COAL MINE METHANE PRODUCTION

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COAL MINE METHANE (CMM)

- Methane is generated during coalification, with a portion remaining trapped under pressure within coal seams and surrounding rock strata. During mining, this methane is released as Coal Mine Methane (CMM).
- Emission sources include seepage from exposed seams in surface or open pit mines, drainage systems, ventilation systems, post-mining activities like processing and transport, and abandoned mines.
- Fugitive methane, emitted from coal mines around the world, represents approximately 8% of the world's anthropogenic methane emissions that constitute a 17% contribution to total anthropogenic greenhouse gas emissions.

- Coal mine methane is a general description for all methane released prior to, during and after mining operations.

- Ventilation air methane is the primary CMM source in underground mines, while drainage systems are significant in surface mines. Methane emissions are typically higher in underground mines due to the greater methane content in deeper coal seams. Emissions from coal mining could be reduced by pre-mine degasification and recovery of methane during coal mining.

WORLD COAL MINE METHANE (CMM) OVERVIEW

- CMM is released from coal mines throughout the world, and often the largest emitters are countries with the highest production of high-rank underground coal.

- Currently, the top two producers of coal and emitters of CMM are **China followed by India**. Other large coal producers include **United States (U.S.), Australia, Indonesia and Russia**.

- Over the past ten years, CMM emissions have been gaining greater attention due to their status as a greenhouse gas (GHG) and their potential use as a clean energy resource. As a result, many countries have begun to perform periodic inventories of their CMM emissions.
  - **Coal Production in India: 893.19 million tonnes in 2022-23**

  - All India Production of coal during **2023-24** was **997.83 MT** with a positive growth of **11.71%.**

- Countries that are Parties to the United Nations Framework Convention on Climate Change (UNFCCC) are committed to reporting their national greenhouse gas inventories to the Secretariat of the Convention.

- Developed (or Annex I) countries such as Australia, Russia, the Ukraine ,and U.S. have reported their stand-alone inventories on an annual basis, which are then peer-reviewed by technical experts. These inventories are posted on the UNFCCC Web site.

- Developing (or Non-Annex I) countries such as China and India report their national greenhouse gas inventories on a less frequent basis as part of a broader national report called a “national communication.”

- The U.S. EPA (United States Environmental Protection Agency) has worked with the reported UNFCCC data and has developed historical estimates and projected estimates (1990–2020) of the global GHG emissions and sinks for a multitude of emission sources. **The total 2005 global anthropogenic CMM emissions were estimated to be 432.3 million metric tons of CO2e (MtCO2e).**
- According to the U.S. EPA equivalency calculator, the 2005 global CMM emissions are equivalent to the total annual GHG emissions (CO2e) of approximately 77.2 million passenger cars. The percent contribution for each county's estimated 2005 CMM emissions are illustrated in Fig 26.

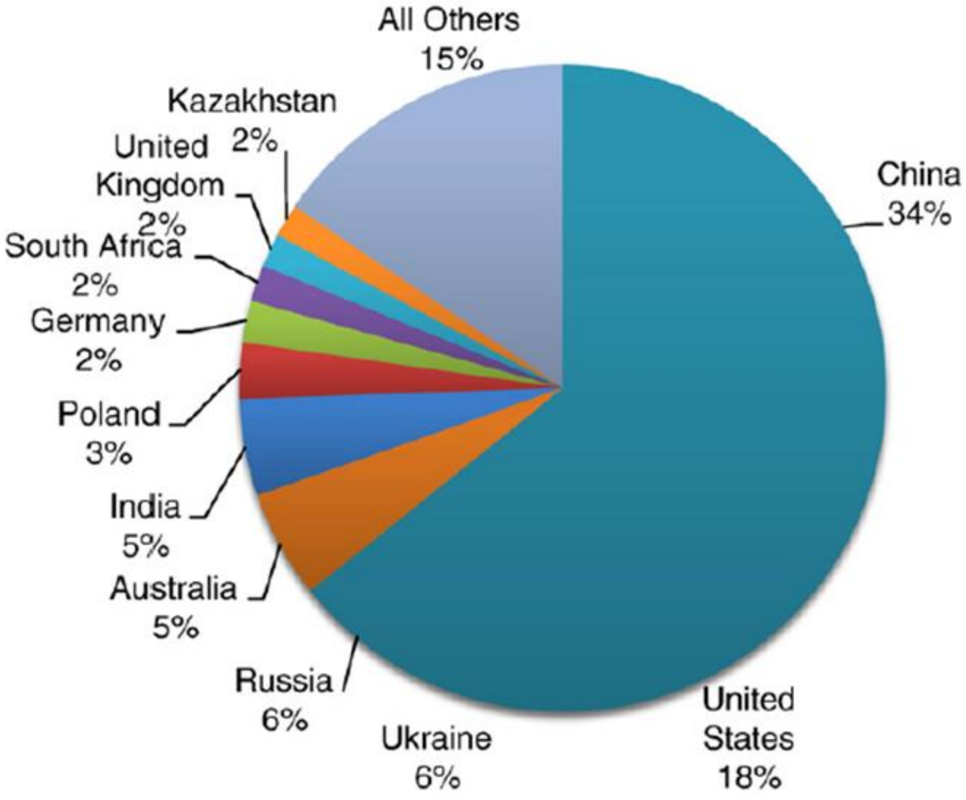
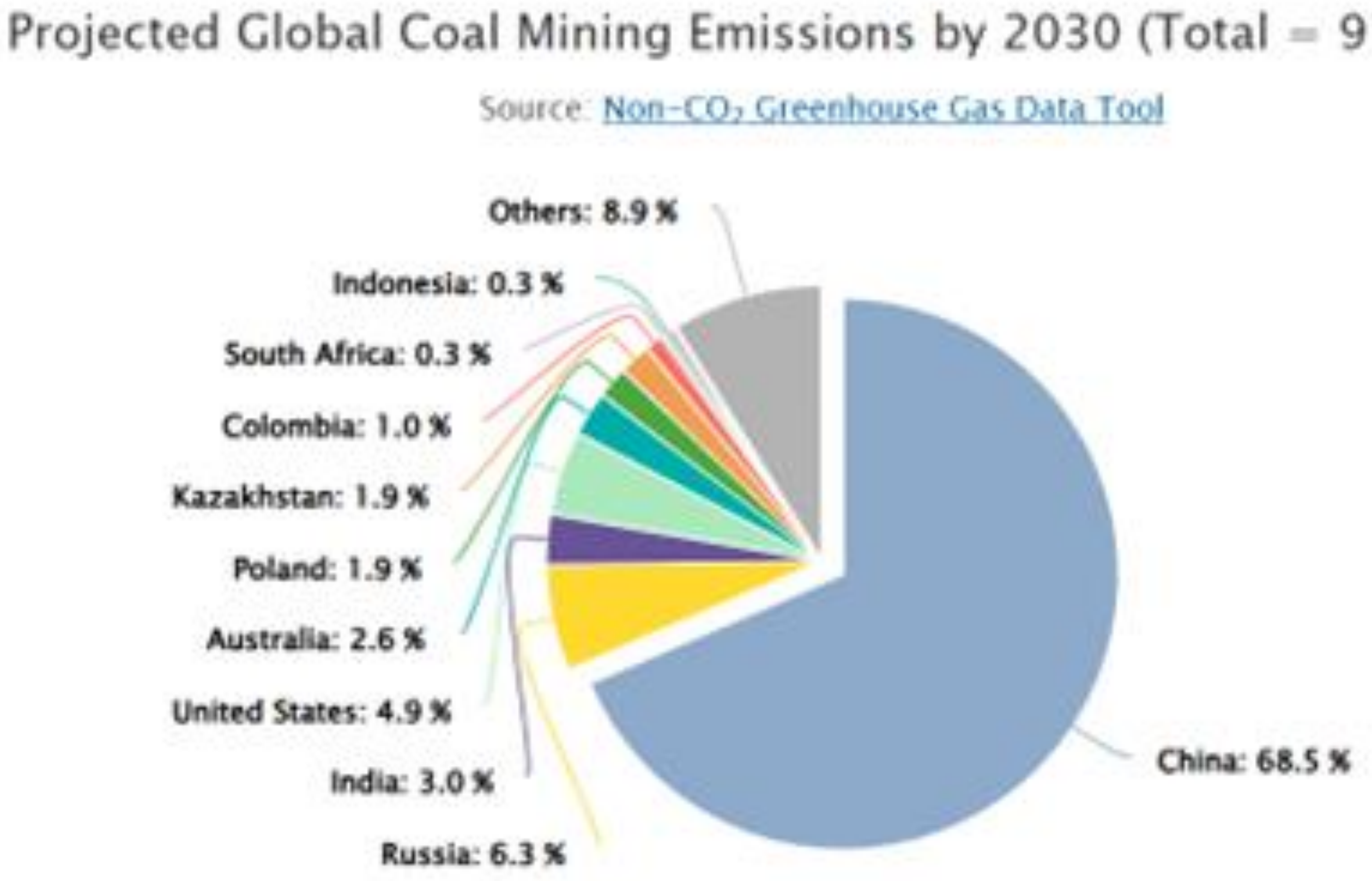


