Contribution of Infrastructure to Oil and Gas Production and Processing Carbon Footprint

John Beath[1], Nyx Black[1], Marjorie Boone[1], Guy Roberts[1], Brandy Rutledge[1],

Amgad Elgowainy[2], Michael Wang[2], Jarod Kelly[2]

[1]Environmental Resources Management, Inc.

[2]Systems Assessment Group, Energy Systems Division, Argonne National Laboratory

October 2014

Abstract

The contribution of capital equipment used to extract oil and gas from the ground, process it into key gas fractions, and refine it, has long been discounted in carbon footprint calculations as not material; however, data in support of this assertion is scarce.

In a unique approach, this paper presents data compiled on the capital infrastructure required through the lifecycle of petroleum production and processing. Publicly available data was gathered and populated to summarize the capital infrastructure associated with offshore and onshore oil and gas production, pipeline distribution to processing, and processing facilities including refinery and gas plant. Data for the refinery was obtained from a refinery that has been demolished. A comprehensive Internet search was conducted to locate equipment characteristics for gas plants, onshore and offshore well site infrastructure, and pipeline. The results presented are totals for the steel and concrete in actual equipment and infrastructure used in each stage, as determined by an equipment inventory and associated process specifications. Previously published results[1] indicated that the carbon footprint contribution is relatively small compared to the fuel combusted to produce and process oil and gas, which is a highly energy-intensive process. This more all-encompassing evaluation of the cradle-to-gate infrastructure impacts as compared to operational impacts expanded on that previous work and results now suggest that carbon impacts from oil and gas-related infrastructure are material to the cradle-to-gate footprint both onshore and offshore.

The data suggest that the carbon footprint of offshore oil and gas production is higher than for the corresponding onshore oil and gas production operations, and that the per unit of energy *cradle-to-grave* carbon footprint of natural gas is lower than for crude oil, owing to large combustion differences. However, the *cradle-to-gate* carbon footprint of natural gas is higher than oil on an energy basis.

Keywords: Refinery, Steel Manufacturing, Capital Equipment, Infrastructure, Oil and Gas

[1] Beath et al, American Center for Life Cycle Assessment (2012)

Introduction

As oil and gas companies search for ways to reduce their carbon footprint in response to corporate reduction commitments, one place that might offer promise is addressing the impact from the large mass of materials that are used to construct equipment and infrastructure for oil and gas operations. The impacts from infrastructure are potentially considerable, even when spread over the lifetime of a facility, because the mass of the infrastructure is so large. This paper sought to determine the materiality of the infrastructure impacts as compared to the significant impacts from combustion-related site activities. Efforts to consider steel use as part of design alternatives decision-making might be appropriate if infrastructure impacts are indeed significant. For example, favoring shallow versus deep well production offshore due to the massive amount of steel required to support platforms, connect wells with pipelines to the platform and to shore processing facilities, and the additional well casing that might be required. Alternatively, considering lighter alloys or aluminum might become a viable alternative as has been a recent trend for offshore "topsides" crew quarters construction.

Oil and gas companies are increasingly required to share data about their operations for safety and environmental reasons. Additionally, with the public focus on sustainability and environmentally-friendly operations, more and more oil and gas companies are voluntarily submitting information to public databases, such as Frac Focus (http://fracfocus.org/), in an effort to gain a public relations advantage. These two observations serve as motivation for this evaluation. Infrastructure and operational details associated with offshore and onshore oil and gas wells, pipelines, gas processing plants, and refineries were gathered from publically available data, or other sources as noted herein. It should be noted that refineries are reluctant to share details about how their facilities are constructed for reasons of competitive advantage as more and more of their technology involves licensed processes. In order to perform this analysis relative to the refinery infrastructure, a demolished refinery's process data was accessed with the permission of the current owner of the surviving equipment and associated property (now operated as a terminal).

One focus of this evaluation was to look in detail at offshore infrastructure impacts because these are a key portion of the input to consumption for US users of oil and natural gas-derived products. Offshore oil and gas production is an important element of the United States fuel supply, but it is currently a relatively small portion compared to onshore production. The National Energy Technology Laboratory (NETL)[2] presents data (Table 4-9) that shows approximately 13% of the consumption by the U.S. of natural gas produced in the US was from offshore sources. Table 6.3 from the Energy Information Administration (EIA) 2011[3] data shows that 8% of the US consumption of natural gas was imported, mostly by pipeline from Canada. For crude oil, EIA reports (Table 5.2) that approximately 26% of crude oil produced domestically was from offshore (presumably the Gulf of Mexico). Based on the averages for

[2] Skone (2012)
[3] US EIA (2012)

onshore versus offshore production for the various contributing countries, imported US crude oil (Tables 5.3 and 5.4) was 17% from offshore sources. Offshore crude oil imports were led by Canada with 26%, the Persian Gulf with 18% and Mexico with 12%. Taking the relative amounts of offshore and onshore foreign and domestic consumed crude oil into account, it is estimated that 21% of the US crude oil supply was from offshore production.

Methodology – Refinery Equipment

This study started with the construction of a detailed equipment inventory for a former refinery using process specification data that had survived the refinery's demolition. This information provided dimensions for many of the distillation towers, reactors, tanks and process vessels. Detailed equipment specification sheets were not available (having been destroyed in a hurricane). Given this situation, the weights of these pieces of equipment were calculated using their geometry and American Petroleum Institute (API) standards for minimum steel thickness (in consideration of process temperature and pressure).[4]

For heat exchangers and process heaters, the heat duty was the only specification available. Internet searching was used to locate various pieces of equipment for sale where both the weight and duty were available. The former refinery data was scaled according to these few data points.

Steel in associated process piping was estimated by conducting a review of piping and instrumentation drawings (P&ID) for a single unit to determine (by count) the number of lines connecting process vessels. The results were scaled up using the total pieces of equipment in the refinery inventory and the value obtained from the count (approximately 5.5 connections per piece of equipment, average six inch nominal pipe diameter, two hundred foot average line length considering height difference and size of unit plot plan; all attributed to 22 process units). From a practical standpoint, this method took into account ancillary piping such as fuel gas, steam, and condensate more effectively than attempts by other estimation approaches.

Structural steel was initially estimated using an old process design rule-of-thumb that suggests that the cost of structural steel is 5% of the cost of associated process equipment (this implies a similar mathematical relationship for mass); however, an Internet search located data for structural steel for a recently constructed gas-to-liquids plant that the mass of steel in piping was a much higher value (50% of the mass of steel in process equipment), so that value was used. Inspection of various photographs and drawings suggests that refinery structural steel is a combination of steel girders and plate steel used for flooring and elevated walkways. It was assumed that plate steel is roughly similar in weight to using a grid structure (consider flattening the grid walkways and a similar surface area would result).

Given the typically large diameter of storage tanks, not only did the tanks dominate the mass of steel obtained, but whether the tank had a floating roof or cone roof was surprisingly significant. Floating roofs are typically made of aluminum and are very thin so they can float effectively but

[4] API (1990)

still provide the appropriate structural stability. Cone roofs are made of carbon steel and the thickness is much closer to that used for tank walls (in order to withstand wind, handle liquid vapor pressure and tank drawdown vacuum, and to support the weight of snow that may accumulate in colder regions).

Because the former refinery developed into its final configuration as an evolutionary process over many years, it was appropriate to question whether the ratio of its tanks storage capacity to crude throughput rate was consistent with more recent industry storage trends. To investigate this, the tankage associated with several other refineries was determined. This was done by consulting satellite photographs available through Google Maps, together with the location of the selected refineries. At maximum magnification, it was possible to use the scale and measure tank diameters on-screen.

Measurements were made for three refineries with refining capacities of 60, 175 and 307 thousand barrels per day – MBPD, (8,200, 23,900, and 41,900 metric tonnes/day). Additionally, three refineries where data was available due to work performed by ERM specifically for these clients were consulted as a cross-check. The results showed that the former refinery had a ratio of 70.6 barrels of tank capacity per BPD (9.6 metric tonnes/day) of refinery charge rate, while the average of the facilities selected for comparison was 47.9 barrels/BPD. As a consequence of this analysis, the steel predicted using the tanks at the former refinery which were dedicated to the "in scope" process units was reduced by applying the ratio of 47.9/70.6 to the initial steel inventory value.

Two key aspects of a refinery that needed to be considered were the crude charge rate and the types of process units that would be included. The study was designed to estimate steel present in an average US refinery. To determine average crude charge rate, EPA's Residual Risk Data for refineries was used (listing 155 US refineries). The resulting average was 118,000 barrels per day (BPD) (16,100 metric tonnes/day). The former refinery used as the basis for the equipment inventory had a design crude rate of 120,000 BPD (16,400 metric tonnes/day) so no adjustment to the former refinery inventory was made.

API's 2000 Worldwide Refining Survey[5] was used to determine which types of units would be included in the average refinery. The assumption made was that units which processed 2% or more of refinery crude charge rate would be included. The resulting types of units (in decreasing throughput order) were: Crude Fractionating, Catalytic Hydrotreating, Vacuum Distillation, Catalytic Cracking, Catalytic Reforming, Coking, Catalytic Hydrocracking, Alkylation, Isomerization and Aromatics Production.

The former refinery did not have all of these units, so those missing from the inventory were "constructed" by consulting the *Hydrocarbon Processing* 2011 "Refinery Processing Handbook"[6] unit flow sheets and using refinery equipment of an appropriate size to "assemble"

---

[5] Stell (2000)
[6] Hydrocarbon Processing (2011)

each unit. Units added based on this 2% assumption were Coking, Catalytic Hydrocracking, and an Isomerization Unit. As a placeholder for miscellaneous units present at other refineries, the Oxygenates Unit, was also included even though it processed less than 2% of crude charge

Results from the refinery equipment inventory are presented in Appendix A.

Methodology – Gas Plant Equipment

A comprehensive Internet search was conducted to locate equipment characteristics for gas plants. To supplement this information, an existing gas plant was reviewed using Google Maps satellite photos coupled with Title V permit application data available on the Texas Commission on Environmental Quality (TCEQ) Remote Document Server (RDS). The scaling of equipment from the photo images was important in establishing the tank listing, as well as the contribution from onsite piping. No other data sources provided this level of detail.

Gas plants vary widely in the degree of treatment required for removal of contaminants such as mercaptans, trace metals, acid gas, etc. Not all gas plants provide a sulfur removal capability, with some deferring this operation to a downstream facility.

To determine the model gas plant capacity, U.S. Energy Information Administration (EIA) data for 2012 was used for gas plants owned by ExxonMobil and Chevron in Texas. The value selected was 5.7 MM standard cubic meters of gas per day (200 MM standard cubic feet per day). Results from the gas plant equipment inventory are presented in Appendix A so they can be compared to corresponding values for the refinery.

Methodology – Onshore Well and Pipeline Infrastructure

In the US, onshore drilling practices have varied widely over time, and continue to evolve. In particular, there is an increasing degree of separation between the process for constructing and operating an unconventional gas well (drilled in an oil shale reserve and typically utilizing hydraulic fracturing to enhance the yield), and a conventionally drilled oil well operated to produce crude oil. As a consequence, this study reports differentiated results for conventional versus unconventional oil and gas wells.

Practices are likely to vary based on geography as a result of differing formations, the availability of water, and proximity to a gas plant or refinery. The study focused on average operating parameters where possible. The contribution from steel was based on what was used in the well itself, in addition to the supporting equipment on site. Well data, including completions details, casing elements, and distance from well to gas plant or refinery, were gathered from selected state agencies. The states that were selected had extensive exploration and production. These states are: New York, Pennsylvania, Texas, and North Dakota. Various filters were applied to the raw data gathered from the various state agencies. Only active / producing wells were selected, and where possible, these were grouped into three sets of data: (1) all wells; (2) wells completed within the past five years; and (3) wells completed within the past 12 months. This was done so that the results would be more forward-looking than backward-looking. Wells not specifically producing oil or gas were excluded (e.g., exploration wells, CO_2 injection, waste disposal, salt water, plugged add/or abandoned). As described above, well data was tagged so that oil and gas wells, as well as unconventional and conventional wells could be differentiated to the extent that the source information would allow.

