VCI Project Management
Construction Management
Engineering

880 West Commerce Road, Suite 402
Harahan, LA 70123

SPR Contract
DE-FE0023538

Letter of Transmittal

To:

Marc Pizzeck
DOE, PE
900 S. Clearview Pkwy
Harahan, LA 70128

Thursday, January 21, 2016

VCI Transmittal No: SPR1502-PO.021-003

SPR Task No:

SPR Task Name: Bayou Choctaw Degas

Subject: Final Conceptual Design Report

Description	Copies	Title	Rev. No.	Rev. Date
Hard Copy				
Electronic Copy	5			
Full Size Drawings				

Cc :

Name	Site	# Of Hard Copies	Transit
Janet Robert	FFPO	0	Email
Alex Sanchez	FFPO	0	Email
Lisa Eldridge	FFPO	1	Hard Copy/Email
Patrick Mihalik	FFPO	1	Hard Copy/Email

Instructions / Comments

	For Instruction		For Approval		For Information		For Clarification
	For Confirmation		For Action		For Comment	X	For Your Use

Comments

Sincerely,

Rich Endriss, P.E., Deputy Project Manager

CONCEPTUAL DESIGN REPORT FOR BAYOU CHOCTAW DEGAS

U.S. DEPARTMENT OF ENERGY
STRATEGIC PETROLEUM RESERVE
PROJECT MANAGEMENT OFFICE
NEW ORLEANS, LOUISIANA
CONTRACT NO. DE-FE-0023538

JANUARY 21, 2016
REVISION 0

VCI
Project Management
Construction Management
Engineering

CONCEPTUAL DESIGN REPORT

BAYOU CHOCTAW DEGAS

PRELIMINARY: NOT INTENDED FOR CONSTRUCTION, BIDDING, RECORDATION, CONVEYANCE, SALES OR PERMIT APPLICATION.

0	ISSUED FOR FINAL REPORT	WL	BT	LM	LM	MP	1-21-16
REV. NO.	CHANGE DESCRIPTION	CHECKED BY	REVIEWED BY	PROJECT ENGINEER	LEAD PROJECT ENGINEER	D.O.E. APP'VL	DATE OF D.O.E APPROVAL

REGISTRATION STAMP

STATE OF LOUISIANA
STEPHEN J. MEADE
REG. NO. 17577
REGISTERED
PROFESSIONAL ENGINEER
IN
MECHANICAL ENGINEERING

1/21/16

NUMBER: 17577

VCI Project Management Construction Management Engineering

URS

VCI PROJECT ENGINEER	VCI PROJECT REVIEWER
L. MADISON	B. TUMINELLO
VCI LEAD PROJECT ENGINEER	**WRITTEN BY**
L. MADISON	E. ORLOSKI
ENGINEER OF RECORD	**CHECKED BY**
S. MEADE, PE	W. LEET
DATE:	**CONTRACT NO.:**
01/21/2016	**DE-FE-0023538**

OFFICE OF ENGINEERING AND CONSTRUCTION

DEPARTMENT OF ENERGY UNITED STATES OF AMERICA

STRATEGIC PETROLEUM RESERVE

TASK NUMBER: N/A

DISCIPLINE:

AFC:

DATE: 1/21/2016

SPECIFICATION SECTION NO.: N/A

REVISION: 0

EXECUTIVE SUMMARY

Degassing by single stage flash remains the technology of choice for effective vapor pressure management of crude oil stored at the Bayou Choctaw (BC) site. Initial evaluation suggests that design of a new degassing unit for BC should be evaluated against the case for redesigning, refurbishing, and relocating Degas II to BC. The new degassing unit may be designed for the full scale BC Drawdown scenario or the smaller capacity In-Storage case. These cases will be carried into optimization and economic evaluation to further refine the costs for each so they can be ranked and a recommendation made as to the best approach. Based on the life cycle cost evaluations to date, as shown in Appendix F, the smaller capacity In-Storage Degassing option has the lowest life cycle cost of 23.4 MM$. In addition to its low life cycle cost, In-Storage Degassing offers ease of siting smaller equipment, and can be modularized for re-use at other SPR sites. Drawdown Degassing has the next lowest life cycle cost of 49.6 MM$. Degassing at the terminal location during drawdown has a higher life cycle cost of 69.7 MM$ and is unattractive when compared to the In-Storage and Drawdown Degassing options. Cooling options considered for vapor pressure management ranged between 142.5 MM$ to 236.7 MM$ and are unattractive. Based on life cycle costs in Appendix I, the preferred method for conditioning the off-gas from the degassing process is amine treating with reinjection of the recovered hydrogen sulfide into the crude followed by refrigeration to maximize LPG recovery. The higher life cycle cost associated with just cooling of the crude to control vapor pressure makes this option unattractive

CONCEPTUAL DESIGN REPORT

1. General Statement of the Project

Task Order TO.021.d.04 authorizes the study of alternative methods to evaluate potentially more economical approaches to vapor pressure management of crude oil stored at the BC site. The study was recommended based on monitoring of vapor pressure data at the BC site. Data modeling and prediction of vapor pressure regain for the BC sweet and sour crude oil streams suggest that some form of vapor pressure mitigation will be required by 2021. If no action is taken by this time, the risk of exposing terminal personnel to high levels of hydrogen sulfide and benzene increases. The size and working condition of the current Degas II plant generally preclude relocation of the plant to the BC site to address the increase in oil vapor pressure. The Degas II plant is too large to relocate to BC on the existing developed property without reconfiguration. The projected cost of refurbishment of the existing plant equipment and piping systems upon completion of processing at West Hackberry (WH) will make the Degas plant move to BC uneconomic. The desired timing of study completion is the end of January, 2016.

2. Scope of Work

This Conceptual Design Report (CDR) summarizes study results completed to date. The report aims to define and evaluate vapor pressure management options for BC with sufficient detail to support DOE selection of a suitable alternative including Rough Order of Magnitude Cost Estimates. To this end, options are presented in this report with:

- Clear and concise descriptions of the alternatives analyzed
- The basis for the alternatives selected
- Explanation of how the selected alternatives meet the approved mission need
- The functions and requirements which define the alternatives and demonstrate the capability for success

- Discussion of facility performance requirements
- Discussion of planning standards and life-cycle cost assumptions.

3. Study Approach

The following technology options were discussed and selected as the most viable alternatives for evaluation during the May 4, 2015 working session of the Vapor Pressure Committee Working Group (VPCWG):

- In-storage, Drawdown, and Terminal Drawdown degassing.
- Mitigation of H_2S emissions at time of Drawdown.
- Removal and disposal of gases.
- Recover or use gases
- Cool crude oil below its bubble point pressure target prior to delivery point.
- Capture flash gases at time of delivery at:
    - On site location
    - Point of delivery

Subsequent to the May 4, 2015 working session, additional options were selected which could reduce but may not eliminate scavenger usage by circulating and cooling cavern inventory:

- Cavern Lake water cooling
- Aquifer water cooling
- Cooling tower cooling
- Chilled water cooling

These options, as well as those previously explored, were broken down into specific categories to explore their feasibility and relative size. The findings associated with this preliminary work are outlined in Section 5.

4. Basis of Design

The following key parameters were used to form the basis for the evaluation of the various options:

- A Drawdown rate of 515,000 bpd (515 MBD) was used for sour crudes from caverns BC15, BC17, BC19, and BC101.
- A Drawdown rate of 300,000 bpd (300 MBD) was used for sweet crudes from caverns BC18 and BC102.

- In-Storage treatment rates between 50,000-70,000 bpd (50-70 MBD) were used for all crudes.
- Sweet crudes come from caverns at a temperature 114 °F.
- Sour crudes come from caverns at a temperature 108 °F.
- Minimum propane recovery is 95%.
- Maximum shrinkage is 0.3%
- Maximum bubble point pressure (BPP) of the crude is 14.7 psia at 93 °F on delivery.

5. Option Evaluation

Both cooling of the crude oil in cavern inventory and degassing the crude either while in cavern inventory or during drawdown are options that can reduce crude BPP. Cooling alone is dependent on crude temperature maintenance to control crude BPP. Degassing, on the other hand, removes the volatile components that contribute to crude BPP. Each has advantages and disadvantages, as summarized in Appendix A, Option Comparison Table. The following sections review in more detail the considerations leading to the conclusion that In-Storage Degassing is the recommended option for maintaining crude BPP at BC.

5.1. Cooling Options

Cooling cavern inventory below the BPP of 14.7 psia is a viable option so long as the temperature of the inventory in the cavern can be maintained. Due to the depth of the salt plug, heat from the cavern walls increases inventory temperature over time and makes it necessary to continually cool inventory. This is accomplished by recirculating cavern inventory through coolers which use a cooling medium. The following options were explored using this basic concept. See Appendix B for an overview of each option together with the basis used in their development.

5.1.1. Cavern Lake Water Cooling

5.1.1.1. Cavern Lake is located at the boundary of the BC site and could be considered for use as the cooling medium for an in-storage circulation system. Water would be pumped from the lake by new water circulation pumps which use the existing water distribution system to reach each of the cavern locations. At each cavern location a new crude circulation pump and cooler would be installed to maintain segregated inventories. The water from the existing inlet header passes through the cooler and returns to the lake in a new return header. Oil from the cavern is drawn through the existing tubing string by the crude circulation pump. It is returned to the cavern through the existing water injection tubing string. Each cavern would be equipped with a new well so that they would remain drawdown ready during the cooling cycle. See Appendix C for the process flow diagram and equipment list with equipment costs for this option.

5.1.1.2. Cooling of the crude in the cavern can reduce the BPP by reducing the temperature low enough to reach the required value of 14.7 psia. However, the water in Cavern Lake varies seasonally in temperature, as shown in Appendix D. During the months of April through September, lake water temperatures are too high to support cooling of the cavern crude. Initial cooling must be undertaken during the October through March period when lake water temperatures are sufficiently low. The cavern crude then regains heat and increases in temperature during the months when no cooling is possible. Sufficient cooling water must be available in Cavern Lake to provide the initial cavern cooling plus the maintenance cooling on a seasonal basis. It is estimated that Cavern Lake can provide 7.1 million barrels of water before thermal contamination occurs due to recycling of the water back to the lake. This is considerably less than the 27 million barrels of water required for the initial cool down of the inventory of a single cavern. The shortage of cool water inventory makes this option infeasible. In addition to providing an insufficient amount of water, this option does not eliminate the need to use scavenger should drawdown occur in the warmer months. Approximately $16,000,000 over the 20 year project life is likely to be incurred if drawdown occurs during the warmest seven months of the year. See Appendix E for Projected Seasonal Vapor Pressure Impacts.

5.1.1.3. To support the drawdown ready requirement during the cooling cycle an additional well for each cavern would be needed so the existing wells can be used for circulation of the crude. This adds an additional $84,000,000 to life cycle costs for this option. There is also an environmental issue associated with returning process water to the lake, as required by this option. To provide suitable mitigation and a position for an environmental assessment, a holding pond and waste water treatment plant must be provided. This will increase the life cycle cost by $27,600,000. Operating costs will also add significantly to this option, as the temperature of the crude oil must be maintained by cooling over the life of the project. When all life cycle costs are considered, this will be one of the highest cost options at $222,900,000, even if there were sufficient lake water to provide the cooling. See Appendix F for a tabulation of life cycle costs.

5.1.2. Aquifer Water Cooling

5.1.2.1. The Plaquemine Aquifer lies beneath the BC site at a depth of between 60 ft. and 500 to 600 ft. and is a potential source of cooling water. Temperatures in the aquifer are cold enough to provide sufficient cooling for the cavern inventory. To develop this water source, producing wells would need to be drilled within the boundaries of the property and spaced in a way to optimize the supply of water. To dispose of the water returning from the intermediate water coolers, a set of injection wells would be drilled to return the water to the aquifer. The location selected would provide the maximum amount of water before thermal contamination from the injection wells reaches the producing wells. Each producing water well is equipped with a downhole pump to supply water so heat can be exchanged with a secondary closed loop cooling system. This secondary system isolates the cavern coolers from the aquifer water. This closed loop circuit circulates warmer water through intermediate water coolers for cooling as it exchanges heat with the cooler water from the aquifer. The cooled water then circulates through the cavern coolers to cool the crude oil from the caverns. Water which leaves the cooler returns to the inlet of the intermediate water coolers to complete the closed loop circuit. The existing water distribution system to the wells is utilized as part of the intermediate water supply system. A new aquifer water supply and return header system would be required to provide cooling water to each one of the cavern locations. As in the Cavern Lake option, each cavern is equipped with a crude oil circulation pump and crude oil cooler. Oil from the cavern is drawn through the existing tubing string by the oil circulation pump. It is returned to the cavern through the existing water injection tubing string. See Appendix C for a process flow diagram and equipment list with equipment costs for this option.

5.1.2.2. To support the drawdown ready requirement during the cooling cycle an additional well for each cavern would be needed so the existing wells can be used for circulation of the crude. This adds an additional $84,000,000 to life cycle costs for this option. There is also an environmental issue associated with returning process water to the aquifer. To provide suitable mitigation and a position for an environmental assessment, an intermediate water circulation system is provided. Thermal contamination of the aquifer may still be an issue, however, and forms a constraint on the amount of water that can be taken from the aquifer. Once thermal breakthrough occurs from the injection wells to the producing wells, the aquifer can no longer supply sufficiently cool water and cooling stops. The amount of water available before this occurs is 76.2 million barrels. This can provide enough cooling to initially cool down five of the six caverns. There is insufficient volume to initially cool down all six caverns or to maintain their temperature. In addition to providing an insufficient amount of water this option also does not eliminate the need to use scavenger should drawdown occur in the warmer months. Approximately $16,000,000 is likely to be incurred if drawdown occurs during the warmest four months of the year. The additional water producing and injection wells will add a cost of $1,520,000 to the project. The equipment cost for this option, however, is the lowest of all options at $13,000,000. Because cavern crude inventory will regain heat from the cavern walls, cooling will be required throughout the life of the project. An additional $10,500,000 in operating cost is included in life cycle costs, as a result. This option has the lowest life cycle cost of all of the cooling options at $142,500,000, as shown in Appendix F. However it has insufficient water to support initial cool down of all six caverns and subsequent temperature maintenance. This together with a higher life cycle cost than any of the degassing options makes it an unattractive option to pursue.

5.1.3.Cooling Tower Cooling

5.1.3.1. Another option for providing a supply of cooling water to the individual caverns is by cooling the water in a cooling tower and then supplying it to the various caverns in a closed loop system. A closed loop system would provide water from the cooling tower basin and pump the supply to each of the caverns. It then passes through the tube side of the cavern cooler and returns to the cooling tower by way of the return header system. The cooling tower utilizes the air brought in by fans to cool the water by evaporation. Water must be added to the system to replace the water lost by evaporation. Water must also be withdrawn from the system to prevent solids build-up within the equipment. The water added must also provide for this amount of blowdown in addition to the water lost by evaporation. Oil from each cavern is circulated through the existing tubing string by the oil circulation pumps. It is returned to the cavern through the existing water injection tubing string. Each cavern is equipped with a new well so that they remain drawdown ready during the cooling cycle.

5.1.3.2. Cooling of the crude in the cavern is dependent upon the temperature of the inlet water from the cooling tower. This water temperature varies seasonally as the wet bulb temperature varies. See Appendix D for seasonal variations in wet bulb temperatures. Cooling towers can be designed to approach this wet bulb temperature within 10 °F. In cool weather the crude temperature can be maintained below that which yields a BPP of 14.7 psia. Once cooling water temperatures rise above this level, cooling stops. The cooled crude in the cavern then regains heat from the cavern walls and the temperature increases. When the seasonal wet bulb temperature is low enough for cooling water to begin cooling again, the cavern crude can start circulating through the coolers. The caverns can be initially cooled down from October through March of each season when the wet bulb temperature is sufficiently low. Each following year the cavern must be re-cooled to eliminate the heat regained from the cavern walls. The initial cool down will allow the cavern inventory to maintain a maximum temperature of 90 °F during reheat before the maintenance cooling cycle begins. The cooling water temperature during the cooling cycle is sufficiently low to maintain this temperature but not to decrease it. This maintenance temperature is high enough to require the addition of scavenger. Seasonal changes in cooling water temperature will require the use of scavenger should drawdown occur during the seven warmest months of the year. This will result in a life cycle cost of $16,000,000. Because heat is regained by the crude oil from the cavern walls, cooling will be required throughout the life of the project. This will add $31,600,000 in operating cost to the life cycle cost of the project. Also adding to the life cycle cost is the $84,000,000 required for the new wells to ensure that the caverns remain drawdown ready. Total life cycle cost for this option is $175,200,000, as shown in Appendix F, which makes it a higher cost than any of the degassing options.

5.1.4. Chilled Water Cooling

5.1.4.1. A chilled water system utilizes refrigeration to reduce cooling water temperatures below those that can be achieved with a conventional cooling tower. Several types of refrigerant are available that can achieve the desired temperatures. One type commonly used for this application is ammonia. All refrigerant systems will require a compressor with a condenser to produce a liquid refrigerant. The refrigerant is then passed through an expansion valve which drops the temperature in the chiller coil to the desired level. Heat from the circulating chilled water is removed in the chiller by vaporization of the refrigerant. From the chiller the vaporized refrigerant returns to the suction of the compressor where the pressure is increased sufficiently to repeat the cycle. A condenser utilizes water from a conventional cooling tower to cool and condense the refrigerant from the compressor discharge. This cooling water is circulated through the cooling tower by pump in a closed loop system. The water that is chilled in the refrigerant chiller is circulated by pump through the crude oil cooler. The return water is circulated back to the chiller where the temperature is reduced by the refrigerant in a closed loop. See Appendix C for the process flow diagram for this system.

Each cavern is equipped with its own refrigeration package, circulation pump, and cooler for temperature maintenance. The chilled water is circulated through the existing water distribution system to the oil cooler. The water from the inlet header passes through the cooler and returns to the chiller. Oil from the cavern is drawn through the existing tubing string by the oil circulation pump. It is returned to the cavern through the existing water injection tubing string. Each cavern is equipped with a new well so that they remain drawdown ready during the cooling cycle.

For initial cool down of cavern inventory two refrigeration packages with circulation pumps and cooler are required. One package is semi-portable and is relocated at each cavern location requiring cool down. After all six caverns have been cooled, the semi-portable unit serves as a spare unit for the other six refrigeration packages which are permanently installed at each well site.

5.1.4.2. Due to the complexity of this system it has the highest equipment cost of all options considered at $69,300,000, as shown in Appendix F. It will also require one new well for each cavern to maintain drawdown readiness at a cost of $84,000,000. Refrigeration of the cooling water allows cooler cavern temperatures to be maintained throughout the year. The cooler temperatures, however, make it more likely that waxing will occur in the equipment which can lead to less reliable operations. Although it is possible to maintain cavern temperatures at a suitable level to maintain a BPP of 14.7 psia, there is a possibility that long term storage at the terminal location will cause the crude temperature to rise and the BPP, as well. As a result, scavenger will still be needed should drawdown occur in the three warmest months of the year. Should this be necessary, an additional cost of $16,000,000 is likely to be incurred over the life of the project. Like other cooling options, heat regain from cavern walls will make it necessary to maintain cooling throughout the life of the project at a life cycle cost for operating expenses of $55,500,000. Total life cycle costs for this option are the highest of the cooling options at $236,700,000, as shown in Appendix F.

5.2. Degassing Options

Increased crude oil BPP at BC is primarily the result of crude oil heating in storage and accumulation of light ends in the stored crude oil. Simply cooling the crude oil to reduce its BPP would seem to be a practical approach to reducing the crude oil BPP of the oil. However, cooling alone will not produce the desired results for all caverns. Removal of the methane and ethane and some of the propane and butanes accumulated in the stored oil can be implemented to reduce the BPP of the stored oil to ensure that scavenger addition is not required. Crude oil degassing removes these volatile components from the crude oil by separation of the vapor from the liquid in a vessel under reduced pressure. The vapor generated will contain the majority of components that contribute to the high BPP. Vapor from the separator is collected in a vapor compression system to allow for disposal. Vapors collected in this fashion can be cooled to increase propane recovery. The cooled gas can then be treated to eliminate the hydrogen sulfide. With the lower crude oil BPP it is possible to add back the hydrogen sulfide without the danger of it vaporizing. This treatment strategy can provide a means of eliminating the need to add a hydrogen sulfide scavenger to the crude. This is the current practice at BC during drawdown and one that can result in an operating cost of $16,000,000 in life cycle costs. Although this cost can be reduced with sophisticated sulfur analyzers and injection rate control, the focus of this study is to eliminate the need to inject liquid scavenger by properly treating the crude oil. Several technologies are available to accomplish this and are compared in more detail in the following Section 6. An overview of the following discussion of each degassing option is provided in the table in Appendix G.

5.2.1. In-Storage Degassing

5.2.1.1. The current method of controlling crude oil BPP is provided by the In-Storage Degas II design. This design utilizes a cavern circulation system that removes crude from the top of the cavern and returns it to the bottom of the cavern. The crude oil from the cavern is pumped through an exchanger which cools the crude before transferring it to a liquid/vapor separator where the crude oil is flashed to atmospheric or slightly lower pressure. Crude oil from this separator is pumped back to the cavern. Vapor released by flashing is gathered in a compression system where it is compressed and then cooled to condense heavier components for addition back in the crude oil. The remaining vapor fraction is treated in an amine unit for removal of the hydrogen sulfide which is also added back to the crude oil. The remaining off-gas from the amine unit is further cooled by refrigeration to reduce the size of the stream and to recover additional propane. The small amount of off-gas that remains following refrigeration is combusted in a flare gas system.

5.2.1.2. The Degas II design capacity is 125 MBD with the processing unit configured to transport from site to site. For Bayou Choctaw (BC), this plant is nearly twice the size required to mitigate the increased BPP at BC. The Degas II plant footprint is too large for the smaller area available at the BC site. Landowner, lease, and security issues severely hinder acquisition of more land over the fence at BC to allow the installation of this larger degassing unit. Hence, re-engineering of Degas II is required to fit it onto the BC site. The existing Degas II unit will be over 15 years old and has been moved twice in that time. A considerable investment will be required to refurbish the equipment (including the connecting piping, electrical wiring, and controls) plus the additional costs associated with breaking down the unit and shipping it to BC will be incurred. Initial estimates of moving Degas II to BC with the required refurbishment and reconfiguration start at 100 % of the estimated TIC for a new and smaller degassing unit. For In-Storage processing of crude oil at BC, re-engineering Degas II as a new, smaller degassing unit for BC appears an attractive alternative to refurbishing and relocating Degas II. This option can be readily designed to satisfy the processing requirements, siting constraints, and operating constraints to operate at BC. However, consideration can also be given to re-using some equipment from Degas II that is in good operating condition and is reasonably sized for the new conditions.

5.2.1.3. The processing equipment required for In-Storage Degassing is of such a size that it can be suitable for modularization. This type of construction allows a more mobile type of design so modules can be readily relocated at other sites once processing is completed at BC. In addition there is a significant cost savings associated with modular construction. It is estimated that 40% of the field constructed portion of the total installed cost (TIC) for degassing is labor. This amounts to approximately $11,900,000 in labor for the In-Storage Degassing option if it were to be 85% field erected. By contrast the modularized process would cost only $7,400,000 in labor if it was 85% shop fabricated, as in past projects of similar scope and scale. Shop fabrication is able to reduce labor costs through increased productivity. The net savings by modular construction, then, is $4,500,000 or more than 20% of the TIC that would result from 85% field erected construction.

5.2.1.4. The In-Storage Degassing option has the lowest equipment TIC of any of the other options at $18,800,000. Although more complex processing is required it is of smaller size. The six caverns at BC can be processed in about 3 years and the modules can be made ready for degassing at other locations. Once processing is completed on a cavern, the cavern contents are left in drawdown ready condition which reduces the amount of duplicate equipment. Well work-overs will be required to cut tubing strings for circulation in the caverns and this is reflected in an additional cost of $2,460,000. Additional operating and maintenance personnel will be required for the additional rotating equipment during the duration of degassing. This is estimated to add an additional $2,100,000 to the life cycle costs. The total life cycle cost for this option is estimated to be $24,000,000 and is the lowest of all of the options considered.

5.2.2. Drawdown Degassing at BC

5.2.2.1. The Drawdown Degassing option will require many of the same processing units as the In-Storage Degassing. Capacity requirements will be greater to accommodate the higher drawdown rate of 515 MBD. This necessarily results in larger sized equipment with a correspondingly higher cost. Some existing equipment is utilized, however. Crude oil from the caverns is cooled in the existing coolers on site. It is then degassed in a new vapor/liquid separator at reduced pressure. From this point, the process is very similar in processing steps to the In-Storage Degassing Option.

5.2.2.2. For Drawdown at BC, a significantly larger area is needed for the larger 515 MBD capacity equipment than for the In-Storage process. The larger equipment can be engineered to fit the available plot space by splitting the process up into its unique pieces and should be considered a feasible option for location at the BC site. However, larger equipment results in an equipment TIC of $30,500,000 which is 60% more than the In-Storage Degassing option. The logistics unique to this type of batch mode operation include equipment lay-up between batches and permanent staffing to address Drawdown critical operations. The latter is estimated to cost $18,600,000 over the project life to maintain a trained staff of 8 operators and partial staff of instrument and rotating equipment technicians. In addition, the process design for Drawdown must achieve a higher threshold of equipment availability to maintain the overall complex reliability at greater than 95 %. Total life cycle cost for this option is $49,600,000 which is far greater than the In-Storage Degassing option. It is, therefore, not as attractive a candidate for degassing as In-Storage Degassing.

5.2.3. Drawdown Degassing at the Terminal

5.2.3.1. In principle, it is possible to implement vapor pressure control on Drawdown at the terminal end of the pipeline. This potentially provides access to more land at the terminal for layout of the processing equipment and facilitates the disposal of the material responsible for the increased vapor pressure in the BC crudes. However, the logistics for pursuing this approach are complicated by the fact that BC crude can be transferred to multiple locations. Where crude oil is typically routed south by pipeline to the St. James Terminal, another delivery point is also located to the north at the ExxonMobil Refinery in Baton Rouge. On Drawdown, oil movement across these two delivery points is made all the more likely by the need to empty the caverns as quickly as possible in response to the nominations (bidding) process for crude oil off-take. Implementing BPP control by degassing at two locations would double life cycle costs for this option. Transfer of control of the degassing systems to third party operations at these locations would significantly reduce overall system reliability. Although there may be some synergies available at the terminal location which could reduce operating costs, life cycle costs at the individual locations are expected to be comparable to the Degassing Option at BC. Total life cycle costs of $99,300,000 would make it the highest cost of the degassing options.

