)		0.0274889								0.0290745	0.0300986	0.0178100	0.0356422
Surface Tension	N/m													
Net Ideal Gas Heating Value	J/m^3		8140.21								0	0	0	0
Net Liquid Heating Value	J/kg		-193384								-220293	-183484	-183484	-176817
Gross Ideal Gas Heating Value	J/m^3		234863								89953.2	18896.8	18896.8	5674.47
Gross Liquid Heating Value	J/kg		3594.22								-170455	-173250	-173250	-173756

Process Streams		**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Composition	**Status:**	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved
Phase: Li ght Liquid	**From Block:**	**Absorber Water Wash**	**Absorber**	**XCHG-103**	**--**	**VSSL-100**	**RCYL-2**	**PUMP-102**	**DTWR-103**	**MIX-100**	**CMPR-100**	**CMPR-101**	**XCHG-101**	**CMPR-102**
	To Block:	**PUMP-102**	**Absorber Water Wash**	**MIX-100**	**Absorber Overhead**	**--**	**MKUP-1**	**SPLT-100**	**K-101**	**RCYL-2**	**XCHG-101**	**XCHG-104**	**VSSL-101**	**XCHG-105**
Mole Fraction														
Water		0.956087		0.870955	1		0.871104	0.956087	0.900664	0.871079			0.997142	
Nitrogen		8.01834E-06		0	0		1.16640E-08	8.01834E-06	0	1.16653E-08			1.06588E-08	
Hydrogen		0		0	0		0	0	0	0			0	
Carbon Monoxide		0		0	0		0	0	0	0			0	
Carbon Dioxide		0.0113181		0.0137669	0		0.0137614	0.0113181	0.0125197	0.0137633			0.00285840	
Methane		0		0	0		0	0	0	0			0	
Methanol		0		0	0		0	0	0	0			0	
Ethane		0		0	0		0	0	0	0			0	
Ethanol		0		0	0		0	0	0	0			0	
Hydrogen Sulfide		0		0	0		0	0	0	0			0	
MDEA		0		0	0		0	0	0	0			0	
O2		1.09939E-06		0	0		1.59930E-09	1.09939E-06	0	1.59941E-09			2.77080E-09	
MEA		0.0325857		0.114725	0		0.114589	0.0325857	0.0864073	0.114605			0	
SO2		0		0.000553172	0		0.000545546	0	0.000409073	0.000552367			0	
Molar Flow		**mol/s**		**mol/s**	**mol/s**		**mol/s**	**mol/s**	**mol/s**	**mol/s**			**mol/s**	
Water		622.517		77846.1	174.849		77984.0	622.517	108860	77970.6			159.761	
Nitrogen		0.00522081		0	0		0.00104420	0.00522081	0	0.00104416			1.70773E-06	
Hydrogen		0		0	0		0	0	0	0			0	
Carbon Monoxide		0		0	0		0	0	0	0			0	
Carbon Dioxide		7.36932		1230.49	0		1231.97	7.36932	1513.21	1231.96			0.457968	
Methane		0		0	0		0	0	0	0			0	
Methanol		0		0	0		0	0	0	0			0	
Ethane		0		0	0		0	0	0	0			0	
Ethanol		0		0	0		0	0	0	0			0	
Hydrogen Sulfide		0		0	0		0	0	0	0			0	
MDEA		0		0	0		0	0	0	0			0	
O2		0.000715820		0	0		0.000143175	0.000715820	0	0.000143164			4.43933E-07	
MEA		21.2168		10254.1	0		10258.4	21.2168	10443.8	10258.4			0	
SO2		0		49.4426	0		48.8390	0	49.4432	49.4426			0	
Mass Fraction														
Water		0.873748		0.672271	1		0.672568	0.873748	0.734829	0.672518			0.993046	
Nitrogen		1.13946E-05		0	0		1.40036E-08	1.13946E-05	0	1.40044E-08			1.65061E-08	
Hydrogen		0		0	0		0	0	0	0			0	
Carbon Monoxide		0		0	0		0	0	0	0			0	
Carbon Dioxide		0.0252679		0.0259591	0		0.0259559	0.0252679	0.0249529	0.0259583			0.00695409	
Methane		0		0	0		0	0	0	0			0	
Methanol		0		0	0		0	0	0	0			0	
Ethane		0		0	0		0	0	0	0			0	
Ethanol		0		0	0		0	0	0	0			0	
Hydrogen Sulfide		0		0	0		0	0	0	0			0	
MDEA		0		0	0		0	0	0	0			0	
O2		1.78456E-06		0	0		2.19326E-09	1.78456E-06	0	2.19331E-09			4.90128E-09	
MEA		0.100971		0.300252	0		0.299978	0.100971	0.239031	0.300007			0	
SO2		0		0.00151838	0		0.00149785	0	0.00118685	0.00151651			0	
Mass Flow		**kg/s**		**kg/s**	**kg/s**		**kg/s**	**kg/s**	**kg/s**	**kg/s**			**kg/s**	
Water		11.2148		1402.42	3.14995		1404.90	11.2148	1961.15	1404.66			2.87813	
Nitrogen		0.000146253		0	0		2.92516E-05	0.000146253	0	2.92505E-05			4.78394E-08	
Hydrogen		0		0	0		0	0	0	0			0	
Carbon Monoxide		0		0	0		0	0	0	0			0	
Carbon Dioxide		0.324320		54.1532	0		54.2183	0.324320	66.5955	54.2181			0.0201550	
Methane		0		0	0		0	0	0	0			0	
Methanol		0		0	0		0	0	0	0			0	
Ethane		0		0	0		0	0	0	0			0	
Ethanol		0		0	0		0	0	0	0			0	
Hydrogen Sulfide		0		0	0		0	0	0	0			0	
MDEA		0		0	0		0	0	0	0			0	
O2		2.29054E-05		0	0		4.58142E-06	2.29054E-05	0	4.58108E-06			1.42053E-08	
MEA		1.29599		626.354	0		626.614	1.29599	637.937	626.613			0	
SO2		0		3.16748	0		3.12881	0	3.16752	3.16748			0	

Process Streams		**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Properties	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Light Liquid**	**From Block:**	**Absorber Water Wash**	**Absorber**	**XCHG-103**	**--**	**VSSL-100**	**RCYL-2**	**PUMP-102**	**DTWR-103**	**MIX-100**	**CMPR-100**	**CMPR-101**	**XCHG-101**	**CMPR-102**
	To Block:	**PUMP-102**	**Absorber Water Wash**	**MIX-100**	**Absorber Overhead**	**--**	**MKUP-1**	**SPLT-100**	**K-101**	**RCYL-2**	**XCHG-101**	**XCHG-104**	**VSSL-101**	**XCHG-105**
Property	**Units**													
Temperature	K	325.584		316.483	302.594		316.597	325.591	398.621	316.597			310.928	
Pressure	Pa	111855		599844	127553		162027	162027	220632	162027			689476	
Mole Fraction Vapor		0		0	0		0	0	0	0			0	
Mole Fraction Light Liquid		1		1	1		1	1	1	1			1	
Molecular Weight	kg/mol	0.0197130		0.0233396	0.0180153		0.0233332	0.0197130	0.0220809	0.0233343			0.0180896	
Mass Density	kg/m^3	1004.41		1039.82	995.124		1039.65	1004.42	975.969	1039.66			993.769	
Molar Flow	mol/s	651.109		89380.2	174.849		89523.2	651.109	120867	89510.4			160.219	
Mass Flow	kg/s	12.8353		2086.09	3.14995		2088.86	12.8353	2668.85	2088.66			2.89829	
Vapor Volumetric Flow	m^3/s	0.0127789		2.00620	0.00316538		2.00920	0.0127788	2.73456	2.00898			0.00291646	
Liquid Volumetric Flow	m^3/s	0.0127789		2.00620	0.00316538		2.00920	0.0127788	2.73456	2.00898			0.00291646	
Std Vapor Volumetric Flow	m^3/s	15.4251		2117.46	4.14224		2120.84	15.4251	2863.38	2120.54			3.79565	
Std Liquid Volumetric Flow	m^3/s	0.0128947		2.08687	0.00315305		2.08966	0.0128947	2.67275	2.08945			0.00290565	
Compressibility		0.000810954		0.00511664	0.000917823		0.00138145	0.00117467	0.00150611	0.00138149			0.00485476	
Specific Gravity		1.00536		1.04081	0.996064		1.04063	1.00537	0.976891	1.04065			0.994708	
API Gravity		7.33115		3.16979	10.0113		3.18525	7.33022	4.59014	3.18327			9.78243	
Enthalpy	J/s	-1.85535E+08		-2.53799E+10	-4.99154E+07		-2.54205E+10	-1.85534E+08	-3.35202E+10	-2.54170E+10			-4.56947E+07	
Mass Enthalpy	J/kg	-1.44551E+07		-1.21662E+07	-1.58464E+07		-1.21695E+07	-1.44550E+07	-1.25598E+07	-1.21690E+07			-1.57661E+07	
Mass Cp	J/(kg*K)	3990.49		3643.50	4133.63		3645.28	3990.43	4141.08	3645.17			4178.15	
Ideal Gas CpCv Ratio		1.27408		1.20044	1.32512		1.20051	1.27408	1.20690	1.20050			1.32428	
Dynamic Viscosity	Pa*s	0.000667814		0.00155840	0.000829453		0.00155074	0.000667807	0.000322953	0.00155091			0.000692804	
Kinematic Viscosity	m^2/s	6.64880E-07		1.49871E-06	8.33517E-07		1.49160E-06	6.64869E-07	3.30905E-07	1.49174E-06			6.97148E-07	
Thermal Conductivity	W/(m*K)	0.560660		0.455924	0.612417		0.456121	0.560666	0.512920	0.456098			0.616673	
Surface Tension	N/m	0.0652679		0.0633993	0.0719272		0.0633873	0.0652665	0.0498888?	0.0633859			0.0700774	
Net Ideal Gas Heating Value	J/m^3	1.96172E+06		6.90666E+06	0		6.89850E+06	1.96172E+06	5.20189E+06	6.89947E+06			0	
Net Liquid Heating Value	J/kg	92892.0		5.03170E+06	-2.46500E+06		5.02488E+06	92892.0	3.51291E+06	5.02563E+06			-2.44907E+06	
Gross Ideal Gas Heating Value	J/m^3	3.96745E+06		9.29110E+06	1.87450E+06		9.28233E+06	3.96745E+06	7.45645E+06	9.28336E+06			1.86914E+06	
Gross Liquid Heating Value	J/kg	2.50332E+06		7.45199E+06	0		7.44521E+06	2.50332E+06	5.93181E+06	7.44591E+06			-1209.96	

Process Streams		**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**	**37**	**38**	**39**	**40**	**41**
Composition	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Total**	**From Block:**	**XCHG-104**	**XCHG-105**	**DTWR-103**	**VSSL-101**	**VSSL-103**	**VSSL-103**	**K-101**	**K-101**	**VSSL-101**	**VSSL-102**	**VSSL-102**	**CMPR-103**	**XCHG-106**	**VSSL-104**	**VSSL-104**
	To Block:	**VSSL-102**	**VSSL-104**	**XCHG-102**	**--**	**SPLT-101**	**CMPR-100**	**XCHG-100**	**DTWR-103**	**CMPR-101**	**--**	**CMPR-102**	**XCHG-106**	**--**	**--**	**CMPR-103**
Mole Fraction																
Water		0.0100810	0.00302720	0.812542	0.997142	0.999243	0.0479879	0.870955	0.984998	0.0100810	0.989811	0.00302720	0.00302720	0.00302720		0.00302720
Nitrogen		0.000153237	0.000154340	2.89227E-05	1.06588E-08	2.63378E-09	0.000147353	0	0	0.000153237	4.43171E-08	0.000154340	0.000154340	0.000154340		0.000154340
Hydrogen		0	0	0	0	0	0	0	0	0	0	0	0	0		
Carbon Monoxide		0	0	0	0	0	0	0	0	0	0	0	0	0		
Carbon Dioxide		0.989745	0.996798	0.187396	0.00285840	0.000721163	0.951845	0.0137669	0.00897910	0.989745	0.0101884	0.996798	0.996798	0.996798		0.996798
Methane		0	0	0	0	0	0	0	0	0	0	0	0	0		
Methanol		0	0	0	0	0	0	0	0	0	0	0	0	0		
Ethane		0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Ethanol		0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Hydrogen Sulfide		0	0	0	0	0	0	0	0	0	0	0	0	0		
MDEA		0	0	0	0	0	0	0	0	0	0	0	0	0	0	
O2		2.06162E-05	2.07645E-05	3.89147E-06	2.77080E-09	6.76245E-10	1.98246E-05	0	0	2.06162E-05	1.15039E-08	2.07645E-05	2.07645E-05	2.07645E-05	0	2.07645E-05
MEA		0	0	2.85105E-05	0	3.54726E-05	6.66570E-12	0.114725	0.00602253	0	0	0	0	0	0	
SO2		0	0	6.05995E-11	0	0	0	0.000553172	1.89583E-08	0	0	0	0	0	0	
Molar Flow		**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s** 0	**mol/s**
Water		40.4421	12.0575	17271.7	159.761	17071.5	200.203	77846.1	31014.0	40.4421	28.3846	12.0575	12.0575	12.0575	0 0	12.0575
Nitrogen		0.614744	0.614743	0.614791	1.70773E-06	4.49966E-05	0.614746	0	0	0.614744	1.27087E-06	0.614743	0.614743	0.614743	0	0.614743
Hydrogen		0	0	0	0	0	0	0	0	0	0	0	0	0	0 0	0
Carbon Monoxide		0	0	0	0	0	0	0	0	0	0	0	0	0	0 0	0
Carbon Dioxide		3970.58	3970.29	3983.36	0.457968	12.3206	3971.04	1230.49	282.719	3970.58	0.292172	3970.29	3970.29	3970.29	0	3970.29
Methane		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Methanol		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ethane		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ethanol		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Sulfide		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MDEA		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O2		0.0827064	0.0827061	0.0827184	4.43933E-07	1.15532E-05	0.0827069	0	0	0.0827064	3.29896E-07	0.0827061	0.0827061	0.0827061	0	0.0827061
MEA		0	0	0.606029	0	0.606029	2.78089E-08	10254.1	189.627	0	0	0	0	0	0	0
SO2		0	0	1.28812E-06	0	0	0	49.4426	0.000596926	0	0	0	0	0	0	0
Mass Fraction																
Water		0.00415162	0.00124148	0.639555	0.993046	0.998120	0.0202181	0.672271	0.958772	0.00415162	0.975471	0.00124148	0.00124148	0.00124148		0.00124148
Nitrogen		9.81304E-05	9.84242E-05	3.53994E-05	1.65061E-08	4.09088E-09	9.65363E-05	0	0	9.81304E-05	6.79138E-08	9.84242E-05	9.84242E-05	9.84242E-05		9.84242E-05
Hydrogen		0	0	0	0	0	0	0	0	0	0	0	0	0		
Carbon Monoxide		0	0	0	0	0	0	0	0	0	0	0	0	0		
Carbon Dioxide		0.995735	0.998645	0.360328	0.00695409	0.00175975	0.979671	0.0259591	0.0213510	0.995735	0.0245287	0.998645	0.998645	0.998645		0.998645
Methane		0	0	0	0	0	0	0	0	0	0	0	0	0		
Methanol		0	0	0	0	0	0	0	0	0	0	0	0	0		
Ethane		0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Ethanol		0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Hydrogen Sulfide		0	0	0	0	0	0	0	0	0	0	0	0	0		
MDEA		0	0	0	0	0	0	0	0	0	0	0	0	0	0	
O2		1.50805E-05	1.51256E-05	5.44049E-06	4.90128E-09	1.19980E-09	1.48356E-05	0	0	1.50805E-05	2.01373E-08	1.51256E-05	1.51256E-05	1.51256E-05	0	1.51256E-05
MEA		0	0	7.60880E-05	0	0.000120139	9.52213E-12	0.300252	0.0198765	0	0	0	0	0	0	
SO2		0	0	1.69618E-10	0	0	0	0.00151838	6.56221E-08	0	0	0	0	0	0	
Mass Flow		**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s** 0	**kg/s**
Water		0.728576	0.217219	311.154	2.87813	307.548	3.60671	1402.42	558.726	0.728576	0.511357	0.217219	0.217219	0.217219	0 0	0.217219
Nitrogen		0.0172211	0.0172210	0.0172224	4.78394E-08	1.26051E-06	0.0172211	0	0	0.0172211	3.56015E-08	0.0172210	0.0172210	0.0172210	0	0.0172210
Hydrogen		0	0	0	0	0	0	0	0	0	0	0	0	0	0 0	0
Carbon Monoxide		0	0	0	0	0	0	0	0	0	0	0	0	0	0 0	0
Carbon Dioxide		174.743	174.731	175.306	0.0201550	0.542225	174.764	54.1532	12.4423	174.743	0.0128583	174.731	174.731	174.731	0	174.731
Methane		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Methanol		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ethane		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ethanol		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Sulfide		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MDEA		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O2		0.00264651	0.00264650	0.00264689	1.42053E-08	3.69690E-07	0.00264652	0	0	0.00264651	1.05563E-08	0.00264650	0.00264650	0.00264650	0	0.00264650
MEA		0	0	0.0370181	0	0.0370181	1.69865E-09	626.354	11.5830	0	0	0	0	0	0	0
SO2		0	0	8.25221E-08	0	0	0	3.16748	3.82414E-05	0	0	0	0	0	0	0

Process Streams		**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**	**37**	**38**	**39**	**40**	**41**
Properties	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Total**	**From Block:**	**XCHG-104**	**XCHG-105**	**DTWR-103**	**VSSL-101**	**VSSL-103**	**VSSL-103**	**K-101**	**K-101**	**VSSL-101**	**VSSL-102**	**VSSL-102**	**CMPR-103**	**XCHG-106**	**VSSL-104**	**VSSL-104**
	To Block:	**VSSL-102**	**VSSL-104**	**XCHG-102**	**--**	**SPLT-101**	**CMPR-100**	**XCHG-100**	**DTWR-103**	**CMPR-101**	**--**	**CMPR-102**	**XCHG-106**	**--**	**--**	**CMPR-103**
Property	**Units**															
Temperature	K	310.928	310.928	384.785	310.928	316.483	316.483	399.696	399.696	310.928	310.928	310.928	311.187	310.928	310.928	310.928
Pressure	Pa	2.79238E+06	1.10316E+07	186158	689476	186158	186158	220632	220632	689476	2.79238E+06	2.79238E+06	1.11358E+07	1.11013E+07*	1.10316E+07	1.10316E+07
Mole Fraction Vapor		0.992852	1	1	0	0	1	0	1	1	0	1	1	1		
Mole Fraction Light Liquid		0.00714825	0	0	1	1	0	1	0	0	1	0	0	0		
Molecular Weight	kg/mol	0.0437448	0.0439281	0.0228881	0.0180896	0.0180356	0.0427595	0.0233396	0.0185081	0.0437448	0.0182801	0.0439281	0.0439281	0.0439281		0.0439281
Mass Density	kg/m^3	55.6013	663.241	1.34760	993.769	990.513	3.05193	986.992	1.24840	12.0761	997.644	55.4445	663.965	666.004		663.241
Molar Flow	mol/s	4011.72	3983.05	21256.4	160.219	17084.4	4171.94	89380.2	31486.3	4011.72	28.6768	3983.05	3983.05	3983.05	0	3983.05
Mass Flow	kg/s	175.492	174.968	486.517	2.89829	308.127	178.390	2086.09	582.751	175.492	0.524216	174.968	174.968	174.968	0 1	174.968
Vapor Volumetric Flow	m^3/s	3.15625	0.263807	361.024	0.00291646	0.311078	58.4516	2.11359	466.800	14.5321	0.000525453	3.15573	0.263519	0.262713	0	0.263807
Liquid Volumetric Flow	m^3/s	3.15625	0.263807	361.024	0.00291646	0.311078	58.4516	2.11359	466.800	14.5321	0.000525453	3.15573	0.263519	0.262713		0.263807
Std Vapor Volumetric Flow	m^3/s	95.0395	94.3601	503.572	3.79565	404.737	98.8352	2117.46	745.925	95.0395	0.679366	94.3601	94.3601	94.3601	0	94.3601
Std Liquid Volumetric Flow	m^3/s	0.214803	0.214276	0.526260	0.00290565	0.308551	0.217709	2.08687	0.585880	0.214803	0.000527611	0.214276	0.214276	0.214276	0	0.214276
Compressibility		0.849807	0.282629	0.988273	0.00485476	0.00128815	0.991186	0.00156994	0.984267	0.966103	0.0197917	0.855783	0.284749	0.283234		0.282629
Specific Gravity				0.790263	0.994708	0.991450	1.47637	0.987925	0.639033	1.51039	0.998587	1.51672	1.51672	1.51672		1.51672
API Gravity					9.78243	9.95361		3.17683			9.19468					
Enthalpy	J/s	-1.57627E+09	-1.60088E+09	-5.68200E+09	-4.56947E+07	-4.86093E+09	-1.60850E+09	-2.47114E+10	-7.54256E+09	-1.57141E+09	-8.20393E+06	-1.56807E+09	-1.60084E+09	-1.60097E+09	0	-1.60088E+09
Mass Enthalpy	J/kg	-8.98203E+06	1.51672 -9.14957E+06	-1.16789E+07	-1.57661E+07	-1.57757E+07	-9.01674E+06	-1.18458E+07	-1.29430E+07	-8.95432E+06	-1.56499E+07	-8.96205E+06	-9.14936E+06	-9.15011E+06		-9.14957E+06
Mass Cp	J/(kg*K)	1049.55	3957.73	1573.50	4178.15	4203.73	891.534	4058.44	1948.00	894.268	4181.74	1040.16	3919.01	3912.68		3957.73
Ideal Gas CpCv Ratio		1.28324	1.28299	1.30453	1.32428	1.32384	1.28231	1.18561	1.30530	1.28324	1.32393	1.28299	1.28287	1.28299		1.28299
Dynamic Viscosity	Pa*s			1.51211E-05	0.000692804	0.000628953	1.59294E-05	0.000364432	1.36670E-05	1.58668E-05	0.000674311	1.66876E-05	5.26628E-05	5.28950E-05		5.25646E-05
Kinematic Viscosity	m^2/s		5.25646E-05	1.12207E-05	6.97148E-07	6.34977E-07	5.21946E-06	3.69235E-07	1.09476E-05	1.31390E-06	6.75903E-07	3.00978E-07	7.93157E-08	7.94214E-08		7.92541E-08
Thermal Conductivity	W/(m*K)		7.92541E-08	0.0266636	0.616673	0.628166	0.0179288	0.478927	0.0293991	0.0178100	0.600358	0.0198082	0.0730077	0.0732657		0.0728889
Surface Tension	N/m				0.0700774	0.0691357		0.0488245?			0.0695623					
Net Ideal Gas Heating Value	J/m^3	0	0.0728889 0	1716.39	0	2135.52	0.000401288	6.90666E+06	362568	0	0	0	0	0		
Net Liquid Heating Value	J/kg	-183484	-176817	-1.63750E+06	-2.44907E+06	-2.45799E+06	-220293	5.03170E+06	-1.92396E+06	-183484	-2.40881E+06	-176817	-176817	-176817		-176817
Gross Ideal Gas Heating Value	J/m^3	18896.8	5674.47	1.52501E+06	1.86914E+06	1.87545E+06	89953.2	9.29110E+06	2.24841E+06	18896.8	1.85540E+06	5674.47	5674.47	5674.47		5674.47
Gross Liquid Heating Value	J/kg	-173250	-173756	-60804.5	-1209.96	2677.60	-170455	7.45199E+06	489938	-173250	-4267.81	-173756	-173756	-173756		-173756
															0	

Process Streams		**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**	**37**	**38**	**39**	**40**	**41**
Composition	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Vapor**	**From Block:**	**XCHG-104**	**XCHG-105**	**DTWR-103**	**VSSL-101**	**VSSL-103**	**VSSL-103**	**K-101**	**K-101**	**VSSL-101**	**VSSL-102**	**VSSL-102**	**CMPR-103**	**XCHG-106**	**VSSL-104**	**VSSL-104**
	To Block:	**VSSL-102**	**VSSL-104**	**XCHG-102**	**--**	**SPLT-101**	**CMPR-100**	**XCHG-100**	**DTWR-103**	**CMPR-101**	**--**	**CMPR-102**	**XCHG-106**	**--**	**--**	**CMPR-103**
Mole Fraction																
Water		0.00302720	0.00302720	0.812542			0.0479879		0.984998	0.0100810		0.00302720	0.00302720	0.00302720		0.00302720
Nitrogen		0.000154340	0.000154340	2.89227E-05			0.000147353		0	0.000153237		0.000154340	0.000154340	0.000154340		0.000154340
Hydrogen		0	0	0			0		0	0		0	0	0		0
Carbon Monoxide		0	0	0			0		0	0		0	0	0		0
Carbon Dioxide		0.996798	0.996798	0.187396			0.951845		0.00897910	0.989745		0.996798	0.996798	0.996798		0.996798
Methane		0	0	0			0		0	0		0	0	0		0
Methanol		0	0	0			0		0	0		0	0	0		0
Ethane		0	0	0			0		0	0		0	0	0		0
Ethanol		0	0	0			0		0	0		0	0	0		0
Hydrogen Sulfide		0	0	0			0		0	0		0	0	0		0
MDEA		0	0	0			0		0	0		0	0	0		0
O2		2.07645E-05	2.07645E-05	3.89147E-06			1.98246E-05		0	2.06162E-05		2.07645E-05	2.07645E-05	2.07645E-05		2.07645E-05
MEA		0	0	2.85105E-05			6.66570E-12		0.00602253	0		0	0	0		0
SO2		0	0	6.05995E-11			0		1.89583E-08	0		0	0	0		0
Molar Flow		**mol/s**	**mol/s**	**mol/s**			**mol/s**		**mol/s**	**mol/s**		**mol/s**	**mol/s**	**mol/s**		**mol/s**
Water		12.0575	12.0575	17271.7			200.203		31014.0	40.4421		12.0575	12.0575	12.0575		12.0575
Nitrogen		0.614743	0.614743	0.614791			0.614746		0	0.614744		0.614743	0.614743	0.614743		0.614743
Hydrogen		0	0	0			0		0	0		0	0	0		0
Carbon Monoxide		0	0	0			0		0	0		0	0	0		0
Carbon Dioxide		3970.29	3970.29	3983.36			3971.04		282.719	3970.58		3970.29	3970.29	3970.29		3970.29
Methane		0	0	0			0		0	0		0	0	0		0
Methanol		0	0	0			0		0	0		0	0	0		0
Ethane		0	0	0			0		0	0		0	0	0		0
Ethanol		0	0	0			0		0	0		0	0	0		0
Hydrogen Sulfide		0	0	0			0		0	0		0	0	0		0
MDEA		0	0	0			0		0	0		0	0	0		0
O2		0.0827061	0.0827061	0.0827184			0.0827069		0	0.0827064		0.0827061	0.0827061	0.0827061		0.0827061
MEA		0	0	0.606029			2.78089E-08		189.627	0		0	0	0		0
SO2		0	0	1.28812E-06			0		0.000596926	0		0	0	0		0
Mass Fraction																
Water		0.00124148	0.00124148	0.639555			0.0202181		0.958772	0.00415162		0.00124148	0.00124148	0.00124148		0.00124148
Nitrogen		9.84242E-05	9.84242E-05	3.53994E-05			9.65363E-05		0	9.81304E-05		9.84242E-05	9.84242E-05	9.84242E-05		9.84242E-05
Hydrogen		0	0	0			0		0	0		0	0	0		0
Carbon Monoxide		0	0	0			0		0	0		0	0	0		0
Carbon Dioxide		0.998645	0.998645	0.360328			0.979671		0.0213510	0.995735		0.998645	0.998645	0.998645		0.998645
Methane		0	0	0			0		0	0		0	0	0		0
Methanol		0	0	0			0		0	0		0	0	0		0
Ethane		0	0	0			0		0	0		0	0	0		0
Ethanol		0	0	0			0		0	0		0	0	0		0
Hydrogen Sulfide		0	0	0			0		0	0		0	0	0		0
MDEA		0	0	0			0		0	0		0	0	0		0
O2		1.51256E-05	1.51256E-05	5.44049E-06			1.48356E-05		0	1.50805E-05		1.51256E-05	1.51256E-05	1.51256E-05		1.51256E-05
MEA		0	0	7.60880E-05			9.52213E-12		0.0198765	0		0	0	0		0
SO2		0	0	1.69618E-10			0		6.56221E-08	0		0	0	0		0
Mass Flow		**kg/s**	**kg/s**	**kg/s**			**kg/s**		**kg/s**	**kg/s**		**kg/s**	**kg/s**	**kg/s**		**kg/s**
Water		0.217219	0.217219	311.154			3.60671		558.726	0.728576		0.217219	0.217219	0.217219		0.217219
Nitrogen		0.0172210	0.0172210	0.0172224			0.0172211		0	0.0172211		0.0172210	0.0172210	0.0172210		0.0172210
Hydrogen		0	0	0			0		0	0		0	0	0		0
Carbon Monoxide		0	0	0			0		0	0		0	0	0		0
Carbon Dioxide		174.731	174.731	175.306			174.764		12.4423	174.743		174.731	174.731	174.731		174.731
Methane		0	0	0			0		0	0		0	0	0		0
Methanol		0	0	0			0		0	0		0	0	0		0
Ethane		0	0	0			0		0	0		0	0	0		0
Ethanol		0	0	0			0		0	0		0	0	0		0
Hydrogen Sulfide		0	0	0			0		0	0		0	0	0		0
MDEA		0	0	0			0		0	0		0	0	0		0
O2		0.00264650	0.00264650	0.00264689			0.00264652		0	0.00264651		0.00264650	0.00264650	0.00264650		0.00264650
MEA		0	0	0.0370181			1.69865E-09		11.5830	0		0	0	0		0
SO2		0	0	8.25221E-08			0		3.82414E-05	0		0	0	0		0

