II. Energy Sector

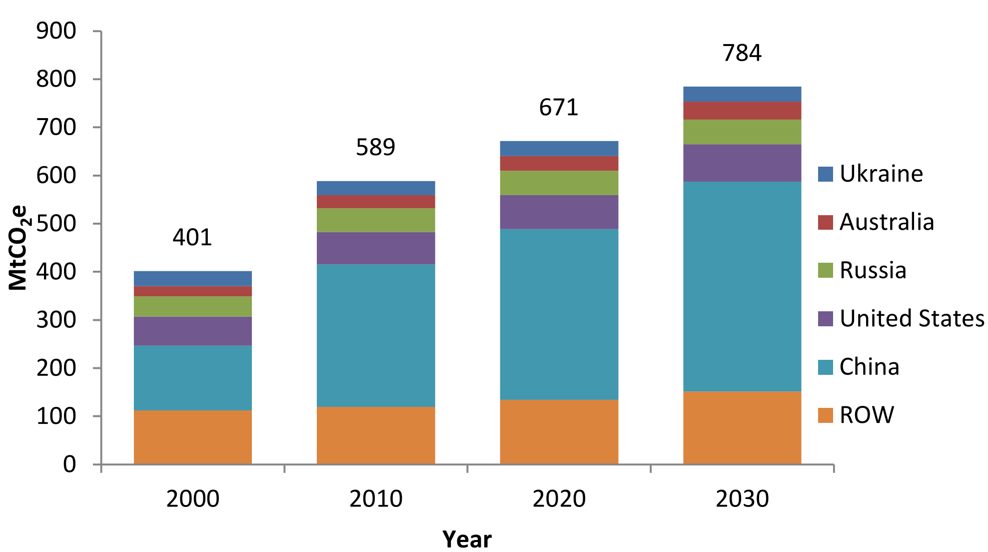
II.1. Coal Mining

II.1.1 Sector Summary

Coal mining is a significant source of anthropogenic GHG emissions. Coal is an important energy resource in many of the world's economies, used for energy generation or as a feedstock in industrial production processes. Extracting this energy resource through underground and surface mining releases methane (CH_4) stored in the coal bed and surrounding geologic strata. The U.S. Energy Information Administration's (USEIA's) (2011) most recent international energy outlook projects a 39% increase in coal production between 2010 and 2035, reflecting continued economic and industrial development of the world's emerging economies. In the absence of widespread adoption of abatement measures by the coal mining sector, expanding coal production to meet growing energy demands will subsequently lead to increases in anthropogenic emissions.

Worldwide, the coal mining industry liberated more than 589 million metric tons of carbon dioxide equivalents ($MtCO_2e$), which accounted for 8% of total anthropogenic CH_4[1] emissions in 2010. The top 5 emitting countries of China, the United States, Russia, Australia, and Ukraine account for more than 80% of coal mining CH_4 emissions. Figure 1-1 summarizes the business-as-usual (BAU) emission baselines for the coal mining sector. By 2030, emissions levels are projected to more than double the levels in 2000. The most rapid period of emissions growth occurred in the first decade of this century. More measured growth is projected beyond 2010. Between 2010 and 2030, emissions are projected to grow by 33%. Currently, China represents over 50% of global emissions. China's share of global emissions is projected to increase to 55% by 2030.

Figure 1-1: CH_4 Emissions from Coal Mining: 2000–2030



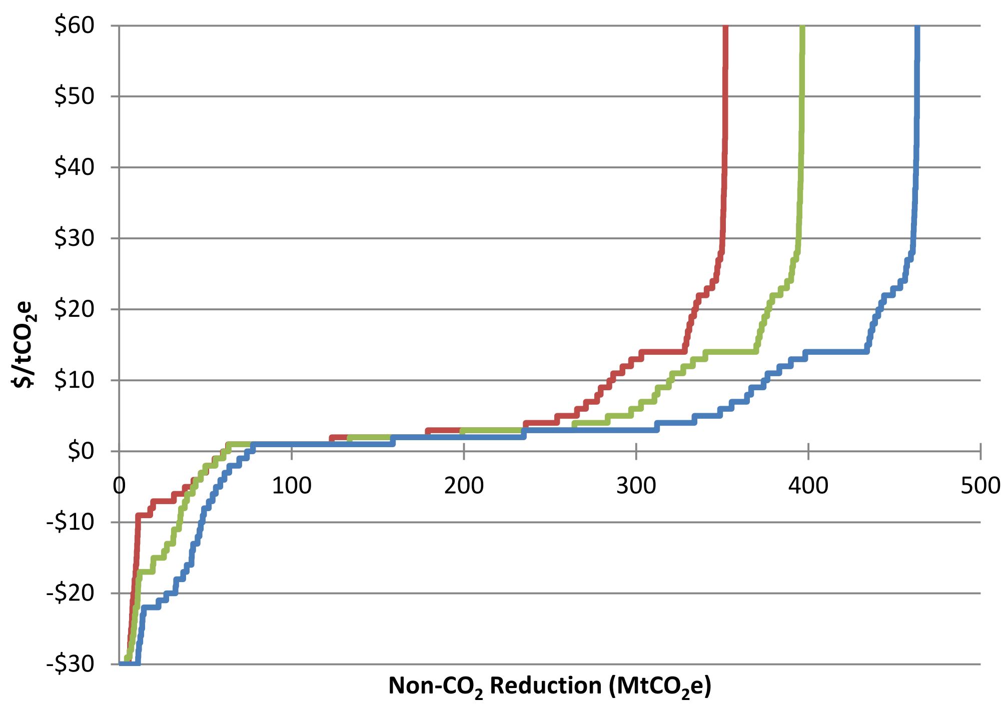
Source: U.S. Environmental Protection Agency (USEPA), 2012.

[1] Global CH_4 in 2010 = 7,549.2 $MtCO_2e$ (see Table A-2 in USEPA, 2012)

Capture for use or destruction are two alternative abatement measures that can mitigate CH_4 emissions associated with underground mining. For mines that are able to utilize the recovered gas, the captured methane represents a potential revenue stream that may offset a portion of the cost of implementing the abatement measure. Specifically, three categories of abatement measures are considered: (1) gas recovery for energy end uses; (2) combustion through flaring; and (3) ventilation air methane (VAM) recovery and destruction through thermal or catalytic oxidation, where low concentrations of CH_4 present in ventilation air exhaust flows are oxidized.

Global abatement potential that is technologically achievable from underground coal mining based on the abatement measures considered is approximately 60% of total annual emissions in 2030. Marginal abatement cost (MAC) curve results are presented in Figure 1-2 for 2010, 2020, and 2030. Maximum abatement potential in the coal mining sector is 400 and 468 $MtCO_2e$ in 2020 and 2030 respectively.

Figure 1-2: Global Abatement Potential in Coal Mining: 2010, 2020, and 2030



While maximum abatement could only be achieved at higher carbon prices, the MAC results suggest that significant opportunities for CH_4 reductions in the coal mining sector at carbon prices at or below \$10. Furthermore there are approximately 78 $MtCO_2e$ of reductions that are cost-effective at currently projected energy prices. These reductions are sometimes referred to as no-regret options.

The following section offers a brief explanation of how CH_4 is emitted from coal mines, followed by a discussion of projected trends in international baseline emissions. Section II.1.3 characterizes possible abatement technologies, outlining their technical specifications, costs and possible benefits, and potential in selected countries. The final section of this chapter discusses emissions reductions that occur following the implementation of each abatement technology and how these reductions are reflected in the MACs.

II.1.2 Methane Emissions from Coal Mining

Methane is produced during a natural process that converts organic material into coal. Methane is stored in the coal through a physical process referred to as sorption. Sorbed methane is condensed within the matrix of the coal as long as the hydrostatic pressure is maintained, but during the mining process, the pressure drops and the gas will begin to desorb and flow into the mine's workings. Methane is also stored in the free spaces of the coal strata and migrates to the mine workings. Many factors affect the quantity of CH_4 released, including the gas content of the coal, the permeability and porosity of the coal seams, the method of mining used, and the production capacity of the mining operation. The concentration of methane present in the coal seam depends on several factors but generally increases with depth. There are four major sources of CH_4 emissions in the coal sector including underground mines, surface mines, post-mining processing, and abandoned mines. Underground mining is the largest single source of emissions in the sector.

Underground Mines. High concentrations of CH_4 in underground coal mines is a safety hazard. Mines are ventilated by use of large fans which are capable of moving large volumes of air through the active workings. Air is drawn across the working face, where coal is being extracted, and exhausted to the atmosphere. This is often adequate to maintain safe levels of methane in the mine workings.

In especially gassy mines, the ventilation system may be supplemented by degasification systems, to ensure adequate evacuation of methane from the mine to ensure safe working conditions. Degasification systems are necessary to ensure safe operations in highly gas prone underground mines that are susceptible to gas outbursts and high methane emissions encountered at the mining face. The primary methods to reduce emissions at the mining face include pre-mine drainage systems that reduce the methane pressure in the coal seam, thereby reducing both the total volume of methane emitted at the mining face and the rate at which it is emitted and post-mining boreholes which drain methane from the collapsed and fractured zone (gob) behind the mining face. These reduce the concentration of methane, especially near the active mining coal face.

Degasification systems consist of a network of boreholes drilled from the surface, or within the mine for the purpose of removing CH_4 before, during, or after mining. These wells extract coal mine methane from the coal seam at relatively high concentrations (30% to 90%). Concentrations vary depending on the type of coal mined and the degasification technique used. In contrast, underground mine ventilation systems emit large quantities of very dilute methane (typically less than 1% methane), known as "ventilation air methane" or VAM.

Traditionally, CH_4 extracted from the mine is released or vented into the atmosphere. It is possible to mitigate underground mine methane emissions, especially from degasification systems, by capturing the gas and either flaring it or recovering and using it for energy. In the case of VAM, the relatively low CH_4 concentration makes it more challenging both technically and economically to mitigate it or recover energy from it.

Surface Mines. Surface mining is a technique used to extract coal from shallow depths at or below the Earth's surface. Because the hydrostatic pressure at shallow depths is lower, the in situ CH_4 content is not as high at surface mines as at underground mines. CH_4 emissions from surface mines (expressed as volume of CH_4 per mass of coal mined) are typically less than from underground mines. As the overlying soil and rock is removed and the coal exposed, CH_4 is emitted directly into the atmosphere. Both because of its lower methane contents and because surface mining is only applicable in certain geographic regions, surface mines may contribute only a small fraction of a country's overall emissions. For example, in the United States in 2009, surface mining accounted for over 60% of coal production, while only accounting for 18% of CH_4 emissions from coal mining (USEPA, 2011b). In China, there is very little surface mining whereas in India almost all coal production is from surface mines. The only technically feasible abatement measures available to surface mining are pre-mine methane drainage in advance of mining, similar to coal bed methane (CBM) recovery operations (USEPA, 2008a), or horizontal boreholes into a high wall where the operation starts as a surface mine but eventually the drift requires the operation to become an underground mine. Given the limited contribution surface mines make to national baseline emissions, this analysis did not consider any abatement measures for surface mining.

Post-mining Operations. Following the mining operations, a series of operations, called *post-mining operations*, constitutes a third source of CH_4 emissions. Not all CH_4 gas is released from coal during the process of coal breakage that takes place during extraction and transport to the surface at mining operations; some emissions occur during the processing, storage, and transport of coal as the coal continues to de-gas. The rate of post-mining emissions depends on the rank of coal and the way it is handled. The highest rate of emissions occurs when coal is crushed, sized, and dried for industrial and utility uses. Given the limited contribution of post-mining emissions to national baseline emissions and the limited technical options to abate these emissions from rail cars or storage piles, this analysis does not consider any abatement measures for post-mining operations.

Abandoned Mines. Abandoned mines are another source of CH_4 emissions. Emissions are released through old wells, ventilation shafts, and cracks and fissures in overlying strata. In some cases, the CH_4 from these mines has been captured and used as a source of natural gas or to generate electricity. The 2006 Intergovernmental Panel on Climate Change (IPCC) guidelines provide a separate methodology for reporting emissions from abandoned coal mines. Hence, emissions from this source are excluded from this analysis and are not included in the baseline estimates. Although there are abatement options for recovering and using methane from abandoned mines, these options were not examined in this analysis.

In summary, the majority of the CH_4 emitted from coal mining operations comes from gassy underground mines via ventilation systems and degasification systems. Smaller, but still significant, amounts of CH_4 are emitted from surface mining and post-mining operations and from abandoned mines. Future levels of CH_4 emissions from coal mining, however, will be primarily determined by the management of CH_4 gas at active underground mines.

II.1.2.1 Activity Data and Related Assumptions

Globally, coal production is expected to increase by 39% from 2010 to 2035, growing at an average annual rate of 1.8%. Future baseline CH_4 emissions estimates are directly related to projections of future levels of coal production. Projected coal production is based on global trends in the demand and supply of coal, which are particularly influenced by the global mix of electricity generation sources. China and India are expected to account for 72% of the increase in global production as they try to meet their demand with domestically produced coal (USEIA, 2011).

Three quarters of the world's recoverable coal reserves are located in five countries: the United States (27%), Russia (18%), China (13%), Australia (9%), and India (7%) (USEIA, 2011). Because global coal consumption is projected to increase over the next several decades, it is also expected that these five countries will produce the majority of coal to meet the demand. Efforts in recent years by China to modernize its coal mining operations are allowing coal to be mined at greater depths and at lower cost. This, combined with a tremendous demand for coal-generated electricity, has contributed to substantial increases in CH_4 emissions.

Emissions factors for coal mining vary depending on the type of coal being mined, the depth at which the mining face is located, and how much coal is being produced in a given year. These factors also vary across countries and time. Emissions factors are estimated for each country and are based on the methodologies detailed in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories. The IPCC guidelines provide a methodology for countries developing emissions factors based on the availability and certainty of emissions data.[2] Table 1-1 reports IPCC Tier 1 emissions factors for underground mines based on CH_4 intensity and coal seam depth unadjusted for any CH_4 utilization or flaring.

Table 1-1: IPCC Suggested Underground Emissions Factors for Selected Countries in m^3/tonne Coal Produced

Tier 1—CH_4 Emissions Factor	Emissions Factor (m^3/tonne)	Emissions Factor[a] (tCO_2e/tonne)
Low (< 200m)	10	0.14
Average	18	0.26
High (> 400m)	25	0.36

Source: IPCC, 2006. Chapter 4: Fugitive Emissions in *2006 IPCC Guidelines for National Greenhouse Gas Inventories. Vol. 2. Energy.* Available at: http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol2.html

[a] Conversion factor of 1 m^3 = 0.0143 tCO_2e

Improvements made in mining technology throughout the last 30 years have resulted in the ability to extract coal from increasingly greater depths. Developing countries' adoption of advanced mining technology has allowed countries such as China and Russia to reach deeper into their existing coal reserves. As noted earlier, the volume of CH_4 in the coal seam may increase at greater depths because of increasing hydrostatic pressure. Thus, it is expected that the CH_4 emission factors will increase as technology allows large coal-producing countries to mine deeper, gassier coal seams.

II.1.2.2 Emissions Estimates and Related Assumptions

This section briefly discusses the historical and projected emissions trends and presents the baseline emissions used in the MAC analysis.[3]

Historical Emissions Estimates

Global CH_4 emissions from coal mining increased by 14% between 1990 and 2010. Key factors that contributed to the emissions growth over this time period include overall increases in coal production as well as technological improvements that have enabled coal mining at increased depths. For additional detail on historical emissions estimates we refer the reader to USEPA's *Global Emissions Report* (2012).

Projected Emissions Estimates

Absent the widespread adoption of abatement technologies, worldwide global CH_4 emissions from coal mining will continue to increase at an accelerated rate. Over the next 20 years, emissions are expected to grow at an average annual rate of 1.5%, compared with 0.07% between 1990 and 2010. The projected increase is driven by a number of factors, including continued mining technology advances and increasing demand for coal for electricity production over the same period. Large, increasingly developed countries, such as China and India, are expected to experience high levels of economic growth. Economic

---

[2] Emissions factors for underground mines, the largest source of CH_4 emissions from coal mining, are the same as those described in the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories, and emissions factors for surface mines, post-mining, and abandoned mines are all based on the IPCC's 2006 guidelines.

