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Greenhouse Gas Permit Application to Construct a DRI/HBP Plant at La Quinta

Prepared for
voestalpine Texas LLC
Corpus Christi, Texas

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1.0 INTRODUCTION AND BACKGROUND

voestalpine Texas LLC (voestalpine) proposes to build a direct reduced iron (DRI) plant in Corpus Christi in San Patricio County in Texas. A site location map showing the location of the plant with respect to the surrounding vicinity is included in this document.

For greenhouse gases (GHGs), a process overview is presented in the remainder of Section 1. Emission calculations used in this best available control technology (BACT) analysis are presented in Section 2. A regulatory review of potentially applicable federal, state, and local regulations related to GHG emissions is presented in Section 3. The details of the BACT analysis are presented in Section 4. Additional information is included in appendices that have already been provided:

- Appendix A – Emission Rate Calculations;
- Appendix B – Figures; and
- Appendix C – Recently Issued Permits and Pending Applications.

1.1 PROCESS OVERVIEW

1.1.1 General Process Description

The Direct Reduction Iron (DRI) process consists of two main components, a Reformer (to produce the reducing agent) and the DRI reactor (where the reaction occurs). The DRI process converts pre-processed iron oxide pellets into highly metallized iron in the form of direct reduced iron (DRI) or hot briquetted iron (HBI), which are ideal feed materials for high quality steelmaking.

Reformer:
The primary raw material source to produce the reducing gas for the reactor is natural gas. Natural gas is reacted with carbon dioxide and water vapor across a proprietary catalyst to produce a reducing gas rich in carbon monoxide and hydrogen.

The important reforming reactions are:

$CH_4 + CO_2 \rightarrow 2CO + 2H_2$
$CH_4 + H_2O \rightarrow CO + 3H_2$

Both of these reforming reactions are endothermic and therefore require energy in the form of heat input. All heat input into the system will solely be from natural gas combusted on the heat side of the reformer.

Reduction:
Most naturally occurring iron oxide has the chemical composition of hematite, Fe_2O_3, and contains about 30 percent oxygen by weight. In the DRI - process, the

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chemically bonded oxygen in the iron ore is removed at elevated temperatures by reaction with carbon monoxide (CO) and hydrogen (H_2) contained in a reducing gas to produce metallic iron (Fe), while liberating carbon dioxide (CO_2) and water vapor (H_2O). The overall reduction reactions are:

$Fe_2O_3 + 3H_2 \rightarrow 2Fe + 3H_2O$
$Fe_2O_3 + 3CO \rightarrow 2Fe + 3CO_2$

An important property of the reducing gas is the reductant/oxidant ratio, or "gas quality." The quality is a measure of the potential for the gas to reduce iron oxide. The quality is defined as the ratio of reductants to oxidants contained in the gas:

$\text{Quality} = \text{reductant/oxidant ratio} = \text{moles } (H_2 + CO)/\text{moles } (H_2O + CO_2)$

Experience has found that the optimum gas quality for hot, fresh reducing gas should be 10 or higher. Also, to obtain essentially complete reduction, the quality of the spent reducing gas exiting the process should be at least 2. Another important property of the reducing gas is the H_2/CO ratio. Control of the H_2/CO ratio affords thermally balanced reduction reactions since reduction with carbon monoxide is exothermic, and reduction with hydrogen is endothermic. That is, the heat required by the hydrogen reaction is balanced by the heat supplied by the carbon monoxide reaction. Therefore, proper reduction temperatures can be maintained without significant additional heat input from fuel combustion. The typical H_2/CO ratio produced by the reformer is about 1.55:1.

A description of the individual process areas is provided below and the Process Flow Diagrams for the facility are included in Appendix D.

1.1.2 *Iron Oxide Storage and Handling*

Pellets are delivered in the surge bin at the port. After weighing the pellets, a conveyor transports the pellets to the pellet storage area. The pellet storage area is equipped with a stacker/reclaimer and will maintain a sufficient supply for one (1) month of operation. The pellets are weighed and transferred to the oxide day bins. The day bins act as a buffer of prepared oxide that is fed to the shaft furnace.

The day bins then discharge to a screening operation to separate the off-specification fractions from the desired 6-20 mm oxide fractions. The desired oxide fractions are discharged on the oxide transfer conveyor. The off specification material is screened further to identify usable fractions. Unusable material is discarded.

The material on the oxide transfer conveyor is weighed and discharged onto the furnace feed conveyor. The furnace feed conveyor is a vertical, pocket type conveyor with flexible sidewalls that deliver material to the top of the shaft furnace structure. The closed furnace feed conveyor discharges through a riffler to the charge hopper at the top of the shaft furnace. The oxide coating station enables feeding of coating directly to the charge hopper of the shaft furnace. The coating is a solid material consisting of cement, burnt lime, hydrated lime, and hydrated dolomite to assist in the reaction process. These materials are maintained in silos. A weight indicator in the charge hopper keeps the operator informed of the quantity of feed in the charge hopper.

All process operations within the Iron Oxide Storage and Handling system are routed to various baghouses for the control of particulate emissions. Iron pellets will be stored in enclosed storage area. Iron ore operations will employ enclosed conveyors and water sprays at conveyor transfer points.

1.1.3 Reduction Reactor

The reduction reactor is a patented furnace with a nominal 7.15-meter internal diameter refractory, lined with abrasion resistant and insulating brickwork/castables to minimize heat loss. Iron ore pellets enter the reactor through the upper dynamic seal leg and are uniformly distributed on the stockline by symmetrical feed pipes. A dynamic seal is created by a small flow of inert seal gas into the upper seal leg of the furnace. This small flow of inert seal gas into the furnace through the seal leg prevents the escape of furnace gases to the atmosphere, while still allowing the free flow of material by gravity into the furnace without the use of lockhoppers.

The iron ore pellets are reduced to metallic iron in the upper portion of the furnace (reduction zone) by contact with hot hydrogen and carbon monoxide gases that are generated in the reformer and flow counter current to the descending iron oxide. The temperature of the reducing gas is typically 840 – 1,000 °C, depending on the specific reactor operating conditions. Specially designed inlet ports ensure that the reducing gases flow uniformly to the furnace burden. Spent reducing gas exits near the top of the reactor and enters the process gas system. The product material typically spends 3-4 hours in the reactor in order to achieve the desired product metallization and is then discharged from the furnace cone at temperatures above 700 °C. The discharge zone consists of the refractory lined furnace cone equipped with hydraulically operated burden feeders and a flow aid insert to aid the flow of the material within the cone.

The reduction reactor is not directly vented to the atmosphere so it does not have a specific emission source associated with it. Seal gas (described below) is used to pressurize both the top and bottom of the reactor so that the system reducing gases do not vent to the atmosphere. Furthermore, the reactor does not produce a melted product; the product remains in solid form throughout the reaction process.

Flaring is only necessary for process upset conditions (e.g. emergency shutdown). Due to the fact that a part of top gas from the reactor at normal process operation is recycled, the process basically has a closed loop. The other part of the top gas (exhaust from reduction reactor) is used as fuel for heating the reformer; that means it`s used in the reformer combustion system. That means for all operation

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conditions (startup, shutdown and normal process conditions): 1) total top gas (exhaust from reduction reactor) will pass the top gas scrubber; and 2) prior to exhaust of top gas, the top gas will pass the reformer combustion system.

1.1.4 *Hot Discharge System*

The hot reduced material is discharged from the furnace via a dynamic seal leg and a hydraulically driven variable speed hot wiper bar. The speed of the burden feeders is ratioed to the average discharge rate of the furnace to achieve a uniform flow of the material from the lower cone to the lower seal leg. The hot material flows across the wiper bar and then passes through a set of hydraulically driven screens, which limit the maximum size of the product passing into the surge hopper of the product discharge chamber. The material is discharged from the surge hopper into several feed legs. These feed legs connect directly to either a briquette machine or the bypass feed screw. For safety, each leg is isolated from its respective discharge device by a slide gate and ball valve.

1.1.5 *Hot Briquetting System*

The briquetting section includes briquette machines with individual grease lubrication stations, briquette strand separators, HBI cooling conveyors, and one bypass line. Hot DRI is supplied to each briquette machine by a screw feeder. The briquette machines are roll type machines which produce "pillow" shaped briquettes about 6 mm by 120 mm. Each roll contains dies which form the briquettes. One of the rolls is forced toward the other roll by means of a hydraulic pressure system, which ensures a uniform pressing force. The continuous briquette strand that exits the briquetting machine is fed to the strand separators to break the strands into individual briquettes, which are then fed to the HBI cooling system for slow cooling and discharge to the product handling system. Off-specification product (remet) produced during plant start-up or process upset bypasses the briquette machines and is discharged through a bypass feed leg to the bypass discharge feeder and then to the HBI cooling system.

The HBI cooling conveyors will spray water to cool the HBI and will be equipped with vapor hoods to remove steam created by the process. Most of the mist will vaporize on contact with the hot HBI and the vapor will be exhausted to the atmosphere via vapor exhaust fans. The vapor removal system consists of ducts, fans and a scrubber designed to capture and minimize the release of steam into the briquette area. Outside air ducts will be directly connected to each vapor hood and vapor removal fans will supply the required amount of unheated outside air directly into the vapor hoods. Spray cooling water that does not vaporize will drain into collection pans and be routed to a sump and then to the waste water facility.

The dust collection system is designed to minimize the escape of dust at the briquette machines. The system consists of an exhaust fan, a cyclone, an additional air valve, a dust collection scrubber, a sump, an exhaust stack, and associated ducts, hoods, pumps and valves. Dusty air and seal gas are collected and conveyed at a sufficient velocity to prevent settling and accumulation within

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the ducts. The gas stream then enters a venturi scrubber where water is sprayed onto the dust particles to create a slurry. The slurry is discharged from the scrubber and pumped to the basin upstream of the clarifier. Cleaned gases are pulled from the dust collection system by the exhaust fan and discharged into the atmosphere through a stack.

1.1.6 *Product Material Handling*

The material is transferred from the briquette cooling conveyors to the HBI conveyors, which are equipped with product scales. The HBI product is transported to the product screening station 1 where it is separated into product fines (0-6.35mm) and HBI (6.35-120mm). The fines are fed into a ground floor product fines bunker, while the HBI is weighed and transported on the product collection conveyor to the stacker conveyor for storage. The HBI product storage has a capacity of 100,000 tons per pile.

The HBI is reclaimed from the HBI product storage and transported via conveyor to the product screening station 2, where it is screened; the HBI is weighed and transported via conveyor to the port.

All process operations within the Product Material Handling system are routed to various baghouses for the control of particulate emissions. The storage pile and associated operations are controlled with fugitive suppressants.

1.1.7 *Process Gas System*

Spent reducing gas (top gas) exits the reduction zone of the reactor through the refractory lined top gas duct and enters the top gas scrubber to be cleaned and cooled. Inside the top gas scrubber, the gas passes through two distinct processing zones. First the gas flows through the venturi portion of the scrubber where it is rapidly cooled and the particulate matter is wetted and removed. Then the warm gas is split into two streams that pass through two parallel packed beds (for additional cooling) and two sets of spin vanes (to remove water droplets) within the scrubber.

After scrubbing and cooling, approximately two-thirds of the clean top gas (now called process gas) flows through a second set of mist eliminators and then to the inlet of the first stage process gas compressor, followed by a second compressor. These compressors are centrifugal type machines designated as first stage and second stage process gas compressors. After compression, the process gas is mixed with natural gas and preheated to form the feed gas for the reformer. The other one-third of the cleaned top gas (now called top gas fuel) is mixed with a small amount of natural gas and then passed through a mist eliminator to remove water droplets before fueling the reformer main burners.

It is important to note that the Top Gas Scrubber is not a control device but a process device. The process gas system does not vent directly to the atmosphere during regular operation.

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1.1.8 *Reformer*

The reformer generates the hot reducing gas (H_2 and CO) required to reduce the iron oxide in the shaft furnace. It has a proprietary tubular style design that reforms natural gas across a proprietary catalyst with both the water vapor and CO_2 in the feed gas. Heat for the reforming reactions is supplied by floor fired (burners are on the floor) main burners, which are located on the bottom of the reformer box between tube rows and between the outside tube rows and the reformer wall. The air required for combustion is preheated in the heat recovery system before being directed to the burners with the main air blower. The reformer box is thermally insulated with refractory material. Natural gas-fired auxiliary burners maintain the reformer box temperature during plant idle conditions to minimize both restart time and thermal cycling of the reformer tubes.

Each reformer bay has a separate sized flue gas port to each of the flue gas headers to ensure uniform heat distribution along the reformer length. The flue gas headers are refractory lined and expansion joints are provided between the single sections of the headers to compensate for thermal expansion. The flue gas exiting the reformer box via the flue gas headers flows to the heat recovery system where the waste heat is recovered.

1.1.9 *Heat Recovery System*

The reformer flue gas exits on both sides of the reformer and enters the parallel train heat recovery system. Each parallel system contains combustion air pre-heaters and feed gas pre-heaters, all of which consist of alloy bundle type heat exchangers suspended in the refractory lined heat recovery ducts. The combustion air pre-heaters are designed to preheat the combustion air to about 600 °C in two stages. The feed gas pre-heaters located downstream of the combustion air pre-heater heat the feed gas to approximately 600 °C as well.

The flue gas exits the parallel trains through a common ejector stack which generates the required draft with a single ejector stack fan. The ejector stack is an induced draft (venturi type) flue gas stack. It uses the ejector stack fan to generate sufficient suction to pull the flue gases out of the reformer and through the heat recovery system. The heat recovery system increases the reformer capacity and reduces the net plant energy consumption by approximately 25-30 percent over the first generation designed in the 1960's.

1.1.10 *Seal Gas and Purge Gas System*

Inert seal gas for the plant, which is used primarily for sealing the top and bottom of the furnace, is provided by the seal gas generation system. This system takes hot reformer flue gas and cools it in a seal gas cooler. The seal gas cooler is a packed bed, direct contact type cooler which cools the reformer flue gas to near ambient temperature. The cooled seal gas is then compressed by a positive displacement type compressor and then cooled in a shell and tube aftercooler to remove the heat of compression. The cooled seal gas passes through a mist eliminator and seal gas dryer. The seal gas dryer is a refrigerant type unit equipped with a stand-by compressor that removes moisture from the wet seal gas. This dry seal gas is then distributed to various plant users.

1.1.11 *Bottom Seal Gas System*

The furnace bottom seal gas system consists of a compressor, a dilution hood, a dust collection scrubber, a fan, and a stack to supply and exhaust seal gas for sealing the bottom of the shaft furnace. The bottom seal gas compressor, a positive displacement run dry type, supplies dry seal gas to the lower seal leg of the shaft furnace at the required pressure. The bottom seal gas is vented through a vent line and collected in the dilution hood, which captures sufficient air to maintain a mixture of gases that remains below minimum explosive limits in the dust collection system. The mixture passes to the dust collection scrubber where entrained dust particles are removed and then the seal gas/air mixture is exhausted through the bottom seal dust collection fan and stack.

1.1.12 *Inert Gas System*

In the case when seal gas may not be available (e.g., for the initial startup as well as after maintenance downtimes), a liquid nitrogen system will be used to supply purge gas. Purge gas is used to purge the combustibles out of the system when needed (such as for a maintenance shutdown). Also, the liquid nitrogen system will be the source for impulse purge for some instruments. The liquid nitrogen system additionally serves as a back-up supply source of some seal gas users, such as the bottom seal gas for the bottom seal leg.

1.1.13 *Machinery and Process Cooling Water System*

The water system consists of machinery cooling water circuit and two process cooling water circuits, which are re-cooled with a secondary cooling circuit (non-conduct with primary circuits) by means of sea water cooling towers.

Sea Water Cooling System:

The hot water returned from the heat exchangers is led through the sea water cooling towers and collected in the cold sea water basin. The sea water cooling tower drift will be according the required value from the BACT analysis. Different pump groups are installed depending on the process requirements, operation flexibility and plant maintenance requirements. Each pump group is additionally equipped with stand-by pump capacity. The cooled water with a temperature of approx. 32°C will be pumped by the cold water pumps to the heat exchangers, which are located at the water treatment plant area, in order to cool the different process cooling water circuits at the core plant area. Instrumentation for the indication of cooling-water temperatures, pressures and flow rates is installed.