Fig. 26. 2005 estimated global CMM emissions (MtCO2e) (U.S. EPA, 2006).

- According to EPA projections, **coal mining will account for approximately 10% of global methane emissions in 2030.** The vast majority of these emissions come from key coal-producing countries, including China, Russia, the United States, India, and Australia. China, the world's largest emitter, would account for nearly 68.5% of these emissions, while Russia mines would release the second most at 6.3%.



- The global trend in estimated CMM emissions from 1990 to 2020 is illustrated in Fig. 27. Between 1990 and 2000, CMM emissions decreased by approximately 27.1%. The drop in global emissions is associated with a decline in coal production in many countries, in addition to a restructuring of the coal industries in countries such as China, Russia, and other Eastern European coal-producing countries. **From 2000, the global CMM emissions are projected to rise by approximately 27.3% or greater.** The expected overall decline is attributed to underground coal mining production shifting to less gassy surface mining (e.g. the Powder River basin in the U.S.) and CMM emissions reductions due to an increase in methane recovery and use projects.

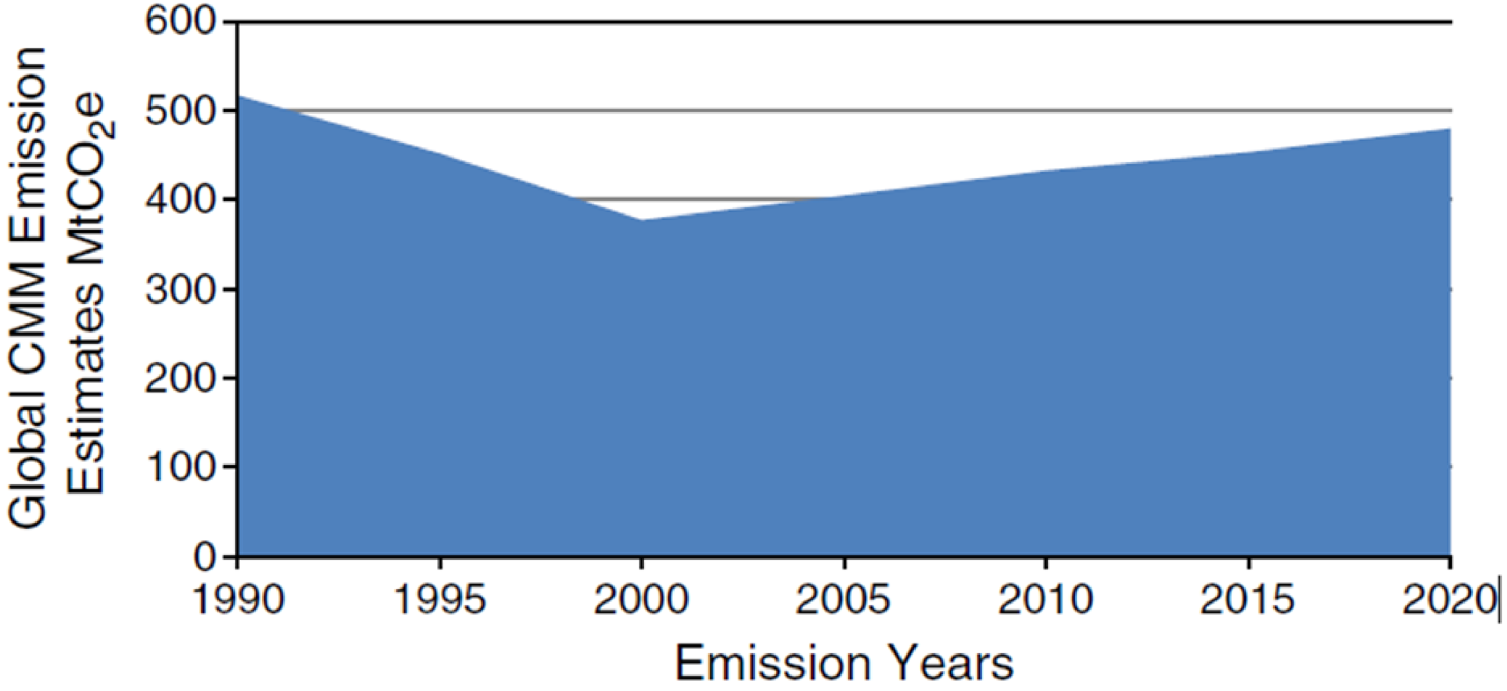


Fig. 27. Estimated global trends in CMM emissions (U.S. EPA, 2006).

Coal mine methane (CMM) recovery

- Coal mine methane (CMM) recovery refers to the process of capturing and utilizing methane gas that is released during coal mining activities. This gas is a potent greenhouse gas and is often vented into the atmosphere during mining operations, but with proper technologies, it can be recovered and used as an energy source.

1. Methane in Coal Mines:

- **Formation**: Methane forms in coal deposits as a byproduct of coal formation, and it can accumulate in the mine seams. As coal is mined, methane can be released into the air.
- **Safety Risk**: Methane is explosive when mixed with air, so it poses significant safety risks to miners, which is why managing its presence is crucial.

2. Recovery Technologies:

- **Pre-Mining Recovery**: Methane can be captured from coal seams before mining begins through wells drilled into the coal layers. This is the most effective way to reduce methane hazards and recover gas.
- **Post-Mining Recovery**: After mining, methane can still be captured through the installation of gas drainage systems, typically involving pipes and pumps to capture the gas as it is released from the mined areas.

3. Utilization of Methane:

- **Electricity Generation**: One of the main uses of recovered methane is for generating electricity. This is done through combustion in engines or turbines.
- **Industrial Use**: Methane can be processed and used as a natural gas for industrial purposes, such as in chemical plants or in the production of fertilizers.
- **Pipeline Quality Gas**: Methane can also be upgraded to a quality that meets natural gas standards and can be fed into gas pipelines.

4. Environmental Benefits:

Methane Reduction: Methane is a much more potent greenhouse gas than CO_2 (over 28 times more potent), so recovering and using it significantly reduces the environmental impact of coal mining.

Reduction of Flaring: Instead of venting methane or flaring it (which still releases CO_2), capturing and utilizing it avoids these emissions altogether.

5. Economic Benefits:

Energy Generation: Capturing methane allows for the production of electricity or other forms of energy, which can be a source of income for mining companies and local communities.

Cost Recovery: The sale of captured methane, particularly if converted into pipeline-quality natural gas, can offset some of the costs of mining operations.

6. Challenges:

- **Technical Challenges**: The effectiveness of methane recovery depends on the coal seam characteristics, such as the amount of gas present and the permeability of the coal.
- **Economic Viability**: The upfront costs of installing methane recovery systems can be high, especially in smaller or older mines, making it less economically feasible in some cases.
- **Regulatory and Safety Concerns**: Regulatory frameworks surrounding methane recovery can vary by region and can sometimes be complex to navigate.