[3] For more detail on baseline development and estimation methodology, the authors refer the reader to the USEPA's *Global Emissions Projection Report* available at: www.epa.gov/climatechange/economics/international.html.

growth in these countries will be the biggest driver of future CH_4 emissions from coal mining. Increasing rates of technological adoption and modernization of mining operations will allow developing countries to mine deeper and more effectively and, in turn, produce more CH_4 emissions. Table 1-2 presents baseline emissions projections by country and region from 2010 to 2030.

Table 1-2: Projected Emissions from Coal Mine CH_4 by Country and Region: 2010 to 2030 ($MtCO_2e$)

Country/Region	2010	2015	2020	2025	2030	CAGR[a] (2010–2030)
Top 5 Emitting Countries						
China	296	321	354	397	436	2.0%
United States	67	70	70	73	78	0.7%
Russia	49	51	51	50	51	0.3%
Australia	27	30	31	34	37	1.5%
Ukraine	30	31	31	31	31	0.3%
Rest of World (ROW) by Region[b]						
Africa	10	11	11	12	12	1.1%
Central & South America	9	11	13	14	16	3.0%
Middle East	0	0	0	0	0	3.5%
Europe	30	29	29	29	29	−0.2%
Eurasia	22	23	23	23	24	0.3%
Asia	45	49	55	61	67	2.0%
North America	3	3	3	3	3	−0.7%
World Total	**589**	**630**	**671**	**725**	**784**	**1.4%**

[a]CAGR = Compound Annual Growth Rate
[b]ROW by Region excludes emissions from top 5 countries.
Source: USEPA, 2012

II.1.3 Abatement Measures and Engineering Cost Analysis

This analysis considers five abatement measures classified into three technology categories that include recovery for pipeline injection, power generation or use as a process fuel/on-site heating, flaring, and catalytic or thermal oxidation of VAM. It should be noted that mitigation of gas from degasification systems and ventilation systems are independent of each other. Abatement measures in the coal mining sector consist of one or more of the following primary components: (1) a drainage and recovery system (where applicable) to remove methane from the coal seam pre-mining or from the gob area post mining, (2) the end-use application for the gas recovered from the drainage system (where applicable), and (3) the ventilation air methane recovery or mitigation system (where applicable).

Costs are derived from USEPA's Coalbed Methane Outreach Program (CMOP) project Cash Flow Model (USEPA, 2011b) and applied to a representative population of underground mines. Table 1-3 summarizes the average total installed capital costs and annual operations and maintenance (O&M) costs for each abatement measure.

Table 1-3: Summary of Abatement Measures for Coal Mines

Abatement Measure	Total Installed Capital Cost[a] (million USD)	Total Annual O&M Cost (million USD)	Technical Lifetime (Years)	Technical Effectiveness[b] (%)
Energy End Uses				
Pipeline injection	8.4	2.4	15	21%
On-site electricity generation	23.0	2.6	15	28%
On-site use for process heat	2.8	1.2	15	28%
Excess Gas Flaring				
Enclosed flare system	2.3	1.5	15	28%
Mitigation of VAM				
VAM oxidation	8.0	1.3	15	19–68%

[a] Capital costs include costs of both recovery and abatement equipment requirements.

[b] Abatement potential expresses the maximum potential emission reductions at a facility level.

This section describes the abatement measures and associated costs of the methane recovery and abatement in the coal mining sector. Each technology is briefly characterized followed by a discussion of costs, potential benefits, technical effectiveness, and applicability assumptions used to estimate the abatement potential.

Technical effectiveness factors are calculated by considering a number of technological efficiency and applicability factors. Table 1-4 presents these factors for each abatement measure. These include the technical effectiveness of the recovery system and reduction efficiency of the utilization or destruction technology. Technical effectiveness, represented by [E] in Table 1-4, of any option at the mine level is equal to the product of the facility applicability, recovery efficiency, technical feasibility, and reduction efficiency factors.

Table 1-4: Factors Used to Estimate Abatement Potential in Coal Mines

Abatement Measure	Facility Applicability [A]	Recovery Efficiency [B]	Technical Feasibility [C]	Reduction Efficiency [D]	Technical Effectiveness [E]
Energy End Uses: Drained Gas					
Pipeline injection	38%	75%	100%	75%	21%
On-site electricity generation	38%	75%	100%	98%	28%
On-site direct use	38%	75%	100%	98%	28%
Mitigation only: Drained gas					
Enclosed flare system	38%	75%	100%	98%	28%
Oxidation of VAM					
VAM oxidation	62%	25% - 90%	77%	98%	19–68%

$Technical\ Effectiveness\ [A] \times [B] \times [C] \times [D] = [E]$

Facility applicability [A] represents the share of total mine-level methane emissions that are available for abatement through degasification and VAM. Approximately one-third[4] of total mine emissions can be recovered through degasification (also commonly referred to as drainage), while the majority of mine emissions are released at low concentrations in the ventilation air referred to as VAM.

Recovery efficiency [B] relates to the collection system (see Section II.1.3.1) itself and reflects what may be recovered through the drainage wells or ventilation exhaust systems. Only a fraction of the total drained CH_4 may be effectively used or destroyed because of natural variances in the volume and concentration of methane collected. With respect to VAM oxidation, for this analysis recovery efficiency is set at 25% in 2010 and grows to 90% by 2030.

Technical feasibility [C] relates to the physical or technical limitations of the technologies. It is technically feasible to safely combust mine gas with CH_4 concentrations greater than 30% for drained gas or 0.25% for VAM. A value of 77% for VAM represents the fraction of exhaust vents with methane concentrations high enough (>0.25%) to allow for oxidation.[5] Finally, the reduction efficiency [D] is the factor that describes the destruction efficiency of each end use or combustion technology. For pipeline injection, the reduction efficiency represents the methane losses that occur during transport from the mine to the point of sale into a natural gas pipeline.

II.1.3.1 Methane Recovery System from Degasification/Drainage Systems

High-quality CH_4 is recovered from coal seams by drilling vertical wells from the surface up to 10 years in advance of a mining operation or drilling in-mine horizontal boreholes several months or years before mining. Most mine operators exercise just-in-time management of gate road development; subsequently, horizontal cross-panel boreholes are installed and drain gas for 6 months or less (USEPA, 2011b).

The components of the capital and annual costs for the drainage wells are outlined as given in USEPA's CMOP Cash Flow Model documentation (USEPA, 2011b). The recovery system includes the equipment required for drainage wells, gas gathering lines, and delivery systems for coal mine methane (CMM). The recovery system is included in the costs of all abatement measures with the exception of VAM oxidation.[6] These costs are additive to the costs associated with each abatement measure.

- **Capital Cost:** The capital costs for a drainage system are a function of the recovered gas flow rate. Equipment requirements include construction of the drainage well(s), a wellhead blower, a satellite compressor station, and gathering pipelines that connect the compressors to the methane end-use technology. The total installed capital costs will vary by location and gas flow rate. For example, assuming a 600 Mcf/day volume of CMM gas (with a CH_4 concentration of 90%), we estimate the capital costs would be $850,000. See Appendix B for additional detail on equipment cost assumptions.

---

[4] The proportion of mine CH_4 emissions recoverable through degasification systems can vary from 0% to 70% depending on the gassiness of the mine. This analysis uses 38%, which represents an average for gassy mines.

[5] This value may be a high estimate based on anecdotal evidence from field testing experience. For example, the number of mines in Asia that meets a threshold for application of available and field-tested VAM abatement systems is much lower.

[6] A recovery system is not required for VAM oxidation because it relies on the mine's existing ventilation system that would be installed before mining operations commence.

- **Annual Operating and Maintenance (O&M) Costs:** The annual costs are required to maintain the drainage system equated to approximately $2.2/Mcf per year. These costs include the ongoing installation of gob wells and the gathering system piping that connects the wells to satellite compressors. In keeping with the example mine of 600 Mcf/day, the annual O&M costs associated with the recovery system would be approximately $475,000.
- **Recovery Efficiency:** Recovery efficiency is assumed to be 75%.

II.1.3.2 Degasification for Utilization in Energy Production

This category of abatement measures includes (1) recovery for pipeline injection and (2) recovery for electricity generation. Both options require a recovery system in place to extract the methane gas from the coal seams. Which technology is most cost-effective will be determined by a combination of regional energy prices and the capital equipment requirements.

Degasification for Pipeline Injection

Natural gas companies may purchase CH_4 recovered from coal mines. CH_4 suitable for sale into natural gas pipelines must have a concentration of at least 96% and contain no more than 4% concentration of noncombustible gases with a maximum of 4% carbon dioxide or nitrogen and 1 ppm oxygen. Although CH_4 from coal mines requires water removal, it is typically free of hydrogen sulfide and other impurities found in natural gas. Hence, little to no additional treatment and processing are necessary to meet the requirements for pipeline injection. In some cases, high-quality CH_4 also can be obtained from gob wells.

Premining degas wells are the preferred recovery method for producing pipeline quality CH_4 from coal seams because the recovered methane is not contaminated with ventilation air from the working areas of the mine.

Gob wells, in contrast, generally do not produce pipeline-quality gas because the methane is frequently mixed with ventilation air. Gob gas CH_4 concentrations can range from 30% to over 90%. It is possible to upgrade gob gas for pipeline quality although blending with pre-mine drained gas and/or oxygen removal may be necessary, adding to the cost of gas processing. However, it is possible to maintain a higher and more consistent gas quality through careful monitoring and adjustment of the vacuum pressure in gob wells as has been demonstrated in the United States (USEPA, 2008b).

The viability of a pipeline project is affected by several key factors. First is a coal mine's proximity to a commercial pipeline. The cost of constructing a pipeline to connect to a commercial pipeline can vary greatly depending on distance. Secondly, and more importantly, the terrain will affect the viability of a commercial pipeline project. Many mining areas are located in hilly and mountainous regions, thus increasing the difficulty and cost of constructing both gathering lines and pipeline to connect to the commercial natural gas pipeline (USEPA, 2008b). Finally, disposal of water produced from vertical wells may be a significant factor in determining the economic viability of a pipeline project.

- **Initial Capital Cost:** The per facility installed capital costs for pipeline injection of gob gas, as described in USEPA (2011b), include the installation of a pressure swing adsorption system to remove nitrogen and carbon dioxide down to a 4% inert level. The utilization cost is a function of both the inlet gas flow rate and methane concentration and includes the cost of dehydration and compression necessary to process the gas and boost the sales gas to pressure for injection in a natural gas transmission pipeline. While there may be a range of pressures at which pipelines operate, this analysis assumes an operating pressure of 900 psig. This option also includes the installation of a catalytic oxygen removal system and a pipeline to connect the mine's gas processing system to a natural gas pipeline. Pipeline costs estimated for this analysis are adjusted based on mine proximity to commercial pipeline but do not attempt to account for variations in terrain across countries.

- **Annual O&M Costs:** The annual costs include costs of recovery system and cost of gas treatment and compression required for injection into commercial natural gas pipelines.
- **Annual Benefits:** Revenues from this option are the gas sales based on the volume of gas produced and the market price of natural gas.
- **Technical Effectiveness:** The analysis assumes a technical effectiveness of 21%. As shown in Table 1-4, this considers a recovery efficiency of 75% (reflects the loss of 25% of the gas cannot be used in pipeline injection because the methane concentration is too low to process to pipeline specifications) and destruction efficiency of 75% to account for losses during transport to point of sale and injection into a commercial natural gas pipeline.
- **Technical Lifetime:** 15 years

Degasification for Electricity Generation

Drained methane can be used to fire internal combustion (IC) engines that drive generators to make electricity for sale to the local power grid (USEPA, 2011b). The quality of methane required for use in power generation can be less than that required for pipeline injection. Internal combustion (IC) engine generators can generate electricity using gas that has heat content as low as 300 Btu/cf or about 30% methane. Mines can use electricity generated from recovered methane to meet their own on-site electricity requirements and can also sell electricity generated in excess of on-site needs to utilities (USEPA, 2008b).

Coal mining is a very energy-intensive industry that could realize significant cost savings by generating its own power. Nearly all equipment used in underground mining runs on electricity, including mining machines, conveyor belts, ventilation fans, and elevators. While most of the equipment used in mining operations is used 250 days a year for two shifts per day, ventilation systems are required to run continuously year round. These systems require large amounts of energy, up to 60% of a mine's total electricity usage. Total electricity demand can exceed 24 kWh per ton of coal produced (USEPA, 2008b).

- **Capital Cost:** The cost for this option includes the cost of gas processing to remove gas contaminants (primarily water vapor and solid particles), the electricity generation equipment, and power grid connection equipment. Costs are assumed to be $1,300/kW. Assuming a 2 MW facility and a capacity factor of 90%, total installed capital costs of electricity generation would be $2.7 million. Total installed capital costs for this abatement measure would be $4.5 million, which includes the $850,000 for recovery, assuming 20% owner's costs and 5% contingencies.
- **Annual O&M Costs:** The annual costs include $0.02/kWh for the engine-gen set in addition to the $2.2/Mcf cost of the recovery system. Assuming a 600 Mcf/d flow and 90% capacity total O&M costs would be approximately $0.8 million USD.
- **Annual Benefits:** Revenues in the form of power sales at market electricity prices. A 2 MW capacity generation facility with a 90% capacity factor would be expected to generate

approximately 16,000 MWh of electricity. Assuming an energy price of \$0.075/kWh[7], this project would generate \$1.2 million in revenue from electricity sales.

- **Technical Effectiveness:** The analysis assumes a technical effectiveness of 28%, assuming a recovery efficiency of 75% and destruction efficiency of 98% in the energy generation unit.
- **Technical Lifetime:** 15 years

II.1.3.3 Degasification for On-site Utilization—Process Heat

This category of abatement measures includes (1) recovery for use in the boiler for supporting in-mine heating and (2) recovery for coal drying.

Mine Boilers

Drained methane can be used to fuel on-site boilers that provide space or water heat to mine facilities. This analysis assumes that existing boilers will be retrofitted to burn methane and that the drained methane is of sufficient quality to fuel the mine's boiler and no additional gas processing is required.

- **Capital Cost:** The costs for this option are primarily associated with the capital cost to retrofit the mine boiler to fire drained gas. The analysis assumes a 8.1 MMBTU/hr[8] average boiler heat load and a retrofit cost of \$7,500/MMBTU/hr. Assuming the mine boiler fuel demand was 10 Mcf/hr, total installed capital costs for this abatement measure would be \$635,000, which includes \$382,000 for the recovery system, \$122,000 for boiler retrofit, and an additional 20% in owner's costs and 5% for contingencies.
- **Annual O&M Costs:** The annual costs are the \$2.4/Mcf to operate the recovery system. Assuming a 240 Mcf/d flow and 90% capacity, the total O&M costs would be approximately \$213,000 USD.
- **Annual Benefits:** Benefits are the energy costs offset by using the drained methane gas as a substitute fuel source (offsetting coal consumption). Revenues associated with this project will be the quantity of coal replaced at the mine mouth coal market price (\$/MMBTU).
- **Technical Effectiveness:** The analysis assumes a recovery efficiency of 75% and destruction efficiency of 98% when combusted in mine boiler.
- **Technical Lifetime:** 15 years

Coal Drying

Another on-site direct use application for drained CMM is to use it as a fuel in thermal coal drying operations at coal preparation plants co-located near an underground mine. The existing coal drying process can be retrofitted to burn methane as a supplemental fuel in addition to burning coal. Similar to the mine boiler option, we assumed the CMM will not require further processing to serve as fuel to the dryer.

- **Capital Cost:** The cost of converting the dryer to burn CMM was assumed to be the same as the cost of converting the boiler firing system [\$7,500/MMBtu/hr]. The analysis assumed an average coal drying rate of 380 tons/hr (USEPA, 1998). Assuming the average coal dryer heating

---

[7] The actual price utilities would be willing to pay will vary depending on market and regulatory environment within the specific country. In the absence of any additional market incentives, purchasers would likely only pay the price of generation in the range of \$0.025/kWhr in the United States.

[8] MMBTU/hr = Million British Thermal Units per hour

requirement is 228 MMBTU/hr,[9] CMM gas with a lower heating value of 991 BTU/cf, the total installed capital costs for this abatement measure would be $635,000, which includes $382,000 for the recovery system, $122,000 for boiler retrofit, and an additional 20% in owner's costs and 5% for contingencies.