The quantity of steel used to construct a well can be divided into drilling and production contributions. Though there are no set guidelines [e.g., from the World Resources Institute (WRI) Greenhouse Gas Protocol] for how these might be handled in building an estimate of this type, it was logical to allocate the drilling aspects to the portion of time the resources were on site while the well was drilled, and to allocate the resources consumed to support ongoing production (and staying permanently on site) across a thirty year life expectation for a well. This differs from the practice of showing capital equipment impacts for a corporate footprint in the year they occur (specified by WRI for corporate footprints).[7, 8] Steel mass from the casing installed in the well, and tubing routed inside it was the largest on-site contributor to the overall steel quantity used. Unlike drilling steel, which is removed after the well is drilled, and other drilling contributors like trucks and the drill rig itself, the casing components remain a permanent part of the well and are not available for future use. The quantity of steel required for this was previously determined[4], and the results from that study were incorporated directly into the equipment inventory table (Appendix B). The inventory was constructed using a combination of Internet search results, textbook descriptions, *Google Maps* views of well sites, and used well equipment for sale.

The impacts associated with pipelines used to gather oil and gas from specific well sites, as well as the pipeline necessary to transfer the oil and gas from well groupings in the field to the centralized refinery or gas plant, were included. The contribution of this piping compared to process equipment from a mass-based perspective was much larger than any other impact. The contribution of pipelines from the gas plant or refinery to downstream consumers was not considered because it was outside the scope of this study, but is likely to be even more significant. Estimation of pipeline distance proved to be an intensive exercise. Initially, refineries and gas plants were identified in the states selected for onshore well data gathering. The assumption was made that oil or gas would be refined/processed within that state, or at the nearest location. For estimating pipeline distance to refineries, a list of US refineries was obtained from EIA. Subsequently it was decided that refineries in adjacent states would also be located on a map and coordinates would be used to calculate the distances to close and nearby refineries, subject to some engineering judgment. In the case of Pennsylvania, the two refineries identified in the state did not have the processing capacity to handle all of the oil and gas produced by the wells. As a consequence, a cluster of refineries in New Jersey was selected as an additional location. The processing capacity assumed in Texas was different as a consequence of how the well data was selected (see below). For the two operators that were the

[7] WRI (2012) Corporate Scope 3
[8] WRI (2012) Product

focus of data collection in Texas, it was assumed based on industry practice that the oil extracted from these wells would go to the ExxonMobil Baytown refinery (for ExxonMobil production), or to either the centroid of Houston refineries or the Western Refinery in El Paso (formerly operated by Chevron) for the oil extracted by Chevron. A list of all gas plants in the US developed by EIA was used to identify the specific gas plants targeted to receive gas from study wells. For the states covered by the study, various Internet sources were used to develop latitude and longitude coordinates so these facilities could be plotted on a GIS map.

For North Dakota and Pennsylvania the distance from each well to each gas plant in the state was computed and the average minimum and maximum of these distances was determined. For New York, no gas plants were identified in the state but there are gas plants in northwest Pennsylvania across the border, so the decision was made to use distances to Pennsylvania gas plants. As suggested above, for Texas, a more detailed approach was taken. Chevron and ExxonMobil were selected as a focus for the study because both companies were known to have significant operations in the state and use dedicated company-owned gas plants. Therefore their wells were plotted in GIS and the distance to each of the company's closest gas plants was calculated. In reality, pipeline routes are rarely straight line distances between two locations due to land holdings, right-of-way agreements, geographic obstacles, etc. Therefore, graphical shape files were attained from the Texas Railroad Commission and these were utilized to overlay the actual oil gathering lines for the fields in question onto the map. Then routes were selected to be reasonably direct and measured using mapping tools. As a result of this effort a scale factor was developed that was applied to all gathering lines distances to account for their actual travel path. These scaling factors were based on a ratio of the available segmented pipeline-estimated distances from shape files to straight-line distances. The factor was estimated to be 1.07, and this additional 7% was applied to all measured straight-line pipeline distances.

<u>Distance From Well to Refinery</u>

For North Dakota, distances from each mapped oil well were computed to the Tesoro refinery in North Dakota and the centroid of the refineries in Billings, Montana. For Pennsylvania, distances were calculated to the two refineries in the state as well as to the centroid of the refineries in southern New Jersey. For Texas, the distance was determined from the Chevron oil wells to the Western refinery in El Paso, and separately to the centroid of the Houston refineries. For the ExxonMobil oil wells, the distance was computed from each oil well to the ExxonMobil oil refinery in Baytown, Texas (just east of Houston). Similar to distance to gas plants, scaling factors for indirect routing were also applied to the oil well to refinery gathering line data. Appendix C summarizes pipeline distance details estimated by state.

<u>Gathering Lines versus Transmission Lines</u>

Data developed by the Texas Railroad Commission was utilized to compile the relative lengths of pipelines in gathering line and transmission line service for both oil and gas in Texas. In this case, the term "transmission lines" refers to those gas service lines which connect gathering lines to gas plants. A "gathering line" is assumed to be a line connecting a single well's output to the first common pipeline. With respect to oil service, the "transmission" lines refer to those lines that connect the gathering lines to the refinery. This data was used to represent the other selected states as well.

Pipeline Diameter

Data developed by the Texas Railroad Commission[9] was also utilized to estimate the diameters of pipelines in gathering line and transmission service for both oil and gas in Texas. The export listing of each registered pipeline in Texas (more than 176,000) was used by a query to determine average the pipeline diameters within each of these categories. Results of these calculations are presented in Appendix C.

Methodology – Offshore Well and Pipeline Infrastructure

Offshore well and pipeline details were developed based on operations in the Gulf of Mexico. An equipment list was compiled for a typical offshore production platform utilizing process flow diagrams (PFDs) and descriptions from literature and vendor websites. Additionally, some data was collected from a scale model of the fixed production platform *Harvest* that is on display at the Ocean Star museum in Galveston, TX. The information available for *Harvest* also included a list of equipment contained in each process area, along with the total weight of each process area, the weight of each piece of the substructure, and the typical production from *Harvest*. The scale model was quite useful in adding supplemental equipment to the inventory such as pumps, spare pumps, condensers, heat exchangers, and reboilers that might not show up on a high-level PFD. An example of a typical high-level PFD for an offshore production platform is shown in Figure 1.

[9] Railroad Commission of Texas (2012)

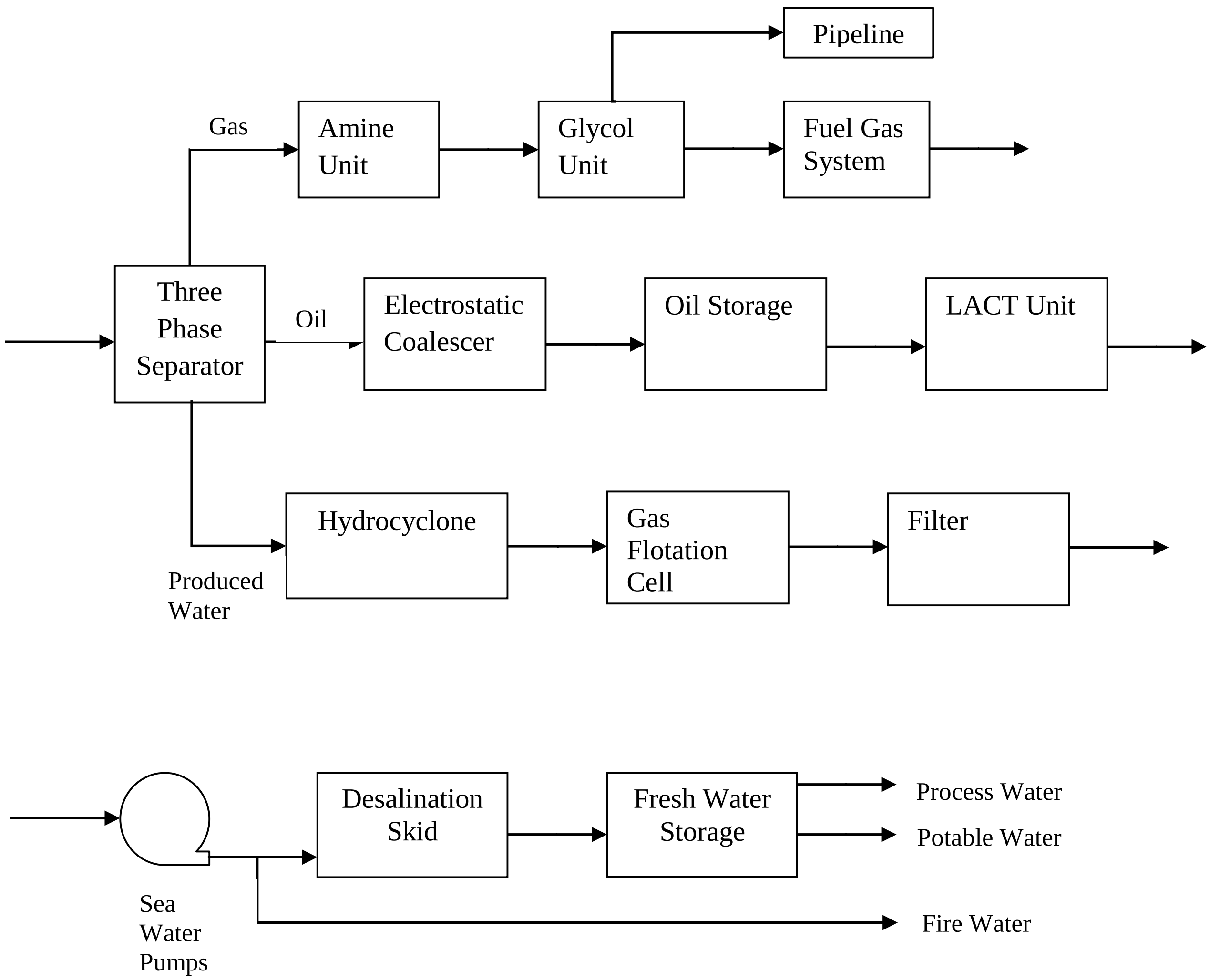

Figure 1 Process Flow Diagram of Offshore Production

Well Depth, Location, and Production

Offshore well location and depth data, as well as 2012 production data, were downloaded from Bureau of Ocean Energy Management (BOEM 1, BOEM 2). The well location and depth data was filtered to retain only wells attached to platforms. Production data was averaged for both oil and gas wells according to platform structure type.

Equipment Inventory for Production Platforms

The production platform was broken into two broad categories: topsides and substructure (legs, pilings, etc.). The topsides were further broken down into the following sub-categories of equipment: separation and oil export, gas, produced water, water, utilities and power generation, living quarters, and miscellaneous. The separation and oil export sub-category included the initial three-phase separation (high-pressure and low-pressure), electrostatic coalescer, heat exchangers, pumps, surge tanks, heaters, chemical injection skids, oil storage tank, and a Lease Automatic Custody Transfer (LACT) Unit. The gas sub-category included knock-out drums, compressors, coolers, amine sweetening unit when necessary, glycol dehydration unit, and fuel gas system (heater, coalescer, scrubber). The produced water sub-category included pumps, flash vessels, hydrocyclone, filter, skimmer vessels, skimmed oil storage, flotation cell, and chemical injection skids. The water sub-category included seawater pumps, desalination skid, fresh water pumps, tanks and piping system, the firewater system, the sewage system, chemical injection skid, potable water storage and pumps, hot water heater, storage, and pumps. The utilities and power generation sub-category included an air compressor skid, control and safety panels, generators, waste heat recovery unit, compressor skid, HVAC equipment, and refrigeration unit. The crew quarters sub-category included living quarters, galley, dining room, recreation rooms, laundry, and storage.