In summary, coal mine methane recovery plays an important role in reducing both the safety risks for miners and the environmental impact of coal mining while also offering economic benefits through energy generation.

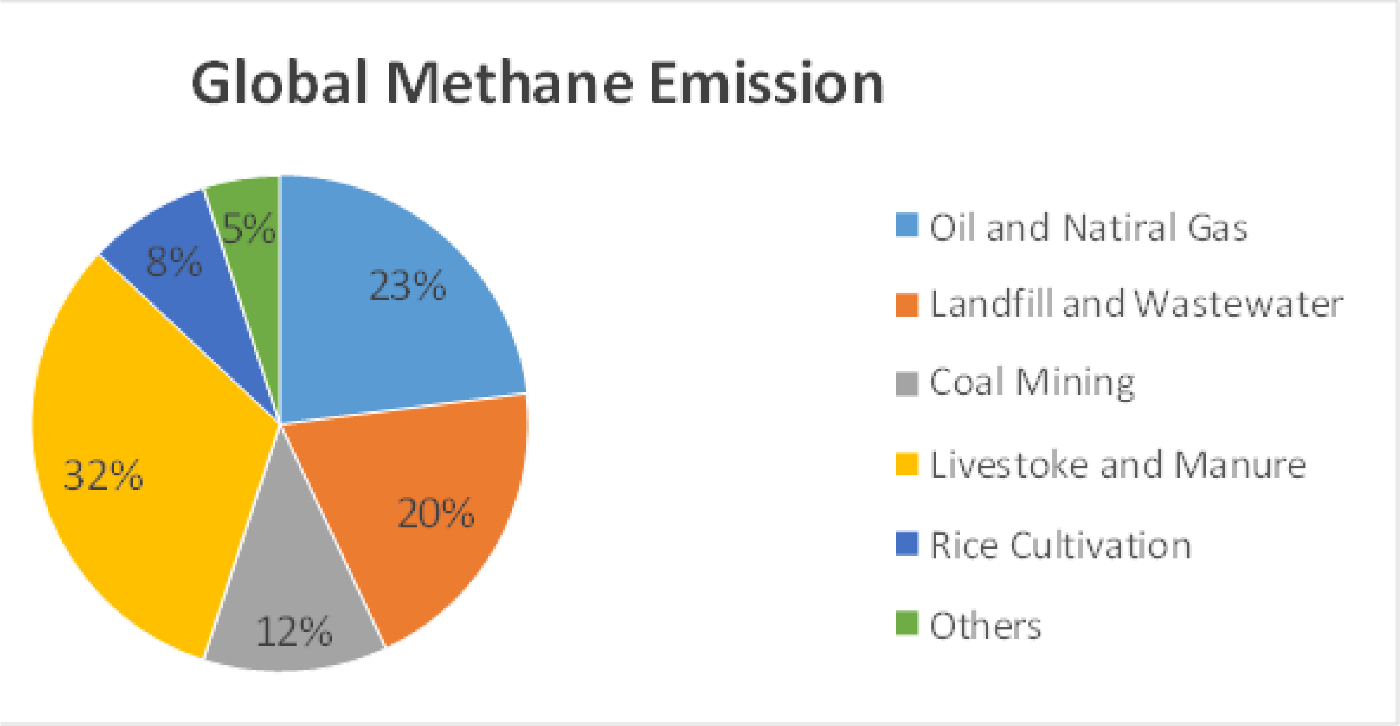
Methane Mitigation Technologies

- Methane is the second most abundant anthropogenic greenhouse gas (GHG) after carbon dioxide (CO_2), and constitutes approximately 20 percent of global emissions. It is classified as a “short-term climate forcer,” with a relatively shorter lifespan in the atmosphere of approximately 12 years.

- Despite its shorter duration and lower emission levels compared to CO_2, methane's global warming potential surpasses that of carbon dioxide by nearly 28 times over a century horizon. It is an exceptionally potent greenhouse gas.

- Eliminating Methane emissions can yield significant benefits in the race to mitigate global temperature rise. The urgency of tackling methane emissions is highlighted in the Paris Agreement, which seeks to limit global temperature rise to well below 2°C above pre-industrial levels (1850-1900). Looking its significant global warming potential, reducing methane emissions is recognized as one of the most effective strategies for achieving short-term climate objectives, making it a key focus in global efforts to combat climate change.

- As part of India’s climate commitments, reducing methane emissions is a crucial element of its climate strategy. Targeting methane emissions from major sectors such as oil and natural gas, coal mining, landfills, and wastewater can significantly lower overall greenhouse gas emissions. For instance, **the oil and gas sector alone contribute nearly 25% of global methane emissions, while coal mining and landfills account for about 12% and 11%, respectively.**



Global Methane Emission by Source (Ref: 2021. Global Methane Assessment.)

Methane mitigation is essential for achieving net-zero targets by addressing one of the most potent and short-lived climate pollutants. For instance, **the oil and gas sector alone contribute nearly 25% of global methane emissions, while coal mining and landfills account for about 12% and 11%, respectively.** Effective methane management in these Sectors is vital to accelerating progress toward a sustainable and climate-resilient future.

BENEFITS OF CAPTURING AND UTILIZING CMM AND MITIGATING CMM EMISSIONS

- There are many benefits for recovering and utilizing CMM, including:

a) reducing greenhouse gas emissions;
b) conserving a local source of valuable,
c) clean-burning energy;
d) enhancing mine safety by reducing in-mine concentrations of methane; and
e) providing revenue to mines

- As a primary constituent of natural gas, methane is an important, relatively clean-burning energy source.

- Effective gas drainage techniques reduce the risks of explosions, and hence lower accident risks. Reducing these risks in turn reduces their associated costs. Costs of methane-related accidents vary widely from country to country but are significant. For example, a 10% work stoppage or idling at a given mine due to a gas-related accident could lead to between US $8 million and $16 million/year in lost revenues at a typical high-production longwall mine. Additional costs of a single fatal accident to a large mining operation could range from US $2 million to more than US $8 million through lost production, legal costs, compensation, and punitive fines.

- Methane capture and use can add significant value to a mining operation. Captured CMM can be directly used to supply or generate energy, harnessing the value of a natural resource. In turn, this can deliver economic returns to the mine through energy sales or cost savings. Moreover, methane utilization adds intrinsic value by generating capital that can be reinvested in mine safety equipment and operations.
- CMM capture projects may experience financial benefits from pipeline sales revenue, reduced power, heating and/or cooling costs from onsite electricity generation, and in qualifying countries for carbon reduction credit revenue from GHG reduction programs such as **CDM (Clean Development Mechanism), JI (Joint Implementation), and voluntary carbon credits.**
- carbon financing may provide the only revenue streams for abatement-only projects, such as ventilation air methane (VAM) oxidation (without energy recovery) or CMM flaring. VAM can also be used for electric or thermal power generation.
- Increased methane recovery also reduces methane-related mining delays, resulting in increased coal productivity.

- CMM emissions from active underground mines may be mitigated by the implementation of methane drainage systems followed by recovery and use projects. Mines can use several reliable degasification methods to drain methane. These methods have been developed primarily to supplement mine ventilation systems that were designed to ensure that methane concentrations in underground mines remain within safe levels.
- Degasification systems include **vertical wells (drilled from the surface into the coal seam months or years in advance of mining), gob wells (drilled from the surface into the coal seam just prior to mining), and in-mine boreholes (drilled from inside the mine into the coal seam or the surrounding strata prior to mining).**

- The quality (purity) of the gas, that is recovered is partially, dependent on the degasification method employed, and may limit how the methane can be used.
- Potential utilization options for medium- to high-quality CMM (in the range of 30% to 100%methane) include a large variety of applications, such as:

(1) use as a fuel in steel furnaces, kilns, and boilers;

(2) in internal combustion (IC) engines or turbines for power generation;

(3) for injection into natural gas pipelines;

(4) As feedstock in the fertilizer industry; or

(5) as vehicle fuel in the form of liquid natural gas (LNG) or compressed natural gas (CNG).