- **Annual O&M Costs:** The annual costs to operate the recovery system are assumed to be $2.4/Mcf. Assuming a 240 Mcf/d flow and 90% capacity factor, total O&M costs would be approximately $213,000 USD.
- **Annual Benefits:** Benefits are the energy costs offset by using the drained methane gas as a substitute fuel source (offsetting coal consumption). Revenues associated with this project will be the quantity of coal replaced based on assumed energy content (MMBTU/ton) at the mine mouth coal market price ($/MMBTU).
- **Technical Effectiveness:** The analysis uses a technical effectiveness of 28%, which assumes a recovery efficiency of 75% and destruction efficiency of 98% when combusted in mine boiler.
- **Technical Lifetime:** 15 years

II.1.3.4 Combustion through Flaring

After recovering methane using the drainage well technique, mines can choose to flare methane of greater than 30% concentration (USEPA, 2011a). Flare systems considered include an open flare and enclosed combustion system, which consists of a mounted burner where the flame is exposed (open) or the flame is enclosed in a stack. The costs of the flaring system consist of firing equipment and monitoring and metering equipment to validate methane destruction levels.

- **Capital Cost:** The cost of installing a flare system to burn CMM was assumed to be $280/Mcf/day. Assuming an average daily flow rate of 600 Mcf gas, the total installed capital costs for this abatement measure would be $1,239,000, which includes $850,000 for the recovery system, $134,000 for the flare system, and an additional 20% in owner's costs and 5% for contingencies.
- **Annual O&M Costs:** The annual costs to operate the recovery system are assumed to be $2.4/Mcf. Assuming a 600 Mcf/d flow and 90% capacity factor, total O&M costs would be approximately $489,000 USD.
- **Annual Benefits:** There are no revenues associated with this option.
- **Technical Effectiveness:** The analysis uses a technical effectiveness of 28%, which assumes a recovery efficiency of 75% and destruction efficiency of 98% when combusted in flaring system.
- **Technical Lifetime:** 15 years

II.1.3.5 VAM Oxidation

Oxidation technologies (both thermal and catalytic) have the potential to use CH_4 emitted from coal mine ventilation air. Extremely low CH_4 concentration levels (typically below 1%) make it economically infeasible to sell this gas to a pipeline. However, thermal oxidizers can combust the VAM converting it to H_2O and CO_2. VAM oxidation is technically feasible at CH_4 concentrations between 0.25% and 1.25%. For mines with lower VAM concentrations, a supplemental gas is required to bring the concentration above the 0.25% concentration limit.

[9] MMBTU/hr = Million British Thermal Units per hour

- **Capital Cost:** Abatement measure costs include the ductwork required to collect VAM exhaust from the mine's ventilation system at the surface vents, the design and installation of a thermal oxidizer unit, and any supporting auxiliary equipment. The total installed capital cost of the VAM oxidizer unit is $23 per unit of recoverable ventilation air flow measured in cubic feet per minute [cfm]. Assuming the recoverable ventilation air flow rate of 100 Mcfm and a CH_4 concentration of 0.2%, capital costs would be $2.3 million USD (=100,000 cfm X $23/cfm). The total installed capital costs for this abatement measure would be approximately $2.8 million after assuming allowances of 20% in owner's costs and 5% for contingencies.
- **Annual O&M Costs:** Annual operating costs include costs to maintain the oxidizer unit, the electricity required to operate the oxidizer blowers (0.075 kWh/mcf), and the periodic relocation costs of moving equipment to the new location of a mine ventilation shaft (every 5 years at a cost of $4/cfm). Assuming a 100 Mcfm flow rate, total O&M costs would be approximately $462,000 USD, where VAM blower electricity costs account for 55% of the annual costs, while oxidizer O&M costs represent 28%, and annualized relocation costs make up the balance.
- **Annual Benefits:** Although low-grade heat can be captured from the VAM oxidizer, little economic benefit can be obtained from it and only under special site-specific conditions; for this reason, we assume there are no energy-related benefits for this abatement measure.
- **Technical Effectiveness:** The analysis assumes a technical effectiveness of between 19% and 68%, which assumes a recovery efficiency of 25% (in 2010) to 90% (in 2030) and destruction efficiency of 98% in a VAM oxidation unit.
- **Technical Lifetime:** 15 years

II.1.3.6 Evaluation of Future Mitigation Option and Trends

Based on our review of existing abatement measures, technology improvements have the potential to reduce the costs of VAM oxidation technology. Despite its abatement potential, VAM oxidation is the measure with the highest abatement costs largely due to three key factors that include: (1) the equipment itself is large and costly; (2) the lack of a revenue source; and (3) only a handful of technologies have been demonstrated at a commercial scale and as such economies of scale in production have not been realized. The development of an international carbon market like the United Nations Framework Convention on Climate Change's (UNFCCC's) Clean Development Mechanism (CDM) or the European Trading System (ETS) would provide a source of revenue from the sale of carbon reduction credits. In addition, improvements in design and catalysts have the potential to reduce the cost of oxidation over time. All other abatement measures described in this chapter are assumed to be mature technologies.

II.1.4 Marginal Abatement Costs Analysis

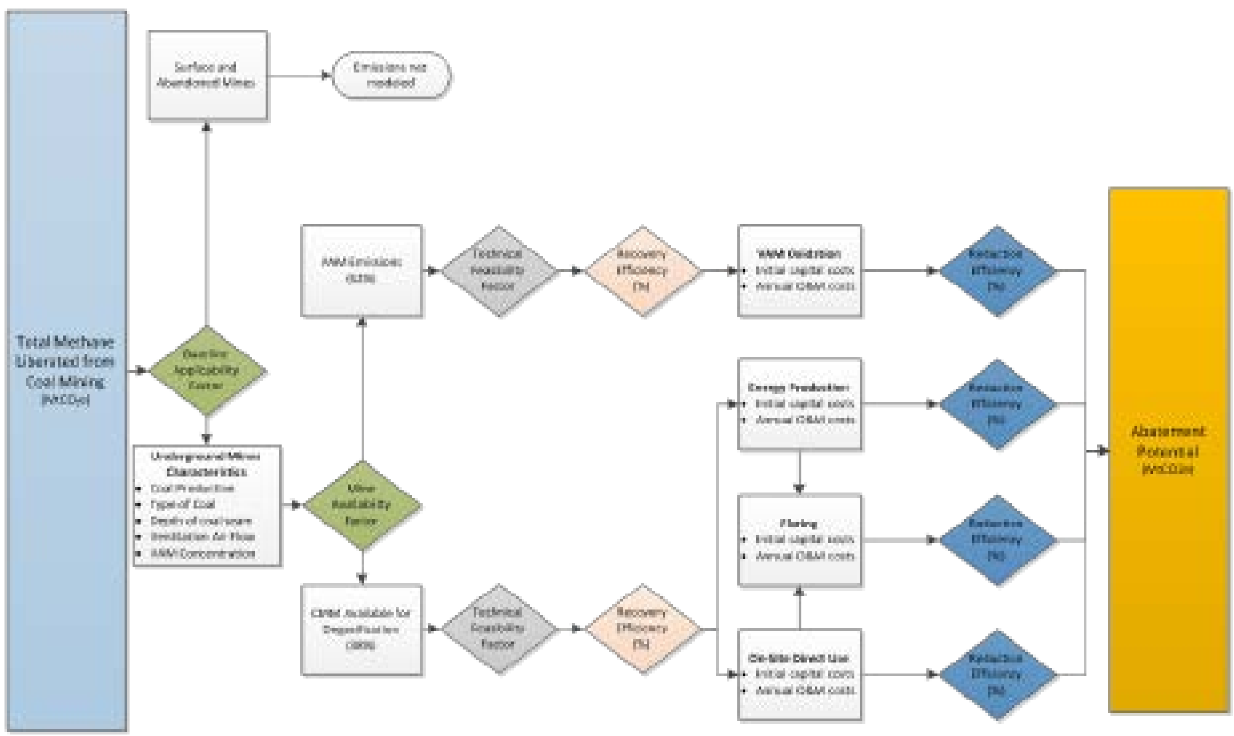
This section describes the methodological approach to the international assessment of CMM abatement measures. Here we describe the modeling approach applied to the sector and highlight the unique facets of the modeling approach that are required to align with the general modeling framework described in the technical summary of this report.

II.1.4.1 Methodological Approach

The analysis seeks to characterize the cost of abatement in the coal mining sector by developing project cost estimates for a series of representative mines that represent the population of active underground coal mines in a reference location, which is the United States. Abatement measures are applied to the technically applicable stream of emissions (degasification, or ventilation air streams). The

MAC model calculates break-even prices for each representative coal mine based on the facility characteristics that include annual methane liberation, presence of existing degasification operations, mine ventilation air flow rate, and VAM concentration. Figure 1-3 illustrates the flow of emissions and the country and technology factors that determine the abatement potential.

Figure 1-3: Flow Chart of the Coal Mining Sector MAC Modeling Approach



The MAC model internationalizes the abatement measures' project costs by applying country-specific factors to adjust individual components of the technology costs and expected benefits (i.e., capital, labor, energy and materials) to transpose costs from a United States context to the international country of interest. The MAC model then applies the general break-even cost calculation using the internationalized costs and benefits to develop country-specific abatement cost estimates.

II.1.4.2 Assessment of Sectoral Trends

Abatement potential estimated in this report is limited to the subset of emissions from underground coal mining activities. No abatement measures are considered for surface mining, abandoned mines, or post-mining operations. The analysis assumed that the majority of emissions from the coal mining sector come from underground coal mining activity. As a result, a significant proportion of the BAU emissions projected (see Table 1-3 above) are available for abatement via the measures discussed in this chapter. This analysis considers country-specific data when available to adjust the basic assumption that between 70% and 98% of emissions are available for abatement (i.e., the quantity of emissions from underground mining activities). For countries for which no other information was available, expert judgment was used to assess the quantity of emissions eligible for abatement.

II.1.4.3 Definition of Model Facilities for the Analysis

A population of representative underground coal mines was developed using publicly available data for the U.S. active underground coal mines. The dataset included detailed information on over 100 active mines with average methane liberation rates greater than 0.1 million cubic feet per day. Information was also available on the methane concentration in mine ventilation air.

The international population of facilities is defined through a representative dataset of underground mines with the accompanying mine-specific characterizations. This includes the gassiness of the mine and the concentration of methane present in the mine's ventilation air.

II.1.4.4 Estimating Abatement Project Costs and Benefits

Mine characteristics for each mine in the facility database were used to estimate abatement project costs and benefits. Applying the costs described in Section II.1.3, the CMOP project Cash Flow Model provided outputs including initial capital investment, annual recurring costs for operation and maintenance, and the quantity of energy saved or offset. The costs and benefits data are then used as inputs in the MAC model. The cost functions used in the CMOP model are assumed to be representative of typical projects in the United States. Please refer to the CMOP model documentation for additional details on how costs are calculated.

Table 1-5 provides an example of how the break-even prices are calculated for each abatement measure. Project costs and benefits calculated for each coal mine are used in the calculation that solve for the break-even price that sets the project's benefits equal to its costs.

The break-even prices presented in Table 1-5 represent weighted average break-even prices weighted by total annual methane liberated across the population of coal mines used for this analysis. Each coal mine will have its own break-even price based on the amount of methane recovered. Break-even prices will be higher for less gassy coal mines and lower (potentially negative) for most gassy mines. Complete international MAC results are presented in Section II.1.4.5.

Table 1-5: Example Break-Even Price Calculation for Coal Mine Abatement Measures

Abatement Option	Reduced Emissions (tCO_2e)	Annualized Capital Costs[b] ($/$tCO_2e$)	Net Annual Cost[a] ($/$tCO_2e$)	Tax Benefit of Depreciation ($/$tCO_2e$)	Break-Even Price[b] ($/$tCO_2e$)
Energy End Uses					
Pipeline Injection	99,629	$18.5	−$19.5	$3.76	−$4.69
Electricity Generation	130,338	$38.7	−$33.0	$7.84	−$2.18
On-Site Direct Use	249,175	$2.5	−$2.8	$0.50	−$0.85
Excess Gas Flaring					
Enclosed Flare System	298,333	$1.7	$5.0	$0.35	$6.33
Combustion of VAM					
VAM Oxidation	46,430	$37.5	$28.0	$7.61	$57.91

[a] Assumes tax rate = 40%; discount rate = 10%, technical lifetime = 15 years

[b] AEO 2010 Energy prices; dry natural gas ($/Mcf); electricity $/kWh); and coal ($/ton)

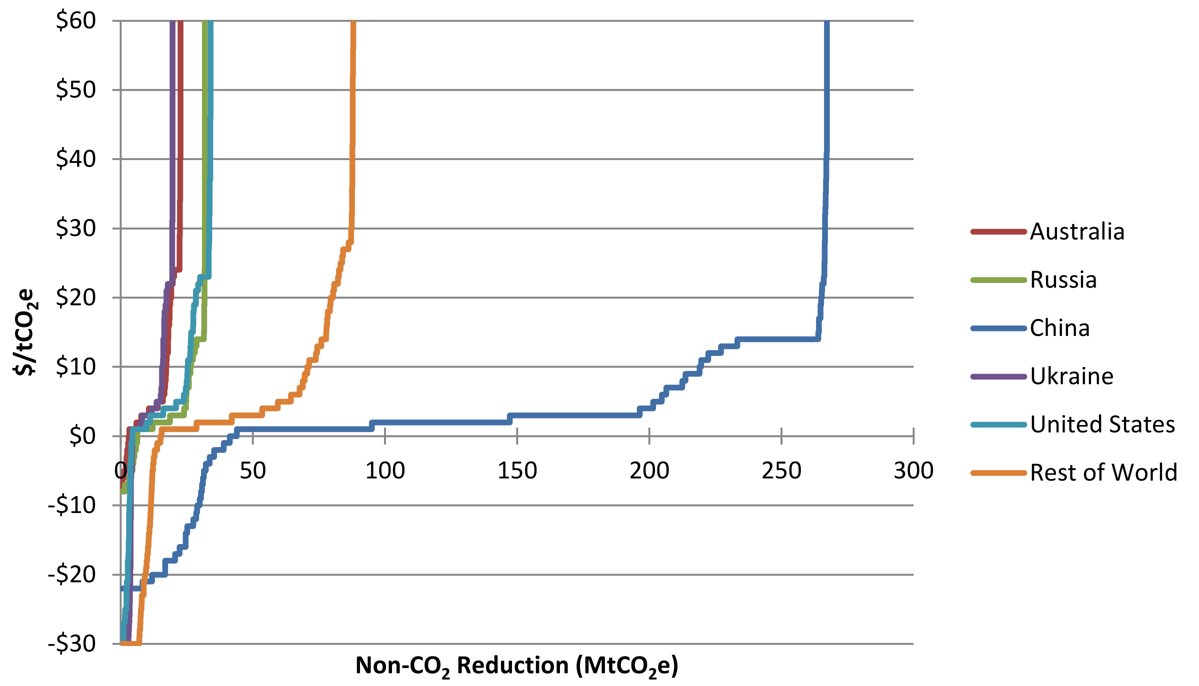
II.1.4.5 MAC Analysis Results

Global abatement potential in 2020 and 2030 is 400 and 468 $MtCO_2e$, respectively. Nearly 16% of the reduction can be achieved by implementing currently available technologies that are cost-effective at projected energy prices. If an additional emission reduction incentive (e.g., tax incentive, subsidy, or tradable emission reduction credit) above the zero break-even price were available to coal mine operators, then additional emission reductions could be cost-effectively achieved. The results of the MAC analysis are presented in Table 1-6 and Figure 1-4 by major country and regional grouping at select break-even prices in 2030.

Table 1-6: Abatement Potential by Region at Selected Break-Even Prices ($/tCO₂e) in 2030

	Break-Even Price ($/$tCO_2e$)										
Country/Region	**–10**	**–5**	**0**	**5**	**10**	**15**	**20**	**30**	**50**	**100**	**100+**
Top 5 Emitting Countries											
Australia		1.9	3.3	15.9	17.3	18.0	19.1	22.4	22.6	22.7	22.9
China	29.8	32.2	43.9	204.7	219.6	264.2	265.3	266.5	267.2	269.6	269.6
Russia		4.5	6.3	24.8	26.6	31.5	31.6	31.8	31.8	32.1	32.1
Ukraine	3.8	4.2	4.4	15.1	16.0	16.4	17.3	19.5	19.6	19.6	19.7
United States	3.4	3.6	4.5	23.8	25.4	27.4	28.5	33.5	34.0	34.2	34.5
Rest of Region											
Africa	1.0	1.0	1.1	6.0	6.6	7.5	7.5	7.5	7.6	7.7	7.7
Central and South America	1.6	1.6	1.9	6.7	7.8	8.0	8.3	9.8	9.9	9.9	10.0
Middle East	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2
Europe	2.1	2.4	2.6	10.8	11.9	12.4	13.0	15.1	15.2	15.2	15.4
Eurasia	0.0	0.0	1.3	8.5	9.6	11.0	11.0	11.1	11.1	11.2	11.2
Asia	6.5	6.8	8.2	30.9	34.0	37.4	38.9	41.9	42.1	42.3	42.4
North America	0.2	0.2	0.3	1.3	1.4	1.4	1.5	1.7	1.8	1.8	1.8
World Total	**48.5**	**58.6**	**77.7**	**348.7**	**376.2**	**435.3**	**442.2**	**461.1**	**463.0**	**466.4**	**467.6**

Figure 1-4: Marginal Abatement Cost Curve for Top 5 Emitters and Rest of World in 2030



II.1.4.6 Uncertainties and Limitations

Several key limitations in current data availability constrain the accuracy of this analysis. Successfully addressing these issues would improve development of the MACs and predictions of their behavior as a function of time. Some of these limitations include the following.