Process Streams		**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**	**37**	**38**	**39**	**40**	**41**
Properties	**Status:**	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved
Phase: **Vapor**	**From Block:**	**XCHG-104**	**XCHG-105**	**DTWR-103**	**VSSL-101**	**VSSL-103**	**VSSL-103**	**K-101**	**K-101**	**VSSL-101**	**VSSL-102**	**VSSL-102**	**CMPR-103**	**XCHG-106**	**VSSL-104**	**VSSL-104**
	To Block:	**VSSL-102**	**VSSL-104**	**XCHG-102**	**--**	**SPLT-101**	**CMPR-100**	**XCHG-100**	**DTWR-103**	**CMPR-101**	**--**	**CMPR-102**	**XCHG-106**	**--**	**--**	**CMPR-103**
Property	**Units**															
Temperature	K	310.928	310.928	384.785			316.483		399.696	310.928		310.928	311.187	310.928		310.928
Pressure	Pa	2.79238E+06	1.10316E+07	186158			186158		220632	689476		2.79238E+06	1.11358E+07	1.11013E+07		1.10316E+07
Mole Fraction Vapor		1	1	1			1		1	1		1	1	1		1
Mole Fraction Light Liquid		0	0	0			0		0	0		0	0	0		0
Molecular Weight	kg/mol	0.0439281	0.0439281	0.0228881			0.0427595		0.0185081	0.0437448		0.0439281	0.0439281	0.0439281		0.0439281
Mass Density	kg/m^3	55.4445	663.241	1.34760			3.05193		1.24840	12.0761		55.4445	663.965	666.004		663.241
Molar Flow	mol/s	3983.05	3983.05	21256.4			4171.94		31486.3	4011.72		3983.05	3983.05	3983.05		3983.05
Mass Flow	kg/s	174.968	174.968	486.517			178.390		582.751	175.492		174.968	174.968	174.968		174.968
Vapor Volumetric Flow	m^3/s	3.15573	0.263807	361.024			58.4516		466.800	14.5321		3.15573	0.263519	0.262713		0.263807
Liquid Volumetric Flow	m^3/s	3.15573	0.263807	361.024			58.4516		466.800	14.5321		3.15573	0.263519	0.262713		0.263807
Std Vapor Volumetric Flow	m^3/s	94.3601	94.3601	503.572			98.8352		745.925	95.0395		94.3601	94.3601	94.3601		94.3601
Std Liquid Volumetric Flow	m^3/s	0.214276	0.214276	0.526260			0.217709		0.585880	0.214803		0.214276	0.214276	0.214276		0.214276
Compressibility		0.855783	0.282629	0.988273			0.991186		0.984267	0.966103		0.855783	0.284749	0.283234		0.282629
Specific Gravity		1.51672	1.51672	0.790263			1.47637		0.639033	1.51039		1.51672	1.51672	1.51672		1.51672
API Gravity																
Enthalpy	J/s	-1.56807E+09	-1.60088E+09	-5.68200E+09			-1.60850E+09		-7.54256E+09	-1.57141E+09		-1.56807E+09	-1.60084E+09	-1.60097E+09		-1.60088E+09
Mass Enthalpy	J/kg	-8.96205E+06	-9.14957E+06	-1.16789E+07			-9.01674E+06		-1.29430E+07	-8.95432E+06		-8.96205E+06	-9.14936E+06	-9.15011E+06		-9.14957E+06
Mass Cp	J/(kg*K)	1040.16	3957.73	1573.50			891.534		1948.00	894.268		1040.16	3919.01	3912.68		3957.73
Ideal Gas CpCv Ratio		1.28299	1.28299	1.30453			1.28231		1.30530	1.28324		1.28299	1.28287	1.28299		1.28299
Dynamic Viscosity	Pa*s	1.66876E-05	5.25646E-05	1.51211E-05			1.59294E-05		1.36670E-05	1.58668E-05		1.66876E-05	5.26628E-05	5.28950E-05		5.25646E-05
Kinematic Viscosity	m^2/s	3.00978E-07	7.92541E-08	1.12207E-05			5.21946E-06		1.09476E-05	1.31390E-06		3.00978E-07	7.93157E-08	7.94214E-08		7.92541E-08
Thermal Conductivity	W/(m*K)	0.0198082	0.0728889	0.0266636			0.0179288		0.0293991	0.0178100		0.0198082	0.0730077	0.0732657		0.0728889
Surface Tension	N/m															
Net Ideal Gas Heating Value	J/m^3	0	0	1716.39			0.000401288		362568	0		0	0	0		0
Net Liquid Heating Value	J/kg	-176817	-176817	-1.63750E+06			-220293		-1.92396E+06	-183484		-176817	-176817	-176817		-176817
Gross Ideal Gas Heating Value	J/m^3	5674.47	5674.47	1.52501E+06			89953.2		2.24841E+06	18896.8		5674.47	5674.47	5674.47		5674.47
Gross Liquid Heating Value	J/kg	-173756	-173756	-60804.5			-170455		489938	-173250		-173756	-173756	-173756		-173756

Process Streams		27	28	29	30	31	32	33	34	35	36	37	38	39	40	41
Composition	**Status:**	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved
Phase: **Light Liquid**	**From Block:**	XCHG-104	XCHG-105	DTWR-103	VSSL-101	VSSL-103	VSSL-103	K-101	K-101	VSSL-101	VSSL-102	VSSL-102	CMPR-103	XCHG-106	VSSL-104	VSSL-104
	To Block:	VSSL-102	VSSL-104	XCHG-102	--	SPLT-101	CMPR-100	XCHG-100	DTWR-103	CMPR-101	--	CMPR-102	XCHG-106	--	--	CMPR-103
Mole Fraction																
Water		0.989811			0.997142	0.999243		0.870955			0.989811					
Nitrogen		4.43171E-08			1.06588E-08	2.63378E-09		0			4.43171E-08					
Hydrogen		0			0	0		0			0					
Carbon Monoxide		0			0	0		0			0					
Carbon Dioxide		0.0101884			0.00285840	0.000721163		0.0137669			0.0101884					
Methane		0			0	0		0			0					
Methanol		0			0	0		0			0					
Ethane		0			0	0		0			0					
Ethanol		0			0	0		0			0					
Hydrogen Sulfide		0			0	0		0			0					
MDEA		0			0	0		0			0					
O2		1.15039E-08			2.77080E-09	6.76245E-10		0			1.15039E-08					
MEA		0			0	3.54726E-05		0.114725			0					
SO2		0			0	0		0.000553172			0					
Molar Flow		**mol/s**			**mol/s**	**mol/s**		**mol/s**			**mol/s**					
Water		28.3846			159.761	17071.5		77846.1			28.3846					
Nitrogen		1.27087E-06			1.70773E-06	4.49966E-05		0			1.27087E-06					
Hydrogen		0			0	0		0			0					
Carbon Monoxide		0			0	0		0			0					
Carbon Dioxide		0.292172			0.457968	12.3206		1230.49			0.292172					
Methane		0			0	0		0			0					
Methanol		0			0	0		0			0					
Ethane		0			0	0		0			0					
Ethanol		0			0	0		0			0					
Hydrogen Sulfide		0			0	0		0			0					
MDEA		0			0	0		0			0					
O2		3.29896E-07			4.43933E-07	1.15532E-05		0			3.29896E-07					
MEA		0			0	0.606029		10254.1			0					
SO2		0			0	0		49.4426			0					
Mass Fraction																
Water		0.975471			0.993046	0.998120		0.672271			0.975471					
Nitrogen		6.79138E-08			1.65061E-08	4.09088E-09		0			6.79138E-08					
Hydrogen		0			0	0		0			0					
Carbon Monoxide		0			0	0		0			0					
Carbon Dioxide		0.0245287			0.00695409	0.00175975		0.0259591			0.0245287					
Methane		0			0	0		0			0					
Methanol		0			0	0		0			0					
Ethane		0			0	0		0			0					
Ethanol		0			0	0		0			0					
Hydrogen Sulfide		0			0	0		0			0					
MDEA		0			0	0		0			0					
O2		2.01373E-08			4.90128E-09	1.19980E-09		0			2.01373E-08					
MEA		0			0	0.000120139		0.300252			0					
SO2		0			0	0		0.00151838			0					
Mass Flow		**kg/s**			**kg/s**	**kg/s**		**kg/s**			**kg/s**					
Water		0.511357			2.87813	307.548		1402.42			0.511357					
Nitrogen		3.56015E-08			4.78394E-08	1.26051E-06		0			3.56015E-08					
Hydrogen		0			0	0		0			0					
Carbon Monoxide		0			0	0		0			0					
Carbon Dioxide		0.0128583			0.0201550	0.542225		54.1532			0.0128583					
Methane		0			0	0		0			0					
Methanol		0			0	0		0			0					
Ethane		0			0	0		0			0					
Ethanol		0			0	0		0			0					
Hydrogen Sulfide		0			0	0		0			0					
MDEA		0			0	0		0			0					
O2		1.05563E-08			1.42053E-08	3.69690E-07		0			1.05563E-08					
MEA		0			0	0.0370181		626.354			0					
SO2		0			0	0		3.16748			0					

Process Streams		**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**	**37**	**38**	**39**	**40**	**41**
Properties	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Light Liquid**	**From Block:**	**XCHG-104**	**XCHG-105**	**DTWR-103**	**VSSL-101**	**VSSL-103**	**VSSL-103**	**K-101**	**K-101**	**VSSL-101**	**VSSL-102**	**VSSL-102**	**CMPR-103**	**XCHG-106**	**VSSL-104**	**VSSL-104**
	To Block:	**VSSL-102**	**VSSL-104**	**XCHG-102**	**--**	**SPLT-101**	**CMPR-100**	**XCHG-100**	**DTWR-103**	**CMPR-101**	**--**	**CMPR-102**	**XCHG-106**	**--**	**--**	**CMPR-103**
Property	**Units**															
Temperature	K	310.928			310.928	316.483		399.696			310.928					
Pressure	Pa	2.79238E+06			689476	186158		220632			2.79238E+06					
Mole Fraction Vapor		0			0	0		0			0					
Mole Fraction Light Liquid		1			1	1		1			1					
Molecular Weight	kg/mol	0.0182801			0.0180896	0.0180356		0.0233396			0.0182801					
Mass Density	kg/m^3	997.644			993.769	990.513		986.992			997.644					
Molar Flow	mol/s	28.6768			160.219	17084.4		89380.2			28.6768					
Mass Flow	kg/s	0.524216			2.89829	308.127		2086.09			0.524216					
Vapor Volumetric Flow	m^3/s	0.000525453			0.00291646	0.311078		2.11359			0.000525453					
Liquid Volumetric Flow	m^3/s	0.000525453			0.00291646	0.311078		2.11359			0.000525453					
Std Vapor Volumetric Flow	m^3/s	0.679366			3.79565	404.737		2117.46			0.679366					
Std Liquid Volumetric Flow	m^3/s	0.000527611			0.00290565	0.308551		2.08687			0.000527611					
Compressibility		0.0197917			0.00485476	0.00128815		0.00156994			0.0197917					
Specific Gravity		0.998587			0.994708	0.991450		0.987925			0.998587					
API Gravity		9.19468			9.78243	9.95361		3.17683			9.19468					
Enthalpy	J/s	-8.20393E+06			-4.56947E+07	-4.86093E+09		-2.47114E+10			-8.20393E+06					
Mass Enthalpy	J/kg	-1.56499E+07			-1.57661E+07	-1.57757E+07		-1.18458E+07			-1.56499E+07					
Mass Cp	J/(kg*K)	4181.74			4178.15	4203.73		4058.44			4181.74					
Ideal Gas CpCv Ratio		1.32393			1.32428	1.32384		1.18561			1.32393					
Dynamic Viscosity	Pa*s	0.000674311			0.000692804	0.000628953		0.000364432			0.000674311					
Kinematic Viscosity	m^2/s	6.75903E-07			6.97148E-07	6.34977E-07		3.69235E-07			6.75903E-07					
Thermal Conductivity	W/(m*K)	0.600358			0.616673	0.628166		0.478927			0.600358					
Surface Tension	N/m	0.0695623			0.0700774	0.0691357		0.0488245?			0.0695623					
Net Ideal Gas Heating Value	J/m^3	0			0	2135.52		6.90666E+06			0					
Net Liquid Heating Value	J/kg	-2.40881E+06			-2.44907E+06	-2.45799E+06		5.03170E+06			-2.40881E+06					
Gross Ideal Gas Heating Value	J/m^3	1.85540E+06			1.86914E+06	1.87545E+06		9.29110E+06			1.85540E+06					
Gross Liquid Heating Value	J/kg	-4267.81			-1209.96	2677.60		7.45199E+06			-4267.81					

Process Streams		**42**	**43**	**45**	**46**	**47**	**48**	**49**	**50**
Composition	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Total**	**From Block:**	**SPLT-101**	**SPLT-101**	**Absorber Water Wash**	**SPLT-100**	**XCHG-108**	**SPLT-100**	**Absorber Overhead**	**MIX-101**
	To Block:	**DTWR-103**	**--**	**Absorber Overhead**	**XCHG-108**	**MIX-101**	**MIX-100**	**MIX-101**	**RCYL-1**
Mole Fraction									
Water		0.999243	0.999243	0.121596	0.956087	0.956087	0.956087	0.994740	0.965443
Nitrogen		2.63378E-09	2.63378E-09	0.806643	8.01834E-06	8.01834E-06	8.01834E-06	8.02791E-06	8.02065E-06
Hydrogen		0	0	0	0	0	0	0	0
Carbon Monoxide		0	0	0	0	0	0	0	0
Carbon Dioxide		0.000721163	0.000721163	0.0139301	0.0113181	0.0113181	0.0113181	0.000286334	0.00864781
Methane		0	0	0	0	0	0	0	0
Methanol		0	0	0	0	0	0	0	0
Ethane		0	0	0	0	0	0	0	0
Ethanol		0	0	0	0	0	0	0	0
Hydrogen Sulfide		0	0	0	0	0	0	0	0
MDEA		0	0	0	0	0	0	0	0
O2		6.76245E-10	6.76245E-10	0.0577996	1.09939E-06	1.09939E-06	1.09939E-06	1.08634E-06	1.09623E-06
MEA		3.54726E-05	3.54726E-05	3.10860E-05	0.0325857	0.0325857	0.0325857	0.00496470	0.0258999
SO2		0	0	0	0	0	0	0	0
Molar Flow		**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**
Water		16202.8	868.718	3979.59	498.013	498.013	124.503	165.474	663.488
Nitrogen		4.27069E-05	2.28975E-06	26399.7	0.00417665	0.00417665	0.00104416	0.00133544	0.00551209
Hydrogen		0	0	0	0	0	0	0	0
Carbon Monoxide		0	0	0	0	0	0	0	0
Carbon Dioxide		11.6937	0.626962	455.903	5.89546	5.89546	1.47386	0.0476315	5.94309
Methane		0	0	0	0	0	0	0	0
Methanol		0	0	0	0	0	0	0	0
Ethane		0	0	0	0	0	0	0	0
Ethanol		0	0	0	0	0	0	0	0
Hydrogen Sulfide		0	0	0	0	0	0	0	0
MDEA		0	0	0	0	0	0	0	0
O2		1.09653E-05	5.87911E-07	1891.65	0.000572656	0.000572656	0.000143164	0.000180712	0.000753368
MEA		0.575190	0.0308391	1.01738	16.9735	16.9735	4.24336	0.825875	17.7993
SO2		0	0	0	0	0	0	0	0
Mass Fraction									
Water		0.998120	0.998120	0.0803832	0.873748	0.873748	0.873748	0.982666	0.898588
Nitrogen		4.09088E-09	4.09088E-09	0.829184	1.13946E-05	1.13946E-05	1.13946E-05	1.23317E-05	1.16083E-05
Hydrogen		0	0	0	0	0	0	0	0
Carbon Monoxide		0	0	0	0	0	0	0	0
Carbon Dioxide		0.00175975	0.00175975	0.0224960	0.0252679	0.0252679	0.0252679	0.000690995	0.0196628
Methane		0	0	0	0	0	0	0	0
Methanol		0	0	0	0	0	0	0	0
Ethane		0	0	0	0	0	0	0	0
Ethanol		0	0	0	0	0	0	0	0
Hydrogen Sulfide		0	0	0	0	0	0	0	0
MDEA		0	0	0	0	0	0	0	0
O2		1.19980E-09	1.19980E-09	0.0678675	1.78456E-06	1.78456E-06	1.78456E-06	1.90613E-06	1.81229E-06
MEA		0.000120139	0.000120139	6.96770E-05	0.100971	0.100971	0.100971	0.0166291	0.0817356
SO2		0	0	0	0	0	0	0	0
Mass Flow		**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**
Water		291.897	15.6502	71.6934	8.97185	8.97185	2.24296	2.98107	11.9529
Nitrogen		1.19637E-06	6.41436E-08	739.544	0.000117002	0.000117002	2.92505E-05	3.74102E-05	0.000154412
Hydrogen		0	0	0	0	0	0	0	0
Carbon Monoxide		0	0	0	0	0	0	0	0
Carbon Dioxide		0.514633	0.0275923	20.0640	0.259456	0.259456	0.0648640	0.00209624	0.261552
Methane		0	0	0	0	0	0	0	0
Methanol		0	0	0	0	0	0	0	0
Ethane		0	0	0	0	0	0	0	0
Ethanol		0	0	0	0	0	0	0	0
Hydrogen Sulfide		0	0	0	0	0	0	0	0
MDEA		0	0	0	0	0	0	0	0
O2		3.50878E-07	1.88125E-08	60.5306	1.83243E-05	1.83243E-05	4.58108E-06	5.78255E-06	2.41069E-05
MEA		0.0351344	0.00188374	0.0621445	1.03679	1.03679	0.259198	0.0504470	1.08724
SO2		0	0	0	0	0	0	0	0

Process Streams		**42**	**43**	**45**	**46**	**47**	**48**	**49**	**50**
Properties	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Total**	**From Block:**	**SPLT-101**	**SPLT-101**	**Absorber Water Wash**	**SPLT-100**	**XCHG-108**	**SPLT-100**	**Absorber Overhead**	**MIX-101**
	To Block:	**DTWR-103**	**--**	**Absorber Overhead**	**XCHG-108**	**MIX-101**	**MIX-100**	**MIX-101**	**RCYL-1**
Property	**Units**								
Temperature	K	316.483	316.483	325.124	325.591	322.039*	325.591	324.779	322.715
Pressure	Pa	186158	186158	109786	162027	127553	162027	109786	109786
Mole Fraction Vapor		0	0	1	0	0	0	0	0
Mole Fraction Light Liquid		1	1	0	1	1	1	1	1
Molecular Weight	kg/mol	0.0180356	0.0180356	0.0272519	0.0197130	0.0197130	0.0197130	0.0182366	0.0193556
Mass Density	kg/m^3	990.513	990.513	1.10741	1004.42	1006.08	1004.42	987.639	1000.55
Molar Flow	mol/s	16215.0	869.376	32727.8	520.887	520.887	130.222	166.349	687.237
Mass Flow	kg/s	292.447	15.6797*	891.895	10.2682	10.2682	2.56706	3.03365	13.3019
Vapor Volumetric Flow	m^3/s	0.295248	0.0158299	805.385	0.0102231	0.0102062	0.00255577	0.00307162	0.0132946
Liquid Volumetric Flow	m^3/s	0.295248	0.0158299	805.385	0.0102231	0.0102062	0.00255577	0.00307162	0.0132946
Std Vapor Volumetric Flow	m^3/s	384.141	20.5959	775.337	12.3400	12.3400	3.08501	3.94089	16.2809
Std Liquid Volumetric Flow	m^3/s	0.292849	0.0157013	1.06690	0.0103158	0.0103158	0.00257894	0.00303611	0.0133519
Compressibility		0.00128815	0.00128815	0.999425	0.00117467	0.000933397	0.00117467	0.000750710	0.000791520
Specific Gravity		0.991450	0.991450	0.940933	1.00537	1.00703	1.00537	0.988572	1.00150
API Gravity		9.95361	9.95361		7.33022	7.33086	7.33022	9.83107	8.04625
Enthalpy	J/s	-4.61357E+09	-2.47359E+08	-1.11592E+09	-1.48427E+08	-1.48573E+08	-3.71068E+07	-4.71960E+07	-1.95769E+08
Mass Enthalpy	J/kg	-1.57757E+07	-1.57757E+07	-1.25118E+06	-1.44550E+07	-1.44692E+07	-1.44550E+07	-1.55575E+07	-1.47174E+07
Mass Cp	J/(kg*K)	4203.73	4203.73	1100.41	3990.43	3971.01	3990.43	4218.25	4027.64
Ideal Gas CpCv Ratio		1.32384	1.32384	1.38470	1.27408	1.27461	1.27408	1.31475	1.28331
Dynamic Viscosity	Pa*s	0.000628953	0.000628953	1.85931E-05	0.000667807	0.000713426	0.000667807	0.000563594	0.000670164
Kinematic Viscosity	m^2/s	6.34977E-07	6.34977E-07	1.67896E-05	6.64869E-07	7.09113E-07	6.64869E-07	5.70648E-07	6.69795E-07
Thermal Conductivity	W/(m*K)	0.628166	0.628166	0.0273730	0.560666	0.557626	0.560666	0.628967	0.573382
Surface Tension	N/m	0.0691357	0.0691357		0.0652665	0.0659214	0.0652665	0.0673332	0.0662612
Net Ideal Gas Heating Value	J/m^3	2135.52	2135.52	1871.44	1.96172E+06	1.96172E+06	1.96172E+06	298885	1.55922E+06
Net Liquid Heating Value	J/kg	-2.45799E+06	-2.45799E+06	-200505	92892.0	92892.0	92892.0	-2.05166E+06	-396198
Gross Ideal Gas Heating Value	J/m^3	1.87545E+06	1.87545E+06	230007	3.96745E+06	3.96745E+06	3.96745E+06	2.19606E+06	3.53868E+06
Gross Liquid Heating Value	J/kg	2677.60	2677.60	-2183.62	2.50332E+06	2.50332E+06	2.50332E+06	412882	2.02657E+06

Process Streams		**42**	**43**	**45**	**46**	**47**	**48**	**49**	**50**
Composition	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Vapor**	**From Block:**	**SPLT-101**	**SPLT-101**	**Absorber Water Wash**	**SPLT-100**	**XCHG-108**	**SPLT-100**	**Absorber Overhead**	**MIX-101**
	To Block:	**DTWR-103**	**--**	**Absorber Overhead**	**XCHG-108**	**MIX-101**	**MIX-100**	**MIX-101**	**RCYL-1**
Mole Fraction									
Water				0.121596					
Nitrogen				0.806643					
Hydrogen				0					
Carbon Monoxide				0					
Carbon Dioxide				0.0139301					
Methane				0					
Methanol				0					
Ethane				0					
Ethanol				0					
Hydrogen Sulfide				0					
MDEA				0					
O2				0.0577996					
MEA				3.10860E-05					
SO2				0					
Molar Flow				**mol/s**					
Water				3979.59					
Nitrogen				26399.7					
Hydrogen				0					
Carbon Monoxide				0					
Carbon Dioxide				455.903					
Methane				0					
Methanol				0					
Ethane				0					
Ethanol				0					
Hydrogen Sulfide				0					
MDEA				0					
O2				1891.65					
MEA				1.01738					
SO2				0					
Mass Fraction									
Water				0.0803832					
Nitrogen				0.829184					
Hydrogen				0					
Carbon Monoxide				0					
Carbon Dioxide				0.0224960					
Methane				0					
Methanol				0					
Ethane				0					
Ethanol				0					
Hydrogen Sulfide				0					
MDEA				0					
O2				0.0678675					
MEA				6.96770E-05					
SO2				0					
Mass Flow				**kg/s**					
Water				71.6934					
Nitrogen				739.544					
Hydrogen				0					
Carbon Monoxide				0					
Carbon Dioxide				20.0640					
Methane				0					
Methanol				0					
Ethane				0					
Ethanol				0					
Hydrogen Sulfide				0					
MDEA				0					
O2				60.5306					
MEA				0.0621445					
SO2				0					

Process Streams		**42**	**43**	**45**	**46**	**47**	**48**	**49**	**50**
Properties	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Vapor**	**From Block:**	**SPLT-101**	**SPLT-101**	**Absorber Water Wash**	**SPLT-100**	**XCHG-108**	**SPLT-100**	**Absorber Overhead**	**MIX-101**
	To Block:	**DTWR-103**	**--**	**Absorber Overhead**	**XCHG-108**	**MIX-101**	**MIX-100**	**MIX-101**	**RCYL-1**
Property	**Units**								
Temperature	K			325.124					
Pressure	Pa			109786					
Mole Fraction Vapor				1					
Mole Fraction Light Liquid				0					
Molecular Weight	kg/mol			0.0272519					
Mass Density	kg/m^3			1.10741					
Molar Flow	mol/s			32727.8					
Mass Flow	kg/s			891.895					
Vapor Volumetric Flow	m^3/s			805.385					
Liquid Volumetric Flow	m^3/s			805.385					
Std Vapor Volumetric Flow	m^3/s			775.337					
Std Liquid Volumetric Flow	m^3/s			1.06690					
Compressibility				0.999425					
Specific Gravity				0.940933					
API Gravity									
Enthalpy	J/s			-1.11592E+09					
Mass Enthalpy	J/kg			-1.25118E+06					
Mass Cp	J/(kg*K)			1100.41					
Ideal Gas CpCv Ratio				1.38470					
Dynamic Viscosity	Pa*s			1.85931E-05					
Kinematic Viscosity	m^2/s			1.67896E-05					
Thermal Conductivity	W/(m*K)			0.0273730					
Surface Tension	N/m								
Net Ideal Gas Heating Value	J/m^3			1871.44					
Net Liquid Heating Value	J/kg			-200505					
Gross Ideal Gas Heating Value	J/m^3			230007					
Gross Liquid Heating Value	J/kg			-2183.62					

Process Streams		**42**	**43**	**45**	**46**	**47**	**48**	**49**	**50**
Composition	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Light Liquid**	**From Block:**	**SPLT-101**	**SPLT-101**	**Absorber Water Wash**	**SPLT-100**	**XCHG-108**	**SPLT-100**	**Absorber Overhead**	**MIX-101**
	To Block:	**DTWR-103**	**--**	**Absorber Overhead**	**XCHG-108**	**MIX-101**	**MIX-100**	**MIX-101**	**RCYL-1**
Mole Fraction									
Water		0.999243	0.999243		0.956087	0.956087	0.956087	0.994740	0.965443
Nitrogen		2.63378E-09	2.63378E-09		8.01834E-06	8.01834E-06	8.01834E-06	8.02791E-06	8.02065E-06
Hydrogen		0	0		0	0	0	0	0
Carbon Monoxide		0	0		0	0	0	0	0
Carbon Dioxide		0.000721163	0.000721163		0.0113181	0.0113181	0.0113181	0.000286334	0.00864781
Methane		0	0		0	0	0	0	0
Methanol		0	0		0	0	0	0	0
Ethane		0	0		0	0	0	0	0
Ethanol		0	0		0	0	0	0	0
Hydrogen Sulfide		0	0		0	0	0	0	0
MDEA		0	0		0	0	0	0	0
O2		6.76245E-10	6.76245E-10		1.09939E-06	1.09939E-06	1.09939E-06	1.08634E-06	1.09623E-06
MEA		3.54726E-05	3.54726E-05		0.0325857	0.0325857	0.0325857	0.00496470	0.0258999
SO2		0	0		0	0	0	0	0
Molar Flow		**mol/s**	**mol/s**		**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**
Water		16202.8	868.718		498.013	498.013	124.503	165.474	663.488
Nitrogen		4.27069E-05	2.28975E-06		0.00417665	0.00417665	0.00104416	0.00133544	0.00551209
Hydrogen		0	0		0	0	0	0	0
Carbon Monoxide		0	0		0	0	0	0	0
Carbon Dioxide		11.6937	0.626962		5.89546	5.89546	1.47386	0.0476315	5.94309
Methane		0	0		0	0	0	0	0
Methanol		0	0		0	0	0	0	0
Ethane		0	0		0	0	0	0	0
Ethanol		0	0		0	0	0	0	0
Hydrogen Sulfide		0	0		0	0	0	0	0
MDEA		0	0		0	0	0	0	0
O2		1.09653E-05	5.87911E-07		0.000572656	0.000572656	0.000143164	0.000180712	0.000753368
MEA		0.575190	0.0308391		16.9735	16.9735	4.24336	0.825875	17.7993
SO2		0	0		0	0	0	0	0
Mass Fraction									
Water		0.998120	0.998120		0.873748	0.873748	0.873748	0.982666	0.898588
Nitrogen		4.09088E-09	4.09088E-09		1.13946E-05	1.13946E-05	1.13946E-05	1.23317E-05	1.16083E-05
Hydrogen		0	0		0	0	0	0	0
Carbon Monoxide		0	0		0	0	0	0	0
Carbon Dioxide		0.00175975	0.00175975		0.0252679	0.0252679	0.0252679	0.000690995	0.0196628
Methane		0	0		0	0	0	0	0
Methanol		0	0		0	0	0	0	0
Ethane		0	0		0	0	0	0	0
Ethanol		0	0		0	0	0	0	0
Hydrogen Sulfide		0	0		0	0	0	0	0
MDEA		0	0		0	0	0	0	0
O2		1.19980E-09	1.19980E-09		1.78456E-06	1.78456E-06	1.78456E-06	1.90613E-06	1.81229E-06
MEA		0.000120139	0.000120139		0.100971	0.100971	0.100971	0.0166291	0.0817356
SO2		0	0		0	0	0	0	0
Mass Flow		**kg/s**	**kg/s**		**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**
Water		291.897	15.6502		8.97185	8.97185	2.24296	2.98107	11.9529
Nitrogen		1.19637E-06	6.41436E-08		0.000117002	0.000117002	2.92505E-05	3.74102E-05	0.000154412
Hydrogen		0	0		0	0	0	0	0
Carbon Monoxide		0	0		0	0	0	0	0
Carbon Dioxide		0.514633	0.0275923		0.259456	0.259456	0.0648640	0.00209624	0.261552
Methane		0	0		0	0	0	0	0
Methanol		0	0		0	0	0	0	0
Ethane		0	0		0	0	0	0	0
Ethanol		0	0		0	0	0	0	0
Hydrogen Sulfide		0	0		0	0	0	0	0
MDEA		0	0		0	0	0	0	0
O2		3.50878E-07	1.88125E-08		1.83243E-05	1.83243E-05	4.58108E-06	5.78255E-06	2.41069E-05
MEA		0.0351344	0.00188374		1.03679	1.03679	0.259198	0.0504470	1.08724
SO2		0	0		0	0	0	0	0

Process Streams		**42**	**43**	**45**	**46**	**47**	**48**	**49**	**50**
Properties	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Light Liquid**	**From Block:**	**SPLT-101**	**SPLT-101**	**Absorber Water Wash**	**SPLT-100**	**XCHG-108**	**SPLT-100**	**Absorber Overhead**	**MIX-101**
	To Block:	**DTWR-103**	**--**	**Absorber Overhead**	**XCHG-108**	**MIX-101**	**MIX-100**	**MIX-101**	**RCYL-1**
Property	**Units**								
Temperature	K	316.483	316.483		325.591	322.039	325.591	324.779	322.715
Pressure	Pa	186158	186158		162027	127553	162027	109786	109786
Mole Fraction Vapor		0	0		0	0	0	0	0
Mole Fraction Light Liquid		1	1		1	1	1	1	1
Molecular Weight	kg/mol	0.0180356	0.0180356		0.0197130	0.0197130	0.0197130	0.0182366	0.0193556
Mass Density	kg/m^3	990.513	990.513		1004.42	1006.08	1004.42	987.639	1000.55
Molar Flow	mol/s	16215.0	869.376		520.887	520.887	130.222	166.349	687.237
Mass Flow	kg/s	292.447	15.6797		10.2682	10.2682	2.56706	3.03365	13.3019
Vapor Volumetric Flow	m^3/s	0.295248	0.0158299		0.0102231	0.0102062	0.00255577	0.00307162	0.0132946
Liquid Volumetric Flow	m^3/s	0.295248	0.0158299		0.0102231	0.0102062	0.00255577	0.00307162	0.0132946
Std Vapor Volumetric Flow	m^3/s	384.141	20.5959		12.3400	12.3400	3.08501	3.94089	16.2809
Std Liquid Volumetric Flow	m^3/s	0.292849	0.0157013		0.0103158	0.0103158	0.00257894	0.00303611	0.0133519
Compressibility		0.00128815	0.00128815		0.00117467	0.000933397	0.00117467	0.000750710	0.000791520
Specific Gravity		0.991450	0.991450		1.00537	1.00703	1.00537	0.988572	1.00150
API Gravity		9.95361	9.95361		7.33022	7.33086	7.33022	9.83107	8.04625
Enthalpy	J/s	-4.61357E+09	-2.47359E+08		-1.48427E+08	-1.48573E+08	-3.71068E+07	-4.71960E+07	-1.95769E+08
Mass Enthalpy	J/kg	-1.57757E+07	-1.57757E+07		-1.44550E+07	-1.44692E+07	-1.44550E+07	-1.55575E+07	-1.47174E+07
Mass Cp	J/(kg*K)	4203.73	4203.73		3990.43	3971.01	3990.43	4218.25	4027.64
Ideal Gas CpCv Ratio		1.32384	1.32384		1.27408	1.27461	1.27408	1.31475	1.28331
Dynamic Viscosity	Pa*s	0.000628953	0.000628953		0.000667807	0.000713426	0.000667807	0.000563594	0.000670164
Kinematic Viscosity	m^2/s	6.34977E-07	6.34977E-07		6.64869E-07	7.09113E-07	6.64869E-07	5.70648E-07	6.69795E-07
Thermal Conductivity	W/(m*K)	0.628166	0.628166		0.560666	0.557626	0.560666	0.628967	0.573382
Surface Tension	N/m	0.0691357	0.0691357		0.0652665	0.0659214	0.0652665	0.0673332	0.0662612
Net Ideal Gas Heating Value	J/m^3	2135.52	2135.52		1.96172E+06	1.96172E+06	1.96172E+06	298885	1.55922E+06
Net Liquid Heating Value	J/kg	-2.45799E+06	-2.45799E+06		92892.0	92892.0	92892.0	-2.05166E+06	-396198
Gross Ideal Gas Heating Value	J/m^3	1.87545E+06	1.87545E+06		3.96745E+06	3.96745E+06	3.96745E+06	2.19606E+06	3.53868E+06
Gross Liquid Heating Value	J/kg	2677.60	2677.60		2.50332E+06	2.50332E+06	2.50332E+06	412882	2.02657E+06

Bryan Research & Engineering, Inc.