- Generally, only high-quality gas (typically greater than 95% methane) can be used for pipeline injection. Vertical wells and horizontal boreholes tend to recover nearly pure methane (over 95% methane). In very gassy mines, gob wells can also recover high-quality methane, especially during the first few months of production. Over time, however, mine air may become mixed with the methane produced by gob wells, resulting in a lower-quality gas.

- Applications for medium-quality (usually greater than 30% methane) gas have been demonstrated in the U.S. and other countries, and include electricity generation (the electricity can be used either onsite or can be sold to utilities); as a fuel for onsite preparation plants or boilers, or for nearby industrial or institutional facilities; and in cutting-edge applications, such as microturbines or fuel cells.
- It is also possible to enrich medium-quality gas to pipeline standards using technologies that separate methane from carbon dioxide, oxygen, and/or nitrogen.
- Another option for improving the quality of mine gas is blending, which is the mixing of lower-quality gas with higher-quality gas whose heating value exceeds pipeline requirements.

- Even mine VAM, which typically contains less than 1% methane, has been successfully demonstrated as an energy source. At a mine in Australia, VAM was successfully used as combustion air in gas-fired internal combustion engines.
- The application of using mine ventilation air as combustion air in gas turbines and coal-fired boilers has also been demonstrated.
- The world's first commercial-scale VAM oxidation project, located in New South Wales, Australia, became operational in September 2007. The plant generates approximately 6 megawatts (MW) of electricity and reduces greenhouse gas emissions by more than 275,000 tCO2e/year

CMM utilization technologies

- CMM is gathered from underground mines and brought to the surface via vertical frac wells, surface-drilled horizontal wells, gob wells, and centralized vacuum stations, which collect the gas produced by in-mine boreholes and VAM systems.

- Not all of the extracted gas is or can be commercially utilized, but depending upon the gas quality and volumes the CMM could be used in a variety of projects, including:

a) natural gas pipeline injection;
b) power generation;
c) ventilation air methane oxidation;
d) power electricity generators for the mine or local region;
e) use as a an energy source—co-firing in boilers, district heating, coal drying;
f) use as a vehicle fuel, and manufacturing or industrial uses such as ammonia production;
g) flaring.

- Currently, commercial CMM utilization is not technically nor economically viable at many CMM drainage projects worldwide. As a result, the drained gas is vented directly to the atmosphere via an exhauster/well head blower. One option to reduce the environmental impact of direct venting is to combust the vented methane in a controlled flare system. CMM flaring has been used successfully in Europe and Australia, but has yet to gain widespread acceptance in the U.S. coal mining industry.

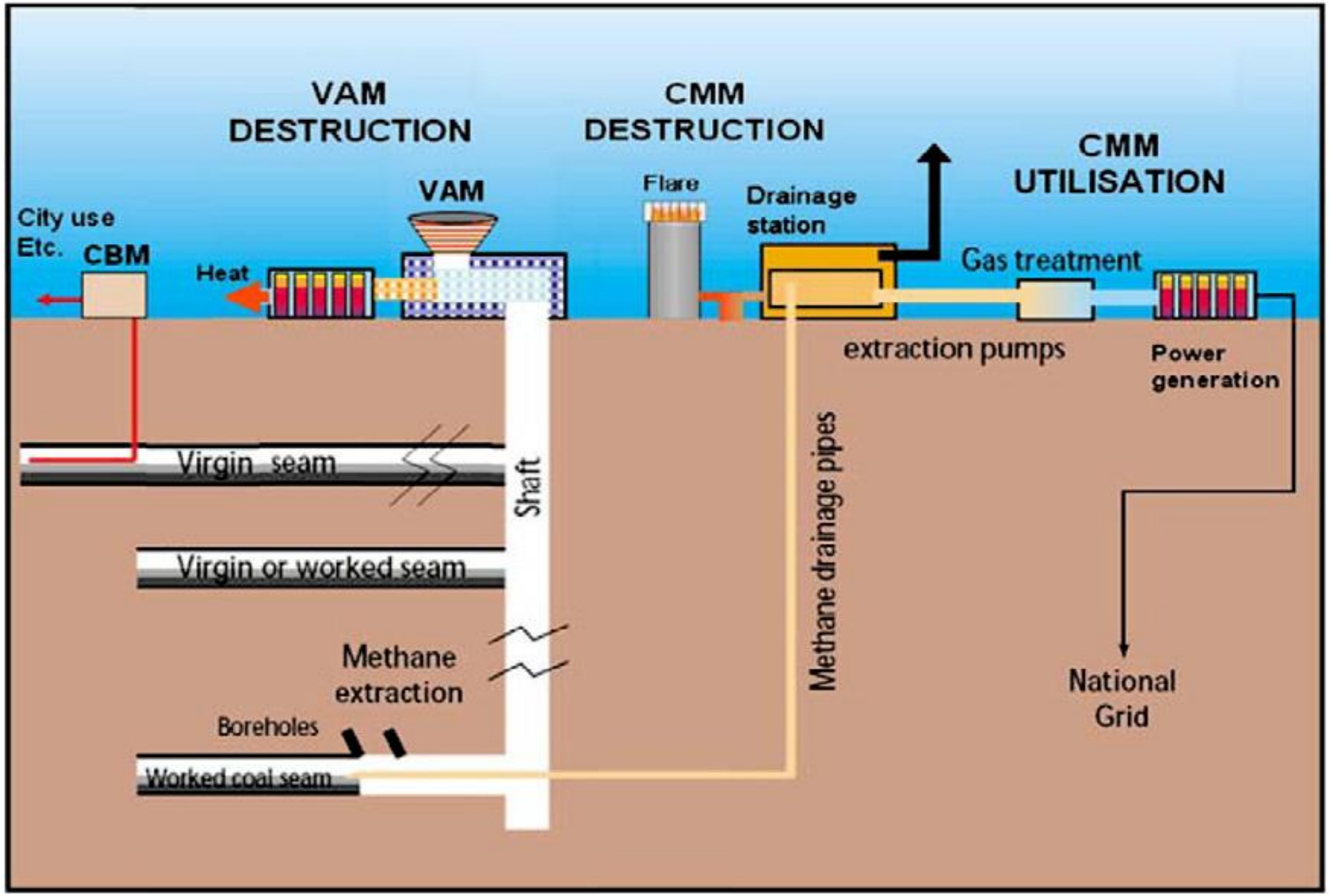


Fig. Multiple CMM end-use and destruction options for underground coal mines.

- The example demonstrates how methane can be used directly to supply or generate energy, which in turn can deliver economic returns for the mine through energy sales or cost savings. Good gas drainage standards and practices will yield gas of stable and usable quality, and will facilitate application of the lowest-cost utilization opportunities. Due to constantly changing mining conditions, gas supply can fluctuate in quality or quantity; thus utilization equipment will occasionally fail or need to be shut down. In these cases, the unused gas can possibly be flared (if >25% methane) to minimize emissions. Methane that cannot be used nor flared can be diluted in ventilation air and can be oxidized via a VAM destruction technology.

Pipeline injection

- Methane liberated during coal mining may be recovered and collected for sale to interstate pipeline systems. Typical pipeline standards require a methane concentration of 90 to 95%.
- The key issues that will determine project feasibility are: (1) whether the recovered gas can meet pipeline quality standards; and (2) whether the costs of production, processing, compression, and transportation are competitivewith other gas sources.
- Gas drained from vertical frac wells, horizontal wells, and in-seam boreholes is usually of sufficient quality (greater than 90% methane) for injection into natural gas pipelines with minimal processing (usually dehydration and carbon dioxide removal).
- Gas from gob wells and cross-measure boreholes is more variable in quality (30–80% methane), depending on the amount of dilution caused by air infiltration into the gob and boreholes.