- **Accurate Distribution of Mine Type for Each Country.** Extrapolating from available information about individual mines to project fugitive emissions at a national level implies that the available data are representative of the country's coal production not already included in the existing database. A more accurate distribution of representative mines would improve the accuracy of the cost estimates and the shape of each MAC. These data would include mines of all sizes, emissions factors, and production levels. This lack of information becomes increasingly problematic when evaluating a country such as China, where the majority of mines are small and private mines are not represented in currently available data sources.
- **Country-Specific Tax and Discount Rates.** In this analysis, a single tax rate was applied to mines in all countries to calculate the annual benefits of each technology. Similarly, the discount rate may vary by country. Improving the level of country-specific detail will help analysts more accurately quantify benefits and break-even prices.
- **Improved Information on Public Infrastructure.** A more detailed understanding of each country's natural gas infrastructure would improve the estimates of costs associated with transporting CH_4 from a coal mine to the pipeline. Countries with little infrastructure will have a much higher transportation cost associated with degasification and enhanced degasification technologies.

- **Concentrations for VAM in International Mines.** The effectiveness and applicability of VAM technology depends on VAM concentration and mine-specific coal production rates. Improved data on the VAM concentration levels for individual mines would enhance the accuracy of cost estimates. This information would also help to more accurately identify the minimum threshold concentration levels that make VAM oxidation an economically viable option.

References

Global Methane Initiative (GMI). 2010. *Coal Mine Methane Country Profiles*. This document provides individual profiles for 37 countries that covers coal production and coal mine methane markets. Available at: http://www.globalmethane.org/tools-resources/coal_overview.aspx.

Mine Safety and Health Administration (MSHA). January 7, 2010. 2008 Mine Data. Personal communications with Chad Hancher at MSHA. Coal Mine Data, methmine08nma.xls.

Somers, J. M and L. Schultz. 2009."Coal Mine Methane Ventilation Air Methane: New Mitigation Technologies." Available at: http://www.epa.gov/cmop/resources/vam.html.

U.S. Energy Information Administration (USEIA). 2011. *International Energy Outlook 2011*. Coal Overview. DOE/EIA-0484(2011). Washington, DC: EIA. Available at: www.eia.gov/forecasts/ieo/.

U.S. Environmental Protection Agency (USEPA). 2012. *Global Anthropogenic Non-CO2 Greenhouse Gas Emissions: 1990-2030*. EPA 430-R-12-006. Washington, DC: USEPA.

U.S. Environmental Protection Agency (USEPA). 2012. *Global Anthropogenic Non-CO2 Greenhouse Gas Emissions: 1990-2030*. EPA 430-R-12-006. Washington, DC: USEPA.

U.S. Environmental Protection Agency (USEPA). 2011a. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009. Annex 3 Methodological Descriptions for Additional Source or Sink Categories.* USEPA #430-R-11-005. Washington, DC: USEPA. Obtained on May 5, 2011, at: http://epa.gov/climatechange/emissions/usinventoryreport.html.

U.S. Environmental Protection Agency (USEPA). 2011b. *User's Manual for Coal Mine Methane Project Cash Flow Model (Version 2)*. Obtained January 25, 2010, at: http://www.epa.gov/cmop/docs/cashflow_user_guide.pdf.

U.S. Environmental Protection Agency (USEPA). *Coal Mine Methane Project Cash Flow Model (Version 2)*. Obtained on January 25, 2010, at: http://www.epa.gov/cmop/resources/index.html.

U.S. Environmental Protection Agency (USEPA). July 2008a. *U.S. Surface Coal Mine Methane Recovery Project Opportunities*. USEPA #430-R-08-001. U.S. EPA Coalbed Methane Outreach Program. Obtained on January 7, 2011, at: http://www.epa.gov/cmop/docs/cmm_recovery_opps_surface.pdf.

U.S. Environmental Protection Agency (USEPA). September 2008b. (Revised January 2009). *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006*. EPA 430-K-04-003. U.S. EPA Coalbed Methane Outreach Program. Obtained January 7, 2010, at http://www.epa.gov/cmop/docs/profiles_2008_final.pdf.

U.S. Environmental Protection Agency (USEPA). 2004. *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 1999–2003*. EPA 430-K-04-003. Washington, DC: Office of Air and Radiation. Available at: http://www.epa.gov/cmop/docs/profiles_2003_final.pdf.

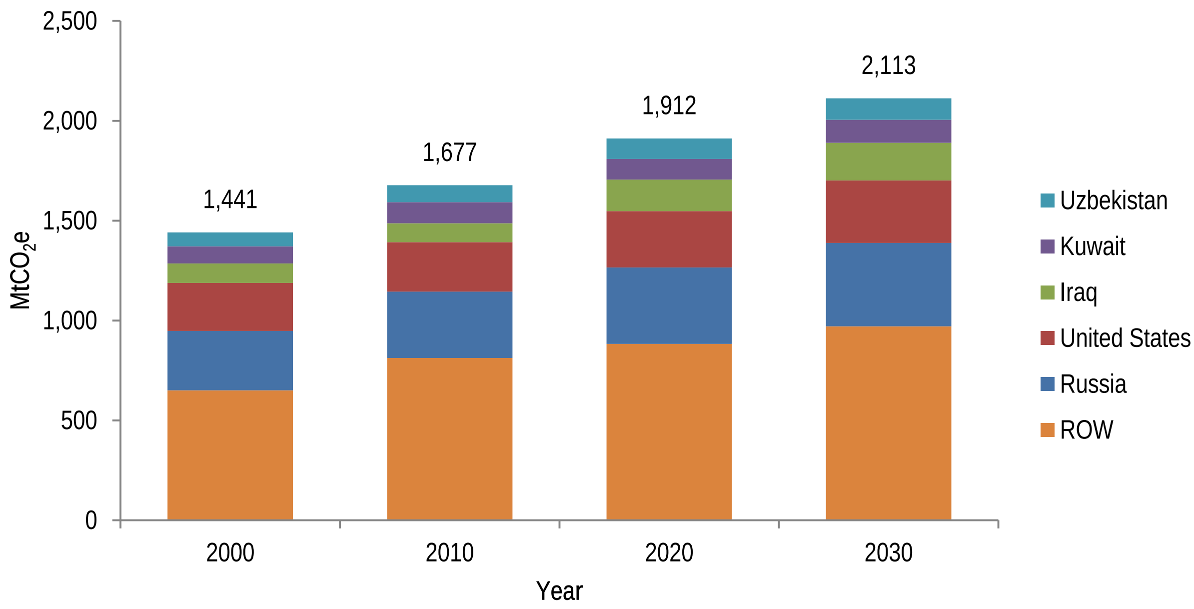
U.S. Environmental Protection Agency (USEPA). November 1998. Use of Coal Mine Methane in Coal Dryers. (US)EPA Coalbed Methane Outreach Program Technical Options Series. USEPA #6202J. Washington, DC: USEPA. Obtained on January 7, 2011, at: http://www.epa.gov/cmop/docs/016red.pdf.

II.2. Oil and Natural Gas Systems

II.2.1 Sector Summary

Oil and natural gas (ONG) systems are a leading source of anthropogenic CH_4 emissions, emitting 1,677 $MtCO_2e$ or 23% of total global CH_4 emissions in 2010 (USEPA, 2012a). Russia, the United States, Iraq, Kuwait, and Uzbekistan accounted for more than half of the world's CH_4 emissions in this sector in 2010. Figure 2-1 presents the business-as-usual baseline projections for the ONG sector between 2000 and 2030.

Figure 2-1: Emissions Projections for the Oil and Natural Gas Systems Sector: 2000–2030

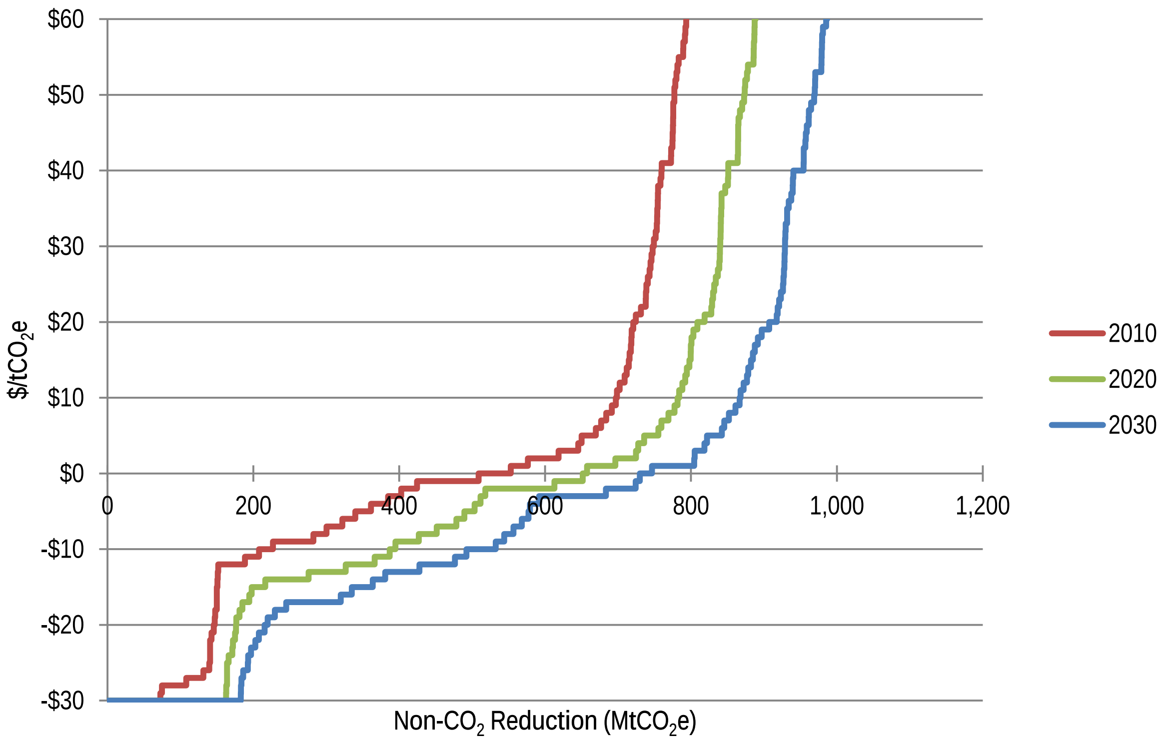


Source: U.S. Environmental Protection Agency (USEPA), 2012a

ONG system emissions are projected to grow 26% between 2010 and 2030 with Brazil and Iraq experiencing the highest rate of growth at 128% and 100%, respectively, over the same time period.

A number of abatement measures are available to mitigate CH_4 losses from activities associated with or directly from the operation of equipment components common across the ONG system segments of production, processing, transmission, and distribution. These abatement options in the ONG system segments generally fall into three categories: equipment modifications/upgrades; changes in operational practices, including direct inspection and maintenance (DI&M); and installation of new equipment. The abatement measures may be applied to components and equipment used in ONG operations, including compressors/engines, dehydrators, pneumatics/controls, pipelines, storage tanks, wells, and other processes and equipment commonly used in some or all of the ONG system segments. The global abatement potential associated with the suite of abatement measures applicable for ONG systems is illustrated in the marginal abatement cost (MAC) curves for 2010, 2020, and 2030 presented in Figure 2-2.

Figure 2-2: Global Abatement Potential in Oil and Natural Gas Systems: 2010, 2020, and 2030



Note: Figure 2-2 does not show the entire MAC curve, an additional 10% of abatement potential is available at prices > $60/tCO2e.

Global abatement potential in the ONG sector is 60% of the sector emissions in 2010, or 997 $MtCO_2e$. The abatement potential increases over time, growing to 1,103 and 1,218 $MtCO_2e$ in 2020 and 2030 respectively (representing 58% of each years' BAU emissions). Nearly 70% of the abatement potential is achievable at a carbon prices below $5. In addition, over 61% of abatement (747 $MtCO_2e$ in 2030) is cost-effective at current energy prices (i.e. a carbon price ≤ $0/$tCO_2e$).

The following section briefly explains CH_4 emissions from ONG systems. This is followed by international CH_4 emissions projections. Subsequent sections characterize the abatement technologies and present the costs and potential benefits. Finally, this chapter concludes with a discussion of the MAC analysis and the regional results.

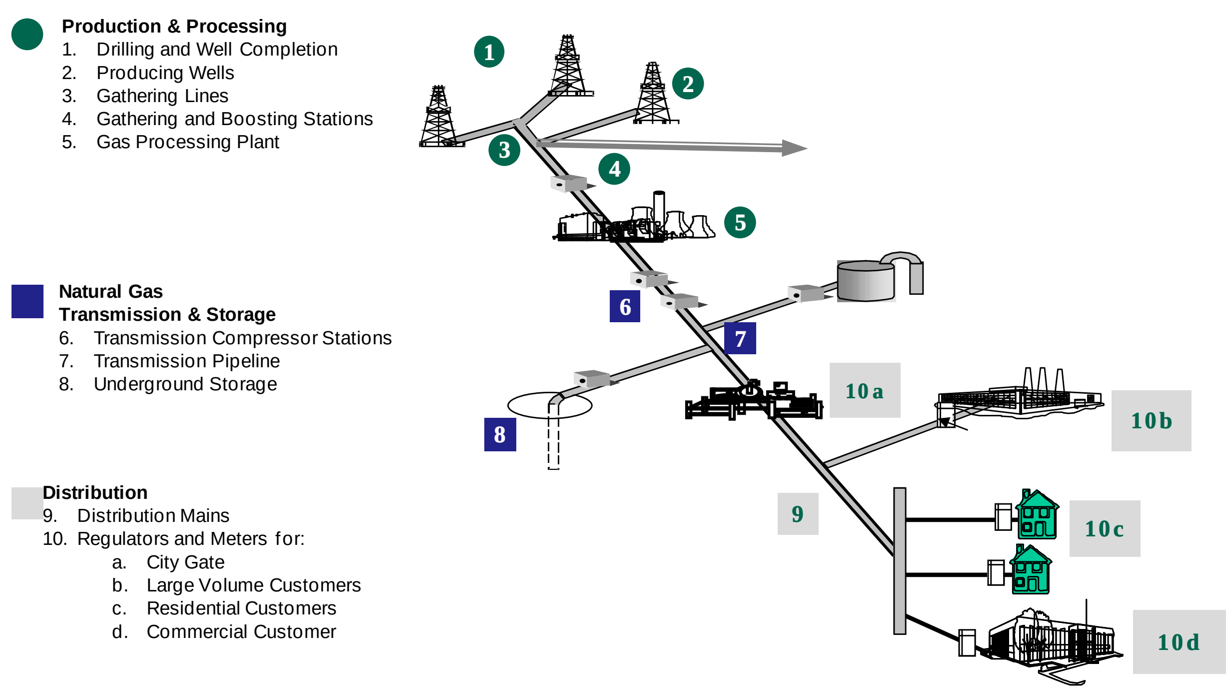
II.2.2 Methane Emissions: Oil and Natural Gas Systems

CH_4 is the principal component of natural gas.[1] Fugitive CH_4 is emitted through activities and components associated with the natural gas production, processing, transmission, and distribution. Oil production and processing upstream of oil refineries can also emit CH_4 in significant quantities through

[1] CH_4 concentrations typically increase as the natural gas moves from production to distribution. Typically CH_4 concentrations in non-associated gas are assumed to be 80% at production, increasing to 87% in processing, and 95% in transmission and distribution. Associated gas typically has a lower concentration (between 65 and 75%) depending on the presence of other hydrocarbons in the gas mix.

routine venting, flaring, and other fugitive sources associated with the production, transmission, upgrading, and refining of crude oil and distribution of crude oil products (IPCC, 2006). Figure 2-3 identifies the facilities and equipment associated with the ONG system segments.