The miscellaneous equipment included cranes, flares, survival boats, and miscellaneous storage vessels. The weight of each individual piece of equipment was estimated using specifications from vendors or from literature data. It was assumed that the topsides were the same for each type of production platform. A list of equipment in each sub-category along with the number of pieces of equipment, weight, and source is given in Appendix D.

The substructure category was not subdivided because weight information for individual components varied depending on the type of substructure; instead a total weight for various substructure types was used, and it was explained based on the sub-elements that were added together.

The museum display for the *Harvest* platform scale model provided design criteria and an equipment list. The relationship between design criteria and the pieces of equipment shown on the scale model were helpful to compile the equipment list for the study's "average" production platform. The design criteria listed for the *Harvest* platform were: 60,000 barrels of oil per day (8,200 metric tonnes/day), 50,000 barrels of water produced per day (8,000 metric tonnes/day), 42,000 MCFD (1.1E6 Nm^3/day) gas production with 10,000 MCFD (2.6E5 Nm^3/day) (sour gas sweetened for fuel, and 100 person crew quarters. It was assumed that most of the oil produced would go directly into a pipeline onshore, but that oil storage for at least a half day's production would be provided in case a process problem occurred. The typical production platform contained both sweetening and dehydration equipment and it was assumed that the gas would either be used as fuel or sent onshore via pipeline. The equipment for the crew quarters was based on 100 persons. Literature sources were consulted to determine the average amount of water needed per resident. The values for houses/hotels were used when values for offshore living were not available. Average cold water storage for hotels was listed as 135 liters/person/day and restaurants 7 liters/meal (The Engineering Toolbox, 2013). Therefore, for three meals per day and living conditions yields approximately 156 liters/person/day. For 100 people with a 10 day emergency supply, 156,000 liters of water storage was estimated to be necessary. Hot water consumption and storage needs were determined in the same manner. Using the upper end of the consumption range of 160 liters/day, peak demand of 45 liters/day, and necessary storage of 30 liters/day, hot water tanks were specified (The Engineering Toolbox, 2013). The weight of the process and water piping systems were estimated using the value given for a jack-up rig (Offshore Energy Today.com, 2011).

The weight of the supporting structure was then considered for a jack up, fixed platform and a compliant tower. As previously mentioned, the topsides were considered to be the same for each type of production platform. Therefore, the total weight of a production platform was determined by adding the total topsides weight to the weight of the substructure. The substructure of a jack-up platform was considered to be the legs and hull. The weight of the legs was estimated to be 2,177 metric tonnes and the hull was 6,622 metric tonnes (Baerheim, Manschot, Olsen, & Eide, 1999). The substructure for the fixed production platform was considered to be the jacket, sacrificial anodes and piling (main piles and skirt piles). The following weights from the Texaco *Harvest* Platform were used for the fixed platform substructure: jacket 15,089 metric tonnes, sacrificial anodes 777 metric tonnes, and piling 6,390 metric tonnes (Texaco, 2013).

Two compliant towers were considered. The first was the Hess *Baldpate* Tower which sits in approximately 503 m of water and measures approximately 580 m to the top of the structure. The substructure weights for *Baldpate* were given as 5,080 metric tonnes for the foundation piles, 7,620 metric tonnes for the tower bottom section, and 17,872 metric tonnes for the tower top section. The second compliant tower considered was the ChevronTexaco *Petronius* Tower which sits in approximately 535 m of water and measures 610 m to the top of the structure. The substructure weights for *Petronius* were given as 7,974 metric tonnes for the foundation piles, 23,832 metric tonnes for the tower bottom section, and 6,169 metric tonnes for the tower top section. (Will, 1999) (Clauss & Lee, 2003).

<u>Equipment Inventory for Floating Production, Storage and Offloading (FPSO) Vessel</u>

The same general process was used for the topsides of the FPSO. In lieu of a scale model to consult, many detailed photographs of the BW Pioneer were reviewed, which is the first FPSO in the Gulf of Mexico and is operated by Petrobras. It is currently (as of this writing) the deepest moored vessel in the world. There are quite a few novel technologies for this vessel such as a detachable turret buoy mooring system which allows the FPSO to detach and move to a safe location in the event of a hurricane. Free-standing hybrid risers were used which attach to their own buoyancy can. This reduces the load on the turret system. The FPSO allows for flexibility in producing the ultra-deep water of GOM and this FPSO is servicing two fields simultaneously. Another differentiation for this scenario is that the oil is shuttled to the coast using two shuttle tankers.

<u>Typical Offshore Well Casing</u>

Literature sources and a drawing from a well diagram from the former MMS for Exxon *Corsair Canyon Block 975 No. 1 Well* were consulted to gain an understanding of typical casing configurations used offshore (conductor casing, surface casing, intermediate casing, production casing). The cross-sectional area for each component (casing or cement) was calculated using outer diameters, wall thickness, annular space, and multiplied by the length of that section to obtain a volume. The volume was multiplied by the density to get a weight of that component. This data was for a well depth of approximately 14,600 ft. (4,450 meters). The lengths of each casing/cement section were then adjusted based on the actual average well depth per platform type to get platform-specific dimensions. The overall weight was then multiplied by the average number of wells per platform type. Innovations with respect to subsea casing materials may lead to more widespread use of plastics. This calculation effort did not consider the use of plastics but it is recommend that they be explored as a future data sensitivity focus.

<u>Platform Type Aligned with Well Count, Location, and Production</u>

Platform structure data was downloaded from BOEM (BOEM 3, BOEM 4). It was assumed that unique complex IDs corresponded to one platform structure, rather than multiple platform structures. The data was filtered to retain only the platforms that were associated with the wells that remained after the initial well filtering step. This process was completed first for oil wells, and then again for gas wells.

<u>Pipeline Estimation to Shore (Trunklines)</u>

An inventory of pipeline to shore was conservatively estimated by calculating the straight-line distance from platform to shore and sizing the diameter of the straight-line pipeline to meet the daily oil or gas production. This production was estimated as the average per well production rate times the average number of wells per platform type. A simplistic approach for estimating the steel of pipelines per platform was developed by assuming each platform has one trunkline to shore. The trunkline diameter was calculated using the average production rate for each platform type, assuming that the pipeline must support that flow rate of associated wells to shore based on the weighted average shore distance relative to that platform type.

<u>Pipeline Estimation from Wells to Platform (Flowlines)</u>

Flowline distance from each associated well to platform was measured from BOEM coordinate data (BOEM 4). Flowline length details from well to platform and back to sea floor were estimated by taking the average water depth of associated wells, times two to estimate flowline to the surface and pipeline back down from the platform (this allows for well products to be processed on the platform before returning to a pipeline on the sea floor enroute to shore), plus the average distance from each well to the platform. The flowline diameter was sized according to the required capacity to meet the average rate of production per type of well (oil or gas).

<u>Rollup of Materials</u>

All materials were rolled up on a per platform basis, and then categorized by platform type [e.g., compliant tower, fixed/tension leg platform, jack-up (floating) platform, or floating production, storage and offloading unit (FPSO)]. The topsides were assumed to be the same for each platform type categorized, with the exception of FPSO. To differentiate oil from gas platforms, the percentage of gas platforms vs. oil platforms was applied to the total weight. Original casing dimensions were based on a 14,600 feet (4,450 meters) offshore well and were adjusted according to the average well depth per platform type, with the exception of FPSO since there was only one FPSO identified in the Gulf of Mexico. Substructures were differentiated by platform type; however, oil and gas substructure platform weights were differentiated by the percentage of oil versus gas platforms overall. Appendices E and F summarize the infrastructure results associated with offshore oil and gas platforms, respectively, including pipeline details. Appendix G rolls up all infrastructure details associated with offshore wells including well infrastructure, platform infrastructure, and pipeline.

Methodology – Overall Mass Balance

In order to put the results from all of these elements of the oil and gas extraction, production, and processing lifecycle into perspective, a mass balance was constructed.

Onshore

It was determined that the average gas well production rate was 274 thousand cubic feet (MCf) per day (7.2E6 Nm^3/day); therefore, a determination was made as to the number of onshore gas wells needed to produce enough gas to feed the average gas plant that processed 200 MMCf/day (5.3E6 Nm^3/day) of gas. Therefore the basis of 729 gas wells was selected.

Likewise the number of onshore oil wells needed to produce enough oil to feed the average refinery was also determined. It was found that 1,200 oil wells produce 120,000 barrels per day (16,400 metric tonnes per day) of crude oil. Therefore, for consistency, 1,200 oil wells was the count chosen as the basis for the refinery process.

The steel from 729 gas wells and its gathering and transmission lines was combined with the steel from the average gas plant to determine the total steel infrastructure associated with onshore gas production. In a similar fashion, the steel from 1,200 oil wells and their gathering and transmission lines was combined with the steel associated with a refinery. These steel mass totals were then allocated to the total production of gas, or oil, over their entire lifetime. In this case, that lifetime was taken as 30 years, and the total daily production of the wells were as stated above (200 MMCf/day of gas, 120 MBBL/day of oil).

Offshore

Similar to onshore, a determination was made as to the number of offshore gas platforms that were required to feed the gas plant processing capacity of 200 MMCf/day (5.7E6 Nm^3/day) determined as the average. An average production capacity of 3.8 MMCf/day (1.1E5 Nm^3/day) was estimated for all offshore platform types. Based on these endpoints, it was determined that 52 average gas platforms would sustain this capacity.

A count of offshore oil platforms was determined by using the same assumption for refining capacity of 120,000 barrels per day (16,200 metric tonnes per day). The average production per oil platform was determined to be 0.3 thousand barrels/day (Mbbl/day) (40 metric tonnes/day). Based on these data points, it was estimated that 405 average oil platforms would be necessary to feed a refinery with a capacity of 120,000 bbl/day.

The mass of steel associated with well, platform, and pipeline was applied to each of these platform counts in order to calculate the total mass of steel associated with oil and natural gas production. Again, these total masses of steel were then allocated with their total production of gas, or oil, over their entire lifetime (30 years, 200 MMCf/day of gas, 120 MBBL/day of oil).

Results

The results of this study reveal the mass of steel infrastructure associated with each MMCF of gas, or MBBL of oil. Table 1 presents these results for both onshore and offshore production of gas and oil. This also shows the breakdown of that steel infrastructure by stage. These, in turn, can be incorporated into a broader perspective of how impactful steel infrastructure is in the production of gas and oil.

Table 1 Mass of steel infrastructure per volume of lifetime well production

	Gas *(lbs steel/MMCF)*	Oil *(lbs steel/MBBL)*
Onshore		
Well Casing/Well	413	617
Gathering/Transmission Lines	359	74
Refinery	-	54
Gas Plant	2	-
Totals (Onshore)	**774**	**745**
Offshore		
Well Casing & Superstructure	1,394	3,626
Transmission Lines	1,118	9,894
Refinery	-	54
Gas Plant	2	-
Totals (Offshore)	**2,514**	**13,574**

These data are then converted to a g GHG/MJ basis using data from GREET2 regarding steel production GHG intensity as well as GREET1 regarding the energy content of gas and oil. We then incorporated this information with the previous 2013 GREET1 infrastructure GHG emissions for oil and gas. Table 2 shows the final GHG intensity data for onshore and offshore steel infrastructure in oil and gas production. Offshore impacts from steel infrastructure are clearly much greater than those for onshore steel infrastructure, with a starker difference for oil than for gas.

Table 2 GHG emissions intensity of onshore and offshore steel infrastructure

	Gas (g GHG/MJ)	Oil (g GHG/MJ)
Onshore	0.6	0.1
Offshore	1.95	1.89

Table 3 shows the final proposed update to GREET1 for oil and gas infrastructure GHG emissions (inclusive of steel and other infrastructure). The "Onshore" and "Offshore" rows, are calculated by incorporating the values from Table 2 with the previous 2013 GREET1 infrastructure values for oil and gas (less the previous 2013 value for steel contribution). Table 3 also shows the "Total" GHG intensity of oil and gas based on a weighted sum of onshore and offshore supply within the US based on production shares. Those shares are presented in Table 4.