- Gob gas and other low-quality gas can reach pipeline quality if it is upgraded or enriched through multi-stage treatment and compressions. Often the gas is transported from individual wells, via an in-field gathering system, to a central processing facility, where it is treated and compressed to meet transmission pipeline specifications.
- There are also other options to increase the quality of CMM, such as improving the well and borehole design to improve gas recovery, blending lower-quality CMM with higher-quality CMM, and increasing the energy content of the gas by spiking the CMM with higher hydrocarbon gasses.

- CMM is collected from the wellbore at relatively low pressures and is compressed to attain the necessary pressure requirements for injection into a transmission pipeline.
- The number of stages needed for compression will depend on the suction and discharge pressures needed to produce the wells and compress the gas into the transmission line, as well as the compression ratios of the equipment.
- Three to four stages of compression are common in CBM/CMM projects in the U.S. due to the low suction pressures required to maintain gas production and the high pressures (ranging from 200 to 1500 psig) required for interstate transmission lines. Pipeline injection projects are the most common CMM abatement projects in the U.S.

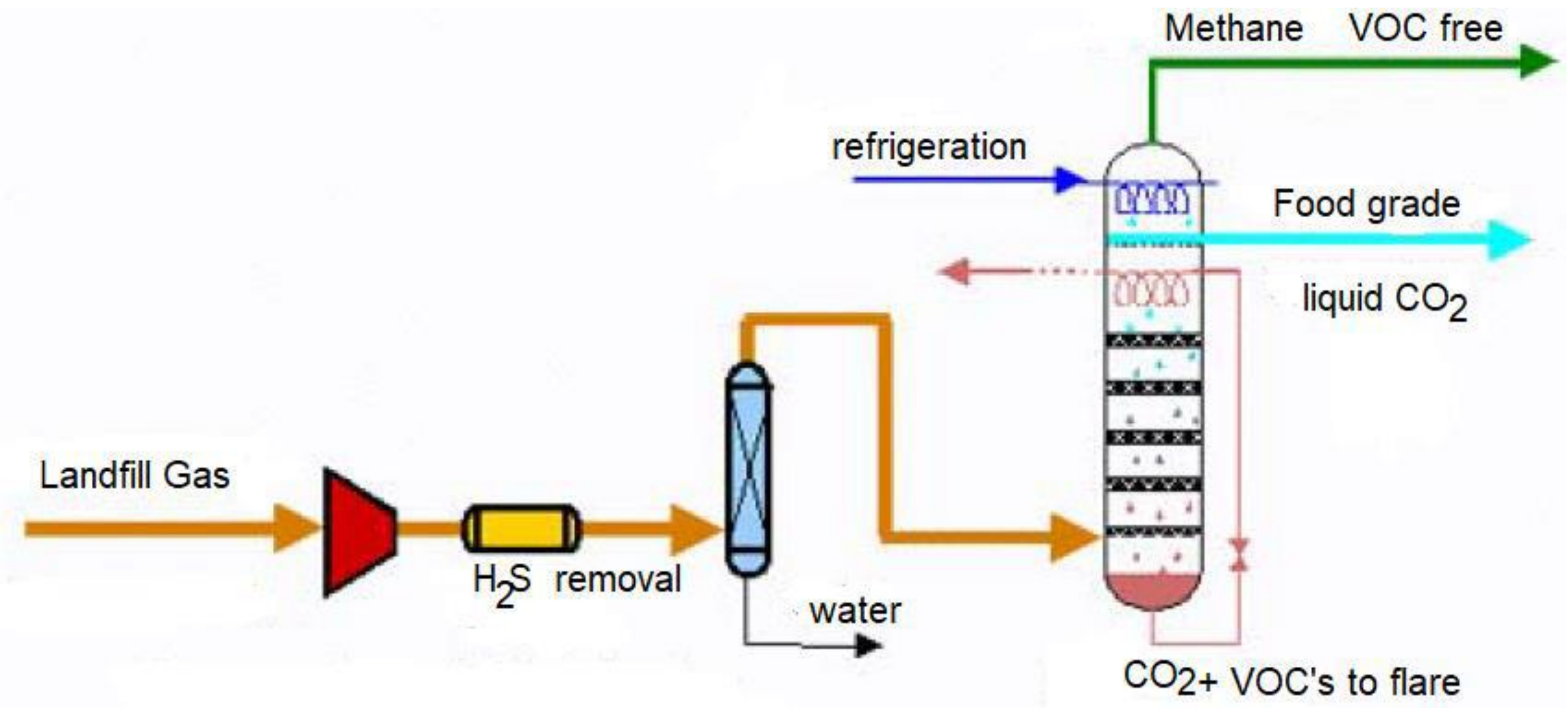
Gas processing

- An integrated processing plant can be installed at a central facility to remove contaminants and increase the quality of the gas to pipeline specifications. In this process, CMM is treated in a series of connected processes which first remove any hydrogen sulfide present (occasionally found in CMM), followed by removal of excess water vapor, oxygen, carbon dioxide, and nitrogen. In the U.S., pipeline quality gas typically must contain less than 0.2% oxygen, less than 3% nitrogen, less than 2% carbon dioxide, and less than 112 kg/MMcm (7 lbs/MMcf) of water vapor, while having a heating value of greater than 967 Btu/scf.
- Several technologies are commercially used to separate methane from other impurities, while some are still in the field demonstration stage. Nitrogen rejection units (NRU) are used to remove the more difficult and costly nitrogen contaminants. Currently, five technologies are available for methane separation: cryogenic, pressure swing adsorption, solvent absorption, molecular gate, and membrane technologies.

MMcm: million cubic meters
Btu: British Thermal Unit

NITROGEN REJECTION UNIT (NRU) TECHNOLOGIES

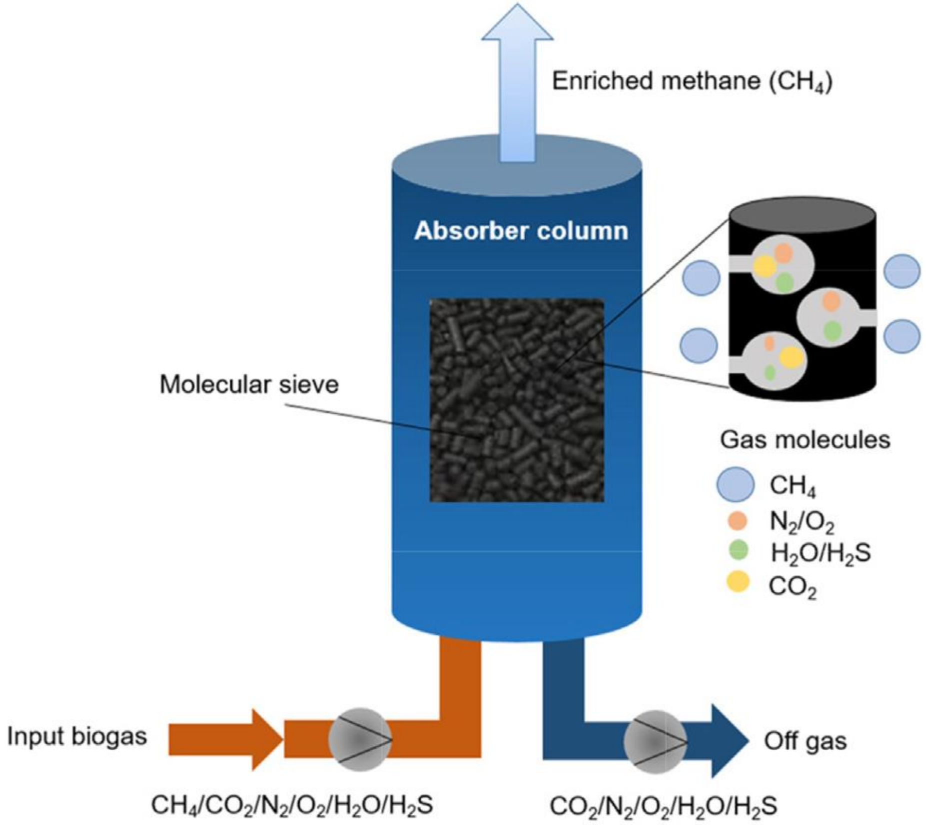
Cryogenic technology:The cryogenic process uses a series of heat exchangers to liquefy the high-pressure feed gas stream. The mixture is then flashed and a nitrogen-rich stream vents from a distillation separator, leaving the methane-rich stream. Designers locate the deoxygenation system at the plant inlet to avoid the danger of explosion within the plant. **Cryogenic plants have the highest methane recovery rate (about 98%)** of any of the technologies, and **they have become standard practice for large-scale projects where they must achieve economies of scale**. However, cryogenic plants tend to be less cost-effective at capacities below 5 Mmscfd (Million standard cubic feet per day), which are more typical of CMM drainage projects