5.2.3.2. Although not a typical degassing process, vapors generated at the storage terminal storage tanks can be collected and eliminated by combustion during drawdown. The St. James Terminal is equipped with six conventional external floating roof storage tanks. These tanks can be equipped with aluminum geodesic domes that allow vapors that escape past the tank roof seals to be captured. A new type of aluminum floating roof would be installed to eliminate the possibility of the roof sinking as a result of high vapor load under the roof. All of the storage tanks at the terminal can be equipped with these roofs and domes at a cost of $42,500,000. In addition a vapor collection and destruction system is required. This system would require 8" and 10" collection lines from each of the storage tanks and a vapor blower for each Vapor Destruction Unit (VDU) to provide sufficient flow to capture the vapor generated between the floating roof and geodesic dome when the tanks are filling.

For the maximum drawdown rate of 515,000 barrels per day anticipated during a drawdown order, a total of three VDUs would be required. A single VDU could be sized to handle the total flow, but the unit would be much larger than the three units which are 11 ft. diameter by 60 ft. in elevation. In addition a second unit would be required to provide the redundancy required for drawdown. The three units, on the other hand, can be sized slightly larger to provide extra capacity should one unit be taken out of service. This is a more cost effective approach.

The VDUs thermally oxidize all vapor components with a destruction efficiency of over 99%. The total cost associated with the VDU collection system is $8,200,000. Operating costs for this type of system will be required during drawdown only and are relatively low. However, the individual blowers and VDU's must be maintained and operated on a frequent basis to ensure reliability and will add $19,000,000 in operating expense to the life cycle costs. Total life cycle cost for this option is $69,700,000, which makes it, too, a high cost Drawdown option.

6. Configuration Alternatives for Degassing Options

Alternatives exist for optimizing individual process blocks within the In-Storage and Drawdown degassing options selected for further study in Section 5 above. The process alternatives that were evaluated are summarized in this section. A brief description of the feasibility of each alternative and the conditions required for that feasibility is found in the evaluation overview in Appendix H of this report. Descriptions of the alternatives by way of generic process schematics together with preliminary equipment sizing for comparison are provided in Appendix C. Some of these alternatives are applicable to both degassing options; some are not. A preliminary comparison of life cycle costs for the various alternatives is found in Appendix I.

6.1. Mitigation of Hydrogen Sulfide Emissions

Hydrogen sulfide (H_2S) poses an emissions problem when combustion is used to convert it to the less toxic sulfur dioxide. When left unconverted it poses a serious exposure hazard as well as a hazardous air pollutant (HAPS) issue which can result in hazardous emissions when vaporization of the crude oil occurs at the terminal storage site. The BC site is located in an area classified as a non-attainment area from an air quality standpoint. It is not likely that sulfur dioxide resulting from the combustion of the hydrogen sulfide will be allowed under existing permits without amendment of the permit. Further permitting work is needed if incineration is to be considered as an alternative. For the purposes of this phase it was assumed that the permitting effort would yield negative results and other options were explored to mitigate the H_2S emissions. These alternatives are evaluated in the following sections.

6.1.1. Injection of Liquid Scavenger

H_2S can be rendered non-volatile in solution by complexation and/or reaction with a liquid scavenger. The use of liquid scavengers injected directly in the crude during Drawdown has been approved by the Louisiana state regulators as an interim measure to cope with the exposure hazard of H_2S in the shipping and handling of high BPP crude. The cost of liquid scavenger injection is quite high from an operating standpoint unless sophisticated sulfur analyzers and injection rate control are implemented to avoid overfeed and scavenger waste. Although specifically allowed for Drawdown, this method of mitigation is also applicable to In-Storage processing. The cost for injection during Drawdown is estimated to nominally cost $16,000,000 over the 20 year project life. One of the objectives of this study is to eliminate this cost by eliminating the use of liquid scavenger.

6.1.2. Amine Treating with Acid Gas Reinjection into Crude

H_2S can be selectively removed from the off-gas for disposal by means of absorption into a physical or chemical solvent. Most commonly, this is done with contact with a regenerable amine solution. The H_2S rich off-gas is contacted with a circulating amine solution across an absorption column wherein the H_2S is selectively absorbed into the amine, liberating an off-gas depleted of H_2S for further process. The H_2S loaded amine is then circulated across a regenerator column where the H_2S and other soluble gases are stripped out as a separate H_2S rich gas stream for reinjection into the crude oil. The stripped amine solution, lean in H_2S, is recycled back to the absorption column to reuse. The capital investment associated with amine contacting systems is relatively low due to the small size required. With selection of a thermally and chemically stable amine tailored to the process, the process is very robust. With proper operator training and H_2S monitoring, the hazards associated with handling an H_2S stream are addressed. From an environmental standpoint, routing the H_2S back to the crude for delivery to downstream refineries which are better equipped to environmentally process H_2S into sulfur is appealing. This option is currently used in the Degas II plant design. The life cycle cost for this alternative is $1,400,000 which makes it more economically attractive than the continued use of scavenger. See Appendix I for life cycle cost comparisons for the alternatives.

6.1.3. Solid Bed Scavenger

H_2S can be selectively removed from the off-gas by adsorption onto a solid bed scavenger with subsequent reaction to chemically "fix" the H_2S into the solid for offsite reprocessing or disposal. Solid material scavengers have been available for a number of years. The oldest of these is iron sponge, a hydrated iron oxide. This type of material is difficult to handle and can react exothermically with air when dumped with the potential to catch fire. It is not suitable for use in the current environment. Other iron based scavengers have been developed that utilize a ceramic base which increases the scavenger cost but decreases the disposal handling problems. These types of scavengers are best suited to small scale requirements such as that produced by the In-Storage processing option.

The use of solid bed scavengers can be more cost effective than a traditional amine scavenging system in specific circumstances where it effectively reduces the risk of working with concentrated H_2S. The life cycle cost for this alternative is estimated to be $3,300,000 which makes it higher in cost than amine treating. When the logistics of periodic solid scavenger change outs and spent scavenger disposal by a third party are factored in to determine whether this alternative is truly viable for processing at the BC site an additional disposal cost of $2,500,000 results. From an environmental standpoint, the production of new process waste streams should be minimized if not avoided. The higher life cycle cost for this alternative makes it unattractive economically.

For the Drawdown option a larger scale scavenging system may be required. This type of system would be based on iron-redox whereby the H_2S is converted to elemental sulfur. A suitable catalyst is circulated to absorb the H_2S and air is used to regenerate the catalyst by conversion of the sulfur to its elemental form. Although the operating cost of such a system is orders of magnitude less than the fixed bed scavenger system, the capital cost is orders of magnitude greater. The life cycle cost for this system is estimated to be $8,600,000, based on the LoCat process, as an example, which makes it unattractive from a cost standpoint.

6.1.4. Liquid Bed Scavenger

H_2S can also be selectively removed from the off-gas by absorption and reaction with a liquid scavenger for offsite reprocessing or disposal. Liquid bed scavengers work in similar fashion to solid bed materials in that they have a fixed volume and can recover a fixed amount of H_2S before change out. The equipment required is similar in capital cost to the solid bed scavenger system. The ease of emptying a liquid based scavenger is partially off-set by the differences in disposal options. Solid based scavengers are typically land filled whereas spent liquid scavengers are either regenerated off-site and recycled or disposed of by incineration or deep well injection. Liquid bed scavenger is better suited to the In-Storage Option where lower rates would reduce the rate of change out frequency of scavenger. However, in the best case scenario, this alternative effectively equates to a batch amine contacting operation which offers no economic advantage over continuous amine contacting and regeneration system operation on site. Hence, this alternative can be eliminated from further consideration.

6.1.5. H_2S Incineration

Disposal of gas containing any amount of H_2S can be achieved by combustion or incineration. Direct incineration of H_2S rich off-gas or off-gas of reduced H_2S concentration with greater than 99.9 % H_2S destruction efficiency remains a viable option subject to the emissions permitting issues mentioned previously. This alternative must be reviewed for the impact of permitting a source that would emit almost 300 tons of sulfur dioxide per year.

6.2. Removal and Disposal of Gas On-Site

H_2S concentration has only a very small impact on crude bubble point pressure (BPP). Larger contributions are made by the lighter crude components such as methane, ethane, propane, and butanes. To meet the vapor pressure requirements of the design basis it is necessary to remove a portion of these materials from the crude as an off-gas stream by degassing and dispose of them. Ideally, this off-gas steam is treated to remove H_2S to satisfy environmental constraints and product sales specifications. The methods and requirements for removal are covered in Section 6.1. This section addresses the various methods for disposal of the methane, ethane, propane, and butane rich off-gas by the alternatives listed below.

6.2.1. Off-gas Incineration

Incineration can be considered as an effective means for disposing of sweetened (H_2S lean) off-gas. Thermal oxidation is a proven process which will combust hydrocarbon material with high thermal destruction efficiency while meeting stringent NO_x emissions requirements. Even so, permit requirement reviews are needed to determine the impact for both the rather low emissions produced by the In-Storage Option and the higher volumes produced by the Drawdown Option. If permit limits are exceeded, the evaluation of this alternative should consider the purchase of NO_x credits as an additional operating cost.

6.2.2. Sell as Fuel Gas

Sweetened off-gas produced from a single stage of flash is high in propane and butane content. The addition of propane refrigeration to chill the off-gas can reduce the amount of materials present in the stream. However, the stream will still have a methane content between 18%-28%, while the ethane and propane content will range between 35%-47% depending upon the cavern crude composition. This methane content is too low and the ethane and propane content too high for normal fuel gas such that it is considered unlikely that a buyer could be found for this material. The In-Storage Option produces too low a volumetric stream to be commercially attractive. The Drawdown option does not guarantee a continuous supply in a given time frame to attract potential buyers. This alternative does not appear feasible for these reasons.

6.2.3. Sell as Y-grade

The sweetened off-gas stream must be condensed to be sold as a liquid Y-grade material. The vapor pressure must be less than 600 psig at 100 ºF when in the liquid state to meet a standard y-grade specification. The methane content of the off-gas is too high to bring the vapor pressure below 1500 psig at 100 ºF. To meet the Y-grade specification additional compression and cooling would be necessary. The resulting Y-grade stream produced at specification during Drawdown is of such a low rate as not to be of commercial interest.

6.2.4. Generate Power

6.2.4.1. The sweetened gas supply available is of a low rate but can be used in smaller turbine generator sets for the generation of electrical power. As seen in Appendix J, a range of power generation alternatives are available. The off-gas supply available in the In-Storage Option has sufficient heating value to fuel the smallest of the micro-turbines shown. In the Drawdown case the off-gas would be able to fuel the turbines at the upper end of the scale shown. Unfortunately the fuel quality is not sufficiently high in methane content to serve as a suitable fuel. Outside fuel gas would have to be imported to the site to blend down the off-gas with high methane content fuel gas. The blended fuel would be sufficient to fuel the micro-turbine to generate a majority of the power required by either the In-Storage or Drawdown cases, as shown in Appendix K. The cost of infrastructure required to bring fuel gas to the site would have to be considered. This fuel source may be required anyway if the H_2S is recovered by circulating amine. It would serve as a source of heat for regeneration of the amine, in this case. The costs associated with increasing microturbine reliability through design and sparing would also have to be considered. Internal combustion engines may offer an alternative to microturbines for the generation of electrical power, subject to similar "lean burn" and reliability considerations. The issues associated with operating this equipment must be considered as well. For example, given the shorter duration of Drawdown, start-up and operation of power generation equipment may prove too problematic to pursue. Given that the equipment TIC is $2,200,000 and the power generated is $820,000, as shown in Appendix I, this option does not appear to be economically attractive.

6.2.4.2. If refrigeration is added to the process to increase the propane recovery without exceeding the BPP, the off-gas rate can be substantially reduced. As the propane has the much higher value as liquid product of $990,000 and the cost of a refrigeration unit is only $26,500, as shown in Appendix I, higher propane recovery is a more attractive alternative. The remaining off-gas stream is, then, too small to be considered for power generation and is eliminated by disposal in a flare system.

6.3. Crude Oil Cooling

Increasing the crude oil temperature in storage increases the crude oil BPP. The longer the crude remains in cavern storage the higher the crude storage temperature becomes as a result of geothermal heating. A reduction in this temperature could be considered as an option for meeting the required bubble point specification for In-Storage or Drawdown. For this condition alone to satisfy the criterion the temperature to which the crude is cooled must ensure that the criteria is not exceeded when placed in atmospheric storage at reasonable summertime ambient conditions. The criterion of a bubble point pressure of 14.7 psia at 93 ºF was selected for this purpose. As can be seen from the table in Appendix L, only cavern BC17 would satisfy the criteria with cooling alone. The other cavern crudes do not meet the criterion and additional processing is required. The simplest and most effective method of meeting the criterion is to provide a single stage of flash to remove the lighter components that contribute the most to the vapor pressure. The following alternatives have been considered as a means to implementing this concept.

6.3.1. No Cooling

The table in Appendix L illustrates that a bubble point pressure can be achieved that will meet the design basis without the benefit of cooling the crude taken from storage, as all BPP values are below the required 14.7 psia at 93 °F. However, this same table shows that crude from cavern BC102 will not recover the required 95% of the propane if cooling is not implemented. Less than 90% of the propane would be recovered in this case. Single stage flash without the benefit of some pre-cooling will not achieve the target specification and, so, is not feasible unless additional means of cooling the off-gas to recover additional liquids is implemented.

6.3.2. Use Existing Exchangers

The existing Drawdown coolers are capable of cooling 515 MBD of crude oil from a temperature of 121 °F to 97 °F using 85 °F cooling water based on the DynMcDermott report of 30 October, 2010. When cooling water at a temperature of 85 °F is used, the Drawdown cooler outlet will reach a temperature of 97 °F with Drawdown from cavern BC102 at a rate of 300 MBD. This outlet temperature is much lower than the 103 °F required to recover 95% of the propane from cavern BC102, so the existing exchangers have sufficient surface area to cool the crude prior to the single stage of flash used to degas the crude. Although compression and cooling may be required for the off-gas recovery, they are not required to meet the propane recovery criteria. Liquid recovered as a result of cooling the compressed gas only increases the propane recovery when the liquid is combined back with the crude. The bubble point pressure of the blended crude can be maintained below the required 14.7 psia at 93 °F.

6.3.3. Air Cooling

Normal design outlet temperature for the process side of an air cooled heat exchanger is set at 120 °F. This temperature is higher than either the sour or sweet crude coming from cavern storage. Air cooling, then, is not an alternative for Drawdown as proper cooling must be available year around to achieve the required propane recovery.

6.3.4. Wet Surface Air Cooling

Cooling water temperature required for the single stage flash is 85 °F. The maximum wet bulb temperature for the BC location is 78 °F based on data taken from the 2005 ASHRAE handbook in Appendix D. Wet Surface Air Cooling can accommodate a 7 °F approach to design and is a reasonable choice for cooling the crude for the In-Storage Option. A cost analysis between a conventional cooling tower and a WSAC would be required for this same decision to be applied to the Drawdown Option.

6.3.5. Lake Water Cooling

Cavern Lake can provide water at temperatures suitable for cooling to the required 103 °F at the inlet of the degassing drum as indicated in DynMcDermott's 30 October, 2010 report. However, returning the water to the lake at a higher temperature will have negative environmental consequences. The potential for contamination of the water should the exchangers begin leaking also could have a negative impact on the lake water quality if returned to the lake. In accord with current practices to avoid these environmental issues, the lake water cannot be circulated back to the lake. Either the lake water must be restricted to a cooling tower water basin to recirculate the water through a cooling tower or routed once-through the exchangers into the caverns to displace the crude. The first solution works for both the In-Storage and Drawdown scenarios although it requires additional investment. The second solution only works for the Drawdown option which requires injecting the water into the cavern to displace the crude oil as demonstrated in current operations. See Section 5 for a more complete evaluation of this alternative as an option to degassing.

6.3.6. Tempered Water Cooling

Tempered water cooling requires the use of refrigeration to reduce the cooling water temperature below 85 °F. As temperatures below this value are not necessary, a tempered water cooling process is not required.

6.3.7. Chilled Water Cooling

Chilled water cooling would normally deliver a cooling water supply at a temperature of 45 °F. If this temperature were required, it would introduce potential fouling or "waxing" of exchanger tube bundles for crudes with high paraffin content. However, neither chilled water nor tempered water systems are required for meeting the cooling requirements of the inlet crude stream

6.3.8. Heating and Cooling

With a single stage flash process additional off-gas can be recovered by raising the inlet temperature and then compressing and cooling the off-gas to recover the required amount of propane. However the incoming crude is at a sufficiently high temperature to flash and meet the bubble point pressure criteria. In fact cavern BC102 must be cooled before the degassing drum to recover 95% of the propane. Heating of the crude prior to degassing is not necessary.

7. Impact of Degassing Process on Site Sustainability Plan (SSP)

The additional process equipment associated with all options reviewed in this study increase the site electrical load and, in turn, will increase the greenhouse gas emissions. Existing greenhouse gas emissions goals will not be attainable, as a result. The recommended option, In-Storage Degassing, will generate approximately 14,700 metric tons of CO_2 equivalent in addition to the greenhouse gas associated with electrical consumption. Greenhouse gas equivalents of 747 metric tons of CO_2 are anticipated during drawdown.

8. Project Schedule and Planning Standards

The project schedule shown in Appendix N is based on degassing cavern inventory at a nominal rate of 67,000 bpd over a 1244 day (3.4 year) period of time. Engineering is expected to start in the beginning of 2017 with the last cavern degassed at the close of the first quarter 2024. Completion of degassing at Bayou Choctaw is followed by 3 months of decommissioning so degassing equipment can be placed in a condition to be relocated to another location for recommissioning.

The degassing options meet the standards set by Level 1, 2, and 3 criteria which apply to this project. The required use of H2S scavenger for all cooling options will make them unable to meet these criteria. During the engineering phase of the project additional industry standards will be used in the design effort. These standards are listed in Appendix O by design category.

9. Summary of Results

Crude oil degassing by single stage flash in combination with crude oil and/or product cooling is the preferred approach to BPP management for crude oil stored at the BC site. Degassing In-Storage or in Drawdown achieves the process objectives for the crude oil stored in all the BC caverns:

- Maximum bubble point pressure of the crude of 14.7 psia at 93 °F
- Minimum 95 % propane recovery from all cavern storage.

The preferred point of departure for designing a degassing unit for both In-Storage and Drawdown features some form of crude cooling followed by a single stage flash to remove light ends with subsequent amine treating of the off-gas to generate sweetened gas for incineration and H_2S rich acid gas for reinjection into the degassed crude. The off-gas is minimized by maximizing the propane recovery through refrigeration of the off-gas. If crude cooling is not implemented, additional cooling of the off-gas stream to recover additional liquid from the gas can be considered.

The In-Storage and Drawdown degassing options have the lowest life cycle costs, as shown in Appendix F. Of these two options In-Storage Degassing has a life cycle cost less than 50% of the Drawdown Degassing option. As the equipment is much smaller in size compared to the Drawdown Degassing option, it will be possible to modularize and re-use at another SPR site when degassing has finished at BC. The larger equipment associated with the Drawdown Degassing option does not lend itself to a modularized design which substantially increases the cost of field installation. It also eliminates the possibility of re-use, as it must remain at the BC site for use during a drawdown order. Additional cost will be incurred for duplication of equipment at multiple sites, if this option were selected. In addition there is a siting difficulty at the BC location due to the larger equipment, as BC land available for the degassing process is limited. Operating personnel required during drawdown would also be required for periodic operation of the Drawdown Degassing equipment to maintain operating reliability. These labor costs are incurred throughout the 20 year life of the project as compared to the In-Storage Degassing option which operates just under three years. These disadvantages highlighted for the Drawdown Degassing option make it less attractive than the In-Storage Degassing option. The In-Storage Degassing option, then, is the recommended one for controlling the BPP at BC.

APPENDIX A

OPTION COMPARISON TABLE

The following table compares the seven major options considered based upon the pros and cons of each. Four options based on cooling alone and three options based on cooling with light ends removal by degassing are included.

OPTION COMPARISON TABLE	
PROS	**CONS**
Cavern Lake Water Cooling:	
1. Simplest process configuration consisting of only new lake water pumps, lake water return header, and one oil circulation pump and exchanger at each cavern.	1. Inadequate water volume to support cooling. Only enough lake water available to support partial cool down of one cavern.
	2. Lake water volume insufficient to maintain a single cavern at required temperature.
	3. Significant NEPA issues and obtaining a discharge permit is a concern as the water could be classified as process water. An EA will be required.
	4. Thermal and oil contamination potential will require a holding pond, treatment plant, analytical testing and monitoring equipment. Pond and plant will require significant plot area.
	5. Lacks drawdown ready capability due to circulation through existing tubing string. Development of 6 wells at $14 MM each will be required.
	6. Delivery point storage conditions can potentially re-heat material in storage tanks during summer months and scavenger will still be required.
	7. Operating costs to maintain cavern temperature are incurred over a twenty year project life which results in a high life cycle cost.
Aquifer Cooling Water:	
1. Capital investment in surface equipment required for cooling is comparable to Cavern Lake Water Cooling Option.	1. Not enough water to be a sustainable solution. Cannot cool down and maintain multiple caverns.
2. Operating cost for surface equipment required for cooling is comparable to the Cavern LakeWater Cooling Option.	2. Significant NEPA issues and obtaining a re-injection permit is a concern as the injected water will be at a higher temperature than the aquifer. An EA will be required.
3. The aquifer contains over ten times more water than Cavern Lake but can only cool down five of the six caverns before thermal breakthrough on water reinjection renders the aquifer useless for cooling.	3. Thermal and oil contamination potential will require an intermediate cooling loop which adds complexity and cost to the process.
	4. Aquifer is a source of drinking water. Must demonstrate that the return water is not process water.
	5. Lacks drawdown ready capability due to circulation through existing tubing string. Development of 6 wells at $14 MM each will be required.
	6. Requires additional capital investment for drilling and equipping the six producing wells and the four injection wells required for cooling and maintaining a single cavern.
	7. Delivery point storage conditions can potentially re-heat material in storage tanks during summer months and scavenger will still be required.
	8. Operating costs to maintain cavern temperature are incurred over a twenty year project life which results in a high life cycle cost.

OPTION COMPARISON TABLE	
PROS	**CONS**
Cooling Tower Cooling:	
1. Surface equipment is essentially the same as the Cavern Lake Water Cooling option as is the capital investment except a closed cooling tower loop is added to replace cavern lake water.	1. Cooling can only occur during six months out of the year during months of cooler wet bulb temperatures.
2. Operating cost of surface equipment is essentially the same as the Cavern Lake Water Cooling option.	2. Seasonal wet bulb temperatures are not sufficiently low to maintain cavern temperatures below 90 ^{o}F before the arrival of the next cooling season.
3. A closed loop cooling water system is sustainable for cavern cool down as well as maintenance through all years.	3. Additional capital investment is required for the cooling tower and water circulation system.
4. Multiple caverns can be cooled down and maintained. However, it is not cost effective to cool down more than one cavern at a time.	5. Lacks drawdown ready capability due to circulation through existing tubing string. Development of 6 wells at $14 MM each will be required.
	6. Requires chemical handling and storage (hazardous chemicals) to minimize bacterial/algal contamination and scaling.
	7. Delivery point storage conditions can potentially re-heat material in storage tanks during summer months and scavenger will still be required.
	8. Operating costs to maintain cavern temperature are incurred over a twenty year project life which results in a high life cycle cost.
Chilled Water Cooling:	
1. All caverns can be cooled down and maintained to meet drawdown requirements.	1. Refrigeration units and a closed loop cooling water system for the refrigeration condenser are required making it the highest capital cost option.
	2. Process is one of the most complex of the options.
	3. Additional operating/maintenance personnel are required for the refrigeration equipment.
	4. Colder chilled water inlet temperatures make paraffin wax out in the crude coolers more likely.
	5. Lacks drawdown ready capability due to circulation through existing tubing string. Development of 6 wells at $14 MM each will be required.
	7. Delivery point storage conditions can potentially re-heat material in storage tanks during summer months and scavenger will still be required.
	8. Operating costs to maintain cavern temperature are incurred over a twenty year project life which results in a high life cycle cost.

OPTION COMPARISON TABLE	
PROS	**CONS**
In-Storage Degassing:	
1. Lowest equipment cost compared to other options.	1. Most complex process of the options compared but with fewer equipment items than the chilled water cooling option, as there is no requirement to maintain cavern conditions once degassing has occurred.
2. Lowest operating cost over 20 years compared to other options.	2. Additional operating/maintenance personnel are required for the additional rotating equipment and are required on a full time basis.
3. Once a cavern is degassed it is drawdown ready for an extended period of time and the degassing equiment can be used on another cavern. As a result, no duplicate equipment is required.	3. Requires well workover to cut the tubing string for circulation in all six caverns.
4. The equipment purchased for BC can be re-used at other locations, as needed.	4. Requires a new return header to connect the degas process to all wells in the crude oil circulation system.
5. Scavenger cost can be eliminated	
6. All caverns can be degassed to meet the drawdown requirement.	
7. Time with which caverns are taken out of drawdown configurtion is minimized.	
8. Operational experience obtained from other SPR installations can be utilized at BC.	
9. Technical know-how available for building small portable units.	
10. Process has proven reliability	
11. Degassing process can be completed in 4 years of operation for all caverns.	
12. Provides a flexible solution for buying new oil with higher vapor pressures.	
13. Permitting issues have been addressed in previous applications. Simpler process to amend existing permits.	
Drawdown Degassing at BC:	
1. Lower operating cost over 20 years than cooling options and potentially lower than In-Storage Degassing option as they are incurred only during drawdown.	1. Equipment cost is higher than the In-Storage Degassing option due to larger size equipment.
2. Eliminates the need to work over wells.	2. Larger equipment requires more plot space which increases the difficulty of siting. Also lessens the probablility that it will be mobile enough to use at other sites.
3. Scavenger cost can be eliminated	3. Highest labor cost. Operating personnel are only required during drawdown but mobilization of qualified operators for drawdown is a concern. Concern addressed through hire of operating complement half-time and/or full-time.
4. All caverns can be degassed to meet the drawdown requirement.	4. Equipment reliability will be difficult to maintain when equipment must stand idle for extended periods between drawdowns.
	5. Duplication of equipment would be required for simultaneous drawdown from multiple sites containing oil unable to meet drawdown requirements.