Machinery Cooling Water:

The machinery cooling water is designed as a closed circuit which supplies cooling water to all indirect coolers such as burden feeders, rotating equipment lubrication oil heat exchangers, etc. The machinery cooling water system basically consists of circulation pumps and heat exchangers. The circulation pumps

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circulate hot water from the machinery cooling water pond through the sea water cooled heat exchangers to the consumers in the core plant area with a cold water temperature of approx. 35°C.

Contaminated Process Water System:

The contaminated process water stream with high solid content from the scrubbers and dedusting plant is conducted to the process classifier for an initial cleaning. The classifier will be designed for continuous processing to separate the coarse grain from slurry water. The settled coarse particles within the classifier will be removed by screw mechanism via a discharge chute. The slurry overflow of the classifier will be fed into the clarifier water collecting pond where the contaminated water from all process gas cleaning systems is collected and flows from there into the clarifier. In the clarifier the suspended solids as well as the precipitated carbonates are separated by gravity. The clarifier overflow is directed into the hot process water pond.

From the clarifier underflow the slurry is pumped to the chamber filter press. The filter cake will be conveyed via belt conveyor to stock yard. In case of emergency the slurry settling pond will be used. The dewatered slurry is unloaded by a front loader onto trucks. Contaminated cold cooling water basin will have a bottom slope to a sump to ensure collecting of settled solids. The sump will be equipped with a sump pump.

Clean Process Water System:

The return water from the seal gas/reformed gas cooler and the inert gas generator will be directly routed to the clean warm water pond. The warm water is pumped by the clean process water pumps from the warm water pond via the sea water cooled heat exchangers, which are located at the central water treatment area, to the corresponding consumers of the core plant area with a cold temperature of approx. 35°C. Instrumentation for the indication of cooling-water temperatures, pressures and flow rates is installed. Any suspended solids are kept within the demanded limits by means of sidestream filtration. The backwash sequence depends on the filter pressure drop and is started automatically. The filters are backwashed with a combined air-water backwash program. Contaminated backwash water is conveyed to the contaminated process water system. The blow down water from the Clean Process Water System will be implemented to the Contaminated Process Water System. Water samples are to be taken and analysed for conformance. Make up water is automatically refilled to compensate for water losses caused by evaporation and blow down.

Process Water Degassing Unit:

Direct contact coolers provide much of the gas cooling in the DRI plant. The gases being cooled are under pressure, so some of the CO and CO_2 are absorbed into the cooling water. Due to the direct contact of process water with CO, CO_2, and process gasses, some gas constituents are dissolved in water at an elevated process gas pressure. This occurs in the process water that is in the top gas scrubber (in particular).

In order to reduce the fugitive emissions at the clarifier and to reduce scaling in process water ducts, a forced degassing unit will be installed. The process water degasser will use pressurized air to strip the process water of the dissolved gasses prior to the clarifier. During this degassing process, CO and CO_2 are released. However, the flow and concentration of CO and CO_2 are irregular since entry to and from the pressurized DRI process is episodic in nature.

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2.0 EMISSIONS ANALYSIS

This section summarizes the methodologies and emission factors used to calculate GHG emissions for each emission source type included in this project. As outlined in the USEPA document, *PSD and Title V Permitting Guidance for Greenhouse Gases* (USEPA, 2011), GHGs are a regulated NSR pollutant under the PSD major source permitting program. The six GHG pollutants are:

- Carbon dioxide (CO_2);
- Nitrous oxide (N_2O);
- Methane (CH_4);
- Hydrofluorocarbons (HFCs);
- Perfluorocarbons (PFCs); and
- Sulfur hexafluoride (SF_6).

The voestalpine facility will not use or process HFCs, PFCs, or SF_6 in the manufacturing process and does not believe these three compounds will be emitted as a result of the manufacturing process. Therefore, only emissions of CO_2, CH_4, and N_2O were examined for comparison to the PSD thresholds. Emission calculations are included in Appendix A.

For this BACT analysis, total GHG, on a carbon dioxide equivalent (CO_2e) basis has been used. The amounts of CO_2, CH_4, and N_2O were converted to tons of CO_2e using the Global Warming Potential (GWP) factors from Subpart A of Part 98, Table A-1, as shown in the table below.

Table 2-1: Global Warming Potentials [100-Year Time Horizon] from Table A-1 to Subpart A of 40 CFR Part 98

Name	CAS Number	Chemical Formula	Global Warming Potential (100 yr)
Carbon dioxide	124-38-9	CO_2	1
Methane	74-82-8	CH_4	21
Nitrous oxide	10024-97-2	N_2O	310

TABLE 2-2: Summary of voestalpine Facility Emissions Compared to PSD Significant Emission Rates

Pollutant	PSD Significant Emission Rate (TPY)	Facility-Wide Emission Rate (TPY)	Significant Source
Greenhouse Gases (GHG) as CO_2e	100,000	1,820,616	Yes

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3.0 REGULATORY REVIEW

The proposed project will be subject to federal and state regulatory requirements as outlined in the following sections. Only those regulations that are potentially applicable to the proposed project were reviewed in this application. The USEPA promulgated a Federal Implementation Plan (FIP) for Texas assuming the PSD permitting authority for large GHG-emitting sources in Texas in accordance with the thresholds established under the Tailoring Rule published on June 3, 2010. All other pollutants are regulated by the Texas Commission on Environmental Quality (TCEQ) under the State Implementation Plan (SIP) and are beyond the scope of this application.

3.1 FEDERAL REGULATIONS

3.1.1 GHG Tailoring Rule

On June 3, 2010, the US Environmental Protection Agency (USEPA) issued a final rule addressing GHG emissions from stationary sources under the Clean Air Act (CAA) permitting programs. This final rule set thresholds for GHG emissions that defined when permits under the Prevention of Significant Deterioration (PSD)/New Source Review (NSR) and Title V Operating Permit programs are required for new and existing industrial facilities.

The GHG PSD Tailoring rule defined a major new source of GHG emissions as emitting 100,000 short tons of CO_2 equivalent (CO_2e) and 100 tons per year (tpy)/250 tpy (depending on the source category) on a mass basis. A major modification under the rule was defined as an emission increase and net emissions increase of 75,000 tpy or more of GHGs on a CO_2e basis and greater than zero tpy of GHGs on a mass basis. For the second phase of the Tailoring Rule, which began on July 1, 2011, PSD requirements for GHGs are triggered for new construction projects that have the potential to emit GHG emissions of at least 100,000 tpy. PSD requirements are triggered for modifications at existing sources only if the existing source's GHG emissions are equal to or greater than 100,000 tpy on a CO_2e basis and equal to or greater than 100 tpy/250 tpy on a mass basis, and the emission increase and net emission increase of GHGs from the modification would be equal to or greater than 75,000 tpy on a CO_2 basis and greater than zero tpy on a mass basis. This application has been prepared because the CO_2e emissions from the voestalpine facility (new construction) will exceed 100,000 tpy.

3.1.2 Mandatory Reporting Rule

Under the Mandatory Reporting Rule (40 CFR Part 98), beginning in 2010, facilities with fuel burning equipment with actual CO_2e emissions greater than or equal to 25,000 metric tpy must submit an annual GHG report that must cover all source categories and GHGs for which calculation methodologies are provided in subparts of the rule. The voestalpine facility will report GHG emissions under 40 CFR Part 98 as applicable.

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4.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS

This application presents a full "top-down" BACT analysis. Under Title 30 of the Texas Administrative Code (TAC) Chapter 116, BACT shall be applied to reduce or eliminate air emissions from a new or modified facility. The TCEQ utilizes a tiered BACT analysis in implementing PSD and state BACT requirements. PSD BACT is applicable to all pollutants that are subject to PSD review. State-only BACT is applicable to all other pollutants which are emitted from a new or modified facility.

Federal BACT is defined in 30 TAC 116.160 and 40 CFR 52.21(b)(12) as:

> *"An emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."*

State BACT is defined in 30 TAC 116.10(1) as:

> *"An air pollution control method for a new or modified facility that through experience and research, has proven to be operational, obtainable, and capable of reducing or eliminating emissions from the facility, and is considered technically practical and economically reasonable for the facility. The emissions reduction can be achieved through technology such as use of add-on control equipment or by enforceable changes in production processes, systems, methods or work practice."*

The USEPA guidance document, *PSD and Title V Permitting Guidance for Greenhouse Gases* (EPA 457/B-11-001), recommends the use of the five-step "top-down" BACT process established in the 1990 draft guidance *New Source Review Workshop Manual* to evaluate and select BACT for GHG. This process requires identification and consideration of available control technologies. The applicant

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must then demonstrate control technologies that are infeasible due to engineering constraints. All remaining technologies are ranked in order of descending order of control effectiveness. The top-ranked control option must be selected unless the applicant can demonstrate that it is not viable due to adverse economic or environmental impacts. If the most effective technology is not selected, then the most effective alternative should be evaluated until an option is selected as BACT.

4.1 KEY STEPS IN A TOP-DOWN BACT ANALYSIS

The five basic steps of a "top-down" BACT analysis are listed below:

Step 1: Identify potential control technologies;
Step 2: Eliminate technically infeasible options;
Step 3: Rank remaining control technologies by control effectiveness;
Step 4: Evaluate the most effective controls and document results; and
Step 5: Select BACT.

These steps are discussed in more detail below.

Step 1 – Identify Potential Control Technologies

The first step is to identify potentially "available" control options for each emission unit and for each pollutant under review. Available options should consist of a comprehensive list of those technologies with a potentially practical application to the emissions unit in question. The list should include lowest achievable emission rate (LAER) technologies, innovative technologies, and controls applied to similar source categories.

For this analysis, the following types of information were researched:

- USEPA's RACT/BACT/LAER Clearinghouse (RBLC) database;
- Federal and state air quality permits;
- Technical books and articles; and
- Guidance documents.

Step 2 – Eliminate Technically Infeasible Options

The second step is to eliminate technically infeasible options from further consideration. To be considered feasible, a technology must be both available and applicable. It is important in this step that any presentation of a technical argument for eliminating a technology from further consideration be clearly documented based on physical, chemical, engineering, and source-specific factors related to safe and successful use of the controls.

Step 3 – Rank Remaining Technically Feasible Control Options

The third step is to rank the technologies not eliminated in Step 2 in order of descending control effectiveness for each pollutant of concern. If the highest ranked technology is proposed as BACT, it is not necessary to perform any further technical or economic evaluation, except for the environmental analyses.

Step 4 – Evaluate Remaining Control Technologies

The fourth step entails an evaluation of energy, environmental, and economic impacts for determining a final level of control. The evaluation begins with the most stringent control option and continues until a technology under consideration cannot be eliminated based on adverse energy, environmental, or economic impacts.

Step 5 – Selection of BACT

The fifth and final step is to select as BACT the most effective of the remaining technologies under consideration for each pollutant of concern. BACT must, as a minimum, be no less stringent than the level of control required by any applicable New Source Performance Standard (NSPS) and National Emission Standard for Hazardous Air Pollutants (NESHAP) or state regulatory standards applicable to the emission units included in the PSD permit application.

This BACT analysis provides background information on potential control technologies, a summary of technology determinations contained in the RBLC database for similar emission units, a discussion of other potential control options that may be applicable to the emission units, and descriptions of proposed BACT emission limits.

Each of the steps listed above have been evaluated in detail for each project-related emissions source combination in the following sections.

In accordance with 40 CFR 52.21(b)(12), an initial review of applicable NSPS regulations was performed in order to ensure that no technology or process less stringent than an applicable NSPS could be identified as BACT. Currently, there are no NSPS rules that apply specifically to direct reduction ironmaking facilities. The NSPS for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60 Subpart IIII, does apply to sources in the voestalpine facility; however, this rule does not contain limitations that would effectively reduce GHG emissions. Thus, the NSPS program does not create a technology floor for the review of BACT for emissions of GHG gases.

A review of applicable NESHAP regulations was also performed in order to ensure that no technology or process less stringent than an applicable maximum achievable control technology (MACT) standard could be identified as BACT. Currently, there are no MACT rules that apply specifically to direct reduction ironmaking facilities. The NESHAP for Stationary Reciprocating Internal Combustion Engines (RICE) (40 CFR 63 Subpart ZZZZ) will apply to sources at the voestalpine facility; however, this rule does not contain limitations that would effectively reduce GHG emissions. Thus, the NESHAP and MACT program do not create a technology floor for the review of BACT for emissions of GHG gases.

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4.2 GREENHOUSE GAS EMISSIONS

CO_2 emissions occur as a by-product of burning fossil fuels and biomass, as well as from land-use changes and other industrial processes. CO_2 is formed through the complete oxidation of organic material. All fossil fuels contain significant amounts of carbon, and during combustion, the fuel carbon is oxidized into carbon monoxide (CO) and CO_2. Full oxidation of fuel carbon to CO_2 is desirable because CO has long been a regulated pollutant with established adverse health impacts, and because full combustion releases more useful energy within the process, maximizing energy conservation and efficiency.

CH_4 emissions result from incomplete combustion. Incomplete combustion can also result in emissions of PM, CO, and organic hazardous air pollutants (HAP). CH_4 emissions can be reduced by operating combustion processes with higher flame temperatures and higher excess oxygen levels. Available control technologies for the control of CH_4 emissions are the same as for the control of CO and VOC emissions, and include good combustion practices, oxidation catalysts, and thermal oxidation. Unfortunately, techniques for reducing CH_4 emissions can increase NO_x emissions. Consequently, achieving low CH_4 and low NO_x emission rates is a balancing act in combustion process design and operation. Because CH_4 emissions are a small fraction of the GHG emissions produced at the voestalpine facility, installing controls for CH_4 emissions alone would not be cost-effective.

N_2O emissions result primarily from low temperature combustion (between temperatures of 900 to 1,700°F). N_2O is formed from volatile nitrogen species (HCN) originating from fuel nitrogen, char nitrogen, and by heterogeneous reactions of nitrogen on the char surface. Therefore, the amount of char and the amount of fuel nitrogen have a significant effect on N_2O emissions. N_2O emissions are usually higher for geologically older fuels. Other sources of N2O emissions include NO_x control systems, such as conventional selective catalytic reduction (SCR) systems and selective non-catalytic reduction (SNCR) systems, which may produce N_2O emissions. Therefore, N_2O emissions may be reduced by not using these systems for the control of NO_x emissions. Because N_2O emissions are a small fraction of the GHG emissions produced at the voestalpine facility, installing controls for N_2O emissions alone would not be cost-effective.

4.3 DESCRIPTION OF GHG CONTROL TECHNOLOGIES

Potential control options are addressed for CO_2 below. Because the primary GHG emitted by the voestalpine facility will be CO_2, the control technologies and measures presented in this section focus on CO_2 control technologies.

4.3.1 CO_2 Control Technologies

In the USEPA document, *PSD and Title V Permitting Guidance for Greenhouse Gases* (USEPA, 2011), potentially applicable control alternatives have been identified and evaluated according to the following three categories: inherently lower-emitting processes/management practices and methods/system designs; add-on controls; and combinations of inherently lower emitting processes/practices/designs and add-on controls. The BACT analysis should consider potentially applicable control techniques from these three categories in order to capture a broad array of potential options for pollution control. However, USEPA has recognized that:

> "*a ... list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant.*" (USEPA, 2011, p. 26)

A series of white papers have been developed by the USEPA that summarize readily available information on control techniques and measures to mitigate GHG emissions from specific industrial sectors. These white papers are intended to provide basic information on GHG control technologies and reduction measures in order to assist regulatory agencies and regulated entities in implementing technologies or measures to reduce GHGs under the CAA, particularly in permitting under the PSD program and the assessment of BACT. Of interest for this BACT analysis, USEPA has developed a white paper for iron and steel manufacturing, *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Iron and Steel Industry* (USEPA, 2012).

4.3.2 Available Technologies for Reducing GHG Emissions in the Iron and Steel Industry

The available control measures that are identified in the USEPA iron and steel white paper for reducing GHG emissions from iron and steel manufacturing can be categorized under the following energy efficiency measures:

- Reductions in fuel consumption, which reduce the direct emissions of GHG from the facility; and
- Reductions in electricity usage, which reduce the indirection emissions of GHG (i.e., power plant emissions).