ProMax® 3.2

with

TSWEET® & PROSIM®

Simulation Report

Project: 800 MW CC 90p Capture w Compression 120309_Promax.pmx

Licensed to Black & Veatch Pritchard, Inc. and Affiliates

Client Name: IEAGHG
Location:
Job:

ProMax Filename: C:\Documents and Settings\bla49785\Desktop\800 MW CC 90p Capture w Compression 120309_Promax.pmx
ProMax Version: 3.2.11188.0
Simulation Initiated: 7/17/2012 8:32:09 AM

Bryan Research & Engineering, Inc.
Chemical Engineering Consultants
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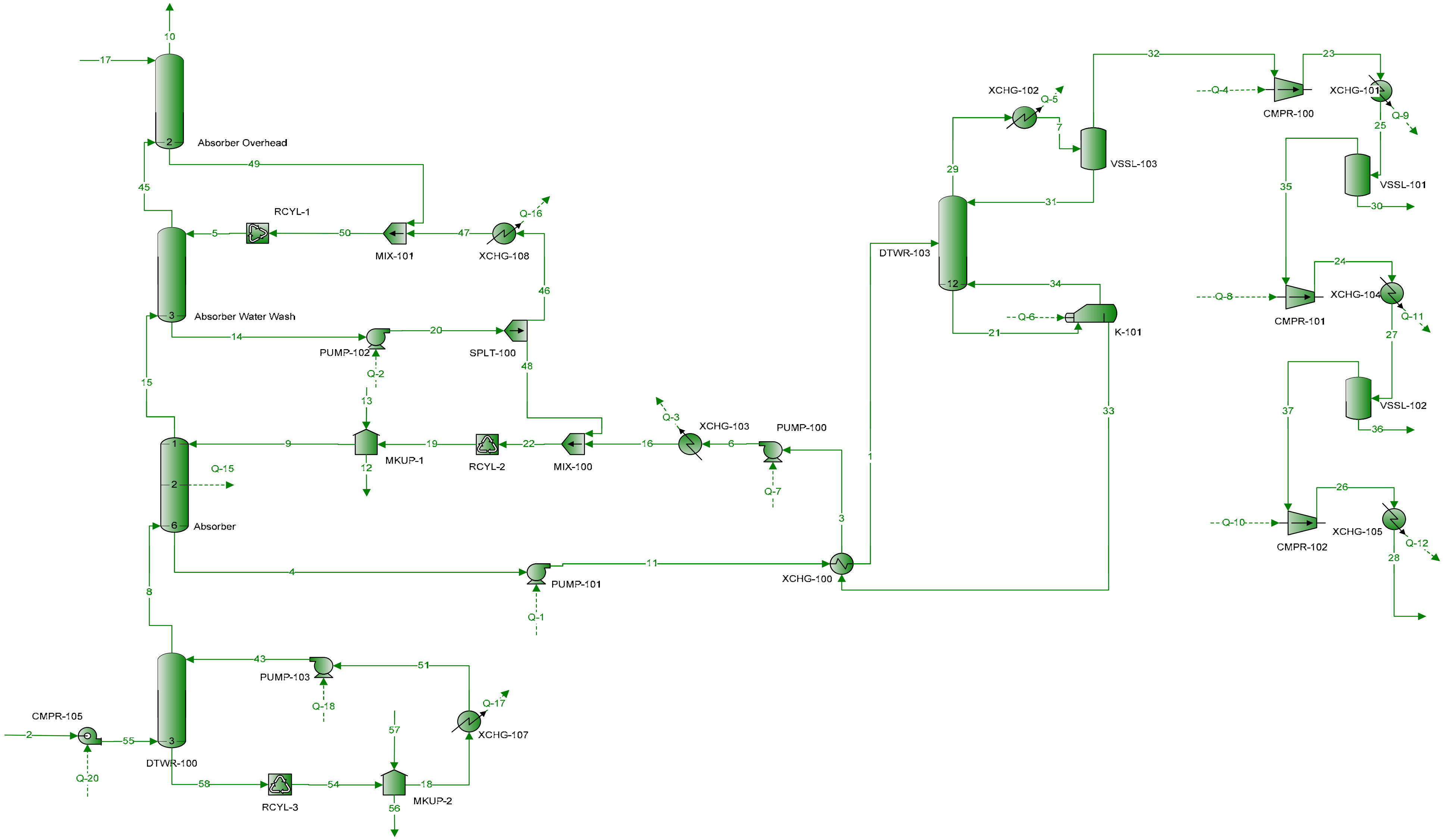
Report Navigator can be activated via the ProMax Navigator Toolbar.
An asterisk (*), throughout the report, denotes a user specified value.
A question mark (?) after a value, throughout the report, denotes an extrapolated or approximate value.


10
17
2
Absorber Overhead
49
45
RCYL-1
5
50
47
Q-16
MIX-101
XCHG-108
46
3
Absorber Water Wash
14
PUMP-102
20
SPLT-100
48
Q-2
15
13
1
9
MKUP-1
19
RCYL-2
22
MIX-100
16
XCHG-103
Q-3
6
PUMP-100
Q-7
2
Q-15
12
6
Absorber
4
PUMP-101
Q-1
11
XCHG-100
3
1
8
DTWR-100
43
PUMP-103
Q-18
51
Q-17
XCHG-107
57
CMPR-105
2
55
3
Q-20
58
RCYL-3
54
MKUP-2
18
56
XCHG-102
Q-5
7
VSSL-103
29
31
DTWR-103
12
34
Q-6
K-101
21
33
32
Q-4
CMPR-100
23
XCHG-101
Q-9
25
VSSL-101
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35
Q-8
CMPR-101
24
XCHG-104
Q-11
27
37
VSSL-102
36
Q-10
CMPR-102
26
XCHG-105
Q-12
28

Process Streams		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Composition	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Total**	**From Block:**	**XCHG-100**	**--**	**XCHG-100**	**Absorber**	**RCYL-1**	**PUMP-100**	**XCHG-102**	**DTWR-100**	**MKUP-1**	**Absorber Overhead**	**PUMP-101**	**MKUP-1**	**--**
	To Block:	**DTWR-103**	**CMPR-105**	**PUMP-100**	**PUMP-101**	**Absorber Water Wash**	**XCHG-103**	**VSSL-103**	**Absorber**	**Absorber**	**--**	**XCHG-100**	**--**	**MKUP-1**
Mole Fraction														
Water		0.829616	0.0875655*	0.865605	0.829616	0.995064	0.865605	0.829238	0.0353354	0.871615	0.0713774	0.829616	0.871549	1
Nitrogen		8.58018E-06	0.751596*	0	8.58018E-06	8.39826E-06	0	3.48387E-05	0.794620	3.85844E-07	0.797002	8.58018E-06	3.86042E-07	0
Hydrogen		0	0*	0	0	0	0	0	0	0	0	0	0	0
Carbon Monoxide		0	0*	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide		0.0556455	0.0409172*	0.0143850	0.0556455	0.00121819	0.0143850	0.170685	0.0432584	0.0137736	0.00445615	0.0556455	0.0137807	0
Methane		0	0*	0	0	0	0	0	0	0	0	0	0	0
Methanol		0	0*	0	0	0	0	0	0	0	0	0	0	0
Ethane		0	0*	0	0	0	0	0	0	0	0	0	0	0
Ethanol		0	0*	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Sulfide		0	0*	0	0	0	0	0	0	0	0	0	0	0
MDEA		0	0*	0	0	0	0	0	0	0	0	0	0	0
O2		2.72372E-06	0.119921*	0	2.72372E-06	2.57638E-06	0	1.10602E-05	0.126786	1.18369E-07	0.127165	2.72372E-06	1.18429E-07	0
MEA		0.114598	0*	0.119875	0.114598	0.00370670	0.119875	3.14032E-05	0	0.114482	1.57191E-10	0.114598	0.114541	2.01680E-17
SO2		0.000128858	0*	0.000134791	0.000128858	0	0.000134791	1.23116E-11	0	0.000128556	0	0.000128858	0.000128621	0
Molar Flow		**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**
Water		31160.9	3752.83*	31081.6	31160.9	159852	31081.6	7671.53	1432.39	32815.4	2884.75	31160.9	5.84926	19.3012
Nitrogen		0.322277	32211.5*	0	0.322277	1.34914	0	0.322304	32211.5	0.0145266	32211.2	0.322277	2.59086E-06	0
Hydrogen		0	0*	0	0	0	0	0	0	0	0	0	0	0
Carbon Monoxide		0	0*	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide		2090.08	1753.61*	516.527	2090.08	195.697	516.527	1579.06	1753.56	518.564	180.097	2090.08	0.0924870	0
Methane		0	0*	0	0	0	0	0	0	0	0	0	0	0
Methanol		0	0*	0	0	0	0	0	0	0	0	0	0	0
Ethane		0	0*	0	0	0	0	0	0	0	0	0	0	0
Ethanol		0	0*	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Sulfide		0	0*	0	0	0	0	0	0	0	0	0	0	0
MDEA		0	0*	0	0	0	0	0	0	0	0	0	0	0
O2		0.102305	5139.52*	0	0.102305	0.413882	0	0.102321	5139.51	0.00445646	5139.41	0.102305	7.94819E-07	0
MEA		4304.39	0*	4304.39	4304.39	595.463	4304.39	0.290520	0	4310.14	6.35292E-06	4304.39	0.768722	3.89267E-16
SO2		4.83999	0*	4.83999	4.83999	0	4.83999	1.13898E-07	0	4.83999	0	4.83999	0.000863222	0
Mass Fraction														
Water		0.612449	0.0558011*	0.661942	0.612449	0.984602	0.661942	0.665315	0.0220594	0.673641	0.0461257	0.612449	0.673512	1
Nitrogen		9.84949E-06	0.744764*	0	9.84949E-06	1.29218E-05	0	4.34646E-05	0.771381	4.63703E-07	0.800877	9.84949E-06	4.63887E-07	0
Hydrogen		0	0*	0	0	0	0	0	0	0	0	0	0	0
Carbon Monoxide		0	0*	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide		0.100352	0.0636974*	0.0268729	0.100352	0.00294463	0.0268729	0.334540	0.0659721	0.0260051	0.00703473	0.100352	0.0260154	0
Methane		0	0*	0	0	0	0	0	0	0	0	0	0	0
Methanol		0	0*	0	0	0	0	0	0	0	0	0	0	0
Ethane		0	0*	0	0	0	0	0	0	0	0	0	0	0
Ethanol		0	0*	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Sulfide		0	0*	0	0	0	0	0	0	0	0	0	0	0
MDEA		0	0*	0	0	0	0	0	0	0	0	0	0	0
O2		3.57148E-06	0.135737*	0	3.57148E-06	4.52805E-06	0	1.57617E-05	0.140588	1.62492E-07	0.145962	3.57148E-06	1.62557E-07	0
MEA		0.286847	0*	0.310819	0.286847	0.0124359	0.310819	8.54283E-05	0	0.3	3.44420E-10	0.286847	0.300119	6.83823E-17
SO2		0.000338279	0*	0.000366549	0.000338279	0	0.000366549	3.51264E-11	0	0.000353318	0	0.000338279	0.000353458	0
Mass Flow		**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**
Water		561.373	67.6084*	559.944	561.373	2879.78	559.944	138.205	25.8049	591.180	51.9696	561.373	0.105376	0.347717
Nitrogen		0.00902808	902.353*	0	0.00902808	0.0377940	0	0.00902882	902.353	0.000406941	902.344	0.00902808	7.25788E-08	0
Hydrogen		0	0*	0	0	0	0	0	0	0	0	0	0	0
Carbon Monoxide		0	0*	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide		91.9835	77.1754*	22.7321	91.9835	8.61251	22.7321	69.4934	77.1735	22.8217	7.92599	91.9835	0.00407031	0
Methane		0	0*	0	0	0	0	0	0	0	0	0	0	0
Methanol		0	0*	0	0	0	0	0	0	0	0	0	0	0
Ethane		0	0*	0	0	0	0	0	0	0	0	0	0	0
Ethanol		0	0*	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Sulfide		0	0*	0	0	0	0	0	0	0	0	0	0	0
MDEA		0	0*	0	0	0	0	0	0	0	0	0	0	0
O2		0.00327363	164.458*	0	0.00327363	0.0132437	0	0.00327414	164.458	0.000142601	164.455	0.00327363	2.54333E-08	0
MEA		262.925	0*	262.925	262.925	36.3727	262.925	0.0177459	0	263.277	3.88056E-07	262.925	0.0469559	2.37777E-17
SO2		0.310068	0*	0.310068	0.310068	0	0.310068	7.29674E-09	0	0.310068	0	0.310068	5.53013E-05	0

Process Streams		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Properties	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Total**	**From Block:**	**XCHG-100**	**--**	**XCHG-100**	**Absorber**	**RCYL-1**	**PUMP-100**	**XCHG-102**	**DTWR-100**	**MKUP-1**	**Absorber Overhead**	**PUMP-101**	**MKUP-1**	**--**
	To Block:	**DTWR-103**	**CMPR-105**	**PUMP-100**	**PUMP-101**	**Absorber Water Wash**	**XCHG-103**	**VSSL-103**	**Absorber**	**Absorber**	**--**	**XCHG-100**	**--**	**MKUP-1**
Property	**Units**													
Temperature	K	372.039*	372.039*	332.490	305.153	313.720	332.554	316.483*	301.993	316.509	313.424	305.172	316.509	316.483*
Pressure	Pa	189606*	101353*	186158	113074	106869	620528*	186158	113074	210290	105490	275790*	210290	620528*
Mole Fraction Vapor		0.00184066	1	0	0	0	0	0.178712	1	0	1	0	0	0
Mole Fraction Light Liquid		0.998159	0	1	1	1	1	0.821288	0	1	0	1	1	1
Molecular Weight	kg/mol	0.0244033	0.0282704	0.0235582	0.0244033	0.0182067	0.0235582	0.0224540	0.0288574	0.0233097	0.0278778	0.0244033	0.0233124	0.0180153
Mass Density	kg/m^3	470.325	0.926415	1034.77	1122.96	992.599	1034.81	8.91445	1.30034	1039.30	1.12903	1122.97	1039.33	990.215
Molar Flow	mol/s	37560.7	42857.5	35907.3	37560.7	160645	35907.3	9251.30	40536.9	37649.0	40415.4	37560.7	6.71134	19.3012
Mass Flow	kg/s	916.604	1211.60*	845.911	916.604	2924.82	845.911	207.728	1169.79	877.588	1126.69	916.604	0.156458	0.347717
Vapor Volumetric Flow	m^3/s	1.94887	1307.83	0.817490	0.816241	2.94662	0.817457	23.3024	899.605	0.844407	997.930	0.816230	0.000150537	0.000351153
Liquid Volumetric Flow	m^3/s	1.94887	1307.83	0.817490	0.816241	2.94662	0.817457	23.3024	899.605	0.844407	997.930	0.816230	0.000150537	0.000351153
Std Vapor Volumetric Flow	m^3/s	889.829	1015.31	850.661	889.829	3805.75	850.661	219.167	960.338	891.922	957.459	889.829	0.158995	0.457254
Std Liquid Volumetric Flow	m^3/s	0.932767	1.42575	0.846494	0.932767	2.92890	0.846494	0.223498	1.38390	0.878216*	1.32525	0.932767	0.000156570	0.000348059
Compressibility		0.00318038	0.999860	0.00153309	0.000968492	0.000751503	0.00510913	0.178195	0.999384	0.00179224	0.999532	0.00236199	0.00179239	0.00429030
Specific Gravity			0.976099	1.03574	1.12402	0.993538	1.03579		0.996367	1.04028	0.962546	1.12403	1.04031	0.991151
API Gravity				2.87544	-5.82637	9.79046	2.86744			3.23837		-5.82829	3.23430	10.0026
Enthalpy	J/s	-1.07644E+10	-1.50270E+09	-1.01434E+10	-1.09857E+10	-4.57464E+10	-1.01429E+10	-2.79919E+09	-1.03224E+09	-1.06886E+10	-7.50600E+08	-1.09855E+10	-1.90536E+06	-5.48979E+06
Mass Enthalpy	J/kg	-1.17438E+07	-1.24027E+06	-1.19911E+07	-1.19852E+07	-1.56408E+07	-1.19905E+07	-1.34753E+07	-882418	-1.21796E+07	-666197	-1.19850E+07	-1.21781E+07	-1.57881E+07
Mass Cp	J/(kg*K)	3780.06	1070.77	3714.94	3287.76	4160.90	3714.58	3076.51	1031.65	3647.87	1063.15	3287.78	3647.65	4203.04
Ideal Gas CpCv Ratio		1.18930	1.37947	1.19403	1.20203	1.31785	1.19401	1.31555	1.38887	1.20061	1.39106	1.20203	1.20057	1.32394
Dynamic Viscosity	Pa*s		2.07563E-05	0.00112727	0.00277288	0.000680079	0.00112702		1.79535E-05	0.00155600	1.84815E-05	0.00277259	0.00155678	0.000631238
Kinematic Viscosity	m^2/s		2.24049E-05	1.08940E-06	2.46927E-06	6.85149E-07	1.08911E-06		1.38068E-05	1.49716E-06	1.63693E-05	2.46897E-06	1.49787E-06	6.37475E-07
Thermal Conductivity	W/(m*K)		0.0303939	0.459770	0.400894	0.616955	0.459808		0.0256695	0.456538	0.0267200	0.400907	0.456478	0.629912
Surface Tension	N/m			0.0605296	0.0886607?	0.0694713	0.0605182			0.0634396		0.0882262?	0.0634370	0.0691872
Net Ideal Gas Heating Value	J/m^3	6.89904E+06	0	7.21670E+06	6.89904E+06	223151	7.21670E+06	1890.53	0	6.89205E+06	0.00946318	6.89904E+06	6.89558E+06	1.21416E-09
Net Liquid Heating Value	J/kg	4.86781E+06	-148633	5.29302E+06	4.86781E+06	-2.15031E+06	5.29302E+06	-1.69631E+06	-65855.2	5.02313E+06	-114924	4.86781E+06	5.02610E+06	-2.46500E+06
Gross Ideal Gas Heating Value	J/m^3	9.20517E+06	164141	9.62487E+06	9.20517E+06	2.11269E+06	9.62487E+06	1.55650E+06	66236.2	9.27614E+06	133797	9.20517E+06	9.27993E+06	1.87450E+06
Gross Liquid Heating Value	J/kg	7.10657E+06	-11082.8	7.71471E+06	7.10657E+06	308346	7.71471E+06	-56085.7	-11478.6	7.44616E+06	-1223.98	7.10657E+06	7.44911E+06	1.69835E-09

Process Streams		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Composition	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Vapor**	**From Block:**	**XCHG-100**	**--**	**XCHG-100**	**Absorber**	**RCYL-1**	**PUMP-100**	**XCHG-102**	**DTWR-100**	**MKUP-1**	**Absorber Overhead**	**PUMP-101**	**MKUP-1**	**--**
	To Block:	**DTWR-103**	**CMPR-105**	**PUMP-100**	**PUMP-101**	**Absorber Water Wash**	**XCHG-103**	**VSSL-103**	**Absorber**	**Absorber**	**--**	**XCHG-100**	**--**	**MKUP-1**
Mole Fraction														
Water		0.475404	0.0875655					0.0479877	0.0353354		0.0713774			
Nitrogen		0.00462301	0.751596					0.000194927	0.794620		0.797002			
Hydrogen		0	0					0	0		0			
Carbon Monoxide		0	0					0	0		0			
Carbon Dioxide		0.518247	0.0409172					0.951756	0.0432584		0.00445615			
Methane		0	0					0	0		0			
Methanol		0	0					0	0		0			
Ethane		0	0					0	0		0			
Ethanol		0	0					0	0		0			
Hydrogen Sulfide		0	0					0	0		0			
MDEA		0	0					0	0		0			
O2		0.00145995	0.119921					6.18784E-05	0.126786		0.127165			
MEA		0.000265302	0					7.71276E-12	0		1.57191E-10			
SO2		8.94313E-09	0					0	0		0			
Molar Flow		**mol/s**	**mol/s**					**mol/s**	**mol/s**		**mol/s**			
Water		32.8678	3752.83					79.3389	1432.39		2884.75			
Nitrogen		0.319619	32211.5					0.322277	32211.5		32211.2			
Hydrogen		0	0					0	0		0			
Carbon Monoxide		0	0					0	0		0			
Carbon Dioxide		35.8298	1753.61					1573.56	1753.56		180.097			
Methane		0	0					0	0		0			
Methanol		0	0					0	0		0			
Ethane		0	0					0	0		0			
Ethanol		0	0					0	0		0			
Hydrogen Sulfide		0	0					0	0		0			
MDEA		0	0					0	0		0			
O2		0.100936	5139.52					0.102305	5139.51		5139.41			
MEA		0.0183421	0					1.27516E-08	0		6.35292E-06			
SO2		6.18297E-07	0					0	0		0			
Mass Fraction														
Water		0.271332	0.0558011					0.0202186	0.0220594		0.0461257			
Nitrogen		0.00410287	0.744764					0.000127708	0.771381		0.800877			
Hydrogen		0	0					0	0		0			
Carbon Monoxide		0	0					0	0		0			
Carbon Dioxide		0.722571	0.0636974					0.979607	0.0659721		0.00703473			
Methane		0	0					0	0		0			
Methanol		0	0					0	0		0			
Ethane		0	0					0	0		0			
Ethanol		0	0					0	0		0			
Hydrogen Sulfide		0	0					0	0		0			
MDEA		0	0					0	0		0			
O2		0.00148002	0.135737					4.63077E-05	0.140588		0.145962			
MEA		0.000513404	0					1.10182E-11	0		3.44420E-10			
SO2		1.81510E-08	0					0	0		0			
Mass Flow		**kg/s**	**kg/s**					**kg/s**	**kg/s**		**kg/s**			
Water		0.592123	67.6084					1.42931	25.8049		51.9696			
Nitrogen		0.00895362	902.353					0.00902808	902.353		902.344			
Hydrogen		0	0					0	0		0			
Carbon Monoxide		0	0					0	0		0			
Carbon Dioxide		1.57685	77.1754					69.2514	77.1735		7.92599			
Methane		0	0					0	0		0			
Methanol		0	0					0	0		0			
Ethane		0	0					0	0		0			
Ethanol		0	0					0	0		0			
Hydrogen Sulfide		0	0					0	0		0			
MDEA		0	0					0	0		0			
O2		0.00322982	164.458					0.00327363	164.458		164.455			
MEA		0.00112039	0					7.78910E-10	0		3.88056E-07			
SO2		3.96105E-08	0					0	0		0			

Process Streams		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Properties	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Vapor**	**From Block:**	**XCHG-100**	**--**	**XCHG-100**	**Absorber**	**RCYL-1**	**PUMP-100**	**XCHG-102**	**DTWR-100**	**MKUP-1**	**Absorber Overhead**	**PUMP-101**	**MKUP-1**	**--**
	To Block:	**DTWR-103**	**CMPR-105**	**PUMP-100**	**PUMP-101**	**Absorber Water Wash**	**XCHG-103**	**VSSL-103**	**Absorber**	**Absorber**	**--**	**XCHG-100**	**--**	**MKUP-1**
Property	**Units**													
Temperature	K	372.039	372.039					316.483	301.993		313.424			
Pressure	Pa	189606	101353					186158	113074		105490			
Mole Fraction Vapor		1	1					1	1		1			
Mole Fraction Light Liquid		0	0					0	0		0			
Molecular Weight	kg/mol	0.0315648	0.0282704					0.0427582	0.0288574		0.0278778			
Mass Density	kg/m^3	1.95150	0.926415					3.05184	1.30034		1.12903			
Molar Flow	mol/s	69.1366	42857.5					1653.32	40536.9		40415.4			
Mass Flow	kg/s	2.18228	1211.60					70.6930	1169.79		1126.69			
Vapor Volumetric Flow	m^3/s	1.11826	1307.83					23.1641	899.605		997.930			
Liquid Volumetric Flow	m^3/s	1.11826	1307.83					23.1641	899.605		997.930			
Std Vapor Volumetric Flow	m^3/s	1.63788	1015.31					39.1679	960.338		957.459			
Std Liquid Volumetric Flow	m^3/s	0.00253930	1.42575					0.0862737	1.38390		1.32525			
Compressibility		0.991430	0.999860					0.991187	0.999384		0.999532			
Specific Gravity		1.08985	0.976099					1.47633	0.996367		0.962546			
API Gravity														
Enthalpy	J/s	-2.18704E+07	-1.50270E+09					-6.37381E+08	-1.03224E+09		-7.50600E+08			
Mass Enthalpy	J/kg	-1.00218E+07	-1.24027E+06					-9.01619E+06	-882418		-666197			
Mass Cp	J/(kg*K)	1196.55	1070.77					891.542	1031.65		1063.15			
Ideal Gas CpCv Ratio		1.28554	1.37947					1.28232	1.38887		1.39106			
Dynamic Viscosity	Pa*s	1.70547E-05	2.07563E-05					1.59297E-05	1.79535E-05		1.84815E-05			
Kinematic Viscosity	m^2/s	8.73927E-06	2.24049E-05					5.21971E-06	1.38068E-05		1.63693E-05			
Thermal Conductivity	W/(m*K)	0.0238583	0.0303939					0.0179298	0.0256695		0.0267200			
Surface Tension	N/m													
Net Ideal Gas Heating Value	J/m^3	15971.7	0					0.000464323	0		0.00946318			
Net Liquid Heating Value	J/kg	-783110	-148633					-220283	-65855.2		-114924			
Gross Ideal Gas Heating Value	J/m^3	908855	164141					89952.7	66236.2		133797			
Gross Liquid Heating Value	J/kg	-112971	-11082.8					-170444	-11478.6		-1223.98			

Process Streams		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Composition	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Light Liquid**	**From Block:**	**XCHG-100**	**--**	**XCHG-100**	**Absorber**	**RCYL-1**	**PUMP-100**	**XCHG-102**	**DTWR-100**	**MKUP-1**	**Absorber Overhead**	**PUMP-101**	**MKUP-1**	**--**
	To Block:	**DTWR-103**	**CMPR-105**	**PUMP-100**	**PUMP-101**	**Absorber Water Wash**	**XCHG-103**	**VSSL-103**	**Absorber**	**Absorber**	**--**	**XCHG-100**	**--**	**MKUP-1**
Mole Fraction														
Water		0.830269		0.865605	0.829616	0.995064	0.865605	0.999238		0.871615		0.829616	0.871549	1
Nitrogen		7.08963E-08		0	8.58018E-06	8.39826E-06	0	3.48412E-09		3.85844E-07		8.58018E-06	3.86042E-07	0
Hydrogen		0		0	0	0	0	0		0		0	0	0
Carbon Monoxide		0		0	0	0	0	0		0		0	0	0
Carbon Dioxide		0.0547925		0.0143850	0.0556455	0.00121819	0.0143850	0.000723847		0.0137736		0.0556455	0.0137807	0
Methane		0		0	0	0	0	0		0		0	0	0
Methanol		0		0	0	0	0	0		0		0	0	0
Ethane		0		0	0	0	0	0		0		0	0	0
Ethanol		0		0	0	0	0	0		0		0	0	0
Hydrogen Sulfide		0		0	0	0	0	0		0		0	0	0
MDEA		0		0	0	0	0	0		0		0	0	0
O2		3.65168E-08		0	2.72372E-06	2.57638E-06	0	2.11076E-09		1.18369E-07		2.72372E-06	1.18429E-07	0
MEA		0.114809		0.119875	0.114598	0.00370670	0.119875	3.82365E-05		0.114482		0.114598	0.114541	0
SO2		0.000129096		0.000134791	0.000128858	0	0.000134791	0		0.000128556		0.000128858	0.000128621	0
Molar Flow		**mol/s**		**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**		**mol/s**		**mol/s**	**mol/s**	**mol/s**
Water		31128.1		31081.6	31160.9	159852	31081.6	7592.19		32815.4		31160.9	5.84926	19.3012
Nitrogen		0.00265801		0	0.322277	1.34914	0	2.64723E-05		0.0145266		0.322277	2.59086E-06	0
Hydrogen		0		0	0	0	0	0		0		0	0	0
Carbon Monoxide		0		0	0	0	0	0		0		0	0	0
Carbon Dioxide		2054.25		516.527	2090.08	195.697	516.527	5.49977		518.564		2090.08	0.0924870	0
Methane		0		0	0	0	0	0		0		0	0	0
Methanol		0		0	0	0	0	0		0		0	0	0
Ethane		0		0	0	0	0	0		0		0	0	0
Ethanol		0		0	0	0	0	0		0		0	0	0
Hydrogen Sulfide		0		0	0	0	0	0		0		0	0	0
MDEA		0		0	0	0	0	0		0		0	0	0
O2		0.00136907		0	0.102305	0.413882	0	1.60375E-05		0.00445646		0.102305	7.94819E-07	0
MEA		4304.37		4304.39	4304.39	595.463	4304.39	0.290520		4310.14		4304.39	0.768722	0
SO2		4.83999		4.83999	4.83999	0	4.83999	0		4.83999		4.83999	0.000863222	0
Mass Fraction														
Water		0.613263		0.661942	0.612449	0.984602	0.661942	0.998104		0.673641		0.612449	0.673512	1
Nitrogen		8.14284E-08		0	9.84949E-06	1.29218E-05	0	5.41160E-09		4.63703E-07		9.84949E-06	4.63887E-07	0
Hydrogen		0		0	0	0	0	0		0		0	0	0
Carbon Monoxide		0		0	0	0	0	0		0		0	0	0
Carbon Dioxide		0.0988676		0.0268729	0.100352	0.00294463	0.0268729	0.00176628		0.0260051		0.100352	0.0260154	0
Methane		0		0	0	0	0	0		0		0	0	0
Methanol		0		0	0	0	0	0		0		0	0	0
Ethane		0		0	0	0	0	0		0		0	0	0
Ethanol		0		0	0	0	0	0		0		0	0	0
Hydrogen Sulfide		0		0	0	0	0	0		0		0	0	0
MDEA		0		0	0	0	0	0		0		0	0	0
O2		4.79086E-08		0	3.57148E-06	4.52805E-06	0	3.74488E-09		1.62492E-07		3.57148E-06	1.62557E-07	0
MEA		0.287531		0.310819	0.286847	0.0124359	0.310819	0.000129499		0.3		0.286847	0.300119	0
SO2		0.000339087		0.000366549	0.000338279	0	0.000366549	0		0.000353318		0.000338279	0.000353458	0
Mass Flow		**kg/s**		**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**		**kg/s**		**kg/s**	**kg/s**	**kg/s**
Water		560.781		559.944	561.373	2879.78	559.944	136.775		591.180		561.373	0.105376	0.347717
Nitrogen		7.44599E-05		0	0.00902808	0.0377940	0	7.41579E-07		0.000406941		0.00902808	7.25788E-08	0
Hydrogen		0		0	0	0	0	0		0		0	0	0
Carbon Monoxide		0		0	0	0	0	0		0		0	0	0
Carbon Dioxide		90.4066		22.7321	91.9835	8.61251	22.7321	0.242042		22.8217		91.9835	0.00407031	0
Methane		0		0	0	0	0	0		0		0	0	0
Methanol		0		0	0	0	0	0		0		0	0	0
Ethane		0		0	0	0	0	0		0		0	0	0
Ethanol		0		0	0	0	0	0		0		0	0	0
Hydrogen Sulfide		0		0	0	0	0	0		0		0	0	0
MDEA		0		0	0	0	0	0		0		0	0	0
O2		4.38086E-05		0	0.00327363	0.0132437	0	5.13180E-07		0.000142601		0.00327363	2.54333E-08	0
MEA		262.924		262.925	262.925	36.3727	262.925	0.0177459		263.277		262.925	0.0469559	0
SO2		0.310068		0.310068	0.310068	0	0.310068	0		0.310068		0.310068	5.53013E-05	0