Table 3 GHG emissions intensity of onshore and offshore oil and gas infrastructure, including steel infrastructure

	Gas (g GHG/MJ)	Oil (g GHG/MJ)
Onshore	1.22	0.55
Offshore	2.57	2.34
Total	**1.39**	**1.02**

Table 4 Shares of domestically produced oil and gas from onshore and offshore sources

Shares	**Gas**	**Oil**
Onshore	87.1%	73.8%
Offshore	12.9%	26.2%

Figure 2 presents the major findings of this study. Note that the "Other infrastructure" category is taken as the infrastructure from the previous 2013 GREET1 less its contribution from steel. From this it is apparent that the processing stages (oil refinery and gas plant) have minor contribution to steel-based GHG emissions for either oil or gas, either onshore or offshore. Offshore production of both oil and gas contribute significantly more GHG emissions than their onshore counterparts with offshore gas production being 110% greater than onshore production, and offshore oil production being 325% more intensive than onshore production. This is driven by the increased need for steel in the wells and platforms, as well as an increased need for steel in transmission. But, Table 1 shows that the increase for transmission lines in offshore oil production versus onshore oil production is far greater than offshore versus onshore gas transmission.

The previous 2013 version of GREET1 provides total contributions from infrastructure of 0.9 gCO2e/MJ, and 0.45 gCO2e/MJ for gas and oil production, respectively. Of that, 0.28, and 0 g

CO2e/MJ were from steel. The total infrastructure contribution intensities can be updated with the share weighted totals in Table3, 1.39 and 1.02 gCO2e/MJ for gas and oil, respectively. This represents a 54% increase in infrastructure-based GHG emissions intensity for gas, and a 127% increase for oil from previous 2013 GREET1 values.

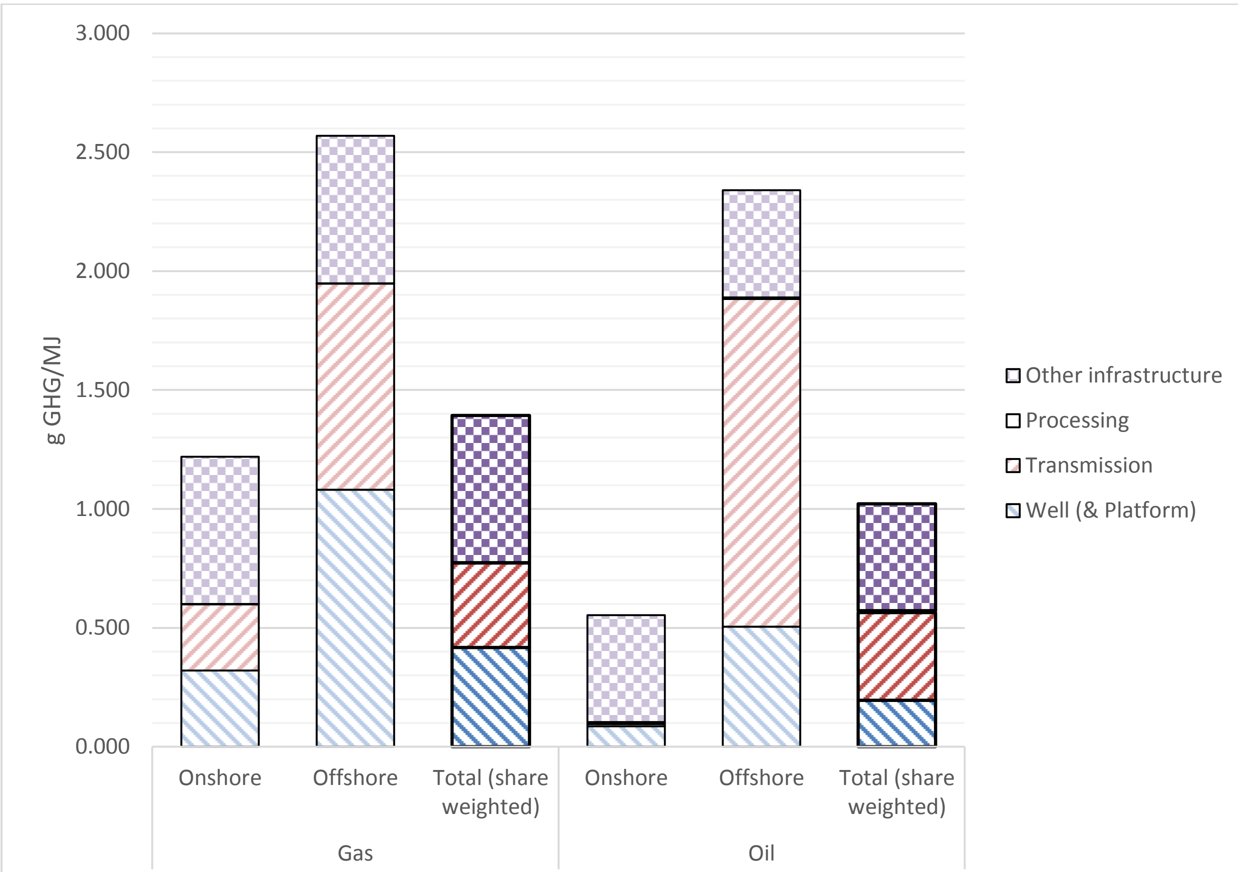

Figure 2 Total GHG emissions intensity for onshore, offshore and share weighted steel infrastructure used in oil and gas production

While these infrastructure contribution increases are substantial when compared to previous infrastructure values, they are less significant when compared to the combustion emissions associated with gas and oil, which are approximately 57 and 73 gCO2e/MJ, respectively. In that context, the increase in cradle-to-grave emissions is less than 1% for both fuels, 0.9% for gas, and 0.8% for oil.

Note that these values are based on average distances, and for the unconventional gas in particular, the impact could grow by a factor of two within the range of distances we observed. Also, note that this steel includes wells, pipelines and either gas plants (for gas) or refineries (for oil), but that the pipelines downstream of refineries and gas plants were not included (considered outside the "gate").

With respect to offshore steel infrastructure, the key finding is that while the well depth, piping to the platform, and piping to shore all contribute, as does the topside process equipment, the impact is dominated by the substructure support. Figure 3 below shows the relative contributions to overall offshore platform system steel for various platform types. It is clear from this that a wide range in steel impacts result from different choices. Older fixed platforms (currently the majority by count) are gradually being replaced with the more steel-intensive approaches such as the (Floating Production Storage and Offloading (FPSO) platforms which more closely resemble a large crude oil transport ship.

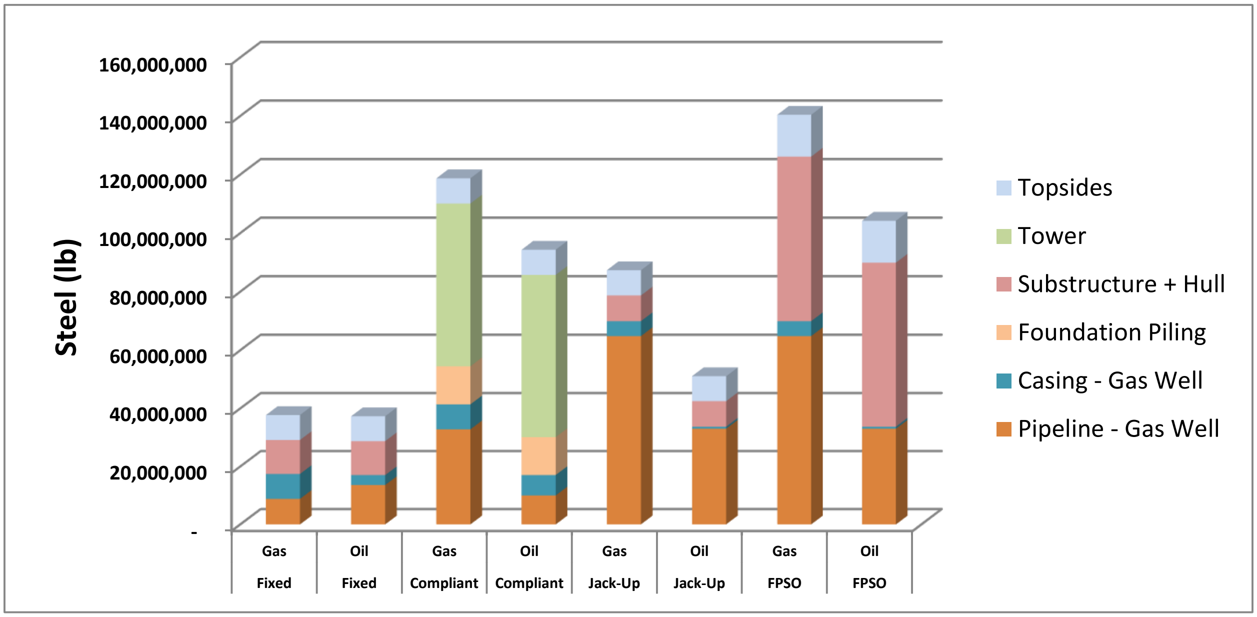

Figure 3 Steel in Various Platform Configurations

Implications - Onshore

More than 70 million pounds of steel (31.7 million kg) are needed to construct a refinery (enough to make 28,000 cars); this is a substantial impact by itself. Refineries are built very infrequently, but new process units within them are built with a much greater frequency.

Consider that pipeline construction involves much more steel than refinery construction when allocated per unit volume output of crude oil or natural gas. A thirty inch gas pipeline that extends 600 miles (say to connect a new gas plant and its family of new wells to an existing distribution system) would consume enough steel [more than 376 million pounds (170 million kg)] to construct five refineries, or to make 2% of the cars produced in the US (just over 150,000).

Much more compelling though is the steel that is installed in oil and gas wells. More than 4,000 gas wells alone were completed in Texas during 2011. Given that an average car contains 2,500 pounds of steel, and that that 7.8 million cars were produced in the US in 2010, the steel installed as casing and tubing in those 4,000 wells could have been used to make 1.5 million cars, or nearly 19% of the cars made in the US.

Implications - Offshore

The wells in the Gulf of Mexico (where the study was focused) are mostly in shallow water at this time, but the newer wells are increasingly being drilled in deeper water. The substructure is a direct function of water depth, so the infrastructure percentage will increase from this value to some extent over the next few years. Another key variable related to depth of water is the pressure demands on undersea piping. As depth increases, the water pressure increases and the thickness of steel increases. Conversely there have also been recent efforts to seek lighter materials and more clever construction methods (such as tensioning versus towers) that will offset this to some extent. There is also a move to begin using alternative materials such as specialized concrete, aluminum and various types of plastics. All of these will have impacts on the footprint (in various directions).

It is important to put these results into perspective. The impact on the values reported here is a strong function of the yield for the platform. The data calculated based on per platform data was much lower than expected, and this may merit further study to better understand how this effect is connected to the rest of the data elements (well network, complexities of combined oil and gas production together, etc.).

Limitations

The process followed to develop the results presented by this paper was comprehensive to the extent that data was publicly available. One exception to this is that the refinery data was made available by a specific oil company. The connection between data sources that forms a key part of the calculations was not intended by the developers of the data, and as a consequence, some accuracy was lost as data that did not favor the connection process was excluded.

Further, this study followed many of the ISO 14040 and 14044 standards required elements, and thus the data used was average data and not specific to any one company. Further, a formal third-party review has not been performed. That said, it is expected that this data and the approaches by this effort will help shape and guide further work to identify these impacts more accurately.

Acknowledgements

This work was supported by the Vehicle Technologies Office and Fuel Cell Technologies Office of the United States Department of Energy's Office of Energy Efficiency and Renewable Energy under contract DE-AC02-06CH11357.