Table 4-1 shows possible energy efficiency improvements that can be made to reduce fuel consumption and also indicates whether these technologies are potentially applicable to the voestalpine facility.

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Table 4-1 Possible Energy Efficiency Improvements (Reduced Fuel Consumption) at voestalpine

Control Measure*	Comment	Applicable at voestalpine facility?
Transport System Efficiency Improvements	Mechanical conveyor systems typically use less energy than pneumatic systems.	Yes, mechanical conveyors will be used where practical. Pneumatic conveyors will be used for fine materials where practical.
Process Control and Management Systems	Automated control systems can be used to maintain operating conditions at optimum levels.	Yes, process control and management systems are planned. Yes, production planning will be optimized to reduce waste. Yes, controls will be used for temperature regulation in process equipment.
Refractory Material Selection	The refractory material lining the shaft furnace is the primary insulating material.	Yes, shaft furnace will be lined on the inside with abrasion resistant and insulating brickwork / castables thereby keeping the heat losses at a minimum. The discharge zone consists of the refractory lined shaft furnace cone equipped with hydraulically operated burden feeders and a flow aid insert, to aid the flow of the material within the cone.
Insulation	Insulation is important to keep heat loses from equipment to a minimum.	Yes, the shaft furnace, pipes, heat exchangers, Reformer etc. will be well insulated to reduce energy losses to the surroundings.
Heat Recovery from Process Streams and Waste-Heat Recovery from Cooling Water	Exhaust streams with significant amounts of heat energy can be recovered for other heating purposes.	Yes, the reformer flue gas exits on both sides of the reformer and enters the parallel train heat recovery system. The heat recovery system increases the reformer capacity and reduces the net plant energy consumption by approximately 25-30%. Each parallel system contains combustion air preheaters and feed gas preheaters. The preheaters consist of alloy bundle type heat exchangers suspended in the refractory lined heat recovery ducts. The combustion air preheaters are designed to preheat the combustion air to about 600 °C in two stages. The feed gas preheaters are located downstream from the hot combustion air preheaters.
Use of Preheaters	Preheaters allow higher energy transfer efficiency and lower fuel requirements.	Yes, Feed Gas and Combustion Air is preheated prior to entering the reformer.

* List of control technologies is adapted from USEPA's white paper for the Portland cement industry (USEPA, 2010).

Additional energy efficiency improvements can be made by effectively managing the electricity used in facility operations. Table 4-2 lists the possible energy efficiency improvements that are potentially applicable to the voestalpine facility.

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Table 4-2: Possible Energy Efficiency Improvements (Reduced Electricity Usage) at voestalpine

Control Measure*	Comment	Applicable at voestalpine facility?
Preventive Maintenance	Training programs and good housekeeping programs can help to decrease energy consumption throughput the facility.	Yes, a preventive maintenance program will be implemented, along with training and good housekeeping programs.
Energy Monitoring and Management System	Energy monitoring and management systems provide for optimal energy recovery and distribution between processes.	Yes, energy monitoring and management systems will be used.
High Efficiency Motors	Energy efficiency opportunities for all motor systems can optimize overall performance. A motor management plan can reduce electricity use and save in energy and maintenance costs.	Yes, NEMA motors will be used for all motors over 50 hp.
Variable Speed Drives (VSDs)	Variable speed drives can reduce energy consumption and therefore reduce CO_2 emissions.	Yes, VSDs will be used for controlling and optimization of process.
High Efficiency Fans	High efficiency fans may reduce power consumption.	Yes, potentially applicable for other fans.
Optimization of Compressed Air Systems	Implementing a comprehensive maintenance plan for compressed air systems and other efficiency improvements can reduce energy consumption.	Yes, voestalpine plans to implement a maintenance plan for compressed air systems and other efficiency improvements.
Lighting System Efficiency Improvements	Automated lighting controls and lights with more efficient bulbs can reduce energy use.	Yes, voestalpine plans to use automated lighting controls and lights with more efficient bulbs.

* List of control technologies is based on USEPA's white paper for iron and steel manufacturing (USEPA, 2012).

Some of these control technologies are technically feasible, though high capital costs could outweigh the expected energy savings. The voestalpine facility will implement energy efficient processes and will use energy efficient electric equipment (motors and fans) and controls where feasible and practical to reduce energy consumption.

4.3.3 *Emerging Technologies for Reducing GHG Emissions in the Iron and Steel Industry*

Significantly, the USEPA white paper for the iron and steel industry identifies integrated DRI/EAF steelmaking as a "near-term" technology for GHG reduction because this approach provides a considerable reduction in CO_2 emissions relative to traditional steelmaking. Examples of DRI/EAF integrated steelmaking are presented in the white paper as follows:

> *Essar's Integrated DRI/EAF Steelmaking:* The Essar Group acquired Minnesota Steel in late 2007 and was constructing a steel-making facility in Minnesota that will convert iron ore to steel product at the mine site; however, construction has been halted due to economic reasons. This

new plant will produce DRI pellets, most of which will be processed in electric arc furnaces (EAF) to produce steel slabs. This DRI/EAF integrated steel-making route requires less energy and produces lower emissions than traditional integrated iron and steelmaking. A DOC 2008 report claims a 41% reduction in CO_2 emissions relative to traditional steelmaking.

Nucor's DRI Iron and Steel Production Facility: In early 2011, Nucor Corporation began construction of an iron and steel complex in Louisiana that will include a pig iron operation utilizing a DRI furnace, along with a pellet operation, blast furnace, coke ovens, and a steel mill. Upon start-up, this facility will be the first DRI facility in the U.S. The PSD permit for this facility was the first to go through the GHG BACT review process in the US (in 1st quarter 2011).

Energy consumption in iron and steel making is considerable, and CO_2 is generated when energy is consumed. Emissions of CO_2 in iron and steel processes are related to three main factors: providing sufficient temperatures in order to carry out chemical reactions and physical treatment needed; providing a reductant (mainly CO) in order to reduce iron oxide; and providing power and steam necessary to run the steelworks.

DRI (also known as sponge iron) offers an alternative steel production route. In the DRI process, iron ore is reduced in its solid state, without forming a liquid metal during reduction. DRI can then be transformed to steel in electric arc furnaces (EAFs). DRI production is common in the Middle East, South America, India, and Mexico. The main benefit of a DRI plant (compared to a blast furnace or other traditional approach) is that a DRI plant uses natural gas (or possibly coal) as a fuel instead of coke, which significantly reduces emissions. To a certain extent, direct reduction (DR) can be an option to reduce CO_2 emissions (IPPC, 2012, p. 15).

Natural gas and coal are the two main fuels used in global DRI production. Most of the global DRI plants (more than 90% in 2007) use (lower grade) natural gas, but coal is primarily used at DRI plants in India. Typical energy consumption for natural gas-based DRI production has been reported as 10.4 GJ/t-DRI (IEA, 2007, p. 132-133) or as a range from 10.5 to 14.5 GJ/t-DRI (IPPC, 2012, p. 534), while the energy consumption for coal-based DRI production is considerably higher (20 to 25 GH/t-DRI) (IEA, 2007, p. 132-133). Natural gas-based DRI production results in lower CO_2 emissions than coal-based DRI production, with emissions ranging from 0.77 to 0.92 ton of CO_2 per ton of steel, depending on the type of electricity used (IEA, 2007, p. 132). In comparison, blast furnace ironmaking produces emissions ranging from approximately 1.6 to 2.2 tons of CO_2 per ton of steel (Midrex, 2012). Therefore, use of the DRI process results in far lower CO_2 emissions than conventional methods.

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The most common technologies (83% of the market in 2007) used for natural gas-based DRI production are Midrex and HYL III (IEA, 2007. p.132). At this time, voestalpine has selected Midrex as the plant supplier. A brief summary of the Midrex process is provided below.

Midrex Technologies, Inc. (Midrex) designs and builds commercial high-temperature, near-stoichiometric reformers that produce a high-quality reformed gas that can be fed directly to a DR shaft furnace. In the past 40 years, Midrex has supplied more than 70 MIDREX Reformers for projects around the world (http://www.midrex.com). To maximize the reformer's efficiency, offgas from the shaft furnace is recycled and blended with fresh natural gas, which is then fed to the reformer (a refractory-lined chamber containing alloy tubes filled with catalyst), where it is heated and reformed as it passes through the tubes. The newly reformed gas, containing 90-92 percent H_2 and CO (dry basis), is then fed hot directly to the shaft furnace as reducing gas. The thermal efficiency of the MIDREX® Reformer is greatly enhanced by a heat recovery system in which heat is recovered from the reformer flue gas to preheat the feed gas mixture and the burner combustion air. The use of recycled gas and the ability to feed hot reformed gas to the shaft furnace without quenching and reheating provide for a very efficient process.

4.3.4 *Long-Term Opportunities for Reducing GHG Emissions in the Iron and Steel Industry*

Other "long-term opportunities" are identified in the USEPA white paper as possible emerging techniques to reduce CO_2 emissions in the iron and steel industry as follows: electrolysis; HIsarna with carbon capture and storage (CCS); and carbon capture and storage (CCS). Of these, only CCS could be an applicable control option for DRI plants.

CCS can make a contribution to the overall GHG reduction effort by reducing the emissions of CO_2 from the use of fossil fuels. Most of the technologies needed for CCS are being used in a variety of industries, but are yet to be widely applied to power generation and industry at a commercial scale. There are also certain industries, such as iron and steel manufacturing and cement production, where CCS is often the only solution for substantial emission reductions (Global CCS Institute, 2012). CCS is the long-term isolation of fossil fuel CO_2 emissions from the atmosphere through capturing and storing the CO_2 deep in the subsurface of the Earth. CCS is made up of three key stages:

1. Capture: Carbon capture is the separation of CO_2 from other gases produced when fossil fuels are combusted to generate power and in other industrial processes. Three main processes are being developed to capture CO_2 from power plants that use coal or gas. These are: pre-combustion capture; post-combustion capture; and oxyfuel combustion capture.

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Pre-combustion capture is mainly applicable to gasification plants, where coal is converted into gaseous components by applying heat under pressure in the presence of steam and sub-stoichiometric O_2. This technology has not been demonstrated for DRI plants.

Post-combustion capture of CO_2 using solvent scrubbing, typically using monoethanolamine (MEA) as the solvent, is a commercially mature technology; however, this technology has not been demonstrated for DRI plants.

Oxy-combustion is the process of burning a fuel in the presence of pure or nearly pure oxygen instead of air. Fuel requirements for oxy-combustion are reduced because there is no nitrogen component to be heated, and the resulting flue gas volumes are significantly reduced. This technology has not been demonstrated for DRI plants.

In industries such as steel mills and cement plants, capture processes have not been developed at a large scale, but an existing capture method could be tailored to suit the particular production process. For instance, collection of CO_2 from cement plants uses post-combustion capture, and collection from modified steel manufacturing processes uses a type of oxyfuel combustion.

2. Transport: After separation, CO_2 is compressed to make it easier to transport and store. It is then transported to a suitable geologic storage site. Today, CO_2 is being transported by pipeline, by ship, and by road tanker.

3. Storage: At a storage site, CO_2 is injected into deep underground rock formations, often at depths of 1 km or more. Appropriate storage sites include depleted oil fields, depleted gas fields, or rock formations which contain a high degree of salinity (saline formations). These storage sites generally have an impermeable rock above them, with seals and other geologic features to prevent CO_2 from returning to the surface. (Global CCS Institute, 2012) Monitoring, reporting, and verification are important to demonstrate that CO_2 is safely stored.

The Global CCS Institute identified 75 large-scale integrated projects (LSIPs) world-wide as of September 2012: 16 projects are currently in construction or operating; and 59 projects are in planning stages. This reflects a net change in the number of projects from the 2011 report (Global CCS Institute, 2011) of one: nine new projects were identified in 2012, while eight were cancelled or put on hold or restructured. These large-scale projects involve the capture, transport, and storage of greater than 800,000 tonnes of CO_2 annually for coal-fired power plants or greater than 400,000 tonnes of CO_2 annually for emission-intensive industrial facilities (Global CCS Institute, 2012). The majority of these projects are in the power generation industry, with 40 LSIPs totaling more than 70 million tonnes per annum (Mtpa) in potential CO_2 capture capacity. However, it should be noted that none of these projects are in the iron and steel sector. The US LSIPs are summarized in Table 4-3 below.

Table 4-3. Large-Scale Integrated Projects for CO_2 Carbon Capture and Storage in the US

Project Name and Industry*	Capture Type	Volume CO2 (Mtpa)	Transport	Storage Type	Date of Operation
CURRENTLY OPERATING					
Val Verde Gas Plant Natural gas processing	Pre-combustion	1.3 Mtpa	Val Verde Pipeline, operated by Sandridge TX, 132-134 km	EOR	1972
Enid Fertilizer CO_2-EOR Project Fertilizer production	Pre-combustion	0.68 Mtpa	Enid-Purdy Pipeline, operated by Merit OK, 188-225 km	EOR	1982
Shute Creek Gas Processing Facility Natural gas processing	Pre-combustion	7 Mtpa	Schute Creek Pipeline, operated by Exxon, Chevron Texaco, Andarko WY, 190 km	EOR	1986
Great Plains Synfuel Plant and Weyburn – Midale Project Synthetic natural gas	Pre-combustion	3 Mtpa	Onshore to onshore pipeline 315 km	EOR	2000
Century Plant Natural gas processing	Pre-combustion	5 Mtpa (+3.5 Mtpa in construction)	Onshore to onshore pipeline 256 km	EOR	2010
CURRENTLY PLANNED					
Air Products Steam Methane Reformer EOR Project Hydrogen production	Post-combustion	1 Mtpa	Green Line Pipeline, operated by Denbury LA to TX, 101-150 or 411 km	EOR	2012
Lost Cabin Gas Plant Natural gas processing	Pre-combustion	1 Mtpa	Greencore Pipeline, operated by Denbury MT to WY, 373 km	EOR	2012
Illinois Industrial CCS Project Chemical production (ethanol)	Industrial separation	1 Mtpa	Onshore to onshore pipeline	Onshore deep saline formations	2013

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Project Name and Industry*	Capture Type	Volume CO2 (Mtpa)	Transport	Storage Type	Date of Operation
Kemper County IGCC Project Power generation	Pre-combustion	3.5 Mtpa	Sonat Pipeline, operated by Denbury MS, 75-80 km	EOR	2014
OTHER					
Coffeyville Gasification Plant Fertilizer production	Pre-combustion	0.85 Mtpa	Onshore to onshore pipeline KS, 112 km	EOR	2013
Lake Charles Gasification Synthetic natural gas	Pre-combustion	4.5 Mtpa	Green Line Pipeline operated by Denbury LA to TX, 441 km	EOR	2014
Medicine Bow Coal-to-Liquids Facility Coal to liquids (CTL)	Pre-combustion	3.6 Mtpa	Greencore Pipeline planned extension, operated by Denbury WY	EOR	2015
NRG Energy Parish CCS Project Power generation	Post-combustion	1.4-1.6 Mtpa	Onshore to onshore pipeline TX	EOR	2015
Texas Clean Energy Project Power generation	Pre-combustion	2.5 Mtpa	Central Basin Pipeline, operated by Kinder Morgan TX, 50-230 km	EOR	2015
Hydrogen Energy California Project (HECA) Power generation	Pre-combustion	3 Mtpa	Onshore to onshore pipeline CA, 6.4 km	EOR	2017
PurGen One Power generation	Pre-combustion	2.6 Mtpa	Onshore to onshore pipeline NJ, 160 km	Offshore deep saline formations	2017
Taylorville Energy Center Power generation	Pre-combustion	1.92 Mtpa	Onshore to onshore pipeline IL, 8 km	Onshore deep saline formations	2017
Tenaska Trailblazer Energy Center Power generation	Post-combustion	5.75 Mtpa	Onshore to onshore pipeline TX, 201-250 km	EOR	Not specified

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Project Name and Industry*	Capture Type	Volume CO2 (Mtpa)	Transport	Storage Type	Date of Operation
Cash Creek Generation Power generation	Pre-combustion	2 Mtpa	Onshore to onshore pipeline KY	EOR	2015
Indiana Gasification Synthetic natural gas	Pre-combustion	4.5 Mtpa	Onshore to onshore pipeline IN	EOR	2015
Mississippi Gasification (Leucadia) Synthetic natural gas	Pre-combustion	4 Mtpa	Free State Pipeline, operated by Denbury MS, 138-176 km	EOR	2015
Riley Ridge Gas Plant Natural gas processing	Pre-combustion	2.5 Mtpa	Onshore to onshore pipeline WY	EOR	2015
FutureGen 2.0 Oxy Combustion Large Scale Test Power generation	Oxyfuel combustion	1.3 Mtpa	Onshore to onshore pipeline IL, <50 km	Onshore deep saline formations	2016
Quintana South Heart Project Power generation	Pre-combustion	2.1 Mtpa	Onshore to onshore pipeline ND	EOR	2017
Kentucky NewGas Synthetic natural gas	Pre-combustion	5 Mtpa	Onshore to onshore pipeline KY	Various options being considered	2018

Of course, adding CCS to any process increases capital costs, as well as ongoing operating and maintenance costs. The costs and status of a few large US projects are summarized below:

- For the Air Products' hydrogen plant in Port Arthur, Texas, which will capture CO_2 and transport it via the Denbury Green Pipeline, construction began in August 2011, and the plant was expected to be operational by the end of 2012. The **$430 million** project will retrofit CO_2 capture technology onto two steam methane reformers used to produce hydrogen at a Valero Energy Corp. refinery in Port Arthur, Texas, and will capture one million tons of CO_2 annually for use in enhanced oil recovery (EOR) operations in Texas oilfields (GHG Monitor, 2012).
- Archer Daniels Midland's CCS Project in Decatur, IL, was expected to be operational by the second half of 2013. This **$208 million** project will capture one million tons of CO_2 annually from ADM's currently existing ethanol plant for sequestration in the Mount Simon sandstone formation. This project will incorporate knowledge gained from a nearby sister CO_2 injection project (managed through one of USDOE's regional

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partnerships) that has been in operation since November 2011 (GHG Monitor, 2012a).