Process Streams		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Properties	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Light Liquid**	**From Block:**	**XCHG-100**	**--**	**XCHG-100**	**Absorber**	**RCYL-1**	**PUMP-100**	**XCHG-102**	**DTWR-100**	**MKUP-1**	**Absorber Overhead**	**PUMP-101**	**MKUP-1**	**--**
	To Block:	**DTWR-103**	**CMPR-105**	**PUMP-100**	**PUMP-101**	**Absorber Water Wash**	**XCHG-103**	**VSSL-103**	**Absorber**	**Absorber**	**--**	**XCHG-100**	**--**	**MKUP-1**
Property	**Units**													
Temperature	K	372.039		332.490	305.153	313.720	332.554	316.483		316.509		305.172	316.509	316.483
Pressure	Pa	189606		186158	113074	106869	620528	186158		210290		275790	210290	620528
Mole Fraction Vapor		0		0	0	0	0	0		0		0	0	0
Mole Fraction Light Liquid		1		1	1	1	1	1		1		1	1	1
Molecular Weight	kg/mol	0.0243901		0.0235582	0.0244033	0.0182067	0.0235582	0.0180357		0.0233097		0.0244033	0.0233124	0.0180153
Mass Density	kg/m^3	1100.89		1034.77	1122.96	992.599	1034.81	990.515		1039.30		1122.97	1039.33	990.215
Molar Flow	mol/s	37491.5		35907.3	37560.7	160645	35907.3	7597.98		37649.0		37560.7	6.71134	19.3012
Mass Flow	kg/s	914.421		845.911	916.604	2924.82	845.911	137.035		877.588		916.604	0.156458	0.347717
Vapor Volumetric Flow	m^3/s	0.830617		0.817490	0.816241	2.94662	0.817457	0.138347		0.844407		0.816230	0.000150537	0.000351153
Liquid Volumetric Flow	m^3/s	0.830617		0.817490	0.816241	2.94662	0.817457	0.138347		0.844407		0.816230	0.000150537	0.000351153
Std Vapor Volumetric Flow	m^3/s	888.191		850.661	889.829	3805.75	850.661	179.999		891.922		889.829	0.158995	0.457254
Std Liquid Volumetric Flow	m^3/s	0.930228		0.846494	0.932767	2.92890	0.846494	0.137224		0.878216		0.932767	0.000156570	0.000348059
Compressibility		0.00135799		0.00153309	0.000968492	0.000751503	0.00510913	0.00128816		0.00179224		0.00236199	0.00179239	0.00429030
Specific Gravity		1.10193		1.03574	1.12402	0.993538	1.03579	0.991451		1.04028		1.12403	1.04031	0.991151
API Gravity		-5.69298		2.87544	-5.82637	9.79046	2.86744	9.95331		3.23837		-5.82829	3.23430	10.0026
Enthalpy	J/s	-1.07426E+10		-1.01434E+10	-1.09857E+10	-4.57464E+10	-1.01429E+10	-2.16181E+09		-1.06886E+10		-1.09855E+10	-1.90536E+06	-5.48979E+06
Mass Enthalpy	J/kg	-1.17479E+07		-1.19911E+07	-1.19852E+07	-1.56408E+07	-1.19905E+07	-1.57756E+07		-1.21796E+07		-1.19850E+07	-1.21781E+07	-1.57881E+07
Mass Cp	J/(kg*K)	3786.23		3714.94	3287.76	4160.90	3714.58	4203.67		3647.87		3287.78	3647.65	4203.04
Ideal Gas CpCv Ratio		1.18918		1.19403	1.20203	1.31785	1.19401	1.32384		1.20061		1.20203	1.20057	1.32394
Dynamic Viscosity	Pa*s	0.000668999		0.00112727	0.00277288	0.000680079	0.00112702	0.000628958		0.00155600		0.00277259	0.00155678	0.000631238
Kinematic Viscosity	m^2/s	6.07687E-07		1.08940E-06	2.46927E-06	6.85149E-07	1.08911E-06	6.34980E-07		1.49716E-06		2.46897E-06	1.49787E-06	6.37475E-07
Thermal Conductivity	W/(m*K)	0.427985		0.459770	0.400894	0.616955	0.459808	0.628155		0.456538		0.400907	0.456478	0.629912
Surface Tension	N/m	0.0819293?		0.0605296	0.0886607?	0.0694713	0.0605182	0.0691354		0.0634396		0.0882262?	0.0634370	0.0691872
Net Ideal Gas Heating Value	J/m^3	6.91174E+06		7.21670E+06	6.89904E+06	223151	7.21670E+06	2301.91		6.89205E+06		6.89904E+06	6.89558E+06	0
Net Liquid Heating Value	J/kg	4.88129E+06		5.29302E+06	4.86781E+06	-2.15031E+06	5.29302E+06	-2.45775E+06		5.02313E+06		4.86781E+06	5.02610E+06	-2.46500E+06
Gross Ideal Gas Heating Value	J/m^3	9.22047E+06		9.62487E+06	9.20517E+06	2.11269E+06	9.62487E+06	1.87562E+06		9.27614E+06		9.20517E+06	9.27993E+06	1.87450E+06
Gross Liquid Heating Value	J/kg	7.12379E+06		7.71471E+06	7.10657E+06	308346	7.71471E+06	2908.92		7.44616E+06		7.10657E+06	7.44911E+06	0

Process Streams		**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**
Composition	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Total**	**From Block:**	**Absorber Water Wash**	**Absorber**	**XCHG-103**	**--**	**MKUP-2**	**RCYL-2**	**PUMP-102**	**DTWR-103**	**MIX-100**	**CMPR-100**	**CMPR-101**	**XCHG-101**
	To Block:	**PUMP-102**	**Absorber Water Wash**	**MIX-100**	**Absorber Overhead**	**XCHG-107**	**MKUP-1**	**SPLT-100**	**K-101**	**RCYL-2**	**XCHG-101**	**XCHG-104**	**VSSL-101**
Mole Fraction													
Water		0.995023	0.0759852	0.865605	1*	0.999970	0.871549	0.995023	0.898810	0.871554	0.0479877	0.0100810	0.0479877
Nitrogen		8.40089E-06	0.792884	0	0*	8.42812E-06	3.86042E-07	8.40089E-06	0	3.86136E-07	0.000194927	0.000202712	0.000194927
Hydrogen		0	0	0	0*	0	0	0	0	0	0	0	0
Carbon Monoxide		0	0	0	0*	0	0	0	0	0	0	0	0
Carbon Dioxide		0.00122876	0.00448111	0.0143850	0*	1.90603E-05	0.0137807	0.00122876	0.0127241	0.0137803	0.951756	0.989652	0.951756
Methane		0	0	0	0*	0	0	0	0	0	0	0	0
Methanol		0	0	0	0*	0	0	0	0	0	0	0	0
Ethane		0	0	0	0*	0	0	0	0	0	0	0	0
Ethanol		0	0	0	0*	0	0	0	0	0	0	0	0
Hydrogen Sulfide		0	0	0	0*	0	0	0	0	0	0	0	0
MDEA		0	0	0	0*	0	0	0	0	0	0	0	0
O2		2.57734E-06	0.126508	0	0*	2.56802E-06	1.18429E-07	2.57734E-06	0	1.18464E-07	6.18784E-05	6.43493E-05	6.18784E-05
MEA		0.00373729	0.000141576	0.119875	0*	0	0.114541	0.00373729	0.0883682	0.114537	7.71276E-12	0	7.71276E-12
SO2		0	1.03743E-13	0.000134791	0*	0	0.000128621	0	9.73759E-05	0.000128596	0	0	0
Molar Flow		**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**
Water		160038	3086.92	31081.6	1398.79*	174837	32802.0	160038	44675.2	32802.9	79.3389	16.0270	79.3389
Nitrogen		1.35119	32211.2	0	0*	1.47360	0.0145292	1.35119	0	0.0145331	0.322277	0.322276	0.322277
Hydrogen		0	0	0	0*	0	0	0	0	0	0	0	0
Carbon Monoxide		0	0	0	0*	0	0	0	0	0	0	0	0
Carbon Dioxide		197.632	182.046	516.527	0*	3.33255	518.657	197.632	632.448	518.653	1573.56	1573.37	1573.56
Methane		0	0	0	0*	0	0	0	0	0	0	0	0
Methanol		0	0	0	0*	0	0	0	0	0	0	0	0
Ethane		0	0	0	0*	0	0	0	0	0	0	0	0
Ethanol		0	0	0	0*	0	0	0	0	0	0	0	0
Hydrogen Sulfide		0	0	0	0*	0	0	0	0	0	0	0	0
MDEA		0	0	0	0*	0	0	0	0	0	0	0	0
O2		0.414537	5139.41	0	0*	0.449000	0.00445725	0.414537	0	0.00445868	0.102305	0.102304	0.102305
MEA		601.102	5.75155	4304.39	0*	0	4310.91	601.102	4392.32	4310.85	1.27516E-08	0	1.27516E-08
SO2		0	4.21459E-09	4.83999	0*	0	4.84085	0	4.84005	4.83999	0	0	0
Mass Fraction													
Water		0.984475	0.0491803	0.661942	1*	0.999936	0.673512	0.984475	0.730821	0.673521	0.0202186	0.00415175	0.0202186
Nitrogen		1.29247E-05	0.797988	0	0*	1.31051E-05	4.63887E-07	1.29247E-05	0	4.64005E-07	0.000127708	0.000129817	0.000127708
Hydrogen		0	0	0	0*	0	0	0	0	0	0	0	0
Carbon Monoxide		0	0	0	0*	0	0	0	0	0	0	0	0
Carbon Dioxide		0.00296990	0.00708521	0.0268729	0*	4.65608E-05	0.0260154	0.00296990	0.0252741	0.0260148	0.979607	0.995671	0.979607
Methane		0	0	0	0*	0	0	0	0	0	0	0	0
Methanol		0	0	0	0*	0	0	0	0	0	0	0	0
Ethane		0	0	0	0*	0	0	0	0	0	0	0	0
Ethanol		0	0	0	0*	0	0	0	0	0	0	0	0
Hydrogen Sulfide		0	0	0	0*	0	0	0	0	0	0	0	0
MDEA		0	0	0	0*	0	0	0	0	0	0	0	0
O2		4.52936E-06	0.145436	0	0*	4.56118E-06	1.62557E-07	4.52936E-06	0	1.62606E-07	4.63077E-05	4.70722E-05	4.63077E-05
MEA		0.0125374	0.000310692	0.310819	0*	0	0.300119	0.0125374	0.243623	0.300111	1.10182E-11	0	1.10182E-11
SO2		0	2.38777E-13	0.000366549	0*	0	0.000353458	0	0.000281557	0.000353390	0	0	0
Mass Flow		**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**
Water		2883.14	55.6118	559.944	25.1996*	3149.74	590.937	2883.14	804.836	590.954	1.42931	0.288731	1.42931
Nitrogen		0.0378514	902.344	0	0*	0.0412804	0.000407013	0.0378514	0	0.000407122	0.00902808	0.00902805	0.00902808
Hydrogen		0	0	0	0*	0	0	0	0	0	0	0	0
Carbon Monoxide		0	0	0	0*	0	0	0	0	0	0	0	0
Carbon Dioxide		8.69768	8.01177	22.7321	0*	0.146664	22.8258	8.69768	27.8337	22.8257	69.2514	69.2434	69.2514
Methane		0	0	0	0*	0	0	0	0	0	0	0	0
Methanol		0	0	0	0*	0	0	0	0	0	0	0	0
Ethane		0	0	0	0*	0	0	0	0	0	0	0	0
Ethanol		0	0	0	0*	0	0	0	0	0	0	0	0
Hydrogen Sulfide		0	0	0	0*	0	0	0	0	0	0	0	0
MDEA		0	0	0	0*	0	0	0	0	0	0	0	0
O2		0.0132647	164.455	0	0*	0.0143675	0.000142627	0.0132647	0	0.000142672	0.00327363	0.00327361	0.00327363
MEA		36.7172	0.351323	262.925	0*	0	263.323	36.7172	268.297	263.320	7.78910E-10	0	7.78910E-10
SO2		0	2.70003E-10	0.310068	0*	0	0.310123	0	0.310072	0.310068	0	0	0

Process Streams		**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**
Properties	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Total**	**From Block:**	**Absorber Water Wash**	**Absorber**	**XCHG-103**	**--**	**MKUP-2**	**RCYL-2**	**PUMP-102**	**DTWR-103**	**MIX-100**	**CMPR-100**	**CMPR-101**	**XCHG-101**
	To Block:	**PUMP-102**	**Absorber Water Wash**	**MIX-100**	**Absorber Overhead**	**XCHG-107**	**MKUP-1**	**SPLT-100**	**K-101**	**RCYL-2**	**XCHG-101**	**XCHG-104**	**VSSL-101**
Property	**Units**												
Temperature	K	314.753	317.208	316.483*	302.594*	316.093	316.509	314.766	398.707	316.508	453.853	453.471	310.928*
Pressure	Pa	108937	108937	599844	126174*	115142	210290	210290*	220632	210290	723950*	2.82685E+06*	689476
Mole Fraction Vapor		0	1	0	0	0	0	0	0	0	1	1	0.961596
Mole Fraction Light Liquid		1	0	1	1	1	1	1	1	1	0	0	0.0384036
Molecular Weight	kg/mol	0.0182083	0.0278342	0.0235582	0.0180153	0.0180159	0.0233124	0.0182083	0.0221563	0.0233123	0.0427582	0.0437434	0.0427582
Mass Density	kg/m^3	992.206	1.15021	1042.30	995.124	990.305	1039.33	992.215	976.753	1039.33	8.28289	33.9941	12.2727
Molar Flow	mol/s	160839	40625.3	35907.3	1398.79	174843	37636.4	160839	49704.8	37637.3	1653.32	1589.83	1653.32
Mass Flow	kg/s	2928.60	1130.77	845.911	25.1996*	3149.95*	877.397	2928.60	1101.28	877.410	70.6930	69.5444	70.6930
Vapor Volumetric Flow	m^3/s	2.95161	983.100	0.811579	0.0253231	3.18079	0.844196	2.95158	1.12749	0.844210	8.53483	2.04578	5.76019
Liquid Volumetric Flow	m^3/s	2.95161	983.100	0.811579	0.0253231	3.18079	0.844196	2.95158	1.12749	0.844210	8.53483	2.04578	5.76019
Std Vapor Volumetric Flow	m^3/s	3810.35	962.431	850.661	33.1379	4142.10	891.624	3810.35	1177.53	891.644	39.1679	37.6637	39.1679
Std Liquid Volumetric Flow	m^3/s	2.93271	1.32935	0.846494	0.0252244	3.15309	0.878024	2.93271	1.10315	0.878037	0.0862737	0.0851222	0.0862737
Compressibility		0.000763905	0.999535	0.00515229	0.000907901	0.000797027	0.00179239	0.00147455	0.00150971	0.00179239	0.990368	0.964778	0.929191
Specific Gravity		0.993144	0.961041	1.04329	0.996064	0.991241	1.04031	0.993153	0.977677	1.04031	1.47633	1.51034	
API Gravity		9.78847		2.86782	10.0113	10.0107	3.23430	9.78666	4.50503	3.23457			
Enthalpy	J/s	-4.57893E+10	-7.96782E+08	-1.01928E+10	-3.99324E+08	-4.97364E+10	-1.06851E+10	-4.57888E+10	-1.37806E+10	-1.06853E+10	-6.28333E+08	-6.13981E+08	-6.40792E+08
Mass Enthalpy	J/kg	-1.56352E+07	-704634	-1.20495E+07	-1.58464E+07	-1.57896E+07	-1.21781E+07	-1.56350E+07	-1.25133E+07	-1.21782E+07	-8.88819E+06	-8.82861E+06	-9.06443E+06
Mass Cp	J/(kg*K)	4165.89	1066.70	3627.70	4133.63	4202.17	3647.65	4165.76	4132.25	3647.66	1015.77	1043.71	947.628
Ideal Gas CpCv Ratio		1.31770	1.39011	1.19708	1.32512	1.32397	1.20057	1.31770	1.20528	1.20058	1.24111	1.23901	1.28463
Dynamic Viscosity	Pa*s	0.000666996	1.86277E-05	0.00163214	0.000829451	0.000635042	0.00155678	0.000666975	0.000325976	0.00155676	2.18006E-05	2.22635E-05	
Kinematic Viscosity	m^2/s	6.72235E-07	1.61950E-05	1.56590E-06	8.33515E-07	6.41259E-07	1.49787E-06	6.72208E-07	3.33734E-07	1.49786E-06	2.63201E-06	6.54923E-07	
Thermal Conductivity	W/(m*K)	0.618082	0.0269771	0.451069	0.612417	0.629382	0.456478	0.618097	0.510734	0.456481	0.0290756	0.0300996	
Surface Tension	N/m	0.0692680		0.0632003	0.0719272	0.0692616	0.0634370	0.0692654	0.0498440?	0.0634373			
Net Ideal Gas Heating Value	J/m^3	224992	8523.14	7.21670E+06	0	0	6.89558E+06	224992	5.31994E+06	6.89534E+06	0.000464323	0	0.000464323
Net Liquid Heating Value	J/kg	-2.14773E+06	-115535	5.29302E+06	-2.46500E+06	-2.46485E+06	5.02610E+06	-2.14773E+06	3.62545E+06	5.02589E+06	-220283	-183473	-220283
Gross Ideal Gas Heating Value	J/m^3	2.11465E+06	151885	9.62487E+06	1.87450E+06	1.87444E+06	9.27993E+06	2.11465E+06	7.58387E+06	9.27967E+06	89952.7	18896.8	89952.7
Gross Liquid Heating Value	J/kg	310864	6483.59	7.71471E+06	0	-8.10121	7.44911E+06	310864	6.04614E+06	7.44890E+06	-170444	-173239	-170444

Process Streams		**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**
Composition	**Status:**	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved
Phase: **Vapor**	**From Block:**	**Absorber Water Wash**	**Absorber**	**XCHG-103**	**--**	**MKUP-2**	**RCYL-2**	**PUMP-102**	**DTWR-103**	**MIX-100**	**CMPR-100**	**CMPR-101**	**XCHG-101**
	To Block:	**PUMP-102**	**Absorber Water Wash**	**MIX-100**	**Absorber Overhead**	**XCHG-107**	**MKUP-1**	**SPLT-100**	**K-101**	**RCYL-2**	**XCHG-101**	**XCHG-104**	**VSSL-101**
Mole Fraction													
Water			0.0759852								0.0479877	0.0100810	0.0100810
Nitrogen			0.792884								0.000194927	0.000202712	0.000202712
Hydrogen			0								0	0	0
Carbon Monoxide			0								0	0	0
Carbon Dioxide			0.00448111								0.951756	0.989652	0.989652
Methane			0								0	0	0
Methanol			0								0	0	0
Ethane			0								0	0	0
Ethanol			0								0	0	0
Hydrogen Sulfide			0								0	0	0
MDEA			0								0	0	0
O2			0.126508								6.18784E-05	6.43493E-05	6.43493E-05
MEA			0.000141576								0	0	0
SO2			1.03743E-13								0	0	0
Molar Flow			**mol/s**								**mol/s**	**mol/s**	**mol/s**
Water			3086.92								79.3389	16.0270	16.0270
Nitrogen			32211.2								0.322277	0.322276	0.322276
Hydrogen			0								0	0	0
Carbon Monoxide			0								0	0	0
Carbon Dioxide			182.046								1573.56	1573.37	1573.37
Methane			0								0	0	0
Methanol			0								0	0	0
Ethane			0								0	0	0
Ethanol			0								0	0	0
Hydrogen Sulfide			0								0	0	0
MDEA			0								0	0	0
O2			5139.41								0.102305	0.102304	0.102304
MEA			5.75155								0	0	0
SO2			4.21459E-09								0	0	0
Mass Fraction													
Water			0.0491803								0.0202186	0.00415175	0.00415175
Nitrogen			0.797988								0.000127708	0.000129817	0.000129817
Hydrogen			0								0	0	0
Carbon Monoxide			0								0	0	0
Carbon Dioxide			0.00708521								0.979607	0.995671	0.995671
Methane			0								0	0	0
Methanol			0								0	0	0
Ethane			0								0	0	0
Ethanol			0								0	0	0
Hydrogen Sulfide			0								0	0	0
MDEA			0								0	0	0
O2			0.145436								4.63077E-05	4.70722E-05	4.70722E-05
MEA			0.000310692								0	0	0
SO2			2.38777E-13								0	0	0
Mass Flow			**kg/s**								**kg/s**	**kg/s**	**kg/s**
Water			55.6118								1.42931	0.288731	0.288731
Nitrogen			902.344								0.00902808	0.00902805	0.00902805
Hydrogen			0								0	0	0
Carbon Monoxide			0								0	0	0
Carbon Dioxide			8.01177								69.2514	69.2434	69.2434
Methane			0								0	0	0
Methanol			0								0	0	0
Ethane			0								0	0	0
Ethanol			0								0	0	0
Hydrogen Sulfide			0								0	0	0
MDEA			0								0	0	0
O2			164.455								0.00327363	0.00327361	0.00327361
MEA			0.351323								0	0	0
SO2			2.70003E-10								0	0	0

Process Streams		**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**
Properties	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Vapor**	**From Block:**	**Absorber Water Wash**	**Absorber**	**XCHG-103**	**--**	**MKUP-2**	**RCYL-2**	**PUMP-102**	**DTWR-103**	**MIX-100**	**CMPR-100**	**CMPR-101**	**XCHG-101**
	To Block:	**PUMP-102**	**Absorber Water Wash**	**MIX-100**	**Absorber Overhead**	**XCHG-107**	**MKUP-1**	**SPLT-100**	**K-101**	**RCYL-2**	**XCHG-101**	**XCHG-104**	**VSSL-101**
Property	**Units**												
Temperature	K		317.208								453.853	453.471	310.928
Pressure	Pa		108937								723950	2.82685E+06	689476
Mole Fraction Vapor			1								1	1	1
Mole Fraction Light Liquid			0								0	0	0
Molecular Weight	kg/mol		0.0278342								0.0427582	0.0437434	0.0437434
Mass Density	kg/m^3		1.15021								8.28289	33.9941	12.0757
Molar Flow	mol/s		40625.3								1653.32	1589.83	1589.83
Mass Flow	kg/s		1130.77								70.6930	69.5444	69.5444
Vapor Volumetric Flow	m^3/s		983.100								8.53483	2.04578	5.75904
Liquid Volumetric Flow	m^3/s		983.100								8.53483	2.04578	5.75904
Std Vapor Volumetric Flow	m^3/s		962.431								39.1679	37.6637	37.6637
Std Liquid Volumetric Flow	m^3/s		1.32935								0.0862737	0.0851222	0.0851222
Compressibility			0.999535								0.990368	0.964778	0.966107
Specific Gravity			0.961041								1.47633	1.51034	1.51034
API Gravity													
Enthalpy	J/s		-7.96782E+08								-6.28333E+08	-6.13981E+08	-6.22684E+08
Mass Enthalpy	J/kg		-704634								-8.88819E+06	-8.82861E+06	-8.95375E+06
Mass Cp	J/(kg*K)		1066.70								1015.77	1043.71	894.274
Ideal Gas CpCv Ratio			1.39011								1.24111	1.23901	1.28325
Dynamic Viscosity	Pa*s		1.86277E-05								2.18006E-05	2.22635E-05	1.58671E-05
Kinematic Viscosity	m^2/s		1.61950E-05								2.63201E-06	6.54923E-07	1.31397E-06
Thermal Conductivity	W/(m*K)		0.0269771								0.0290756	0.0300996	0.0178110
Surface Tension	N/m												
Net Ideal Gas Heating Value	J/m^3		8523.14								0	0	0
Net Liquid Heating Value	J/kg		-115535								-220283	-183473	-183473
Gross Ideal Gas Heating Value	J/m^3		151885								89952.7	18896.8	18896.8
Gross Liquid Heating Value	J/kg		6483.59								-170444	-173239	-173239

Process Streams		**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**
Composition	**Status:**	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved
Phase: **Light Liquid**	**From Block:**	**Absorber Water Wash**	**Absorber**	**XCHG-103**	**--**	**MKUP-2**	**RCYL-2**	**PUMP-102**	**DTWR-103**	**MIX-100**	**CMPR-100**	**CMPR-101**	**XCHG-101**
	To Block:	**PUMP-102**	**Absorber Water Wash**	**MIX-100**	**Absorber Overhead**	**XCHG-107**	**MKUP-1**	**SPLT-100**	**K-101**	**RCYL-2**	**XCHG-101**	**XCHG-104**	**VSSL-101**
Mole Fraction													
Water		0.995023		0.865605	1	0.999970	0.871549	0.995023	0.898810	0.871554			0.997142
Nitrogen		8.40089E-06		0	0	8.42812E-06	3.86042E-07	8.40089E-06	0	3.86136E-07			1.41001E-08
Hydrogen		0		0	0	0	0	0	0	0			0
Carbon Monoxide		0		0	0	0	0	0	0	0			0
Carbon Dioxide		0.00122876		0.0143850	0	1.90603E-05	0.0137807	0.00122876	0.0127241	0.0137803			0.00285813
Methane		0		0	0	0	0	0	0	0			0
Methanol		0		0	0	0	0	0	0	0			0
Ethane		0		0	0	0	0	0	0	0			0
Ethanol		0		0	0	0	0	0	0	0			0
Hydrogen Sulfide		0		0	0	0	0	0	0	0			0
MDEA		0		0	0	0	0	0	0	0			0
O2		2.57734E-06		0	0	2.56802E-06	1.18429E-07	2.57734E-06	0	1.18464E-07			8.64846E-09
MEA		0.00373729		0.119875	0	0	0.114541	0.00373729	0.0883682	0.114537			0
SO2		0		0.000134791	0	0	0.000128621	0	9.73759E-05	0.000128596			0
Molar Flow		**mol/s**		**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**			**mol/s**
Water		160038		31081.6	1398.79	174837	32802.0	160038	44675.2	32802.9			63.3119
Nitrogen		1.35119		0	0	1.47360	0.0145292	1.35119	0	0.0145331			8.95261E-07
Hydrogen		0		0	0	0	0	0	0	0			0
Carbon Monoxide		0		0	0	0	0	0	0	0			0
Carbon Dioxide		197.632		516.527	0	3.33255	518.657	197.632	632.448	518.653			0.181472
Methane		0		0	0	0	0	0	0	0			0
Methanol		0		0	0	0	0	0	0	0			0
Ethane		0		0	0	0	0	0	0	0			0
Ethanol		0		0	0	0	0	0	0	0			0
Hydrogen Sulfide		0		0	0	0	0	0	0	0			0
MDEA		0		0	0	0	0	0	0	0			0
O2		0.414537		0	0	0.449000	0.00445725	0.414537	0	0.00445868			5.49120E-07
MEA		601.102		4304.39	0	0	4310.91	601.102	4392.32	4310.85			0
SO2		0		4.83999	0	0	4.84085	0	4.84005	4.83999			0
Mass Fraction													
Water		0.984475		0.661942	1	0.999936	0.673512	0.984475	0.730821	0.673521			0.993047
Nitrogen		1.29247E-05		0	0	1.31051E-05	4.63887E-07	1.29247E-05	0	4.64005E-07			2.18353E-08
Hydrogen		0		0	0	0	0	0	0	0			0
Carbon Monoxide		0		0	0	0	0	0	0	0			0
Carbon Dioxide		0.00296990		0.0268729	0	4.65608E-05	0.0260154	0.00296990	0.0252741	0.0260148			0.00695344
Methane		0		0	0	0	0	0	0	0			0
Methanol		0		0	0	0	0	0	0	0			0
Ethane		0		0	0	0	0	0	0	0			0
Ethanol		0		0	0	0	0	0	0	0			0
Hydrogen Sulfide		0		0	0	0	0	0	0	0			0
MDEA		0		0	0	0	0	0	0	0			0
O2		4.52936E-06		0	0	4.56118E-06	1.62557E-07	4.52936E-06	0	1.62606E-07			1.52983E-08
MEA		0.0125374		0.310819	0	0	0.300119	0.0125374	0.243623	0.300111			0
SO2		0		0.000366549	0	0	0.000353458	0	0.000281557	0.000353390			0
Mass Flow		**kg/s**		**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**			**kg/s**
Water		2883.14		559.944	25.1996	3149.74	590.937	2883.14	804.836	590.954			1.14058
Nitrogen		0.0378514		0	0	0.0412804	0.000407013	0.0378514	0	0.000407122			2.50793E-08
Hydrogen		0		0	0	0	0	0	0	0			0
Carbon Monoxide		0		0	0	0	0	0	0	0			0
Carbon Dioxide		8.69768		22.7321	0	0.146664	22.8258	8.69768	27.8337	22.8257			0.00798650
Methane		0		0	0	0	0	0	0	0			0
Methanol		0		0	0	0	0	0	0	0			0
Ethane		0		0	0	0	0	0	0	0			0
Ethanol		0		0	0	0	0	0	0	0			0
Hydrogen Sulfide		0		0	0	0	0	0	0	0			0
MDEA		0		0	0	0	0	0	0	0			0
O2		0.0132647		0	0	0.0143675	0.000142627	0.0132647	0	0.000142672			1.75712E-08
MEA		36.7172		262.925	0	0	263.323	36.7172	268.297	263.320			0
SO2		0		0.310068	0	0	0.310123	0	0.310072	0.310068			0