Figure 2-3: Segments of Oil and Natural Gas Systems



Source: Adapted from American Gas Association (AGA) and Natural Gas STAR Program.

Table 2-1 provides examples of the typical facilities and equipment that comprise ONG systems. Fugitive CH_4 emissions result from equipment leaks, system upsets, process venting, and deliberate flaring at oil and gas production fields, natural gas processing facilities, natural gas transmission lines and compressor stations, natural gas storage facilities, and natural gas distribution lines (USEPA, 2012a).

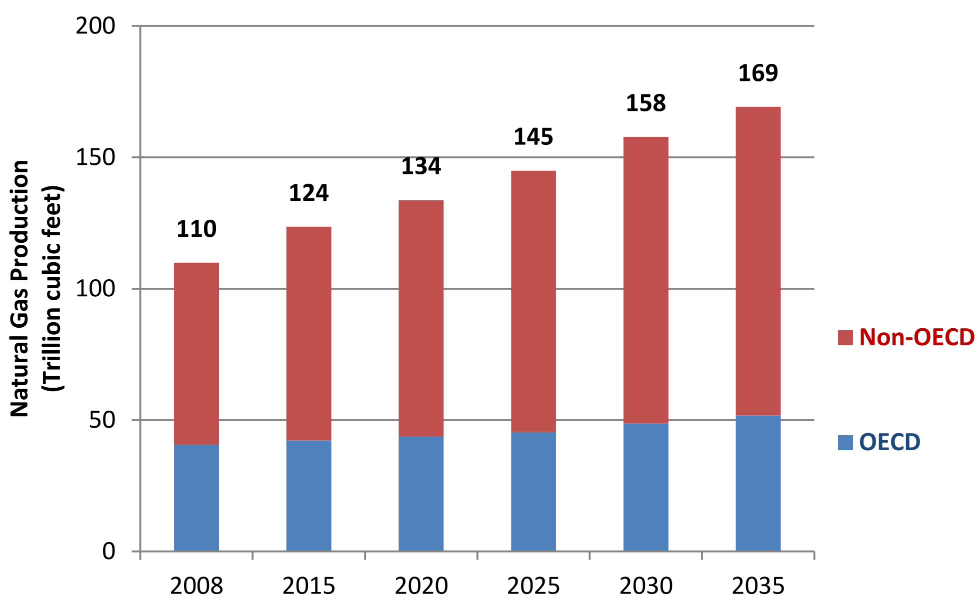
Table 2-1: Emissions Source from Oil and Natural Gas Systems

Segment	Facility	Equipment at the Facility
Production	Wells, central gathering facilities	Separators, pneumatic devices, chemical injection pumps, dehydrators, compressors, heaters, meters, pipelines, liquid storage tanks
Processing	Gas plants	Vessels, dehydrators, compressors, acid gas removal (AGR) units, heaters, pneumatic devices
Transmission and storage	Transmission pipeline networks, compressor stations, meter and pressure-regulating stations, underground injection/withdrawal facilities, liquefied natural gas (LNG) facilities	Vessels, compressors, pipelines, meters/pressure regulators, pneumatic devices, dehydrators, heaters
Distribution	Main and service pipeline networks, meter and pressure-regulating stations	Pipelines, meters, pressure regulators, pneumatic devices, customer meters

II.2.2.1 Activity Data or Important Sectoral or Regional Trends and Related Assumptions

Emissions from ONG systems are closely correlated with the quantity of ONG produced and consumed. Globally, production and consumption of natural gas are expected to increase in both the near term and long term. Between 2008 and 2035, natural gas supplies are expected to increase by almost 60 trillion cubic feet, or roughly 1.6% per year (EIA [U.S. Energy Information Administration], 2011a). The majority of production growth is projected to occur in non-Organisation for Economic Co-operation and Development (OECD) countries most notably, in the Middle East, Asia, and Africa regions, where production growth rates average 2.8, 2.5, and 2.4% per year, respectively. Figure 2-4 presents projected global gas production by major region from 2008 to 2035. Growth in natural gas production from non-OECD countries between 2015 and 2035 is projected to be twice the growth in production from OECD countries. Expanded production in non-OECD countries is expected to exceed regional demand allowing for net exports to OECD countries.

Figure 2-4: Global Natural Gas Production: 2015–2035



Source: U.S. Energy Information Administration (EIA). (2011a). *International Energy Outlook 2011*. Table G1. World total natural gas production by region, Reference case, 2008–2035.

Another trend in the international gas market is the increased production of unconventional gas resources (i.e., tight gas, shale gas, and coalbed methane). Preliminary international estimates suggest that the quantity of "technically recoverable shale gas resources" is equal to all existing proven natural gas reserves worldwide (EIA, 2011b). Although the unconventional gas resources have not been fully assessed, energy experts are projecting significant increases in production over 2035 time horizon. The most notable increases are expected in the United States, Canada, and China, where unconventional gas is expected to account for 47, 51, and 72% of domestic production, respectively, in 2035 (EIA, 2011a). Technology advancements in horizontal drilling and hydraulic fracturing have enabled the United States to tap into its vast unconventional gas resources. Emerging research on extraction techniques from shale gas formations suggests there are different emissions profiles compared with conventional gas production.

II.2.2.2 Emissions Estimates and Related Assumptions

This section briefly discusses the historical and projected emission trends globally and presents the baseline emissions used in the MAC analysis.[2]

Historical Emissions Estimates

Emissions from ONG systems globally grew by 31% between 1990 and 2010 with an average annual growth rate of 1.4%. Key factors that contributed to the growth in emissions include expansions in ONG production and increases in natural gas consumption.

Projected Emissions Estimates

Worldwide CH_4 emissions from ONG systems are projected to increase by 26% between 2010 and 2030 (an average annual rate of 1.2%), slightly lower than in early years (1990–2010). By 2030, the top 5 emitting countries are projected to account for 55% of global emissions in this sector. Although Russia and the United States remain the largest emitters in this sector, their relative share of the world's emissions is expected to fall slightly as the ONG industry in Africa and the Middle East expands in future years. Table 2-2 presents the projected baseline CH_4 emissions for the top 5 emitting countries and remaining country groups by world region.

Table 2-2: Projected Baseline CH_4 Emissions for Oil and Natural Gas Systems by Country/Region: 2010–2030 ($MtCO_2e$)

Country/Region	2010	2015	2020	2025	2030	CAGR[a] (2010–2030)
Top 5 Emitting Countries						
Russia	332.0	341.9	382.8	401.8	417.9	1.2%
United States	247.8	258.3	281.6	307.2	313.1	1.2%
Iraq	94.1	109.2	157.8	172.9	187.9	3.5%
Kuwait	106.0	106.9	103.8	108.2	115.9	0.4%
Uzbekistan	84.7	95.8	102.7	104.9	107.3	1.2%
Rest of Regions						
Africa	274.5	292.2	291.1	302.9	315.1	0.7%
Central and South America	58.0	59.7	67.7	75.8	84.2	1.9%
Middle East	131.5	138.6	131.4	136.1	137.9	0.2%
Europe	42.8	41.6	40.9	41.3	42.4	0.0%
Eurasia	90.8	104.8	112.0	115.7	120.4	1.4%
Asia	128.4	141.1	149.7	156.7	164.8	1.3%
North America	86.6	88.2	90.2	97.2	106.1	1.0%
World Total	1,677.3	1,778.3	1,911.8	2,020.6	2,112.9	1.2%

[a]CAGR = Compound Annual Growth Rate

Source: USEPA, 2012a.

[2] For more detail on baseline development and estimation methodology, we refer the reader to the USEPA's Global Emissions Projection Report available at: http://www.epa.gov/climatechange/economics/international.html. Note that national emissions inventories are often recalculated when new data become available. The Inventory of U.S. Emissions and Sinks (the source of United States emissions estimate presented in this report) has been updated since this analysis was conducted, and the revised 2010 value for oil and gas methane emissions is 174 $MtCO_2e$.

II.2.3 Abatement Measures and Engineering Cost Analysis

Within the four segments of ONG systems, a number of abatement measures can be applied to mitigate CH_4 losses from activities associated with or directly from the operation of equipment and components. The abatement measures, such as inspection and maintenance programs for leaks or equipment retrofits or modifications, may be applied to ONG processes and equipment, including compressors/engines, dehydrators, pneumatics/controls, pipelines, storage tanks, and wells.

Abatement measures available to mitigate CH_4 losses from activities associated with or directly from the operation of equipment components common across the ONG system segments of production, processing, transmission, and distribution. These abatement options in the ONG system segments generally fall into three categories: equipment modifications/upgrades; changes in operational and maintenance practices including DI&M; and installation of new equipment. ONG industry-related voluntary programs such as the Global Methane Initiative (GMI) and USEPA's Natural Gas STAR Program, which are aimed at identifying cost-effective CH_4 emission reduction opportunities, have developed a well-documented catalog of potential CH_4 abatement measures that are applicable across the segments of the ONG system. Abatement measures documented by the USEPA's Natural Gas STAR Program serve as the basis for estimating the costs of abatement measures used in this analysis. It is important to note that although abatement measures identified by the Natural Gas STAR Program are cited as cost-effective based on Industry Partner-reported experiences, the abatement measure's cost-effectiveness is determined by the component's emissions rate and the value of energy recovered. This analysis uses average emission factors when estimating the break-even prices for each measure. In many cases, these average emission rates are lower than the case study examples cited in the Natural Gas STAR Program's documentation. As a result, abatement measures cited as cost-effective by the Natural Gas STAR Program's Partners may not necessarily be the lowest cost options in the MAC analysis.

This section discusses the abatement measures considered for this analysis and presents the costs, benefits, technical applicability, reductions efficiency, and the expected technology lifetime of each measure. The abatement measures presented in Tables 2.3 through 2.6 provide an overview of the options considered in each segment of the oil and gas sector. A more complete list of the abatement measures included in the Oil and Gas Sector MAC model is provided as Appendix D to this chapter.

II.2.3.1 Oil and Natural Gas Production

The production segment of the ONG system consists of wells, compressors, dehydrators, pneumatic devices, chemical injection pumps, heaters, meters, pipeline, liquid storage tanks, and central gathering/storage facilities. Table 2-3 presents the list of abatement measures applied to the production segment of ONG systems. In addition, this section characterizes two important abatement measures considered in the production segment: reduced emissions from hydraulically fractured gas well completions and installation of vapor recovery units (VRUs) on crude oil storage tanks.

Reduced Emissions for Hydraulically Fractured Natural Gas Well Completions

Reduced emissions completion (REC) is a method designed to capture 90% of the gas that would otherwise be flared or vented during new well construction and workovers on existing wells that are hydraulically fractured. Equipment includes a sand trap, separator, and a gathering line to route gas to sales pipelines or reserve tanks. Depending on the well field operations and frequency of well completions, it may be more cost-effective to rent rather than purchase capital equipment (USEPA, 2011a). The use of RECs will result in increased sales of recovered gas. Furthermore, condensate may also

Table 2-3: Abatement Measures Applied in Oil and Gas Production Segments

Abatement Measure	Component	Total Installed Capital Cost ($2008)	Annual O&M ($2008)	Time Horizon	Technical Effectiveness[a]
Directed Inspection & Maintenance at Gas Production Facilities	Chemical Injection Pumps	—	6,675	1	40%
Installing Surge Vessels for Capturing Blowdown Vents	Compressor BD	158,940	28,078	15	50%
Installing Electronic Starters on Production Field Compressors	Compressor Starts	2,649	5,849	10	75%
Directed Inspection & Maintenance at Gas Production Facilities	Deepwater Gas Platforms	—	50,000	1	95%
Install Flash Tank Separators on dehydrators	Dehydrator Vents	6,540	—	5	30% to 60%
Optimize glycol circulation rates in dehydrators	Dehydrator Vents	—	15	1	33% to 67%
Installing Catalytic Converters on Gas Fueled Engines and Turbines	Gas Engines - Exhaust Vented	7,924	4,374	10	56%
Installing Plunger Lift Systems in Gas Wells	Gas Well Workovers	5,646	(13,855)	5	80%
Replace Gas-Assisted Glycol Pumps with Electric Pumps	Kimray Pumps	2,788	1,949	10	100%
Directed Inspection & Maintenance at Gas Production Facilities	Non-associated Gas Wells	—	817	1	95%
Installing Plunger Lift Systems in Gas Wells	Non-associated Gas Wells	5,646	(13,855)	5	80%
Directed Inspection & Maintenance on Offshore Oil Platforms	Offshore Platforms, Deepwater oil, fugitive, vented and combusted	—	50,000	1	43%
Flaring Instead of Venting on Offshore Oil Platforms	Offshore Platforms, Shallow water Oil, fugitive, vented and combusted	165,888,859	4,976,666	15	98%
Installing Vapor Recovery Units on Storage Tanks	Oil Tanks	473,783	161,507	15	58%
Using Pipeline Pump-Down Techniques to Lower Gas Line Pressure Before Maintenance	Pipeline BD	—	1,352	1	90%
Directed Inspection & Maintenance at Gas Production Facilities	Pipeline Leaks	—	82	1	60%
Convert Gas Pneumatic Controls to Instrument Air	Pneumatic Device Vents	72,311	24,321	10	50% to 90%
Replacing High-bleed Pneumatic Devices in the Natural Gas Industry	Pneumatic Device Vents	165	—	10	8% to 17%

(continued)

Table 2-3: Abatement Measures Applied in Oil and Gas Production Segments (continued)

Abatement Measure	Component	Total Installed Capital Cost ($2008)	Annual O&M ($2008)	Time Horizon	Technical Effectiveness[a]
Directed Inspection & Maintenance at Gas Production Facilities	Shallow water Gas Platforms	—	33,333	1	95%
Reduced Emission Completions for Hydraulically Fractured Natural Gas Wells	Unconventional Gas Well Completions	—	30,038	1	90%
Reduced Emission Completions for Hydraulically Fractured Natural Gas Wells	Unconventional Gas Well Workovers	—	30,039	1	90%
Installing Surge Vessels for Capturing Blowdown Vents	Vessel BD	158,940	28,078	15	50%
Installing Plunger Lift Systems in Gas Wells	Well Clean Ups (LP Gas Wells)	5,646	(13,855)	5	40%

[a] Technical effectiveness reflects the percentage reduction achievable from implementing the abatement measure considering the presence of complementary options. Technical effectiveness is the product of three separate factors—the reduction efficiency, technical applicability, and market penetration.

[b] Lower technical effectiveness is due to limited applicability at LP gas wells.

be sold, generating additional revenue. The actual savings generated from these sales also depends on the market price of gas and gas liquids. Although hydraulically fractured natural gas well completions are currently limited to the United States and Canada, the analysis assumes that this technology will be adopted by other countries over time.

- **Capital cost:** This analysis assumes that natural gas producers rent the REC equipment from a third-party service provider hence there are no initial capital costs. If a well operator were to be purchase equipment, the capital cost of the equipment would be approximately $500,000 or more depending on the complexity of the REC set-up (USEPA, 2011a).
- **Annual operation and maintenance (O&M) cost:** Cost of implementing this abatement measure represents the incremental cost of REC to recover the gas over the traditional well completion cost. The equipment rental costs range between $700 and $6,500/per day (equivalent to $815 to $7,568 in 2008 dollars). Completions typically take between 3 and 10 days. This analysis assumes 7 days for well clean-up and completions at a cost of $30,000 in 2008 dollars.
- **Annual benefits:** Revenues may be derived from gas sales from avoided venting/flaring operations. Additional benefits could come from the sale of recovered natural gas condensate. In the United States, an average of 34 barrels of condensate are recovered during each completion or recompletion (USEPA, 2011b). Although the value of the recovered gas condensate would be determined by the gas composition, based on an assumed price of $70 per barrel (bbl), the recovered gas condensate would contribute an additional $2,400 in revenues per completion or recompletion.
- **Applicability:** This technique applies to hydraulically fractured gas well completions and workovers.
- **Technical Effectiveness:** This analysis assumes a technical effectiveness is 54% which is the product of the 90% reduction efficiency and a technical applicability of 60% and market penetration of 100%.

- **Technical lifetime**: 1 implementation event per year per hydraulically fractured well.