References – General and Onshore

1. American Petroleum Institute, Design and Construction of Large, Welded, Low-Pressure Storage Tanks, API Standard 620,, Refining Department, June 1990, pp 3-15 to 3-16.
2. Argonne National Laboratory (2007), Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model (GREET 2 Version 2.7) (http://greet.es.anl.gov).
3. Argonne National Laboratory (2013), Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model (GREET1-2013) (http://greet.es.anl.gov).
4. Beath, J.M., Boone, M.A. (2012): Real-World Environmental Impact Assessment of Hydraulic Fracturing, Air and Waste Management Association National Meeting, San Antonio, Texas, June 19-22, 2012.
5. Beath, J.M., Boone, M.A., Wang, M, Elgowainy, A. (2012): Contribution of Infrastructure to Oil Production and Processing Carbon Footprint, American Center for Life Cycle Assessment National Meeting Proceedings, September 2012.
6. Beath, J.M., Boone, M.A., Rutledge, B., Black, N., Elgowainy, A., Wang, M. (2013): Streamlined Determination of the Carbon Footprint of Offshore Oil and Gas Operations, American Center for Life Cycle Assessment National Meeting Proceedings, October 2013.
7. Clark, C.E., Han, J., Burnham, A., Dunn, J.B., Wang, M., (2011): Life-Cycle Analysis of Shale and Natural Gas, ANL/ESD/11-11, December 2011, Center for Transportation Research, Energy Systems Division, Argonne National Laboratory (http://www.transportation.anl.gov/pdfs/EE/813.PDF).
8. EPA, Petroleum Refinery Source Characterization and Emission Model for Residual Risk Assessment, Prepared by RTO for US Environmental Protection Agency, July 1, 2002 (http://www.epa.gov/ttnchie1/efpac/protocol/refinery_RR_model_documentation_Final.pdf).
9. Eaton C, New Technologies Require New Math in Oilfield, Houston Chronicle, November 24, 2013
10. Hydrocarbon Processing, Gas Processes 2009.
11. Hydrocarbon Processing, Refining Process Handbook 2011.
12. Kidnay, A.J., Parrish, W.R., McCarthney, D.G. (2011): Fundamentals of Natural Gas Processing, CRC Press.
13. Loh, H.P., Lyons, J., White, C.W. (2002): Process Equipment Cost Estimation Final Report, DOE/NETL-2002/1169 (http://www.diquima.upm.es/Evirtual/hda/docs/TQI/process%20equipment%20cost%20estimation.pdf).
14. Nguyen, J.P. (1996): Drilling, Oil and Gas Field Development Techniques, Institut Francais du Petrole Publications.
15. Railroad Commission of Texas (2012): Digital Map Data (purchased shape files) (http://www.rrc.state.tx.us/forms/maps/digital/digmapstate.php).
16. Stell, J., (2000): Worldwide Refining Survey, Oil and Gas Journal, December 18, 2000.
17. Santoro, R.L., Howarth, R.H., Ingraffea, A.R. (2011): Indirect Emissions of Carbon Dioxide from Marcellus Shale Gas Development, A Technical Report From the Agriculture, Energy, and Environment Program at Cornell University (http://www.eeb.cornell.edu/howarth/Marcellus.htm).
18. Shires, T.M., Loughran, C. J., (2004): Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry, Prepared for the American Petroleum Industry (http://www.api.org/~/media/Files/EHS/climate-change/2009_GHG_COMPENDIUM.ashx).
19. Skone, T. J., (2011): Life Cycle Greenhouse Gas Inventory of Natural Gas Extraction, Delivery and Electricity Production, DOE/NETL-2011/1522, National Energy Technology Laboratory (http://www.netl.doe.gov/energy-analyses/pubs/NG-GHG-LCI.pdf).

20. Skone, T.J., (2012): Role of Alternative Energy Sources: Natural Gas Power Technology Assessment, EOE/NETL-2011/1536, National Energy Technology Laboratory(http://www.netl.doe.gov/energy-analyses/pubs/NGTechAssess.pdf
21. The Petroleum Economist Ltd., Fundamentals of Gas-To-Liquids, ISBN: 1 86186 215 6 (2005), (http://www.petroleum-economist.com/).
22. World Resources Institute (2012): Corporate Value Chain (Scope 3) Accounting and Reporting Standard, Greenhouse Gas Protocol (http://www.ghgprotocol.org/files/ghgp/public/Corporate%20Value%20Chain%20%28Scope%203%29%20Accounting%20and%20Reporting%20Standard.pdf).
23. World Resources Institute (2012): Product Life Cycle Accounting and Reporting Standard, Greenhouse Gas Protocol (http://www.ghgprotocol.org/files/ghgp/Product%20Life%20Cycle%20Accounting%20and%20Reporting%20Standard.pdf).
24. U.S. Energy Information Administration (2012): Annual Energy Review 2011 (http://www.eia.gov/totalenergy/data/annual/pdf/aer.pdf)
25. U.S. Energy Information Administration (2012): Natural Gas Annual Energy Respondent Query System (http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP9).

References - Offshore

1. America West Drilling Supply. (2013). *Air compressor system*. Retrieved 2013, from America West Drilling Supply: http://www.americawestdrillingsupply.com/Hurricane/B18_Offshore.asp

2. American Petroleum Institute. (2004). *Specifications for Offshore Pedestal Mounted Cranes.* Washington, D.C.: American Petroleum Institute.

3. ARC Industries, LLC. (2010). *Offshore Living Quarters & Equipment Rental*. Retrieved 2013, from ARC Industries Offshore Living Quarters: http://www.arcindustriesllc.com/library.html

4. Baerheim, M., Manschot, D., Olsen, T., & Eide, H. (1999). The Siri Production Jack-up Platform. Houston, Texas: Offshore Technology Conference.

5. Caterpillar. (2013). *Offshore generator set.* Retrieved 2013, from Caterpillar: http://catoilandgas.cat.com/cda/files/2180302/7/LEHW0088-03%20P3.pdf

6. Ciarapica, F. E., & Giacchetta, G. (2003). The Treatment of "Produced Water" in Offshore Rig: Comparison Between Traditional Installation and Innovative Systems. Sydney, Australia: Fifth International Membrane Science & Technology Conference.

7. Clauss, G. F., & Lee, J. Y. (2003). Dynamic Behaviour of Compliant Towers in Deep Sea. Cancun, Mexico: 22nd International Conference of Offshore Mechanics and Arctic Engineering.

8. Coates Offshore. (2011). *After Coolers.* Retrieved 2013, from Coates Offshore: http://coatesoffshore.com/products-and-services/after-coolers.html

9. Coates Offshore. (2011). *Heat Exchangers.* Retrieved 2013, from Coates Offshore : http://coatesoffshore.com/products-and-services/10k-heat-exchanger.html

10. Coffin World Water Systems. (2009). *Reverse Osmosis Fresh WaterMaking Systems for Marine and Offshore.* Retrieved 2013, from Coffin World Water Systems: http://www.marship.nl/downloads/cms/AQUASEP%20fresh%20water%20maker.pdf

11. Dan Marine Alscott Group. (2009). *DMA HVAC Product Manual.* Retrieved 2013, from DM Alscott Marine Offshore HVAC Ltd: http://www.alscott.ca/pdf/DMA_HVACR_PRODUCT_MANUAL.pdf

12. Exterran. (2013). *Amine Treating System.* Retrieved 2013, from Exterran: http://www.exterran.com/Content/Docs/Products/A200-Amine-System-English-A4.pdf

13. Hanson Tank. (2000, April 5). *Hot water generator.* Retrieved 2013, from Hanson Tank: http://hansontank.us/hotwatergenerators/WI558B.jpg

14. Hanson Tank. (2011, March 30). *Hot water storage tank.* Retrieved 2013, from Hanson Tank: http://hansontank.us/hotwatertanks/GS48585V.jpg

15. Integrated Flow Solutions. (2004). *Custody Transfer Metering System.* Retrieved 2013, from Integrated Flow Solutions: http://ifsolutions.com/images/FMS-100.0.pdf

16. Integrated Flow Solutions. (2004). *Custom Chemical Injection System.* Retrieved 2013, from Integrated Flow Solutions: http://ifsolutions.com/images/CCIS-100.0.pdf

17. Integrated Flow Solutions. (2004). *Fuel Gas Conditioning Systems.* Retrieved 2013, from Integrated Flow Solutions: http://ifsolutions.com/images/FGCS-100.0.pdf

18. Integrated Flow Solutions. (2004). *High Pressure Pumping System.* Retrieved 2013, from Integrated Flow Solutions: http://ifsolutions.com/images/PSHP-200.0.pdf

19. Integrated Flow Solutions. (2004). *Medium Pressure Pumping System.* Retrieved 2013, from Integrated Flow Solutions: http://ifsolutions.com/images/PSMP-100.0.pdf

20. Knott, T. (2006, April 19). *Drops in the ocean.* Retrieved 2013, from Oil Online: http://www.oilonline.com/default.asp?id=259&nid=32350&name=Drops+in+the+ocean

21. Marine Plant Systems Pty Ltd. (2013). *Sewage Treatment Systems*. Retrieved 2013, from Marine Plant Systems Pty Ltd: http://www.marineplantsystems.com/hamann-sewage-treatment.html

22. Material Management Resources, Inc. (2012, March 16). *TEG Dehydration Unit for sale.* Retrieved 2013, from Material Management Resources, Inc.: http://mmrsurplusphoto.com/BF%20IRG-11-214%20L2%20TEG%20Dehydration.pdf

23. Mathavan, C. (2010, March 17-20). *Offshore Oil and Gas Production Systems.* Retrieved 2013, from Industry-Academia Workshop on "Technology Imperatives for Exploration and Production of Oil & Gas" at Kaziranga Assam On March 17-20, 2010: http://petrofed.winwinhosting.net/upload/IAI/17-20mar10/OffshoreoilandProd.pdf

24. Offshore Energy Today.com. (2011, September 12). *PV Shipyard Announces Load-out of 1st Jack-Up Rig Built in Vietnam.* Retrieved 2013, from Offshoe Energy Today.com:

http://www.offshoreenergytoday.com/pv-shipyard-announces-load-out-of-1st-jack-up-rig-built-in-vietnam/

25. Offshore Technology.com. (2012). *Himech Equipments-Flare and Burner Boom Systems for Offshore Applications*. Retrieved 2013, from OffshoreTechnology.com: http://www.offshore-technology.com/contractors/flare/himech

26. Reddy, R. (1972). Commissioning a Gas Turbine-Compressor or Single Lift Package for Offshore Gas ReinjectionApplications. Proceedings of the First Turbomachinery Symposium.

27. Siemens. (2009). *Veirsep Horizontal Floatation System.* Retrieved 2013, from Siemens Water Technologies: http://www.water.siemens.com/SiteCollectionDocuments/Product_Lines/Monosep/Brochures/ZP-VEIRSEP-DS-0209.pdf

28. Skinner Tank Company. (2011, February). *Common Tank Sizes.* Retrieved 2013, from Skinner Tank Company: http://www.skinnertank.com/media/3857/commontanksizes2011rev.pdf

29. Solar Turbines A Caterpillar Company. (2009). *Compressor Set and Mechanical Drive.* Retrieved 2013, from Solar Turbines A Caterpillar Company: http://mysolar.cat.com/cda/layout?m=35420&x=7

30. Swales, G. L., & Todd, B. (1989). Nickel-containing alloy piping for offshore oil and gas production. Halifax, Nova Scotia: 28th Annual Conference of Metallurgists of the Canadian Institute of Mining and Metallurgy. Meeting of Sea and Science.