Process Streams		14	15	16	17	18	19	20	21	22	23	24	25
Properties	Status:	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved
Phase: **Light Liquid**	From Block:	Absorber Water Wash	Absorber	XCHG-103	--	MKUP-2	RCYL-2	PUMP-102	DTWR-103	MIX-100	CMPR-100	CMPR-101	XCHG-101
	To Block:	PUMP-102	Absorber Water Wash	MIX-100	Absorber Overhead	XCHG-107	MKUP-1	SPLT-100	K-101	RCYL-2	XCHG-101	XCHG-104	VSSL-101
Property	**Units**												
Temperature	K	314.753		316.483	302.594	316.093	316.509	314.766	398.707	316.508			310.928
Pressure	Pa	108937		599844	126174	115142	210290	210290	220632	210290			689476
Mole Fraction Vapor		0		0	0	0	0	0	0	0			0
Mole Fraction Light Liquid		1		1	1	1	1	1	1	1			1
Molecular Weight	kg/mol	0.0182083		0.0235582	0.0180153	0.0180159	0.0233124	0.0182083	0.0221563	0.0233123			0.0180896
Mass Density	kg/m^3	992.206		1042.30	995.124	990.305	1039.33	992.215	976.753	1039.33			993.769
Molar Flow	mol/s	160839		35907.3	1398.79	174843	37636.4	160839	49704.8	37637.3			63.4934
Mass Flow	kg/s	2928.60		845.911	25.1996	3149.95	877.397	2928.60	1101.28	877.410			1.14857
Vapor Volumetric Flow	m^3/s	2.95161		0.811579	0.0253231	3.18079	0.844196	2.95158	1.12749	0.844210			0.00115577
Liquid Volumetric Flow	m^3/s	2.95161		0.811579	0.0253231	3.18079	0.844196	2.95158	1.12749	0.844210			0.00115577
Std Vapor Volumetric Flow	m^3/s	3810.35		850.661	33.1379	4142.10	891.624	3810.35	1177.53	891.644			1.50419
Std Liquid Volumetric Flow	m^3/s	2.93271		0.846494	0.0252244	3.15309	0.878024	2.93271	1.10315	0.878037			0.00115149
Compressibility		0.000763905		0.00515229	0.000907901	0.000797027	0.00179239	0.00147455	0.00150971	0.00179239			0.00485476
Specific Gravity		0.993144		1.04329	0.996064	0.991241	1.04031	0.993153	0.977677	1.04031			0.994708
API Gravity		9.78847		2.86782	10.0113	10.0107	3.23430	9.78666	4.50503	3.23457			9.78245
Enthalpy	J/s	-4.57893E+10		-1.01928E+10	-3.99324E+08	-4.97364E+10	-1.06851E+10	-4.57888E+10	-1.37806E+10	-1.06853E+10			-1.81084E+07
Mass Enthalpy	J/kg	-1.56352E+07		-1.20495E+07	-1.58464E+07	-1.57896E+07	-1.21781E+07	-1.56350E+07	-1.25133E+07	-1.21782E+07			-1.57661E+07
Mass Cp	J/(kg*K)	4165.89		3627.70	4133.63	4202.17	3647.65	4165.76	4132.25	3647.66			4178.15
Ideal Gas CpCv Ratio		1.31770		1.19708	1.32512	1.32397	1.20057	1.31770	1.20528	1.20058			1.32428
Dynamic Viscosity	Pa*s	0.000666996		0.00163214	0.000829451	0.000635042	0.00155678	0.000666975	0.000325976	0.00155676			0.000692805
Kinematic Viscosity	m^2/s	6.72235E-07		1.56590E-06	8.33515E-07	6.41259E-07	1.49787E-06	6.72208E-07	3.33734E-07	1.49786E-06			6.97149E-07
Thermal Conductivity	W/(m*K)	0.618082		0.451069	0.612417	0.629382	0.456478	0.618097	0.510734	0.456481			0.616673
Surface Tension	N/m	0.0692680		0.0632003	0.0719272	0.0692616	0.0634370	0.0692654	0.0498440?	0.0634373			0.0700774
Net Ideal Gas Heating Value	J/m^3	224992		7.21670E+06	0	0	6.89558E+06	224992	5.31994E+06	6.89534E+06			0
Net Liquid Heating Value	J/kg	-2.14773E+06		5.29302E+06	-2.46500E+06	-2.46485E+06	5.02610E+06	-2.14773E+06	3.62545E+06	5.02589E+06			-2.44907E+06
Gross Ideal Gas Heating Value	J/m^3	2.11465E+06		9.62487E+06	1.87450E+06	1.87444E+06	9.27993E+06	2.11465E+06	7.58387E+06	9.27967E+06			1.86914E+06
Gross Liquid Heating Value	J/kg	310864		7.71471E+06	0	-8.10121	7.44911E+06	310864	6.04614E+06	7.44890E+06			-1209.84

Process Streams	**26**	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**	**37**	**38**	**39**	**40**
Composition Status:	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved
Phase: **Total** From Block:	CMPR-102	XCHG-104	XCHG-105	DTWR-103	VSSL-101	VSSL-103	VSSL-103	K-101	K-101	VSSL-101	VSSL-102	VSSL-102	CMPR-103	XCHG-106	VSSL-104
To Block:	XCHG-105	VSSL-102	--	XCHG-102	--	DTWR-103	CMPR-100	XCHG-100	DTWR-103	CMPR-101	--	CMPR-102	XCHG-106	--	--
Mole Fraction															
Water	0.00302719	0.0100810	0.00302719	0.829238	0.997142	0.999238	0.0479877	0.865605	0.985225	0.0100810	0.989812	0.00302719	0.00307574	0.00307574	
Nitrogen	0.000204171	0.000202712	0.000204171	3.48387E-05	1.41001E-08	3.48412E-09	0.000194927	0	0	0.000202712	5.86246E-08	0.000204171	0	0	
Hydrogen	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Carbon Monoxide	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Carbon Dioxide	0.996704	0.989652	0.996704	0.170685	0.00285813	0.000723847	0.951756	0.0143850	0.00840163	0.989652	0.0101875	0.996704	0.996924	0.996924	
Methane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Methanol	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Ethane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Ethanol	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Hydrogen Sulfide	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
MDEA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
O2	6.48123E-05	6.43493E-05	6.48123E-05	1.10602E-05	8.64846E-09	2.11076E-09	6.18784E-05	0	0	6.43493E-05	3.59067E-08	6.48123E-05	0	0	
MEA	0	0	0	3.14032E-05	0	3.82365E-05	7.71276E-12	0.119875	0.00637350	0	0	0	0	0	
SO2	0	0	0	1.23116E-11	0	0	0	0.000134791	4.49243E-09	0	0	0	0	0	
Molar Flow	mol/s	mol/s	mol/s	mol/s	mol/s	mol/s	mol/s	mol/s	mol/s	mol/s	mol/s	mol/s	mol/s	mol/s	mol/s
Water	4.77830	16.0270	4.77830	7671.53	63.3119	7592.19	79.3389	31081.6	13593.6	16.0270	11.2487	4.77830	12.0958	12.0958	0
Nitrogen	0.322276	0.322276	0.322276	0.322304	8.95261E-07	2.64723E-05	0.322277	0	0	0.322276	6.66238E-07	0.322276	0	0	0
Hydrogen	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Carbon Monoxide	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide	1573.26	1573.37	1573.26	1579.06	0.181472	5.49977	1573.56	516.527	115.921	1573.37	0.115775	1573.26	3920.55	3920.55	0
Methane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Methanol	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ethane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ethanol	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Sulfide	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MDEA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O2	0.102304	0.102304	0.102304	0.102321	5.49120E-07	1.60375E-05	0.102305	0	0	0.102304	4.08061E-07	0.102304	0	0	0
MEA	0	0	0	0.290520	0	0.290520	1.27516E-08	4304.39	87.9381	0	0	0	0	0	0
SO2	0	0	0	1.13898E-07	0	0	0	4.83999	6.19841E-05	0	0	0	0	0	0
Mass Fraction															
Water	0.00124151	0.00415175	0.00124151	0.665315	0.993047	0.998104	0.0202186	0.661942	0.958988	0.00415175	0.975473	0.00124151	0.00126135	0.00126135	
Nitrogen	0.000130206	0.000129817	0.000130206	4.34646E-05	2.18353E-08	5.41160E-09	0.000127708	0	0	0.000129817	8.98394E-08	0.000130206	0	0	
Hydrogen	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Carbon Monoxide	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Carbon Dioxide	0.998581	0.995671	0.998581	0.334540	0.00695344	0.00176628	0.979607	0.0268729	0.0199778	0.995671	0.0245265	0.998581	0.998739	0.998739	
Methane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Methanol	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Ethane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Ethanol	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Hydrogen Sulfide	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
MDEA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
O2	4.72131E-05	4.70722E-05	4.72131E-05	1.57617E-05	1.52983E-08	3.74488E-09	4.63077E-05	0	0	4.70722E-05	6.28537E-08	4.72131E-05	0	0	
MEA	0	0	0	8.54283E-05	0	0.000129499	1.10182E-11	0.310819	0.0210347	0	0	0	0	0	
SO2	0	0	0	3.51264E-11	0	0	0	0.000366549	1.55500E-08	0	0	0	0	0	
Mass Flow	kg/s	kg/s	kg/s	kg/s	kg/s	kg/s	kg/s	kg/s	kg/s	kg/s	kg/s	kg/s	kg/s	kg/s	kg/s
Water	0.0860824	0.288731	0.0860824	138.205	1.14058	136.775	1.42931	559.944	244.892	0.288731	0.202649	0.0860824	0.217909	0.217909	0
Nitrogen	0.00902803	0.00902805	0.00902803	0.00902882	2.50793E-08	7.41579E-07	0.00902808	0	0	0.00902805	1.86636E-08	0.00902803	0	0	0
Hydrogen	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Carbon Monoxide	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide	69.2383	69.2434	69.2383	69.4934	0.00798650	0.242042	69.2514	22.7321	5.10163	69.2434	0.00509522	69.2383	172.541	172.541	0
Methane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Methanol	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ethane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ethanol	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Sulfide	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MDEA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O2	0.00327360	0.00327361	0.00327360	0.00327414	1.75712E-08	5.13180E-07	0.00327363	0	0	0.00327361	1.30575E-08	0.00327360	0	0	0
MEA	0	0	0	0.0177459	0	0.0177459	7.78910E-10	262.925	5.37153	0	0	0	0	0	0
SO2	0	0	0	7.29674E-09	0	0	0	0.310068	3.97094E-06	0	0	0	0	0	0

Process Streams		**26**	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**	**37**	**38**	**39**	**40**
Properties	**Status:**	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved
Phase: **Total**	**From Block:**	**CMPR-102**	**XCHG-104**	**XCHG-105**	**DTWR-103**	**VSSL-101**	**VSSL-103**	**VSSL-103**	**K-101**	**K-101**	**VSSL-101**	**VSSL-102**	**VSSL-102**	**CMPR-103**	**XCHG-106**	**VSSL-104**
	To Block:	**XCHG-105**	**VSSL-102**	**--**	**XCHG-102**	**--**	**DTWR-103**	**CMPR-100**	**XCHG-100**	**DTWR-103**	**CMPR-101**	**--**	**CMPR-102**	**XCHG-106**	**--**	**--**
Property	**Units**															
Temperature	K	453.773	310.928	310.928	385.403	310.928	316.483	316.483	399.865	399.865	310.928	310.928	310.928	457.284	310.928	310.928
Pressure	Pa	1.10661E+07*	2.79238E+06	1.10316E+07	186158	689476	186158	186158	220632	220632	689476	2.79238E+06	2.79238E+06	1.11358E+07	1.11013E+07*	2.72343E+06
Mole Fraction Vapor		1	0.992852	1	1	0	0	1	0	1	1	0	1	1	1	
Mole Fraction Light Liquid		0	0.00714825	0	0	1	1	0	1	0	0	1	0	0	0	
Molecular Weight	kg/mol	0.0439268	0.0437434	0.0439268	0.0224540	0.0180896	0.0180357	0.0427582	0.0235582	0.0185082	0.0437434	0.0182801	0.0439268	0.0439295	0.0439295	
Mass Density	kg/m^3	145.765	55.5983	663.034	1.32018	993.769	990.515	3.05184	989.884	1.24788	12.0757	997.644	55.4414	144.964	666.481	
Molar Flow	mol/s	1578.46	1589.83	1578.46	9251.30	63.4934	7597.98	1653.32	35907.3	13797.5	1589.83	11.3645	1578.46	3932.65	3932.65	0
Mass Flow	kg/s	69.3367	69.5444	69.3367	207.728	1.14857	137.035	70.6930	845.911	255.366	69.5444	0.207744	69.3367	172.759	172.759	0
Vapor Volumetric Flow	m^3/s	0.475675	1.25084	0.104575	157.349	0.00115577	0.138347	23.1641	0.854556	204.640	5.75904	0.000208234	1.25063	1.19174	0.259211	
Liquid Volumetric Flow	m^3/s	0.475675	1.25084	0.104575	157.349	0.00115577	0.138347	23.1641	0.854556	204.640	5.75904	0.000208234	1.25063	1.19174	0.259211	
Std Vapor Volumetric Flow	m^3/s	37.3945	37.6637	37.3945	219.167	1.50419	179.999	39.1679	850.661	326.868	37.6637	0.269230	37.3945	93.1661	93.1661	0
Std Liquid Volumetric Flow	m^3/s	0.0849131	0.0851222	0.0849131	0.223498	0.00115149	0.137224	0.0862737	0.846494	0.256652	0.0851222	0.000209089	0.0849131	0.211571	0.211571	0
Compressibility		0.883888	0.849828	0.282708	0.988083	0.00485476	0.00128816	0.991187	0.00157935	0.984265	0.966107	0.0197917	0.855804	0.887558	0.283041	
Specific Gravity		1.51667		1.51667	0.775274	0.994708	0.991451	1.47633	0.990819	0.639037	1.51034	0.998586	1.51667	1.51677	1.51677	
API Gravity						9.78245	9.95331		2.87481			9.19475				
Enthalpy	J/s	-6.13824E+08	-6.24611E+08	-6.34358E+08	-2.44934E+09	-1.81084E+07	-2.16181E+09	-6.37381E+08	-9.92237E+09	-3.30366E+09	-6.22684E+08	-3.25118E+06	-6.21359E+08	-1.52899E+09	-1.58098E+09	0
Mass Enthalpy	J/kg	-8.85280E+06	-8.98146E+06	-9.14895E+06	-1.17911E+07	-1.57661E+07	-1.57756E+07	-9.01619E+06	-1.17298E+07	-1.29370E+07	-8.95375E+06	-1.56499E+07	-8.96148E+06	-8.85042E+06	-9.15135E+06	
Mass Cp	J/(kg*K)	1244.47	1049.53	3959.44	1599.69	4178.15	4203.67	891.542	4039.46	1950.91	894.274	4181.74	1040.15	1241.64	3909.07	
Ideal Gas CpCv Ratio		1.23854	1.28325	1.28299	1.30563	1.32428	1.32384	1.28232	1.18221	1.30469	1.28325	1.32393	1.28299	1.23775	1.28297	
Dynamic Viscosity	Pa*s	2.50272E-05		5.25405E-05	1.49822E-05	0.000692805	0.000628958	1.59297E-05	0.000373697	1.36649E-05	1.58671E-05	0.000674314	1.66878E-05	2.51389E-05	5.29519E-05	
Kinematic Viscosity	m^2/s	1.71696E-07		7.92426E-08	1.13486E-05	6.97149E-07	6.34980E-07	5.21971E-06	3.77516E-07	1.09505E-05	1.31397E-06	6.75906E-07	3.00998E-07	1.73414E-07	7.94499E-08	
Thermal Conductivity	W/(m*K)	0.0356427		0.0728618	0.0268317	0.616673	0.628155	0.0179298	0.473436	0.0294183	0.0178110	0.600360	0.0198091	0.0358757	0.0733317	
Surface Tension	N/m					0.0700774	0.0691354		0.0486729?			0.0695623				
Net Ideal Gas Heating Value	J/m^3	0	0	0	1890.53	0	2301.91	0.000464323	7.21670E+06	383697	0	0	0	0	0	
Net Liquid Heating Value	J/kg	-176806	-183473	-176806	-1.69631E+06	-2.44907E+06	-2.45775E+06	-220283	5.29302E+06	-1.89843E+06	-183473	-2.40881E+06	-176806	-176882	-176882	
Gross Ideal Gas Heating Value	J/m^3	5674.45	18896.8	5674.45	1.55650E+06	1.86914E+06	1.87562E+06	89952.7	9.62487E+06	2.27227E+06	18896.8	1.85540E+06	5674.45	5765.47	5765.47	
Gross Liquid Heating Value	J/kg	-173745	-173239	-173745	-56085.7	-1209.84	2908.92	-170444	7.71471E+06	518942	-173239	-4267.41	-173745	-173773	-173773	

Process Streams		**26**	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**	**37**	**38**	**39**	**40**
Composition	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Vapor**	**From Block:**	**CMPR-102**	**XCHG-104**	**XCHG-105**	**DTWR-103**	**VSSL-101**	**VSSL-103**	**VSSL-103**	**K-101**	**K-101**	**VSSL-101**	**VSSL-102**	**VSSL-102**	**CMPR-103**	**XCHG-106**	**VSSL-104**
	To Block:	**XCHG-105**	**VSSL-102**	**--**	**XCHG-102**	**--**	**DTWR-103**	**CMPR-100**	**XCHG-100**	**DTWR-103**	**CMPR-101**	**--**	**CMPR-102**	**XCHG-106**	**--**	**--**
Mole Fraction																
Water		0.00302719	0.00302719	0.00302719	0.829238			0.0479877		0.985225	0.0100810		0.00302719	0.00307574	0.00307574	
Nitrogen		0.000204171	0.000204171	0.000204171	3.48387E-05			0.000194927		0	0.000202712		0.000204171	0	0	
Hydrogen		0	0	0	0			0		0	0		0	0	0	
Carbon Monoxide		0	0	0	0			0		0	0		0	0	0	
Carbon Dioxide		0.996704	0.996704	0.996704	0.170685			0.951756		0.00840163	0.989652		0.996704	0.996924	0.996924	
Methane		0	0	0	0			0		0	0		0	0	0	
Methanol		0	0	0	0			0		0	0		0	0	0	
Ethane		0	0	0	0			0		0	0		0	0	0	
Ethanol		0	0	0	0			0		0	0		0	0	0	
Hydrogen Sulfide		0	0	0	0			0		0	0		0	0	0	
MDEA		0	0	0	0			0		0	0		0	0	0	
O2		6.48123E-05	6.48123E-05	6.48123E-05	1.10602E-05			6.18784E-05		0	6.43493E-05		6.48123E-05	0	0	
MEA		0	0	0	3.14032E-05			7.71276E-12		0.00637350	0		0	0	0	
SO2		0	0	0	1.23116E-11			0		4.49243E-09	0		0	0	0	
Molar Flow		**mol/s**	**mol/s**	**mol/s**	**mol/s**			**mol/s**		**mol/s**	**mol/s**		**mol/s**	**mol/s**	**mol/s**	
Water		4.77830	4.77830	4.77830	7671.53			79.3389		13593.6	16.0270		4.77830	12.0958	12.0958	
Nitrogen		0.322276	0.322276	0.322276	0.322304			0.322277		0	0.322276		0.322276	0	0	
Hydrogen		0	0	0	0			0		0	0		0	0	0	
Carbon Monoxide		0	0	0	0			0		0	0		0	0	0	
Carbon Dioxide		1573.26	1573.26	1573.26	1579.06			1573.56		115.921	1573.37		1573.26	3920.55	3920.55	
Methane		0	0	0	0			0		0	0		0	0	0	
Methanol		0	0	0	0			0		0	0		0	0	0	
Ethane		0	0	0	0			0		0	0		0	0	0	
Ethanol		0	0	0	0			0		0	0		0	0	0	
Hydrogen Sulfide		0	0	0	0			0		0	0		0	0	0	
MDEA		0	0	0	0			0		0	0		0	0	0	
O2		0.102304	0.102304	0.102304	0.102321			0.102305		0	0.102304		0.102304	0	0	
MEA		0	0	0	0.290520			1.27516E-08		87.9381	0		0	0	0	
SO2		0	0	0	1.13898E-07			0		6.19841E-05	0		0	0	0	
Mass Fraction																
Water		0.00124151	0.00124151	0.00124151	0.665315			0.0202186		0.958988	0.00415175		0.00124151	0.00126135	0.00126135	
Nitrogen		0.000130206	0.000130206	0.000130206	4.34646E-05			0.000127708		0	0.000129817		0.000130206	0	0	
Hydrogen		0	0	0	0			0		0	0		0	0	0	
Carbon Monoxide		0	0	0	0			0		0	0		0	0	0	
Carbon Dioxide		0.998581	0.998581	0.998581	0.334540			0.979607		0.0199778	0.995671		0.998581	0.998739	0.998739	
Methane		0	0	0	0			0		0	0		0	0	0	
Methanol		0	0	0	0			0		0	0		0	0	0	
Ethane		0	0	0	0			0		0	0		0	0	0	
Ethanol		0	0	0	0			0		0	0		0	0	0	
Hydrogen Sulfide		0	0	0	0			0		0	0		0	0	0	
MDEA		0	0	0	0			0		0	0		0	0	0	
O2		4.72131E-05	4.72131E-05	4.72131E-05	1.57617E-05			4.63077E-05		0	4.70722E-05		4.72131E-05	0	0	
MEA		0	0	0	8.54283E-05			1.10182E-11		0.0210347	0		0	0	0	
SO2		0	0	0	3.51264E-11			0		1.55500E-08	0		0	0	0	
Mass Flow		**kg/s**	**kg/s**	**kg/s**	**kg/s**			**kg/s**		**kg/s**	**kg/s**		**kg/s**	**kg/s**	**kg/s**	
Water		0.0860824	0.0860824	0.0860824	138.205			1.42931		244.892	0.288731		0.0860824	0.217909	0.217909	
Nitrogen		0.00902803	0.00902803	0.00902803	0.00902882			0.00902808		0	0.00902805		0.00902803	0	0	
Hydrogen		0	0	0	0			0		0	0		0	0	0	
Carbon Monoxide		0	0	0	0			0		0	0		0	0	0	
Carbon Dioxide		69.2383	69.2383	69.2383	69.4934			69.2514		5.10163	69.2434		69.2383	172.541	172.541	
Methane		0	0	0	0			0		0	0		0	0	0	
Methanol		0	0	0	0			0		0	0		0	0	0	
Ethane		0	0	0	0			0		0	0		0	0	0	
Ethanol		0	0	0	0			0		0	0		0	0	0	
Hydrogen Sulfide		0	0	0	0			0		0	0		0	0	0	
MDEA		0	0	0	0			0		0	0		0	0	0	
O2		0.00327360	0.00327360	0.00327360	0.00327414			0.00327363		0	0.00327361		0.00327360	0	0	
MEA		0	0	0	0.0177459			7.78910E-10		5.37153	0		0	0	0	
SO2		0	0	0	7.29674E-09			0		3.97094E-06	0		0	0	0	

Process Streams		**26**	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**	**37**	**38**	**39**	**40**
Properties	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Vapor**	**From Block:**	**CMPR-102**	**XCHG-104**	**XCHG-105**	**DTWR-103**	**VSSL-101**	**VSSL-103**	**VSSL-103**	**K-101**	**K-101**	**VSSL-101**	**VSSL-102**	**VSSL-102**	**CMPR-103**	**XCHG-106**	**VSSL-104**
	To Block:	**XCHG-105**	**VSSL-102**	**--**	**XCHG-102**	**--**	**DTWR-103**	**CMPR-100**	**XCHG-100**	**DTWR-103**	**CMPR-101**	**--**	**CMPR-102**	**XCHG-106**	**--**	**--**
Property	**Units**															
Temperature	K	453.773	310.928	310.928	385.403			316.483		399.865	310.928		310.928	457.284	310.928	
Pressure	Pa	1.10661E+07	2.79238E+06	1.10316E+07	186158			186158		220632	689476		2.79238E+06	1.11358E+07	1.11013E+07	
Mole Fraction Vapor		1	1	1	1			1		1	1		1	1	1	
Mole Fraction Light Liquid		0	0	0	0			0		0	0		0	0	0	
Molecular Weight	kg/mol	0.0439268	0.0439268	0.0439268	0.0224540			0.0427582		0.0185082	0.0437434		0.0439268	0.0439295	0.0439295	
Mass Density	kg/m^3	145.765	55.4414	663.034	1.32018			3.05184		1.24788	12.0757		55.4414	144.964	666.481	
Molar Flow	mol/s	1578.46	1578.46	1578.46	9251.30			1653.32		13797.5	1589.83		1578.46	3932.65	3932.65	
Mass Flow	kg/s	69.3367	69.3367	69.3367	207.728			70.6930		255.366	69.5444		69.3367	172.759	172.759	
Vapor Volumetric Flow	m^3/s	0.475675	1.25063	0.104575	157.349			23.1641		204.640	5.75904		1.25063	1.19174	0.259211	
Liquid Volumetric Flow	m^3/s	0.475675	1.25063	0.104575	157.349			23.1641		204.640	5.75904		1.25063	1.19174	0.259211	
Std Vapor Volumetric Flow	m^3/s	37.3945	37.3945	37.3945	219.167			39.1679		326.868	37.6637		37.3945	93.1661	93.1661	
Std Liquid Volumetric Flow	m^3/s	0.0849131	0.0849131	0.0849131	0.223498			0.0862737		0.256652	0.0851222		0.0849131	0.211571	0.211571	
Compressibility		0.883888	0.855804	0.282708	0.988083			0.991187		0.984265	0.966107		0.855804	0.887558	0.283041	
Specific Gravity		1.51667	1.51667	1.51667	0.775274			1.47633		0.639037	1.51034		1.51667	1.51677	1.51677	
API Gravity																
Enthalpy	J/s	-6.13824E+08	-6.21359E+08	-6.34358E+08	-2.44934E+09			-6.37381E+08		-3.30366E+09	-6.22684E+08		-6.21359E+08	-1.52899E+09	-1.58098E+09	
Mass Enthalpy	J/kg	-8.85280E+06	-8.96148E+06	-9.14895E+06	-1.17911E+07			-9.01619E+06		-1.29370E+07	-8.95375E+06		-8.96148E+06	-8.85043E+06	-9.15135E+06	
Mass Cp	J/(kg*K)	1244.47	1040.15	3959.44	1599.69			891.542		1950.91	894.274		1040.15	1241.64	3909.07	
Ideal Gas CpCv Ratio		1.23854	1.28299	1.28299	1.30563			1.28232		1.30469	1.28325		1.28299	1.23775	1.28297	
Dynamic Viscosity	Pa*s	2.50272E-05	1.66878E-05	5.25405E-05	1.49822E-05			1.59297E-05		1.36649E-05	1.58671E-05		1.66878E-05	2.51389E-05	5.29519E-05	
Kinematic Viscosity	m^2/s	1.71696E-07	3.00998E-07	7.92426E-08	1.13486E-05			5.21971E-06		1.09505E-05	1.31397E-06		3.00998E-07	1.73414E-07	7.94499E-08	
Thermal Conductivity	W/(m*K)	0.0356427	0.0198091	0.0728618	0.0268317			0.0179298		0.0294183	0.0178110		0.0198091	0.0358757	0.0733317	
Surface Tension	N/m															
Net Ideal Gas Heating Value	J/m^3	0	0	0	1890.53			0.000464323		383697	0		0	0	0	
Net Liquid Heating Value	J/kg	-176806	-176806	-176806	-1.69631E+06			-220283		-1.89843E+06	-183473		-176806	-176882	-176882	
Gross Ideal Gas Heating Value	J/m^3	5674.45	5674.45	5674.45	1.55650E+06			89952.7		2.27227E+06	18896.8		5674.45	5765.47	5765.47	
Gross Liquid Heating Value	J/kg	-173745	-173745	-173745	-56085.7			-170444		518942	-173239		-173745	-173773	-173773	

Process Streams		**26**	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**	**37**	**38**	**39**	**40**
Composition	**Status:**	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved
Phase: **Light Liquid**	**From Block:**	CMPR-102	XCHG-104	XCHG-105	DTWR-103	VSSL-101	VSSL-103	VSSL-103	K-101	K-101	VSSL-101	VSSL-102	VSSL-102	CMPR-103	XCHG-106	VSSL-104
	To Block:	XCHG-105	VSSL-102	--	XCHG-102	--	DTWR-103	CMPR-100	XCHG-100	DTWR-103	CMPR-101	--	CMPR-102	XCHG-106	--	--
Mole Fraction																
Water			0.989812			0.997142	0.999238		0.865605			0.989812				
Nitrogen			5.86246E-08			1.41001E-08	3.48412E-09		0			5.86246E-08				
Hydrogen			0			0	0		0			0				
Carbon Monoxide			0			0	0		0			0				
Carbon Dioxide			0.0101875			0.00285813	0.000723847		0.0143850			0.0101875				
Methane			0			0	0		0			0				
Methanol			0			0	0		0			0				
Ethane			0			0	0		0			0				
Ethanol			0			0	0		0			0				
Hydrogen Sulfide			0			0	0		0			0				
MDEA			0			0	0		0			0				
O2			3.59067E-08			8.64846E-09	2.11076E-09		0			3.59067E-08				
MEA			0			0	3.82365E-05		0.119875			0				
SO2			0			0	0		0.000134791			0				
Molar Flow			mol/s			mol/s	mol/s		mol/s			mol/s				
Water			11.2487			63.3119	7592.19		31081.6			11.2487				
Nitrogen			6.66238E-07			8.95261E-07	2.64723E-05		0			6.66238E-07				
Hydrogen			0			0	0		0			0				
Carbon Monoxide			0			0	0		0			0				
Carbon Dioxide			0.115775			0.181472	5.49977		516.527			0.115775				
Methane			0			0	0		0			0				
Methanol			0			0	0		0			0				
Ethane			0			0	0		0			0				
Ethanol			0			0	0		0			0				
Hydrogen Sulfide			0			0	0		0			0				
MDEA			0			0	0		0			0				
O2			4.08061E-07			5.49120E-07	1.60375E-05		0			4.08061E-07				
MEA			0			0	0.290520		4304.39			0				
SO2			0			0	0		4.83999			0				
Mass Fraction																
Water			0.975473			0.993047	0.998104		0.661942			0.975473				
Nitrogen			8.98394E-08			2.18353E-08	5.41160E-09		0			8.98394E-08				
Hydrogen			0			0	0		0			0				
Carbon Monoxide			0			0	0		0			0				
Carbon Dioxide			0.0245265			0.00695344	0.00176628		0.0268729			0.0245265				
Methane			0			0	0		0			0				
Methanol			0			0	0		0			0				
Ethane			0			0	0		0			0				
Ethanol			0			0	0		0			0				
Hydrogen Sulfide			0			0	0		0			0				
MDEA			0			0	0		0			0				
O2			6.28537E-08			1.52983E-08	3.74488E-09		0			6.28537E-08				
MEA			0			0	0.000129499		0.310819			0				
SO2			0			0	0		0.000366549			0				
Mass Flow			kg/s			kg/s	kg/s		kg/s			kg/s				
Water			0.202649			1.14058	136.775		559.944			0.202649				
Nitrogen			1.86636E-08			2.50793E-08	7.41579E-07		0			1.86636E-08				
Hydrogen			0			0	0		0			0				
Carbon Monoxide			0			0	0		0			0				
Carbon Dioxide			0.00509522			0.00798650	0.242042		22.7321			0.00509522				
Methane			0			0	0		0			0				
Methanol			0			0	0		0			0				
Ethane			0			0	0		0			0				
Ethanol			0			0	0		0			0				
Hydrogen Sulfide			0			0	0		0			0				
MDEA			0			0	0		0			0				
O2			1.30575E-08			1.75712E-08	5.13180E-07		0			1.30575E-08				
MEA			0			0	0.0177459		262.925			0				
SO2			0			0	0		0.310068			0				