- Leucadia's Lake Charles CCS Project is an industrial project being funded by the USDOE. The **$436 million** project will construct a greenfield petroleum coke-to-chemicals gasification plant with carbon capture that will produce methanol near Lake Charles, LA. The project will then be linked up to Denbury Resource's existing Green CO_2 pipeline, which will transport more than four million tons of CO_2 captured annually to EOR operations in Texas' West Hastings oil field.
- The Texas Clean Energy Project (TCEP) is a 400 MW 'polygen' IGCC plant being developed by Summit Power Group, LLC, which is currently in negotiations with a Chinese bank for financing of the **$2.9 billion** project set for west Texas. Progress on the project has been steady since a long-term CO_2 sales agreement was signed with Whiting Petroleum Corporation last year. This plant and potentially two others (GHG Monitor, 2012b) will be built in close proximity to depleted oilfields, eliminating the need for long pipelines that can often run as much as $2 million per mile.

For the global iron and steel industry, the following approaches are underway as pilot projects to control GHG emissions (Bellona, 2012):

- In Europe, 48 companies and organizations from 15 countries have launched a co-operative R&D project under the Ultra-Low CO_2 Steelmaking (ULCOS) consortium. One of them is the ArcelorMittal & ULCOS joint project on steel-CCS, where post-combustion CO_2 capture will be applied on a steel plant. The project has applied for NER300 funding and was submitted by the French Government to the European Investment Bank in May 2011;
- Small-scale demonstrations of CO_2 capture from processes such as DRI, HIsarna, and oxyfuel are being developed in France, Germany, the Netherlands, Sweden, and the United Arab Emirates.

The DRI process involves conversion of iron ore to iron through the use of a reduction gas (usually natural gas) chemically converted to hydrogen and CO. Potential capture of CO_2 can be done through pre-combustion (gasification), PSA (pressure swing absorption) or VPSA (Vacuum PSA) or chemical absorption.

The HIsarna steelmaking process combines twin screw reactors, smelting and cyclone converter furnace technologies. It operates using pure oxygen instead of air, resulting in a top gas that is nitrogen-free and has a high concentration of CO_2. HIsarna equipped with CCS could capture approximately 80% of the CO_2 process from producing liquid iron from iron ore and coal. Capture technologies are PSA or VPSA. A HIsarna pilot plant is under construction in IJmuiden, the Netherlands (Bellona, 2012).

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4.3.5 *CH_4 Control Technologies*

Available control technologies for the control of CH_4 emissions are the same as for the control of CO and VOC emissions, and include good combustion practices, oxidation catalysts, and thermal oxidation. Techniques for reducing CH_4 emissions can increase NO_x emissions. Consequently, achieving low CH_4 and NOx emission rates is a balancing act in combustion process design and operation. Because CH_4 emissions will be a small fraction of the GHG emissions produced, installing controls for CH_4 alone would not be cost-effective.

4.3.6 *N_2O Control Technologies*

The control of N_2O emissions is primarily achieved through combustion controls. In addition, post combustion catalyst systems including SCR, and NCSR, and thermal destruction control systems may reduce N_2O emissions. However, NO_x control systems including conventional SCR systems and SNCR systems, may produce N_2O emissions. Therefore, N_2O emissions may be reduced by not using these systems for the control of NO_x emissions. Because N_2O emissions will be a small fraction of the GHG emissions produced, installing controls for N_2O emissions alone would not be cost-effective.

4.4 *SUMMARY OF PROPOSED BACT*

A summary of the proposed voestalpine facility GHG emissions is presented in Table 4-4. Proposed monitoring strategy is to determine compliance based on total natural gas consumption divided by total HBI production (including regular and off-spec DRI product). voestalpine proposes to monitor CO_2e emissions on the basis of a 12-month rolling total. Fuel analyses will be conducted as required to demonstrate practical enforceability.

TABLE 4-4: Summary of Proposed GHG BACT Determinations for voestalpine

Company, Date	Process Description	Emission Limits	Control Type and Efficiency
voestalpine 2013	Facility-Wide	Proposed BACT-PSD CO_2e Limit – 1,820,616 tpy facility-wide.	No add-on controls.
voestalpine 2013	Reformer Main Flue Ejector Stack, Emission Source 29	Proposed BACT-PSD: CO_2e Limit – 1,680,207 tpy.	Energy integration through combustion of spent reducing gas. Use of low-carbon fuel (natural gas). Limit total quantity of natural gas consumption per metric ton of product.
voestalpine 2013	Hot Pressure Relief Vent (Flare), Emission Source 38	Proposed BACT-PSD: CO_2e Limit – 2,236 tpy.	Use of natural gas fuel for the flare's pilot and as supplemental fuel (if needed). Good combustion practices and proper maintenance.

Company, Date	Process Description	Emission Limits	Control Type and Efficiency
voestalpine 2013	Seal Gas Vents	Proposed BACT-PSD: CO_2e Limit – emissions vent through the Charge Hopper Baghouse, BSG Wet Scrubber, and Briquetter Wet Scrubber as shown below.	Good combustion practices and proper maintenance.
voestalpine 2013	Charge Hopper Baghouse, Emission Source 17	Proposed BACT-PSD: CO_2e Limit – 54,702 tpy.	No additional controls feasible.
voestalpine 2013	BSG Wet Scrubber, Emission Source 8	Proposed BACT-PSD: CO_2e Limit – 54,702 tpy.	No additional controls feasible.
voestalpine 2013	Briquetter Wet Scrubber, Emission Source 9	Proposed BACT-PSD: CO_2e Limit – 27,351 tpy.	No additional controls feasible.
voestalpine 2013	Process Water Degasser, Emission Source 30	Proposed BACT-PSD: CO_2e Limit – 1,126 tpy.	No additional controls feasible.
voestalpine 2013	Emergency Generator, Emission Source 34	Proposed BACT-PSD: CO_2e Limit – 197 tpy (based on 100 hrs).	Good combustion practices and proper maintenance. Engines must comply with NSPS Subpart IIII based on manufacturer's specifications.
voestalpine 2013	Fire Pump, Emission Source 35	Proposed BACT-PSD: CO_2e Limit –12.8 tpy (based on 100 hrs).	Good combustion practices and proper maintenance. Engines must comply with NSPS Subpart IIII based on manufacturer's specifications..
voestalpine 2013	Fugitive Components, Emission Source Fugitives	Proposed BACT-PSD: CO_2e Limit – 84 tpy.	Use of an audio/visual/olfactory (AVO) program to monitor for leaks; and use of high quality components and materials of construction.
voestalpine 2013	Facility-wide	Proposed BACT-PSD: implement energy efficient operations.	Utilize mechanical conveyors, heat recovery, and other energy efficiencies as appropriate to the facility's design.
voestalpine 2013	Facility-wide	Proposed BACT-PSD: implement energy efficient equipment.	Utilize preventive maintenance, energy monitoring and management, high efficiency motors, variable speed drives, high efficiency fans, optimized compressed air systems, and efficient lighting systems as appropriate to the facility's design.

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4.5 REFORMER MAIN FLUE EJECTOR STACK

Emission Sources and Process Descriptions

Emission Source	Description
Reformer Main Flue Ejector Stack, Emission Source 29	Spent shaft furnace gas is combusted as fuel in the reformer in order to recover the remaining chemical energy in the gas. Top gas has a low fuel value, about one-fourth that of natural gas, so the fuel is mixed with natural gas to maintain stable combustion by increasing the BTU content of the top gas and to provide enough energy to run the reforming process.

In order to address BACT for emissions of CO_2e from the DRI facility, voestalpine reviewed technologies technically applicable to the production equipment installed at the facility for manufacturing DRI. This section describes a detailed, step-by-step BACT analysis for control of CO_2e emissions from the reformer main flue ejector stack at the voestalpine facility.

Emissions from the reformer main flue ejector stack result from two main processes, the DRI shaft furnace and the reformer.

4.5.1 CO_2e Emissions from the Reformer Main Flue Ejector Stack – Shaft Furnace

The shaft furnace is a countercurrent shaft reactor where the reducing gas generated by the reformer reacts with the iron ore to form metallized iron. Although it is called a furnace, combustion does not actually occur within the reactor. The CO and H_2 of the reducing gas scavenge oxygen from the iron oxides in the iron oxide pellets, reducing the oxygenation state of the ores. The resulting products of the reduction process are pure iron, CO_2, and water.

$$Fe_2O_3 + 3\ CO \rightarrow 2\ Fe + 3\ CO_2$$

$$Fe_2O_3 + 3\ H_2 \rightarrow 2\ Fe + 3\ H_2O$$

The rate at which these reactions occur determines the residence time needed to metallize the iron oxide pellets into DRI product, which typically takes several hours. In the shaft furnace, fresh reducing gas, rich in CO and H_2 (total 95%) from the reformer, enters at the bottom of the furnace, while iron oxide pellets are fed from the top, so that the gas flow is countercurrent to the descending iron oxide pellets. As the reduction reaction progresses, CO_2 and water vapor are formed in the gas stream as reaction products. The spent reducing gas then exits the furnace at the top of the furnace and is ducted for recycle to the reformer.

Current DRI process designs release CO_2 from the process gas loop by off-taking a stream of spent reducing gas (also known as top gas) prior to recycle back to the reformer and using this stream as fuel in the reformer. At the top of the shaft furnace, the partially spent reducing gas exits and is recompressed, enriched with natural gas, preheated, and transported back to the gas reformer as follows: After scrubbing and cooling, approximately two-thirds of the clean top gas (now

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called process gas) flows through a second set of mist eliminators and then to the inlet of the first stage process gas compressor. The process gas compressors are centrifugal type machines specifically selected for the process. These machines are designated the first stage and second stage process gas compressors. After compression, the process gas is mixed with natural gas to form the feed gas for the reformer. Feed gas is preheated prior to entering the reformer. The reformer "reforms" the mixture back to CO and H_2, which is then ready for re-use by the shaft furnace. (This loop is called the process gas loop.)

Although CO_2 is not vented from the reactor directly, it is generated by the reduction reactions in the furnace. Therefore, the efficiency of the reactions in the furnace may have an impact on the overall efficiency of the facility, including combustion sources, and thus an impact on total GHG emissions. Recent EPA guidance for GHG BACT indicates that efficiency improvements of the source should be considered in any determination of BACT, and are in fact likely to be primary controls in many cases. BACT considerations for the process gas loop are discussed below.

Step 1 - Identify Potential Control Technologies

A search of USEPA's RBLC database revealed the following entries for the control of CO_2e emissions from the DRI manufacturing process. Documentation compiled in this research is presented in the table below.

TABLE 4-5: Summary of RBLC Data for CO_2e Emissions from DRI Plants

RBLC ID Number Company, Date	Process Description	Emission Limits	Control Type and Efficiency
Consolidated Environmental Management Inc. – Nucor St. James, LA 07/19/2012	Process Heater (to replace Reformer) (DRI-108 – DRI Unit #1)	BACT-PSD: CO_2e Limit – no more than 13 MMBtu (decatherms) of natural gas per metric tonne of DRI (11.79 MMBtu/ton of DRI). Compliance based on total natural gas consumption divided by total production (including regular and off-spec DRI product) of the facility on a 12-month rolling total.	Good combustion practices, acid gas separation system, energy integration.
MN-0085 Essar Steel Minnesota LLC Itasca, MN 05/10/2012	Indurating Furnace Stacks (Waste Gas and Hood Furnace)	BACT-PSD: CO_2e Limit - 710,000 ton/yr 12-month rolling sum.	Energy efficiency measures, such as heat recovery, use of preheaters, etc. Use of lower emitting processes. Good design/ operating practices for furnace. Use of natural gas fuel. CCS deemed technically infeasible.

RBLC ID Number Company, Date	Process Description	Emission Limits	Control Type and Efficiency
LA-0248 Consolidated Environmental Management Inc. – Nucor St. James, LA 01/27/2011	Reformer Main Flue Stack (DRI-108 – DRI Unit #1) Reformer Main Flue Stack (DRI-208 – DRI Unit #2) Package Boiler (DRI-109) Package Boiler (DRI-209)	BACT-PSD: CO_2e Limit – no more than 13 decatherms of natural gas per tonne of DRI (11.79 MMBtu/ton of DRI). Compliance based on total natural gas consumption divided by total production (including regular and off-spec DRI product) of the facility on a 12-month rolling total.	Good combustion practices, acid gas separation system, energy integration.
MN-0070 Minnesota Steel Industries, LLC 09/07/2007	DRI Plant	BACT-PSD: CO_2e Limit – None.	No requirement for GHG controls.

The following technologies and innovative processes were identified as potential control measures for CO_2e emissions associated with the shaft furnace.

1. Process Gas Carbon Capture with Dedicated Sequestration
2. Process Gas Carbon Capture with Transport and Sequestration

A description of each of the identified technologies or processes is presented below.

Process Gas Carbon Capture with Dedicated Sequestration

In evaluating the use of natural gas as a raw material, an inefficient DRI process will consume large volumes of natural gas for each ton of DRI produced, while an efficient process will operate closer to theoretical limits of DRI/natural gas ratios. These theoretical limits are based upon the stoichiometry of the reduction reaction.

One means of reducing natural gas consumption is to remove the oxygen that is being freed from the iron oxide ore from the process gas loop of the reducing gas. This oxygen, in the form of CO_2 and water vapor, inhibits the reaction of CO and H_2 with the oxygen of the ore when either or both are present at high levels. While some CO_2 and water vapor are necessary in the reactions of the reformer, the removal of excess CO_2 and water vapor in the system will improve overall efficiency.

Current DRI process designs release CO_2 and water vapor from the process gas loop by off-taking a stream of spent reducing gas (prior to recycle back to the reformer) and using this stream as fuel in the reformer. The DRI process inherently removes water vapor from the spent reducing gas being recycled to

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the reformer in a quench step. As the gas is cooled, its capacity to hold water is reduced, and the water is captured in the process water system.