31. T & P Well Testers of Lafayette, Inc. (n.d.). *Offshore equipment for sale*. Retrieved 2013, from T & P Well Testers of Lafayette, Inc.: http://www.tpwelltesters.com/

32. Texaco. (2013). Texaco Harvest Platform Scale Model and Design Specifications. Ocean Star Museum. Galveston, TX.

33. The Engineering Toolbox. (2013). *Cold Water Storage per Occupant*. Retrieved 2013, from EngineeringToolBox.com: http://www.engineeringtoolbox.com/cold-water-person-d_86.html

34. The Engineering Toolbox. (2013). *Hot water consumption per occupant*. Retrieved 2013, from The Engineering Toolbox: http://www.engineeringtoolbox.com/hot-water-consumption-person-d_91.html

35. The Engineering Toolbox. (n.d.). *Dimensions of Fuel Oil Storage Tanks*. Retrieved 2013, from Engineering Tool Box: http://www.engineeringtoolbox.com/fuel-oil-storage-tanks-dimensions-d_1585.html

36. Tiger Offshore Rental, LTD. (n.d.). *25 BBL MPT (Marine Portable Tank).* Retrieved 2013, from Tiger Offshore Rental, LTD: http://www.tigeroffshorerentals.com/25%20BBL%20MPT.html

37. Tranter International. (2008, March 27). *Tranter Supplies Plate Heat Exchangers to Kizomba A FPSO.* Retrieved 2013, from Offshore Technology.Com: http://www.offshore-technology.com/contractors/separation/tranter/press2.html

38. Volvo Penta. (2006). *Marine Diesel Inboard engines.* Retrieved 2013, from Volvo Penta Diesel Inboard Engines:

http://www.volvopenta.com/SiteCollectionDocuments/Penta/Engine%20range/Marine%20Commercial/Engine_Range_MC_2006.pdf

39. Weatherford. (2009). *Surge Tank.* Retrieved 2013, from http://www.weatherford.com/weatherford/groups/web/documents/weatherfordcorp/WFT120076.pdf

40. Weatherford. (2010). *Three-Phase Well Test Separator.* Retrieved 2013, from http://www.weatherford.com/weatherford/groups/web/documents/weatherfordcorp/WFT120079.pdf

41. Will, S. (1999). Compliant towers: the next generation. *Offshore*.

42. BOEM 1: http://www.data.boem.gov/homepg/data_center/well/well.asp, under ASCII Downloads, File Name "Borehole" (fixed).
43. BOEM 2: http://www.data.boem.gov/homepg/pubinfo/freeasci/product/freeprod_ogora.asp, under OGOR-A Production for 2012.
44. BOEM 3: http://www.data.boem.gov/homepg/data_center/platform/platform.asp, under ASCII Downloads, Platform Structures (fixed).
45. BOEM 4: http://www.data.boem.gov/homepg/data_center/platform/platform.asp, under ASCII Downloads, Platform Masters (fixed)
46. BOEM 5: http://www.boem.gov/Environmental-Stewardship/Environmental-Studies/Gulf-of-Mexico-Region/Air-Quality/2008-Gulfwide-NIF-platform-inventory.aspx

Appendix A - Refinery and Gas Plant Steel Inventory

	Model Refinery Quantity	Refinery Steel (kg)	% of Total	Average Weight/ Piece of Equipment (kg)	Model Gas Plant Quantity	Gas Plant Steel (kg)	% of Total	Average Weight/ Piece of Equipment (kg)
Blowers	3	19,864	0.1%	5,297				
Boilers	9	386,182	1.2%	34,327				
Buildings					19	34,531	1.8%	1,817
Clarifiers	3	65,455	0.2%	17,455				
Compressors	27	103,831	0.3%	3,076	6	39,000	2.1%	6,500
Distillation Towers	96	1,932,568	6.0%	16,105	23	287,152	15.2%	12,485
Distillation Towers - Trays	96	888,121	2.8%	7,401	23	189,472	10.0%	8,238
Distillation Towers - Downcomers	96	92,041	0.3%	767	23	18,947	1.0%	824
Engines					1	2,364	0.1%	2,364
Filters	8	141,762	0.4%	14,176				
Flanges	30232	497,008	1.5%	13	1,114	17,115	0.9%	15
Flares					2	1,425	0.1%	713
Heat Exchangers	293	2,217,348	6.9%	6,054	4	20,800	1.1%	5,200
Miscellaneous						10,735	0.6%	
Piping		7,827,279	24.4%			520,795	27.5%	
Process Heaters	45	2,597,618	8.1%	46,180	2	170,773	9.0%	85,386
Pumps	310	344,653	1.1%	889	3	3,685	0.2%	1,228
Reactors	45	1,075,304	3.3%	19,117				
Stacks	2	19,118	0.1%	7,647				
Still Vents						26,576	1.4%	
Structural Steel		1,225,756	3.8%			260,398	13.8%	
Tanks	131	10,168,362	31.7%	62,097	24	221,351	11.7%	9,223
Valves	15061	1,581,073	4.9%	84	315	35,738	1.9%	113
Vessels	145	938,890	2.9%	5,180	12	31,060	1.6%	2,588
Total	**46602**	**32,122,230**	**100.0%**		**1571**	**1,891,916**	**100.0%**	
Amortization Over 30 Years		1,070,741				63,064		

Notes:
(1) Refinery Steel: The quanitity of steel shown reflects the 20% uncertainty upward adjustment, but the equipment count does not
(2) Gas Plant Steel: The quanitity of steel shown reflects the 30% uncertainty upward adjustment, but the equipment count does not
(3) The average weight was derived by reducing the total steel by 20% before dividing by the number of pieces of equipment

		Refinery	**Gas Plant**
Uncertainty Scale-Up Factor		1.2	1.3
Tank Scale-Down Factor		0.68	

Appendix B - Conventional/Unconventional Oil and Gas Well Steel and Concrete Inventory

All values are kilograms	All Well Types		Conventional Wells, Undifferentiated for Gas or Oil [1]	Conventional Gas Wells	Conventional Oil Wells	Undifferentiated Gas Wells [2]	Undifferentiated Oil Wells [3]	Unconventional Wells, Undifferentiated for Gas or Oil [4]	Unconventional Gas Wells	Unconventional Oil Wells
Stage	Concrete	Steel	Steel	Steel	Steel	Steel	Steel	Steel	Steel	Steel
All Conventional Stages - Misc			1,829							
All Unconventional Stages - Misc								1,829		
Completion Only			1,965							
Completion/Fracturing	105,834			189,550	145,521			7,020	398,716	729,604
Drilling		1,571	12,996					13,002		
Gas Compression and Dehydration		113,263								
Pipeline - Average						489,521	36,868			
Production		22,135	2,045							
Site prep/well pad			1,308					1,308		
Workover		4,439								
Grand Total	105,834	141,407	20,143	189,550	145,521	489,521	36,868	23,158	398,716	729,604

	Gas	Oil
Conventional Well Steel Total (kg)	**840,622**	**343,939**
All Conventional Stages - Misc	1,829	1,829
Completion Only	1,965	1,965
Completion/Fracturing	189,550	145,521
Drilling	14,567	14,567
Gas Compression and Dehydration	113,263	113,263
Pipeline - Average	489,521	36,868
Production	24,180	24,180
Site prep/well pad	1,308	1,308
Workover	4,439	4,439
Unconventional Well Steel Total (kg)	**1,052,803**	**931,037**
All Unconventional Stages - Miscellaneous	1,829	1,829
Completion/Fracturing	405,736	736,623
Drilling	14,572	14,572
Gas Compression and Dehydration	113,263	113,263
Pipeline - Average	489,521	36,868
Production	22,135	22,135
Site prep/well pad	1,308	1,308
Workover	4,439	4,439

NOTES:
1. Conventional Wells, Undifferentiated for Gas or Oil = Wells conventionally drilled and completed where the infrastructure has not been differentiated for oil versus gas wells.
2. Undifferentiated Gas Wells = Gas wells where the associated infrastructure has not been differentiated for conventional versus unconventional drilling and completion processes.
3. Undifferentiated Oil Wells = Oil wells where the associated infrastructure has not been differentiated for conventional versus unconventional drilling and completion processes.
4. Unconventional Wells, Undifferentiated for Gas or Oil = Wells unconventionally drilled and completed where the infrastructure has not been differentiated for oil versus gas wells.
5. Material quantities summarized in "All Well Types" include infrastructure that is ubiquitous to all well types (conventional, unconventional, oil, and gas).

Appendix C - Summary of Well Counts and Pipeline Distances by States

Dist Well to Gas Plant/Refinery	Min	Average	Max	Well Count
	kilometers	kilometers	kilometers	
PA Gas	0.2	107	---	58,092
TX Gas	36	211	678	94,851
ND Gas	5.7	14	27	135
PA Oil	47	166	389	17,308
TX Oil	205	360	510	151,617
ND Oil	213	353	494	7550

	Min	Max
	kilometers	kilometers
Extremes - Gas	0.2	678
Extremes - Oil	47	510

Gathering Pipeline Assumptions (TX Only):		Oil	Gas
Average Pipeline KM per Well in TX		360	211
Average Gathering KM per Well, TX		2.3	27
% of total KM assumed to be gathering:		1%	13%
	Min	Average	Max
	kilometers	kilometers	kilometers
Gathering Lines - Gas	0.2	22	86
Gathering Lines - Oil	0.3	2	3
Transmission Lines - Gas	0.0	149	592
Transmission Lines - Oil	47	338	506

Transmission Pipeline Assumptions:				
Refinery Capacity	120000	BPD	16371	Tonne/Day
Production per Oil Well	100	BPD	14	Tonne/Day
Wells to Sustain 1 Refinery	1200	Wells		
Gas Plant Capacity	199746	MCF/Day	5250946	Nm3/Day
Production per Gas Well	0.274	MMSCF/Day	7203	Nm3/Day
Wells to Sustain 1 Gas Plant	729	Wells		

Pipe Specifications:

Gas Gathering	Crude Gathering	Gas Transmission	Crude Transmission	Notes:
6.8	5.1	19.1	11.6	Averages of Pipe IDs (inches) from RRC Data for Texas
8.0	6.0	20.0	12.0	Nominal ID (inches) - selected as next nominal ID up from average
---	---	1069655	155184	Capacity, MCF or Barrels
---	---	5	1	Transmission Lines Required to Meet Refinery/Gas Plant Capacity
		7.35E-03	1.08E-03	Transmission Equivalent per Well - to be applied to prorated transmission line weights

Conversions:	
7.33	Barrels per Metric tonne Crude (EIQ, 2012, US)
38.04	SCF per Nm3

Appendix D - High Level Summary of Offshore Topsides Equipment Weights

Category	Equipment Item	Pieces of Equipment	Total Weight (tonnes)	Source
Separation and Oil Export	Three-phase separator, high pressure	2	30	(Weatherford, 2010)
	Three-phase separator, low pressure	2	18	(T & P Well Testers of Lafayette, Inc.) (Mathavan, 2010)
	Surge tank	2	18	(Weatherford, 2009)
	Heater	2	23	(Tranter International, 2008)
	Electrostatic coalescer	2	13	(Knott, 2006)
	Electrostatic coalescer separator	2	18	(Knott, 2006)
	Heater	2	23	(Tranter International, 2008)
	Chemical injection skid	1	25	(Integrated Flow Solutions, 2004)
	Waste heat recovery unit	12	53	(Mathavan, 2010) (Coates Offshore, 2011) (The Engineering Toolbox) (Coates Offshore, 2011)
	Oil storage tank	2	1,461	(Skinner Tank Company, 2011)
	Heat exchanger	4	48	(Coates Offshore, 2011)
	LACT unit	1	27	(Integrated Flow Solutions, 2004)
	Piping system	1	862	(Offshore Energy Today.com, 2011)
	Pumps	18	404	(Integrated Flow Solutions, 2004) (Integrated Flow Solutions, 2004)
Gas	Amine sweetening unit	10	145	(Exterran, 2013)
	Glycol dehydration unit	13	116	(Material Management Resources, Inc., 2012)
	Fuel gas conditioning system	2	54	(Integrated Flow Solutions, 2004)
	Knock out drum	8	91	(Tiger Offshore Rental, LTD)
	Compressor	6	82	(Solar Turbines A Caterpillar Company, 2009)
	Cooler	6	72	(Coates Offshore, 2011)
Produced Water	Hydrocyclone	2	36	(The Treatment of "Produced Water" in Offshore Rig: Comparison Between Traditional Installation and Innovative Systems, 2003)
	Flotation cell	2	32	(Siemens, 2009)
	Flash vessel	2	18	(Weatherford, 2009)
	Skimmer vessel	2	18	(Weatherford, 2009)
	Oil tank (to be pumped back to oil process)	2	23	(Tiger Offshore Rental, LTD)
	Chemical injection skid	5	125	(Integrated Flow Solutions, 2004)
	Pumps	14	313	(Integrated Flow Solutions, 2004)
	Filter	2	18	(Weatherford, 2009)
Water	Desalination skid	1	5	(Coffin World Water Systems, 2009)
	Seawater piping system	12	116	(Nickel-containing alloy piping for offshore oil and gas production, 1989)
	Seawater pumps	6	150	(Integrated Flow Solutions, 2004)
	Freshwater piping system	6	102	(Nickel-containing alloy piping for offshore oil and gas production, 1989)
	Freshwater pumps	6	150	(Integrated Flow Solutions, 2004)