Process Streams		**26**	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**	**37**	**38**	**39**	**40**
Properties	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Light Liquid**	**From Block:**	**CMPR-102**	**XCHG-104**	**XCHG-105**	**DTWR-103**	**VSSL-101**	**VSSL-103**	**VSSL-103**	**K-101**	**K-101**	**VSSL-101**	**VSSL-102**	**VSSL-102**	**CMPR-103**	**XCHG-106**	**VSSL-104**
	To Block:	**XCHG-105**	**VSSL-102**	**--**	**XCHG-102**	**--**	**DTWR-103**	**CMPR-100**	**XCHG-100**	**DTWR-103**	**CMPR-101**	**--**	**CMPR-102**	**XCHG-106**	**--**	**--**
Property	**Units**															
Temperature	K		310.928			310.928	316.483		399.865			310.928				
Pressure	Pa		2.79238E+06			689476	186158		220632			2.79238E+06				
Mole Fraction Vapor			0			0	0		0			0				
Mole Fraction Light Liquid			1			1	1		1			1				
Molecular Weight	kg/mol		0.0182801			0.0180896	0.0180357		0.0235582			0.0182801				
Mass Density	kg/m^3		997.644			993.769	990.515		989.884			997.644				
Molar Flow	mol/s		11.3645			63.4934	7597.98		35907.3			11.3645				
Mass Flow	kg/s		0.207744			1.14857	137.035		845.911			0.207744				
Vapor Volumetric Flow	m^3/s		0.000208234			0.00115577	0.138347		0.854556			0.000208234				
Liquid Volumetric Flow	m^3/s		0.000208234			0.00115577	0.138347		0.854556			0.000208234				
Std Vapor Volumetric Flow	m^3/s		0.269230			1.50419	179.999		850.661			0.269230				
Std Liquid Volumetric Flow	m^3/s		0.000209089			0.00115149	0.137224		0.846494			0.000209089				
Compressibility			0.0197917			0.00485476	0.00128816		0.00157935			0.0197917				
Specific Gravity			0.998586			0.994708	0.991451		0.990819			0.998586				
API Gravity			9.19475			9.78245	9.95331		2.87481			9.19475				
Enthalpy	J/s		-3.25118E+06			-1.81084E+07	-2.16181E+09		-9.92237E+09			-3.25118E+06				
Mass Enthalpy	J/kg		-1.56499E+07			-1.57661E+07	-1.57756E+07		-1.17298E+07			-1.56499E+07				
Mass Cp	J/(kg*K)		4181.74			4178.15	4203.67		4039.46			4181.74				
Ideal Gas CpCv Ratio			1.32393			1.32428	1.32384		1.18221			1.32393				
Dynamic Viscosity	Pa*s		0.000674314			0.000692805	0.000628958		0.000373697			0.000674314				
Kinematic Viscosity	m^2/s		6.75906E-07			6.97149E-07	6.34980E-07		3.77516E-07			6.75906E-07				
Thermal Conductivity	W/(m*K)		0.600360			0.616673	0.628155		0.473436			0.600360				
Surface Tension	N/m		0.0695623			0.0700774	0.0691354		0.0486729?			0.0695623				
Net Ideal Gas Heating Value	J/m^3		0			0	2301.91		7.21670E+06			0				
Net Liquid Heating Value	J/kg		-2.40881E+06			-2.44907E+06	-2.45775E+06		5.29302E+06			-2.40881E+06				
Gross Ideal Gas Heating Value	J/m^3		1.85540E+06			1.86914E+06	1.87562E+06		9.62487E+06			1.85540E+06				
Gross Liquid Heating Value	J/kg		-4267.41			-1209.84	2908.92		7.71471E+06			-4267.41				

Process Streams		**41**	**42**	**43**	**45**	**46**	**47**	**48**	**49**	**50**	**51**	**54**	**55**	**56**
Composition	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Total**	**From Block:**	**VSSL-104**	**--**	**PUMP-103**	**Absorber Water Wash**	**SPLT-100**	**XCHG-108**	**SPLT-100**	**Absorber Overhead**	**MIX-101**	**XCHG-107**	**RCYL-3**	**CMPR-105**	**MKUP-2**
	To Block:	**CMPR-103**	**VSSL-104**	**DTWR-100**	**Absorber Overhead**	**XCHG-108**	**MIX-101**	**MIX-100**	**MIX-101**	**RCYL-1**	**PUMP-103**	**MKUP-2**	**DTWR-100**	**--**
Mole Fraction														
Water		0.00307574	0.00307574*	0.999970	0.0717392	0.995023	0.995023	0.995023	0.999900	0.995066	0.999970	0.999970	0.0875655	0.999970
Nitrogen		0	0*	8.42812E-06	0.796689	8.40089E-06	8.40089E-06	8.40089E-06	8.34163E-06	8.40037E-06	8.42812E-06	8.42812E-06	0.751596	8.42812E-06
Hydrogen		0	0*	0	0	0	0	0	0	0	0	0	0	0
Carbon Monoxide		0	0*	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide		0.996924	0.996924*	1.90603E-05	0.00445475	0.00122876	0.00122876	0.00122876	9.87794E-06	0.00121801	1.90603E-05	1.90603E-05	0.0409172	1.90603E-05
Methane		0	0*	0	0	0	0	0	0	0	0	0	0	0
Methanol		0	0*	0	0	0	0	0	0	0	0	0	0	0
Ethane		0	0*	0	0	0	0	0	0	0	0	0	0	0
Ethanol		0	0*	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Sulfide		0	0*	0	0	0	0	0	0	0	0	0	0	0
MDEA		0	0*	0	0	0	0	0	0	0	0	0	0	0
O2		0	0*	2.56802E-06	0.127115	2.57734E-06	2.57734E-06	2.57734E-06	2.55553E-06	2.57715E-06	2.56802E-06	2.56802E-06	0.119921	2.56802E-06
MEA		0	0*	0	2.76856E-06	0.00373729	0.00373729	0.00373729	7.91196E-05	0.00370505	0	0	0	0
SO2		0	0*	0	0	0	0	0	0	0	0	0	0	0
Molar Flow		**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**	**mol/s**
Water		12.0958	12.0958*	174837	2900.51	158317	158317	1721.34	1414.55	159732	174837	177158	3752.83	2320.31
Nitrogen		0	0*	1.47360	32211.2	1.33666	1.33666	0.0145331	0.0118008	1.34846	1.47360	1.49315	32211.5	0.0195565
Hydrogen		0	0*	0	0	0	0	0	0	0	0	0	0	0
Carbon Monoxide		0	0*	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide		3920.55	3920.55*	3.33255	180.111	195.506	195.506	2.12569	0.0139743	195.520	3.33255	3.37678	1753.61	0.0442271
Methane		0	0*	0	0	0	0	0	0	0	0	0	0	0
Methanol		0	0*	0	0	0	0	0	0	0	0	0	0	0
Ethane		0	0*	0	0	0	0	0	0	0	0	0	0	0
Ethanol		0	0*	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Sulfide		0	0*	0	0	0	0	0	0	0	0	0	0	0
MDEA		0	0*	0	0	0	0	0	0	0	0	0	0	0
O2		0	0*	0.449000	5139.41	0.410079	0.410079	0.00445868	0.00361530	0.413694	0.449000	0.454959	5139.52	0.00595879
MEA		0	0*	0	0.111936	594.637	594.637	6.46533	0.111930	594.749	0	0	0	0
SO2		0	0*	0	0	0	0	0	0	0	0	0	0	0
Mass Fraction														
Water		0.00126135	0.00126135*	0.999936	0.0463657	0.984475	0.984475	0.984475	0.999690	0.984608	0.999936	0.999936	0.0558011	0.999936
Nitrogen		0	0*	1.31051E-05	0.800670	1.29247E-05	1.29247E-05	1.29247E-05	1.29683E-05	1.29251E-05	1.31051E-05	1.31051E-05	0.744764	1.31051E-05
Hydrogen		0	0*	0	0	0	0	0	0	0	0	0	0	0
Carbon Monoxide		0	0*	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide		0.998739	0.998739*	4.65608E-05	0.00703345	0.00296990	0.00296990	0.00296990	2.41257E-05	0.00294421	4.65608E-05	4.65608E-05	0.0636974	4.65608E-05
Methane		0	0*	0	0	0	0	0	0	0	0	0	0	0
Methanol		0	0*	0	0	0	0	0	0	0	0	0	0	0
Ethane		0	0*	0	0	0	0	0	0	0	0	0	0	0
Ethanol		0	0*	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Sulfide		0	0*	0	0	0	0	0	0	0	0	0	0	0
MDEA		0	0*	0	0	0	0	0	0	0	0	0	0	0
O2		0	0*	4.56118E-06	0.145925	4.52936E-06	4.52936E-06	4.52936E-06	4.53819E-06	4.52944E-06	4.56118E-06	4.56118E-06	0.135737	4.56118E-06
MEA		0	0*	0	6.06699E-06	0.0125374	0.0125374	0.0125374	0.000268209	0.0124304	0	0	0	0
SO2		0	0*	0	0	0	0	0	0	0	0	0	0	0
Mass Flow		**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**	**kg/s**
Water		0.217909	0.217909*	3149.74	52.2535	2852.13	2852.13	31.0104	25.4836	2877.61	3149.74	3191.55	67.6084	41.8011
Nitrogen		0	0*	0.0412804	902.344	0.0374443	0.0374443	0.000407122	0.000330582	0.0377749	0.0412804	0.0418283	902.353	0.000547843
Hydrogen		0	0*	0	0	0	0	0	0	0	0	0	0	0
Carbon Monoxide		0	0*	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide		172.541	172.541*	0.146664	7.92660	8.60412	8.60412	0.0935504	0.000615000	8.60474	0.146664	0.148610	77.1754	0.00194641
Methane		0	0*	0	0	0	0	0	0	0	0	0	0	0
Methanol		0	0*	0	0	0	0	0	0	0	0	0	0	0
Ethane		0	0*	0	0	0	0	0	0	0	0	0	0	0
Ethanol		0	0*	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Sulfide		0	0*	0	0	0	0	0	0	0	0	0	0	0
MDEA		0	0*	0	0	0	0	0	0	0	0	0	0	0
O2		0	0*	0.0143675	164.455	0.0131220	0.0131220	0.000142672	0.000115685	0.0132377	0.0143675	0.0145581	164.458	0.000190674
MEA		0	0*	0	0.00683742	36.3223	36.3223	0.394923	0.00683703	36.3291	0	0	0	0
SO2		0	0*	0	0	0	0	0	0	0	0	0	0	0

Process Streams		**41**	**42**	**43**	**45**	**46**	**47**	**48**	**49**	**50**	**51**	**54**	**55**	**56**
Properties	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Total**	**From Block:**	**VSSL-104**	**--**	**PUMP-103**	**Absorber Water Wash**	**SPLT-100**	**XCHG-108**	**SPLT-100**	**Absorber Overhead**	**MIX-101**	**XCHG-107**	**RCYL-3**	**CMPR-105**	**MKUP-2**
	To Block:	**CMPR-103**	**VSSL-104**	**DTWR-100**	**Absorber Overhead**	**XCHG-108**	**MIX-101**	**MIX-100**	**MIX-101**	**RCYL-1**	**PUMP-103**	**MKUP-2**	**DTWR-100**	**--**
Property	**Units**													
Temperature	K	310.928	310.928*	299.838	313.835	314.766	313.706*	314.766	313.769	313.720	299.817*	316.093	389.730	316.093
Pressure	Pa	2.72343E+06	2.72343E+06*	273722	106869	210290	175816	210290	106869	106869	101353	115142	115142	115142
Mole Fraction Vapor		1	1	0	1	0	0	0	0	0	0	0	1	0
Mole Fraction Light Liquid		0	0	1	0	1	1	1	1	1	1	1	0	1
Molecular Weight	kg/mol	0.0439295	0.0439295	0.0180159	0.0278741	0.0182083	0.0182083	0.0182083	0.0180191	0.0182066	0.0180159	0.0180159	0.0282704	0.0180159
Mass Density	kg/m^3	53.8380	53.8380	996.003	1.14214	992.215	992.627	992.215	991.219	992.599	995.987	990.305	1.00459	990.305
Molar Flow	mol/s	3932.65	3932.65	174843	40431.3	159109	159109	1729.95	1414.69	160524	174843	177163	42857.5	2320.38
Mass Flow	kg/s	172.759	172.759	3149.95	1126.99	2897.10	2897.10	31.4995*	25.4915	2922.60	3149.95	3191.75	1211.60	41.8037
Vapor Volumetric Flow	m^3/s	3.20887	3.20887	3.16259	986.729	2.91983	2.91862	0.0317466	0.0257173	2.94439	3.16264	3.22300	1206.06	0.0422130
Liquid Volumetric Flow	m^3/s	3.20887	3.20887	3.16259	986.729	2.91983	2.91862	0.0317466	0.0257173	2.94439	3.16264	3.22300	1206.06	0.0422130
Std Vapor Volumetric Flow	m^3/s	93.1661	93.1661	4142.10	957.836	3769.36	3769.36	40.9833	33.5147	3802.88	4142.10	4197.07	1015.31	54.9709
Std Liquid Volumetric Flow	m^3/s	0.211571	0.211571	3.15309	1.32554	2.90116	2.90116	0.0315436	0.0255166	2.92668	3.15309	3.19493	1.42575	0.0418454
Compressibility		0.859587	0.859587	0.00198602	0.999529	0.00147455	0.00123648	0.00147455	0.000744677	0.000751500	0.000735441	0.000797027	0.999950	0.000797027
Specific Gravity		1.51677	1.51677	0.996944	0.962417	0.993153	0.993565	0.993153	0.992156	0.993537	0.996928	0.991241	0.976099	0.991241
API Gravity							9.78727	9.78666	10.0090	9.79053	10.0109	10.0107		10.0107
Enthalpy	J/s	-1.54834E+09	-1.54834E+09	-4.99490E+10	-7.53945E+08	-4.52963E+10	-4.53092E+10	-4.92495E+08	-4.02674E+08	-4.57119E+10	-4.99498E+10	-5.03965E+10	-1.47975E+09	-6.60065E+08
Mass Enthalpy	J/kg	-8.96242E+06	-8.96242E+06	-1.58571E+07	-668992	-1.56350E+07	-1.56395E+07	-1.56350E+07	-1.57964E+07	-1.56409E+07	-1.58573E+07	-1.57896E+07	-1.22133E+06	-1.57896E+07
Mass Cp	J/(kg*K)	1033.60	1033.60	10.0079 4119.07	1063.42	9.78666 4165.76	4160.43	4165.76	4190.19	4160.91	4119.27	4202.17	1073.86	4202.17
Ideal Gas CpCv Ratio		1.28297	1.28297	1.32536	1.39100	1.31770	1.31780	1.31770	1.32403	1.31785	1.32536	1.32397	1.37799	1.32397
Dynamic Viscosity	Pa*s	1.66534E-05	1.66534E-05	0.000879839	1.84983E-05	0.000666975	0.000680507	0.000666975	0.000663713	0.000680071	0.000879945	0.000635042	2.14656E-05	0.000635042
Kinematic Viscosity	m^2/s	3.09325E-07	3.09325E-07	8.83370E-07	1.61961E-05	6.72208E-07	6.85562E-07	6.72208E-07	6.69593E-07	6.85141E-07	8.83490E-07	6.41259E-07	2.13675E-05	6.41259E-07
Thermal Conductivity	W/(m*K)	0.0197299	0.0197299	0.608585	0.0267487	0.618097	0.616859	0.618097	0.626487	0.616959	0.608555	0.629382	0.0315743	0.629382
Surface Tension	N/m			0.0724712?		0.0692654	0.0694721	0.0692654	0.0697144	0.0694714	0.0724756?	0.0692616		0.0692616
Net Ideal Gas Heating Value	J/m^3	0	0	0	166.673	224992	224992	224992	4763.16	223052	0	0	0	0
Net Liquid Heating Value	J/kg	-176882	-176882	-2.46485E+06	-115380	-2.14773E+06	-2.14773E+06	-2.14773E+06	-2.45826E+06	-2.15044E+06	-2.46485E+06	-2.46485E+06	-148633	-2.46485E+06
Gross Ideal Gas Heating Value	J/m^3	5765.47	5765.47	1.87444E+06	134660	2.11465E+06	2.11465E+06	2.11465E+06	1.87959E+06	2.11258E+06	1.87444E+06	1.87444E+06	164141	1.87444E+06
Gross Liquid Heating Value	J/kg	-173773	-173773	-8.10121	-1073.09	310864	310864	310864	6657.05	308210	-8.10121	-8.10121	-11082.8	-8.10121

Process Streams	41	42	43	45	46	47	48	49	50	51	54	55	56
Composition Status:	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved
Phase: **Vapor** From Block:	VSSL-104	--	PUMP-103	Absorber Water Wash	SPLT-100	XCHG-108	SPLT-100	Absorber Overhead	MIX-101	XCHG-107	RCYL-3	CMPR-105	MKUP-2
To Block:	CMPR-103	VSSL-104	DTWR-100	Absorber Overhead	XCHG-108	MIX-101	MIX-100	MIX-101	RCYL-1	PUMP-103	MKUP-2	DTWR-100	--
Mole Fraction													
Water	0.00307574	0.00307574		0.0717392								0.0875655	
Nitrogen	0	0		0.796689								0.751596	
Hydrogen	0	0		0								0	
Carbon Monoxide	0	0		0								0	
Carbon Dioxide	0.996924	0.996924		0.00445475								0.0409172	
Methane	0	0		0								0	
Methanol	0	0		0								0	
Ethane	0	0		0								0	
Ethanol	0	0		0								0	
Hydrogen Sulfide	0	0		0								0	
MDEA	0	0		0								0	
O2	0	0		0.127115								0.119921	
MEA	0	0		2.76856E-06								0	
SO2	0	0		0								0	
Molar Flow	mol/s	mol/s		mol/s								mol/s	
Water	12.0958	12.0958		2900.51								3752.83	
Nitrogen	0	0		32211.2								32211.5	
Hydrogen	0	0		0								0	
Carbon Monoxide	0	0		0								0	
Carbon Dioxide	3920.55	3920.55		180.111								1753.61	
Methane	0	0		0								0	
Methanol	0	0		0								0	
Ethane	0	0		0								0	
Ethanol	0	0		0								0	
Hydrogen Sulfide	0	0		0								0	
MDEA	0	0		0								0	
O2	0	0		5139.41								5139.52	
MEA	0	0		0.111936								0	
SO2	0	0		0								0	
Mass Fraction													
Water	0.00126135	0.00126135		0.0463657								0.0558011	
Nitrogen	0	0		0.800670								0.744764	
Hydrogen	0	0		0								0	
Carbon Monoxide	0	0		0								0	
Carbon Dioxide	0.998739	0.998739		0.00703345								0.0636974	
Methane	0	0		0								0	
Methanol	0	0		0								0	
Ethane	0	0		0								0	
Ethanol	0	0		0								0	
Hydrogen Sulfide	0	0		0								0	
MDEA	0	0		0								0	
O2	0	0		0.145925								0.135737	
MEA	0	0		6.06699E-06								0	
SO2	0	0		0								0	
Mass Flow	kg/s	kg/s		kg/s								kg/s	
Water	0.217909	0.217909		52.2535								67.6084	
Nitrogen	0	0		902.344								902.353	
Hydrogen	0	0		0								0	
Carbon Monoxide	0	0		0								0	
Carbon Dioxide	172.541	172.541		7.92660								77.1754	
Methane	0	0		0								0	
Methanol	0	0		0								0	
Ethane	0	0		0								0	
Ethanol	0	0		0								0	
Hydrogen Sulfide	0	0		0								0	
MDEA	0	0		0								0	
O2	0	0		164.455								164.458	
MEA	0	0		0.00683742								0	
SO2	0	0		0								0	

Process Streams		**41**	**42**	**43**	**45**	**46**	**47**	**48**	**49**	**50**	**51**	**54**	**55**	**56**
Properties	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Vapor**	**From Block:**	**VSSL-104**	**--**	**PUMP-103**	**Absorber Water Wash**	**SPLT-100**	**XCHG-108**	**SPLT-100**	**Absorber Overhead**	**MIX-101**	**XCHG-107**	**RCYL-3**	**CMPR-105**	**MKUP-2**
	To Block:	**CMPR-103**	**VSSL-104**	**DTWR-100**	**Absorber Overhead**	**XCHG-108**	**MIX-101**	**MIX-100**	**MIX-101**	**RCYL-1**	**PUMP-103**	**MKUP-2**	**DTWR-100**	**--**
Property	**Units**													
Temperature	K	310.928	310.928		313.835								389.730	
Pressure	Pa	2.72343E+06	2.72343E+06		106869								115142	
Mole Fraction Vapor		1	1		1								1	
Mole Fraction Light Liquid		0	0		0								0	
Molecular Weight	kg/mol	0.0439295	0.0439295		0.0278741								0.0282704	
Mass Density	kg/m^3	53.8380	53.8380		1.14214								1.00459	
Molar Flow	mol/s	3932.65	3932.65		40431.3								42857.5	
Mass Flow	kg/s	172.759	172.759		1126.99								1211.60	
Vapor Volumetric Flow	m^3/s	3.20887	3.20887		986.729								1206.06	
Liquid Volumetric Flow	m^3/s	3.20887	3.20887		986.729								1206.06	
Std Vapor Volumetric Flow	m^3/s	93.1661	93.1661		957.836								1015.31	
Std Liquid Volumetric Flow	m^3/s	0.211571	0.211571		1.32554								1.42575	
Compressibility		0.859587	0.859587		0.999529								0.999950	
Specific Gravity		1.51677	1.51677		0.962417								0.976099	
API Gravity														
Enthalpy	J/s	-1.54834E+09	-1.54834E+09		-7.53945E+08								-1.47975E+09	
Mass Enthalpy	J/kg	-8.96242E+06	-8.96242E+06		-668992								-1.22133E+06	
Mass Cp	J/(kg*K)	1033.60	1033.60		1063.42								1073.86	
Ideal Gas CpCv Ratio		1.28297	1.28297		1.39100								1.37799	
Dynamic Viscosity	Pa*s	1.66534E-05	1.66534E-05		1.84983E-05								2.14656E-05	
Kinematic Viscosity	m^2/s	3.09325E-07	3.09325E-07		1.61961E-05								2.13675E-05	
Thermal Conductivity	W/(m*K)	0.0197299	0.0197299		0.0267487								0.0315743	
Surface Tension	N/m													
Net Ideal Gas Heating Value	J/m^3	0	0		166.673								0	
Net Liquid Heating Value	J/kg	-176882	-176882		-115380								-148633	
Gross Ideal Gas Heating Value	J/m^3	5765.47	5765.47		134660								164141	
Gross Liquid Heating Value	J/kg	-173773	-173773		-1073.09								-11082.8	

Process Streams		41	42	43	45	46	47	48	49	50	51	54	55	56
Composition	Status:	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved
Phase: **Light Liquid**	From Block:	VSSL-104	--	PUMP-103	Absorber Water Wash	SPLT-100	XCHG-108	SPLT-100	Absorber Overhead	MIX-101	XCHG-107	RCYL-3	CMPR-105	MKUP-2
	To Block:	CMPR-103	VSSL-104	DTWR-100	Absorber Overhead	XCHG-108	MIX-101	MIX-100	MIX-101	RCYL-1	PUMP-103	MKUP-2	DTWR-100	--
Mole Fraction														
Water				0.999970		0.995023	0.995023	0.995023	0.999900	0.995066	0.999970	0.999970		0.999970
Nitrogen				8.42812E-06		8.40089E-06	8.40089E-06	8.40089E-06	8.34163E-06	8.40037E-06	8.42812E-06	8.42812E-06		8.42812E-06
Hydrogen				0		0	0	0	0	0	0	0		0
Carbon Monoxide				0		0	0	0	0	0	0	0		0
Carbon Dioxide				1.90603E-05		0.00122876	0.00122876	0.00122876	9.87794E-06	0.00121801	1.90603E-05	1.90603E-05		1.90603E-05
Methane				0		0	0	0	0	0	0	0		0
Methanol				0		0	0	0	0	0	0	0		0
Ethane				0		0	0	0	0	0	0	0		0
Ethanol				0		0	0	0	0	0	0	0		0
Hydrogen Sulfide				0		0	0	0	0	0	0	0		0
MDEA				0		0	0	0	0	0	0	0		0
O2				2.56802E-06		2.57734E-06	2.57734E-06	2.57734E-06	2.55553E-06	2.57715E-06	2.56802E-06	2.56802E-06		2.56802E-06
MEA				0		0.00373729	0.00373729	0.00373729	7.91196E-05	0.00370505	0	0		0
SO2				0		0	0	0	0	0	0	0		0
Molar Flow				mol/s		mol/s	mol/s	mol/s	mol/s	mol/s	mol/s	mol/s		mol/s
Water				174837		158317	158317	1721.34	1414.55	159732	174837	177158		2320.31
Nitrogen				1.47360		1.33666	1.33666	0.0145331	0.0118008	1.34846	1.47360	1.49315		0.0195565
Hydrogen				0		0	0	0	0	0	0	0		0
Carbon Monoxide				0		0	0	0	0	0	0	0		0
Carbon Dioxide				3.33255		195.506	195.506	2.12569	0.0139743	195.520	3.33255	3.37678		0.0442271
Methane				0		0	0	0	0	0	0	0		0
Methanol				0		0	0	0	0	0	0	0		0
Ethane				0		0	0	0	0	0	0	0		0
Ethanol				0		0	0	0	0	0	0	0		0
Hydrogen Sulfide				0		0	0	0	0	0	0	0		0
MDEA				0		0	0	0	0	0	0	0		0
O2				0.449000		0.410079	0.410079	0.00445868	0.00361530	0.413694	0.449000	0.454959		0.00595879
MEA				0		594.637	594.637	6.46533	0.111930	594.749	0	0		0
SO2				0		0	0	0	0	0	0	0		0
Mass Fraction														
Water				0.999936		0.984475	0.984475	0.984475	0.999690	0.984608	0.999936	0.999936		0.999936
Nitrogen				1.31051E-05		1.29247E-05	1.29247E-05	1.29247E-05	1.29683E-05	1.29251E-05	1.31051E-05	1.31051E-05		1.31051E-05
Hydrogen				0		0	0	0	0	0	0	0		0
Carbon Monoxide				0		0	0	0	0	0	0	0		0
Carbon Dioxide				4.65608E-05		0.00296990	0.00296990	0.00296990	2.41257E-05	0.00294421	4.65608E-05	4.65608E-05		4.65608E-05
Methane				0		0	0	0	0	0	0	0		0
Methanol				0		0	0	0	0	0	0	0		0
Ethane				0		0	0	0	0	0	0	0		0
Ethanol				0		0	0	0	0	0	0	0		0
Hydrogen Sulfide				0		0	0	0	0	0	0	0		0
MDEA				0		0	0	0	0	0	0	0		0
O2				4.56118E-06		4.52936E-06	4.52936E-06	4.52936E-06	4.53819E-06	4.52944E-06	4.56118E-06	4.56118E-06		4.56118E-06
MEA				0		0.0125374	0.0125374	0.0125374	0.000268209	0.0124304	0	0		0
SO2				0		0	0	0	0	0	0	0		0
Mass Flow				kg/s		kg/s	kg/s	kg/s	kg/s	kg/s	kg/s	kg/s		kg/s
Water				3149.74		2852.13	2852.13	31.0104	25.4836	2877.61	3149.74	3191.55		41.8011
Nitrogen				0.0412804		0.0374443	0.0374443	0.000407122	0.000330582	0.0377749	0.0412804	0.0418283		0.000547843
Hydrogen				0		0	0	0	0	0	0	0		0
Carbon Monoxide				0		0	0	0	0	0	0	0		0
Carbon Dioxide				0.146664		8.60412	8.60412	0.0935504	0.000615000	8.60474	0.146664	0.148610		0.00194641
Methane				0		0	0	0	0	0	0	0		0
Methanol				0		0	0	0	0	0	0	0		0
Ethane				0		0	0	0	0	0	0	0		0
Ethanol				0		0	0	0	0	0	0	0		0
Hydrogen Sulfide				0		0	0	0	0	0	0	0		0
MDEA				0		0	0	0	0	0	0	0		0
O2				0.0143675		0.0131220	0.0131220	0.000142672	0.000115685	0.0132377	0.0143675	0.0145581		0.000190674
MEA				0		36.3223	36.3223	0.394923	0.00683703	36.3291	0	0		0
SO2				0		0	0	0	0	0	0	0		0

Process Streams		**41**	**42**	**43**	**45**	**46**	**47**	**48**	**49**	**50**	**51**	**54**	**55**	**56**
Properties	**Status:**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**	**Solved**
Phase: **Light Liquid**	**From Block:**	**VSSL-104**	**--**	**PUMP-103**	**Absorber Water Wash**	**SPLT-100**	**XCHG-108**	**SPLT-100**	**Absorber Overhead**	**MIX-101**	**XCHG-107**	**RCYL-3**	**CMPR-105**	**MKUP-2**
	To Block:	**CMPR-103**	**VSSL-104**	**DTWR-100**	**Absorber Overhead**	**XCHG-108**	**MIX-101**	**MIX-100**	**MIX-101**	**RCYL-1**	**PUMP-103**	**MKUP-2**	**DTWR-100**	**--**
Property	**Units**													
Temperature	K			299.838		314.766	313.706	314.766	313.769	313.720	299.817	316.093		316.093
Pressure	Pa			273722		210290	175816	210290	106869	106869	101353	115142		115142
Mole Fraction Vapor				0		0	0	0	0	0	0	0		0
Mole Fraction Light Liquid				1		1	1	1	1	1	1	1		1
Molecular Weight	kg/mol			0.0180159		0.0182083	0.0182083	0.0182083	0.0180191	0.0182066	0.0180159	0.0180159		0.0180159
Mass Density	kg/m^3			996.003		992.215	992.627	992.215	991.219	992.599	995.987	990.305		990.305
Molar Flow	mol/s			174843		159109	159109	1729.95	1414.69	160524	174843	177163		2320.38
Mass Flow	kg/s			3149.95		2897.10	2897.10	31.4995	25.4915	2922.60	3149.95	3191.75		41.8037
Vapor Volumetric Flow	m^3/s			3.16259		2.91983	2.91862	0.0317466	0.0257173	2.94439	3.16264	3.22300		0.0422130
Liquid Volumetric Flow	m^3/s			3.16259		2.91983	2.91862	0.0317466	0.0257173	2.94439	3.16264	3.22300		0.0422130
Std Vapor Volumetric Flow	m^3/s			4142.10		3769.36	3769.36	40.9833	33.5147	3802.88	4142.10	4197.07		54.9709
Std Liquid Volumetric Flow	m^3/s			3.15309		2.90116	2.90116	0.0315436	0.0255166	2.92668	3.15309	3.19493		0.0418454
Compressibility				0.00198602		0.00147455	0.00123648	0.00147455	0.000744677	0.000751500	0.000735441	0.000797027		0.000797027
Specific Gravity				0.996944		0.993153	0.993565	0.993153	0.992156	0.993537	0.996928	0.991241		0.991241
API Gravity				10.0079		9.78666	9.78727	9.78666	10.0090	9.79053	10.0109	10.0107		10.0107
Enthalpy	J/s			-4.99490E+10		-4.52963E+10	-4.53092E+10	-4.92495E+08	-4.02674E+08	-4.57119E+10	-4.99498E+10	-5.03965E+10		-6.60065E+08
Mass Enthalpy	J/kg			-1.58571E+07		-1.56350E+07	-1.56395E+07	-1.56350E+07	-1.57964E+07	-1.56409E+07	-1.58573E+07	-1.57896E+07		-1.57896E+07
Mass Cp	J/(kg*K)			4119.07		4165.76	4160.43	4165.76	4190.19	4160.91	4119.27	4202.17		4202.17
Ideal Gas CpCv Ratio				1.32536		1.31770	1.31780	1.31770	1.32403	1.31785	1.32536	1.32397		1.32397
Dynamic Viscosity	Pa*s			0.000879839		0.000666975	0.000680507	0.000666975	0.000663713	0.000680071	0.000879945	0.000635042		0.000635042
Kinematic Viscosity	m^2/s			8.83370E-07		6.72208E-07	6.85562E-07	6.72208E-07	6.69593E-07	6.85141E-07	8.83490E-07	6.41259E-07		6.41259E-07
Thermal Conductivity	W/(m*K)			0.608585		0.618097	0.616859	0.618097	0.626487	0.616959	0.608555	0.629382		0.629382
Surface Tension	N/m			0.0724712?		0.0692654	0.0694721	0.0692654	0.0697144	0.0694714	0.0724756?	0.0692616		0.0692616
Net Ideal Gas Heating Value	J/m^3			0		224992	224992	224992	4763.16	223052	0	0		0
Net Liquid Heating Value	J/kg			-2.46485E+06		-2.14773E+06	-2.14773E+06	-2.14773E+06	-2.45826E+06	-2.15044E+06	-2.46485E+06	-2.46485E+06		-2.46485E+06
Gross Ideal Gas Heating Value	J/m^3			1.87444E+06		2.11465E+06	2.11465E+06	2.11465E+06	1.87959E+06	2.11258E+06	1.87444E+06	1.87444E+06		1.87444E+06
Gross Liquid Heating Value	J/kg			-8.10121		310864	310864	310864	6657.05	308210	-8.10121	-8.10121		-8.10121