As an acid gas, CO_2 can be separated from certain gas streams with the use of an amine absorber system. Amine absorption has been in use for many years on smaller scales, typically for the treatment of hydrogen sulfide (H_2S, also an acid gas) from gases in the petroleum and natural gas industry. These amine absorber systems, when scaled-up to the flow requirements of the DRI process, have the ability to separate CO_2 from the spent reducing gas leaving the shaft furnace which will be used as fuel in the reformer. Removing CO_2 from the spent reducing gas used as fuel in the reformer has the benefit of increasing combustion efficiency incrementally.

The amine solution used to absorb CO_2 must be regenerated through heating, typically using a steam reboiler. After treatment for the removal of sulfur compounds such as H_2S, the resulting gas is nearly pure CO_2. This gas stream should require little additional treatment effort to produce pipeline-quality, commercial grade CO_2.

Separating CO_2 from the process gas must be paired with some form of storage, or sequestration, in order for the technology to provide any reduction in CO_2 emissions. In fact, CO_2 separation without storage actually results in an increase in total CO_2 generation, since the separation system has an energy demand as well, in the form of a reboiler for regenerating amine solution rich in CO_2, and electrical needs for system equipment.

Dedicated sequestration involves the injection of CO_2 into an on-site or nearby geological formation, such an active oil reservoir (enhanced oil recovery), a brine aquifer, an unmined coal seam, basalt rock formation, or organic shale bed. Geologic sequestration is being studied in several locations and geologies, with varying results and predictions. Clearly, in order for geologic sequestration to be a feasible technology, a promising geological formation must be located at or very near to the facility location.

Process Gas Carbon Capture with Transport and Sequestration

As described above, CO_2 can be separated from certain gas streams with the use of an amine absorber system. Separating CO_2 from the process gas must be paired with some form of storage, or sequestration, in order for the technology to provide any reduction in CO_2 emissions. In fact, CO_2 separation without storage actually results in an increase in total CO_2 generation, since the separation system has an energy demand as well, in the form of a reboiler for regenerating amine solution rich in CO_2, and electrical needs for system equipment.

Off-site CO_2 sequestration involves utilization of a third-party CO_2 pipeline system in order to transport CO_2 to distant geologic formations that may be more conducive to sequestration than sites in the immediate area. Building such a pipeline for dedicated use by a single facility will almost certainly make any

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project economically infeasible, from both an absolute and BACT-review perspective. However, such an option may be effective only if both adequate storage capacity exists downstream and reasonable transportation prices can be arranged with the pipeline operator.

Step 2 - Eliminate Technically Infeasible Options

Process Gas Carbon Capture with Dedicated Sequestration

As discussed above, dedicated geological sequestration of CO_2 requires close proximity to a favorable geologic formation. According to the US Department of Energy's (USDOE) National Energy Technology Laboratory (NETL), no basalt formations exist near the project site. The Barnett Shale (Coal Seam) is approximately 360 miles from Corpus Christi based on the distance from Corpus Christi, TX, to Hill, TX, which is included in the 2007 Eastern Extension of the Barnett Shale project.

Saline formations are layers of porous rack that are saturated with brine. The Frio Brine Pilot Experiment is approximately 250 miles from Corpus Christi based on the distance from Corpus Christi, TX, to Dayton, TX. (This project is complete, but it is not known if there will be an expansion or a similar project in the area on a larger scale.) As described by NETL, "less is known about saline formations because they lack the characterization experience that industry has acquired through resource recovery from oil and gas reservoirs and coal seams. Therefore there is an amount of uncertainty regarding the suitability of saline formations for CO_2 storage." Due to the high degree of uncertainty in utilizing saline formations for dedicated CO_2 storage, this type of sequestration has been deemed technically infeasible.

Texas is well known as a major producer of oil and natural gas, and voestalpine researched the sequestration of CO_2 in oil and gas reservoirs through enhanced oil recovery (EOR) techniques. Without a nearby active oil reservoir, or depleted natural gas reservoir, this option becomes technically infeasible.

Step 3 - Rank Remaining Technically Feasible Control Options

1. Process Gas Carbon Capture (15%) with Transport and Sequestration (99%)

The reaction efficiency improvement strategy of removing CO_2 and water vapor from the process gas loop has the potential to reduce overall GHG emissions (almost exclusively CO_2) by 15% or more, on an equal production basis. However, this CO_2 gas stream would have to be transported and sequestered for reducing GHG emissions.

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Step 4 - Evaluate Remaining Control Technologies

Process Gas Carbon Capture with Transport and Sequestration

A Midrex plant could include adding an amine-based CO_2 removal system and required supporting equipment, resulting in approximately 50% less CO_2 emissions sent to the atmosphere due to selective CO_2 capture (assuming it is used by an off-taker) compared to the base non-CO_2 removal option.

Process gas CO_2 separation has been demonstrated in industry as an effective efficiency improvement measure. The capital cost of incorporating this technology in a new facility is offset by the reduced operational cost of natural gas consumption. The amine solution used to absorb CO_2 and other acid gases from the process stream is regenerable for use over many cycles, and thus does not create an adverse environmental impact. Finally, total energy consumption of the facility is reduced, removing the concern of an adverse energy penalty. Thus, process gas CO_2 separation and water removal can be deemed effective considering potential adverse impacts.

Utilizing a long-distance pipeline to deliver captured CO_2 to sequestration sites would virtually eliminate CO_2 emissions from this source. However, the economic feasibility of transporting CO_2 for sequestration at a distant storage site depends on whether a long-distance pipeline exists within a reasonable distance of the facility in order to make a connection to the system. At this time, there are less than 4,000 miles of CO_2 pipelines currently constructed in the US.

Denbury Resources operates a dedicated CO_2 pipeline -- Green Pipeline – that extends from Louisiana to near Houston, Texas. The nearest branch of this pipeline is approximately 220 miles away from Corpus Christi. The Denbury Resources pipeline system stretches from Jackson Dome in Mississippi, to Donaldsonville, Louisiana, and west to the West Hastings oil field south of Houston, Texas. Naturally occurring CO_2 is extracted from a geologic formation near Jackson Dome and used for EOR in several fields along the pipeline route. Additionally, Denbury has sought out planned industrial projects along the pipeline route to from which to purchase additional CO_2 volumes. The nearest branches of this pipeline system are approximately 220 miles away from the voestalpine facility. Pipeline connections at this distance would cost on the order of millions of dollars, plus the additional cost of compression equipment, and on-going electricity and maintenance requirements.

Denbury has entered into contracts with several industrial projects along its pipeline route which, if constructed, will deliver CO_2 from these industrial sources to the pipeline system for EOR. However, it should be noted that these are voluntary contracts entered into by for-profit companies without any sort of regulatory driver. An agreement of value can therefore be reached by the parties, since the option to walk away from the contract remains to both sides. The imposition of operating permit requirements to this sort of negotiation

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would fundamentally alter the relationship between the parties, and the economics of the transaction being negotiated.

An operating permit requirement, such as a BACT determination, requiring a facility to contract with a single third-party for specific services places the facility in an untenable economic position. Denbury is a for-profit, publically traded company, which has a fiduciary responsibility to obtain the best return for its shareholder as possible, just like any other for-profit enterprise. A BACT requirement conditioning the voestalpine facility's operation on the use of the Green Line pipeline would place Denbury in the position of being a natural monopoly such as a utility, upon whose services voestalpine would depend for the operation of the DRI facility. However, Denbury's pipeline operations are not currently considered to be such a utility and are not regulated. Without regulation as a utility, Denbury could exact any price it wished to allow access to the pipeline and use denial of such access rights as a tool in any negotiations. These facts make the use of this third-party pipeline economically infeasible. Even if an equitable contract could be agreed to in the short term, the supply/demand relationship imposed by a permit requirement would make the voestalpine project completely unviable as a long-term investment. Therefore, the use of a third-party pipeline for transport of CO_2 to distant sequestration sites is deemed to be economically infeasible.

If use of the Denbury pipeline is considered, the approximate cost for a post-combustion carbon capture and sequestration (CCS) system can be estimated as follows, based on site specific information from voestalpine and from the *Report of the Interagency Task Force on Carbon Capture* (August, 2010). CCS is a three-step process that includes the capture of CO_2 from industrial sources, transport of the captured CO_2 (usually in pipelines), and storage of that CO_2 in suitable geologic reservoirs. Technologies exist for all three components of CCS. In this study, site specific costs are provided by voestalpine for CO_2 capture. However, site specific costs are not available for CO_2 transport and CO_2 storage, so costs are estimated as follows:

- CO_2 capture - For a new CO_2 captureproject at the voestalpine facility, site specific costs for a CO_2 removal plant are estimated as $164,100,000 (shown in the table below) for a plant with a size to capture and produce approximately 512,574 tpy of CO_2. This results in capital cost of $320.15 per installed ton of CO_2.
- CO_2 transport – The *Report of the Interagency Task Force on Carbon Capture* cites studies showing that CO_2 pipeline transport costs for a 100-kilometer (62 mile) pipeline range from approximately $1.10 per ton of CO_2 to $3.30 per ton of CO_2 (see page 37). As mentioned earlier in this section, a pipeline length of approximately 220 miles would be needed to transport CO_2 from voestalpine to the Denbury pipeline, so the costs would be substantially more than estimated here for 62 miles.
- CO_2 storage - The *Report of the Interagency Task Force on Carbon Capture* cites cites project costs associated with CO_2 storage have been estimated

to be approximately \$0.44 per ton of CO_2 to \$22.05 per ton of CO_2 (see page 44).

TABLE 4-6: Approximate Cost for Construction and Operation of a Post-Combustion CCS System at voestalpine

CCS System Component	Specific Cost	Tons of CO_2 Controlled, Transported, and Stored per Year	Total Cost
CO_2 Capture and Compression Facilities	\$320 (\$/installed ton of CO_2 Controlled)	512,574 tpy	\$164,100,000
Capital equipment costs for CO_2 separation (such as heat exchangers, amine scrubber, and/or mole sieves) and purification equipment	-	-	\$72,800,000
Compression equipment to pipeline conditions (including H_2S removal after compression)	-	-	\$62,200,000
Engineering and design costs to incorporate above equipment	-	-	\$10,000,000
Operating costs: Scrubber media/sieves – initial; Scrubber media/sieves – annual replacement; and kW for system	-	-	15,000,000 (\$/year)
Wastewater treatment plant modifications directly tied to CCS additions	-	-	\$3,500,000
Engineering and design costs to incorporate wastewater treatment plant modifications	-	-	\$500,000
Operating costs: Wastewater treatment plant	-	-	100,000 (\$/year)
CO_2 Transport Facilities (per 100 km of pipeline)	1.10 to 3.30 (\$/ton of CO_2 controlled)	512,574 tpy	1,127,663 (\$/year)
CO_2 Storage Facilities	0.44 to 22.05 (\$/ton of CO_2 controlled)	512,574 tpy	5,766,458 (\$/year)
Total CCS System Cost (CAPEX)	**290.69 (\$/installed ton of CO_2 Controlled)**	**512,574 tpy**	**\$149,000,000**
Total CCS System Cost (OPEX)	**42.91(\$/ton of CO_2 controlled)**	**512,574 tpy**	**\$21,994,121 (\$/year)**

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NOTES:

Capture and compression costs

- CAPEX= \$149,000,000/ 512,574 tpy = \$290.69 per installed ton of CO_2 controlled
- OPEX = \$15,100,000/ 512,574 tpy = \$29.46 per ton of CO_2 controlled

Total transport costs = \$2.20 per ton of CO_2 x 512,574 tpy = \$1,127,663

Total storage costs = \$11.25 per ton of CO_2 x 512,574 tpy = \$5,766,458

At approximately capital cost of \$290.69 per installed ton of CO_2 controlled and operation cost of \$42.91 per installed ton of CO_2 controlled , using CCS at the voestalpine facility is found to be economically infeasible.

Further, the site specific environmental, health, and safety (EHS) impacts of using CCS should be considered. Although there are likely climate benefits that result from CCS, there are also potential risks to the environment and human health as follows:

- A global risk that transported and stored CO_2 is eventually re-emitted to the atmosphere, thus reducing any mitigation for climate change;
- Local risks resulting from environmental impacts of pipeline construction, materials consumption, and hazards due to possible unplanned loss of CO_2 containment; and
- Upstream risks related to additional fuel use related to CCS (landscape damage, discharges to water, emissions to air, solid waste generation, etc.).

Step 5 – Selection of BACT

None of the identified technologies remain, having been deemed technically or economically infeasible. BACT is selected as no add-on control.

4.5.2 *CO_2e Emissions from the Reformer Main Flue Ejector Stack – Reformer*

Reducing gas is generated initially from natural gas, which is heated and reformed in the reformer at an elevated temperature. At this elevated temperature, the natural gas dissociates into a reducing gas rich in CO and hydrogen (H_2), which are the primary reductants for the DRI process:

$$CH_4 + CO_2 \rightarrow 2\ CO + 2\ H_2$$

$$CH_4 + H_2O \rightarrow CO + 3\ H_2$$

The reformer generates the hot reducing gas (CO and H_2) required to reduce the iron oxide in the shaft furnace. It has a proprietary tubular style design in which natural gas dissociates into a reducing gas rich in CO and H_2, which are the primary chemicals used to remove the oxygen (O_2) from the iron ore. Heat for the reforming reactions is supplied by floor-fired (burners are on the floor) main burners, which are located on the bottom of the reformer box between tube rows and between the outside tube rows and the reformer wall. The air required for

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combustion is preheated in the heat recovery system before being directed to the burners with the main air blower. Natural gas-fired auxiliary burners maintain the reformer box temperature during plant idle conditions to minimize both restart time and thermal cycling of the reformer tubes.

CO_2 is born in the fuel gas and simply passes through the combustion process as an inert. Current MIDREX-DRI process designs release CO_2 from the process gas loop by off-taking a stream of spent reducing gas (prior to recycle back to the reformer) and using this stream as fuel in the reformer. After scrubbing and cooling, the other one-third of the cleaned top gas from the scrubber (now called top gas fuel) is mixed with a small amount of natural gas to become the fuel mixture for the reformer main burners. The fuel mixture passes through a mist eliminator to remove water droplets and it is used by the reformer main burners.

This arrangement serves to both allow for an outlet of CO_2 from the process gas and increase the energy efficiency of the reformer through energy integration. While this increases the energy efficiency of the reformer by providing more gases to surround the reformer tubes for heat transfer, the CO_2 is still released to the atmosphere. CO_2 released from the reformer in this manner is mixed with products of combustion and other inert gases, and is not suitable for sequestration. BACT considerations for the flue gas loop are discussed below.

Step 1 - Identify Potential Control Technologies

The following technologies and innovative processes were identified as potential control measures for GHG emissions associated with the reformer.

1. Flue Gas Carbon Capture with Dedicated Sequestration
2. Flue Gas Carbon Capture with Transport and Sequestration
3. Energy Integration through Combustion of Spent Reducing Gas
4. Low-Carbon Fuel (Natural Gas Combustion)
5. Maximized Combustion Efficiency

A description of each of the identified technologies or processes is presented below.

Flue Gas Carbon Capture with Dedicated Sequestration

Flue gas CO_2 separation differs from process gas CO_2 separation, in that the remaining gas is primarily water vapor and nitrogen (N_2) from the combustion air. These gases are both undesirable in the reducing gas used in the shaft furnace, to which the process gas is recycled after CO_2 separation. Therefore, it is inherently necessary to operate separate and distinct systems for separating CO_2 from flue gas and process gas, so that flue gas water vapor and N_2 could be released to the atmosphere instead of mixing with the process gas return.

Flue Gas Carbon Capture with Transport and Sequestration

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Flue gas CO_2 separation differs from process gas CO_2 separation, in that the remaining gas is primarily water vapor and N_2 from the combustion air. These gases are both undesirable in the reducing gas used in the shaft furnace, either inhibiting the reduction reaction (water), creating the potential for generating unnecessary criteria pollutant emissions (N_2 converting into NO_X), or increasing energy demand in order to heat unnecessary constituents in the process gas (both). Therefore, it is inherently necessary to operate separate and distinct systems for separating CO_2 from flue gas and process gas, so that flue gas water vapor and N_2 could be released to the atmosphere instead of mixing with the process gas return.