OPTION COMPARISON TABLE	
PROS	**CONS**
	6. Circulation system and return header needed to provide for periodic run of equipment to ensure reliability during drawdown.
Drawdown at St. James with VDUs:	
1. Lower operating cost over 20 years than cooling options and potentially lower than In-Storage Degassing option as they are incurred only during drawdown.	1. Equipment cost is higher than the In-Storage Degassing option due to tank modifications required to receive high BPP crude.
2. Eliminates the need to work over wells.	2. Highest labor cost. Operating personnel are only required during drawdown but mobilization of qualified operators for drawdown is a concern. Concern addressed through hire of operating complement half-time and/or full-time.
3. Scavenger cost can be eliminated	3. Equipment reliability will be difficult to maintain when equipment must stand idle for extended periods between drawdowns.
	4. Duplication of equipment would be required for simultaneous drawdown from multiple sites containing oil unable to meet drawdown requirements.
	5. Vapor from storage will be high in H2S and VDUs may not be able to meet current permit levels.
	6. Storage tanks must be taken out of service while modifications are in progress.
	7. Limited site area will make equipment siting difficult and impose constraints on construction of geodesic domes.

APPENDIX B

DESCRIPTION OF OPTIONS

A process description for each of the seven options evaluated is included here. The following descriptions for the four cooling options and the three degassing options provide the basis used for development of the design and life cycle cost analysis. The same descriptions are also found in the main body of the report in Section 5. The basis for the life cycle cost evaluations summarized in the Appendices F and I are listed here as well.

DESCRIPTION OF OPTIONS

Cavern Lake Water Cooling

Process Description

Cavern Lake is located at the boundary of the Bayou Choctaw site and is considered for use as the cooling media for an in-storage circulation system. Water would be pumped from the lake by new water circulation pumps which use the existing water distribution system to reach each of the cavern locations. At each cavern location a new crude circulation pump and cooler would be installed to maintain segregated inventories. The water from the existing inlet header passes through the cooler and returns to the lake in a new return header. Oil from the cavern is drawn through the existing tubing string by the crude circulation pump. It is returned to the cavern through the existing water injection tubing string. Each cavern would be equipped with a new well so that they would remain drawdown ready during the cooling cycle.

Basis

The following basis was used to evaluate this option:

- Minimum recorded cavern lake temperatures for the period from June 2013 to May 2014 from BC DCS data.
- Cavern Lake volume of 300 MM gal. as determined from an estimated area of 500,000 sq. ft. and a depth of 80 ft.
- Oil circulation is hydraulically limited by velocity in the 10" tubing to a rate of 120,000 bpd.
- BC101 was selected to represent typical cavern conditions for all 6 caverns.
- Cavern circulation was selected as top out-bottom in.
- Geothermal temperature regain for all caverns is based on BC101 temperature response for the period from April 1996 to August 1998.
- Cooling water rates are based on the minimum required to provide acceptable exchanger performance.
- The initial cooling cycle was started in October.
- Cooling was operated seasonally and was terminated when lake water temperatures approached cavern top temperatures.
- Opex is based on 4% of TIC for equipment (does not include cavern wells and workovers)
- Electrical cost is based on an average winter cost of $0.01864/Kw-hr.
- Holding pond is sized for 24 hours of cooling water.
- Treatment plant is sized for 33 days of processing holding pond inventory.

Aquifer Water Cooling

Process Description

The Plaquemine Aquifer lies beneath the Bayou Choctaw site at a depth of between 60 ft. and 500 to 600 ft. and is a potential source of cooling water. Temperatures in the aquifer are cold enough to provide sufficient cooling for the cavern inventory. To develop this water source producing wells would be drilled within the boundaries of the property and spaced in a way to optimize the supply of water. To dispose of the water returning from the intermediate water coolers a set of injection wells would be drilled. The location selected would provide the maximum amount of water before thermal contamination from the injection wells reaches the producing wells. Each producing water well is equipped with a downhole pump to supply water to exchange heat with a secondary closed loop cooling system, thereby isolating the cavern coolers from the aquifer water. This closed loop circuit passes water through the intermediate water coolers for cooling as it exchanges heat with the cooler water from the aquifer. The cooled water then circulates through the cavern coolers to cool the crude oil from the caverns. Water which leaves the cooler returns to the inlet of the intermediate water coolers to complete the closed loop circuit. The existing water distribution system to the wells is utilized as part of the intermediate water supply system. A new aquifer water supply and return header system would be required to provide cooling water to each one of the cavern locations. As in the Cavern Lake option, each cavern is equipped with a crude oil circulation pump and crude oil cooler. Oil from the cavern is drawn through the existing tubing string by the oil circulation pump. It is returned to the cavern through the existing water injection tubing string. Each cavern is equipped with a new well so that they remain drawdown ready during cooling.

Basis

The following basis was used to evaluate this option:

- An aquifer temperature of 55 °F.
- Six producing wells and four injection wells placed so as to maximize available water within the boundary of the site.
- Aquifer water volume of 3,200 MM gal as determined from the maximum volume that can be injected before thermal breakthrough occurs in the producing wells.
- Oil circulation is set to cool down the cavern inventory over 12 months.
- BC101 was selected to represent typical cavern conditions for all 6 caverns.
- Cavern circulation was selected as top out-bottom in.
- Geothermal temperature regain for all caverns is based on BC101 temperature response for the period from April 1996 to August 1998.
- Cooling water rates are based on the minimum required to provide acceptable exchanger performance.
- Cooling was terminated altogether when thermal breakthrough occurs from the injection to producing wells.
- Opex is based on 4% of TIC for equipment (does not include cavern wells and workovers)
- Electrical cost is based on an average yearly cost of $0.03235/Kw-hr.

Cooling Tower Cooling

Process Description

Another option for providing a supply of cooling water to the individual caverns is by cooling the water in a cooling tower and then supplying it to the various caverns in a closed loop system. A closed loop system would provide water from the cooling tower basin and pump the supply to each of the caverns. It would pass through the tube side of the cavern cooler and return to the cooling tower by way of the return header system. The cooling tower, then, utilizes the air brought in by fans to cool the water by evaporation. Water must be added to the system to replace the water lost by evaporation. Water must also be withdrawn from the system to prevent solid build-up within the equipment. The water added must also provide for this amount of blowdown in addition to the water lost by evaporation. Oil from each cavern is circulated through the existing tubing string by the oil circulation pumps. It is returned to the cavern through the existing water injection tubing string. Each cavern is equipped with a new well so that they remain drawdown ready during the cooling cycle.

Basis

The following basis was used to evaluate this option:

- Seasonal Wet bulb temperatures from the 2005 ASHRAE Handbook for the Bayou Choctaw region.
- Approach to wet bulb temperature is 10 °F as determined by a reasonable cooling tower design.
- Cavern cooling is initiated when cooling water supply temperatures drop below cavern top temperatures and terminated when supply temperatures approach cavern top temperatures.
- Oil circulation is hydraulically limited by velocity in the 10" tubing to a rate of 120,000 bpd.
- BC101 was selected to represent typical cavern conditions for all 6 caverns.
- Cavern circulation was selected as top out-bottom in.
- Geothermal temperature regain for all caverns is based on BC101 temperature response for the period from April 1996 to August 1998.
- Cooling water rates are based on the minimum required to provide acceptable exchanger performance.
- Opex is based on 4% of TIC for equipment (does not include cavern wells and workovers).
- Cooling tower make-up water treatment costs are included in the overall Opex costs.
- Electrical cost is based on an average winter cost of $0.01864/Kw-hr.
- Surface disposal of cooling tower blowdown is acceptable with a discharge permit amendment (permit cost not included).

Chilled Water Cooling

Process Description

A chilled water system utilizes refrigeration to reduce cooling water temperatures below those that can be achieved with a conventional cooling tower. Several types of refrigerant are available that can achieve the desired temperatures. One common one in use is ammonia. All refrigerant systems will require a compressor with a condenser to produce a liquid refrigerant. The refrigerant is then passed through an expansion valve which drops the temperature in the chiller coil to the desired level. Heat from the circulating chilled water is removed in the chiller by vaporization of the refrigerant. From the chiller the vaporized refrigerant returns to the suction of the compressor where the pressure is increased sufficiently to repeat the cycle. A condenser utilizes water from a conventional cooling tower to cool and condense the refrigerant from the compressor discharge. This cooling water is circulated through the cooling tower by pump in a closed loop system. The water that is chilled in the refrigerant chiller is circulated by pump through the crude oil cooler. The return water is circulated back to the chiller where the temperature is reduced by the refrigerant in a closed loop.

Each cavern is equipped with its own refrigeration package, circulation pump, and cooler for temperature maintenance. The chilled water is circulated through the existing water distribution system to the oil cooler. The water from the inlet header passes through the cooler and returns to the chiller. Oil from the cavern is drawn through the existing tubing string by the oil circulation pump. It is returned to the cavern through the existing water injection tubing string. Each cavern is equipped with a new well so that they remain drawdown ready during the cooling cycle.

For initial cool down of cavern inventory two refrigeration packages with circulation pumps and cooler are required. One package is semi-portable and is relocated at each cavern location requiring cool down. After all six caverns have been cooled, the semi-portable unit serves as a spare unit for the other six refrigeration packages.

Basis

The following basis was used to evaluate this option:

- Ammonia was selected as the refrigerant.
- The water circulated to the oil cooler was chilled to 44 °F.
- Oil circulation is hydraulically limited by velocity in the 10" tubing to a rate of 120,000 bpd.
- BC101 was selected to represent typical cavern conditions for all 6 caverns.
- Cavern circulation was selected as top out-bottom in.
- Geothermal temperature regain for all caverns is based on BC101 temperature response for the period from April 1996 to August 1998.
- Chilled water rates are based on the minimum required to provide acceptable exchanger performance.
- Cooling tower water was assumed to be 85 °F to provide a 10 °F approach to maximum wet bulb temperatures in the BC region.
- Opex is based on 4% of TIC for equipment (does not include cavern wells and workovers)
- Electrical cost is based on an average yearly cost of $0.03235/Kw-hr.

In-Storage Degassing

Process Description

A single process package would be utilized for degassing the six caverns at BC. The equipment is packaged to make it portable for use at other SPR sites. With this process crude oil from the top of the cavern storage would be circulated through a cooler to reduce the temperature prior to separation of the volatile vapor in a two-phase separator at slightly above atmospheric pressure. The cooler is supplied with water from a closed loop cooling water system equipped with a cooling tower. The off-gas from this degassing separator is compressed and cooled to recover the heavier components from the off-gas stream and thereby reduce the shrinkage of the crude processed. An air cooled exchanger is used as the source of cooling. The outlet of the air cooled exchanger is collected in a vapor/liquid separator and the off-gas is sent to an amine unit for recovery of hydrogen sulfide. The liquid from the separator is combined with the liquid from the degassing separator and is transferred by the crude circulation pump back to the bottom of the cavern in a new return header. The hydrogen sulfide from the amine unit is combined with the off-gas product for disposal. The amine package consists of a contactor and regenerator so regenerated amine can be circulated by pump in a closed loop system. The off-gas from the amine contactor is further condensed by propane refrigerant to remove additional heavy components for injection back into the crude. The small amount of off-gas and hydrogen sulfide that remains after recovery of the heavier components is sent to a high efficiency flare for final disposal by combustion. The flare is elevated and is sized to handle the larger relief loads from the equipment during a fire scenario.

Basis

The following basis was used to evaluate this option:

- Ambient air is 95 °F.
- Cooling water approaches wet bulb temperatures within 10 °F.
- Oil circulation is set at 72,000 bpd.
- BC19 was selected to establish equipment sizes for cost estimating.
- Cavern circulation was selected as top out-bottom in.
- Geothermal temperature regain for all caverns is based on BC101 temperature response for the period from April 1996 to August 1998.
- Cooling water rates are based on the minimum required to provide acceptable exchanger performance.
- The amine unit is the smallest packaged unit commercially available with a rated circulation rate of 10 gpm.
- The refrigeration package is rated at approximately 1 ton.
- Recovery of propane is greater than 95% and is limited by the BPP of 14.7 psia at 93 °F.
- Opex is based on 4% of TIC for equipment.
- Electrical cost is based on an average yearly cost of $0.03235/Kw-hr.

- Work-over cost to position tubing string for degassing and then reposition it for drawdown is $400,000/cavern

Drawdown Degassing at BC

Process Description

Due to the larger size of the degassing equipment required for drawdown, the equipment would be located for dedicated use at BC. With this process crude oil from cavern storage would be drawn down through the existing crude cooler to reduce the temperature prior to separation of the volatile vapor in a two phase separator at near atmospheric pressure. The off-gas from this degassing separator is compressed and cooled to recover the heavier components from the off-gas stream and thereby reduce the shrinkage of the crude processed. An air cooled exchanger is used as the source of cooling for condensation of the off-gas. Two stages of compression and cooling are required for sufficient reduction of the off-gas rate. The outlet of the second stage air cooled exchanger is collected in a vapor/liquid separator and the off-gas is sent to an amine unit for recovery of hydrogen sulfide. The liquids from each of the compressor discharge separators are combined with the liquid from the degassing separator which is transferred by pump to the pipeline supplying crude to the terminal. The hydrogen sulfide that is recovered from the amine unit is injected back into the crude from the degassing separator. The amine package consists of a contactor and regenerator with amine circulated by pump in a closed loop system. The off-gas from the amine contactor is further condensed by propane refrigerant to remove additional heavy components for injection back into the crude. The small amount of off-gas that remains after recovery of the heavier components is sent to a high efficiency flare for final disposal by combustion. The flare is elevated and is large enough to handle relief loads from the equipment during a fire scenario.

Crude oil is removed from the cavern by existing pumps and water injection system. Water used for injection into the cavern is first used as a cooling media in the crude oil coolers. No additional return header or closed cooling water system is required for this configuration. No additional wells are needed to maintain drawdown readiness.

Basis

The following basis was used to evaluate this option:

- Ambient air is 95 °F.
- Air cooling results in a process outlet temperature of 120 °F.
- Oil drawdown rate is 515,000 bpd.
- Sour cavern BC19 was selected to establish equipment sizes for cost estimating.
- Water enters the cavern at the bottom; oil leaves the cavern at the top.
- Existing cavern pumps and exchangers are utilized.
- The amine unit is the smallest packaged unit commercially available with a rated circulation rate of 10 gpm.
- The refrigeration package is rated at approximately 10 ton.
- Recovery of propane is greater than 95% and is limited by the BPP of 14.7 psia at 93 °F.
- Opex is based on 4% of TIC for equipment.
- Electrical cost is based on an average yearly cost of $0.03235/Kw-hr.

- Operating and electrical costs are based on a single drawdown.
- Provision is made for a circulation header for intermittent equipment runs to maintain reliability.
- Labor required for intermittent equipment runs is $900,000/yr. (8 trained operators, ½ instrument technician, ½ rotating equipment technician).

Drawdown Degassing at St. James Terminal

Process Description

Vapor generated from leakage through the floating roof seals on the storage tanks is captured within a geodesic dome fitted to the top of each storage tank. This dome allows in-breathing when the tank empties and out-breathing when the tank is filling. The out-breathing vapor is routed to a vapor destruction unit (VDU) through connecting piping. A vapor blower is installed upstream of each VDU to move the vapor from the tank to the VDU. Detonation arrestors are provided upstream and downstream of the blower to prevent a source of ignition back-flowing to the tank. In addition to the geodesic dome each of the existing floating roofs is replaced with an aluminum roof designed to prevent the roof from sinking when vapor passes the seals.

Basis

The following basis was used to evaluate this option:

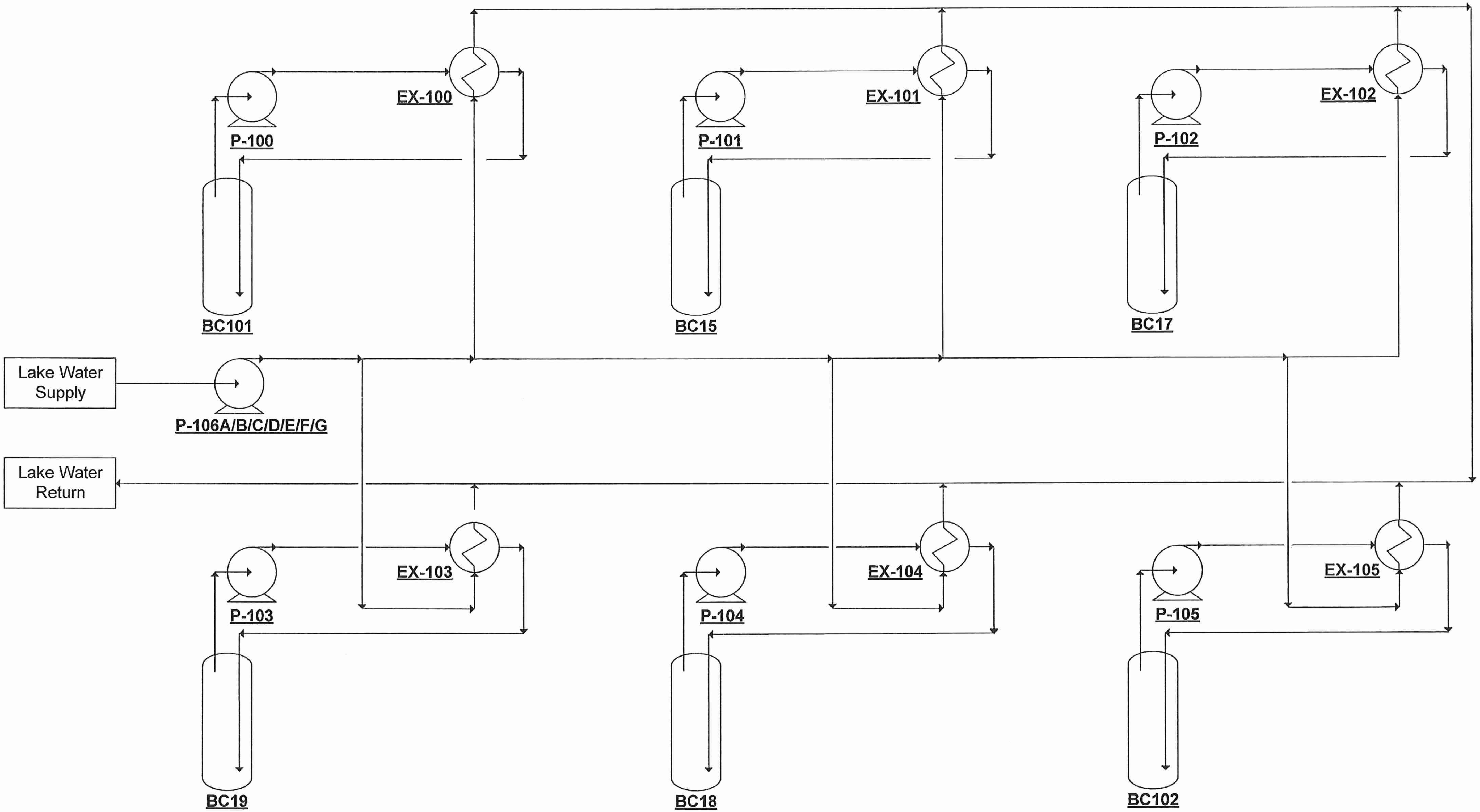
- Ambient air is 95 °F.
- Oil drawdown rate is 515,000 bpd.
- Water enters the cavern at the bottom; oil leaves the cavern at the top.
- Existing cavern pumps and exchangers are utilized.
- Recovery of propane is greater than 95% and is limited by the BPP of 14.7 psia at 93 °F.
- Opex is based on 4% of TIC for equipment.
- Electrical cost is based on an average yearly cost of $0.03235/Kw-hr.
- Operating and electrical costs are based on a single drawdown.
- Six tanks are fitted with geodesic domes. Four tanks are 400,000 barrel tanks and two are 200,000 barrel tanks.
- VDU capacity is based on the maximum fill rate of 515,000 bpd with 3 VDUs operating.
- Labor required for intermittent equipment runs is $900,000/yr. (8 trained operators, ½ instrument technician, ½ rotating equipment technician).

APPENDIX C

OPTION SCHEMATICS WITH SIZED AND COSTED EQUIPMENT LISTS

The attached schematics summarize the degassing and optimization options pictorially in the most general of terms with preliminary equipment sizing and costing for comparisons. The collection of schematics followed by their corresponding equipment sizing and cost includes:

Cavern Lake Water Cooling



P-100/101/102/103/104/105
In-Storage Circulation Pump

3,581 GPM at 205 PSI dP
BHP: 714 HP

P-106A/B/C/D/E/F/G
Water Circulation Pump

7,986 GPM at 200 PSI dP
BHP: 1553 HP

EX-100/101/102/103/104/105
Cavern In-Storage Cooler

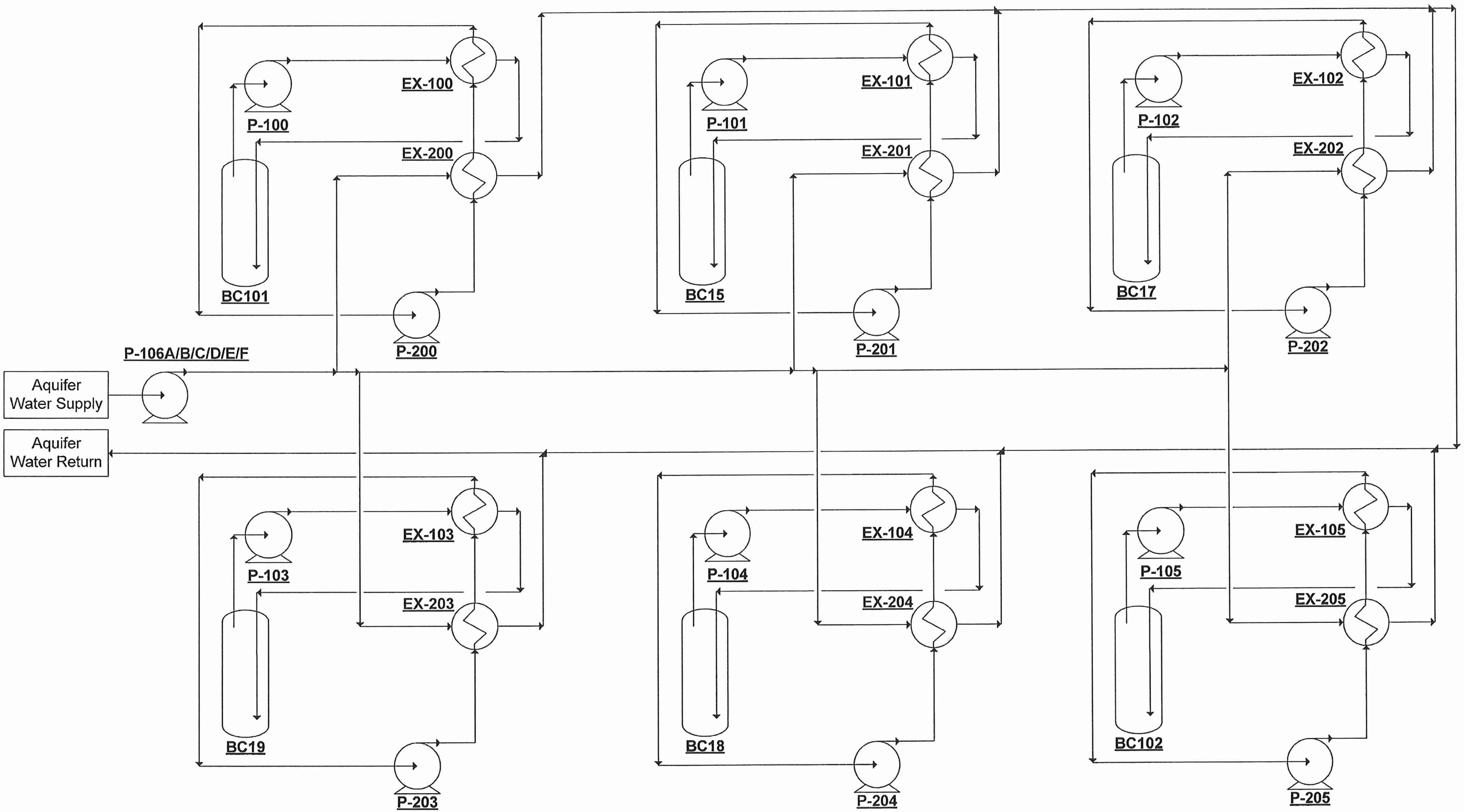
Duty: 20.2 MMBTU/HR

REPORT-C-2A
Rev. 0, 01/21/2016

Client:	VCI/US Department of Energy		URS Job No.: 38988843
Project:	SPR Bayou Choctaw Degas	MECHANICAL EQUIPMENT LIST	By: EAO
			Rev: B
Location:	Bayou Choctaw, LA		Date: 1/14/16

