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Combustion Turbine Power Plants

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Lee Layton, P.E

Table of Contents

Cover Photograph: Broad River CT Plant, South Carolina. The plant consists of 5 x 170 MW units. Photo is courtesy of Calpine.

Introduction

Combustion turbines (CT) are one of the primary workhorses of the power industry. Because of the abundance of natural gas, new central station power plants will likely be combined cycle plants that use combustion turbines as the first stage as well as used individually as "peakers". Smaller CTs have characteristics favorable for use in distributed energy resource (DER) applications.

Small combustion turbines are found in a broad array of applications including mechanical drives, base load grid-connected power generation, peaking power, and remote off-grid applications. CTs can also be used in cogeneration applications usually with the addition of a heat recovery steam generator. Combustion turbines are also available in transportable configurations allowing the plant to be moved from one location to another.

The concept of a turbine engine has been around for hundreds of years. As early as 150 AD the concept of a steam turbine was presented. In the early 1900's the first gas turbines were produced that could actually generate more power than needed to run the turbine itself. In 1930, Sir Frank Whittle patented the design for a gas turbine for jet propulsion and this unit was the basis of the first utility power generation gas turbine, which was placed in service by Brown, Boveri, & Cie (BBC) in 1939 in Switzerland.

Combustion turbines used for power generation range in size from units starting at about 1 MW to over a 400 MW. Units from 1-15 MW are generally referred to as industrial turbines, a term which differentiates them from larger utility grade turbines and smaller microturbines.

Gas turbines are relatively inexpensive with capital costs ranging from $300-$1000/kW and the costs tend to increase with decreasing power output. Compared with reciprocating engines, combustion turbines tend to cost more for smaller sizes and less at the larger sizes.

The construction process for gas turbines can take as little as several weeks to a few months, compared to years for base load power plants. Their other main advantage is the ability to be turned on and off within minutes, supplying power during peak demand. Since single cycle (gas turbine only) power plants are less efficient than combined cycle plants, they are usually used as peaking power plants, which operate anywhere from several hours per day to a few dozen hours per year, depending on the electricity demand and the generating capacity of the region. In areas with a shortage of base load and load following power plant capacity or low fuel costs, a gas turbine power plant may regularly operate during most hours of the day. A large single cycle gas turbine power plant typically produces 100 to 400 megawatts of power and has 35–45% thermal efficiency.

Combustion turbines have relatively low installation costs, low emissions, high heat recovery, infrequent maintenance requirements, but low energy efficiency. See Table 1 for an overview of the advantages and disadvantages of combustion turbines.

Table 1
Combustion Turbines

Advantages	Disadvantages
Low capital cost	Reduced efficiencies at part load
Readily available over a wide range of power outputs (1MW to over 400MW)	Sensitivity to ambient conditions
Capability of producing high-temperature steam using exhaust heat	Small system cost and efficiency not as good as larger systems
Low operating pressure	High operating costs
High power-to-weight ratio	
Proven reliability and availability	

Gas turbine technology has steadily advanced since its inception and continues to evolve; research is active in producing ever smaller gas turbines. Computer design, along with material advances, has allowed higher compression ratios and temperatures, more efficient combustion and better cooling of engine parts. On the emissions side, the challenge in technology is increasing turbine inlet temperature while reducing peak flame temperature to achieve lower NOx emissions to cope with the latest regulations.

In this course, we will take a detailed look at the natural gas industry including where the current and expected gas reserves are located. Then we will go into the details of how a combustion - or gas - turbine power plant works. Finally, we will discuss some of the environmental impacts of combustion turbines. But first, let’s look at the natural gas industry.

Chapter 1
Natural Gas as a Fuel Source

Natural gas is a gas consisting primarily of methane. It is found associated with other fossil fuels, in coal beds, and is created by organisms in marshes, bogs, and landfills. It is an important fuel source and a major feedstock for fertilizers.

Before natural gas can be used as a fuel, it must undergo extensive processing to remove almost all materials other than methane. The by-products of that processing include ethane, propane, butanes, pentanes, and higher molecular weight hydrocarbons, elemental sulfur, carbon dioxide, water vapor, and sometimes helium and nitrogen.

History

Before there was an understanding of what natural gas was, it posed somewhat of a mystery to man. Sometimes, such things as lightning strikes would ignite natural gas that was escaping from under the earth's crust. This would create a fire coming from the earth, burning the natural gas as it seeped out from underground. These fires puzzled most early civilizations, and were the root of much myth and superstition. One of the most famous of these types of flames was found in ancient Greece around 1000 B.C. The Greeks, believing it to be of divine origin, built a temple on the flame. This temple housed a priestess who was known as the Oracle of Delphi, giving out prophecies she claimed were inspired by the flame.