Energy Integration through Combustion of Spent Reducing Gas

Minimizing the use of natural gas fuel is naturally the primary method of reducing GHG emissions from combustion. Energy integration has the most potential for reducing fuel consumption, by reducing wasted energy as much as possible. The DRI process design includes the use of spent reducing gas from the process (known as top gas) as fuel for the process. Top gas contains a large fraction of CO and H_2, which retains a residual fuel value. This top gas fuel is mixed with the fuel natural gas, replacing a portion of the needed heat input to the process. This design integrates the energy cycle of the process in order to capture as much residual chemical energy from the shaft furnace gases as possible.

Low-Carbon Fuel (Natural Gas Combustion)

The use of natural gas as a combustion fuel, in preference over other fossil fuels such as oil or coal, results in fewer GHG emissions per unit of energy output. This property has been well documented, and is reflected in 40 CFR Part 98, Table C-1 (the Mandatory Reporting Rule for Emissions of Greenhouse Gases), where natural gas is ranked as having one of the lowest CO_2 generation rates of any of the fuels listed. Natural gas also has benefits over other fossil fuels from the perspective of other criteria pollutant emissions, such as sulfur oxides (SO_x).

Maximized Combustion Efficiency

Maximizing combustion efficiency reduces the consumption of fuel by optimizing the quantity of usable energy transferred from the fuel to the process. Combustion efficiency is maximized when the combustion zone is provided the best possible mix of fuel and air conditions, such as fuel/air ratio, fuel temperature, combustion air temperature, combustion zone pressure, heat transfer area, and the like.

Step 2 - Eliminate Technically Infeasible Options

voestalpine has evaluated the technical feasibility/infeasibility of each control strategy identified under Step 1 of the BACT analysis. The evaluation of these

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technologies must review whether the specific technology is available for the application and is effective at reducing CO_2 emissions.

Flue Gas Carbon Capture with Dedicated Sequestration

As discussed above, CO_2 released from the reformer is mixed with products of combustion and other inert gases, and is not suitable for sequestration. Therefore, carbon capture with dedicated sequestration is not technically feasible and has been eliminated.

Flue Gas Carbon Capture with Transport and Sequestration

As discussed above, CO_2 released from the reformer is mixed with products of combustion and other inert gases, and is not suitable for sequestration. Therefore, carbon capture with transport and sequestration is not technically feasible and has been eliminated.

Step 3 - Rank Remaining Technically Feasible Control Options

1. Energy Integration through Combustion of Spent Reducing Gas (60%)
2. Low-Carbon Fuel (Natural Gas Combustion) (40%)
3. Maximized Combustion Efficiency (10%)

Step 4 - Evaluate Remaining Control Technologies

Energy Integration through Combustion of Spent Reducing Gas

In order to measure the overall GHG effectiveness of the process, the most relevant parameter that can be measured is natural gas consumption. This is due to the fact that the DRI process uses natural gas as both a fuel for energy input into the process, and also as a raw material, generating reducing gas that reacts with the iron oxide content of iron ore to remove oxygen and produce metallic iron. Both routes of natural gas consumption ultimately result in the formation of CO_2. Thus, reducing the total quantity of natural gas consumed by the facility, both fuel and raw material natural gas streams, is the most effective means of reducing GHG generation. This approach is consistent with the output-based metric approach outlined in the GHG BACT Guidance recently published by EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases*, USEPA, OAQPS, Nov. 2010.

In order for the measurement of natural gas consumption to be meaningful, it must be evaluated on an equal production basis. Thus, the proper metric for measuring the natural gas consumption of the process, and thus the GHG efficiency, is in units of natural gas consumed per ton of DRI product. The consumption of natural gas is considered to be the sum of natural gas consumed as fuel and as a raw material, so that all sources of natural gas consumption are accounted for in the metric. Due to production rate and product quality

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variability in any production process, production rates should be inclusive of all production at the facility, both of regular and off-spec materials.

Low-Carbon Fuel (Natural Gas Combustion)

Natural gas combustion results in significantly less CO_2 generation per unit of energy when compared to most other fuels. When compared with pulverized coal combustion, natural gas can be expected to generate as much as 40% less CO_2 per unit of energy. Since natural gas is an essential raw material in creating the reducing gas needed for the process chemistry, it is also the natural selection for fueling combustion sources such as the reformer.

Maximized Combustion Efficiency

Maximizing combustion efficiency reduces the consumption of fuel by optimizing the quantity of usable energy transferred from the fuel to the process. Combustion efficiency is maximized when the combustion zone is provided the best possible mix of fuel and air conditions, such as fuel/air ratio, fuel temperature, combustion air temperature, combustion zone pressure, heat transfer area, and the like.

Step 5 - Selection of BACT

For GHG emissions generated by combustion at the reformer, BACT is selected to be energy integration through the combustion of spent reducing gas, combined with natural gas combustion for supplemental energy needs. The BACT selection represents inherent design aspects of the DRI process, and as such, these are not add-on controls.

voestalpine is proposing a BACT limit from the reformer main flue ejector stack of 13 MMBtu natural gas per tonne HBI produced. This limit will be achieved with the use of good combustion practices to minimize the CO_2e emissions that occur during the combustion of natural gas and top gas in the reformer.

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TABLE 4-7: Summary of BACT for CO_2e Emissions from Reformer Main Flue Ejector Stack at voestalpine

Company, Date	Process Description	Emission Limits	Control Type and Efficiency
voestalpine 2013	Reformer Main Flue Ejector Stack, Emission Source 29	Proposed BACT-PSD: CO_2e Limit –no more than 13 MMBtu (decatherms) of natural gas/tonne HBI produced. Compliance based on total natural gas consumption divided by total production (including regular and off-spec DRI product) of the facility on a 12-month rolling total.	Energy integration through combustion of spent reducing gas. Use of low-carbon fuel (natural gas). Limit total quantity of natural gas consumption per metric ton of product.

4.6 *HOT PRESSURE RELIEF VENT (FLARE)*

Emission Sources and Process Descriptions

Emission Source	Description
Hot Pressure Relief Vent (Flare), Emission Source 38	The hot pressure relief vent (flare) prevents an uncontrolled release of CO from the system by combusting the reducing gas.

The shaft furnace must run as close to steady state operation as possible in order to produce DRI product of acceptable quality. Flaring is only necessary for process upset conditions (e.g. emergency shutdown). The pressure of the reducing gas must be maintained below that of the seal gas system or an uncontrolled release of reducing gas will result from the top seal and bottom seal. To maintain this condition, the reducing gas is occasionally flared to prevent a rise in pressure. The hot pressure relief vent (flare) prevents an uncontrolled release of CO from the system by combusting the reducing gas.

4.6.1 *CO_2e Emissions from the Hot Pressure Relief Vent (Flare)*

This section describes a detailed, step-by-step BACT analysis for control of CO_2e emissions from the hot pressure relief vent (flare) at the voestalpine facility.

Step 1 – Identify Potential Control Technologies

A search of USEPA's RBLC database revealed the following entries for the control of CO_2e emissions from the hot pressure relief vent (flare) at DRI plants. Documentation compiled in this research is presented in the table below.

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TABLE 4-8: Summary of RBLC Data for CO_2e Emissions from Hot Pressure Relief Vent (Flare) at DRI Plants

RBLC ID Number Company, Date	Process Description	Emission Limits	Control Type and Efficiency
Consolidated Environmental Management Inc. – Nucor St. James, LA 07/19/2012	Hot Flare (to revise Hot Flare) (DRI-110 – DRI Unit #1)	BACT-PSD: CO_2e Limit – none.	Good combustion practices. No other control specified.
IN-1035 Hoosier Energy REC INC. – Merom Generating Station Sullivan County, IN 11/10/2011	Coal Bed Methane-Fired Standby Flare w/Propane-Fired Pilot	BACT-PSD: CO_2e Limit – 3,235 lb/MW-hr, 4,852 tpy (12-month consecutive period).	Good combustion practices and proper maintenance.
LA-0248 Consolidated Environmental Management, Inc. – Nucor St. James, LA 01/27/2011	Hot Flare (DRI-110, Unit No. 1)	BACT-PSD: CO_2e Limit – none.	Good combustion practices. No other control specified.
LA-0248 Consolidated Environmental Management, Inc. – Nucor St. James, LA 01/27/2011	Hot Flare (DRI-210, Unit No. 2)	BACT-PSD: CO_2e Limit – none.	Good combustion practices. No other control specified.

The following list of control technologies represent technologies that have been used for the control of CO_2 emissions from the hot pressure relief vent (flare) and from similar sources in other industries.

1. Carbon Capture with Dedicated Sequestration
2. Carbon Capture with Transport and Sequestration
3. Low-Carbon Fuel (Natural Gas Combustion)
4. Good Combustion Practices and Proper Maintenance

Carbon Capture with Dedicated Sequestration

CO_2 released from the hot pressure vent (flare) is mixed with products of combustion and other inert gases, and is not suitable for sequestration. Therefore, carbon capture with dedicated sequestration is not technically feasible and has been eliminated.

Carbon Capture with Transport and Sequestration

CO_2 released from the hot pressure vent (flare) is mixed with products of combustion and other inert gases, and is not suitable for sequestration.

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Therefore, carbon capture with dedicated sequestration is not technically feasible and has been eliminated.

Low-Carbon Fuel (Natural Gas Combustion)

Use of fuels containing lower concentrations of carbon generate less CO_2 than other higher carbon fuels. Typically, gaseous fuels such as natural gas contain less carbon, and thus lower CO_2 potential, than liquid or solid fuels such as diesel or coal. The hot pressure vent (flare) will be equipped with a natural gas-fired pilot to provide a constant flame source to ignite the flare system.

Good Combustion Practices and Proper Maintenance

Good combustion practices for flares include appropriate maintenance of equipment (such as periodic flare tip maintenance) and operating within the recommended heating value and flare tip velocity as specified by its design. Using good combustion practices results in longer life of the equipment and more efficient operation. Therefore, such practices indirectly reduce GHG emissions by supporting operation as designed and with consideration of other energy optimization practices incorporated into the voestalpine facility.

Step 2 – Eliminate Technically Infeasible Options

The Hot Pressure Relief Vent flare is not a process flare, but an intermittent use MSS flare to control pressure of the reducing gas in the shaft furnace. Therefore, no continuous stream (other than pilot gas) is being combusted, and add on controls are not technically feasible. Periodic maintenance will help maintain the efficiency of the flare.

Carbon Capture with Dedicated Sequestration

As discussed above, carbon capture with dedicated sequestration is not technically feasible and has been eliminated.

Carbon Capture with Transport and Sequestration

As discussed above, carbon capture with transport and sequestration is not technically feasible and has been eliminated.

Step 3 – Rank Remaining Technically Feasible Control Options

1. Low-Carbon Fuel (Natural Gas Combustion) (40%)
2. Good Combustion Practices and Proper Maintenance (50%)

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Step 4 – Evaluate Remaining Control Technologies

Low-Carbon Fuel (Natural Gas Combustion)

voestalpine proposes to use natural gas for the flare's pilot and as supplemental fuel, if needed, to maintain appropriate vent stream heating value as required by applicable air quality regulations. Liquid and solid fossil fuels are not proposed for use with the flare.

Good Combustion Practices and Proper Maintenance

voestalpine will incorporate good combustion practices and proper maintenance as recommended by the flare manufacturer. Further, voestalpine will minimize maintenance, startup, and shutdown events that can increase CO_2e emissions. Good combustion practices include the following:

- Operator practices - based on written operating procedures incorporating good combustion practices including startup, shutdown, and malfunction;
- Maintenance knowledge – equipment maintained by personnel with training specific to equipment;
- Maintenance practices – based on written site specific procedures for best/optimum maintenance practices;
- Fuel quality (analysis) – periodic fuel sampling and analysis where composition could vary;
- Use of clean fuel – use of pipeline quality natural gas;
- Combustion air distribution – including routine and periodic adjustments and checks of air distribution system;
- Good engineering design – maintain records of manufacturer's specifications and maintenance guidelines; and
- Visible emissions monitoring – maintain records of visible emissions observations.

Step 5 – Selection of BACT

Based on the top-down BACT analysis, the best available technology for controlling CO_2e emissions from the natural gas pilot for the hot pressure relief vent (flare) is use of natural gas for the flare's pilot and as supplemental fuel (if needed), good combustion practices, and proper maintenance. voestalpine will install a natural gas-fired flare tip.

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TABLE 4-9: *Summary of BACT for CO_2e Emissions from Hot Pressure Relief Vent (Flare) at voestalpine*

Company, Date	Process Description	Emission Limits	Control Type and Efficiency
voestalpine 2013	Hot Pressure Relief Vent (Flare), Emission Source 38	Proposed BACT-PSD: CO_2e Limit – included in 13 MMBtu (decatherms) of natural gas/tonne HBI produced limit. Compliance based on total natural gas consumption divided by total production (including regular and off-spec DRI product) of the facility on a 12-month rolling total.	Use of natural gas fuel for the flare's pilot and as supplemental fuel (if needed). Good combustion practices and proper maintenance.

4.7 SEAL GAS VENT

Emission Sources and Process Descriptions

Emission Source	Description
Seal Gas Vents	Seal gas exits from three seal gas vents: Charge Hopper Baghouse (Emission Source 17); BSG Wet Scrubber (Emission Source 8); and Briquetter Wet Scrubber (Emission Source 9)..

In order to prevent the reducing gas from escaping the furnace, a higher pressure gas called seal gas is applied at both the charging and discharging opening. The seal gas is allowed to escape the furnace while the reducing gas is retained. Due to the higher seal gas pressure, a portion is also entrained into the reactor and combined with the spent reducing gas travels back to the reformer. This seal gas is merely a small amount of cooled flue gas from the reformer combustion side, and primarily consists of atmospheric nitrogen, CO_2, and water vapor.

4.7.1 CO_2e Emissions from the Seal Gas Vents

CO_2 is present in seal gas that is emitted from three seal gas vents (Charge Hopper Dedusting [Emission Source 17], Furnace Wet Scrubbber [BSG Wet Scrubber] [Emission Source 8], and Briquetter Wet Scrubber [Emission Source 9]) because it is simply reformer flue gas diverted for the purpose of retaining the reducing gas within the shaft furnace. Control of CO_2 from the seal gas vent is most appropriately addressed at combustion within the reformer. This section performs a detailed, step-by-step BACT analysis for control of CO_2 emissions from the seal gas vents at the voestalpine facility.

Step 1 – Identify Potential Control Technologies

A search of USEPA's RBLC database revealed the following entries for the control of CO_2e emissions from the seal gas vent at DRI plants. Documentation compiled in this research is presented in the table below.

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TABLE 4-10: Summary of RBLC Data for CO_2e Emissions from Seal Gas Vent at DRI Plants

RBLC ID Number Company, Date	Process Description	Emission Limits	Control Type and Efficiency
Consolidated Environmental Management Inc. – Nucor St. James, LA 07/19/2012	Removed Upper Seal Gas Vent (DRI-106, Unit No. 1)	BACT-PSD: CO_2e Limit – none.	N/A
LA-0248 Consolidated Environmental Management – Nucor St. James, LA 01/27/2011	Upper Seal Gas Vent (DRI-106, Unit No. 1)	BACT-PSD: CO_2e Limit – none.	No controls feasible.
LA-0248 Consolidated Environmental Management – Nucor St. James, LA 01/27/2011	Upper Seal Gas Vent (DRI-206, Unit No. 2)	BACT-PSD: CO_2e Limit – none.	No controls feasible.

The following list of control technologies represent technologies that have been used for the control of CO_2 emissions from the seal gas vent (reformer).

1. Good Combustion Practices and Proper Maintenance

Good Combustion Practices and Proper Maintenance

Good combustion practices include appropriate maintenance of equipment and operating within the recommended air to fuel ratio recommended by the manufacturer. Using good combustion practices in conjunction with proper maintenance results in longer life of the equipment and more efficient operation. Therefore, such practices indirectly reduce GHG emissions by supporting operation as designed and with consideration of other energy optimization practices incorporated into the voestalpine facility. voestalpine will incorporate such combustion practices and proper maintenance as recommended by the reformer manufacturer.