Reference Drawing from Appendix B of Conceptual Design Report	TAG #	DESCRIPTION	Note	NUMBER OF ITEMS	MATERIAL OF CONST.	SIZE Diameter or Width, ft	SIZE Length, ft	DIFF HEAD ft	SIZE (each) GPM (normal) ACFM	DIFF PRESS psi	DEAD HEAD PRESS psi	WEIGHT (each) lb, empty	DUTY MMBTU/hr	U BTU/hr/ft2-°F	SIZE (each) ft2	UA (each)	TYPE	BRAKE HORSEPOWER hp	MOTOR HORSEPOWER hp/volts	MOTORS PER UNIT	SHELL DESIGN MAWP psig	SHELL DESIGN TEMP °F	TUBE DESIGN MAWP psig	TUBE DESIGN TEMP °F	EQUIPMENT COST
IN-STORAGE COOLING WITH CAVERN LAKE WATER																									
In-Storage Cooling-Cavern Lake Water	EX-100	BC101 Cavern In-Storage Cooler		1									20.2		43,420										$846,500
	EX-101	BC15 Cavern In-Storage Cooler		1									20.2		43,420										$846,500
	EX-102	BC17 Cavern In-Storage Cooler		1									20.2		43,420										$846,500
	EX-103	BC19 Cavern In-Storage Cooler		1									20.2		43,420										$846,500
	EX-104	BC18 Cavern In-Storage Cooler		1									20.2		43,420										$846,500
	EX-105	BC102 Cavern In-Storage Cooler		1									20.2		43,420										$846,500
	P-100	BC101 In-Storage Circulation Pump		1					3,581	205								714	800						$174,700
	P-101	BC15 In-Storage Circulation Pump		1					3,581	205								714	800						$174,700
	P-102	BC17 In-Storage Circulation Pump		1					3,581	205								714	800						$174,700
	P-103	BC19 In-Storage Circulation Pump		1					3,581	205								714	800						$174,700
	P-104	BC18 In-Storage Circulation Pump		1					3,581	205								714	800						$174,700
	P-105	BC102 In-Storage Circulation Pump		1					3,581	205								714	800						$174,700
	P-106 A/B/C/D/E/F/G	Water Circulation Pumps		7					7,986	200								1,553	1750						$1,883,700
		Major Equipment Total																							$8,010,900
	Non-equipment	Lake Water Return Header and Electrical		1		**20"-48"**	Various																		$6,392,612
		TIC Total																							**$38,436,212**

Aquifer Water Cooling



P-100/101/102/103/104/105
In-Storage Circulation Pump

776 GPM at 205 PSI dP
BHP: 155 HP

P-200/201/202/203/204/205
Intermediate Water Circulation Pump

902 GPM at 75 PSI dP
BHP: 66 HP

P-106A/B/C/D/E/F
Produced Water Pump

300 GPM at 30 PSI dP
BHP: 9 HP

EX-100/101/102/103/104/105
Cavern In-Storage Cooler

Duty: 5.2 MMBTU/HR

EX-200/201/202/203/204/205
Intermediate Water Cooler

Duty: 5.3 MMBTU/HR

REPORT-C-3A
Rev. 0, 01/21/2016

Client:	VCI/US Department of Energy
Project:	SPR Bayou Choctaw Degas
Location:	Bayou Choctaw, LA

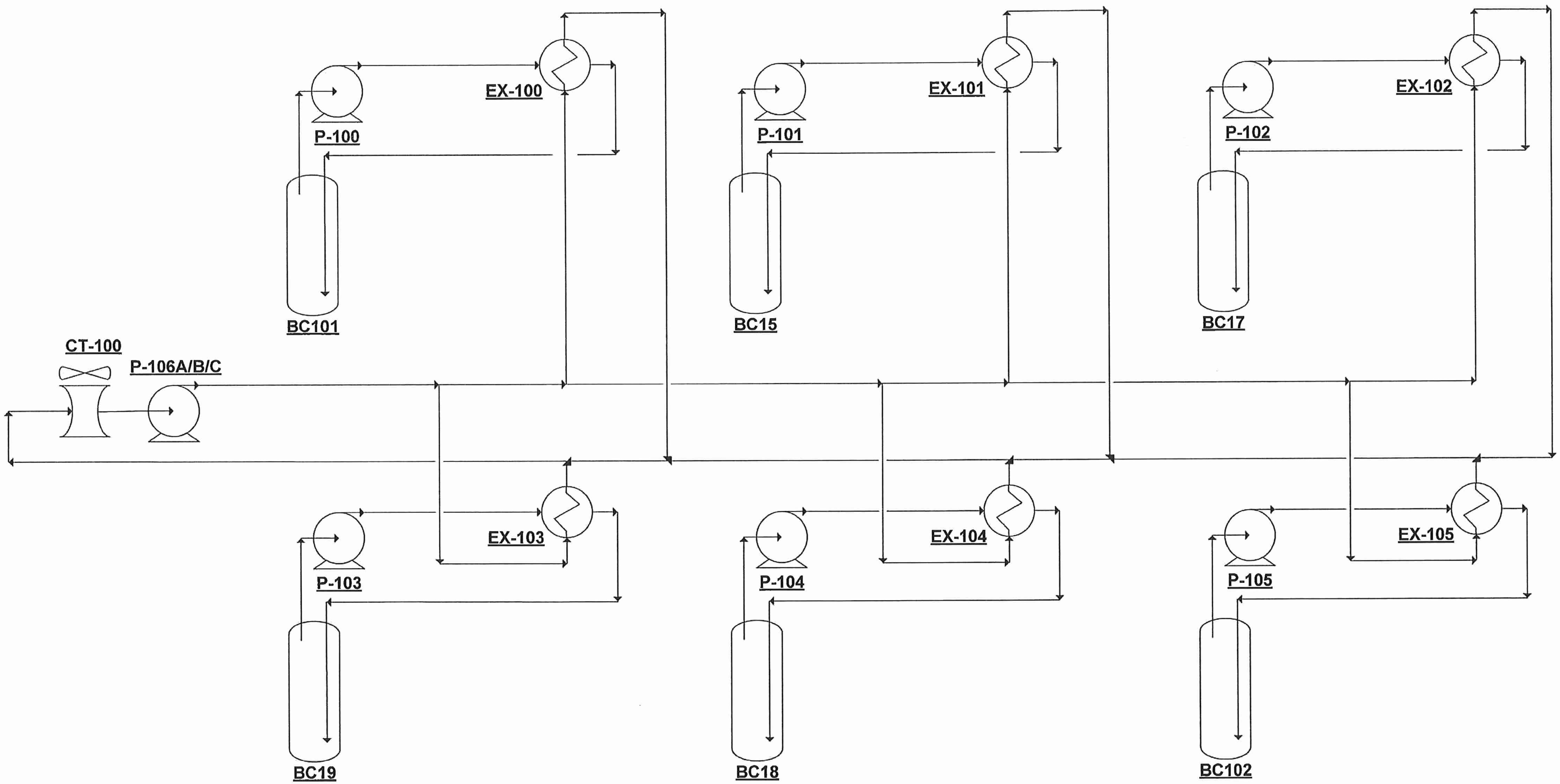
MECHANICAL EQUIPMENT LIST

URS

Job No.:	38988843
By:	EAO
Rev:	B
Date:	1/14/16

Reference Drawing from Appendix B of Conceptual Design Report	TAG #	DESCRIPTION	Note	NUMBER OF ITEMS	MATERIAL OF CONST.	SIZE Diameter or Width, ft	SIZE Length, ft	DIFF HEAD ft	SIZE (each) GPM (normal) ACFM	DIFF PRESS psi	DEAD HEAD PRESS psi	WEIGHT (each) lb, empty	DUTY MMBTU/hr	U BTU/hr/ft2-°F	SIZE (each) ft2	UA (each)	TYPE	BRAKE HORSEPOWER hp	MOTOR HORSEPOWER hp/volts	MOTORS PER UNIT	SHELL DESIGN MAWP psig	SHELL DESIGN TEMP °F	TUBE DESIGN MAWP psig	TUBE DESIGN TEMP °F	EQUIPMENT COST
IN-STORAGE COOLING WITH AQUIFER WATER AND INTERMEDIATE COOLING																									
In-Storage Cooling-Aquifer Water	EX-100	BC101 Cavern In-Storage Cooler		1									5.2		6,038										$161,281
	EX-101	BC15 Cavern In-Storage Cooler		1									5.2		6,038										$161,281
	EX-102	BC17 Cavern In-Storage Cooler		1									5.2		6,038										$161,281
	EX-103	BC19 Cavern In-Storage Cooler		1									5.2		6,038										$161,281
	EX-104	BC18 Cavern In-Storage Cooler		1									5.2		6,038										$161,281
	EX-105	BC102 Cavern In-Storage Cooler		1									5.2		6,038										$161,281
	EX-200	BC101 Intermediate Water Cooler		1									5.3		2,500										$87,202
	EX-201	BC15 Intermediate Water Cooler		1									5.3		2,500										$87,202
	EX-202	BC17 Intermediate Water Cooler		1									5.3		2,500										$87,202
	EX-203	BC19 Intermediate Water Cooler		1									5.3		2,500										$87,202
	EX-204	BC18 Intermediate Water Cooler		1									5.3		2,500										$87,202
	EX-205	BC102 Intermediate Water Cooler		1									5.3		2,500										$87,202
	P-100	BC101 In-Storage Circulation Pump		1					776	205								155	200						$68,887
	P-101	BC15 In-Storage Circulation Pump		1					776	205								155	200						$68,887
	P-102	BC17 In-Storage Circulation Pump		1					776	205								155	200						$68,887
	P-103	BC19 In-Storage Circulation Pump		1					776	205								155	200						$68,887
	P-104	BC18 In-Storage Circulation Pump		1					776	205								155	200						$68,887
	P-105	BC102 In-Storage Circulation Pump		1					776	205								155	200						$68,887
	P-200	BC101 Intermediate Water Circulation Pump		1					902	75								66	75						$76,787
	P-201	BC15 Intermediate Water Circulation Pump		1					902	75								66	75						$76,787
	P-202	B17 Intermediate Water Circulation Pump		1					902	75								66	75						$76,787
	P-203	BC19 Intermediate Water Circulation Pump		1					902	75								66	75						$76,787
	P-204	BC18 Intermediate Water Circulation Pump		1					902	75								66	75						$76,787
	P-205	BC102 Intermediate Water Circulation Pump		1					902	75								66	75						$76,787
	P-106 A/B/C/D/E/F	Produced Water Pumps (1)		6					300	30								9	10						$106,800
		Major Equipment Total																							$2,471,736
	Non-equipment	Aquifer Water Supply/Return Headers		2		10"	5600'																		$3,184,570
		TIC Total																							**$13,071,515**

Cooling Tower Cooling



P-100/101/102/103/104/105
In-Storage Circulation Pump

3,581 GPM at 275 PSI dP
BHP: 958 HP

CT-100
Cooling Tower

Duty: 20.4 MMBTU/HR

P-106A/B/C
Cooling Water Circulation Pump

7,845 GPM at 70 PSI dP
BHP: 534 HP

EX-100/101/102/103/104/105
Cavern In-Storage Cooler

Duty: 18.2 MMBTU/HR

REPORT-C-4A
Rev. 0, 01/21/2016

Client:	VCI/US Department of Energy
Project:	SPR Bayou Choctaw Degas
Location:	Bayou Choctaw, LA

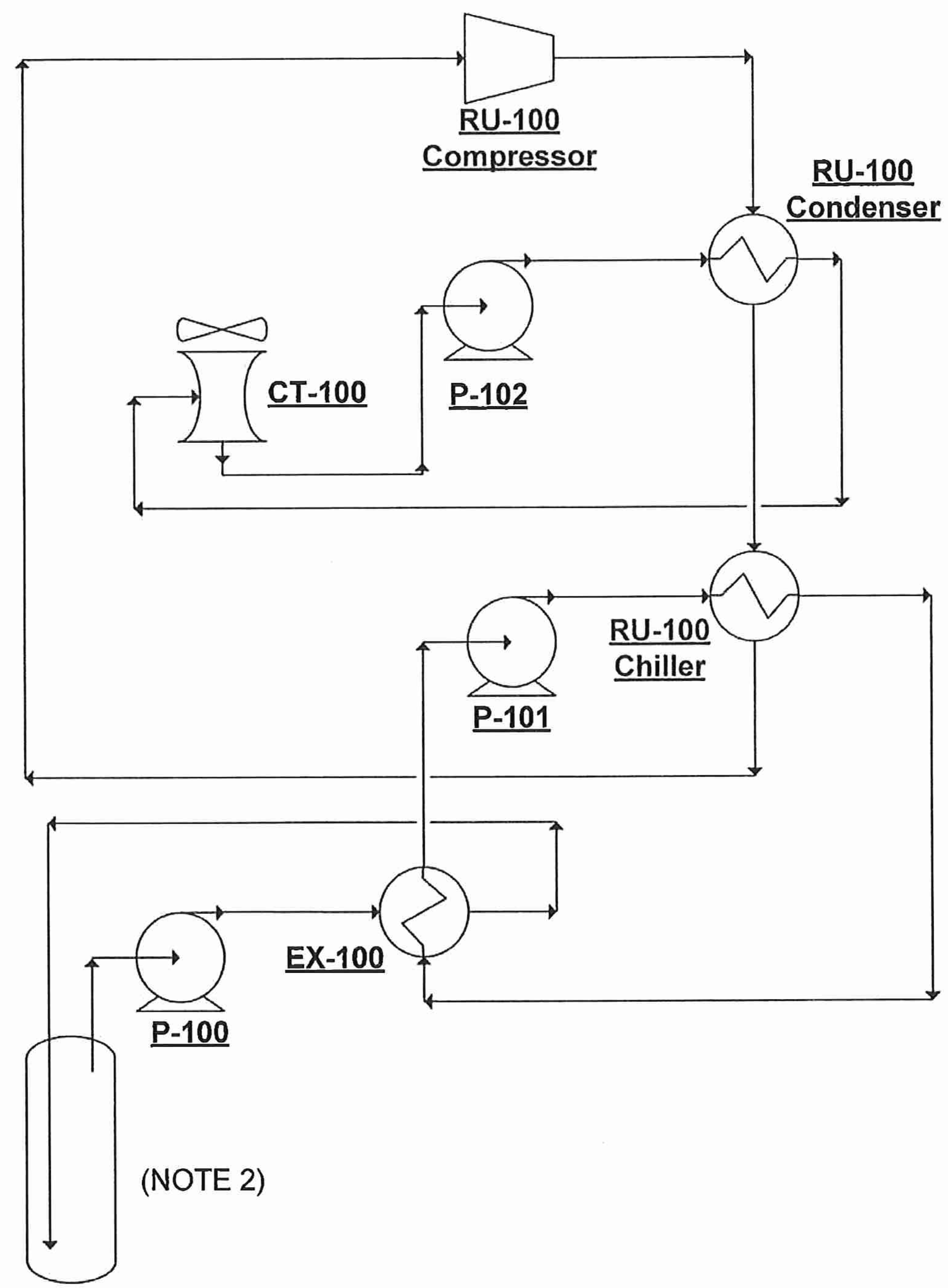
MECHANICAL EQUIPMENT LIST

URS

Job No.:	38988843
By:	EAO
Rev:	B
Date:	1/14/16

Reference Drawing from Appendix B of Conceptual Design Report	TAG #	DESCRIPTION	Note	NUMBER OF ITEMS	MATERIAL OF CONST.	SIZE Diameter or Width, ft	SIZE Length, ft	DIFF HEAD ft	SIZE (each) GPM (normal) ACFM	DIFF PRESS psi	DEAD HEAD PRESS psi	WEIGHT (each) lb, empty	DUTY MMBTU/hr	U BTU/hr/ft2-°F	SIZE (each) ft2	UA (each)	TYPE	BRAKE HORSEPOWER hp	MOTOR HORSEPOWER hp/volts	MOTORS PER UNIT	SHELL DESIGN MAWP psig	SHELL DESIGN TEMP °F	TUBE DESIGN MAWP psig	TUBE DESIGN TEMP °F	EQUIPMENT COST
IN-STORAGE COOLING WITH COOLING TOWER WATER																									
In-Storage Cooling-Cooling Tower	EX-100	BC101 Cavern InStorage Cooler		1									18.2		54,420										$1,043,700
	EX-101	BC15 Cavern InStorage Cooler		1									18.2		54,420										$1,043,700
	EX-102	BC17 Cavern InStorage Cooler		1									18.2		54,420										$1,043,700
	EX-103	BC19 Cavern InStorage Cooler		1									18.2		54,420										$1,043,700
	EX-104	BC18 Cavern InStorage Cooler		1									18.2		54,420										$1,043,700
	EX-105	BC102 Cavern InStorage Cooler		1									18.2		54,420										$1,043,700
	P-100	BC101 In-Storage Circulation Pump		1					3,581	275								958	1000						$206,400
	P-101	BC15 In-Storage Circulation Pump		1					3,581	275								958	1000						$206,400
	P-102	BC17 In-Storage Circulation Pump		1					3,581	275								958	1000						$206,400
	P-103	BC19 In-Storage Circulation Pump		1					3,581	275								958	1000						$206,400
	P-104	BC18 In-Storage Circulation Pump		1					3,581	275								958	1000						$206,400
	P-105	BC102 In-Storage Circulation Pump		1					3,581	275								958	1000						$206,400
	P-106 A/B/C	Cooling Water Circulation Pumps		3					7,845	70								534	600						$778,800
	CT-100	Cooling Tower											20.4												$337,100
		Major Equipment Total																							$8,279,400
	Non-equipment	Cooling Water Return Header and Electrical		1		20"-48"	Various																		$6,392,612
		TIC Total																							**$39,510,212**

Chilled Water Cooling (NOTE 1)



NOTES: 1) Typical for 7 units, one for each of 6 caverns plus one spare portable unit.
2) Typical for each of 6 caverns BC101, BC15, BC17, BC19, BC18, and BC102.

RU-100 Chiller
Refrigeration Chiller
Duty: 15.0 MMBTU/HR
(1250 tons)

RU-100 Compressor
Refrigeration Compressor
2,481 ACFM at 186 PSI dP
BHP: 1,531 HP

RU-100 Condenser
Refrigeration Condenser
Duty: 18.9 MMBTU/HR

P-100
Crude In-Storage Circulation Pump
3,535 GPM at 246 PSI dP
BHP: 846 HP

CT-100
Cooling Tower
Duty: 19.0 MMBTU/HR

P-101
Chilled Water Circulation Pump
1,647 GPM at 70 PSI dP
BHP: 112 HP

P-102
Cooling Water Supply Pump
1,490 GPM at 70 PSI dP
BHP: 101 HP

EX-100
Cavern In-Storage Cooler
Duty: 14.8 MMBTU/HR

REPORT-C-5A
Rev. 0, 01/21/2016

Client:	VCI/US Department of Energy
Project:	SPR Bayou Choctaw Degas
Location:	Bayou Choctaw, LA

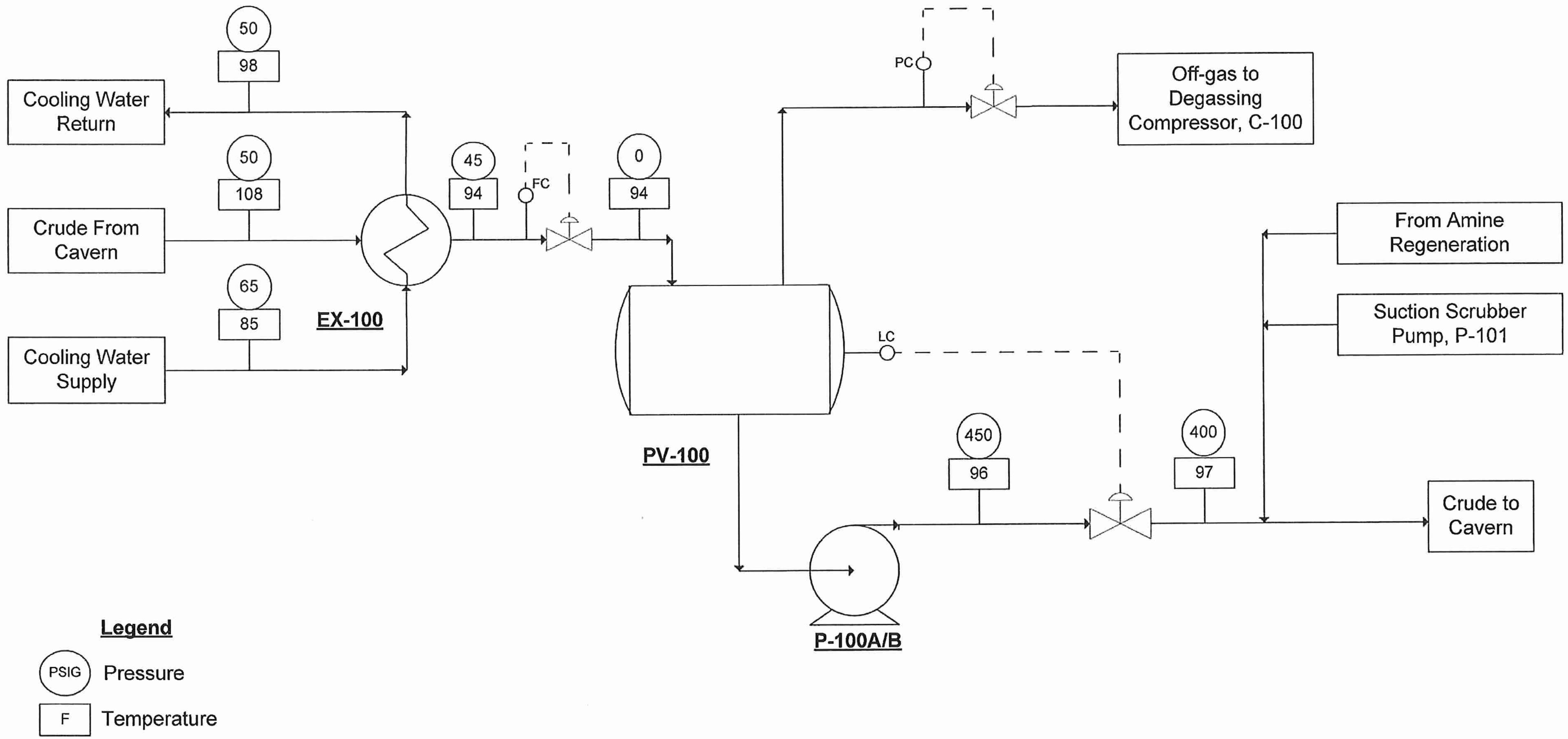
MECHANICAL EQUIPMENT LIST

URS

Job No.:	38988843
By:	EAO
Rev:	B
Date:	1/14/16

Reference Drawing from Appendix B of Conceptual Design Report	TAG #	DESCRIPTION	Note	NUMBER OF ITEMS	MATERIAL OF CONST.	SIZE	SIZE	DIFF HEAD	SIZE (each)	DIFF PRESS	DEAD HEAD PRESS	WEIGHT (each)	DUTY	U	SIZE (each)	UA (each)	TYPE	BRAKE HORSEPOWER	MOTOR HORSEPOWER	MOTORS PER UNIT	SHELL DESIGN MAWP	SHELL DESIGN TEMP	TUBE DESIGN MAWP	TUBE DESIGN TEMP	EQUIPMENT COST
						Diameter or Width, ft	Length, ft	ft	GPM (normal) ACFM	psi	psi	lb, empty	MMBTU/hr	BTU/hr/ft2-°F	ft2			hp	hp/volts		psig	°F	psig	°F	
IN-STORAGE CHILLED WATER COOLING FOR BC101																									
In-Storage Cooling-Chilled Water	EX-100	Cavern InStorage Cooler		1									14.8		21,800										$423,900
	P-100	Crude InStorage Circulation Pump		1					3,535	246								846	900						$177,900
	CT-100	Cooling Tower		1									19.0												$43,900
	P-101	Chilled Water Circulation Pump		1					1,647	70								112							$71,500
	P-102	Cooling Water Supply Pump		1					1,490	70								101							$68,700
	RU-100 Chiller	Refrigeration Chiller		1									15.0 (1250 tons)		17,456										$1,690,400
	RU-100 Compressor	Refrigeration Compressor		1					2,481	186								1,531							incl.
	RU-100 Condenser	Refrigeration Condenser		1									18.90		7,218										incl.
		Major Equipment Total (1 Package)																							**$2,476,300**
		TIC Total (1 Package)																							**$9,905,200**
		TIC Total (7 Packages-includes 1 Cooldown Portable)																							**$69,336,400**

In-Storage Degassing
Cavern BC19



P-100A/B
Crude Circulation Pump

2090 GPM at 450 PSI dP
BHP: 91 HP

EX-100
Crude Circulation Cooler

Duty: 5.8 MMBTU/HR

PV-100
Degassing Drum

11'-0" ID x 55'-0" S/S
D.P. 50 PSIG

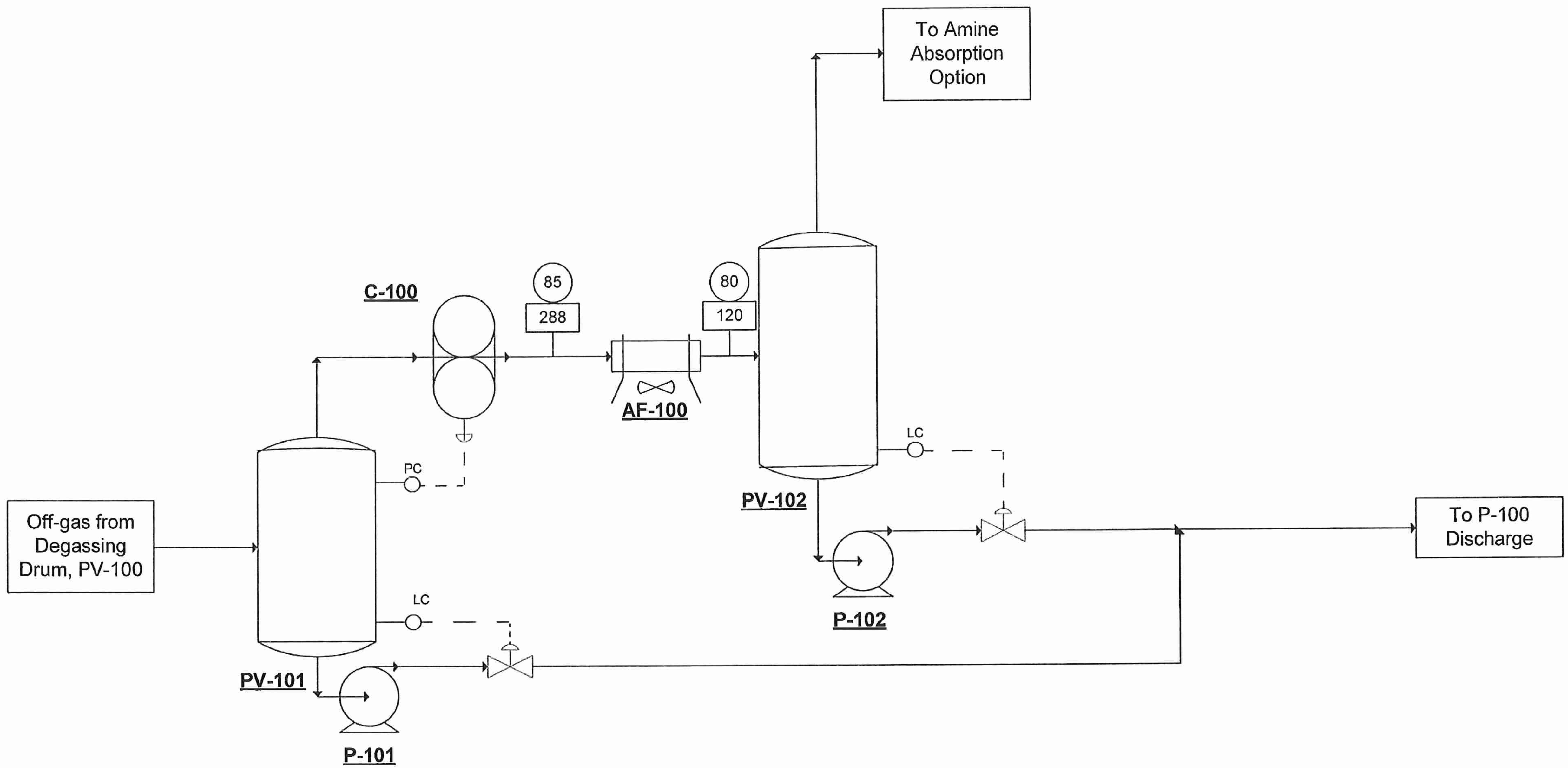
REPORT-C-6A
Rev. 0, 01/21/2016

Client:	VCI/US Department of Energy		Job No.: 38988843
Project:	SPR Bayou Choctaw Degas	**MECHANICAL EQUIPMENT LIST**	By: EAO/DMS
Location:	Bayou Choctaw, LA	URS	Rev: B
			Date: 1/14/16