In the 1800s, natural gas was usually produced as a byproduct of producing oil, since the small, light gas carbon chains come out of solution as it undergoes pressure reduction from the reservoir to the surface. Unwanted natural gas can be a disposal problem at the well site. If there is not a market for natural gas near the wellhead it was virtually useless since it must be piped to the end user. In the 1800s and early 1900s, such unwanted gas was usually burned off at the well site. Often, unwanted gas was pumped back into the reservoir with an 'injection' well for disposal or re-pressurizing the producing formation. In locations with a high natural gas demand, pipelines were constructed to take the gas from the well site to the end consumer.

An early commercial form of natural gas was known as “town gas”. *Town gas* is a mixture of methane and other gases, mainly the highly toxic carbon monoxide that can be used in a similar way to natural gas and can be produced by treating coal chemically. Most town "gashouses" located in the eastern United States in the late nineteenth and early twentieth century’s were simple by-product coke ovens which heated bituminous coal in air-tight chambers. The gas driven off from the coal was collected and distributed through town-wide networks of pipes to residences and other buildings where it was used for cooking and lighting purposes. The coal tar that collected in the bottoms of the gashouse ovens was often used for roofing and other waterproofing purposes, and also, when mixed with sand and gravel, was used for creating bitumen for the surfacing of local streets.

Manufactured natural gas of this type was first brought to the United States in 1816, when it was used to light the streets of Baltimore, Maryland. However, this manufactured gas was much less efficient, and less environmentally friendly, than modern natural gas that comes from underground.

Chemical Composition

Natural gas is colorless, shapeless, and odorless in its pure form. It is abundant in the United States and when burned it gives off a great deal of energy and few emissions. Unlike other fossil fuels, natural gas is clean burning and emits lower levels of potentially harmful byproducts into the air.

Natural gas is a combustible mixture of hydrocarbon gases. While natural gas is formed primarily of methane, it can also include ethane, propane, butane and pentane. Table 2 shows the "typical" make-up of natural gas. The make-up varies based on the source of the gas.

Table 2
Composition of Natural Gas

Component	Symbol	Percentage
Methane	CH_4	70-90%
Ethane	C_2H_6	0-20%
Propane	C_3H_8	
Butane	C_4H_{10}	
Carbon Dioxide	CO_2	0-8%
Oxygen	O_2	0-0,2%
Nitrogen	N_2	0-5%
Hydrogen Sulphide	H_2S	0-5%
Rare Gases	A, He, Ne, Xe	Trace amounts

As you can see from Table 2, natural gas is almost pure methane.

Natural gas is considered *dry* when it is almost pure methane, having had most of the other commonly associated hydrocarbons removed. When other hydrocarbons are present, the natural gas is considered *wet*.

Found in reservoirs underneath the earth, natural gas is often associated with oil deposits. Once brought from underground, the natural gas is refined to remove impurities such as water, other gases, sand, and other compounds. Some hydrocarbons are removed and sold separately, including propane and butane. Other impurities are also removed, such as hydrogen sulfide (the refining of which can produce sulfur, which is then also sold separately). After refining, the clean natural gas is transmitted through a network of pipelines. From these pipelines, natural gas is delivered to its point of use.

Natural gas is a fossil fuel. Like oil and coal, this means that it is, essentially, the remains of plants and animals and micro-organisms that lived millions and millions of years ago. Fossil fuels are formed when organic matter (such as the remains of a plant or animal) is compressed under the earth, at very high pressure for a very long time. This is referred to as *thermogenic methane*. Similar to the formation of oil, thermogenic methane is formed from organic particles that are covered in mud and other sediment. Over time, more and more sediment and mud and other debris are piled on top of the organic matter. This sediment and debris puts a great deal of pressure on the organic matter, which compresses it. This compression, combined with high temperatures found deep underneath the earth, breaks down the carbon bonds in the organic matter. As we go deeper and deeper under the earth’s crust, the temperature gets higher and higher. At low temperatures, more oil is produced relative to natural gas. At higher temperatures, however, more natural gas is created, as opposed to oil. That is why natural gas is usually associated with oil in deposits that are a couple of miles below the earth's crust. Deeper deposits, very far underground, usually contain primarily natural gas, and in many cases, pure methane.

Natural gas can also be formed through the transformation of organic matter by tiny micro-organisms. This type of methane is referred to as *biogenic methane*. Methanogens, tiny methane-producing micro-organisms, chemically break down organic matter to produce methane. These micro-organisms are commonly found in areas near the surface of the earth that are void of oxygen. These micro-organisms also live in the intestines of most animals, including humans. Formation of methane in this manner usually takes place close to the surface of the earth, and the methane produced is usually lost into the atmosphere. In certain circumstances, however, this methane can be trapped underground, recoverable as natural gas. An example of biogenic methane is landfill gas. Waste-containing landfills produce a relatively large amount of natural gas from the decomposition of the waste materials that they contain.