Process Streams		57	58
Composition	Status:	Solved	Solved
Phase: **Total**	From Block:	--	DTWR-100
	To Block:	MKUP-2	RCYL-3
Mole Fraction			
Water		1	0.999970
Nitrogen		0	8.42814E-06
Hydrogen		0	0
Carbon Monoxide		0	0
Carbon Dioxide		0	1.90604E-05
Methane		0	0
Methanol		0	0
Ethane		0	0
Ethanol		0	0
Hydrogen Sulfide		0	0
MDEA		0	0
O2		0	2.56803E-06
MEA		0	0
SO2		0	0
Molar Flow		mol/s	mol/s
Water		0	177158
Nitrogen		0	1.49316
Hydrogen		0	0
Carbon Monoxide		0	0
Carbon Dioxide		0	3.37679
Methane		0	0
Methanol		0	0
Ethane		0	0
Ethanol		0	0
Hydrogen Sulfide		0	0
MDEA		0	0
O2		0	0.454960
MEA		0	0
SO2		0	0
Mass Fraction			
Water		1	0.999936
Nitrogen		0	1.31051E-05
Hydrogen		0	0
Carbon Monoxide		0	0
Carbon Dioxide		0	4.65609E-05
Methane		0	0
Methanol		0	0
Ethane		0	0
Ethanol		0	0
Hydrogen Sulfide		0	0
MDEA		0	0
O2		0	4.56118E-06
MEA		0	0
SO2		0	0
Mass Flow		kg/s	kg/s
Water		0	3191.55
Nitrogen		0	0.0418284
Hydrogen		0	0
Carbon Monoxide		0	0
Carbon Dioxide		0	0.148611
Methane		0	0
Methanol		0	0
Ethane		0	0
Ethanol		0	0
Hydrogen Sulfide		0	0
MDEA		0	0
O2		0	0.0145582
MEA		0	0
SO2		0	0

Process Streams		**57**	**58**	
Properties	**Status:**	**Solved**	**Solved**	
Phase: **Total**	**From Block:**	**--**	**DTWR-100**	
	To Block:	**MKUP-2**	**RCYL-3**	
Property	**Units**			
Temperature	K	299.817*	316.093	
Pressure	Pa	275790*	115142	
Mole Fraction Vapor		0	0	
Mole Fraction Light Liquid		1	1	
Molecular Weight	kg/mol	0.0180153	0.0180159	
Mass Density	kg/m^3	996.004	990.305	
Molar Flow	mol/s	0	177163	
Mass Flow	kg/s	0	3191.75	
Vapor Volumetric Flow	m^3/s			
Liquid Volumetric Flow	m^3/s			
Std Vapor Volumetric Flow	m^3/s	0	4197.07	
Std Liquid Volumetric Flow	m^3/s	0	3.19494	3.22300
Compressibility		0.00200110	0.000797027	3.22300
Specific Gravity				
API Gravity				
Enthalpy	J/s	0	-5.03965E+10	0.991240
Mass Enthalpy	J/kg	-1.58578E+07	-1.57896E+07	
Mass Cp	J/(kg*K)			10.0107
Ideal Gas CpCv Ratio		1.32536	1.32397	
Dynamic Viscosity	Pa*s			
Kinematic Viscosity	m^2/s			4202.17 0.000635039
Thermal Conductivity	W/(m*K)			6.41256E-07
Surface Tension	N/m			
Net Ideal Gas Heating Value	J/m^3	0	0	0.629382
Net Liquid Heating Value	J/kg	-2.46500E+06	-2.46485E+06	0.0692016
Gross Ideal Gas Heating Value	J/m^3	1.87450E+06	1.87444E+06	
Gross Liquid Heating Value	J/kg	0	-8.10123	

Process Streams		57	58
Composition	Status:	Solved	Solved
Phase: **Vapor**	From Block:	--	DTWR-100
	To Block:	MKUP-2	RCYL-3
Mole Fraction			
Water			
Nitrogen			
Hydrogen			
Carbon Monoxide			
Carbon Dioxide			
Methane			
Methanol			
Ethane			
Ethanol			
Hydrogen Sulfide			
MDEA			
O2			
MEA			
SO2			
Molar Flow			
Water			
Nitrogen			
Hydrogen			
Carbon Monoxide			
Carbon Dioxide			
Methane			
Methanol			
Ethane			
Ethanol			
Hydrogen Sulfide			
MDEA			
O2			
MEA			
SO2			
Mass Fraction			
Water			
Nitrogen			
Hydrogen			
Carbon Monoxide			
Carbon Dioxide			
Methane			
Methanol			
Ethane			
Ethanol			
Hydrogen Sulfide			
MDEA			
O2			
MEA			
SO2			
Mass Flow			
Water			
Nitrogen			
Hydrogen			
Carbon Monoxide			
Carbon Dioxide			
Methane			
Methanol			
Ethane			
Ethanol			
Hydrogen Sulfide			
MDEA			
O2			
MEA			
SO2			

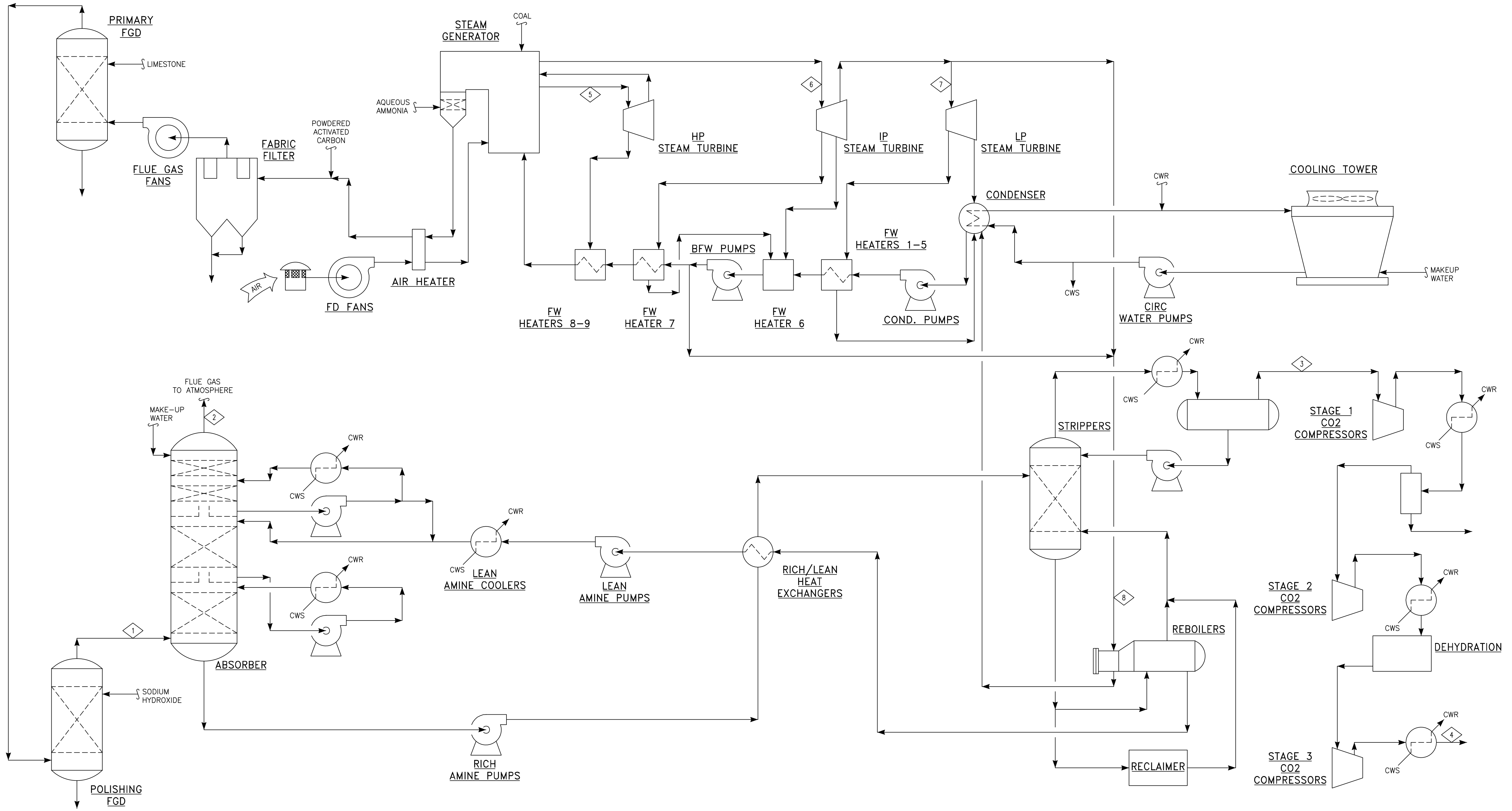
Process Streams		**57**	**58**
Properties	**Status:**	**Solved**	**Solved**
Phase: **Vapor**	**From Block:**	**--**	**DTWR-100**
	To Block:	**MKUP-2**	**RCYL-3**
Property	**Units**		
Temperature	K		
Pressure	Pa		
Mole Fraction Vapor			
Mole Fraction Light Liquid			
Molecular Weight	kg/mol		
Mass Density	kg/m^3		
Molar Flow	mol/s		
Mass Flow	kg/s		
Vapor Volumetric Flow	m^3/s		
Liquid Volumetric Flow	m^3/s		
Std Vapor Volumetric Flow	m^3/s		
Std Liquid Volumetric Flow	m^3/s		
Compressibility			
Specific Gravity			
API Gravity			
Enthalpy	J/s		
Mass Enthalpy	J/kg		
Mass Cp	J/(kg*K)		
Ideal Gas CpCv Ratio			
Dynamic Viscosity	Pa*s		
Kinematic Viscosity	m^2/s		
Thermal Conductivity	W/(m*K)		
Surface Tension	N/m		
Net Ideal Gas Heating Value	J/m^3		
Net Liquid Heating Value	J/kg		
Gross Ideal Gas Heating Value	J/m^3		
Gross Liquid Heating Value	J/kg		

Process Streams		**57**	**58**
Composition	**Status:**	Solved	Solved
Phase: **Light Liquid**	**From Block:**	--	DTWR-100
	To Block:	MKUP-2	RCYL-3
Mole Fraction			
Water			0.999970
Nitrogen			8.42814E-06
Hydrogen			0
Carbon Monoxide			0
Carbon Dioxide			1.90604E-05
Methane			0
Methanol			0
Ethane			0
Ethanol			0
Hydrogen Sulfide			0
MDEA			0
O2			2.56803E-06
MEA			0
SO2			0
Molar Flow			**mol/s**
Water			177158
Nitrogen			1.49316
Hydrogen			0
Carbon Monoxide			0
Carbon Dioxide			3.37679
Methane			0
Methanol			0
Ethane			0
Ethanol			0
Hydrogen Sulfide			0
MDEA			0
O2			0.454960
MEA			0
SO2			0
Mass Fraction			
Water			0.999936
Nitrogen			1.31051E-05
Hydrogen			0
Carbon Monoxide			0
Carbon Dioxide			4.65609E-05
Methane			0
Methanol			0
Ethane			0
Ethanol			0
Hydrogen Sulfide			0
MDEA			0
O2			4.56118E-06
MEA			0
SO2			0
Mass Flow			**kg/s**
Water			3191.55
Nitrogen			0.0418284
Hydrogen			0
Carbon Monoxide			0
Carbon Dioxide			0.148611
Methane			0
Methanol			0
Ethane			0
Ethanol			0
Hydrogen Sulfide			0
MDEA			0
O2			0.0145582
MEA			0
SO2			0

Process Streams		**57**	**58**
Properties	**Status:**	**Solved**	**Solved**
Phase: **Light Liquid**	**From Block:**	**--**	**DTWR-100**
	To Block:	**MKUP-2**	**RCYL-3**
Property	**Units**		
Temperature	K		316.093
Pressure	Pa		115142
Mole Fraction Vapor			0
Mole Fraction Light Liquid			1
Molecular Weight	kg/mol		0.0180159
Mass Density	kg/m^3		990.305
Molar Flow	mol/s		177163
Mass Flow	kg/s		3191.75
Vapor Volumetric Flow	m^3/s		3.22300
Liquid Volumetric Flow	m^3/s		3.22300
Std Vapor Volumetric Flow	m^3/s		4197.07
Std Liquid Volumetric Flow	m^3/s		3.19494
Compressibility			0.000797027
Specific Gravity			0.991240
API Gravity			10.0107
Enthalpy	J/s		-5.03965E+10
Mass Enthalpy	J/kg		-1.57896E+07
Mass Cp	J/(kg*K)		4202.17
Ideal Gas CpCv Ratio			1.32397
Dynamic Viscosity	Pa*s		0.000635039
Kinematic Viscosity	m^2/s		6.41256E-07
Thermal Conductivity	W/(m*K)		0.629382
Surface Tension	N/m		0.0692616
Net Ideal Gas Heating Value	J/m^3		0
Net Liquid Heating Value	J/kg		-2.46485E+06
Gross Ideal Gas Heating Value	J/m^3		1.87444E+06
Gross Liquid Heating Value	J/kg		-8.10123

Appendix C. Simplified PFDs and Stream Sheets for Reference Cases with Integral CO_2 Capture/Compression

Reference Case 2 – SCPC, 90% CO_2 Capture
Reference Case 4 – NGCC, 90% CO_2 Capture



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IEA GHG R&D PROGRAMME
CO2 CAPTURE SCALE-UP STUDY

SIMPLIFIED PROCESS FLOW DIAGRAM
CASE 2-900MW SCPC PLANT 90% CO2 CAPTURE

PROJECT
DRAWING NUMBER
175185-CUUU-M2010
REV C
CODE
AREA

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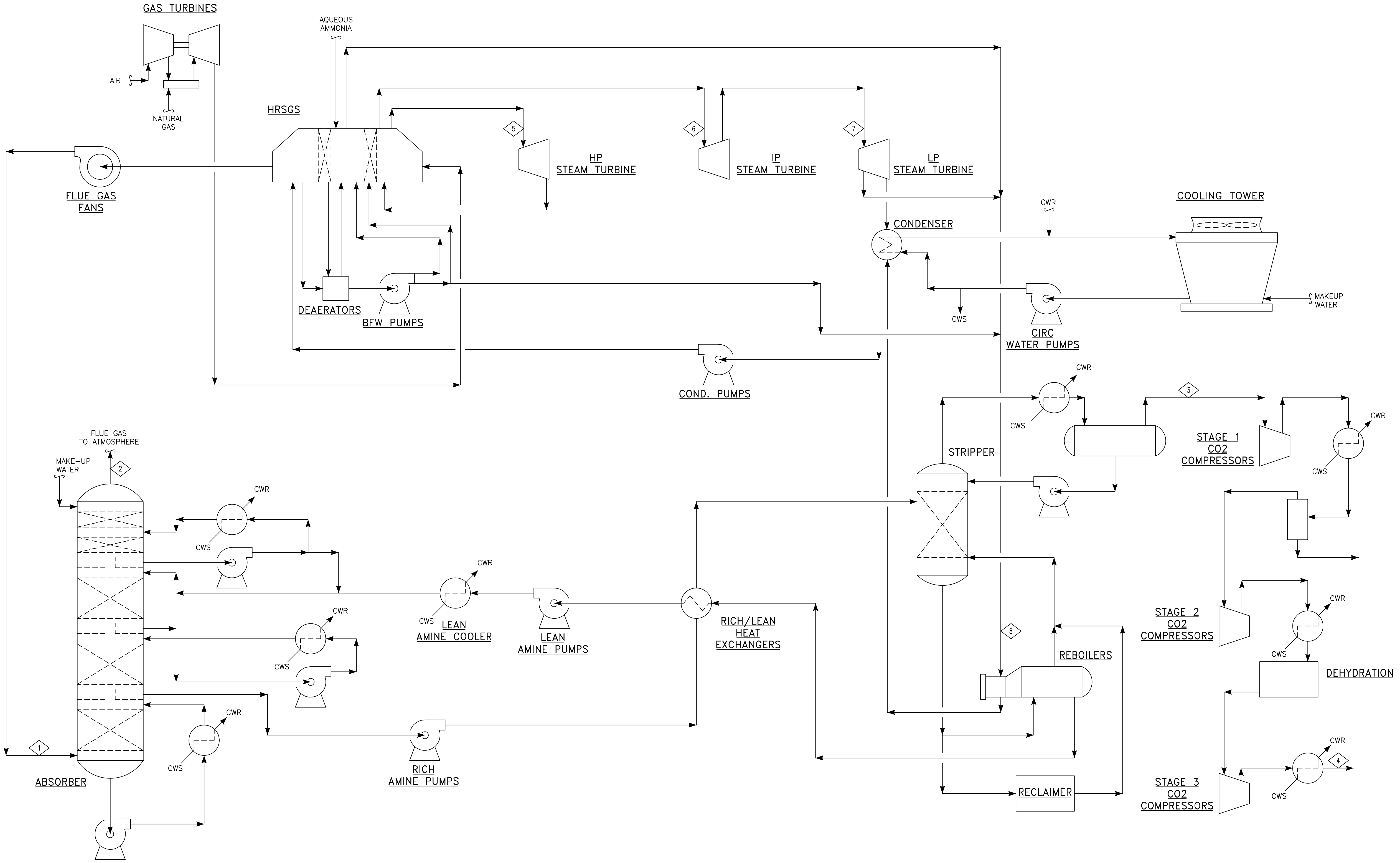
IEA CO2 Capture Scale-Up Study
B&V Project: 175185

BLACK & VEATCH
Preliminary Stream Sheet
CASE 2 - SCPC, 90% CO2 Capture

17-Apr-2012
Rev: A

Stream:		1	2	3	4	5	6	7	8
Medium:		FLUE GAS	FLUE GAS	CO2	CO2	STEAM	STEAM	STEAM	STEAM
From:		POLISHING SCRUBBER	ABSORBER	STRIPPER	COMPRESSION	MAIN STEAM	HOT REHEAT	IP TURBINE	CROSSOVER/ FEEDWATER
To:		ABSORBER	ATMOSPHERE	COMPRESSION	STORAGE	HP TURBINE	IP TURBINE	LP TURBINE	REBOILERS
Mole-flow	kmol/h	135,350	117,802	15,021	14,297	143,667	117,722	59,683	45,572
Mass-flow	kg/s	1,083	891	178	175	719	589	299	228
Mass-flow	MT/h	3,898	3,209	642	630	2,588	2,121	1,075	821
Pressure	kPa	115.51	108.61	186.16	11,032	25,440	4,811	897.3	446.1
Temperature	°C	54	51	48	38	582.2	582.2	329.9	147.8
Composition									
N2	%mole	70.22%	80.68%	0.01%	0.02%	0.00%	0.00%	0.00%	0.00%
CO2	%mole	11.78%	1.35%	95.18%	99.98%	0.00%	0.00%	0.00%	0.00%
O2	%mole	5.03%	5.78%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
H2O	%mole	12.97%	12.19%	4.80%	0.00%	100.00%	100.00%	100.00%	100.00%
NO2	%mole	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CO	%mole	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
SO2+SO3	%mole	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	%mole	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Molar Flow									
N2	kmol/h	95,041.37	95,039.12	2.21	2.21	0	0	0	0
CO2	kmol/h	15,943.99	1,591.21	14,297.47	14,294.39	0	0	0	0
O2	kmol/h	6,808.00	6,809.98	0.3	0.3	0	0	0	0
H2O	kmol/h	17,554.64	14,361.01	720.82	0	143,666.77	117,722.16	59,682.60	45,572.37
NO2	kmol/h	0	0	0	0	0	0	0	0
CO	kmol/h	0	0	0	0	0	0	0	0
SO2+SO3	kmol/h	2.17	0	0	0	0	0	0	0
Total	kmol/h	135,350.17	117,801.32	15,020.80	14,296.90	143,666.77	117,722.16	59,682.60	45,572.37
Mass Flow									
N2	kg/s	739.74	739.72	0.02	0.02	0	0	0	0
CO2	kg/s	194.92	19.45	174.79	174.75	0	0	0	0
O2	kg/s	60.52	60.53	0	0	0	0	0	0
H2O	kg/s	87.85	71.87	3.61	0	718.94	589.11	298.67	228.06
NO2	kg/s	0	0	0	0	0	0	0	0
CO	kg/s	0	0	0	0	0	0	0	0
SO2+SO3	kg/s	0.04	0	0	0	0	0	0	0
Total	kg/s	1,083.06	891.58	178.41	174.77	718.94	589.11	298.67	228.06



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IEA GHG R&D PROGRAMME
CO2 CAPTURE SCALE-UP STUDY

SIMPLIFIED PROCESS FLOW DIAGRAM
CASE 4-800MW NGCC PLANT, 90% CO2 CAPTURE

PROJECT
DRAWING NUMBER 175185-CUUU-M2011
REV C
CODE
AREA

IEA CO2 Capture Scale-Up Study
B&V Project: 175185

BLACK & VEATCH
Preliminary Stream Sheet
CASE 4 - NGCC, 90% CO2 Capture

17-Apr-2012
Rev: A

Stream:		1	2	3	4	5	6	7	8
Medium:		FLUE GAS	FLUE GAS	CO2	CO2	STEAM	STEAM	STEAM	STEAM
From:		FLUE GAS FANS	ABSORBER	STRIPPER	COMPRESSION	MAIN STEAM	HOT REHEAT	IP TURBINE	LP STEAM/ FEEDWATER
To:		ABSORBER	ATMOSPHERE	COMPRESSION	STORAGE	HP TURBINE	IP TURBINE	LP TURBINE	REBOILERS
Mole-flow	kmol/h	154,287	147,909	5,975	5,687	30,208	35,242	35,242	18,329
Mass-flow	kg/s	1,212	1,139	71	70	151	176	176	92
Mass-flow	MT/h	4,362	4,098	255	250	544	635	635	330
Pressure	kPa	117.21	108.61	186.16	11,032	12,400	3,144	640.1	446.5
Temperature	°C	109	51	43	38	563	565	332	147.6
Composition									
N2	%mole	75.16%	78.40%	0.02%	0.02%	0.00%	0.00%	0.00%	0.00%
CO2	%mole	4.09%	0.42%	95.18%	99.97%	0.00%	0.00%	0.00%	0.00%
O2	%mole	11.99%	12.51%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%
H2O	%mole	8.76%	8.68%	4.80%	0.00%	100.00%	100.00%	100.00%	100.00%
NO2	%mole	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CO	%mole	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
SO2+SO3	%mole	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	%mole	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Molar Flow									
N2	kmol/h	115,961.49	115,960.51	1.1	1.1	0	0	0	0
CO2	kmol/h	6,312.99	614	5,687.00	5,685.77	0	0	0	0
O2	kmol/h	18,502.25	18,503.42	0.34	0.34	0	0	0	0
H2O	kmol/h	13,510.22	12,832.60	286.74	0	30,207.66	35,242.27	35,242.27	18,328.86
NO2	kmol/h	0	0	0	0	0	0	0	0
CO	kmol/h	0	0	0	0	0	0	0	0
SO2+SO3	kmol/h	0	0	0	0	0	0	0	0
Total	kmol/h	154,286.95	147,910.53	5,975.18	5,687.21	30,207.66	35,242.27	35,242.27	18,328.86
Mass Flow									
N2	kg/s	902.57	902.56	0.01	0.01	0	0	0	0
CO2	kg/s	77.18	7.51	69.52	69.51	0	0	0	0
O2	kg/s	164.46	164.47	0	0	0	0	0	0
H2O	kg/s	67.61	64.22	1.43	0	151.17	176.36	176.36	91.72
NO2	kg/s	0	0	0	0	0	0	0	0
CO	kg/s	0	0	0	0	0	0	0	0
SO2+SO3	kg/s	0	0	0	0	0	0	0	0
Total	kg/s	1,211.82	1,138.76	70.97	69.52	151.17	176.36	176.36	91.72

Appendix D. Reference Case Electricity Generation Summary

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Electricity Generation Performance Summary
CASES 1 - 4

IEA GHG Plant Performance Summary

		Case 1	Case 2	Case 3	Case 4
Reference Case Description		Supercritical Pulverized Coal Rankine Cycle		2-on-1 G-Class Gas Turbine Combined Cycle	
Fuel Type		Coal	Coal	Natural Gas	Natural Gas
CO_2 Capture		No	90%	No	90%
Electrical Output					
Gross Output					
Steam Turbine Generator (STG)	MW	900.1	756.6	280.4	223.7
Gas Turbine Generators (total)	MW	n/a	n/a	529.5	529.5
Total Gross Output	MW	900.1	756.6	809.9	753.2
Auxiliary Electric Load					
Power Block	MW	35.5	35.1	19.6	22.1
Flue Gas Fans	MW	17.2	44	n/a	26.1
Air Quality Systems	MW	5.8	8.5	n/a	n/a
CO_2 Capture	MW	n/a	5.2	n/a	3.6
CO_2 Compression	MW	n/a	75.0	n/a	25.5
Total Auxiliary Electric Load	MW	58.5	167.8	19.6	77.3
Net Plant Output	MW	841.6	588.8	790.3	675.9
Energy Penalty	%	n/a	-30.0%	n/a	-14.5%
Energy Penalty	MW/t-CO2		0.4022		0.4614
Electrical Production Efficiency					
Fuel Input (NCV)	GJ/h	7,500	7,500	4,906	4,906
Fuel Input (GCV)	GJ/h	7,815	7,815	5,433	5,433
Net Plant Heat Rate (NCV)	kJ/kWh	8,912	12,738	6,208	7,259
Net Plant Heat Rate (GCV)	kJ/kWh	9,285	13,272	6,874	8,038
Net Plant Thermal Efficiency (NCV)	%	40.4%	28.3%	58.0%	49.6%
Net Plant Thermal Efficiency (GCV)	%	38.8%	27.1%	52.4%	44.8%
CO_2 Emissions					
CO_2 for Transport	MT/h	n/a	629	n/a	250
CO_2 to Atmosphere	MT/h	702	73	276	28
CO_2 to Atmosphere	kg/MWh-net	834	124	349	41

Appendix E. Reference Case Major Equipment Lists

Reference Case 1 – SCPC, No CO_2 Capture
Reference Case 2 – SCPC, 90% CO_2 Capture
Reference Case 3 – NGCC, No CO_2 Capture
Reference Case 4 – NGCC, 90% CO_2 Capture

BLACK & VEATCH
Major Equipment List
CASE 1 - SCPC, No Capture

Quantity	Description	Type	Size		Material	Notes
			Parameter 1	Parameter 2		
1	Steam Generator	Supercritical PC, two-pass tangential or wall-fired, on reheat, overfire air, low NOx burners	7,699 GJ/h-GCV heat input	584.2 / 258.3 ° C/ bar(a) main steam exit conditions		
1	Steam Turbine Generator	Condensing, reheat 4 flow LP turbine with 1,016 mm last stage blades	2,589 MT/h throttle (main steam)	582.0 / 254.4 ° C/ bar(a) throttle		1,050 kVA generator, 0.9 power factor
1	Selective Catalytic Reduction	29% Aqueous ammonia	3,240 MT/h gas flow	84% NO_x Removal Efficiency		2 kPa pressure drop.
1	Powdered Activated Carbon Injection		3,720 MT/h gas flow			Mercury removal.
1	Fabric Filter	Pulse-jet fabric filter	3,720 MT/h gas flow	99.9% PM_{10} Removal Efficiency		2-casing design, 10 compartments per casing. 2 kPa pressure drop.
2	Flue Gas Fans	Axial fan, 50% of flow.	9.2 kPa flue gas pressure rise (operating)	8,600 kW		2x ID axial fans in parallel.
1	Flue Gas Desulfurization	Limestone forced oxidation (LSFO) spray tower	3,720 MT/h gas flow	97.5% SO_2 Removal Efficiency		1.5 kPa pressure drop.
2	Condensers	Two pass, Shell & Tube	1,750 GJ/h		CS shell 304 SS tube material	
1	Cooling Tower	Counterflow, 16 cells (2 banks of 8 cells)	3,600 GJ/h		Fiberglass reinforced plastic structure	Approximate overall dimensions: 130 m (length), 36 m (width), 18 m (height).