Reference Drawing from Appendix C of Conceptual Design Report	TAG #	DESCRIPTION	Note	NUMBER OF ITEMS	MATERIAL OF CONST.	SIZE Diameter or Width, ft	SIZE Length, ft	DIFF HEAD ft	SIZE (each) GPM (normal) ACFM	DIFF PRESS psi	DEAD HEAD PRESS psi	WEIGHT (each) lb, empty	DUTY MMBTU/hr	U BTU/hr/ft2-°F	SIZE (each) ft2	UA (each)	TYPE	BRAKE HORSEPOWER hp	MOTOR HORSEPOWER hp/volts	MOTORS PER UNIT	EQUIPMENT COST
IN-STORAGE OPTIONS																					
Degassing: Cavern BC19, page C-5	EX-100	Crude Circulation Cooler		1									5.8	50	14270	713491	AEL				$251,600
	P-100 A/B	Crude Circulation Pump		2					2090	450								915	1000		$593,600
	PV-100	Degassing Drum		1		11'-0"	55'-0" S-S			50											$106,000
		Oil Circulation Header		1		10"	5600'														$1,592,285
Compression: Cavern BC19, page C-6	AF-100	Compressor Discharge Cooler		2									0.01898	90	2	204					
	C-100	Degassing Compressor		2					31	130								3.92	3		$1,941,600
	P-101	Suction Scrubber Pump		2					1.0	385								0.374368	0.5		$26,400
	PV-101	Compressor Suction Scrubber		2		1'-6"	4'-6" S-S														$10,800
	PV-102	Compressor Discharge Scrubber		2		1'-6"	4'-6" S-S														$10,800
	P-102	Discharge Scrubber Pump		2					1.0	350								0.340335	0.5		$26,400
		Compressor Package Total without Spare Items		2																	**$2,016,000**
Cooling Water System: Cavern BC19, page C-7	CT-100	Cooling Tower		1									6.0	90	161889	14570000					$123,600
	P-104 A/B	Cooling Water Circulation Pump		2				172	1193	74.5								86	100		$155,200
H2S Scavenging, page C-8	PV-200	Injection Water Separator	1	1		1'-6"	4'-6" S-S														$5,300
	PV-201	H2S Absorber	1	1		4'-0"	12'-0" S-S														$20,500
Amine Absorption Unit: Cavern BC19, page C-9	AF-300	Amine Cooler		1									0.15								
	EX-300	Rich/Lean Heat Exchanger		1									0.45								
	EX-301	Stripper Condenser		1									0.30								
	EX-302	Stripper Reboiler		1									0.72								
	P-300 A/B	Recirculation Pump		2					10	75								0.73	0.75		$31,700
	P-301 A/B	Reflux Pump		2					10	75								0.73	0.75		$31,700
	PV-300	Flash Tank		1		2'-0"	6'-0" S-S														
	PV-301	Reflux Accumulator		1		1'-4"	3'-0" S-S														
	T-300	Absorber Column		1		1'-4"	20'-0" S-S														
	T-301	Stripper Column		1		1'-4"	15'-0" S-S														
		Amine Package Total without Spare Items		1																	$750,000
Refrigeration Package, page C-10	EX-400	Evaporator		1									0.014	50	5	267					
	C-400	Refrigeration Compressor		1					5.1									2.5	3		
	AF-400	Refrigerant Condenser		1									0.020	90	6	512					
	PV-400	Refrigerant Suction Scrubber		1		0'-6"	1'-6" S/S														
	PV-401	Refrigerant Economizer		1		0'-6"	1'-6" S/S														
		Refrigeration Package Total without Spare Items		2																	$31,200
Power Generation Package, Page C-11	GT-400	Off-gas Turbine	1	1																	
	GE-400	Off-gas Generator	1	1																	
		Generator Package Total without Spare Items	1	1																	$1,302,300
	FL-100	Elevated Flare		1					68,100 lb/hr												$71,200
	BL-100 A/B	Flare Combustion Air Blower		2														15	15		$140,200
		Major Equipment Total																			**$5,894,284.97**
		TIC Total																			**$18,800,284.97**

Notes 1) Option rejected. Shown as reference & not included in Major Equipment Total

In-Storage Compression
Cavern BC19



Legend

PSIG Pressure

F Temperature

C-100
Degassing Compressor

31 ACFM at 70 PSI dP
BHP: 2.1 HP

P-101
Suction Scrubber Pump

1.0 GPM at 385 PSI dP
BHP: 0.5 HP

AF-100
Compressor Discharge Cooler

Duty: 18,977 BTU/HR

P-102
Discharge Scrubber Pump

1.0 GPM at 350 PSI dP
BHP:

PV-101
Compressor Suction Scrubber

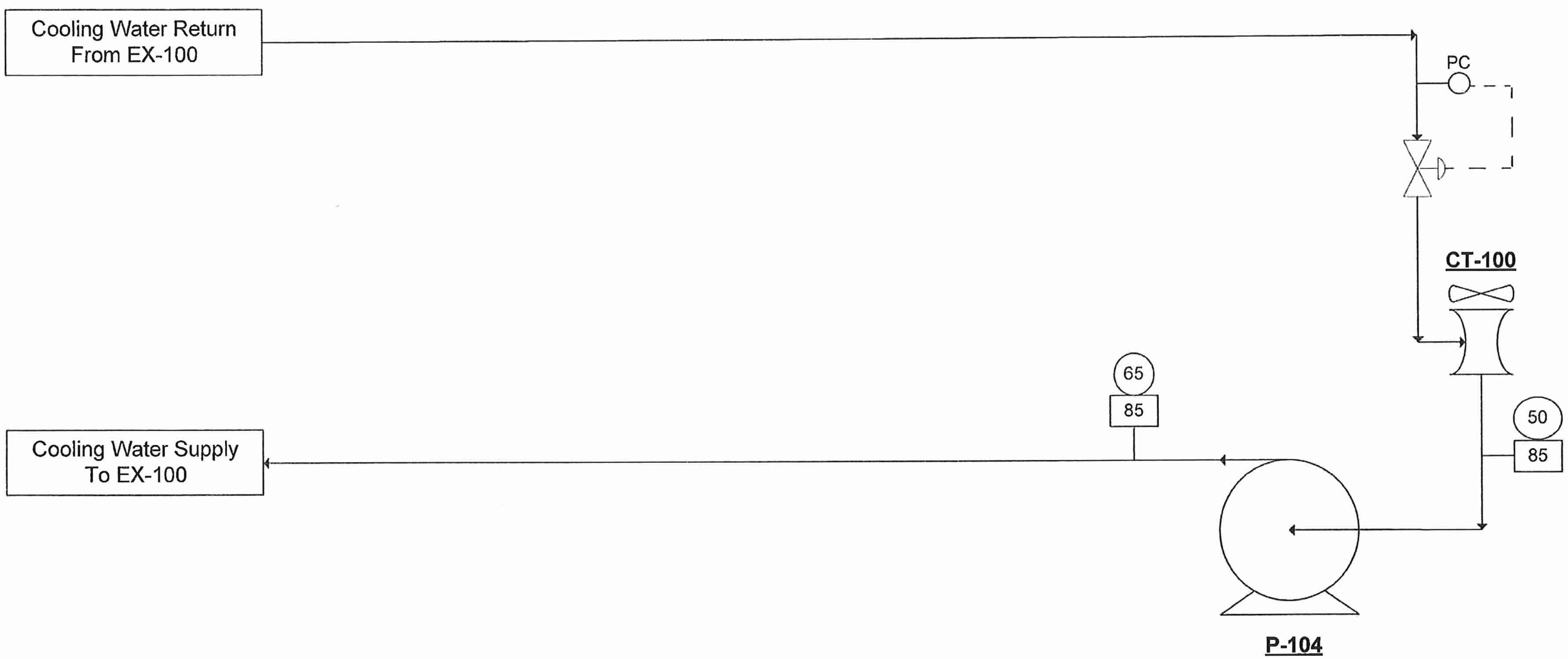
18" ID x 4'-6" S/S

PV-102
Compressor Suction Scrubber

18" ID x 4'-6" S/S

REPORT-C-7
Rev. 0, 01/21/2016

Cooling Water System
In-Storage Option
Cavern BC19



Legend

PSIG Pressure

F Temperature

P-104
Cooling Water Circulation Pump

1193 GPM at 172 FT. Head
BHP: 86 HP

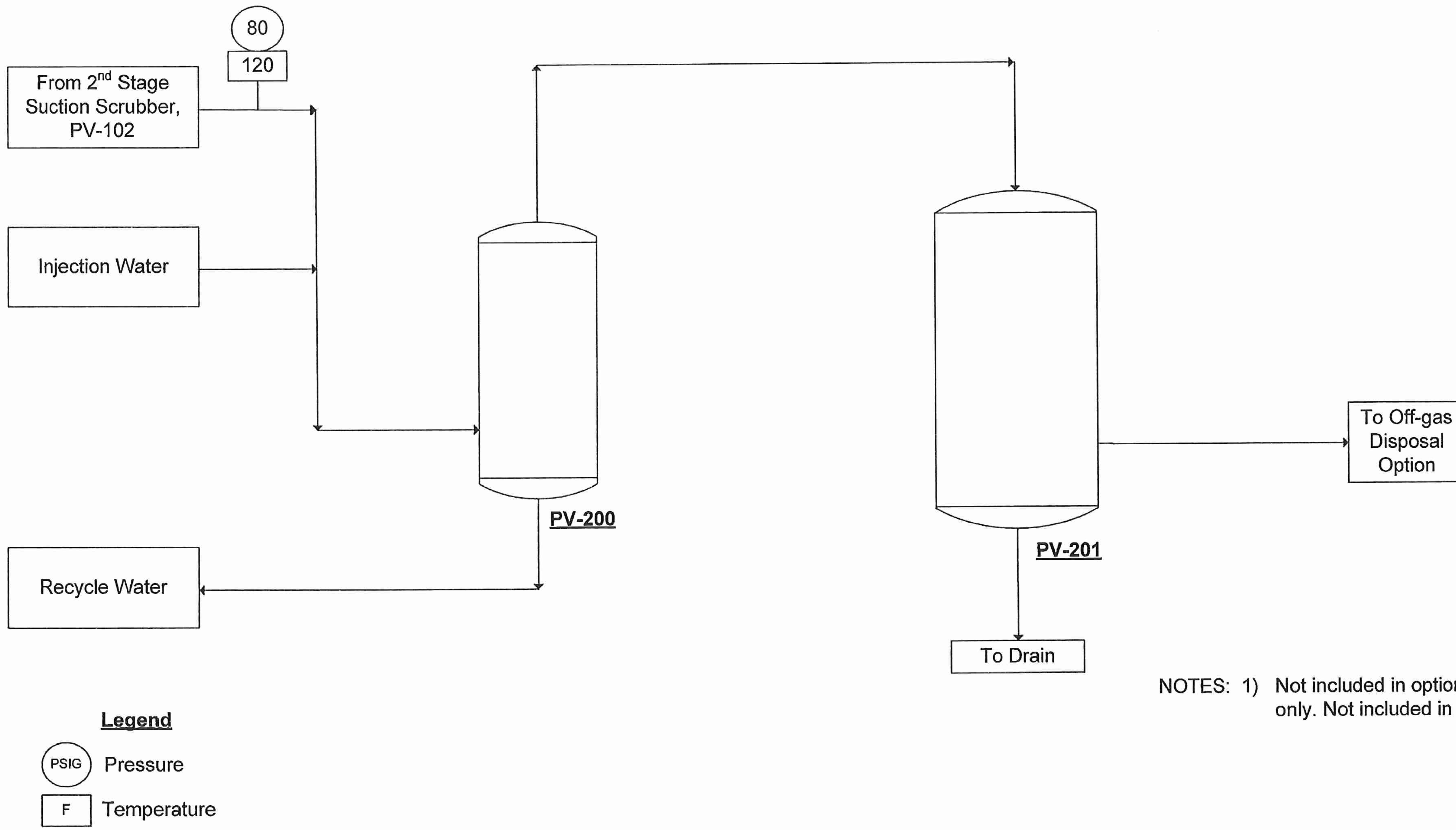
CT-100
Cooling Tower

Duty: 6.0 MMBTU/HR

REPORT-C-8
Rev. 0, 01/21/2016

H2S Scavenging In-Storage Option

(NOTE 1)



NOTES: 1) Not included in option. Shown for reference only. Not included in major equipment total.

PV-200
Injection Water Seperator

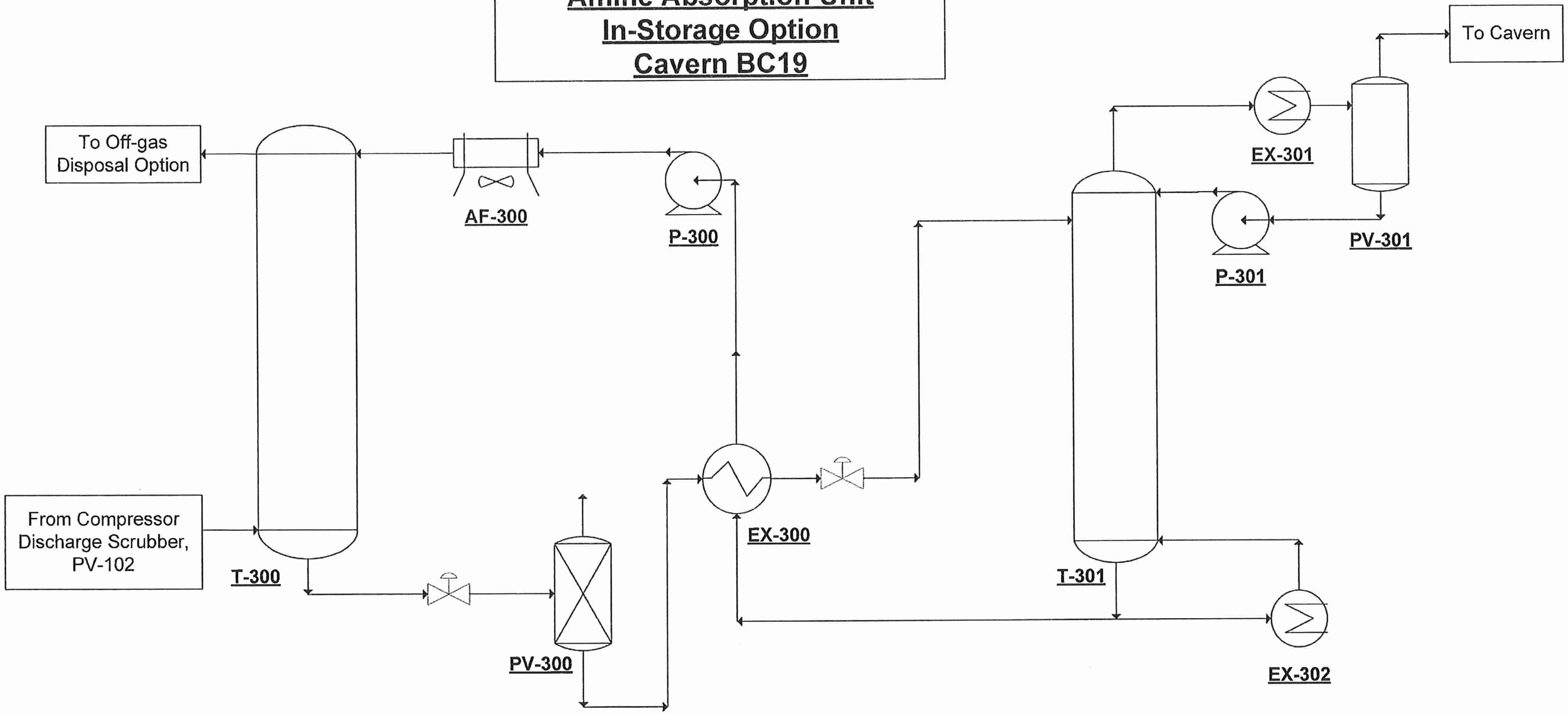
18" ID x 4'-6" S/S

PV-201
H2S Absorber

48" ID x 12'-0" S/S

REPORT-C-9
Rev. 0, 01/21/2016

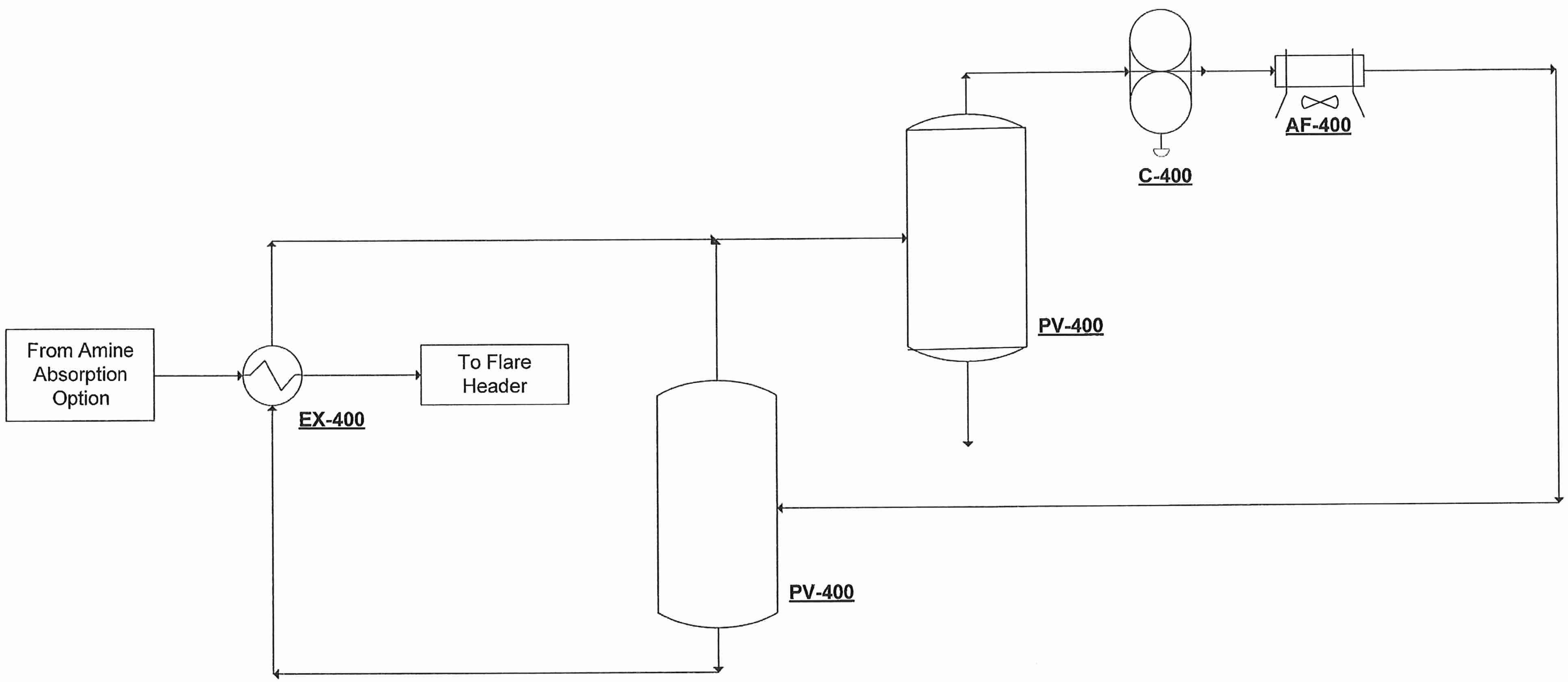
Amine Absorption Unit
In-Storage Option
Cavern BC19



T-300 **Absorber** 16" ID x 20'-0" S/S	**PV-300** **Flash Tank** 24" ID x 72" S/S	**EX-300** **Rich/Lean Exchanger** Duty: 0.45 MMBTU/HR	**T-301** **Stripper** 16" ID x 15'-0" S/S	**P-300** **Recirculation Pump** 10 GPM at 75 PSI dP 0.75 Motor HP
AF-300 **Amine Cooler** Duty: 0.15 MMBTU/HR	**EX-301** **Stripper Condenser** Duty: 0.30 MMBTU/HR	**EX-302** **Stripper Reboiler** Duty: 0.72 MMBTU/HR	**P-301** **Reflux Pump** 10 GPM at 75 PSI dP 0.75 Motor HP	**PV-301** **Reflux Accumulator** 16" ID x 36" S/S

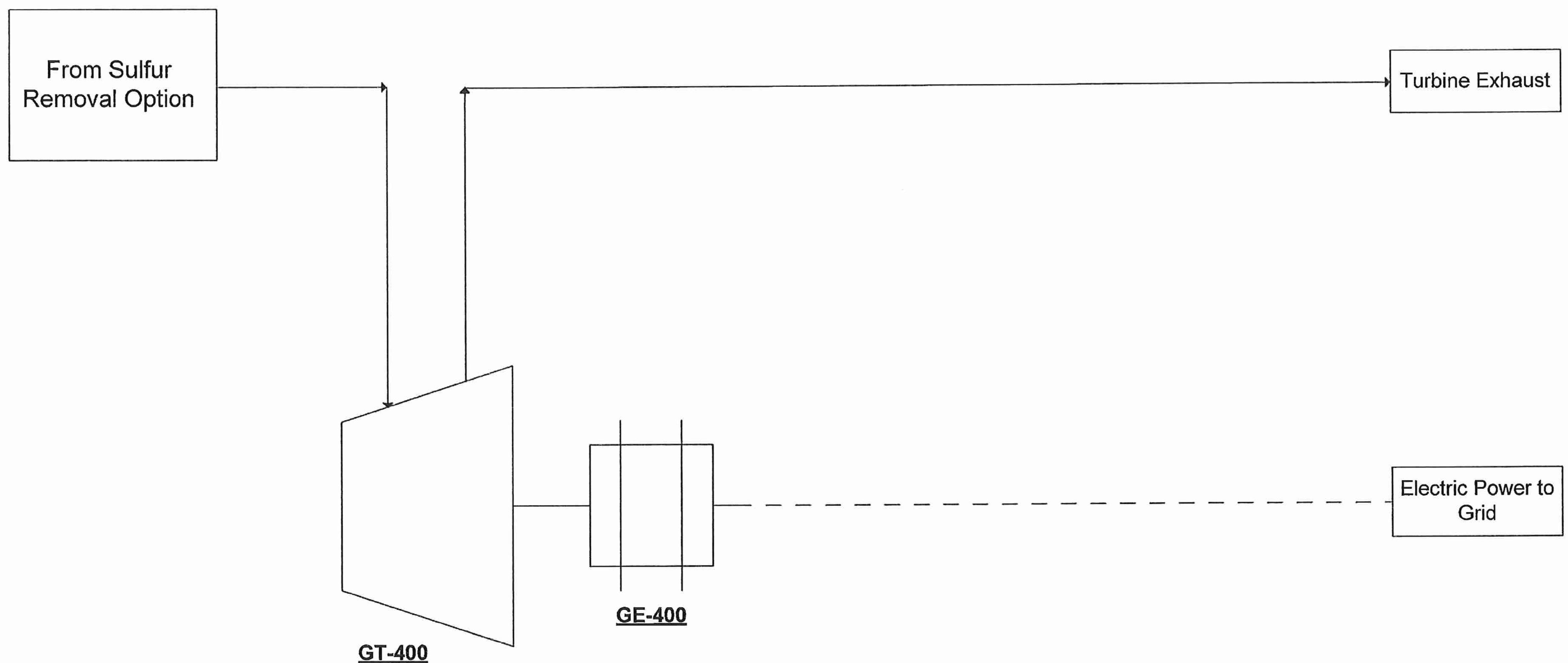
REPORT-C-10
Rev. 0, 01/21/2016

In-Storage Refrigeration Package



C-400	AF-400	PV-400	PV-401	EX-400
Refrigeration Compressor	Refrigerant Condenser	Refrigerant Suction Scrubber	Refrigerant Economizer	Evaporator
5.1 ACFM at XX PSI dP BHP: 2.5 HP	Duty: 20,000 BTU/HR	6" ID x 1'-6" S/S	6" ID x 1'-6" S/S	Duty: 14,000 BTU/HR