Install Vapor Recovery Units (VRUs)

Crude oil and condensate storage tanks are widely used to stabilize the flow of oil or condensate between wells and transportation sites. Inside these tanks, light hydrocarbons (often with a heavy concentration of methane) dissolved in the crude oil or condensate flash out of solution and collect between the liquid and the roof of the tank. As liquid levels fluctuate, vapors are often vented into the atmosphere. VRUs can capture 95% of these light hydrocarbon vapor emissions (USEPA, 2006a). The recovered vapors can be sold or used on site as fuel.

- **Capital costs:** Capital costs range from $40,000 to $120,000 (equivalent to $50,000 to $140,000 in 2008 dollars), depending on the capacity of the unit (between 25 and 500 Mcf per day), sales line pressure, number of tanks, size and type of compressor, and the degree of automation. Installation costs range from 50 to 100% of the capital equipment cost and vary depending on the location of the tanks and the size of the VRU required.
- **Annual costs**: Incremental annual O&M costs are about 15% of initial cost. The annual costs are determined by the capacity of the VRU, as well as the location (weather), electricity costs, and the type of oil produced.
- **Annual benefits**: VRUs can reduce the hydrocarbon vapor emissions of hydrocarbon liquid storage tanks by about 95%. The vapors that are recovered can be used in several different ways. They can be used on site as fuel (where their value is equal to the price of the fuel they displaced). Alternatively, the vapors can be piped to a natural gas gathering pipeline or to a processing plant that separates the natural gas liquids and the methane and sells them separately. Because the recovered vapors generally have a higher Btu content than pipeline quality natural gas, the vapors are more valuable and sell for a higher price on an energy content basis.
- **Applicability**: Applied to crude oil and condensate storage tanks
- **Technical Effectiveness:** The technical effectiveness of this option is 58% based on a reduction efficiency of 95%, technical applicability of 61%, and a market penetration of 100%.
- **Technical Lifetime**: 15 years

For detailed discussion of other options available to the ONG production segments, we refer the reader to USEPA's Natural Gas STAR Program website.

II.2.3.2 Gas Processing and Transmission Segments

The processing segment of the natural gas system consists of gas plant facilities that incorporate the use of vessels, dehydrators, compressors, acid gas removal (AGR) units, heaters, and pneumatic devices. The transmission segment consists of transmission pipeline networks, compressor stations, and meter and pressure-regulating stations. Table 2-4 and Table 2-5 present the list of abatement measures applied to the gas processing and gas transmissions segment of a natural gas system. Similar to the previous section, this section briefly characterizes four important abatement measures considered in the gas processing and transmission segment.

Directed Inspection & Maintenance (DI&M) on Processing Plants and Booster Stations

DI&M is a cost-effective approach to reduce methane emissions from leaking components throughout the oil and natural gas industry including at natural gas processing plants. The activities include a four-part process that identifies, prioritizes, and implements the most cost-effective emissions reductions. Step 1 of the process is to identify and measure the leaks using leak detection and measurement techniques.

Table 2-4: Abatement Measures for the Natural Gas Processing Segment

Abatement Measure	Component	Total Installed Capital Cost ($2008)	Annual O&M ($2008)	Time Horizon	Technical Effectiveness[a]
Installing Surge Vessels for Capturing Blowdown Vents	Blowdowns/Venting	158,940	28,078	15	50%
Directed Inspection & Maintenance at Processing Plants and Booster Stations - Compressors	Centrifugal Compressors (dry seals)	—	15,581	1	12%
Directed Inspection & Maintenance at Processing Plants and Booster Stations - Compressors	Centrifugal Compressors (wet seals)	—	6,131	1	12%
Replacing Wet Seals with Dry Seals in Centrifugal Compressors	Centrifugal Compressors (wet seals)	380,804	(102,803)	5	66%
Installing Catalytic Converters on Gas Fueled Engines and Turbines	Gas Engines - Exhaust Vented	7,924	4,374	10	56%
Replace Gas-Assisted Glycol Pumps with Electric Pumps	Kimray Pumps	2,788	1,949	10	100%
Directed Inspection & Maintenance at Processing Plants and Booster Stations	Plants	—	10,134	5	95%
Directed Inspection & Maintenance at Processing Plants and Booster Stations - Compressors	Recip. Compressors	—	6,131	1	10%
Early replacement of Reciprocating Compressor Rod Packing Rings	Recip. Compressors	7,800	0	5	1%
Fuel Gas Retrofit for BD valve - Take Recip. Compressors Offline	Recip. Compressors	2,365	—	5	21%
Reciprocating Compressor Rod Packing (Static-Pac)	Recip. Compressors	5,696	—	5	0%

[a] Technical effectiveness reflects the percentage reduction achievable from implementing the abatement measure considering the presence of complementary options. Technical effectiveness is the product of three separate factors: the reduction efficiency, technical applicability, and market penetration.

Steps 2 and 3 are to assess the measurements to determine which leaks are most cost-effective to repair by comparing the value of the natural gas lost through leakage to the overall cost of repair. Lastly, in Step 4 a survey plan is developed for future DI&M to focus efforts on those sources most likely to be leaking and reduce the cost of subsequent programs. Although the initial expense of the survey can be relatively high, it was found that the costs can be recovered in the first year through reductions in gas leakage. USEPA (2003a) documentation suggests the initial baseline survey cost is typically between $1 and $2 per component on average. Depending on their size, typical processing facilities may have between 14,000 and 55,000 components. Subsequent follow-up surveys are found to cost significantly less compared with the initial survey, because they are more targeted to the components that are most likely to leak and the most beneficial to repair.

Table 2-5: Abatement Measures for the Natural Gas Transmission Segment

Abatement Measure	Component	Total Installed Capital Cost ($2008)	Annual O&M ($2008)	Time Horizon	Technical Effectiveness[a]
Directed Inspection and Maintenance at Compressor Stations - Compressors	Centrifugal Compressors (dry seals)	—	15,581	1	13% to 14%
Replacing Wet Seals with Dry Seals in Centrifugal Compressors	Centrifugal Compressors (wet seals)	380,804	(102,803)	5	71% to 77%
Install Flash Tank Separators on dehydrators	Dehydrator Vents	9,504	—	5	67%
Optimize glycol circulation rates in dehydrators	Dehydrator vents	—	15	1	67%
Installing Catalytic Converters on Gas Fueled Engines and Turbines	Engine/Turbine Exhaust Vented	7,924	4,374	10	56%
Directed Inspection and Maintenance at Gate Stations and Surface Facilities	M&R (Trans. Co. Interconnect)	—	1,741	1	72%
Directed Inspection and Maintenance on Transmission Pipelines	Pipeline Leaks	—	41	1	60%
Using Pipeline Pump-Down Techniques to Lower Gas Line Pressure Before Maintenance	Pipeline venting	—	1,352	1	90%
Convert Gas Pneumatic Controls to Instrument Air	Pneumatic Devices	72,311	24,321	10	50% to 90%
Replacing High-bleed Pneumatic Devices in the Natural Gas Industry	Pneumatic Devices	165	—	10	8% to 17%
Directed Inspection and Maintenance at Compressor Stations - Compressors	Recip Compressor	—	15,581	1	10% to 12%
Early replacement of Reciprocating Compressor Rod Packing Rings	Recip Compressor	7,800	—	5	1%
Early replacement of Reciprocating Compressor Rod Packing Rings and Rods	Recip Compressor	41,068	—	5	1% to 74%
Fuel Gas Retrofit for BD valve - Take Recip. Compressors Offline	Recip Compressor	2,365	—	5	36% to 39%
Reciprocating Compressor Rod Packing (Static-Pac)	Recip Compressor	5,696	—	5	6% to 9%
Installing Surge Vessels for Capturing Blowdown Vents	Station venting	158,940	28,078	15	50%
Directed Inspection and Maintenance at Compressor Stations	Stations	—	1,398	1	85%
Directed Inspection and Maintenance at Gas Storage Wells	Wells (Storage)	—	651	1	95%

[a] Technical effectiveness reflects the percentage reduction achievable from implementing the abatement measure considering the presence of complementary options. Technical effectiveness is the product of three separate factors: the reduction efficiency, technical applicability, and market penetration.

DI&M analysis parameters include:

- **Capital costs:** There is no capital costs associated with this option.
- **Annual costs:** Initial survey design and leak detection, measurement, and repair. This analysis assumes a $1 to $2 cost per component for leak detection and repair. The analysis assumes an average processing plant has approximately 14,000 components.
- **Benefits:** Gas savings from emission reductions.
- **Applicability**: Applicable to gas processing, gas gathering and booster stations, gas storage wells, gate stations and surface facilities, and transmission compressor stations.
- **Technical Effectiveness**: This analysis assumes a technical effectiveness of 95% based on a 95% reduction efficiency, a 100% technical applicability factor, and a 100% market penetration factor.
- **Technical Lifetime**: This analysis assumes a 1 year technical lifetime.

Identify and Replace or Retrofit High-Bleed Pneumatic Devices

Pneumatic devices are widely used as controllers and monitors in the production sector, pressure regulators and valve controllers in the processing sector, and actuators and regulators in the transmission sector of the natural gas industry. When driven by natural gas, pneumatic devices release or bleed natural gas into the atmosphere and thus are a leading source of methane emissions in the natural gas industry. Replacing high-bleed devices with low-bleed devices and installing low-bleed retrofit kits on operating devices can reduce emissions by between 50 and 90% (USEPA, 2006b).

- **Capital costs:** Capital costs are the main component of replacement and retrofitting and vary greatly among the options. Multiple options can be employed at once to reduce gas bleed. Some typical options include replacing high-bleed level and pressure controllers with low-bleed controllers, reducing supply pressure, and repairing leaks. This analysis assumes the capital cost to be $165, which represents the incremental cost between a high bleed device and a low bleed device (USEPA, 2011b).
- **Annual costs:** Some improved maintenance costs are recurring. Maintenance costs are small relative to the cost of equipment. Replacing and retrofitting devices can potentially reduce annual maintenance costs. For this analysis the incremental operation and maintenance (O&M) cost is assumed to be $0.
- **Benefits:** Revenue from gas savings of reduced methane leakage. Reductions in methane emissions range from 45 to 260 Mcf per device annually depending on the device and application.
- **Applicability**: Applicable for high to moderate bleed pneumatic devices in the gas transmission segments.
- **Technical Effectiveness:** Technical effectiveness for this option ranges between 8% and 16% depending on the gas bleed rate. This analysis assumes a reduction efficiency of 9% (low bleed), 23% (medium bleed) and 25% (high bleed). The technical applicability of 50%, 75%, and 90% for low-, medium-, and high-bleed devices, respectively. Market penetration rate is assumed to be 100% for all devices.
- **Technical Lifetime**: 10 years

Reducing Methane Emissions from Compressor Rod Packing Systems

In natural gas compressors, the packing systems are used to maintain a tight seal around the piston rod, preventing unwanted gas leakage while allowing the rod to move freely (USEPA, 2006). Leak rates depend on the fit, alignment of the packing parts, and wear. New packing systems installed on smooth, well-aligned compressor rods can be expected to leak as little as 11.5 scfh. Leak rates increase as the system ages because of wear on the packing rings and piston rod. Regularly monitoring and replacing these systems can result in cost savings and emissions reductions. This abatement measure is applied to compressors in the gas processing and transmission segments of the natural gas system. Packing systems comprise flexible rings that are secured around the compressor shaft. Packing cups hold the rings in place, and a nose gasket reduces leaks around the packing cups. Conventional packing rings have a life expectancy of about 3 to 5 years, but when the packing breaks down, leaks tend to increase so dramatically that it may be desirable to replace packing rings even more frequently. A new, well-functioning system could leak as little as 11 standard cubic feet per hour (scfh), compared with worn compressor rod packing systems that have leak rates as high as 900 scfh (USEPA, 2006c).

- **Capital costs:** Replacement compressor rod packing systems range from $7,800 per unit to replace the packing rings to over $41,000 for replacement of the piston rods and packing rings.
- **Annual costs:** There are no annual costs for these options.
- **Benefits:** Revenue from gas savings of reduced methane leakage.
- **Applicability**: Applies to reciprocating compressors located at processing plants and compressor stations in the transmission segment
- **Technical Effectiveness:** Technical effectiveness for this option is 1.5%, based on a reduction efficiency of 10% a technical applicability of 15%, and a market penetration of 100%.
- **Technical Lifetime**: 5 years.

Replacing Wet Seals with Dry Seals in Centrifugal Compressors

Centrifugal compressors are used in the production, processing, and transmission of natural gas. The seals located on the rotating shafts to reduce methane leakage have traditionally been “wet” (oil) seals. Replacement of wet seals with dry seals leads to substantially reduced emissions and operating costs. The dry seals are the only piece of capital equipment required and may be installed during a scheduled downtime. The lifetime of dry seals may be double that of wet seals, and they also emit significantly lower emissions. It has been estimated that the wet seals may pay for themselves in as little as 11 months (USEPA, 2006d). Other benefits include lower electricity requirements and maintenance costs and increased operating efficiency of the compressor and pipeline, which may also lead to higher gas sales.

- **Capital costs:** This analysis assumes a capital cost of $381,000 in 2008 dollars for wet seal replacement on a compressor with a shaft beam size of 6 inches. Cost of dry seals ($15,200 per shaft inch) represents 48% of initial capital costs; equipment testing services (~0.5% of equipment cost); engineering, procurement, and construction (EPC) services were assumed to be 100% of equipment and testing costs.
- **Annual costs:** O&M costs of dry seals are expected to be less than O&M costs for wet seals because of reduced electricity requirements, increased operating efficiency of the compressor, increased reliability of the compressor, and potentially lower maintenance costs. Hence, incremental recurring costs are assumed to equal a cost savings of just over $100,000 each year. These incremental cost savings are added to the annual benefits resulting from increased gas sales.
- **Benefits:** Revenue from gas savings of reduced methane leakage. Other annual cost savings due to lower operation and maintenance costs are captured in the annual costs.
- **Applicability**: Applies to centrifugal compressors located at gas processing plants and compressor stations in the transmission segment.

- **Technical Effectiveness:** Technical effectiveness for this option is 66%. This value is based on a reduction efficiency of 85%, a technical applicability of 78% and a market potential of 100%.
- **Technical Lifetime**: 5 years

II.2.3.3 Gas Distribution Segment

The distribution segment consists of main and service pipeline networks, meter and pressure-regulating stations, pneumatic devices, and customer meters. Table 2-6 presents the list of abatement measures applied to the distribution segment of a natural gas system. DI&M activities' cost and benefit components are discussed below.

Table 2-6: Abatement Measures for the Distribution Segment

Abatement Measure	Component	Total Installed Capital Cost ($2008)	Annual O&M ($2008)	Time Horizon	Technical Effectiveness[a]
Directed Inspection and Maintenance at Gate Stations and Surface Facilities	M&R <100	—	1,604	1	30% to 80%
Replace Cast Iron Pipeline	Mains—Cast Iron	373,633	182	5	95%
Replace Unprotected Steel Pipeline	Mains—Unprotected steel	373,633	182	5	95%
Replace Unprotected Steel Service Lines	Services—Unprotected steel	418,023	311	5	95%

[a] Technical effectiveness reflects the percentage reduction achievable from implementing the abatement measure considering the presence of complementary options. Technical effectiveness is the product of three separate factors: the reduction efficiency, technical applicability, and market penetration.

DI&M at Gate Stations and Surface Facilities

Leaking meters, pipes, valves, flanges, fittings, open-ended lines, and pneumatic controllers at gate stations and surface facilities are a significant source of methane emissions. DI&M is a proven and cost-effective way to detect, measure, prioritize, and repair equipment leaks to reduce methane emissions and achieve gas savings (USEPA, 2003b). To implement DI&M, first, a baseline survey identifies and quantifies leaks at gate stations and surface facilities. The results of this survey are then used to direct repairs toward the components that were identified as being most susceptible to leaking and the most profitable to repair. Then, the results of the initial survey are used to guide subsequent inspections and maintenance.

- **Capital costs:** There are no capital costs associated with this option.
- **Annual costs:** The costs associated with starting a DI&M program are the cost of labor and equipment for identifying leaking components and estimating the mass leak rate of those components; the labor cost for recording survey information; the labor cost of pinpointing leaking components that are cost-effective to repair; the cost of parts, labor, and equipment downtime to fix the leaks; and the cost of labor for developing a plan that directs future inspection and maintenance. Costs differ depending on the type of screening and measurement equipment used and the characteristics of the staff who conduct the surveys and repairs. Maintenance and repair are ongoing, so most costs are recurring. Annual costs vary depending on the frequency and comprehensiveness of the surveys and repairs. Over time, the scope and frequency of the surveys can be fine-tuned, as patterns emerge. This analysis assumes an average annual cost of $1,600 in 2008 dollars.