	Freshwater tanks	1	260	(Skinner Tank Company, 2011)
	Water piping system to units (firewater, sewage, cooling water, etc.)	1	862	(Offshore Energy Today.com, 2011)
	Firewater system	22	269	(Integrated Flow Solutions, 2004) (Nickel-containing alloy piping for offshore oil and gas production, 1989) (Solar Turbines A Caterpillar Company, 2009) (The Engineering Toolbox) (Coates Offshore, 2011)
	Chemical injection skid	4	100	(Integrated Flow Solutions, 2004)
	Sewage system skid	1	2	(Marine Plant Systems Pty Ltd, 2013)
	Hot water system	8	27	(Hanson Tank, 2011) (The Engineering Toolbox, 2013) (Hanson Tank, 2000) (Integrated Flow Solutions, 2004)
	Potable water tank	1	328	(Skinner Tank Company, 2011)
	Potable water pumps	10	68	(Integrated Flow Solutions, 2004)
Utilities & Power Generation	Air compressor skid	2	28	(America West Drilling Supply, 2013)
	Generator engine system	10	554	(Caterpillar, 2013)
	Waste heat recovery unit	8	58	(Coates Offshore, 2011) (Mathavan, 2010) (Integrated Flow Solutions, 2004) (The Engineering Toolbox)
	Gas turbine compressor	3	993	(Commissioning a Gas Turbine-Compressor or Single Lift Package for Offshore Gas ReinjectionApplications, 1972)
	Compressor skid	2	91	(Solar Turbines A Caterpillar Company, 2009)
	HVAC system	80	55	(Dan Marine Alscott Group, 2009)
	Control and safety panels	10	7	(Solar Turbines A Caterpillar Company, 2009)
Living Quarters	Crew quarters-sleeper cabins and recreation rooms	20	132	(ARC Industries, LLC, 2010)
	Galley, dining rooms, laundry and storage	40	202	(ARC Industries, LLC, 2010)
Miscellaneous	Crane	3	170	(American Petroleum Institute, 2004)
	Flare booms	3	24	(Offshore Technology.com, 2012)
	Flare knock-out drums	3	34	(Tiger Offshore Rental, LTD)
	Survival boat engines	2	3	(Volvo Penta, 2006)
TOTAL TOPSIDES			**8,884**	

Appendix E Offshore Oil Platform and Pipeline Infrastructure

Platform Structure Type (BEOM.gov list)		Well Count by Platform Structure Type	Platform Count by Platform Structure Type	Avg. No. of Wells Per Platform Structure Type	Avg. Well Depth Per Platform Structure Type (ft.)	Avg. Distance to Shore Per Platform Structure Type (Nautical miles)	Avg. Well to Platform Piping Distance Per Platform Structure Type Depth x 2 x Count of Wells + Well2Platform Distance		Avg. 2011 Oil Production Per Platform Structure Type (BPD)
							feet	miles	
Compliant Tower (CT)	CT	14	1	14	8,624	21	2,049	0.4	326
Fixed Leg Platform (FIXED)	FIXED	211	88	2	8,486	38	3,047	0.6	288
<u>Combined</u>: **SPAR Platform - floating production system (SPAR)** **Semi Submersible (Column Stabilized Unit) Floating Production System (SEMI)**		**1**	**1**	**1**	**12,943**	**137**	**40,274**	**7.6**	**1,350**
SPAR Platform - floating production system (SPAR)	SPAR	1	1	1	12,943	137	40,274	7.6	1,350
Semi Submersible (Column Stabilized Unit) Floating Production System (SEMI)	SEMI	0	0	N/A	N/A	N/A	N/A	N/A	N/A
<u>Combined:</u> **Mini Tension Leg Platform (MTLP),** **Tension Leg Platform (TLP)**		**6**	**2**	**4**	**8,924**	**93**	**7,427**	**1.4**	**233**
Mini Tension Leg Platform (MTLP)	MTLP	1	1	1	12,650	86	27,136	5.1	27
Tension Leg Platform (TLP)	TLP	5	1	5	8,179	94	3,485	0.7	274
Floating production, storage and offloading (FPSO)	FPSO	0	0	N/A	N/A	N/A	N/A	N/A	N/A
Mobile Production Unit (MOPU)	MOPU	0	0	N/A	N/A	N/A	N/A	N/A	N/A
Well Protector (WP)	WP	5	5	1	8,696	9	786	0.1	729
Caisson (CAIS)	CAIS	17	17	1	11,423	8	236	0.04	193

Weighted Averages				
Avg. No of Wells Per Platform for All Platform Structure Types	**Avg. Well Depth for all Wells/All Platform Structure Types (ft.)**	**Avg. Distance to Shore for All Platform Structure Types (Nautical miles)**	**Avg. Well to Platform Piping Distance Per Platform Structure Type (feet)**	**Avg. 2011 Oil Production For All Platform Structure Types (BPD)**
3	8898	37	3070	295

Total Well Count		254
Total Platform Structure Count		114

	Case		Case Description:
Average tons CO2e/BBL	**1**	2.75	Bulk Average of All BOEM Production and Platform Data - Zeros Omitted
Average tons CO2e/BBL	**2**	0.02	RFF Average (Average GoM Platform Production) and Average of All BOEM Platform Emissions (Zeros Omitted)
Average tons CO2e/BBL	**3**	0.02	Average Well Production > 500 BPD and Average of All BOEM Platform Emissions (Zeros Omitted)

						Flowlines (Assumed one per Well per Platform)			
Pipeline		**Well to Platform to Trunkline Flowline ID Estimate (PIP) (inches per line)**	**Adjusted Flowline ID to meet <50 ft/s Velocity (inches per line)**	**Erosional Velocity (ft/s) Erosional Effects at 50 ft/s**	**Density (lb/ft3)**	**Pipe Length (ft)**	**Outer Pipe Weight (lbs)**	**Inner Pipe Weight (lbs)**	**Total Flowline Weight x Number of Wells per Platform (lbs)**
Compliant Tower (CT)	CT	4	4	0.01	489	2,049	79,929	130,512	2,946,164
Fixed Leg Platform (FIXED)	FIXED	6	6	0.03	489	3,047	151,363	269,352	1,008,759
Combined: **SPAR Platform - floating production system (SPAR)** **Semi Submersible (Column Stabilized Unit) Floating Production System (SEMI)**									
SPAR Platform - floating production system (SPAR)	SPAR	6	6	0.36	489	40,274	2,000,576	3,560,049	5,560,625
Semi Submersible (Column Stabilized Unit) Floating Production System (SEMI)	SEMI	N/A	N/A	N/A	489	N/A	N/A	N/A	N/A
Combined: **Mini Tension Leg Platform (MTLP),** **Tension Leg Platform (TLP)**									
Mini Tension Leg Platform (MTLP)	MTLP	1	2	0.06	489	27,136	769,175	1,058,256	1,827,431
Tension Leg Platform (TLP)	TLP	4	4	0.03	489	3,485	135,960	222,002	1,789,809
Floating production, storage and offloading (FPSO)	FPSO	N/A	N/A	N/A	489	N/A	N/A	N/A	N/A
Mobile Production Unit (MOPU)	MOPU	N/A	N/A	N/A	489	N/A	N/A	N/A	N/A
Well Protector (WP)	WP	28	28	0.01	489	786	131,282	283,096	414,378
Caisson (CAIS)	CAIS	26	26	0.00	489	236	36,892	79,153	116,045

(Continuation of table below)

	Trunklines (Assumed one per Platform for Simplicity)					
Pipeline	**Trunkline per Platform ID Estimate (inches)**	**Adjusted Trunkline ID to meet <50 ft/s Velocity (inches per line)**	**Erosional Velocity (ft/s) Erosional Effects at 50 ft/s**	**Pipe Length (ft)**	**Pipe Weight (lbs)**	**Total Pipeline Weight (lbs)**
Compliant Tower (CT)	12	12	0.002	127,596	18,971,675	21,917,839
Fixed Leg Platform (FIXED)	9	10	0.01	229,921	28,953,559	29,962,318
Combined: **SPAR Platform - floating production system (SPAR)** **Semi Submersible (Column Stabilized Unit) Floating Production System (SEMI)**						**72,497,610**
SPAR Platform - floating production system (SPAR)	6	6	0.36	832,412	66,936,984	72,497,610
Semi Submersible (Column Stabilized Unit) Floating Production System (SEMI)	N/A	N/A	N/A	N/A	N/A	N/A
Combined: **Mini Tension Leg Platform (MTLP),** **Tension Leg Platform (TLP)**						**64,771,260**
Mini Tension Leg Platform (MTLP)	1	2	0.06	522,536	18,235,711	20,063,142
Tension Leg Platform (TLP)	9	10	0.01	571,144	71,923,075	73,712,884
Floating production, storage and offloading (FPSO)	N/A	N/A	N/A	N/A	N/A	N/A
Mobile Production Unit (MOPU)	N/A	N/A	N/A	N/A	N/A	N/A
Well Protector (WP)	28	28	0.01	57,114	18,890,287	19,304,665
Caisson (CAIS)	26	26	0.00	47,178	14,530,335	14,646,380

Appendix F Offshore Gas Platform and Pipeline Infrastructure

Platform Structure Type (BEOM.gov list)		Well Count by Platform Structure Type	Platform Count by Platform Structure Type	Avg. No. of Wells Per Platform Structure Type	Avg. Well Depth Per Platform Structure Type (ft.)	Avg. Distance to Shore Per Platform Structure Type (Nautical miles)	Avg. Well to Platform Piping Distance Per Well Per Platform Structure Type Depth x 2 x Count of Wells + Well2Platform Distance		Avg. 2011 Oil Production Per Platform Structure Type (BPD)	Avg. 2011 Gas Production Per Platform Structure Type (MCFD)
							feet	miles		
Compliant Tower (CT)	CT	27	3	14	10,841	66	2,228	0.4	642	16,167
Fixed Leg Platform (FIXED)	FIXED	2,765	757	4	9,318	39	984	0.2	107	2,407
Combined: **SPAR Platform - floating production system (SPAR)** **Semi Submersible (Column Stabilized Unit) Floating Production System (SEMI)**		**103**	**18**	**6**	**15,253**	**100**	**16,516**	**3.1**	**3,513**	**28,862**
SPAR Platform - floating production system (SPAR)	SPAR	78	13	6	14,798	106	11,486	2.2	3,107	23,565
Semi Submersible (Column Stabilized Unit) Floating Production System (SEMI)	SEMI	25	5	5	16,674	78	32,211	6.1	4,782	45,388
Combined: **Mini Tension Leg Platform (MTLP),** **Tension Leg Platform (TLP)**		**82**	**15**	**7**	**16,539**	**101**	**14,894**	**2.8**	**2,897**	**28,606**
Mini Tension Leg Platform (MTLP)	MTLP	7	4	2	14,126	73	17,778	3.4	811	1,850
Tension Leg Platform (TLP)	TLP	75	11	7	16,765	103	14,625	2.8	3,091	31,103
Floating production, storage and offloading (FPSO)	FPSO	1	1	1	26,222	160	73,458	13.9	6,877	871
Mobile Production Unit (MOPU)	MOPU	3	1	3	14,509	91	16,464	3.1	2,701	12,740
Well Protector (WP)	WP	164	92	2	10,017	19	647	0.1	70	985
Caisson (CAIS)	CAIS	218	187	1	11,153	15	3,656	0.7	109	1,612