Pressure swing adsorption (PSA): Gasses when under pressure tend to get adsorbed on solid surfaces. While more gas is adsorbed with a pressure increase, reducing the pressure releases or desorbs the gas. PSA utilizes the property of varying affinities of gasses for a given solid surface to separate a mixture of gasses. **In the case of CMM, nitrogen is removed from low-quality gas by passing the gas mixture under pressure through a vessel containing an adsorbent bed that preferentially adsorbs nitrogen, leaving the gas coming out of the vessel to be rich in methane.** When the adsorbent bed is saturated, the pressure is reduced to release the adsorbed nitrogen, preparing the bed for another cycle. Usually very porous materials are selected as adsorbents for PSA systems because they provide surface areas large enough to adsorb significant amounts of gas, even though the adsorbed layer may be only one or only a few molecules thick. **Adsorbents typically used are activated carbon, silica gel, alumina, and zeolite.**

Some specialty adsorbents, including zeolites and carbon molecular sieves, selectively adsorb gasses based on the size of their molecules; only those gasses that have molecules smaller than the pore size of the absorbents are allowed into the adsorbent structure.

PSA recovers up to 95% of available methane and can operate on a continuous basis with minimal onsite attention. PSA systems have excellent turndown capability, so they are able to operate effectively with gas flowing at a fraction of the rated capacity.



Molecular gate: This process removes nitrogen and other contaminants from the methane, whereas other processes remove the methane from the nitrogen. The process uses a new type of molecular sieve that has the unique ability to adjust pore size openings within an accuracy of 0.1 Å. For CMM, the sieve pore size is set smaller than the molecular diameter of methane and above the molecular diameters of nitrogen, oxygen, carbon dioxide, and water, as indicated in Fig. This permits the nitrogen and other contaminants to enter the pores and to be adsorbed while excluding the methane, which passes through the fixed bed of adsorbent at essentially the same pressure as the feed.

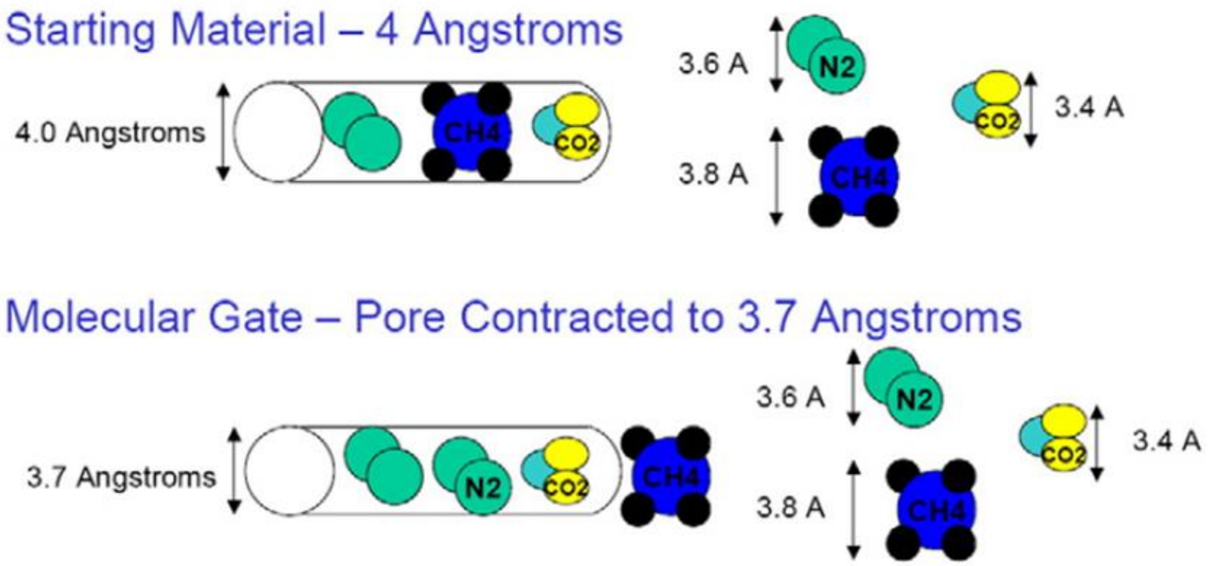
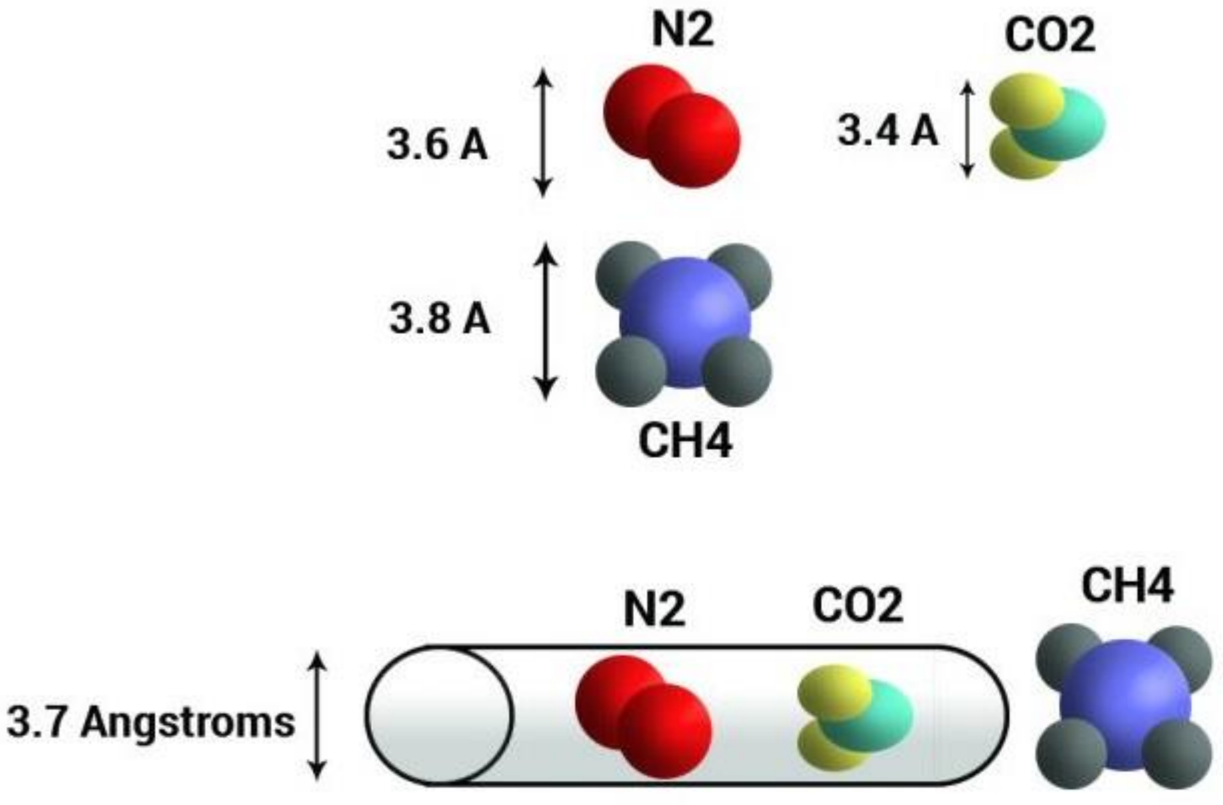


Fig. 30. Molecular gate sieve pore adjustments (U.S. EPA, 2008).