- **Benefits:** Gas savings and methane emissions reductions vary widely depending on the number of stations involved in the DI&M program and how long the program has been operating.
- **Applicability**: Applies to components inside gate stations and surface facilities.
- **Technical Effectiveness** 30% to 80%; higher efficiency for facilities handling higher volumes of natural gas. Technical effectiveness measure assumes reduction efficiency between 30% and 80%, technical applicability of 90% to 100% and a market penetration of 100%.
- **Technical Lifetime**: 5 years

II.2.4 Marginal Abatement Costs Analysis

This section discusses the methodological approach used to conduct the international MAC analysis in the ONG sector.

II.2.4.1 Methodological Approach

The MAC analysis approach consists of four sequential steps. Step 1 was to assess the sectoral trends, which entailed reviewing recent international energy statistics for oil and gas. The second step was to develop source-level emission estimates that could be used to build different model ONG systems. These model systems reflect country-specific variations in production process techniques, level of maintenance, and vintage of the existing infrastructure. Step 3 was to estimate country-specific abatement costs and benefits based on the relative cost factors for labor, energy, and non-energy inputs. Step three was to compute the break-even prices for each country-specific abatement measure. Finally, the MAC model computes the abatement potential as a cumulative reduction for each measure assuming full (system-wide) implementation. Sorting the break-even prices lowest to highest, the incremental reductions are cumulated to construct the MAC curve presented in Section II.2.4.2.

Assessment of Sectoral Trends

The objective in assessing the sectoral trends is to understand how emissions differ across countries and how they vary over time. This not only considers aggregate growth or decline in emissions but also any potential shift in sector emissions across the oil and gas segments. To this end, we reviewed the current international gas and oil industry activity data for 2010. Statistics reviewed included gross natural gas production, oil production, LNG imports, and gas processing throughput (EIA, 2011; *Oil & Gas Journal*, 2011). In the absence of real infrastructure data, these statistics provide insights on the relative importance of segments internationally. Table 2-7 presents these key statistics for the 10 largest emitting countries in 2010.

Table 2-7: International Statistics on Key Activity Drivers: 2010

Country	2010 Emissions ($MtCO_2e$)	Dry Natural Gas Production[a] (Bcf/year)	Crude Oil Production[b] (Mbbl/day)	Gas Processing Plant Throughput[c] (MMcfd)	Gas Transmission Pipelines[d] (km)
Russia	332.0	22,965	10,146	926	160,952
United States	247.8	26,858	9,688	45,808	548,665
Kuwait	106.0	422	2,450	1,034	269
Iraq	94.1	596	2,408	1,550	3,365
Angola	84.9	364	1,988	137	-
Uzbekistan	84.7	2,123	105	NA	10,253
Libya	77.4	1,069	1,789	2,567	-
Canada	53.3	6,695	3,483	29,154	75,835
Iran	47.2	7,774	4,252	10,509	20,725
Venezuela	30.2	2,510	2,375	3,555	5,347

[a] EIA. International Energy Statistics: Gross Natural Gas Production.

[b] EIA. International Energy Statistics: Total Oil Supply.

[c] *Oil & Gas Journal* [*OGJ*]. June 6, 2011. *Worldwide Processing Survey*.

[d] CIA. 2011. The World Factbook.

[e] EIA. 2012. Country analysis Brief–Uzbekistan. Available at: http://www.eia.gov/countries/cab.cfm?fips=UZ

Although differences in annual production and throughput provide some indication of the size of a country's ONG system, considerations of age and the condition of the infrastructure are major factors in determining the rate of source-level emissions and in turn the abatement potential associated with each abatement measure. In general, countries with aging infrastructure will have "leakier" components and in turn have a greater abatement potential. Conversely, countries with newly developed infrastructure will have less abatement potential.

Another important trend to consider is the expansion of unconventional gas (shale gas) production. The growth in unconventional gas production (e.g., the United States, Canada, and China) is likely to result in an increased frequency of hydraulically fractured gas well completions and related workovers. In the absence of any regulatory or voluntary actions to reduce emissions from these sources, this trend suggests that the gas production segment will represent an even greater proportion of these nations' baseline emissions over time.

Defining International Model Facilities for the Analysis

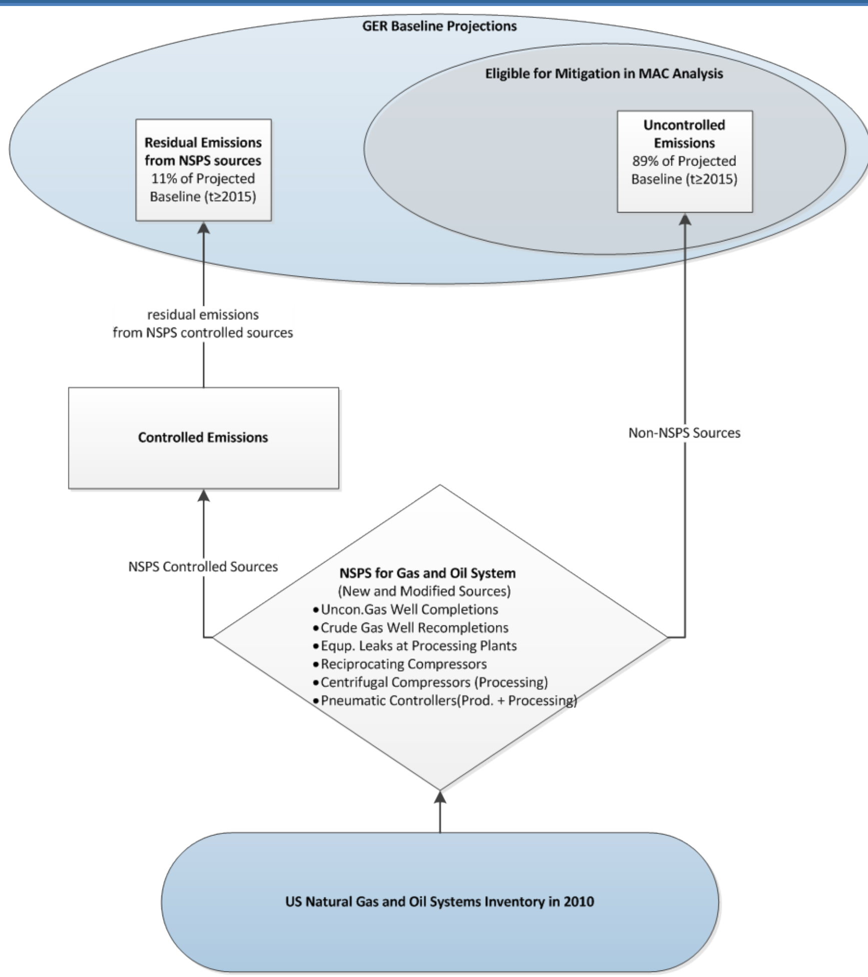
For this analysis, we developed model ONG systems for each segment based initially on the USEPA ONG system emissions inventory. Scaling factors were developed based on country-specific activity factors developed from the international statistics illustrated in Table 2-6. Where reliable data were available, international adjustments were made to reflect specific country systems. For countries for which data were not available, this analysis assumed the gas and oil system was similar to that in the United States in terms of the distribution of emissions (total BAU emissions for each country is exogenous to the MAC model obtained from USEPA, 2012a). The relative international factor was multiplied by the percentage share of U.S. gas and oil CH_4 emissions inventory at the segment/component source level (e.g., compressors, valves, connections, pneumatic devices). The resulting "Technical Applicability" (TA) factor is used to allocate a fraction of the national baseline emissions to each component source in the ONG inventory (e.g., wells, tanks, compressors, valves).

Multiplying the TA factor by the baseline emissions yields the subset of emissions available for reductions from each component source and abatement measure. The TA factor comprises two parts. The U.S. 2010 GHG emissions inventory serves as the basis for the distribution of emissions across the constituent components (see USEPA, 2012b, Annex 3). The second component of the TA factor is the country- and segment-specific relative activity factor (e.g., total oil production, gross natural gas production).

Regulatory Considerations for the U.S. Natural Gas and Oil System

Special considerations were made for the United States to reflect the New Source Performance Standards (NSPS) regulation that was in effect starting in year 2012. This regulation will affect the production and processing segments of the ONG system by requiring the use of abatement measures included in this analysis to control for volatile organic compound (VOC) emissions from major new and modified emitting sources in the United States. This mitigation is no longer considered additional and thus should be removed from the U.S. domestic MAC curve. For the purposes of this analysis, we have removed emissions sources covered under the NSPS regulation and any subsequent abatement potential that would have come from these sources. Figure 2-5 illustrates the key elements that led us to the resulting distribution of emissions.

Figure 2-5: Diagram of BAU Emissions for the United States Oil and Natural Gas System



To capture the impact of the NSPS regulation for model years 2015 and beyond, we needed to estimate the relative distribution of emissions that will be associated with controlled and uncontrolled sources. We start with the 2010 U.S. inventory (USEPA, 2012), which is the basis of our analysis. Next, we identify all components in the inventory subject to the NSPS in the production and processing segments.

For the NSPS controlled sources, we applied controls to these components using the reduction efficiency (%) for each abatement measure from the MAC model to estimate the level of abatement achieved by the NSPS rule. In Figure 2-5, controlled emissions equals the sum of reductions achieved across the NSPS sources. The residual emissions from NSPS sources are assumed to be included in the projected baselines (2015 to 2030).

For the purposes of this analysis, we estimated residual emissions from controlled sources were 11% of projected emissions, while emissions from uncontrolled sources were 89% of projected emissions. We applied these shares to the baseline projections for years ≥ 2015.

This approach assumes a fixed distribution of emission over time in the MAC model. We recognize the limitations of this assumption and would ideally like to apply a trend to the shares for model years beyond 2015. Unfortunately, at the time of writing this report, data to develop this trend were not available. Any future work related to the U.S. MAC curve should consider developing a more dynamic trend that more accurately estimates the level of NSPS-controlled emissions and the subsequent distribution of emissions in the baseline projections over time.

Based on the analysis described here, the United States' abatement potential presented in the MAC modeling results can be summarized in the following expression:

$$Abatement\ Potential(USA) = \sum Uncontrolled\ Emissions_{i,t} * Technical\ Effectiveness_{i,j,t}$$

where:

$Technical\ Effectiveness_{i,j,t} = Reduction\ Efficiency_{i,j,t} * Tech\ Applicability_{i,j,t} * Market\ Penetration_{i,j,t}$

i = Uncontrolled emissions source

j = Abatement technology

t = Modeled year

Estimate Abatement Project Costs and Benefits

Turning to the abatement measures discussed in Section II.2.3, the analysis begins with technology costs for the United States as reported in the USEPA Lesson Learned documentation. We applied the Nelson-Farrar[3] Oil Field and Refinery Operation cost indices to convert from reported-year costs to 2008 dollars (USD) for capital and O&M costs, respectively. Next, we applied the country-specific relative price factors for labor, energy, and nonenergy components of annual costs and benefits. This final step yielded country-specific costs and benefits used to compute the break-even price for each abatement measure. Abatement measure costs and technical efficiencies were applied to estimate the break-even prices. Table 2-7 presents the break-even prices for selected ONG system abatement measures for the United States in 2010. For this analysis, we used the abatement measure costs, revenue, and reduction efficiency as described in Section II.2.3 to estimate the break-even price for each abatement measure. A complete list of ONG system abatement measures is presented in Appendix C.

[3] Nelson-Farrar Annual Cost Indices are available in the first issue of each quarter of the *Oil and Gas Journal*.

The first step is to estimate the reduced emissions on a per unit basis for each technology. This value is calculated by multiplying the abatement measure's technical efficiency by the annual emissions per unit of the component or process to which the abatement measure is being applied. The resulting annual reduced emissions serve as the denominator in the break-even price calculation.

In Table 2-8 we present abatement cost and revenues per metric ton of CO_2 equivalent (tCO_2e) reduced for the abatement measures with the largest national emissions reductions. Costs include the annualized total installed capital cost and annual O&M costs. Offsetting these costs are the annual revenue in terms of gas savings and the tax benefit of depreciation. The break-even prices reported in Table 2-8 are calculated by subtracting the annual revenues from the annualized costs.

Table 2-8: Example Break-Even Price Calculation based on 2010 MAC for the United States

Abatement Measure	System Component/ Process	Reduced Emissions per Unit (tCO_2e)	Annualized Capital Costs ($/$tCO_2e$)	Annual Cost ($/$tCO_2e$)	Annual Revenue ($/$tCO_2e$)	Tax Benefit of Depreciation ($/$tCO_2e$)	Break-Even Price ($/$tCO_2e$)	National Incremental Reductions ($MtCO_2e$)
Production								
Convert Gas Pneumatic Controls to Instrument Air	Pneumatic Device Vents	71.0	$335.68	$441.41	$10.01	$82.50	$684.58	15.29
Reduced Emission Completions for Hydraulically Fractured Natural Gas Wells	Unconventional Gas Well Completions	2,703.96	$0.00	$11.11	$10.01	$0.00	$1.10	8.82
Replacing High-bleed Pneumatic Devices in the Natural Gas Industry	Pneumatic Device Vents	9.7	$7.38	$0.00	$10.01	$1.81	−$4.44	2.30
Processing								
Directed Inspection & Maintenance at Processing Plants and Booster Stations	Plants	1,109.0	$0.00	$9.14	$10.01	$0.00	−$0.87	0.50
Fuel Gas Retrofit for BD valve - Take Recip. Compressors Offline	Recip. Compressors	351.9	$2.96	$0.00	$10.01	$0.90	−$7.95	1.34
Replacing Wet Seals with Dry Seals in Centrifugal Compressors	Centrifugal Compressors (wet seals)	5,000.8	$33.48	−$20.56	$10.01	$10.15	−$7.24	2.53
Transmission								
Convert Gas Pneumatic Controls to Instrument Air	Pneumatic Devices	89.9	$2,898.32	$3,811.28	$10.01	$712.36	$5,987.24	2.88
Directed Inspection and Maintenance at Compressor Stations	Stations	3,655.9	$0.00	$0.41	$10.01	$0.00	−$9.60	6.61
Fuel Gas Retrofit for BD valve - Take Recip. Compressors Offline	Recip Compressor	1,014.8	$1.07	$0.00	$10.01	$0.32	−$9.26	5.65
Distribution								
Directed Inspection and Maintenance at Gate Stations and Surface Facilities	M&R >300	511.6	$0.00	$3.40	$10.01	$0.00	−$6.60	1.58
Directed Inspection and Maintenance at Gate Stations and Surface Facilities	M&R 100-300	220.2	$0.00	$7.90	$10.01	$0.00	−$2.10	2.48
Replace Cast Iron Pipeline	Mains—Cast Iron	91.7	$1,790.73	$1.99	$10.01	$543.06	$1,239.65	2.54

Note: Break-even price assumes a 10% discount rate and a 40% tax rate. Annual energy benefits are based on a natural gas price of $4/Mcf

From Table 2-8, the annualized capital cost are calculated using the total installed capital costs discussed in Section II.2.3 and expressed in the following equation:

$$Annualized\ Costs = \frac{Total\ Capital\ Cost}{ER \cdot (1 - TR) \cdot \sum_{t=1}^{T} \frac{1}{(1 + DR)^t}}$$

Where:

ER = Annual reduced emissions per unit (e.g. compressor, well, dehydrator, etc.)