Weighted Averages

Avg. No of Wells Per Platform for All Platform Structure Types	Avg. Well Depth for all Wells/All Platform Structure Types (ft.)	Avg. Distance to Shore for All Platform Structure Types (Nautical miles)	Avg. Well to Platform Piping Distance Per Platform Structure Type (feet)	Avg. 2011 Oil Production For All Platform Structure Types (BPD)	Avg. 2011 Gas Production For All Platform Structure Types (MCFD)
4	9,851	40	2,001	286	3854

Total Well Count		3,363
Total Platform Structure Count		1,074

Average tons CO2e/MCF	1	0.05	Bulk Average of All BOEM Production and Platform Data - Zeros Omitted
Average tons CO2e/MCF	2	0.004	RFF Average (Average GoM Platform Production) and Average of All BOEM Platform Emissions (Zeros Omitted)
Average tons CO2e/MCF	3	0.009	Average Well Production > 1000 MCF and Average of All BOEM Platform Emissions (Zeros Omitted)

						Flowlines (Assumed one per Well per Platform)			
Pipeline		**Well to Platform to Trunkline Flowline ID Estimate (PIP) (inches per line) (Equation 1 to Calculate D)**	**Adjusted Flowline ID to meet <50 ft/s Velocity (inches per line) (Equation 2 to Calculate V)**	**Erosional Velocity (ft/s) Erosional Effects at 50 ft/s**	**Density (lb/ft3)**	**Pipe Length (ft)**	**Outer Pipe Weight (lbs)**	**Inner Pipe Weight (lbs)**	**Total Flowline Weight x Number of Wells per Platform (lbs)**
Compliant Tower (CT)	CT	0.01	4	36	489	2,228	86,897	141,890	3,126,767
Fixed Leg Platform (FIXED)	FIXED	0.01	4	19	489	984	38,401	62,702	393,060
<u>Combined</u>: **SPAR Platform - floating production system (SPAR)** **Semi Submersible (Column Stabilized Unit) Floating Production System (SEMI)**									
SPAR Platform - floating production system (SPAR)	SPAR	0.02	8	30	489	11,486	693,027	1,298,963	12,105,172
Semi Submersible (Column Stabilized Unit) Floating Production System (SEMI)	SEMI	0.04	10	44	489	32,211	2,287,082	4,438,465	33,627,732
<u>Combined:</u> **Mini Tension Leg Platform (MTLP),** **Tension Leg Platform (TLP)**									
Mini Tension Leg Platform (MTLP)	MTLP	0.01	4	28	489	17,778	693,516	1,132,407	3,651,845
Tension Leg Platform (TLP)	TLP	0.03	8	33	489	14,625	882,447	1,653,997	18,446,861
Floating production, storage and offloading (FPSO)	FPSO	0.02	4	27	489	73,458	2,865,586	4,679,071	7,544,657
Mobile Production Unit (MOPU)	MOPU	0.03	8	32	489	16,464	993,400	1,861,960	8,566,079
Well Protector (WP)	WP	0.01	4	17	489	647	25,239	41,211	120,620
Caisson (CAIS)	CAIS	0.01	4	42	489	3,656	142,611	232,862	445,748

(Continuation of table below)

Pipeline		Trunklines (Assumed one per Platform for Simplicity) Trunkline per Platform ID Estimate (inches)	Adjusted Trunkline ID to meet <50 ft/s Velocity (inches per line)	Erosional Velocity (ft/s) Erosional Effects at 50 ft/s	Pipe Length (ft)	Pipe Weight (lbs)	Total Pipeline Weight (lbs)
Compliant Tower (CT)	CT	0.08	14	40	403,041	69,098,576	72,225,342
Fixed Leg Platform (FIXED)	FIXED	0.04	6	33	235,230	18,915,641	19,308,701
<u>Combined</u>: **SPAR Platform - floating production system (SPAR)** **Semi Submersible (Column Stabilized Unit) Floating Production System (SEMI)**							**142,660,333**
SPAR Platform - floating production system (SPAR)	SPAR	0.11	16	45	646,393	125,529,703	137,634,875
Semi Submersible (Column Stabilized Unit) Floating Production System (SEMI)	SEMI	0.13	22	46	475,143	124,712,031	158,339,764
<u>Combined:</u> **Mini Tension Leg Platform (MTLP),** **Tension Leg Platform (TLP)**							**144,645,661**
Mini Tension Leg Platform (MTLP)	MTLP	0.04	6	25	445,067	35,789,300	39,441,145
Tension Leg Platform (TLP)	TLP	0.12	18	47	626,933	136,017,888	154,464,749
Floating production, storage and offloading (FPSO)	FPSO	0.03	4	27	972,160	56,050,743	63,595,400
Mobile Production Unit (MOPU)	MOPU	0.08	12	43	552,916	82,210,591	90,776,669
Well Protector (WP)	WP	0.02	4	30	117,425	6,770,260	6,890,880
Caisson (CAIS)	CAIS	0.02	4	49	89,093	5,136,736	5,582,484

Appendix G - Platform, FPSO, Casing, and Pipeline Materials Inventory Summary

All weights are in kg

	Fixed/TL, Compliant, Jack-up - Topsides		**Fixed/TL - Casing/Substructure**			**Compliant - Casing/Substructure**		**Jack-up (Floating)- Casing/Substructure**		**FPSO - Topsides and Substructure**	
Sum of Prorated Weight - 30 Years Assumption	Column Labels										
	Any		Fixed/Tension Leg		Fixed	Compliant		Jack-up		FPSO	
Platform Element	*Aluminum*	*Steel*	*Steel*	*Concrete*	*Steel*	*Steel*	*Concrete*	*Steel*	*Concrete*	*Aluminum*	*Steel*
Topsides-Gas	---	561,296	---	---	---	---	---	---	---	---	561,296
Topsides-Living quarters	334,091	---	---	---	---	---	---	---	---	334,091	---
Topsides-Misc	---	231,652	---	---	---	---	---	---	---	24,150	3,650,060
Topsides-Produced Water	---	583,496	---	---	---	---	---	---	---	---	606,142
Topsides-Separation & Oil Export	---	3,027,613	---	---	---	---	---	---	---	---	4,421,631
Topsides-Utilities & power generation	---	1,789,636	---	---	---	---	---	---	---	---	1,789,636
Topsides-Water	---	2,420,403	---	---	---	---	---	---	---	---	3,285,908
Tower bottom section	---	---	---	---	---	31,518,182	---	---	---	---	---
Tower top section	---	---	---	---	---	24,090,909	---	---	---	---	---
(blank)	---	---	---	---	---	---	---	---	---	---	---
Mooring system	---	---	---	---	---	---	---	---	---	---	1,002,091
Hull	---	---	---	---	---	---	---	6,636,364	---	---	51,686,364
Substructure	---	---	---	---	11,746,172	---	---	2,181,818	---	---	3,509,091
Foundation piles	---	---	---	---	---	13,081,818	---	---	---	---	---
Casing, Gas Well	---	---	8,621,261	4,511,771	---	8,568,759	4,484,295	5,130,214	2,684,798	---	---
Casing, Oil Well	---	---	3,413,321	1,786,295	---	6,982,737	3,654,281	748,555	391,742	---	---

Pipeline, Gas	---	---	8,776,682	---	---	32,829,701	---	64,845,606
Pipeline, Oil	---	---	13,619,236	---	---	9,962,654	---	32,953,459

Fixed and Tension Leg Platforms		
Key Elements - Gas Platforms	*Steel*	*% of Total*
Topsides	8,614,096	23%
Substructure + Hull	11,746,172	31%
Tower	0	0%
Foundation Piling	0	0%
Casing - Gas Well	8,621,261	23%
Pipeline - Gas Well	8,776,682	23%
Total	37,758,211	100%
Key Elements - Oil Platforms	*Steel*	*% of Total*
Topsides	8,614,096	23%
Substructure + Hull	11,746,172	31%
Tower	0	0%
Foundation Piling	0	0%
Casing - Oil Well	3,413,321	9%
Pipeline - Oil Well	13,619,236	36%
Total	37,392,824	100%

Jack-Up (Floating) Platform		
Key Elements - Gas Platforms	*Steel*	*% of Total*
Topsides	8,614,096	10%
Substructure + Hull	8,818,182	10%
Tower	0	0%
Foundation Piling	0	0%
Casing - Gas Well	5,130,214	6%
Pipeline - Gas Well	64,845,606	74%
Total	87,408,097	100%
Key Elements - Oil Platforms	*Steel*	*% of Total*
Topsides	8,614,096	17%
Substructure + Hull	8,818,182	17%
Tower	0	0%
Foundation Piling	0	0%
Casing - Oil Well	748,555	1%
Pipeline - Oil Well	32,953,459	64%
Total	51,134,292	100%

Compliant Platform		
Key Elements - Gas Platforms	*Steel*	*% of Total*
Topsides	8,614,096	7%
Substructure + Hull	0	0%
Tower	55,609,091	47%
Foundation Piling	13,081,818	11%
Casing - Gas Well	8,568,759	7%
Pipeline - Gas Well	32,829,701	28%
Total	118,703,465	100%
Key Elements - Oil Platforms	*Steel*	*% of Total*
Topsides	8,614,096	9%
Substructure + Hull	0	0%
Tower	55,609,091	59%
Foundation Piling	13,081,818	14%
Casing - Oil Well	6,982,737	7%
Pipeline - Oil Well	9,962,654	11%
Total	94,250,396	100%

FPSO		
Key Elements - Gas Platforms	*Steel*	*% of Total*
Topsides	14,314,673	10%
Substructure + Hull	56,197,545	40%
Tower	0	0%
Foundation Piling	0	0%
Casing - Gas Well	5,130,214	4%
Pipeline - Gas Well	64,845,606	46%
Total	140,488,038	100%
Key Elements - Oil Platforms	*Steel*	*% of Total*
Topsides	14,314,673	14%
Substructure + Hull	56,197,545	54%
Tower	0	0%
Foundation Piling	0	0%
Casing - Oil Well	748,555	1%
Pipeline - Oil Well	32,953,459	32%
Total	104,214,233	100%

Note - using floating pipeline data for FPSO

	Topsides, Substructure, Casing						Pipeline	
	Gas Platforms			Oil Platforms			Gas	Oil
Platform Type	***Aluminum***	***Steel***	***Concrete***	***Aluminum***	***Steel***	***Concrete***	***Steel***	
Compliant Tower	302,032	78,455,607	4,484,295	32,059	14,400,895	3,654,281	32,829,701	9,962,654
Fixed/Tension Leg Platform	302,032	27,027,766	4,511,771	32,059	5,367,084	1,786,295	8,776,682	13,619,236
Jack-up (Floating) Platform	302,032	20,889,697	2,684,798	32,059	2,421,350	391,742	64,845,606	32,953,459
FPSO	323,864	63,745,894	N/A	34,377	6,766,324	N/A	N/A	N/A

All weights are in kg

Typical Platform/Pipeline Summary for Complaint Tower, kg Steel		
	Gas	Oil
Topsides, Substructure, Casing	78,455,607	14,400,895
Pipeline	32,829,701	9,962,654

Notes:
1. The topsides were assumed to be the same for each supporting substructure. To differentiate oil from gas platforms, the percentage of gas platforms vs. oil platforms was applied to the total weight.
2. Original casing dimensions were based on an 14,600 ft (4,450 m) offshore well and were ratio-ed according to the average well depth per platform type.
3. Platform details are predominantly based on Gulf of Mexico platform structures.
4. Pipeline dimensions are calculated on OilWellRollup and GasRollup tabs.
5. Substructures were differentiated by platform type; however, oil and gas substructure platform weights were differentiated by the percentage of oil vs. gas platforms overall.

Gas Platforms Count	1,074
Oil Platforms Count	114

Weight of topside from Ocean Star:	13,607,771	kg
Calculations Above:	8,948,187	kg
	66%	Remaining 33% is attributable to non-steel/non-aluminum infrastructure that was not inventoried.