Molecular Gate adsorbent is unique in that the pore size is tightly controlled during the manufacturing of the adsorbent, and thus is customized to most preferentially adsorb a specifically sized target molecule. In the diagram below, note that the size of the pore in the adsorbent is controlled to 3.7 Angstroms. Smaller molecules, such as carbon dioxide (CO2) and nitrogen (N2) are able to fit into the pores and be strongly adsorbed, while the methane (CH4) molecule is too large to fit in the pore. The result is a reliable separation of methane from CO2 and N2.



The pore size is controlled to prevent methane from entering the pores, thus assuring a reliable separation

Solvent absorption: Sometimes referred to as "selective absorption," this process uses specific solvents that have different absorption capacities with respect to different gasses. In CMM applications, a solvent selectively absorbs methane while rejecting a nitrogen-rich stream in a refrigerated environment. The petroleum industry commonly uses selective absorption to enrich gas streams.

Membrane: This process uses membranes to selectively pass methane, ethane, and higher hydrocarbons while retaining nitrogen. A simple one-stage membrane unit is appropriate for feed gas containing about 6 to 8% nitrogen. However, more commonly, nitrogen concentrations are higher and require a two-step or two-stage membrane system.

- In the single-stage membrane configuration, a 525.6 kmol/h (11,780 Nm3/h) natural gas stream containing 10 %mol of N2 at the feed pressure of 35 bar and temperature of 30 ◦C as the feed stream enters the membrane module, and the permeate stream is the purified gas as the main product. The pressure of the permeate-side is 1 bar. In this configuration, a compressor and a cooler are used to increase pressure and decrease the temperature of the main product stream, respectively. The scheme of the single-stage membrane process for the separation of N2 from CH4 is shown in Fig.

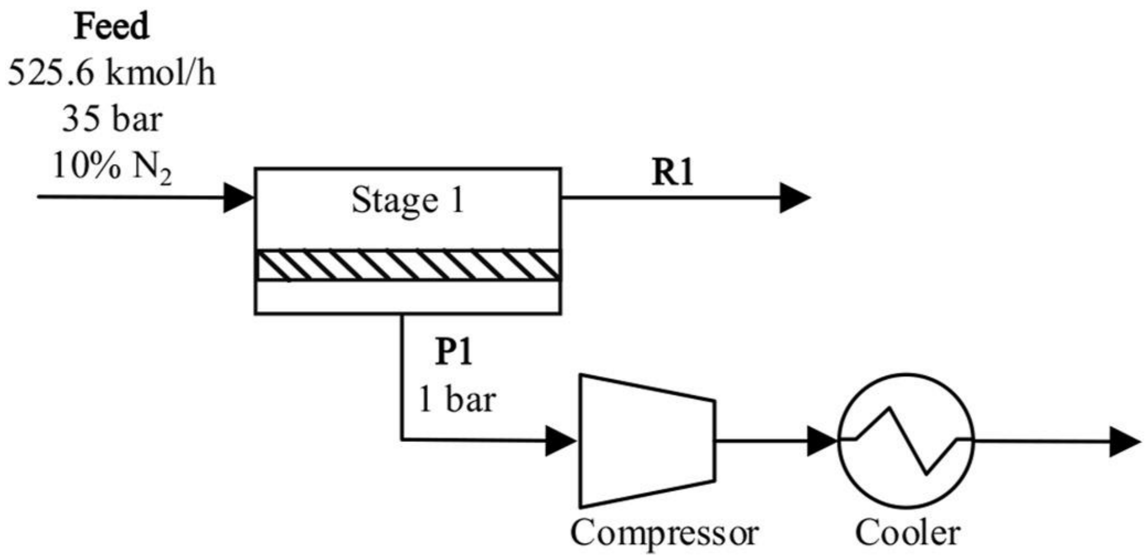
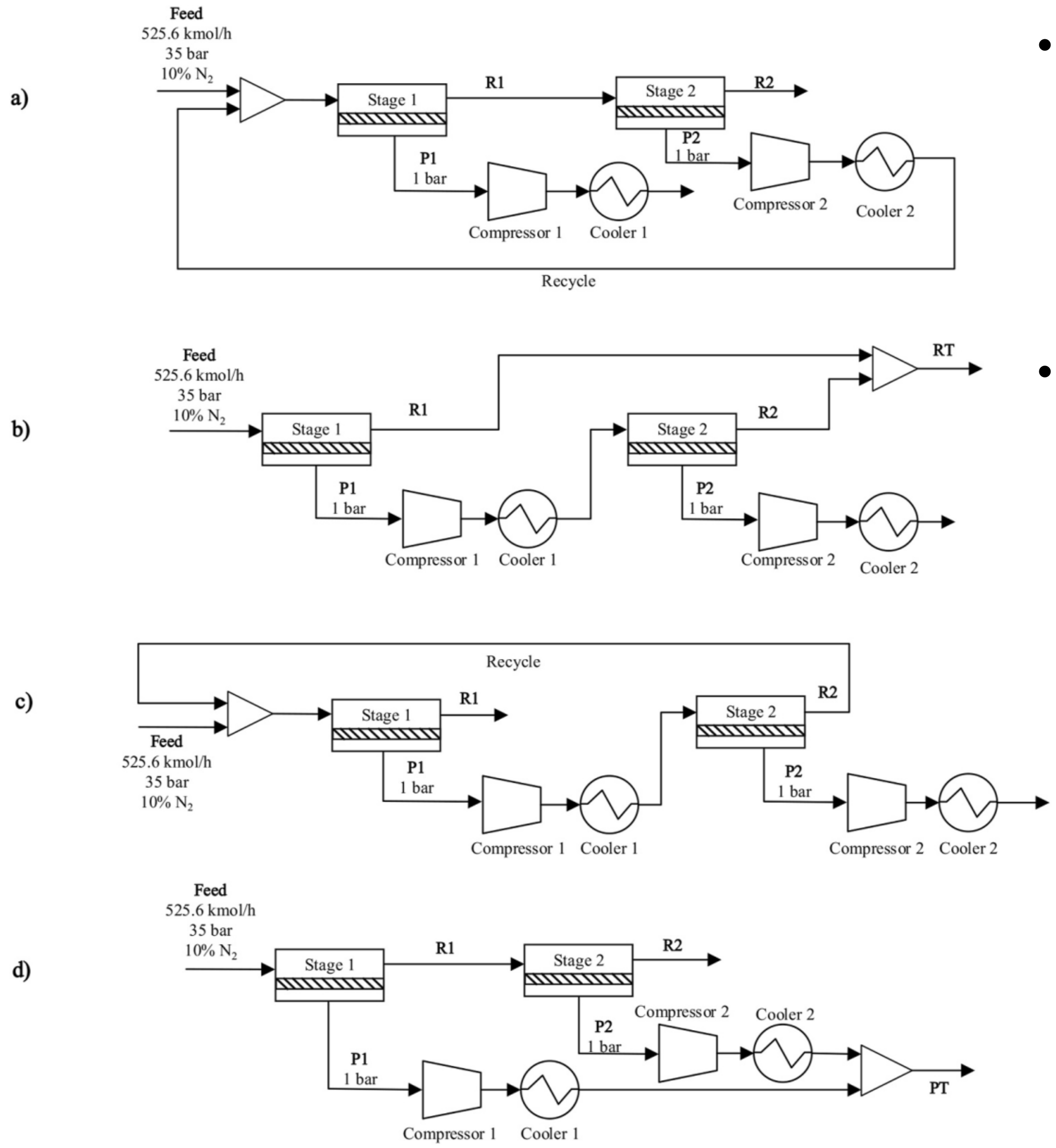


Fig. The single-stage gas separation process.