Step 2 – Eliminate Technically Infeasible Options

The identified control strategy is technically feasible and has not been eliminated.

Step 3 – Rank Remaining Technically Feasible Control Options

1. Good Combustion Practices and Proper Maintenance (50%)

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Step 4 – Evaluate Remaining Control Technologies

Good Combustion Practices and Proper Maintenance

voestalpine will incorporate good combustion practices and perform maintenance as recommended by the reformer manufacturer.

Step 5 – Selection of BACT

BACT for CO_2 was already determined as good combustion practices for the reformer flue gas, and no additional control is feasible for the use of a small portion of this flue gas as seal gas.

TABLE 4-11: Summary of BACT for CO_2e Emissions from Seal Gas Vents at voestalpine

Company, Date	Process Description	Emission Limits	Control Type and Efficiency
voestalpine 2013	Seal Gas Vents	Proposed BACT-PSD: CO_2e Limit – emissions vent through the Charge Hopper Baghouse, BSG Wet Scrubber, and Briquetter Wet Scrubber as shown below.	Good combustion practices and proper maintenance.
voestalpine 2013	Charge Hopper Baghouse, Emission Source 17	Proposed BACT-PSD: CO_2e Limit – 54,702 tpy.	No additional controls feasible.
voestalpine 2013	BSG Wet Scrubber, Emission Source 8	Proposed BACT-PSD: CO_2e Limit – 54,702 tpy.	No additional controls feasible.
voestalpine 2013	Briquetter Wet Scrubber, Emission Source 9	Proposed BACT-PSD: CO_2e Limit – 27,351 tpy.	No additional controls feasible.

4.8 PROCESS WATER DEGASSER

Emission Sources and Process Descriptions

Emission Source	Description
Process Water Degasser, Emission Source 30	Degasification will be used to remove CO_2 emissions from process water.

Due to the required direct contact of process water with process gases, some traces of gas constituents are dissolved in water at elevated process gas pressure. In order to reduce the fugitive emissions at the clarifier and to reduce scaling in process water ducts a forced degassing will be installed. The return water flow from the top gas scrubber weir (after depressurization) is routed to a degasser vessel where air (coming from a separate air fan) is flowing upwards in countercurrent to the down flowing hot return water. The majority of the dissolved gas constituents (CO_2, CO, etc.) are collected in the degasser vent gas flow and released to atmosphere at a safe location. The degassed water from the degasser is flowing to the clarifier.

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4.8.1 *CO_2e Emissions from the Process Water Degasser*

All partial flow rates from process water system (including direct cooling) are collected and treated at the process water treatment plant. Due to the required direct contact of process water with process gases (top gas scrubber in particular), some traces of gas constituents (CO_2, CO, etc.) are dissolved in water at elevated process gas pressure. The return water flow from the top gas scrubber weir (after depressurization) is routed to a degasser vessel where air (coming from a separate air fan) flows countercurrent to the hot return water. The majority of the dissolved gas constituents (CO_2, CO, etc.) are collected in the degasser vent gas flow and released to atmosphere at safe location. The degassed water from the degasser then flows to the clarifier.

The amount of CO_2, CO, etc. in the return water flow from direct contact of process water with process gas (e.g., gas scrubber systems) is a result of basic physics principles of gas wet treatment technology; the degassing of the return water flow has to operate because of industrial hygiene and safety reasons only. The CO_2 emissions at the degasser can be estimated via calculation using the theoretical absorption capacity (Henry`s Law) and the flow rates. Furthermore the flow and concentration of CO and CO_2 are irregular since entry to and from the pressurized DRI process is episodic in nature too.

<u>Step 1 – Identify Potential Control Technologies</u>

A search of USEPA's RBLC database revealed the following entries for the control of CO_2e emissions from the process water degasser at DRI plants. Documentation compiled in this research is presented in the table below.

TABLE 4-12: Summary of RBLC Data for CO_2e Emissions from Process Water Degasser at DRI Plants

RBLC ID Number Company, Date	Process Description	Emission Limits	Control Type and Efficiency
- Formosa Plastics Corp. Point Comfort, TX November 2012 Permit Application	Process Water Stripper	Proposed BACT-PSD: CO_2e Limit – none.	caustic/water wash tower.
IA-0206 CF Industries Nitrogen, LLC Port Neal Nitrogen Complex 07/12/2013	Condensate Steam Stripper	BACT-PSD: CO_2e Limit – none.	Good operating practices.
LA-0272 Dyno Nobel Louisiana Ammonia, LLC Ammonia Production Facility 03/27/2013	CO_2 Stripper Vent	BACT-PSD: CO_2e Limit – none.	Energy efficiency measures.

RBLC ID Number Company, Date	Process Description	Emission Limits	Control Type and Efficiency
MN-0070 Minnesota Steel Industries, LLC Itasca, MN 09/07/2007	Quench Cooling Water Blowdown Line 1	BACT-PSD: CO_2e Limit – none.	N/A
MN-0070 Minnesota Steel Industries, LLC Itasca, MN 09/07/2007	Process Water Blowdown Line 1	BACT-PSD: CO_2e Limit – none.	N/A

The following list of control technologies represent technologies that have been used for the control of CO_2 emissions from the process water degasser.

1. Caustic/Water Scrubber
2. Good Operating Practices and Proper Maintenance

Caustic/Water Scrubber

A caustic/water scrubber can be used for the removal of acid gases (e.g., CO_2 and trace H_2S) from the process water degasser exhaust. A control efficiency of 95 to 99% can be attained depending on the type of reagent used (such as 20% caustic solution) and the scrubber design.

Good Operating Practices and Proper Maintenance

Good operating practices include appropriate maintenance of equipment and operating within the operational parametersrecommended by the manufacturer. Using good operating practices in conjunction with proper maintenance results in longer life of the equipment and more efficient operation. Therefore, such practices indirectly reduce GHG emissions by supporting operation as designed and with consideration of other energy optimization practices incorporated into the voestalpine facility. voestalpine will incorporate such operating practices and proper maintenance as recommended by the process water degasser manufacturer.

Step 2 – Eliminate Technically Infeasible Options

The identified control strategies are technically feasible and have not been eliminated.

Step 3 – Rank Remaining Technically Feasible Control Options

1. Caustic/Water Scrubber (99%)
2. Good Operating Practices (50%)

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Step 4 – Evaluate Remaining Control Technologies

Caustic/Water Scrubber

Although technically feasible, use of a caustic/water scrubber to control the small amount of GHG emissions that occur from process water degassing is clearly cost prohibitive. Process water degassing operations contribute insignificant quantities of GHGs (less than 0.06% of project CO_2e emissions), so use of add-on controls cannot be cost effective.

Good Operating Practices and Proper Maintenance

voestalpine will incorporate good operating practices and perform maintenance as recommended by the process water degassing manufacturer.

Step 5 – Selection of BACT

BACT for CO_2 emissions from the process water degasser is determined to be good operating practices and proper maintenance for the process water degasser, and no additional control is feasible for the small CO_2 emissions resulting from the removal of seal gas dissolved in process water.

TABLE 4-13: Summary of BACT for CO_2e Emissions from Process Water Degasser at voestalpine

Company, Date	Process Description	Emission Limits	Control Type and Efficiency
voestalpine 2013	Process Water Degasser, Emission Source 30	Proposed BACT-PSD: CO_2e Limit – 1,126 tpy.	Good operating practices and proper maintenance.

4.9 EMERGENCY GENERATOR AND FIRE PUMP

Emission Sources and Process Descriptions

Emission Source	Description
Emergency Generator, Emission Source 34	To ensure the supply of electric power in case of failure of the main incoming supply, an emergency diesel generator is provided for powering selected electrical consumers.
Fire Pump, Emission Source 35	To ensure the supply of water in case of fire, an emergency diesel fire pump is provided for fire protection.

4.9.1 CO_2e Emissions from the Emergency Generator and Fire Pump

The three GHGs—CO_2, CH_4, and N_2O—are emitted during the combustion of fossil fuels. CO_2 accounts for the majority of the GHG emissions from stationary combustion sources. This section performs a detailed, step-by-step BACT analysis for control of CO_2 from the engines for the emergency generator and fire pump at the voestalpine facility.

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Step 1 – Identify Potential Control Technologies

A search of USEPA's RBLC database revealed the following entries for the control of CO_2e emissions from emergency engines. Documentation compiled in this research is presented in the table below.

TABLE 4-14: Summary of RBLC Data for CO_2e Emissions from Emergency Generators and Fire Pumps

RBLC ID Number Company, Date	Process Description	Emission Limits	Control Type and Efficiency
LA-0256 Westlake Vinyls Company LP Ascension Parish, LA 12/06/11	Emergency Generator, 1818 HP, Natural Gas	BACT-PSD: GHG limit – CO_2e 1,509.23 lb/hr, 39.24 tpy.	USE OF NATURAL GAS AS FUEL AND GOOD COMBUSTION PRACTICES.
FL-0328* ENI U.S. Operating Company, Inc. Lloyd Ridge (OCS), FL 10/27/2011 *Draft Determination	Emergency Engine, Diesel	BACT-PSD: GHG Limit – CO_2 14.6 tpy, 12-month rolling.	Use of good combustion practices, based on the current manufacturer's specifications for this engine.
FL-0328* ENI U.S. Operating Company, Inc. Lloyd Ridge (OCS), FL 10/27/2011 *Draft Determination	Emergency Fire Pump Engine, Diesel	BACT-PSD: GHG Limit – CO_2 2.4 tpy, 12-month rolling.	Use of good combustion practices, based on the current manufacturer's specifications for this engine.
LA-0254 Entergy Louisiana LLC LA 08/16/11	Emergency Diesel Generator, 1250 HP	BACT-PSD: GHG Limit – 163 lb/MMBtu, 12-month rolling.	Proper operation and good combustion practices.
LA-0254 Entergy Louisiana LLC LA 08/16/11	Emergency Fire Pump, 350 HP, Diesel	BACT-PSD: GHG Limit – 163 lb/MMBtu, 12-month rolling.	Proper operation and good combustion practices.
TX-0481 Air Products LP Baytown, TX 11/02/04	Emergency Generator	BACT-PSD: CO_2 Limit - 2.24 lb/hr, 0.99 tpy.	No control specified.

The RBLC database did not identify any add-on CO_2 control technologies for emergency engines; only good combustion practices were identified in the RBLC as BACT for emergency engines. However, the following list of control technologies represent technologies that could be used for the control of GHG emissions from emergency engines.

1. Carbon Capture with Dedicated Sequestration
2. Carbon Capture with Transport and Sequestration
3. Low-Carbon Fuel
4. Good Combustion Practices and Proper Maintenance

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Carbon Capture with Dedicated Sequestration

CO_2 released from the emergency engines is mixed with products of combustion and other inert gases, and is not suitable for sequestration.

Carbon Capture with Transport and Sequestration

CO_2 released from the emergency engines is mixed with products of combustion and other inert gases, and is not suitable for sequestration.

Low-Carbon Fuel

Using fuels containing lower concentrations of carbon generates less CO_2 than other higher carbon fuels. Typically, gaseous fuels such as natural gas contain less carbon, and thus lower CO_2 potential, than liquid or solid fuels such as diesel or coal.

The use of natural gas as a combustion fuel, in preference over other fossil fuels such as diesel, results in fewer GHG emissions per unit of energy output. This property has been well documented, including through USEPA's GHG Reporting Rule, which lists natural gas as having the lowest CO_2 emission factor of any primary fossil fuel. Natural gas also has benefits over the use of diesel fuel, from the perspective of emissions from other pollutants, such as sulfur dioxide and particulate matter.

Good Combustion Practices and Proper Maintenance

Good combustion practices for compression ignition engines include appropriate maintenance of equipment (such as periodic testing as will be conducted weekly) and operating within the recommended air to fuel ratio recommended by the manufacturer. Using good combustion practices in conjunction with proper maintenance results in longer life of the equipment and more efficient operation. Therefore, such practices indirectly reduce GHG emissions by supporting operation as designed and with consideration of other energy optimization practices incorporated into the voestalpine facility.

Step 2: Eliminate Technically Infeasible Options

Carbon Capture with Dedicated Sequestration

CO_2 released from the emergency engines is mixed with products of combustion and other inert gases, and is not suitable for sequestration. Therefore, carbon capture with dedicated sequestration is not technically feasible and has been eliminated. Also, because the emergency generator and fire pump will normally operate 100 hours per year or less and because their stack gases are low in volume and CO_2 mass rate, the capture, and segregation of CO_2 for sequestration is considered a technically infeasible control option for the emergency engines at the voestalpine facility.

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Carbon Capture with Transport and Sequestration

CO_2 released from the emergency engines is mixed with products of combustion and other inert gases, and is not suitable for sequestration. Therefore, carbon capture with transport and sequestration is not technically feasible and has been eliminated. Also, because the emergency generator and fire pump will normally operate 100 hours per year or less and because their stack gases are low in volume and CO_2 mass rate, the capture, transport, and segregation of CO_2 for sequestration is considered a technically infeasible control option for the emergency engines at the voestalpine facility.

Low-Carbon Fuel

Because the emergency generator and fire pump are intended for emergency use, these engines must be designed to use non-volatile fuel such as diesel fuel. Use of volatile (low-carbon) natural gas in an emergency situation could exacerbate a potentially volatile environment that could be present under certain conditions, resulting in unsafe operation. Therefore, non-volatile fuel is appropriate and necessary for emergency equipment. Therefore, use of low-carbon fuel is considered technically infeasible for emergency engine operation.

Step 3 – Rank Remaining Technically Feasible Control Options

1. Good Combustion Practices and Proper Maintenance (50%)

Step 4 – Evaluate Remaining Control Technologies

Good Combustion Practices and Proper Maintenance

voestalpine will incorporate good combustion practices and perform maintenance as recommended by the emergency generator and fire pump manufacturers.

Step 5: Select BACT

A top-down BACT analysis was performed for emissions of CO_2e from emergency engines. voestalpine will maintain good combustion practices and proper maintenance for the emergency generator and fire pump to control CO_2e emissions.

Further, these new engines will be subject to the NSPS for Stationary Compression Ignition Internal Combustion Engines (40 CFR 60 Subpart IIII), and specific emissions standards for various pollutants must be met during normal operation, such that the engines will meet or exceed BACT.

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TABLE 4-15 Summary of BACT for CO_2e Emissions from Emergency Generator and Fire Pump at voestalpine

Company, Date	Process Description	Emission Limits	Control Type and Efficiency
voestalpine 2013	Emergency Generator, Emission Source 34	Proposed BACT-PSD: CO_2e Limit –197 tpy (based on 100 hrs).	Good combustion practices and proper maintenance. Engines must comply with NSPS Subpart IIII based on manufacturer's specifications.
voestalpine 2013	Fire Pump, Emission Source 35	Proposed BACT-PSD: CO_2e Limit –12,8 tpy (based on 100 hrs).	Good combustion practices and proper maintenance. Engines must comply with NSPS Subpart IIII based on manufacturer's specifications..

4.10 FUGITIVES

This section describes a detailed, step-by-step BACT analysis for control of CO_2e emissions from the fugitive components for voestalpine.

Emission Sources and Process Descriptions

Fugitive components for voestalpine will include: valves; pressure relief valves; pump seals; compressor seals; and sampling connections. GHG emissions from leaking pipe components (fugitive emissions) from the proposed project will include both CO_2 and CH_4; however, the ratio of CO_2 to CH_4 in pipeline-quality natural gas is relatively low. For purposes of the GHG calculations, it was assumed all piping components will be in a rich CH_4 stream.

The following discussion presents a BACT evaluation of fugitive CO_2 and CH_4 emissions, and because the fugitive emission controls presented in this analysis will provide similar levels of emission reduction for both CO_2 and CH_4, the BACT evaluation has been combined into a single analysis.

4.10.1 CO_2e Emissions from Fugitive Components

A search of USEPA's RBLC database identified the following entries for the control of CO_2e emissions from fugitive components. Related permits and permit applications are also included.