Power Generation In-Storage Option

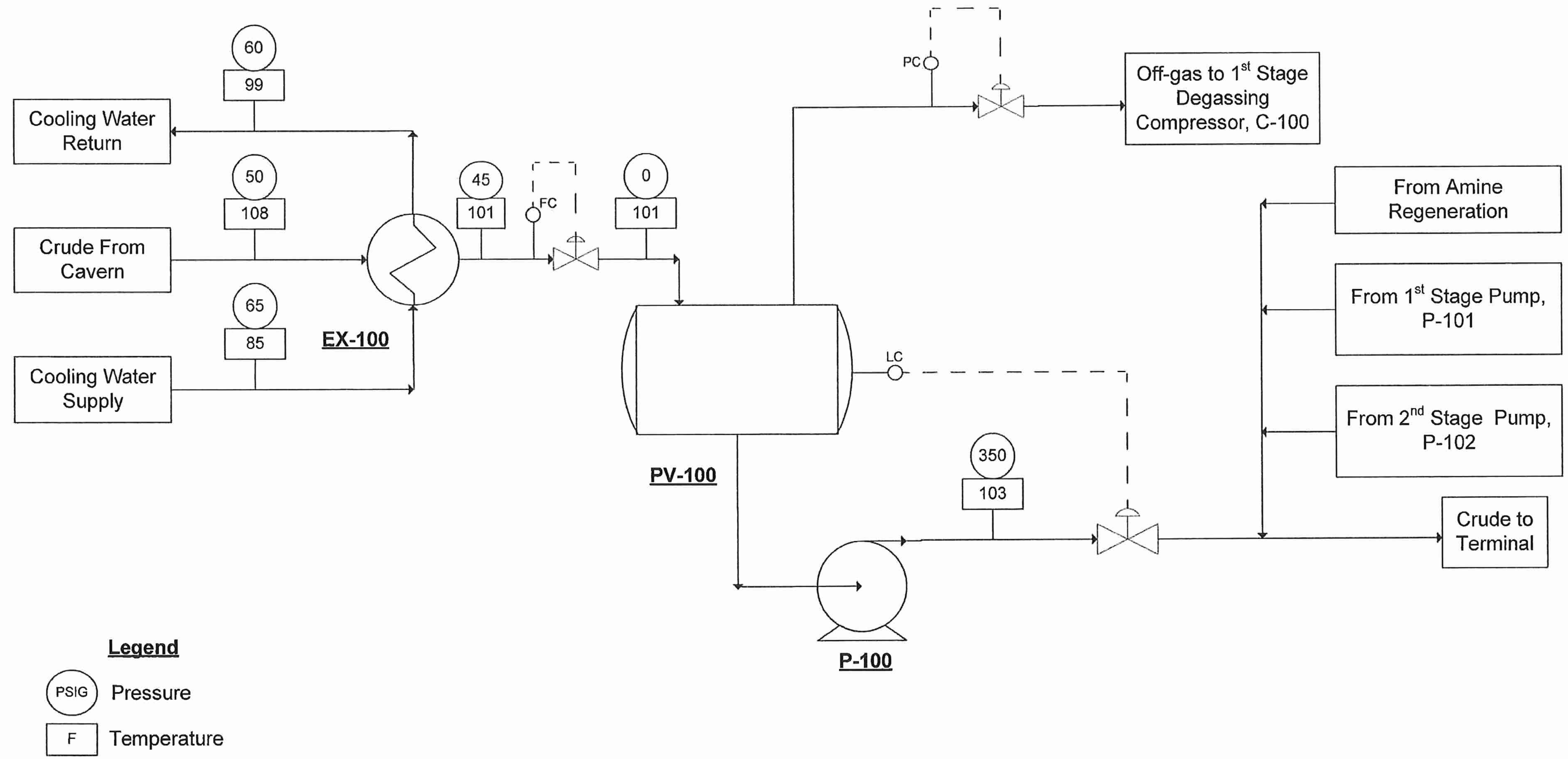


GT-400
Off-gas Turbine
BHP: 1286

GE-400
Off-gas Generator
MW: 0.863

Note: BC102 sets design requirements for GT-400 and GE-400

Degassing at Drawdown
Cavern BC19



P-100
Crude Transfer Pump

15,320 GPM at 350 PSI dP
BHP: 5,214 HP

EX-100
Existing Drawdown Cooler

Duty: 20.6 MMBTU/HR

PV-100
Degassing Drum

21'-6" ID x 108'-0" S/S
D.P. 50 PSIG

REPORT-C-13A
Rev. 0, 01/21/2016

Client:	VCI/US Department of Energy
Project:	SPR Bayou Choctaw Degas
Location:	Bayou Choctaw, LA

MECHANICAL EQUIPMENT LIST

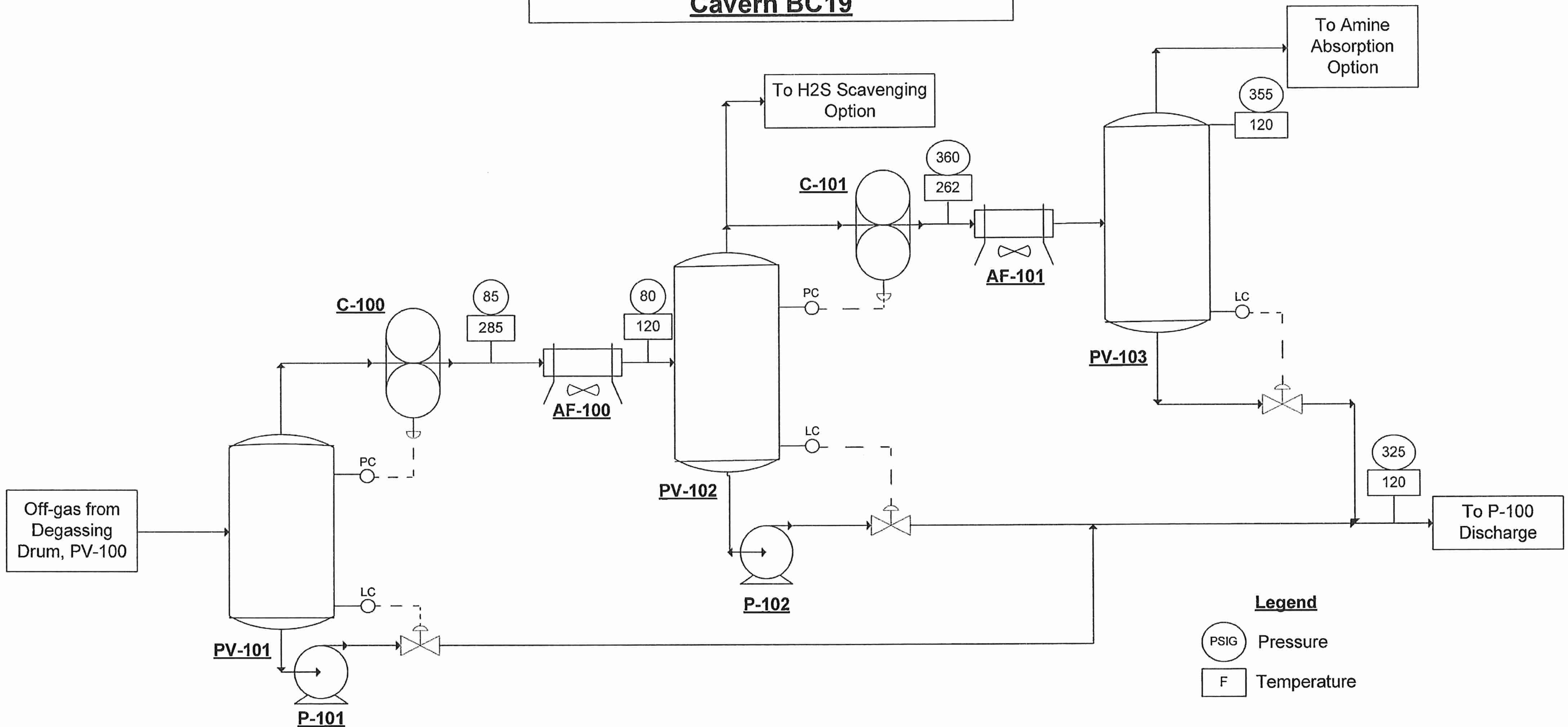
URS

Job No.:	38988843
By:	EAO/DMS
Rev:	B
Date:	1/14/16

Reference Drawing from Appendix C of Conceptual Design Report	TAG #	DESCRIPTION	Note	NUMBER OF ITEMS	MATERIAL OF CONST.	SIZE Diameter or Width, ft	SIZE Length, ft	DIFF HEAD ft	SIZE (each) GPM (normal) ACFM	DIFF PRESS psi	DEAD HEAD PRESS psi	WEIGHT (each) lb, empty	DUTY MMBTU/hr	U BTU/hr/ft2-°F	SIZE (each) ft2	UA (each)	TYPE	BRAKE HORSEPOWER hp	MOTOR HORSEPOWER hp/volts	MOTORS PER UNIT	EQUIPMENT COST
DRAWDOWN OPTIONS																					
Degassing: Cavern BC19, page C12	EX-100	Existing Drawdown Cooler		1									20.6	50	55785	2789252	AEL				
	P-100 A/B	Crude Transfer Pump		2					15320	350								5214			$1,311,200
	PV-100	Degassing Drum		1		21'-6"	108'-0" S-S			50											$678,500
		Oil Circulation Header		1		10"	5600'														$1,592,285
Compression: Cavern BC19, page C-13	AF-100	1st Stage Discharge Cooler		1									0.160	90	17	1536					$35,700
	AF-101	2nd Stage Discharge Cooler	1	1									0.250	90	35	3135					$36,900
	C-100 A/B	1st Stage Degassing Compressor		2					341	85								62.0	75		$1,863,400
	C-101 A/B	2nd Stage Degassing Compressor	1	2					51	350								46.0	50		$1,747,800
	P-101 A/B	1st Stage Pump		2					0.2800	270								0.074	0.125		$26,400
	PV-101	1st Stage Suction Scrubber		1		1'-6"	4'-6" S-S														$5,400
	PV-102	2nd Stage Suction Scrubber	1	1		1'-6"	4'-6" S-S														$5,400
	PV-103	2nd Stage Discharge Scrubber		1		1'-6"	4'-6" S-S														$5,400
Cooling Water System: Cavern BC19, page C-14	CT-100	Cooling Tower		1									21.8								$73,600
	P-104 A/B	Cooling Water Circulation Pump		2				172	2566	74.5								186			$208,000
H2S Scavenging, page C-15	PV-200	Injection Water Separator	2	1		1'-6"	4'-6" S-S														$5,300
	PV-201	H2S Absorber	2	1		9'-0"	18'-0" S-S														$48,800
Amine Absorption Unit: Cavern BC19, page C-16	AF-300	Amine Cooler		1									0.150								
	EX-300	Rich/Lean Heat Exchanger		1									0.450								
	EX-301	Stripper Condenser		1									0.300								
	EX-302	Stripper Reboiler		1									0.72								
	P-300 A/B	Recirculation Pump		2					10	75								0.73	0.750		$31,700
	P-301 A/B	Reflux Pump		2					10	75								0.73	0.750		$31,700
	PV-300	Flash Tank		1		2'-0"	6'-0" S-S														
	PV-301	Reflux Accumulator		1		1'-4"	3'-0" S-S														
	T-300	Absorber Column		1		1'-4"	20'-0" S-S														
	T-301	Stripper Column		1		1'-4"	15'-0" S-S														
		Amine Package Total without Spare Items		1																	$750,000
Refrigeration Package, page C-18	EX-400/500	Evaporator		2									0.126	50	50	2481					
	C-400/500	Refrigeration Compressor		2					156.0									44.2	50		
	AF-400/500	Refrigerant Condenser		2									0.238	90	50	4465					
	PV-400/500	Refrigerant Suction Scrubber		2		0'-6"	1'-6" S-S														
	PV-401/501	Refrigerant Economizer		2		0'-6"	1'-6" S-S														
		Refrigeration Package Total without Spare Items																			$34,200
Vapor Destruction Unit, page C-20	FL-100	Elevated Flare		1					237,200 lb/hr												$189,200
	BL-100 A/B	Flare Combustion Air Blower		2														30			$193,800
		Major Equipment Total																			$7,228,300
		TIC Total																			$30,505,484.97

Notes
1) Required for Crude Injection Option Only
2) Alternative rejected. Shown for reference & not included in Major Equipment Total.

Compression at Drawdown Cavern BC19



C-100
1st Stage Degassing Compressor
341 ACFM at 85 PSI dP
BHP: 62 HP

AF-100
1st Stage Discharge Cooler
Duty: 0.16 MMBTU/HR

PV-101
1st Stage Suction Scrubber
18" ID x 4'-6" S/S

P-101
1st Stage Pump
0.28 GPM at 270 PSI dP
BHP: 0.074 HP

C-101
2nd Stage Degassing Compressor
51 ACFM at 350 PSI dP
BHP: 46 HP
Note (1)

PV-102
2nd Stage Suction Scrubber
18" ID x 4'-6" S/S

P-102
2nd Stage Pump
0.3034 GPM at 270 PSI dP
BHP: 0.06 HP

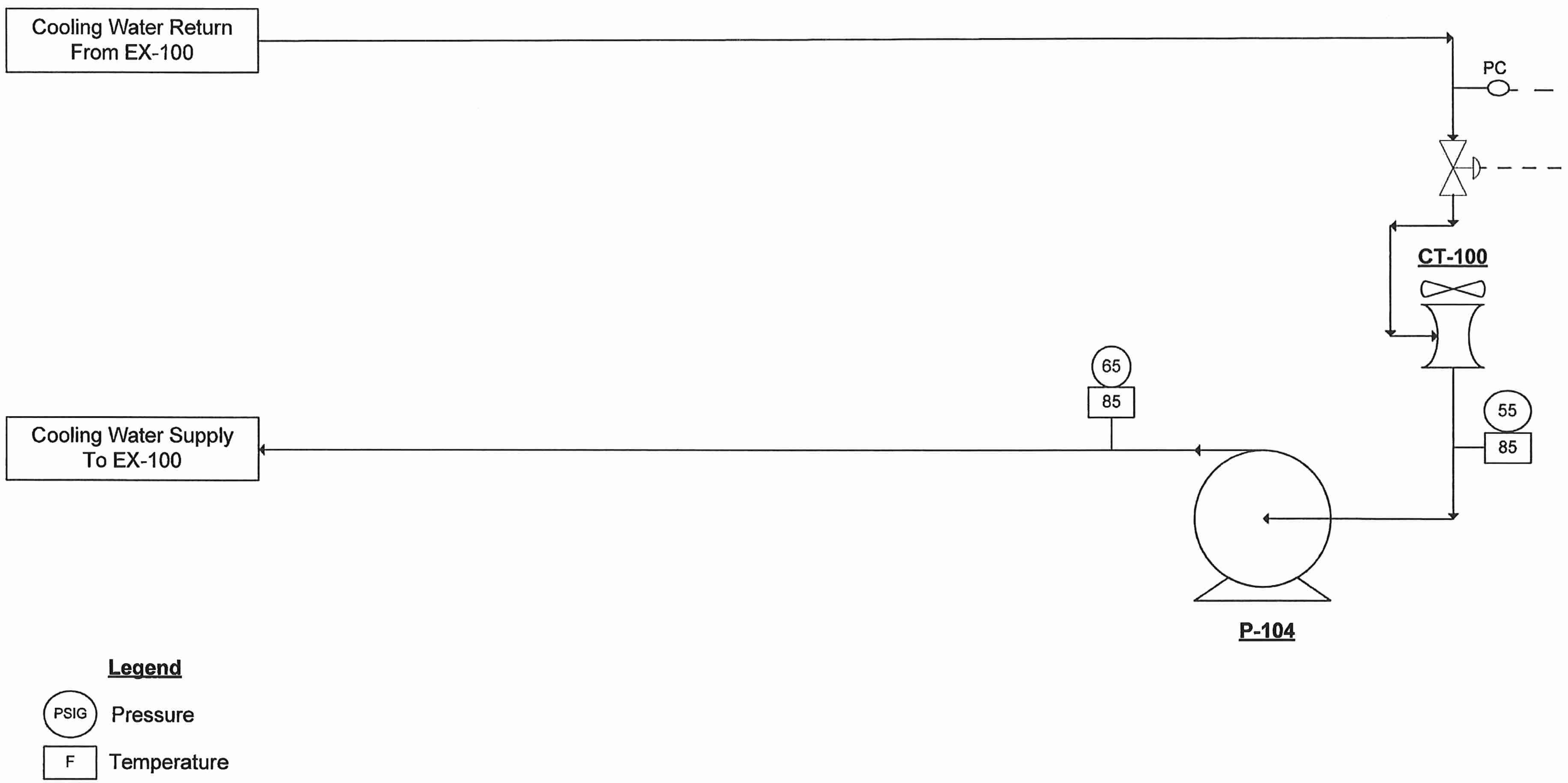
AF-101
2nd Stage Discharge Cooler
Duty: 0.25 MMBTU/HR

PV-103
2nd Stage Discharge Scrubber
18" ID x 4'-6" S/S
Note (1)

Notes: (1) Required for Crude Injection Option Only

REPORT-C-14
Rev. 0, 01/21/2016

Cooling Water System
Drawdown Option
Cavern BC19



P-104
Cooling Water Circulation Pump

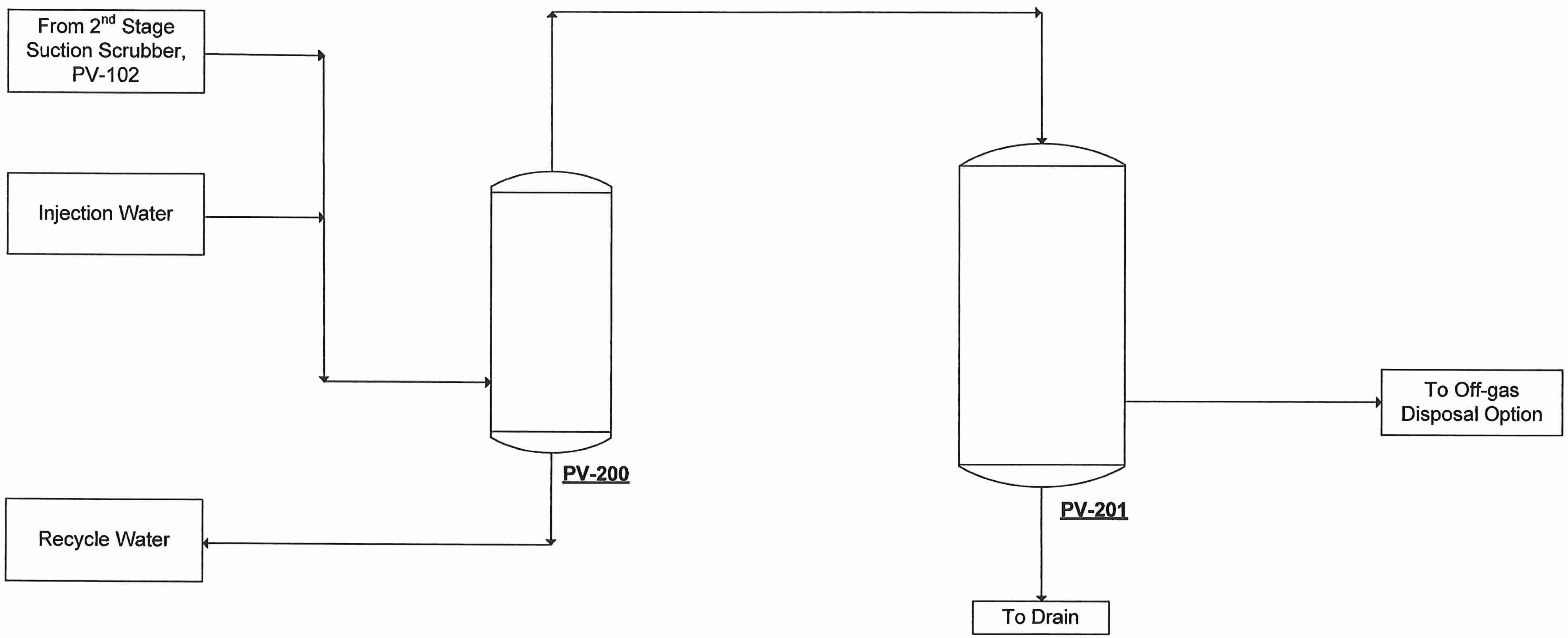
2,566 GPM at 172 FT. Head
BHP: 186 HP

CT-100
Cooling Tower

Duty: 21.8 MMBTU/HR

H2S Scavenging Drawdown Option

(NOTE 1)



NOTES: 1) Not included in option. Shown for reference only. Not included in major equipment total.

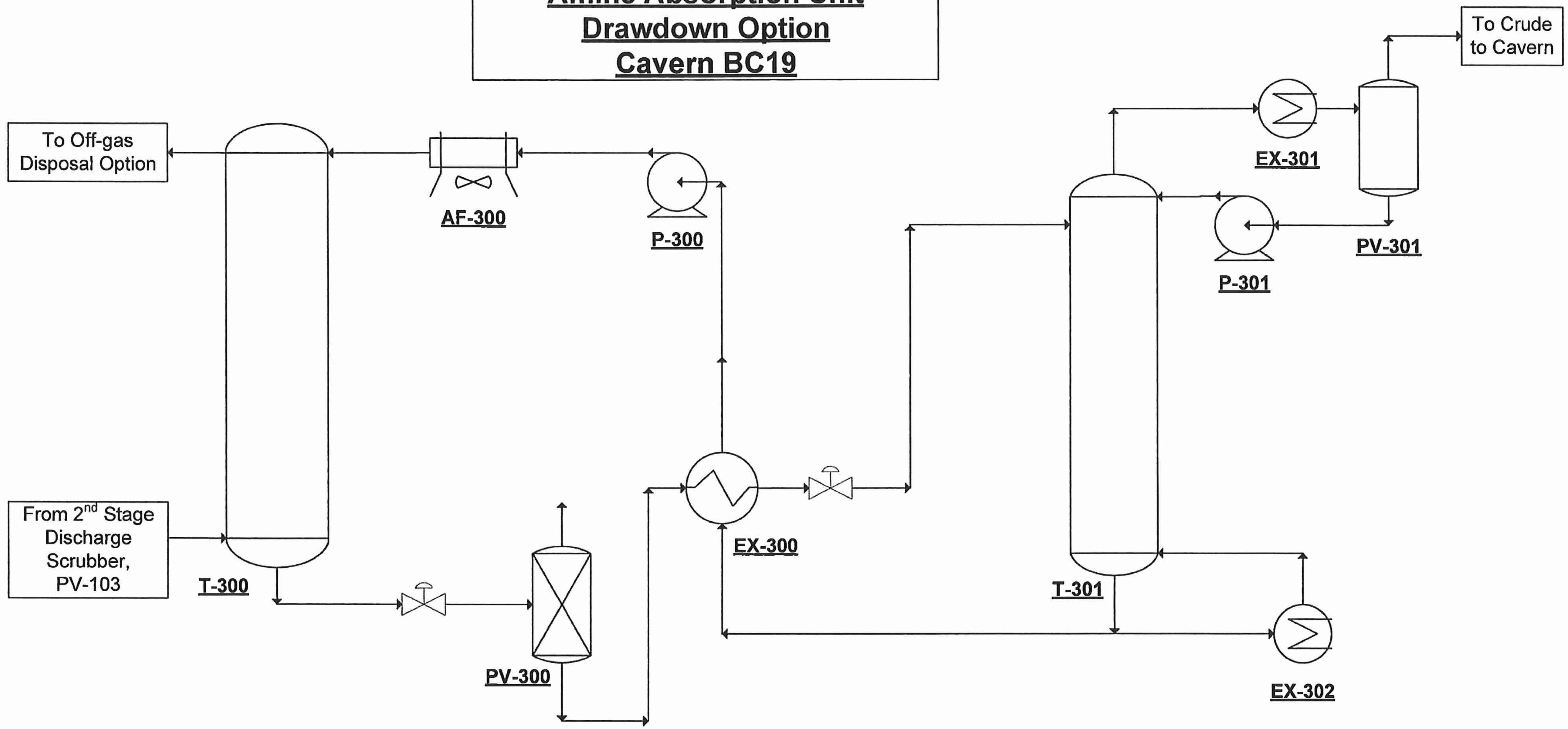
PV-200
Injection Water Seperator

18" ID x 4'-6" S/S

PV-201
H2S Absorber

108" ID x 18'-0" S/S

Amine Absorption Unit
Drawdown Option
Cavern BC19

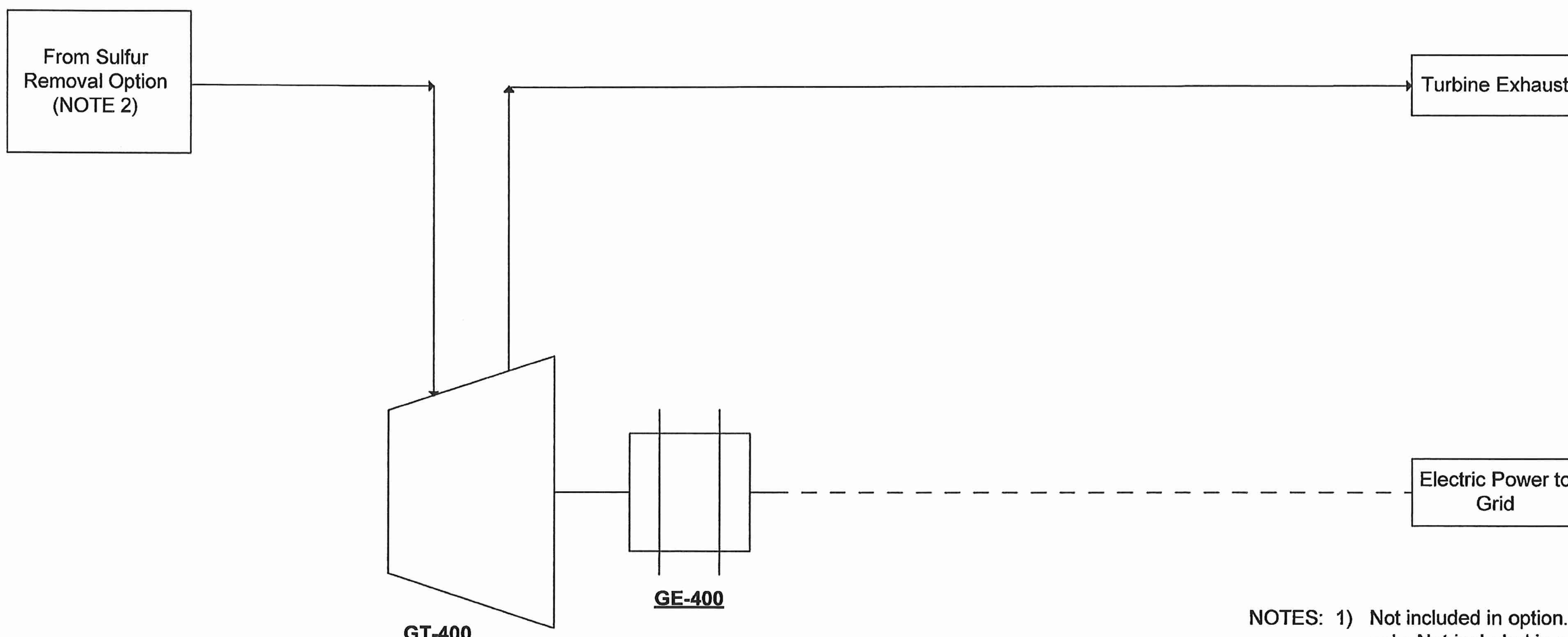


T-300 Absorber	**PV-300 Flash Tank**	**EX-300 Rich/Lean Exchanger**	**T-301 Stripper**	**P-300 Recirculation Pump**
16" ID x 20'-0" S/S	24" ID x 72" S/S	Duty: 0.45 MMBTU/HR	16" ID x 15'-0" S/S	10 GPM at 75 PSI dP 0.75 Motor HP