TR = Tax rate

T = Technology lifetime in years

DR = Discount rate

Annual O&M costs and expected revenues are calculated using the following equations. International variation in break-even prices is achieved by using regionally adjusted prices for energy labor and materials when computing the country specific annual costs and benefits.

$$Annual\ O\&M\ Costs = \frac{Annual\ O\&M\ Costs}{ER}$$

$$Annual\ Revenues = \frac{Annual\ Revenues}{ER}$$

The tax benefit of depreciation is calculated for each option using the following equation:

$$Tax\ Benefit\ of\ Depreciation = \frac{Total\ Capital\ Costs}{ER \cdot T} \cdot \frac{TR}{(1 - TR)}$$

Finally, the break-even price is calculated by subtracting the benefits from the costs as shown in the equation below.

$$\begin{aligned} &Break\text{-}even\ Price \\ &\quad = Annualized\ Capital\ Cost + Annual\ O\&M\ Cost - Annual\ Revenues \\ &\quad - Tax\ Benefit\ of\ Depreciation \end{aligned}$$

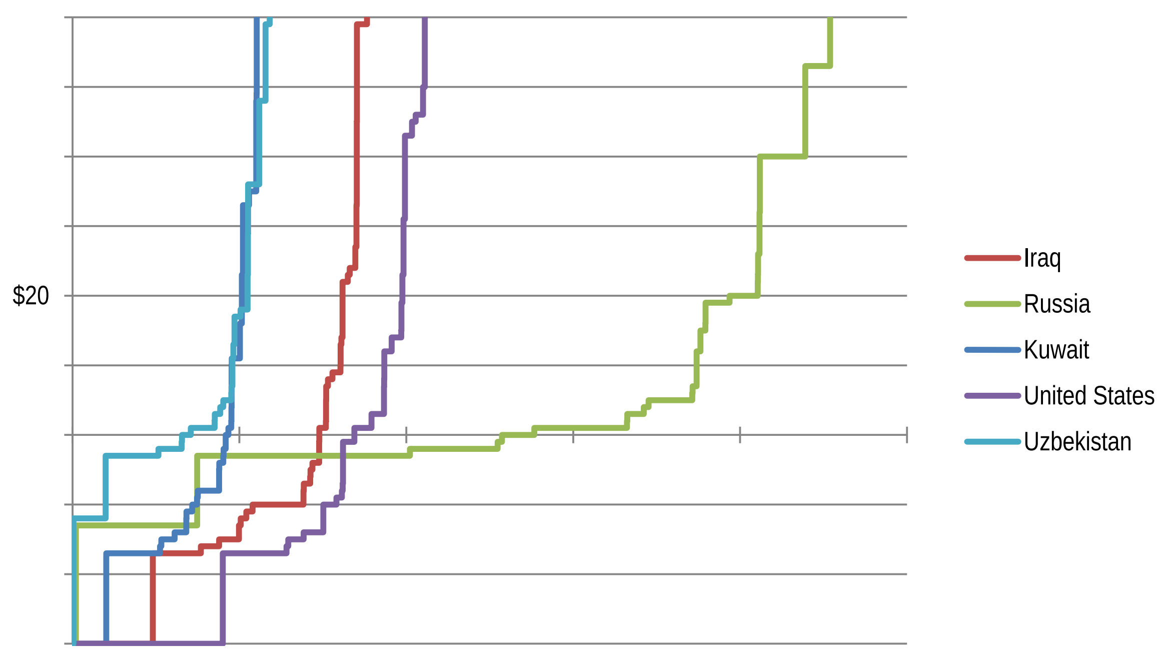
II.2.4.2 MAC Analysis Results

As highlighted at the beginning of this chapter, global abatement potential related to ONG systems equates to approximately 58% of total annual emissions. MAC curve results are presented in Table 2-9 and Figure 2-6. Maximum abatement potential for ONG systems is 1,218 $MtCO_2e$ in 2030. For the year 2030, the results suggest that 842 $MtCO_2e$ or 40% of CH_4 reductions in the ONG sector can be achieved at carbon prices less than or equal to $5/$tCO_2e$. Furthermore over 35% of the 2030 emission reductions (747 $MtCO_2e$) are cost-effective at current energy prices (carbon prices ≤ $0/$tCO_2e$). However, because natural gas prices vary greatly by region, the break-even price and quantity of cost effective reductions varies by country.

Table 2-9: Abatement Potential by Region at Selected Break-Even Prices in 2030

	Break-Even Price ($/tCO$_2$e)										
Country/Region	–10	–5	0	5	10	15	20	30	50	100	100+
Top 5 Emitting Countries											
Iraq	69.2	71.9	73.9	76.0	80.3	80.9	80.9	85.1	85.2	89.9	110.0
Kuwait	37.3	44.0	46.7	47.6	47.7	50.1	50.7	51.1	55.2	58.6	73.5
Russia	37.3	37.3	138.3	185.7	187.0	189.6	205.3	205.8	219.5	232.8	266.9
United States	79.1	81.0	84.4	93.3	93.4	98.5	98.8	99.2	105.5	109.7	140.5
Uzbekistan	9.9	9.9	35.4	47.6	47.9	48.5	52.4	52.6	57.8	59.6	68.3
Rest of Region											
Africa	116.3	124.0	124.1	129.4	135.8	136.2	141.4	142.2	145.0	149.3	178.8
Central and South America	31.8	32.7	32.8	34.2	36.2	36.3	37.4	38.3	38.4	40.6	49.4
Middle East	43.2	51.6	53.3	55.3	57.8	58.5	58.7	60.7	61.2	63.6	78.4
Europe	15.0	16.0	16.3	16.8	17.2	17.4	18.0	18.2	18.8	19.8	26.1
Eurasia	22.9	23.3	42.6	51.0	52.3	53.5	56.9	57.0	61.6	64.2	76.7
Asia	40.4	55.8	59.2	62.7	69.4	71.0	72.1	73.6	75.1	76.7	90.6
North America	29.9	32.0	39.3	42.7	43.3	44.4	44.9	45.2	46.5	47.7	59.6
World Total	532.2	579.3	746.5	842.3	868.1	884.9	917.5	928.9	969.8	1,012.4	1,218.6

Figure 2-6: Marginal Abatement Cost Curves for Top 5 Emitters in 2030



The MAC illustrates the cumulative abatement achievable at incrementally higher carbon prices. At extremely high break-even prices (> $500/t$CO_2$e), the MAC becomes inelastic or unresponsive. The point at which the MAC becomes unresponsive to any price change can also be considered the technical potential associated with the suite of abatement measures considered. Thus, it can be inferred that additional reductions beyond approximately 58% of the projected baseline in 2030 would be unlikely without additional policy incentives or technology improvements.

Economies of scale have an impact on the cost-effectiveness of the abatement options. Hence, abatement measures may have a lower break-even price when applied to facilities with higher CH_4 emission rates and higher break-even price at facilities with a lower emissions rate.

II.2.4.3 Uncertainties and Limitations

Several key areas of uncertainty constrain the accuracy of this analysis. Addressing these uncertainties would improve the development of the MACs and predictions of their behavior as a function of time. Two primary limitations are discussed below.

Improved information on the distribution of emissions in international baselines. This analysis relies on historical activity factors to adjust the distribution of U.S. baseline emissions to develop projections by country. Improvements to information on how gas and oil baselines are changing over time and across segments would improve the accuracy of abatement potential estimates.

Complete information on current abatement technologies used in the gas and oil industry internationally. Additional information on the current and planned implementation of abatement measures internationally would improve the international estimates of abatement.

References

Intergovernmental Panel on Climate Change (IPCC). (2006). *2006 IPCC Guidelines for National Greenhouse Gas Inventories: Volume 2 Energy. Chapter 4 Fugitive Emissions.* Obtained from: http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol2.html.

U.S. Energy Information Administration (EIA). (2011a). *International Energy Outlook 2011*. DOE/EIA—0484(2011). Washington, DC: EIA. Obtained from: http://www.eia.gov/forecasts/ieo/nat_gas.cfm.

U.S. Energy Information Administration (EIA). (2011b). *World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States*. Washington, DC: EIA. Obtained from: http://www.eia.gov/analysis/studies/worldshalegas/.

U.S. Energy Information Administration (EIA). (2011c). *International Energy Statistics: Gross Natural Gas Production.* Washington, DC: EIA. Obtained from: http://tonto.eia.doe.gov/cfapps/ipdbproject/IEDIndex3.cfm?tid=3&pid=3&aid=1.

U.S. Energy Information Administration (EIA). (2011d). *International Energy Statistics: Total Oil Supply.* IEA: Washington D.C. Obtained from: http://www.eia.gov/cfapps/ipdbproject/IEDIndex3.cfm?tid=5&pid=53&aid=1.

U.S. Energy Information Administration (EIA). (2012). Country Analysis Brief – Uzbekistan. Washington, DC: EIA. Obtained from: http://www.eia.gov/countries/country-data.cfm?fips=UZ.

U.S. Environmental Protection Agency and Gas Research Institute (USEPA/GRI). (1996). *Methane Emissions from the Natural Gas Industry Volume 2: Technical Report*. EPA-600/R-96-080b. Washington, DC: USEPA.

U.S. Environmental Protection Agency (USEPA). (2003a, October). *Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations*. Lessons Learned from Natural Gas STAR Partners. Washington, DC: USEPA.

U.S. Environmental Protection Agency (USEPA). (2003b, October). *Directed Inspection and Maintenance at Gate Stations and Surface Facilities.* Lessons Learned from Natural Gas STAR Partners. Washington, DC: USEPA.

U.S. Environmental Protection Agency (USEPA). (2006a, October). *Installing Vapor Recovery Units on Storage Tanks*. Lessons Learned From Natural Gas STAR Partners. Washington, DC: USEPA.

U.S. Environmental Protection Agency (USEPA). (2006b, October). *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Lessons Learned From Natural Gas STAR Partners. Washington, DC: USEPA.

U.S. Environmental Protection Agency (USEPA). (2006c, October). *Reducing Methane Emissions from Compressor Rod Packing Systems*. Lessons Learned From Natural Gas STAR Partners. Washington, DC: USEPA.

U.S. Environmental Protection Agency (USEPA). (2006d, October). *Replacing Wet Seals with Dry Seals in Centrifugal Compressors*. Lessons Learned from Natural Gas STAR Partners. Washington, DC: USEPA.

U.S. Environmental Protection Agency (USEPA). (2010). *Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry*. Background Technical Support Document. Washington, DC: USEPA. Obtained from: http://www.epa.gov/climatechange/emissions/downloads10/Subpart-W_TSD.pdf.

U.S. Environmental Protection Agency (USEPA). (2011a). *Reduced Emission Completions for Hydraulically Fractured Natural Gas Wells*. Lessons Learned from Natural Gas STAR Partners. Washington, DC: USEPA.

U.S. Environmental Protection Agency (USEPA). (2011b). *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution—Background Technical Support Document for Proposed Standards*. EPA-453/R-11-002. Washington, DC: USEPA.

U.S. Environmental Protection Agency (USEPA). (2012a). *Global Anthropogenic Non-CO2 Greenhouse Gas Emissions: 1990-2030*. EPA 430-R-12-006. Washington, DC: USEPA. Obtained from: http://www.epa.gov/climatechange/economics/international.html.

U.S. Environmental Protection Agency (USEPA). (2012b). *U.S. Greenhouse Gas Inventory Report: Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2010.* EPA 430-R-12-001. Washington, DC: USEPA. Obtained from: http://epa.gov/climatechange/emissions/usinventoryreport.html.

U.S. Environmental Protection Agency (USEPA). (2012c). 2011 Annex 3: Methodological Descriptions for Additional Source or Sink Categories. Sections 3.4 and 3.5. In *2012 U.S. Greenhouse Gas Inventory Report: Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009*. EPA 430-R-12-001. Washington, DC: USEPA. Obtained from: http://epa.gov/climatechange/emissions/usinventoryreport.html.

Natural Gas Star Program Lessons Learned Documents Referenced in Model

U.S. Environmental Protection Agency (USEPA). October 2006. Reducing Methane Emissions from Compressor Rod Packing Systems: Lessons Learned from Natural Gas Star Partners. Washington, DC: USEPA. Obtained April 2, 2013 from http://www.epa.gov/gasstar/tools/recommended.html.

U.S. Environmental Protection Agency (USEPA). October 2006. Replacing Wet Seals with Dry Seals in Centrifugal Compressors: Lessons Learned from Natural Gas Star Partners. Washington, DC: USEPA. Obtained on April 2, 2013 from http://www.epa.gov/gasstar/tools/recommended.html.

U.S. Environmental Protection Agency (USEPA). October 2006. Reducing Emissions When Taking Compressors Offline: Lessons Learned from Natural Gas Star Partners. Washington, DC: USEPA. Obtained on April 2, 2013 from http://www.epa.gov/gasstar/tools/recommended.html.

U.S. Environmental Protection Agency (USEPA). October 2006. Replacing Glycol Dehydrators with Desiccant Dehydrators: Lessons Learned from Natural Gas Star Partners. Washington, DC: USEPA. Obtained on April 2, 2013 from http://www.epa.gov/gasstar/tools/recommended.html.

U.S. Environmental Protection Agency (USEPA). October 2006. Optimize Glycol Circulation and Install Flash Tank Separators in Dehydrators: Lessons Learned from Natural Gas Star Partners. Washington, DC: USEPA. Obtained on April 2, 2013 from http://www.epa.gov/gasstar/tools/recommended.html.

U.S. Environmental Protection Agency (USEPA). October 2003. Directed Inspection and Maintenance at Compressor Stations: Lessons Learned from Natural Gas Star Partners. Washington, DC: USEPA. Obtained on April 2, 2013 from http://www.epa.gov/gasstar/tools/recommended.html.

U.S. Environmental Protection Agency (USEPA). October 2003. Directed Inspection and Maintenance at Gate Stations and Surface Facilities: Lessons Learned from Natural Gas Star Partners. Washington, DC: USEPA. Obtained on April 2, 2013 from http://www.epa.gov/gasstar/tools/recommended.html.

U.S. Environmental Protection Agency (USEPA). October 2003. Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations: Lessons Learned from Natural Gas Star Partners. Washington, DC: USEPA. Obtained on April 2, 2013 from http://www.epa.gov/gasstar/tools/recommended.html.

U.S. Environmental Protection Agency (USEPA). October 2006. Replacing Gas-Assisted Glycol Pumps with Electric Pumps: Lessons Learned from Natural Gas Star Partners. Washington, DC: USEPA. Obtained on April 2, 2013 from http://www.epa.gov/gasstar/tools/recommended.html.

U.S. Environmental Protection Agency (USEPA). October 2006. Using Pipeline Pump-Down Techniques to Lower Gas Line Pressure Before Maintenance: Lessons Learned from Natural Gas Star Partners. Washington, DC: USEPA. Obtained on April 2, 2013 from http://www.epa.gov/gasstar/tools/recommended.html.

U.S. Environmental Protection Agency (USEPA). October 2006. Composite Wrap for Non-Leaking Pipeline Defects: Lessons Learned from Natural Gas Star Partners. Washington, DC: USEPA. Obtained on April 2, 2013 from http://www.epa.gov/gasstar/tools/recommended.html.

U.S. Environmental Protection Agency (USEPA). October 2006. Using Hot Taps for In Service Pipeline Connections: Lessons Learned from Natural Gas Star Partners. Washington, DC: USEPA. Obtained on April 2, 2013 from http://www.epa.gov/gasstar/tools/recommended.html.

U.S. Environmental Protection Agency (USEPA). October 2006. Convert Gas Pneumatic Controls to Instrument Air: Lessons Learned from Natural Gas Star Partners. Washington, DC: USEPA. Obtained on April 2, 2013 from http://www.epa.gov/gasstar/tools/recommended.html.

U.S. Environmental Protection Agency (USEPA). October 2006. Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry: Lessons Learned from Natural Gas Star Partners. Washington, DC: USEPA. Obtained on April 2, 2013 from http://www.epa.gov/gasstar/tools/recommended.html.

U.S. Environmental Protection Agency (USEPA). (2006a, October). *Installing Vapor Recovery Units on Storage Tanks*. Lessons Learned From Natural Gas STAR Partners. Washington, DC: USEPA. Obtained from http://www.epa.gov/gasstar/tools/recommended.html.

U.S. Environmental Protection Agency (USEPA). 2011. Reduced Emission Completions for Hydraulically Fractured Natural Gas Wells: Lessons Learned from Natural Gas Star Partners. Washington, DC: USEPA. Obtained on April 2, 2013 from http://www.epa.gov/gasstar/tools/recommended.html.

U.S. Environmental Protection Agency (USEPA). October 2006. Installing Plunger Lift Systems in Gas Wells: Lessons Learned from Natural Gas Star Partners. Washington, DC: USEPA. Obtained on April 2, 2013 from http://www.epa.gov/gasstar/tools/recommended.html.

U.S. Environmental Protection Agency (USEPA). 2011. Options for Removing Accumulated Fluid and Improving Flow in Gas Wells: Lessons Learned from Natural Gas Star Partners. Washington, DC: USEPA. Obtained on April 2, 2013 from http://www.epa.gov/gasstar/tools/recommended.html.

U.S. Environmental Protection Agency (USEPA). 2011. Install Electric Motor Starters: Partner Reported Opportunities (PROs) for Reducing Methane Emissions. PRO Fact Sheet No. 105. Washington, DC: USEPA. Obtained on April 2, 2013 from http://www.epa.gov/gasstar/tools/recommended.html.