TABLE 4-16: Summary of RBLC Data for CO_2e Emissions from Fugitive Components

RBLC ID Number Company, Date	Process Description	Emission Limits	Control Type and Efficiency

RBLC ID Number Company, Date	Process Description	Emission Limits	Control Type and Efficiency
- Cheniere Corpus Christi Pipeline, Sinton Compressor Station 08/31/2013	Fugitive Emissions	Proposed BACT-PSD: CO_2e Limit – none.	Conduct annual GHG surveys in compliance with 40 CFR 60 Part 98.
- Celanese, Ltd. – Clear Lake Plant August 2013	Fugitive Emissions	Proposed BACT-PSD: CO_2e Limit – none.	Implementation of 28LAER LDAR program; use of an AVO program to monitor for leaks in between instrumented checks; and use of high quality components and materials of construction.
LA-0271 Crosstex Processing Services, LLC - Plaquemine NGL Fractionation Plant 05/24/2013	Fugitive Emissions	BACT-PSD: CO_2e Limit – none.	Compliance with LDAR programs under 40 CFR 60 Subpart OOOO, LAC 33:III.2111, and LAC 33:III.2122.
LA-0266 Crosstex Processing Services, LLC - Eunice Gas Extraction Plant 05/01/2013	Process Fugitives	BACT-PSD: CO_2e Limit – none.	Compliance with LDAR programs: NSPS KKK and LAC 33:III.2121.
- Dominion Cove Point LNG, LP March 2013	Fugitives	Proposed BACT-PSD: CO_2e Limit – 53.6 ton/yr 12-month rolling total.	Implementation of an LDAR program; implementation of an AVO monitoring program.
- Corpus Christi Liquefaction, LLC August 2012 (*Permit Application)	Fugitives	Proposed BACT-PSD: CO_2e Limit – 38 ton/yr 12-month rolling total.	Use of leakless components (welded flanges) to the maximum extent possible; implementation of 28VHP LDAR program.
LA-0263 Phillips 66 Company – Alliance Refinery 07/25/2012	Hydrogen Plant Fugitives	BACT-PSD: CO_2e Limit – none.	Implementation of the Louisiana Refinery MACT leak detection and repair (LDAR) program; monitoring for total hydrocarbon content instead of VOC.

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RBLC ID Number Company, Date	Process Description	Emission Limits	Control Type and Efficiency
- ETC Texas Pipeline – Jackson May 2012	Fugitive Emissions	BACT-PSD: CO_2e Limit – none.	Emissions shall be calculated annually based on the emission factors from Table W-1A of 40 CFR Part 98, Subpart W, Petroleum and Natural Gas Systems and using the reduction credit from 28LAER and calculations given in the TCEQ Technical Guidance Document for Equipment Leak Fugitives, dated October 2000.
LA-0257 Sabine Pass LNG, LP and Sabine Pass Liquefaction, LLC – Sabine Pass LNG Terminal 12/06/2011	Fugitive Emissions	BACT-PSD: CO_2e Limit – 89,629 ton/yr annual maximum.	Conduct a leak detection and repair (LDAR) program.
- Freeport LNG Development, LP December 2011 (*Permit Application)	Fugitives for Pretreatment Facility	Proposed BACT-PSD: CO_2e Limit – none.	Implementation of 28MID LDAR program (with quarterly monitoring) and AVO program in between LDAR checks.
- Freeport LNG Development, LP December 2011 (*Permit Application)	Fugitives for Liquefaction Plant	Proposed BACT-PSD: CO_2e Limit – none.	Implementation of 28MID LDAR program (with quarterly monitoring) and AVO program in between LDAR checks.
TX-0612 Lower Colorado River Authority – Thomas C. Ferguson Power Plant 11/10/2011	Fugitive Natural Gas Emissions	BACT-PSD: CO_2e limit – 327.2 ton/yr 365-day rolling average. BACT-PSD: CH_4 limit – 16.2 ton/yr 365-day rolling average.	Because the emissions from this unit are calculated to be 96% methane (CH_4), the remaining pollutant emissions (CO_2) are not accounted for.

* RBLC data obtained from USEPA RBLC, Process Type 50.999, other petroleum and natural gas production and refining sources.

Step 1 – Identify Potential Control Technologies

The following technologies were identified as potential control measures for CO_2e emissions associated with fugitive components.

1. Installing Leakless Technology Components
2. Implementing Various LDAR Programs

3. Implementing an Alternative Monitoring Program
4. Implementing an Audio/Visual/Olfactory (AVO) Monitoring Program
5. Designing and Constructing Facilities with High Quality Components and Materials of Construction

Carbon capture with dedicated sequestration and carbon capture with transport and sequestration are not included in this list because CO_2 and CH_4 emissions released from fugitive components are not easily captured for sequestration purposes.

Installing Leakless Technology Components

Emissions from pumps and valves can be reduced through the use of leakless valves (such as welded bonnet bellows valves and diaphragm valves) and sealless pumps (such as diaphragm, canned, and magnetic-driven pumps). This is the most effective of the controls.

Leakless technologies are highly effective in eliminating fugitive emissions from the specific interface where installed; however, fugitive leaks may still occur because leak interfaces remain even with leakless technology components in place. As an example, the sealing mechanism (such as a bellows) is not repairable online and may leak in the event of a failure until the next unit shutdown.

Implementing Various LDAR Programs

LDAR programs are required by a number of state and federal air regulations for the control of VOC emissions. BACT determinations related to control of VOC emissions rely on technical feasibility, economic reasonableness, reduction of potential environmental impacts, and regulatory requirements for these instrumented programs.

Implementing an Alternative Monitoring Program

Alternate monitoring programs have proven to be effective in leak detection and repair. For example, the use of sensitive infrared camera technology has become widely accepted as a cost effective means for identifying leaks of hydrocarbons and may also be effective for identifying leaks of CO_2 and CH_4.

Implementing an AVO Monitoring Program

Leaking fugitive components can be identified through audio, visual, or olfactory (AVO) methods. The fugitive emissions from piping components are expected to have a discernible odor, making them detectable by olfactory means. A large leak can be detected by sound and/or sight. The visual detection can be a direct viewing of leaking gases, or a secondary indicator such as condensation around a leaking source due to cooling of the expanding gas as it leaves the leak interface. AVO programs are commonly used in various industries.

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Designing and Constructing Facilities with High Quality Components and Materials of Construction

A key element in the control of fugitive emissions is the use of high quality equipment that is designed for the specific service in which it is employed. For example, a valve that has been manufactured under high quality conditions have a reduced likelihood of a leak.

Step 2: Eliminate Technically Infeasible Options

Installing Leakless Technology Components

The use of leakless technology components to eliminate fugitive emission sources is an available option; however, these technologies are generally considered to be technically infeasible except for specialized service, and the use of leakless technologies can actually result in higher maintenance and shutdown emissions. For example, some leakless technologies, such as bellows valves, cannot be repaired without a unit shutdown that often generates additional emissions. Also, using leakless connectors can result in an inability to isolate small areas; therefore, requiring the clearance of a larger area or a full shutdown to perform maintenance. As a result, further consideration of leakless technology for GHG controls is unwarranted.

Step 3 – Rank Remaining Technically Feasible Control Options

1. Implementing Various LDAR Programs
2. Implementing an Alternative Monitoring Program
3. Implementing an Audio/Visual/Olfactory (AVO) Monitoring Program
4. Designing and Constructing Facilities with High Quality Components and Materials of Construction

Step 4 – Evaluate Remaining Control Technologies

Implementing Various LDAR Programs

Conventional LDAR programs are designed to control VOC emissions and vary in stringency. CH_4 is not considered a VOC, so LDAR programs have not previously been required for streams containing a high CH_4 content. However, instrumented monitoring is effective for identifying leaking CH_4 emissions, and with CH_4 having a GWP greater than CO_2, instrumented monitoring of the fuel system for CH_4 would be an effective method for control of CO_2e emissions.

The table below is a summary of the Texas Commission on Environmental Quality's (TCEQ's) LDAR programs and the control efficiencies that may be achieved with each. The TCEQ's 28LAER program is one of the TCEQ's most stringent LDAR programs, which was developed to satisfy LAER requirements in ozone non-attainment areas. The voestalpine facility will be located in an attainment area, so LAER requirements are not applicable. Accordingly, the use of the 28 LAER LDAR program is not appropriate. The next most stringent LDAR program is TCEQ's 28MID program. The 28MID program requires quarterly instrumented monitoring with a leak definition of 500 ppmv, accompanied by intense directed maintenance, which is generally assigned a control effectiveness of 97%.

Although technically feasible, use of an LDAR program to control the negligible amount of GHG emissions that occur as process fugitives is clearly cost prohibitive. Natural gas lines contribute insignificant quantities of GHGs (less than 0.005% of project CO_2e emissions), so use of an LDAR program cannot be cost effective.

TABLE 4-17: Summary of TCEQ Control Efficiencies for Leak Detection and Repair (LDAR) Programs

Equipment/Service	28M	28RCT	28VHP	28MID	28LAER	Audio/Visual/Olfactory[1]
Valves						
Gas/Vapor	75%	97%	97%	97%	97%	97%
Light Liquid	75%	97%	97%	97%	97%	97%
Heavy Liquid[2]	0%[3]	0%[4]	0%[4]	0%[4]	0%[4]	97%
Pumps						
Light Liquid	75%	75%	85%	93%	93%	93%
Heavy Liquid[2]	0%[3]	0%[3]	0%[5]	0%[6]	0%[6]	93%
Flanges/Connectors						
Gas/Vapor[7]	30%	30%	30%	30%	97%	97%
Light Liquid[7]	30%	30%	30%	30%	97%	97%
Heavy Liquid	30%	30%	30%	30%	30%	97%
Compressors	75%	75%	85%	95%	95%	95%
Relief Valves (Gas/Vapor)	75%	97%	97%	97%	97%	97%
Open-ended Lines[8]	75%	97%	97%	97%	97%	97%
Sampling Connections	75%	97%	97%	97%	97%	97%

Notes:

1. Audio, visual, and olfactory walk-through inspections are applicable for inorganic/odorous and low vapor pressure compounds such as chlorine, ammonia, hydrogen sulfide, hydrogen fluoride, and hydrogen cyanide.
2. Monitoring components in heavy liquid service is not required by any of the 28 Series LDAR programs. If monitored with an instrument, the applicant must demonstrate that the VOC being monitored has sufficient vapor pressure to allow reduction.
3. No credit may be taken if the concentration at saturation is below the leak definition of the monitoring program (i.e. (0.044 psia/14.7 psia) x 106 = 2,993 ppmv versus leak definition = 10,000 ppmv).

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4. Valves in heavy liquid service may be given a 97% reduction credit if monitored at 500 ppmv by permit condition provided that the concentration at saturation is greater than 500 ppmv.
5. Pumps in heavy liquid service may be given an 85% reduction credit if monitored at 2,000 ppmv by permit condition provided that the concentration at saturation is greater than 2,000 ppmv.
6. Pumps in heavy liquid service may be given a 93% reduction credit if monitored at 500 ppmv by permit condition provided that the concentration at saturation is greater than 500 ppmv.
7. If the applicant decides to monitor connectors using an organic vapor analyzer (OVA) at the same leak definition as valves, then the applicable valve reduction credit may be used instead of the 30% reduction credit. If this option is chosen, the applicant shall continue to perform the weekly physical inspections in addition to the quarterly OVA monitoring.
8. The 28 Series quarterly LDAR programs require open-ended lines to be equipped with an appropriately sized cap, blind flange, plug, or a second valve. If so equipped, open-ended lines may be given a 100% control credit.

Implementing an Alternative Monitoring Program

Similarly, although technically feasible, use of an alternative monitoring program to control the negligible amount of GHG emissions that occur as process fugitives is clearly cost prohibitive. Natural gas lines contribute insignificant quantities of GHGs (less than 0.02% of project CO2e emissions), so use of an alternative monitoring program cannot be cost effective.

Implementing an Audio/Visual/Olfactory (AVO) Monitoring Program

An AVO monitoring program is effective because of the frequency of observation opportunities as operating technicians make rounds and inspect equipment during routine inspections of operating areas. This method cannot generally identify leaks at a leak rate as low as instrumented reading can identify; however, larger leak rates have higher potential impacts than do lower leaks. Therefore, this method is effective for identification of larger leaks due to the frequency of observation.

Designing and Constructing Facilities with High Quality Components and Materials of Construction

The use of high quality components is effective in preventing CO_2 and CH_4 emissions, particularly compared to the use of lower quality components. State-of-the-art valves, seals, and piping will be designed to be as fully pressure containing as possible. Examples include installing valves that are equipped with lubrication/sealant ports around stem packing, ensuring correct flange alignment during construction, use of spiral wound gaskets in flanges, and use of dry gas seals for centrifugal compressors.

Step 5: Select BACT

For CO_2e emissions from fugitive components, BACT is selected to be use of an AVO program to monitor for leaks; and use of high quality components and materials of construction. voestalpine also proposes a numerical BACT limit for CO_2e emissions as shown in the table below.

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TABLE 4-18: Summary of Proposed BACT for CO_2e Emissions from Fugitive Components for voestalpine

Company, Date	Process Description	Emission Limits	Control Type and Efficiency
voestalpine 2013	Fugitive Components	Proposed BACT-PSD: CO_2e Limit – 84 tpy.	Use of an AVO program to monitor for leaks in between instrumented checks; and use of high quality components and materials of construction.

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4.11 *OTHER MEASURES*

Terrestrial sequestration involves the fixation of the CO_2 into vegetative biomass and soils. For example, trees use CO_2 as they grow, and some agricultural practices, such as no-till farming, keep CO_2 in the soil (rather than releasing it when the land is tilled). This type of approach is being used in some states, such as Mississippi and other Lower Mississippi Valley states by the US Fish and Wildlife Service (USFWS). The USFWS, in conjunction with company partners and other conservation agencies, has added 40,000 acres of restored habitat to its national wildlife refuges and more than 80,000 acres to native habitats (USFWS, 2010). However, as summarized by the Southwest Regional Partnership for Carbon Sequestration (SWP):

> *"… terrestrial carbon capacity in the Southwest region is limited by low average annual precipitation and yearly variability in precipitation. Even in systems managed for carbon storage, wet years followed by a series of dry years may result in a net carbon flux out of the system. Opportunity to increase carbon storage on range lands is limited because most areas are at a relatively stable equilibrium given land use history and management. Much of the desert grassland and shrub land areas with less than 12 inches of annual precipitation are subject to loss of cover and exposure to wind and water erosion. Retaining soil carbon levels in these ecosystems will require active restoration practices that are challenging, given current technologies"* (SWP, 2012).

Because terrestrial sequestration is unlikely to be effective in Texas, this technology was not evaluated further in this application.

The use of solar collectors or wind turbines to generate energy at DRI plants is potentially feasible, but the existing infrastructure may not be sufficient to supply extra power to the grid. This technology was not evaluated further in this application.

5.0 ADDITIONAL REQUIREMENTS UNDER PSD

An analysis of ambient air quality impacts is not provided with this application as there are no National Ambient Air Quality Standards (NAAQS) or PSD increments established for GHG (per EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases*).

Since there are no NAAQS or PSD increments for GHGs, the requirements in sections 52.21(k) and 51.166(k) of EPA's regulations to demonstrate that a source does not cause contribute to a violation of the NAAQS are not applicable to GHGs. Therefore, there is no requirement to conduct dispersion modeling or ambient monitoring for CO_2 or GHGs. Additionally, an analysis of Air Quality Related Values (AQRV) is not provided because GHGs do not contribute to regional haze or terrestrial/aquatic acid deposition.

A pre-construction monitoring analysis for GHG is not being provided with this application in accordance with EPA's recommendations (per EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases*). EPA does not consider it necessary for applicants to gather monitoring data to assess ambient air quality for GHGs under 40 CFR 52.21(m)(1)(ii), 40 CFR 51.166(m)(1)(ii), or similar provisions that may be contained in state rules based on EPA's rules. GHGs do not affect "ambient air quality" in the sense that EPA intended when these parts of EPA's rules were initially drafted. Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for purpose of assessing ambient air impacts of GHGs

A PSD application for the criteria pollutants is being submitted to the Texas Commission for Environmental Quality (TCEQ) under separate cover. Impact evaluations related to the Federal Endangered Species Act (biological assessment) and the National Historic Preservation Act (cultural assessment) are being submitted to USEPA under separate cover.

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