AF-300 Amine Cooler	**EX-301 Stripper Condenser**	**EX-302 Stripper Reboiler**	**P-301 Reflux Pump**	**PV-301 Reflux Accumulator**
Duty: 0.15 MMBTU/HR	Duty: 0.30 MMBTU/HR	Duty: 0.72 MMBTU/HR	10 GPM at 75 PSI dP 0.75 Motor HP	16" ID x 36" S/S

Power Generation Drawdown Option

(NOTE 1)

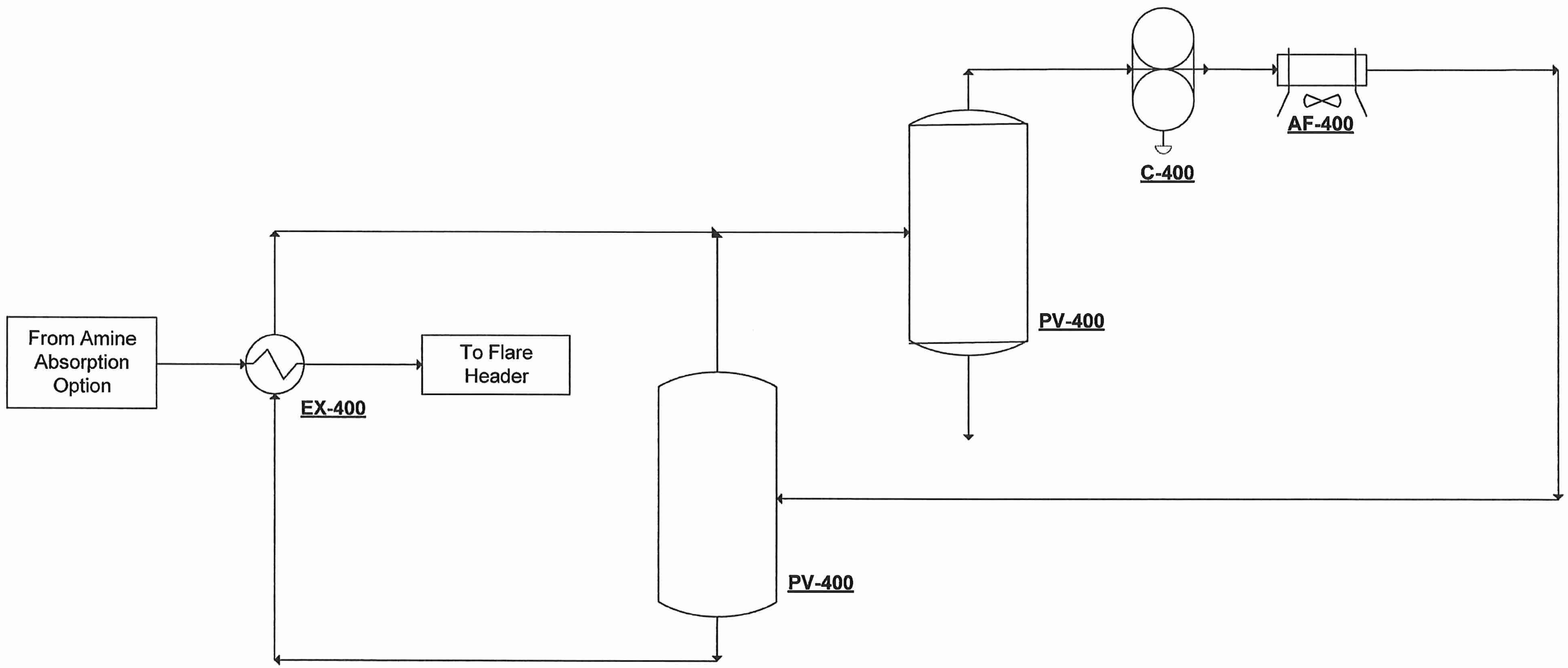


NOTES: 1) Not included in option. Shown for reference only. Not included in major equipment total.
2) BC102 sets design requirements for GT-400 and GE-400.

GT-400
Off-gas Turbine
BHP: 3749

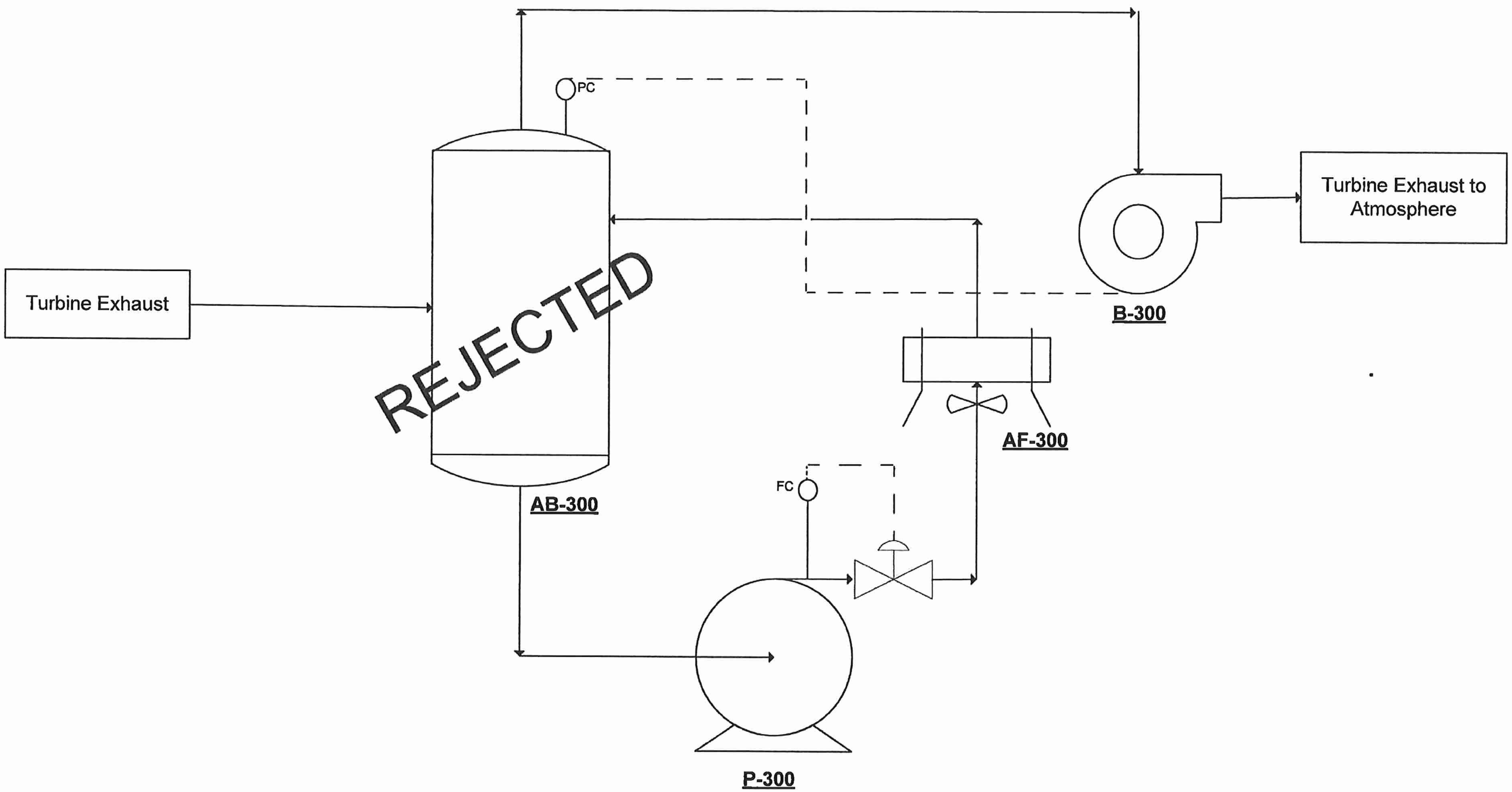
GE-400
Off-gas Generator
MW: 2.516

Drawdown Refrigeration Package



C-400 Refrigeration Compressor	AF-400 Refrigerant Condenser	PV-400 Refrigerant Suction Scrubber	PV-401 Refrigerant Economizer	EX-400 Evaporator
5.1 ACFM at XX PSI dP BHP: 2.5 HP	Duty: 20,000 BTU/HR	6" ID x 1'-6" S/S	6" ID x 1'-6" S/S	Duty: 14,000 BTU/HR

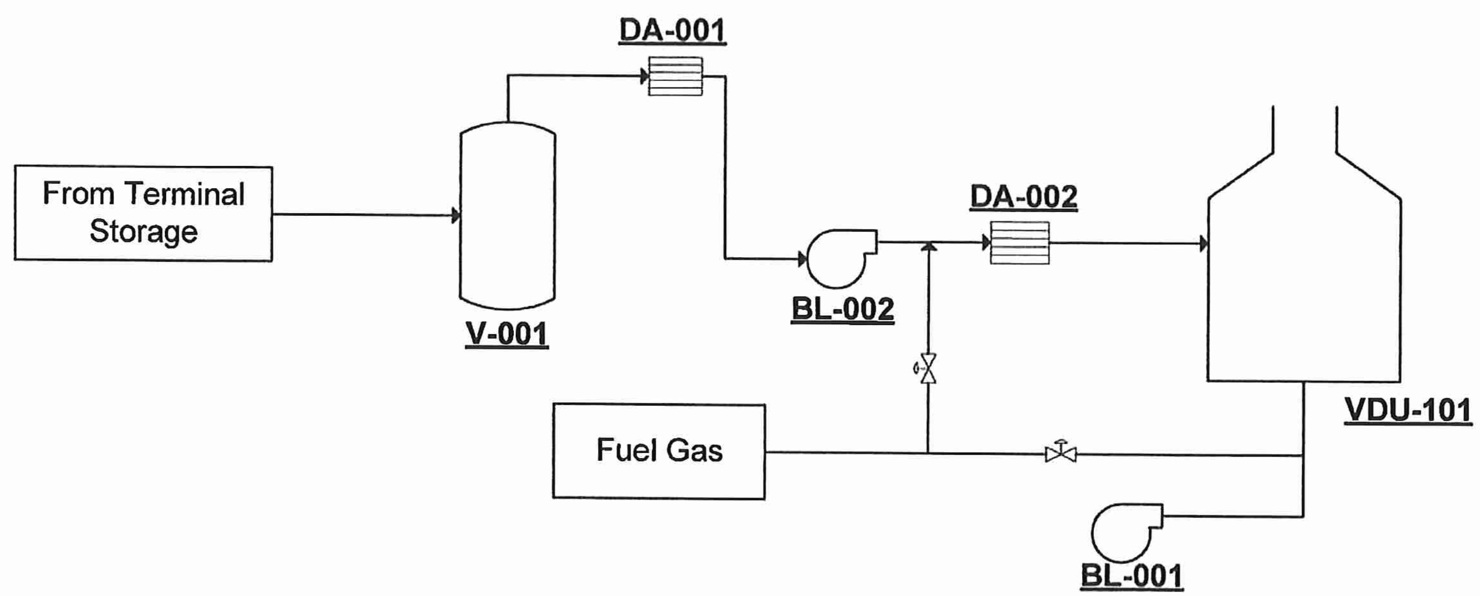
Exhaust Gas Clean-Up Drawdown Option



B-300	**AB-300**	**P-300**	**AF-300**
Turbine Exhaust Blower	**Exhaust Gas Absorber**	**Absorber Circulation Pump**	**Absorber Recirculation Cooler**
X" H20 at XXX ACFM BHP:	X" ID x X'-X" T/T	XXX FT. Head at XXX GPM	Duty: XXX BTU/HR

REPORT-C-20
Rev. 0, 01/21/2016

Drawdown Option at Terminal
(NOTE 1)



NOTE: 1) Typical of 3 units.

BL-001
Combustion Air Blower
XX ACFM at X PSI dP
BHP: 5 HP

BL-002
Vapor Blower
915 ACFM at 5 PSI dP
BHP: 50 HP

V-001
Liquid Knockout Drum
36" ID x 8'-0"

DA-001
Upstream Detonation Arrestor
8" ID

DA-002
Downstream Detonation Arrestor
8" ID

VDU-101
Vapor Destruction Unit
132" ID x 60'-0"

REPORT-C-21A
Rev. 0, 01/21/2016

Client:	VCI/US Department of Energy		Job No.:	38988843
Project:	SPR Bayou Choctaw Degas	MECHANICAL EQUIPMENT LIST	By:	EAO
Location:	Bayou Choctaw, LA	URS	Rev:	B
			Date:	1/14/16

Reference Drawing from Appendix C of Conceptual Design Report	TAG #	DESCRIPTION	Note	NUMBER OF ITEMS	MATERIAL OF CONST.	SIZE Diameter or Width, ft	SIZE Length, ft	DIFF HEAD ft	SIZE (each) GPM (normal)	DIFF PRESS psi	DEAD HEAD PRESS psi	WEIGHT (each) lb, empty	DUTY MMBTU/hr	U BTU/hr/ft2-°F	SIZE (each) ft2	UA (each)	TYPE	BRAKE HORSEPOWER hp	MOTOR HORSEPOWER hp/volts	MOTORS PER UNIT	SHELL DESIGN MAWP psig	SHELL DESIGN TEMP °F	TUBE DESIGN MAWP psig	TUBE DESIGN TEMP °F	EQUIPMENT COST
DRAWDOWN VDU AT ST. JAMES TERMINAL																									
	VDU-101	Vapor Destruction Unit		1		11'-0"	60'-0" el.		915																$980,659
	BL-001	Combustion Air Blower		1														5	7.5						
	BL-002	Vapor Blower		1					915	5								50	75						$105,133
	DA-001	Upstream Detonation Arrestor		1		8"																			$51,680
	DA-002	Downstream Detonation Arrestor		1		8"																			$51,680
	V-001	Liquid Knockout Drum		1		3'-0"	8'-0"																		$108,867
	VDU-102	Vapor Destruction Unit		1		11'-0"	60'-0" el.		915																$980,659
	BL-003	Combustion Air Blower		1														5	7.5						
	BL-004	Vapor Blower		1					915	5								50	75						$105,133
	DA-003	Upstream Detonation Arrestor		1		8"																			$51,680
DRAWDOWN VDU AT ST. JAMES TERMINAL, page C-20	DA-004	Downstream Detonation Arrestor		1		8"																			$51,680
	V-002	Liquid Knockout Drum		1		3'-0"	8'-0"																		$108,867
	VDU-103	Vapor Destruction Unit		1		11'-0"	60'-0" el.		915																$980,659
	BL-005	Combustion Air Blower		1														5	7.5						
	BL-006	Vapor Blower		1					915	5								50	75						$105,133
	DA-005	Upstream Detonation Arrestor		1		8"																			$51,680
	DA-006	Downstream Detonation Arrestor		1		8"																			$51,680
	V-003	Liquid Knockout Drum		1		3'-0"	8'-0"																		$108,867
		Major Equipment Total																							$3,894,057
	Non-equipment	Storage Tank Modifications		6																					$42,500,000
	Non-equipment	Interconnecting Piping		1		10"	Various																		$1,592,285
		TIC Total																							$50,727,275.70

APPENDIX D

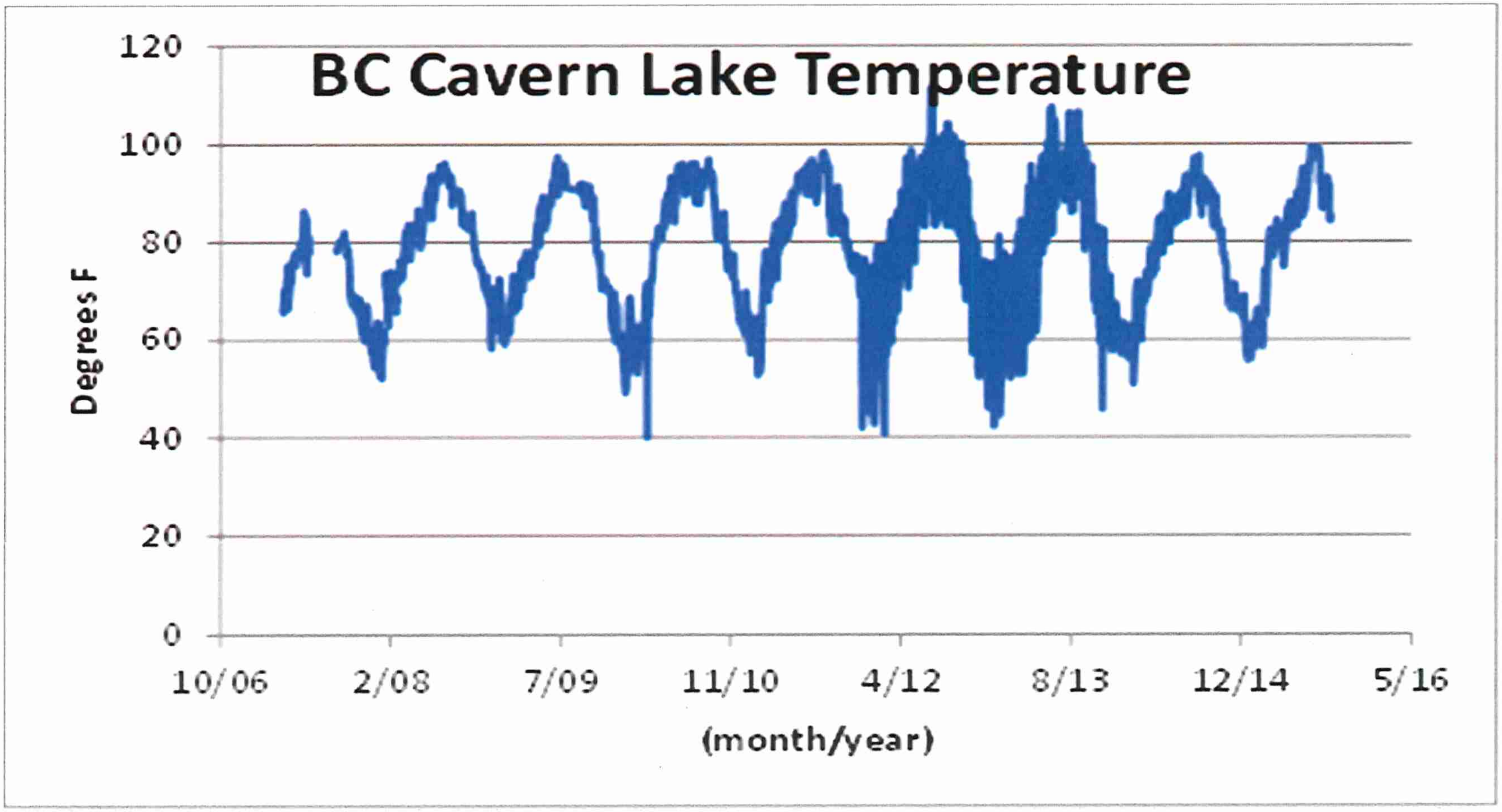
COOLING OPTION DATA

D-2 Cavern Lake Recorded Temperatures at BC

Cavern Lake temperatures referenced in the attached graph are for the period from October 2006 to October, 2015 and are taken from the current BC Data Historian as read at Point ID4R000TI70 at the intake sump. Temperatures used for the cooling option analysis are based on minimum recorded temperatures for the period of April 2014 to March 2015, as indicated from this data. Even using these minimum temperatures to provide the most ideal conditions for cooling could not enable this option to meet performance criteria.

D-3 Dry Bulb and Wet Bulb Temperatures for BC

The wet bulb temperatures taken from the literature and tabulated here were used to determine cooling tower water supply temperatures to the exchanger used to the crude oil from cavern storage. This was used to evaluate the cooling option with cooling tower water. Dry bulb temperatures were used to determine that air cooling of the oil was not an option during the warmer months.


BC Cavern Lake Temperature
Degrees F
120
100
80
60
40
20
0
10/06
2/08
7/09
11/10
4/12
8/13
12/14
5/16
(month/year)

DRY BULB AND WET BULB TEMPERATURES

Bayou Choctaw Cavern Location

Month	Dry Bulb °C	Wet Bulb °C
January	25.2	20.2
February	26.3	19.9
March	28.5	20.4
April	30.4	21.6
May	33.3	24.2
June	34.9	25.1
July	35.5	25.7
August	35.8	25.4
September	34.6	24.6
October	31.8	23.4
November	28.2	21.8
December	26.1	21.4

APPENDIX E

PROJECTED SEASONAL VAPOR PRESSURE IMPACTS

The following charts illustrate the impact of seasonal variations in ambient temperature on the vapor pressure of both BC sweet and BC Sour crude oil at the terminal should a drawdown occur during the months indicated.

Projected Seasonal Vapor Pressure Impacts
Oct-15
CURRENT

treams	Oct 15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16
BC SW	OK-GOR	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR
BC SO	OK GOR	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR

treams	Oct 16	N v-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr- 7	May- 7	Jun-17	Jul- 7	Aug- 7	Sep- 7
BC SW	OK-GOR	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR
BC SO	OK-GOR	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR

Streams	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18
BC SW	OK-GOR	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR
BC SO	OK-GOR	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR

Streams	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19
BC SW	OK-GOR	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR
BC SO	OK-GOR	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR

Streams	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20
BC SW	OK-GOR	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR
BC SO	OK-GOR	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR

Streams	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21
BC SW	OK-GOR	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR
BC SO	OK-GOR	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR

Streams	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22
BC SW	OK-GOR	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR
BC SO	OK-GOR	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR

	Historical Data
OK	BP <= 14.7 psi
OK-GOR	BP > 14.7 psi GOR <= 0.6 scf/bbl, H_2S Scavenger Required
Note 1	GOR > 0.6 scf/bbl

* Original data basis from the 4th Quarter Vapor Pressure Model, August 2015

Projected Seasonal Vapor Pressure Impacts
Oct-15
BC Cooling

Streams	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16
BC SW	OK-GOR	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR
BC SO	OK-GOR	OK	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR

Streams	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17
BC SW	OK-GOR	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR
BC SO	OK-GOR	OK	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR

Streams	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18
BC SW	OK-GOR	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR
BC SO	OK	OK	OK	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR

Streams	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19
BC SW	OK-GOR	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR
BC SO	OK	OK	OK	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK

Streams	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20
BC SW	OK-GOR	OK	OK	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR
BC SO	OK	OK	OK	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK

Streams	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21
BC SW	OK	OK	OK	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK
BC SO	OK	OK	OK	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK

Streams	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22
BC SW	OK	OK	OK	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK
BC SO	OK	OK	OK	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK

	Historical Data
OK	BP <= 14.7 psi
OK-GOR	BP > 14.7 psi GOR <= 0.6 scf/bbl, H_2S Scavenger Required
Note 1	GOR > 0.6 scf/bbl

* Original data basis from the 4th Quarter Vapor Pressure Model, August 2015

REPORT-E-3
Rev 0, 01/21/2016

Projected Seasonal Vapor Pressure Impacts
Oct-15
BC Cooling with 2σ Regain

Streams	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16
BC SW	OK-GOR	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR
BC SO	OK-GOR	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR

Streams	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17
BC SW	OK-GOR	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR
BC SO	OK-GOR	OK	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR

Streams	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18
BC SW	OK-GOR	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR
BC SO	OK-GOR	OK	OK	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR

Streams	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19
BC SW	OK-GOR	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR	OK-GOR
BC SO	OK	OK	OK	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR

Streams	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20
BC SW	OK-GOR	OK	OK	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR
BC SO	OK	OK	OK	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR

Streams	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21
BC SW	OK	OK	OK	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR
BC SO	OK	OK	OK	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR

Streams	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22
BC SW	OK	OK	OK	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR
BC SO	OK	OK	OK	OK	OK	OK	OK	OK	OK-GOR	OK-GOR	OK-GOR	OK-GOR

	Historical Data
OK	BP <= 14.7 psi
OK-GOR	BP > 14.7 psi GOR <= 0.6 scf/bbl, H_2S Scavenger Required
Note 1	GOR > 0.6 scf/bbl

* Original data basis from the 4th Quarter Vapor Pressure Model, August 2015

APPENDIX F

LIFE CYCLE COST COMPARISONS

The following table compares the seven options evaluated over a 20 year life cycle. It provides the economic justification for selecting the degassing option over those options that rely on strictly cooling.