BLACK & VEATCH
Major Equipment List
CASE 2 - SCPC, 90% CO2 Capture

Quantity	Description	Type	Size		Material	Notes
			Parameter 1	Parameter 2		
1	Steam Generator	Supercritical PC, two-pass tangential or wall-fired, on reheat, overfire air, low NOx burners	7,699 GJ/h-GCV heat input	584.2 / 258.2 ° C/ bar(a) main steam exit conditions		
1	Steam Turbine Generator	Condensing, reheat 4 flow LP turbine with 851 mm last stage blades	2,588 MT/h throttle (main steam)	582.2 / 254.4 ° C/ bar(a) throttle		890 kVA generator, 0.9 power factor
1	Selective Catalytic Reduction	29% Aqueous ammonia	3,240 MT/h gas flow	84% NO_x Removal Efficiency		2 kPa pressure drop.
1	Powdered Activated Carbon Injection		3,720 MT/h gas flow			Mercury removal.
1	Fabric Filter	Pulse-jet fabric filter	3,720 MT/h gas flow	99.9% PM_{10} Removal Efficiency		2-casing design, 10 compartments per casing. 2 kPa pressure drop.
4	Flue Gas Fans	2x axial fans in parallel, 2x axial fans in series (4 total)	12.4 kPa flue gas pressure rise (operating)	11,000 kW (operating)		2x axial fans in parallel, 2x axial fans in series (4 total)
1	Primary Flue Gas Desulfurization	Limestone forced oxidation (LSFO) spray tower	3,720 MT/h gas flow	97.5% SO_2 Removal Efficiency		1.5 kPa pressure drop.
1	Polishing Flue Gas Desulfurization	Sodium Hydroxide (NaOH) Caustic Scrubber	3,720 MT/h gas flow	20.4% SO_2 Removal Efficiency		SO_2 flue gas concentration of 10 ppm assumed for amine CO_2 capture process. 1.5 kPa pressure drop.
2	Condensers	Two pass, Shell & Tube	800 GJ/h		CS shell 304 SS tube material	
1	Cooling Tower	Counterflow, 22 cells (2 banks of 11 cells)	4,400 GJ/h		Fiberglass reinforced plastic structure	Approximate overall dimensions: 180 m (length), 36 m (width), 18 m (height).
1	CO_2 Absorber	Random Packing	17.8 m x 17.8 m x 28 m		Concrete	Square concrete tower with SS internal supports
2	CO_2 Strippers	Random Packing	7.2 m ID x 23 m T/T		CS	
8	Stripper Reboilers	Shell and Tube	175 GJ/h	170 cm ID x 12.2 m T/T	CS	821 MT/h of 4.5 bar(a) steam
5	Stripper Overhead Coolers	Shell and Tube	215 GJ/h	152 cm ID x 11.5 m T/T	CS	23,200 m^3/h of cooling water (total)
2	Rich Amine Pumps	Centrifugal	850 kW	7,380 m^3/h		2 x 100%
2	Lean Amine Pumps	Centrifugal	870 kW	7,420 m^3/h		2 x 100%
3	Rich/Lean Heat Exchangers	Plate and Frame	450 GJ/h	1.4 m x 7.4 m	316 SS	
5	Lean Amine Coolers	Plate and Frame	200 GJ/h	1.4 m x 7.4 m	316 SS	21,600 m^3/h cooling water (total)
5	Absorber Side Draw Coolers	Plate and Frame	175 GJ/h	1.4 m x 7.4 m	316 SS	
2	Absorber Water Wash Pumps	Centrifugal	13 kW	610 m^3/h		2 x 100%
1	Absorber Water Wash Cooler	Plate and Frame	1 GJ/h	0.3 m x 1.1 m	316 SS	
2	Three Stage CO_2 Compressors	Centrifugal	37,500 kW	16.9 m x 4.5 m		110 bar(a) final pressure
5	Stage 1 CO_2 Compressor Intercoolers	Shell and Tube	23 GJ/h	152 cm ID x 11.5 m T/T	CS	2,440 m^3/h cooling water (total)
2	Stage 2 CO_2 Compressor Intercoolers	Shell and Tube	50 GJ/h	132 cm ID x 10.7 m T/T	CS	2,080 m^3/h cooling water (total)
2	Stage 3 CO_2 Compressor Aftercoolers	Shell and Tube	93 GJ/h	132 cm ID x 10.7 m T/T	CS	4,020 m^3/h cooling water (total)
2	Molecular Sieve Dehydration Packages	Regenerative desiccant	2,650 kg/h water removal	512 cm ID x 24 m T/T		1 operating and 1 regenerating

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Major Equipment List
CASE 3 - NGCC, No Capture

Quantity	Description	Type	Size		Material	Notes
			Parameter 1	Parameter 2		
2	Gas Turbine Generators	G-Class, Air Cooled	2,130 MT/h inlet airflow	620 ° C exhaust		2 x 50%.
2	Heat Recovery Steam Generators	Horizontal drum, 3-pressure	2,181 MT/h gas flow	1,290 GJ/h (heat to steam)		Integral ammonia injection grid, SCR catalyst, CO catalyst. 2 x 50%.
1	Steam Turbine Generator	Condensing, reheat 3-press. 2 flow LP turbine with 1,016 mm last stage blades	544 MT/h throttle (HP steam)	562 / 124 ° C/ bar(a) throttle		330 kVA generator, 0.9 power factor
1	Condenser	Two pass, Shell & Tube	1,600 GJ/h		CS shell 304 SS tube material	
1	Cooling Tower	Counterflow, 8 cells (1 bank of 8 cells)	1,600 GJ/h		Fiberglass reinforced plastic structure	Approximate overall dimensions: 130 m (length), 18 m (width), 18 m (height).

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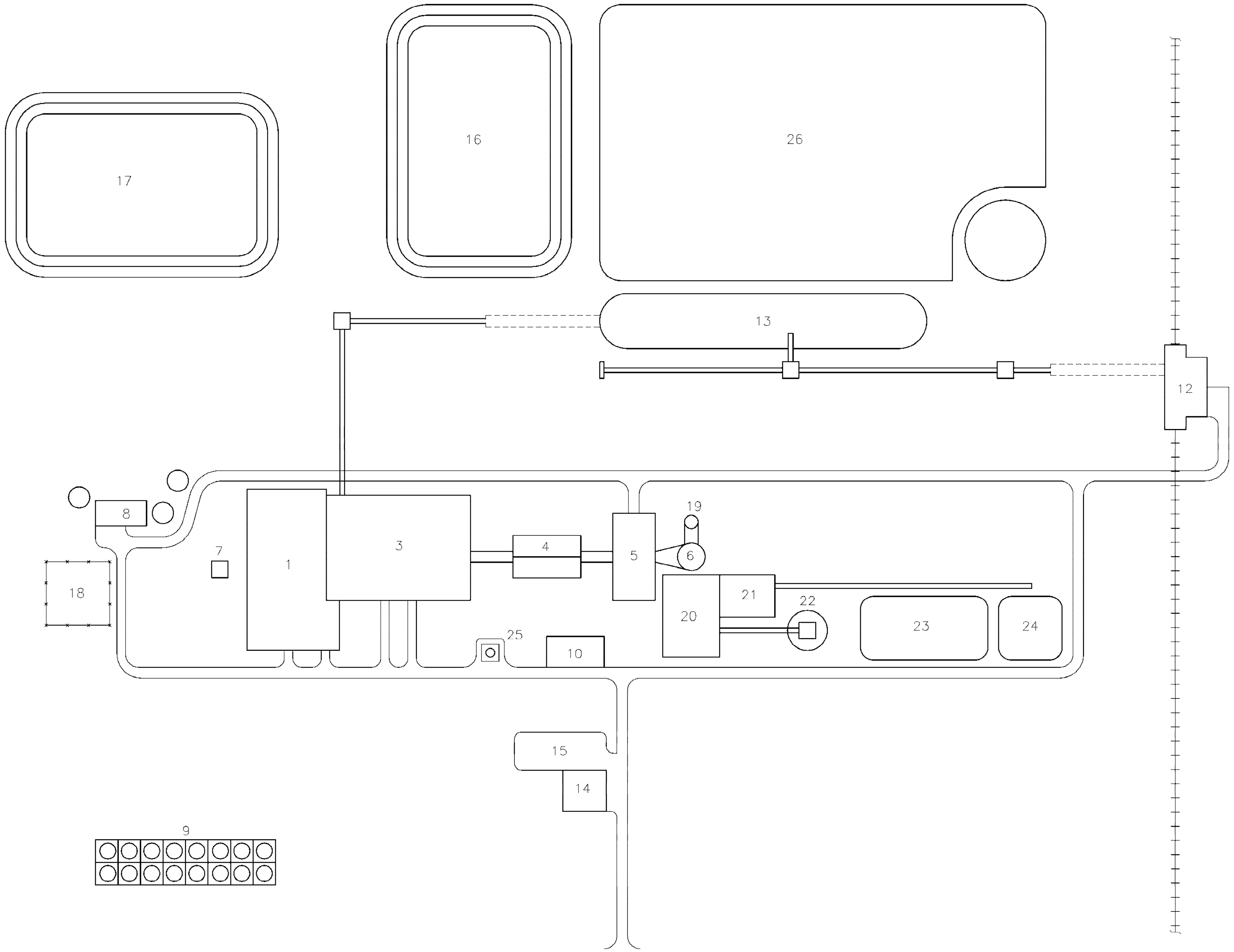
Major Equipment List
CASE 4 - NGCC, 90% CO2 Capture

Quantity	Description	Type	Size		Material	Notes
			Parameter 1	Parameter 2		
2	Gas Turbine Generators	G-Class, Air Cooled	2,130 MT/h inlet airflow	620 ° C exhaust		2 x 50%.
2	Heat Recovery Steam Generators	Horizontal drum, 3-pressure	2,181 MT/h gas flow	1,270 GJ/h (heat to steam)		Integral ammonia injection grid, SCR catalyst, CO catalyst. 2 x 50%.
1	Steam Turbine Generator	Condensing, reheat 3-press. 2 flow LP turbine with 851 mm last stage blades	544 MT/h throttle (HP steam)	563 / 124 ° C/ bar(a) throttle		260 kVA generator, 0.9 power factor
1	Condenser	Two pass, Shell & Tube	900 GJ/h		CS shell 304 SS tube material	
1	Cooling Tower	Counterflow, 12 cells (2 banks of 6 cells)	2,300 GJ/h		Fiberglass reinforced plastic structure	Approximate overall dimensions: 100 m (length), 36 m (width), 18 m (height).
3	Quench Cooler Heat Exchangers	Plate and Frame	200 GJ/h	1.4 m x 7.4 m	316 SS	13,600 m^3/h cooling water (total)
2	Quench Cooler Pumps	Centrifugal	200 kW	11,520 m^3/h		2 x 100%
2	Flue Gas Fans	Axial, 50% of flow	14.0 kPa flue gas pressure rise	13,050 kW (operating)		2 x 50%
1	CO_2 Absorber	Random Packing	17.8 m x 17.8 m x 28 m		Concrete	Square concrete tower with SS internal supports.
1	CO_2 Stripper	Random Packing	7 m ID x 23 m T/T		CS	
4	Stripper Reboilers	Shell and Tube	175 GJ/h	152 cm ID x 12.2 m T/T	CS	330 MT/h of 4.5 bar(a) steam
2	Stripper Overhead Coolers	Shell and Tube	221 GJ/h	152 cm ID x 11.5 m T/T	CS	9,550 m^3/h cooling water (total)
2	Rich Amine Pumps	Centrifugal	350 kW	2,930 m^3/h		2 x 100%
2	Lean Amine Pumps	Centrifugal	450 kW	2,930 m^3/h		2 x 100%
2	Rich/Lean Heat Exchangers	Plate and Frame	375 GJ/h	1.1 m x 6.0 m	316 SS	
1	Lean Amine Cooler	Plate and Frame	225 GJ/h	1.4 m x 7.4 m	316 SS	4,550 m^3/h cooling water (total)
1	Absorber Side Draw Cooler	Plate and Frame	220 GJ/h	1.4 m x 7.4 m	316 SS	
2	Absorber Water Wash Pumps	Centrifugal	500 kW	10,500 m^3/h		2 x 100%
2	Absorber Water Wash Coolers	Plate and Frame	45 GJ/h	1.4 m x 7.4 m	316 SS	
2	Three Stage CO_2 Compressors	Centrifugal	12,750 kW	10.5 m x 2.9 m		110 bar(a) final pressure
2	Stage 1 CO_2 Compressor Intercoolers	Shell and Tube	23 GJ/h	147 cm ID x 10.7 m T/T	CS	970 m^3/h cooling water (total)
1	Stage 2 CO_2 Compressor Intercooler	Shell and Tube	19 GJ/h	132 cm ID x 10.7 m T/T	CS	830 m^3/h cooling water (total)
1	Stage 3 CO_2 Compressor Aftercooler	Shell and Tube	75 GJ/h	132 cm ID x 9 m T/T	CS	1,600 m^3/h cooling water (total)
2	Molecular Sieve Dehydration Packages	Regenerative desiccant	1,050 kg/h water removal	324 cm ID x 24 m T/T		1 operating and 1 regenerating

Appendix F. Reference Case Site Arrangement Drawings

Reference Case 1 – SCPC, No CO_2 Capture
Reference Case 2 – SCPC, 90% CO_2 Capture
Reference Case 3 – NGCC, No CO_2 Capture
Reference Case 4 – NGCC, 90% CO_2 Capture



FACILITIES LEGEND

ITEM NO.	FACILITY
1	STEAM TURBINE BUILDING
2	NOT USED
3	STEAM GENERATOR BUILDING
4	PULSE JET FABRIC FILTER
5	ID FAN BUILDING
6	FLUE GAS DESULFURIZATION (FGD) ABSORBER
7	GENERATOR STEP-UP TRANSFORMER
8	WATER/WASTEWATER TREATMENT BUILDING
9	COOLING TOWER
10	PACI EQUIPMENT AREA
11	NOT USED
12	COAL UNLOADING BUILDING
13	ACTIVE COAL STORAGE PILE
14	ADMINISTRATION BUILDING
15	PARKING
16	COAL PILE RUNOFF POND
17	WASTE WATER COLLECTION POND
18	SWITCHYARD
19	STACK
20	FGD/DEWATERING BUILDING
21	REAGENT PREP BUILDING
22	FGD BYPRODUCT STORAGE
23	INACTIVE LIMESTONE STORAGE
24	ACTIVE LIMESTONE STORAGE
25	AQUEOUS AMMONIA STORAGE
26	RESERVE COAL STORAGE

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IEA GHG R&D PROGRAMME
CO2 CAPTURE SCALE-UP STUDY

PRELIMINARY SITE ARRANGEMENT
CASE 1 – 900MW SCPC PLANT, NO CAPTURE

PROJECT
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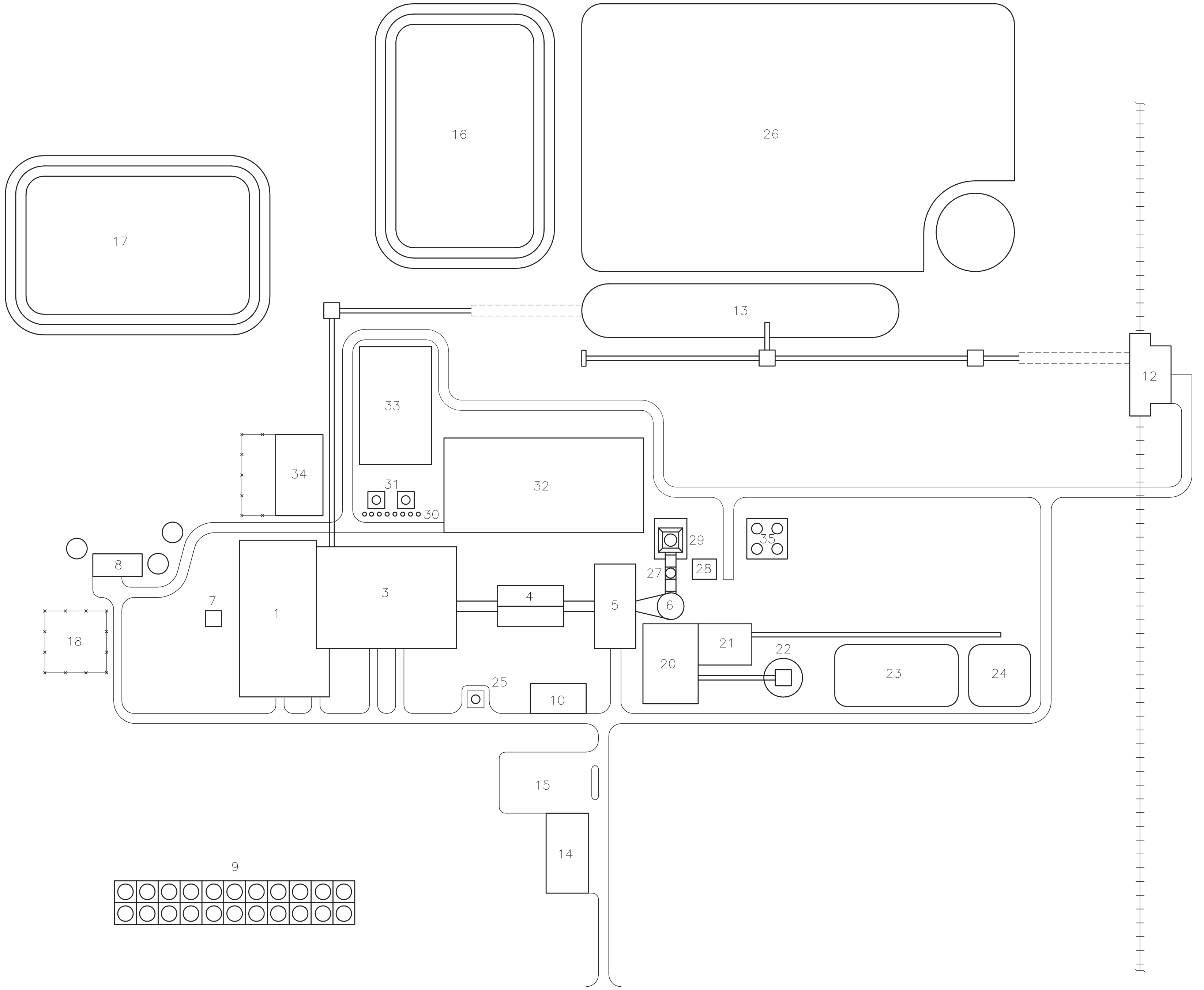

FACILITIES LEGEND

ITEM NO.	FACILITY
1	STEAM TURBINE BUILDING
2	NOT USED
3	STEAM GENERATOR BUILDING
4	PULSE JET FABRIC FILTER
5	ID FAN BUILDING
6	FLUE GAS DESULFURIZATION (FGD) ABSORBER
7	GENERATOR STEP-UP TRANSFORMER
8	WATER TREATMENT BUILDING
9	COOLING TOWER
10	PACI/DSI EQUIPMENT AREA
11	NOT USED
12	COAL UNLOADING BUILDING
13	ACTIVE COAL STORAGE PILE
14	ADMINISTRATION BUILDING
15	PARKING
16	COAL PILE RUNOFF POND
17	WASTE WATER COLLECTION POND
18	SWITCHYARD
19	NOT USED
20	FGD/DEWATERING BUILDING
21	REAGENT PREP BUILDING
22	FGD BYPRODUCT STORAGE
23	INACTIVE LIMESTONE STORAGE
24	ACTIVE LIMESTONE STORAGE
25	AQUEOUS AMMONIA STORAGE
26	RESERVE COAL STORAGE
27	POLISHING FGD
28	CAUSTIC SODA HANDLING/STORAGE
29	ABSORBER/STACK
30	STRIPPER REBOILERS (TYP X 8)
31	CO2 STRIPPERS (TYP X 2)
32	CO2 CAPTURE EQUIPMENT
33	CO2 COMPRESSION & DEHYDRATION
34	CO2 PROCESS EQUIPMENT ELECTRICAL BUILDING
35	AMINE SOLUTION STORAGE

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CO2 CAPTURE SCALE-UP STUDY

PRELIMINARY SITE ARRANGEMENT
CASE 2 – 900MW SCPC PLANT, 90% CO2 CAPTURE

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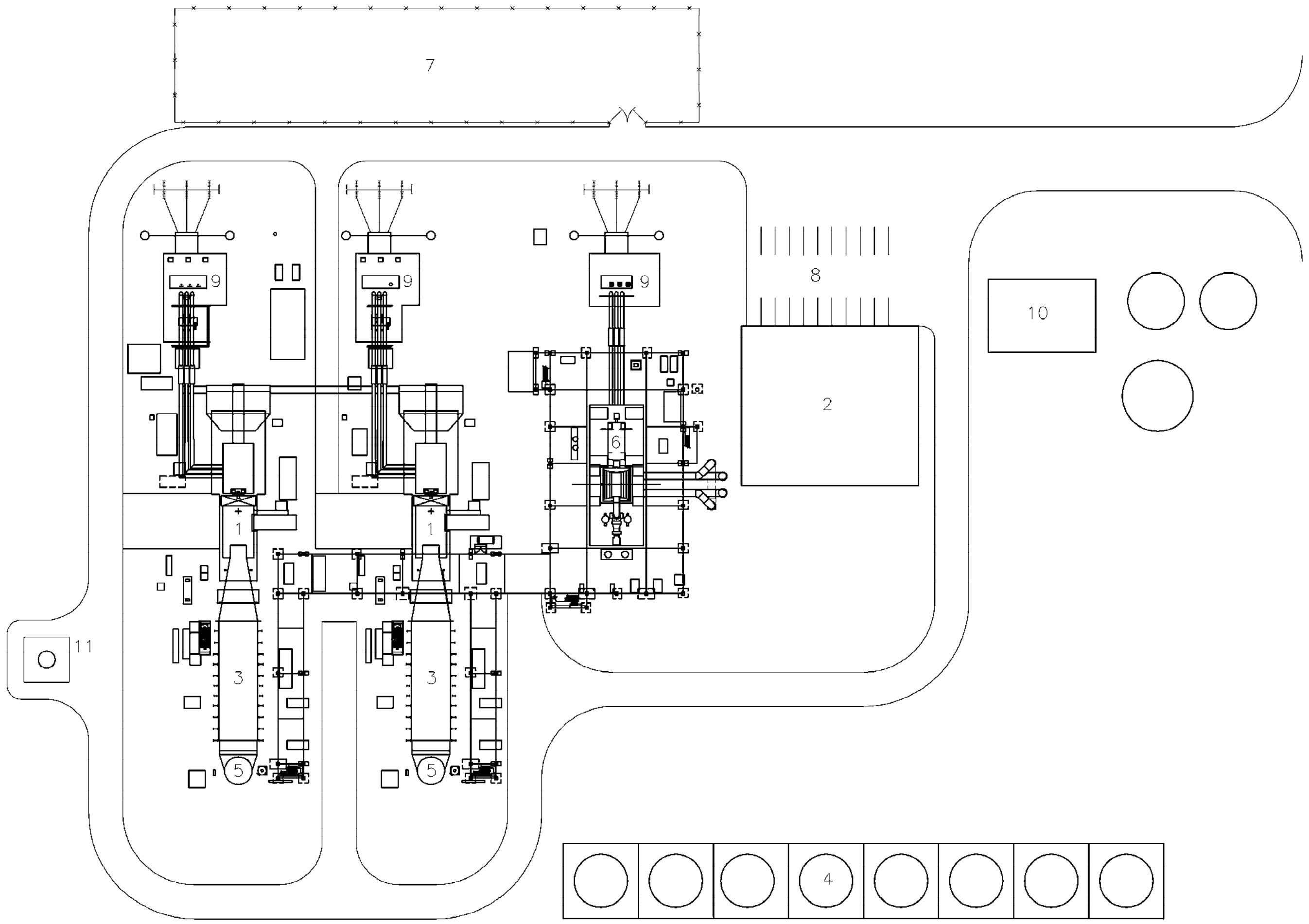
FACILITIES LEGEND

ITEM NO.	FACILITY
1	COMBUSTION TURBINES (TYP X 2)
2	ADMINISTRATION BUILDING
3	HEAT RECOVERY STEAM GENERATOR/SCR (TYP X 2)
4	COOLING TOWER
5	STACKS (TYP X 2)
6	STEAM TURBINE
7	SWITCHYARD
8	PARKING
9	GENERATOR STEP-UP TRANSFORMERS (TYP X 3)
10	WATER TREATMENT BUILDING
11	AQUEOUS AMMONIA STORAGE



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C02 CAPTURE SCALE-UP STUDY

PRELIMINARY SITE ARRANGEMENT
CASE 3 – 800 MW NGCC, NO C02 CAPTURE

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FACILITIES LEGEND

ITEM NO.	FACILITY
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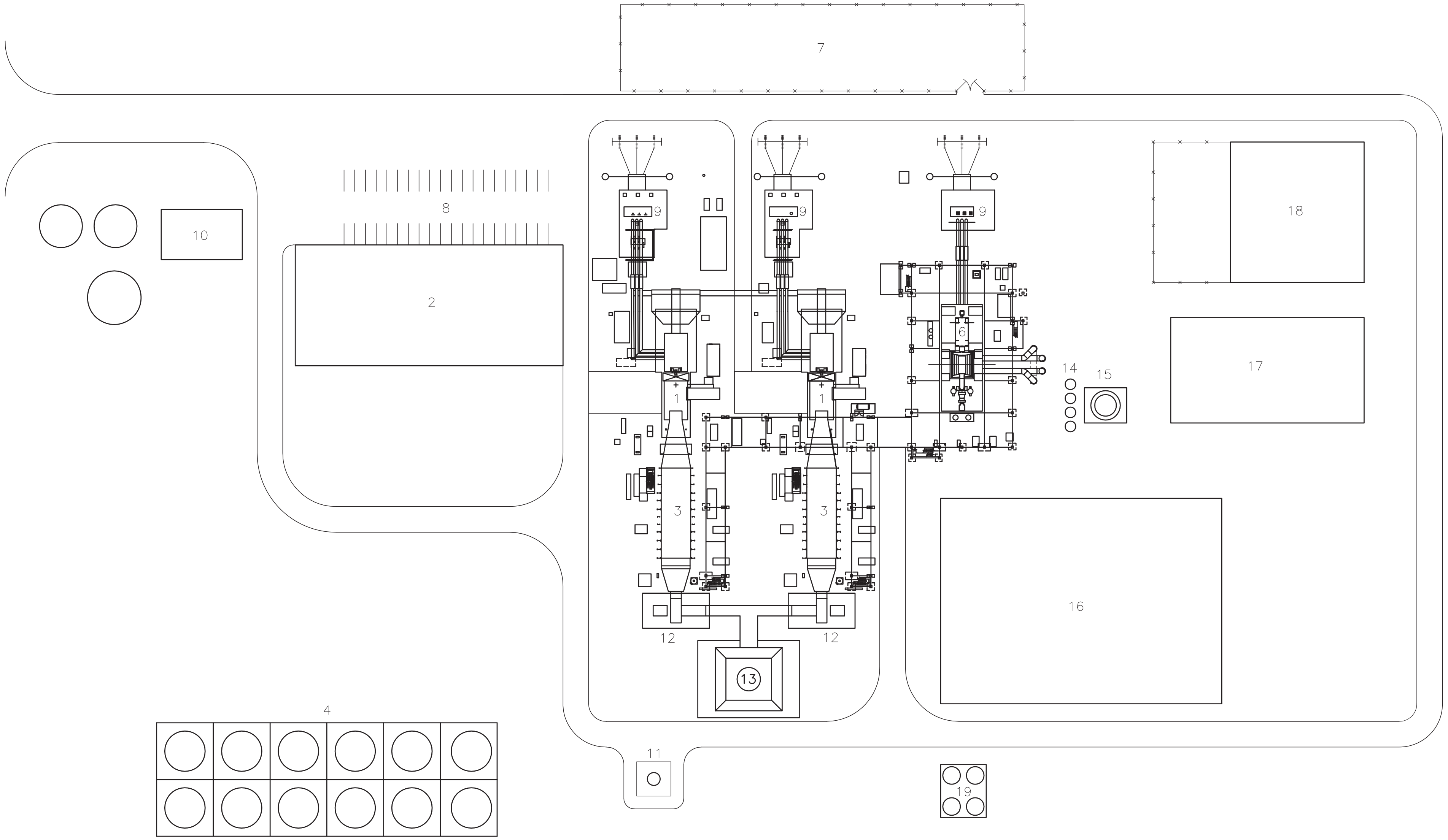
2	ADMINISTRATION BUILDING
3	HEAT RECOVERY STEAM GENERATOR/SCR (TYP X 2)
4	COOLING TOWER
5	NOT USED
6	STEAM TURBINE
7	SWITCHYARD
8	PARKING
9	GENERATOR STEP-UP TRANSFORMERS (TYP X 3)
10	WATER/WASTEWATER TREATMENT BUILDING
11	AQUEOUS AMMONIA STORAGE
12	FLUE GAS BOOSTER FANS (TYP X 2)
13	ABSORBER/STACK
14	STRIPPER REBOILERS (TYP X 4)
15	CO2 STRIPPER
16	CO2 CAPTURE EQUIPMENT
17	CO2 COMPRESSION & DEHYDRATION
18	CO2 PROCESS EQUIPMENT ELECTRICAL BUILDING
19	AMINE SOLUTION STORAGE



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IEA GHG R&D PROGRAMME
CO2 CAPTURE SCALE-UP STUDY

PRELIMINARY SITE ARRANGEMENT
CASE 4 – 800 MW NGCC, 90% CO2 CAPTURE

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Appendix G. Other Post-Combustion Capture Technologies

Other technologies are also being considered for post-combustion capture besides the use of amines. While this study focused only on amines, many nations are involved in R&D programs using other technologies to determine cost, viability, and future potential. This section briefly outlines some of the technologies being evaluated, the potential and drawbacks of each, and potential commercialization routes.

AMMONIA

Similar to post-combustion capture using an amine solvent, ammonia can be used in a chemical absorption process. Contact with CO_2 can occur either at a temperature slightly cooler than typical flue gas temperatures (about 35 to 40° C) or low temperatures (chilled, roughly 5° C). Absorption of CO_2 and regeneration of ammonia are performed in roughly the same fashion as the process for amines. The use of ammonia instead of amines has greater theoretical potential to reduce the parasitic load and subsequent cost of capture relative to amines because of the lower heat of reaction, greater absorption capacity, and lower chemical costs. The downside of ammonia is that the reaction time is slower, requiring large contactors to remove the necessary amount of CO_2. This increases the overall capital cost. In addition, the high vapor pressure of ammonia requires that either the process be performed at cooler temperatures than those for amine or that a separate scrubber be added to prevent the release of ammonia vapors into the atmosphere. Focus should be placed on speeding absorption rates and reducing sensible heat requirements in future capture designs that use ammonia.

OTHER ABSORBENTS

Besides the use of amines and ammonia, other types of absorbents being investigated including ionic liquids, oligomeric solvents, and enzymes. A summary of each is listed below:

- **Ionic Liquids:** Ionic liquids are complex salt molecules that are liquid at room temperature. There is a wide diversity of molecule types with a number of different functional groups that can be included or removed to modify their characteristics. Advantages include low volatility, thermal stability, and relatively low regeneration energy. Problems that have been encountered with ionic liquids include low CO_2 absorption capacity, low pressures required for regeneration, high viscosity, high cost, and toxicity. Because there are so many different types of ionic liquids, the goal is to try to pair desired attributes to create a solvent that can compete with known absorption liquids.
- **Oligomeric Solvents:** Oligomers are short chain polymer compounds that can be used for CO_2 capture. As with ionic liquids, oligomeric solvents can utilize a wide number of functional groups. Research is currently ongoing to understand which compound types are best suited for CO_2 capture, with rankings provided for cost, availability, ease of handling, ease of capture, stability, etc.

- **Enzymes:** Enzymes are used in the natural world to capture CO_2 in the bloodstreams of animals for transfer to the lungs. The main enzyme in this process is carbonic anhydrase. Experimentation has been performed to determine whether a carbonic anhydrase-based system that mimics the natural CO_2 removal process can be applied to power plant flue gases. Use of carbonic anhydrase has been tested both in a fixed bed absorber and doped to a membrane. The major advantage of the process is the very fast rate of reaction. Issues include sensitivity to impurities in the flue gas and developing an appropriate regeneration system.

Besides the use of liquids for CO_2 absorption, solid sorbents, such as salt oxides and carbonates, can be immobilized on solid support systems to react with CO_2. Other types of solid sorbents include various zeolites, molecular sieves, activated carbon, metal organic frameworks (MOFs), and metal monoliths. Advantages of solid sorbents include reduced emissions, high CO_2 capacity, low regeneration energy, and the potential for multi-pollutant control. Research organizations throughout the world have performed solid-sorbent demonstrations directed at CO_2 capture. However, these projects still exist at the laboratory scale and will require further development prior to commercial design. The main drawbacks to solid sorbent technology are expected to be durability, cost, selectivity, and material handling requirements. Substantial material handling infrastructure would be required just for the raw sorbent handling, which is expected to require significant capital costs and area requirements.

One potential commercialization route for solid sorbents is to produce carbonates that can be used as a substitute for components of cement. The process is similar to a solid absorption process, except that the absorption occurs in the aqueous state under alkaline conditions. Issues in the application of this technology are the effect of impurities on performance, acceptance of the product by the cement industry, ability to capture large amounts of CO_2, energy requirements, finding appropriate water sources, production of alkalinity, and having sufficient demand for the end product.

An additional post-combustion capture route that has received attention is the use of algae for biological absorption. The process is fairly simple: algae is grown in large ponds or photobioreactors in the presence of sunlight and CO_2. The algae is then harvested and processed, with its oils used for fuels and chemicals, while the remaining material can be converted to higher value products or used as a fuel for heat and power. The desire is to develop algae facilities that are near power stations to capture large amounts of flue gas CO_2. However, there are many barriers to this development: large amounts of flat land are needed, water requirements are high, the capture rate is slow compared to conventional absorbents and adsorbents, and it is likely that the impurities present in flue gas will affect the growth or quality of the algae.