- In the two-stage process, various configurations with two membranes are designed to remove N2 from CH4 for a 525.6 kmol/h (11,780 Nm3/h) natural gas stream containing 10 %mol of N2 at the feed pressure of 35 bar and temperature of 30 ◦C as the feed stream. The scheme of two-stage membrane operation with different configurations is indicated in Fig.

Fig. Different configurations for the two-stage gas separation process.



- In the first configuration (Fig. a), the retentate of the first stage goes to the second stage, as the feed stream and the permeate stream of the second membrane unit recycles and mixed with the feed stream of the first membrane unit. The permeate of the first stage (P1 stream) is the final product, as the purified natural gas stream.
- In the second configuration (Fig. b), the permeate stream of the first membrane unit, after passing through a compressor and a cooler, enters the second stage. In this design, the permeate stream of the second membrane unit (P2 stream) is considered as the final product.
- The third configuration (Fig. c) is similar to the previous configuration with a recycle stream. In the third design, the retentate stream of the second stage is recycled and mixed with the feed stream of the first membrane unit. However, the cost of the third configuration is slightly lower than the second configuration.
- In the fourth configuration (Fig. d), the retentate of the first membrane unit goes to the second stage as the feed stream. After passing through a compressor and a cooler, the permeate streams of the two membrane units are mixed to form the final product.

OTHER IMPURITY AND WATER VAPOR REMOVAL TECHNOLOGIES

Oxygen removal: After nitrogen rejection, deoxygenation is the most technically challenging and expensive process. It is especially important since most pipelines have very strict oxygen limits (typically 0.1% or 1000 parts per million). NRU technologies such as PSA will experience oxygen rejection in proportion to nitrogen rejection and may need very little deoxygenation as a final processing step. Oxygen rejection associated with cryogenic or solvent absorption NRUs is more critical due to explosion danger, and it must be the first system component. Since deoxygenation results in a substantial temperature rise, if inlet gas is likely to contain over 1.5% oxygen, a two-stage recycle system is needed to avoid unacceptably high temperatures.

Carbon dioxide removal: Several technologies are available commercially, including **amine units, membrane technology, and selective adsorption**. Amine units are tolerant of only low levels of oxygen in the feed stream, so the amine unit must be downstream of the de-oxygenation unit. Often amine systems are used to treat gas removed from virgin coal beds, but an adsorption system may be more attractive for treating highly contaminated gas such as gob gas or abandoned mine CMM. However, amine systems may experience corrosion and degradation from the amine solvents used in the process. Amine systems commonly operate at high pressure and require compression of the feed gas. The gas stream from amine units is often water-saturated and a glycol dehydration unit is used to bring the gas to pipeline specifications.

Water vapor removal: Dehydration of CMM is the simplest part of any integrated system design. Inadequate water removal, however, can result in corrosion damage to delivery pipes and can be quite serious. **Most system suppliers will employ a molecular sieve dehydration stage because of its proven record and economical operation.**

OTHER CMM UPGRADING OPTIONS

- Horizontal boreholes and “longhole” horizontal boreholes also can produce pipeline quality gas when the integrity of the in-mine piping system is closely monitored. However, the amount of methane produced from these methods is sometimes not large enough to warrant investments in the necessary surface facilities. In cases where mines are developing utilization strategies for larger amounts of gas recovered from vertical or gob wells, it may be possible to use the gas recovered from in-mine boreholes to supplement production.
- Another option to upgrade gas quality is to blend the low Btu gas with higher Btu gas to obtain a higher heating value above the pipeline quality requirements. As a result of blending, the Btu content of the overall mixture can meet acceptable levels for pipeline injection. Spiking the CMM with higher hydrocarbon gasses such as propane is also an option, but this application is dependent upon the pipeline's acceptance of spiked gas. Gas processing may still be required in combination with improved extraction techniques, blending, and spiking in order to meet pipeline specifications.

CMM UTILISATIONS

Auto Fuel in form of Compressed Natural Gas (CNG): CNG is already an established clean and environment friendly fuel. Depending upon the availability of CBM/CMM, this could be a good end use. Utilization of recovered CBM/CMM as fuel in form of CNG for mine dump truck is already part of demonstration project titled "Coalbed Methane Recovery & Commercial Utilization Project" presently under implementation in collaboration with UNDP/GEF at Sudamdih and Moonidih mines of BCCL.

Feed Stock for Fertilizer: M/S Sindri Modernization Plant (SMP), Sindri is utilizing fuel oil as feedstock for its cracker complex. The installed capacity of this plant is 900 tonne per day ammonia and is operational at 80% of capacity during last three years. The CBM/CMM produced from Jharia, Bokaro coalfields can be utilized at Sindri, which will economise the operations.

Fuel for Industrial Use: It may provide an economical fuel for a number of industries like cement plant, refractories, Rolling mills etc. in Dhanbad, Bokaro, Palamu regions in view of the superior combustion properties of CMM.

Use of CMM at Steel Plants: Blast furnace operations use metallurgical coke to produce most of the energy required to melt the iron ore to iron. Since coke is becoming increasingly expensive in the U.S., the steel industry is seeking low-capital options that reduce coke consumption, increase productivity and reduce operating costs. All blast furnaces in North America inject some type of supplement fuel, such as natural gas, coke oven gas, oils and tars, or coal to form additional carbon monoxide and hydrogen for combustion, and chemical reduction of iron-bearing materials into molten iron. Of these fuels, natural gas and pulverised coal are the most widely accepted for injection.

- **Recent full-scale tests have shown that injecting natural gas into blast furnaces at the rate of 195.4 cubic meters per ton of hot metal can reduce coke consumption by 30%, and can increase iron-making capacity by 40%. Coal mine methane provides the same benefits as conventional natural gas, and could easily be substituted for, or mixed with, natural gas for blast furnace use as long as it meets gas quality requirements (low sulfur content and at least 94% methane). Injection of CBM/CMM in blast furnace of Bokaro Steel Plant will improve performance and can enhance its productivity.**

***Power Generation*:**

- CMM can be ideal fuel for co-generation Power plants to bring in higher efficiency and is preferred fuel for new thermal power plant on count of lower capital investment and higher operational efficiency. At the lower end of value, power generation of about 800MW in Jharkhand is possible from the identified blocks.

- CMM may also be used as a fuel for power generation. Unlike pipeline injection, power generation does not require pipeline-quality methane nor much compression. Gas engines can generate electricity using methane that has a heat content of 350 Btu/cf.

- Mines can use electricity generated from recovered methane to meet their own onsite electricity requirements, and they can sell electricity generated in excess of their onsite needs to utilities.

- Outside of the U.S., power generation is often the preferred option for using CMM. Power generation projects using CMM are operating at coal mines in several countries, including China, Australia, the United Kingdom, and Germany.

- Currently, reciprocating or internal combustion (IC) engines are the most likely technology to be used for a CMM project. Boiler/steam turbines are generally not cost-effective in sizes below 30 MW, while gas turbines are not the optimal choice for projects requiring 10 MW or less.
- Furthermore, gas turbines typically cannot utilize CMM below 50% methane and require the gas to be compressed prior to use. However, when used in the right applications, gas turbines are smaller and lighter than IC engines, more efficient, and historically have had lower operation and maintenance costs.
- While maintaining pipeline quality gas output from gob wells can be difficult, the heating value of gob gas is generally compatible with the combustion needs of gas engines.
- One potential problem with using gob gas is that production, methane concentration, and rate of flow are generally not predictable—wide variations in the Btu content of the fuel may create operating difficulties.
- Equipment for blending the air and methane may be needed to ensure that variations in the heating value of the fuel remain within an acceptable range for gas engines and possess approximately 10% allowable variability for gas turbines.

- The level of electric capacity that may be generated depends on the amount of methane recovered and the “heat rate” (i.e., Btu to kWh conversion) of the generator. For example, simple cycle gas turbines typically have heat rates in the range of 10,000 Btu/kWh, while combined cycle gas turbines could have heat rates of 7000 Btu/kWh. Gas engine heat rates can range from 9000 to 11,000 Btu/kWh, depending on the model of the engine.