LIFE CYCLE COST COMPARISONS
Option Evaluation

Cost Category	Cavern Lake Water Cooling	Aquifer Water Cooling	Cooling Tower Cooling	Chilled Water Cooling	In-Storage Degassing	Drawdown Degassing	Drawdown VDU at St. James
Equipment TIC (1)	$38,436,212	$13,071,515	$39,510,212	$69,336,400	$18,800,285	$30,505,485	$50,727,276
Cavern Wells & Workovers	$84,000,000 (2)	$84,000,000 (2)	$84,000,000 (2)	$84,000,000 (2)	$2,460,000 (3)	$0	$0
Water Wells (4)	$0	$1,520,000	$0	$0	$0	$0	$0
Electrical Power	$4,010,932 (5)	$17,448,523 (6)	$4,127,472 (5)	$11,873,677 (6)	$606,572 (7)	$560,188 (8)	$16,476 (8)
OPEX	$52,833,236 (9)	$10,457,212 (9)	$31,608,170 (9)	$55,469,120 (9)	$2,106,948 (9)	$18,579,332 (10)	$18,963,365 (10)
Holding Pond & Treatment Plant (11)	$27,605,333	$0	$0	$0	$0	$0	$0
H2S Scavenger Usage	$16,000,000 (12)	$16,000,000 (13)	$16,000,000 (12)	$16,000,000 (13)	$0	$0	$0
Total Life Cycle Cost (20 yrs)	**$222,885,713**	**$142,497,250**	**$175,245,854**	**$236,679,197**	**$23,973,805**	**$49,645,005**	**$69,707,117**

Notes (1) TIC is a factored estimate based on 4.0 times equipment cost.
(2) One new well/cavern at $14,000,000/well for six caverns
(3) $10,000/well for initial string cuts plus $400,000/well for workover to restore string for six caverns.
(4) Six producing wells with pumps plus four injection wells.
(5) Average cost of peak and off-peak for winter at $0.01864/kw-hr.
(6) Average yearly cost of $0.03235/kw-hr.
(7) Average yearly cost of $0.03235/kw-hr for 1023 processing days.
(8) Average yearly cost of $0.03235/kw-hr for one drawdown.
(9) 4% of equipment TIC.
(10) Includes $900,000 per year to retain 8 trained operators, 1/2 instrument technician, 1/2 rotating equipment technician
(11) Sizing based on 24 hour retention time for holding pond, 33 days of processing for treatment plant.
(12) Scavenger usage likely to be required if drawdown occurs during warmest 7 months of the year.
(13) Scavenger usage likely to be required if drawdown occurs during warmest 3 months of the year.

APPENDIX G

DEGASSING OPTION EVALUATION

As discussed, degassing by single stage flash, similar to past SPR processing configurations, suffices to satisfy the crude oil processing objectives to address the high Bayou Choctaw bubble point pressure of the inventoried crude oil. The attached table summarizes the three degassing options examined and establishes the rational for selecting the ones for cost estimating.

Option Description	Alternatives	Pursue	Discussion	Relative Cost[1]
In-Storage Degassing	Relocate Degas II	No	Relocation feasible but not recommended given high capital cost associated with reuse: • High capital cost for refurbishing equipment including piping, electrical, and controls which are now at end of life to service Bayou Choctaw (BC) • High capital cost for re-engineering system to fit plot space at BC due to larger equipment size. • High capital cost for relocating equipment to BC • Combined capital costs likely to exceed 50-60 % of new unit. Recommend against refurbishment and relocation in favor of new unit.	50 – 60 % Base Capex Base Opex
	Engineer New Degassing Unit	Yes	Build new system to address logistics of degassing Bayou Choctaw (BC): • Capture capital cost reduction associated with reduction in processing rate relative to Degas II design • Secure capital cost reduction associated with design and operation of smaller unit relative to Drawdown • Consider major equipment reuse where equipment sizes compatible and in good condition • Size and arrange equipment to fit into available plot space within the existing fence line. Recommend proceeding with development of option to build new unit for in storage degassing on site at Bayou Choctaw.	Base Capex Base Opex

Option Description	Alternatives	Pursue	Supporting Argument	Relative Cost[1]
Drawdown Degassing at BC	Locate at Bayou Choctaw	Yes	Build new system with equipment sized for Drawdown: • Higher capital cost associated with larger equipment sizing for Drawdown rate • Size and arrange larger equipment to fit into available plot space within fence line of Bayou Choctaw site • Location off-site at Bayou Choctaw not recommended given extra costs associated with current landowner issues, lease costs, and costs of securing site outside existing fence line. Recommend proceeding with development of option to build new unit for Drawdown degassing on site at Bayou Choctaw.	Hi Capex Hi Opex
Drawdown Degassing at Terminal	Locate at terminal	No	Location at terminal feasible but not recommended given potentially high capital cost of equipping a remote terminal: • Oil movement logistics complicated by offtake bidding process • Processing logistics complicated by two offtake routes across three terminals • High operating costs associated with staffing and operating degassing units at a remote terminal • Significant reduction in system readiness/reliability associated with surrendering control to third parties at the terminals. Recommend against Drawdown degassing at terminal in favor of degassing on site at Bayou Choctaw. Consideration given to installation of geodesic domes on storage tanks together with vapor destruction units at remote terminal.	Hi Capex Hi Opex

[1]Capex = capital expenditures; Opex = operating expenditures. Hi/Lo values cited are qualitative comparison statements relative to base case identified in table.

APPENDIX H

DEGASSING OPTIMIZATION ALTERNATIVES

The development of the preferred degassing process configuration will entail optimization of several process alternatives to determine the most reliable and cost effective configuration within operational and environmental constraints. Some of these options are summarized below with recommendations on which to carry forward to finalize the degassing unit design.

Option Description	Alternatives	Pursue	Discussion	Relative Cost[1]
Mitigate H_2S Emissions	Liquid Scavenger Injection into Crude	Yes	Currently practiced method to chemically fix H2S in exported crude oil: • Applicable to In -Storage or Drawdown • High chemical cost • Carry over as upper bound economic constraint on solutions • Strive to reduce and eliminate scavenger consumption to cut costs	Lo Capex Hi Opex
	Amine Treating with Acid Gas Reinjection into Crude	Yes	Well accepted practice for capturing and removing H2S from gas streams: • Applicable to In-Storage or Drawdown • Amine regenerated in process to minimize amine consumption • High capital and operating costs • Continuous operation with respect to scavenger use • Requires third party monitoring of amine quality to ensure smooth operation • Generates no new process waste streams • Avoids many of the safety and environmental issues associated with alternative methods of handling and disposal of H2S.	Hi Capex Hi Opex
	Solid Bed Scavenger	Yes	Alternative approach to amine treating: • Applicable to In-Storage or Drawdown • Scavenger not typically regenerable • High operating cost • Batch operation with respect to scavenger use • Requires third party change out of spent scavenger on periodic basis • Waste generation and disposal are not appealing from an environmental standpoint. • Metals reclamation from spent scavenger required to make use.	Hi Capex Hi Opex

Option Description	Alternatives	Pursue	Discussion	Relative Cost[1]
Mitigate H_2S Emissions (Cont'd)	Liquid Bed Scavenger	No	Alternative approach to amine treating: • Applicable to In-Storage or Drawdown • Scavenger not typically regenerable • High operating cost • Typically batch operation with respect to scavenger consumption • Oily waste generation and disposal are not appealing from an environmental standpoint.	Hi Capex Hi Opex
	Incineration	Yes	Commonly practiced method of H2S disposal: • Applicable to In-Storage or Drawdown • Requires combustion or incineration equipment designed for high H2S thermal destruction efficiency • Subject to permit limits on NO_x and SO_x emissions • Not appealing from an environmental standpoint for the disposal of H2S rich streams • Better suited to disposal of H2S lean (treated) streams to minimize emissions from an environmental standpoint.	Base Capex Base Opex
Removal and Disposal of Gas On-site	Incineration	Yes	Commonly practiced method of treated gas disposal: • Applicable to In-Storage or Drawdown • Subject to permit limits on NO_x and SO_x emissions • May require amendment to Bayou Choctaw air emissions permit • May require purchase of credits to offset emissions.	Base Capex Base Opex
Removal and Disposal of Gas On-site (Cont'd)	Sell as Fuel Gas	No	Produced gas cannot be sold as fuel gas given the low methane content and higher butane plus content.	
	Sell as Y-grade	No	Production rates of Y-grade during Drawdown and In-Storage are not sufficiently high to be commercially viable.	
	Generate Power	Yes	Alternative to incineration: • Philosophically more appealing than simply incinerating gas	Hi Capex Lo Opex

Option Description	Alternatives	Pursue	Discussion	Relative Cost[1]
Removal and Disposal of Gas On-site (Cont'd)	Generate Power (Cont'd)		• Requires composition adjustment by blending with purchased fuel gas for combustion in lean gas turbines or reciprocating engines. • Applicable to the In-Storage option • Cannot be applied to the Drawdown option with reasonable reliability.	
Crude Oil Cooling[2]	No Cooling	No	Crude oil cooling is required to recover 95% of propane from cavern BC102.	
	In Cavern Cooling	No	Cannot achieve bubble point pressure (BPP) target of 14.7 psig at 93 °F for all caverns by cooling alone.	
	Use Existing Heat Exchangers	Yes	The existing heat exchangers provide sufficient surface area if water is cooled to 85 °F.	Base Capex Base Opex
	Air Cooling	No	Air cooling cannot cool crude oil sufficiently to recover 95% propane from cavern BC102 year around.	
	Wet Surface Air Cooling (WSAC)	Yes	Applicable to In-Storage or Drawdown options although its use must be economically justified against a conventional cooling tower for the Drawdown option.	Base Capex Base Opex
	Once-through Water Cooling with Lake Water	Yes	Application limited by environmental limitations: • Suitable for once-through cooling of crude oil in Drawdown option when water routed to cavern as brine in line with current practice • Not suitable for once-through cooling of crude oil in In-Storage option given threats of high outfall water temperature and potential oil leakage into outfall.	Lo Capex Lo Opex
	Recirculated Water Cooling with Lake Water	Yes	Applicable to In-Storage or Drawdown options with installation of cooling tower and recirculating water system	Base Capex Base Opex
	Tempered Water Cooling	No	A cooling water temperature of 85 °F is achievable without tempered water cooling and is sufficiently cool to achieve process objectives.	
	Chilled Water Cooling	No	A cooling water temperature of 85 °F is achievable without chilled water cooling and is sufficiently cool to achieve	

			process objectives.	
Option Description	**Alternatives**	**Pursue**	**Discussion**	**Relative Cost[1]**
Crude Oil Cooling (Cont'd)[2]	Heating and Cooling	No	Heating not required as cavern temperatures are high enough to degas to meet bubble point pressure (BPP) requirement.	

[1]Capex = capital expenditures; Opex = operating expenditures. Hi/Lo values cited are qualitative comparison statements relative to base case identified in table.

[2]Only the effects of crude oil cooling upon the capability to satisfy the BPP and propane recovery design parameters are examined here. Options to reconfigure flash pressure, gas cooling, gas compression, and gas cleanup within the In-Storage and Drawdown degassing options to economically optimize the respective flowsheets on propane recovery within reliability constraints is deferred to the next study phase.

APPENDIX I

LIFE CYCLE COST COMPARISONS DEGASSING TECHNOLOGY ALTERNATIVES

The following life cycle cost analysis compares three alternatives for mitigating the hydrogen sulfide content of the crude to eliminate the scavenger. In addition, life cycle costs are compared for two alternatives for utilizing the off-gas produced by the degassing process. The results of these initial comparisons provide guidance for optimizing degassing unit design going forward.

LIFE CYCLE COST COMPARISONS
In-Storage Degassing Technology Alternative Evaluation

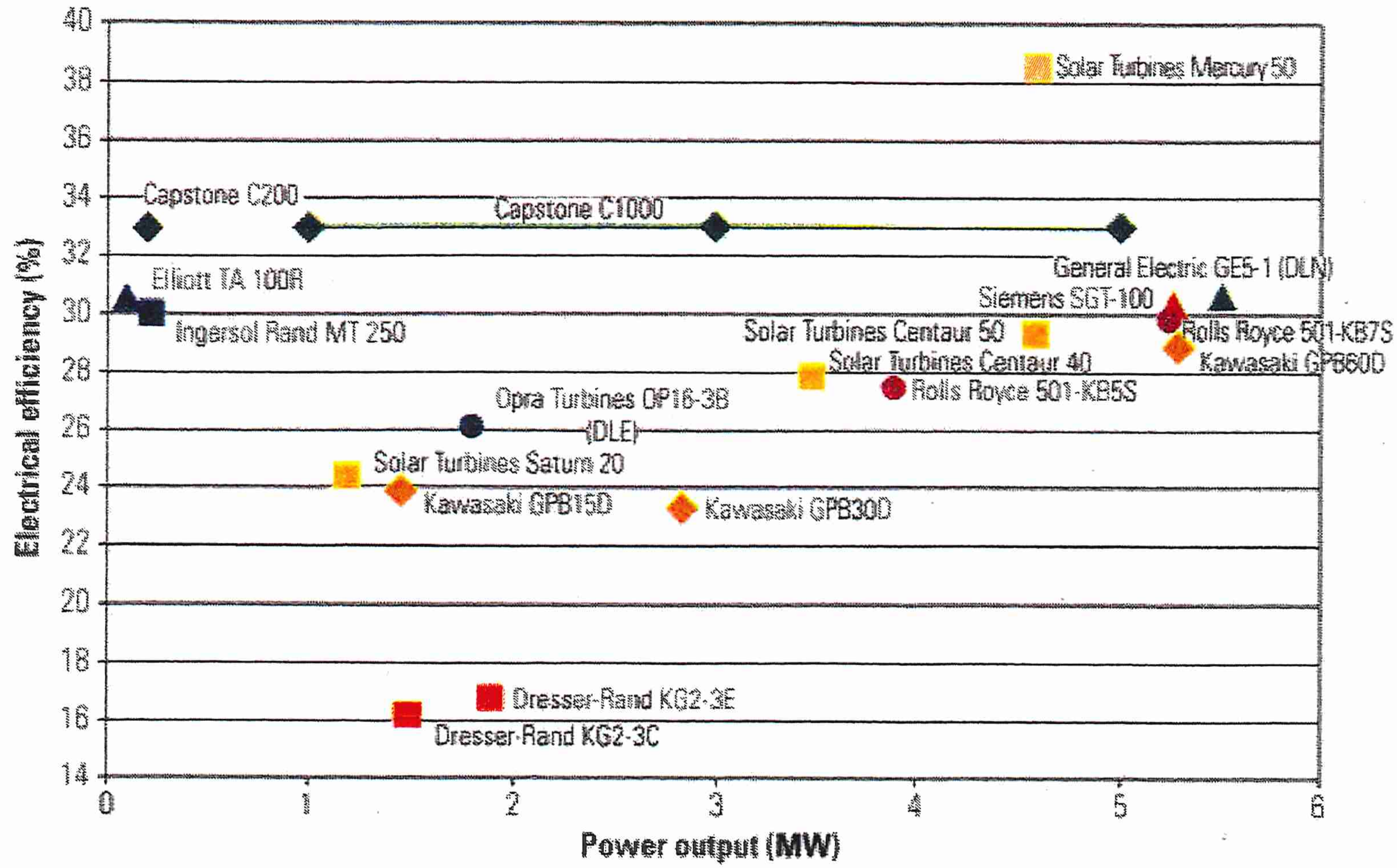
Cost Category	Amine Treating with Acid Gas Reinjection	Solid Fixed Bed Scavenger	LoCat	Refrigeration	Power Generation	
Equipment TIC	$1,382,780 (2)	$272,000 (2)	$8,000,000 (1)	$53,040 (2)	$2,213,910 (2)	
Fuel, Catalyst, or Chemicals		$2,482,317 (3)	$82,744 (4)		$14,270 (8)	
Disposal (5)		$530,000	$82,800			
Electrical Power (6)	$888		$121,797	$1,481	($816,773)	
OPEX (7)	$55,311	$10,880	$320,000			
Improved Product Yield				($990,653) (9)		
Total Life Cycle Cost (20 yrs)	**$1,438,980**	**$3,295,197**	**$8,607,341**	**($936,133)**	**$1,411,407**	

Notes (1) TIC is a factored estimate based on 4.0 times equipment cost.
(2) TIC is a factored estimate based on 1.7 times equipment cost.
(3) $3/lb sulfur removed
(4) $0.10/lb sulfur removed
(5) $200/ton disposed
(6) Average yearly cost of $0.03235/kw-hr for 1052 processing days.
(7) 4% of equipment TIC.
(8) Supplemental Fuel Gas at $2.41/MMBTU (Nymex 11/16/2015 value for December 15, 2015 Contract) for 1052 processing days.
(9) Crude value at $44.62/bbl (ICE 11/16/2015 value for January, 2016 contract), propane recovery from 95% to 99.3%

APPENDIX J

TURBINE DRIVEN GENERATOR SIZES BY MANUFACTURERS

The attached graph taken from an article in Power magazine, 11/01/2010, "Microturbine Technology Matures", by Stephen Gillett, summarizes commercial micro-turbine sizing based on recently available suppliers. Micro-turbines are one option for power generation for the proposed degassing process. Micro-turbine development for commercial application has come a long way in recent years. The plotted results show what may be possible for degassing process design.


Electrical efficiency (%)
Power output (MW)
40
38
36
34
32
30
28
26
24
22
20
18
16
14
0
1
2
3
4
5
6
Capstone C200
Capstone C1000
Elliott TA 100R
Ingersol Rand MT 250
Opra Turbines OP16-3B (DLE)
Solar Turbines Saturn 20
Kawasaki GPB15D
Kawasaki GPB30D
Solar Turbines Mercury 50
General Electric GE5-1 (DLN)
Siemens SGT-100
Solar Turbines Centaur 50
Solar Turbines Centaur 40
Rolls Royce 501-KB5S
Rolls Royce 501-KB7S
Kawasaki GPB60D
Dresser-Rand KG2-3E
Dresser-Rand KG2-3C

APPENDIX K

POWER GENERATION SUPPLY AND DEMAND

The attached tables provide a quick snapshot of the potential value of installing micro-turbines to supply power for the degassing process. The tables summarize potential power supply from burning the sweetened off-gas relative to the electrical load required to run the degassing unit. These values should be considered preliminary for the sole purpose of estimating the potential value of power generation.

	Power from Grid at Drawdown	**In-Storage Power from Grid**
Equipment Reference	**Appendix C, C-13B**	**Appendix C, C-6B**
Consumers	**BHP**	**BHP**
P-100	5214	914.5
AF-100	5	5.0
AF-101	5	5.0
AF-300	0.5	0.5
C-100	62	3.9
C-101	46	N/A
CT-100	120	20.0
P-101	0.07	0.4
P-102	N/A	0.3
P-104	186	86.4
P-300	0.73	0.7
P-301	0.73	0.7
C-400	44.2	2.5
BL-100	30.00	15.0
Total	**5714**	**1037**
	KW	**KW**
Total Consumers	4261	774
Generator GT-400	2796	959
Power from Grid	**1465**	**(185)**

APPENDIX L

COOLING OPTIONS WITH SINGLE STAGE FLASH

The attached table traces the conceptual value of crude oil cooling to bring the Bayou Choctaw (BC) crude oil back on spec with respect to the target bubble point pressure for crude oil sale. The basic process receives oil from the cavern which is passed through heat exchange with the cooler water injected into the cavern to remove the oil. The cooled oil is then introduced into a gas/liquid separator at low pressure to remove enough off-gas to control crude BPP or propane recovery. A single stage flash with and without cooling is considered. The conclusion reached, based on this data, is that simply cooling the crude oil to bring it to BPP specification will not work for all caverns.

COOLING WITH SINGLE STAGE FLASH

Operating Condtion		Parameter	BC15	BC17	BC18	BC19	BC101	BC102
Cool to BPP of 14.7 psia	(1)	Temperature at Flash Drum-°F	87	98	90	78	72	68
Cool to 93 °F at 14.7 psia	(2)	C3 Recovery off Flash Drum-%	99.7	100.0	99.8	99.3	99.1	97.5
No Cooling	(3)	C3 Recovery off Flash Drum-%	98.3	98.9	95.9	97.6	97.6	89.8
No Cooling	(4)	Degassed Crude BPP at 93 °F-psi	12.7	12.6	11.52	12.7	12.8	13.2
No Cooling	(5)	Volume Loss_%	0.04	0.02	0.10	0.06	0.06	0.13
Cool to Recover 95% C3	(6)	Temperature at Flash Drum-°F	n.a.	n.a.	n.a.	n.a.	n.a.	103
Maximum Drawdown with No Cooling	(7)	Drawdown Rate-bpd	515,000	515,000	300,000	515,000	515,000	300,000
Maximum Drawdown with No Cooling	(8)	Offgas Rate-acfm	299	184	428	402	431	579

Notes:
(1) Flash drum is operating at a pressure of 14.7 psia and cold enough to eliminate off-gas.
(2) Flash drum is operating at a pressure of 14.7 psia and at 93 °F. Propane recovery is greater than 95% for all caverns.
(3) Crude cooler is bypassed. Propane recovery is greater than 95% for all caverns but BC102.
(4) Crude cooler is bypassed. BPP is less than 14.7 psia for all caverns.
(5) Crude cooler is bypassed. Volume %loss is less than 0.3% for all caverns.
(6) Crude from BC102 must be cooled to 103 °F to recover 95% propane. Other caverns require no cooling.
(7) Rate used for the analysis.
(8) Off-gas produced from the flash drum at the crude rate used in the analysis with no cooling.

APPENDIX M

BUBBLE POINT PRESSURE AND % PROPANE RECOVERY BY COOLING OPTIONS

The attached table traces the conceptual value of crude oil cooling to bring the Bayou Choctaw (BC) crude oil back on spec with respect to the targeted propane recovery to minimize crude oil value loss in degassing the oil. The basic process receives oil from the cavern which is passed through heat exchanger with the cooler water injected into the cavern to recover the oil. The cooled oil is then introduced into a gas/liquid separator at low pressure to remove enough off-gas to control crude bppp and propane recovery. The options consider using no cooling before the flash which results in low propane recovery from BC102. Cooling with 85 °F cooling water is still not sufficient to achieve a 95% propane recovery. The final option compresses and condenses a portion of the off-gas to meet both the BPP and propane recovery targets. These results show that crude oil cooling can be used in combination with degassing at atmospheric pressure to achieve both targets. The results also show that cooling is necessary at one or more points in the degassing process (at the front end, at the back end, or both) to achieve the targeted propane recovery.

BAYOU CHOCTAW PROCESS PARAMETERS DURING DRAWDOWN							
CASE DESCRIPTION	PARAMETER	BC15	BC17	BC18	BC19	BC101	BC102
Case 1: No Cooling Followed by Flash	BPP at 93 F	12.7	12.6	11.7	12.7	12.7	11.6
	% C3 Recovery	98.3	99.0	95.8	97.7	97.5	89.8
Case 2: Cooling with 85 F CWS Followed by Flash	BPP at 93 F	13.4	13.3	13.0	13.4	13.4	13.0
	% C3 Recovery	98.5	99.1	97.9	97.9	97.7	93.9
Case 3: Cooling with 85 F CWS Followed by Flash, Compression, and Cooling	BPP at 93 F	13.5	13.4	13.3	13.7	13.7	13.9
	% C3 Recovery	99.1	99.5	98.9	98.7	98.5	97.5

APPENDIX N

IN-STORAGE DEGASSING PROJECT SCHEDULE

The attached project schedule highlights the critical tasks associated with implementation of the In-Storage Degassing option at Bayou Choctaw. The schedule was developed on the following basis:

- Crude inventory is degassed at the rate of 67,500 bpd
- The following inventories are degassed within the times shown in the following schedule.

BC15	18.01 MMbbl
BC17	12.63 MMbbl
BC18	16.91 MMbbl
BC19	13.60 MMbbl
BC101	13.92 MMbbl
BC102	7.54 MMbbl

- 21 days of plant maintenance downtime every 24 months is included.

PROJECT SCHEDULE

Bayou Choctaw In-Storage Degassing Project

Task Name	Duration	Start	Finish	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Bayou Choctaw In-Storage Degassing Project	2703	1/1/2017	5/27/2024										
Engineering	365	1/1/2017	1/1/2018										
Construction	1004	1/1/2018	10/1/2020										
Start-up	92	10/1/2020	1/1/2021										
Degassing Processing	1244	10/1/2020	2/27/2024										
BC101 Degassing	206	10/1/2020	4/25/2021										
BC19 Degassing	201	4/25/2021	11/12/2021										
BC15 Degassing	267	11/12/2021	8/6/2022										
BC102 Degassing	133	8/6/2022	12/17/2022										
BC18 Degassing	250	12/17/2022	8/24/2023										
BC17 Degassing	187	8/24/2023	2/27/2024										
Decommissioning	90	2/27/2024	5/27/2024										

APPENDIX O

IN-STORAGE DEGASSING PLANNING STANDARDS

The following table illustrates which industry standards will be applied to the design of the degassing process during the engineering phase of the project. Note that all ISBL piping is designed to ANSI B31.3 or Refinery Piping Code whereas all OSBL piping is designed to ANSI B31.8.

PLANNING STANDARDS

Bayou Choctaw Degassing Project

Category	Code/Standard
ISBL Piping	ANSI B31.3/Refinery Piping Code/ASME/
OSBL Piping	ANSI B31.8
Pressure Vessels	ASME VIII
Buildings	ANSI
Structural	AISC, ASCE
Electrical	NFPA, NEMA API RP500A, IEEE, ANSI
Sanitary	EPA
Safety	OSHA 1910.119, NFPA, API 520, API 521, ANSI/ISA-S84.01
Fire Protection	UL, NFPA
Air Craft Warning	FAA
Water Pollution	EPA
Air Pollution	EPA
Noise	OSHA
Concrete	ACI
Roads	AI, AASHO
Materials	ASTM, ASME
Mechanical Equipment	NEMA, API
Welding	ASME IX, API 1104
Heat Exchangers	TEMA, ASME, API
Process Heaters	API RP 550 Part III
Spacing	OIA