A third way in which methane (and natural gas) may be formed is through *abiogenic processes*. Extremely deep under the earth's crust, there exist hydrogen-rich gases and carbon molecules. As these gases gradually rise towards the surface of the earth, they may interact with minerals that also exist underground, in the absence of oxygen. This interaction may result in a reaction, forming elements and compounds that are found in the atmosphere (including nitrogen, oxygen, carbon dioxide, argon, and water). If these gases are under very high pressure as they move toward the surface of the earth, they are likely to form methane deposits, similar to thermogenic methane.

Energy content of Natural Gas

Quantities of natural gas are measured in *standard cubic feet*, which correspond to 16C and 14.73 psia. One standard cubic foot of natural gas produces around 1,028 British Thermal Units (BTU). The actual heating value, when the water formed does not condense, is the net heat of combustion and can be as much as 10% less.

In the United States, retail sales are often in units of therms; 1 therm = 100,000 BTU. Gas meters measure the volume of gas used, and this is converted to therms by multiplying the volume by the energy content of the gas used during that period, which varies slightly over time. Wholesale transactions are generally done in million deca-therms (MMDth). A million deca-therms is roughly a billion cubic feet of natural gas.

The energy content of natural gas can be expressed on a higher heating value or lower heating value basis. Higher heating value includes the heat of vaporization of water formed as a product of combustion, whereas lower heating value does not.

The quantity known as *higher heating value* (HHV) is determined by bringing all the products of combustion back to the original pre-combustion temperature, and in particular condensing any vapor produced. In other words, HHV assumes all the water component is in liquid state at the end of combustion.

The quantity known as *lower heating value* (LHV) is determined by subtracting the heat of vaporization of the water vapor from the higher heating value. This treats any H_2O formed as a vapor and, therefore, the energy required to vaporize the water therefore is not realized as heat. LHV calculations assume that the water component of a combustion process is in vapor state at the end of combustion, as opposed to the higher heating value (HHV) which that assumes all of the water in a combustion process is in a liquid state after a combustion process.

The fact that natural gas, or natural gas fired equipment, can be quoted on either a HHV or an LHV basis is a source of endless confusion in the industry. While it is customary for manufacturers to rate equipment on a lower heating value basis, fuel is generally purchased on the basis of higher heating value. There is an approximately 10% difference in values between HHV and LHV.

Natural Gas Resources

There is an abundance of natural gas in North America, but it is a non-renewable resource, the formation of which takes thousands and possibly millions of years. Therefore, understanding the availability of our supply of natural gas is important as we increase our use of this fossil fuel.

A common misconception about natural gas is that we are running out, which is not true. In fact, there is a vast amount of natural gas estimated to still be in the ground.

Fossil natural gas can be *associated* (found in oil fields) or *non-associated* (isolated in natural gas fields), and is also found in coal beds and is called coalbed methane. It sometimes contains significant quantities of ethane, propane, butane, and pentane—heavier hydrocarbons removed prior to use as a consumer fuel—as well as carbon dioxide, nitrogen, helium and hydrogen sulfide.

Natural gas is commercially produced from oil fields and natural gas fields. Gas produced from oil wells is also called “casinghead gas”. The natural gas industry is producing gas from increasingly more challenging resource types: sour gas, tight gas, shale gas and coalbed methane.

Before we go too far in defining natural gas resources, we need to define a few terms used in the industry.

Conventional and Unconventional Natural Gas

Conventional natural gas exists in the earth, trapped in reservoirs. Historically, conventional natural gas deposits have been the most practical and easiest deposits to mine. *Unconventional natural gas* does not exist in these conventional reservoirs - rather, this natural gas takes another form, or is present in a peculiar formation that makes its extraction quite different from conventional resources. Unconventional natural gas is gas that is generally considered more difficult or less economical to extract, usually because the technology to reach it has not been developed fully, or is too expensive. Examples of unconventional gas include deep gas, tight gas, shale gas, coalbed methane, geopressurized zones, and methane hydrates. Let’s look at each of these briefly.

Deep natural gas is exactly what it sounds like - natural gas that exists in deposits very far underground, beyond 'conventional' drilling depths. This gas is typically 15,000 feet or deeper underground, quite a bit deeper than conventional gas deposits, which are traditionally only a few thousand feet deep at most.

Tight Gas is gas that is stuck in a very tight formation underground, trapped in unusually impermeable, hard rock, or in a sandstone or limestone formation that is unusually impermeable and non-porous (i.e., tight sand).

Shale Gas exists in shale deposits, which formed 350 million of years ago. Shale is a very fine-grained sedimentary rock, which is easily breakable into thin, parallel layers. Shale represents a large and growing share of the United States recoverable resource base. We'll discuss shale gas in more detail a little later.

Coalbed methane is formed underground under similar geologic conditions as natural gas and oil. These coal deposits are commonly found as seams that run underground, and are mined by digging into the seam and removing the coal. Many coal seams also contain natural gas, either within the seam itself or the surrounding rock. This coalbed methane is trapped underground, and is generally not released into the atmosphere until coal mining activities unleash it.

Geopressurized zones are natural underground formations that are under unusually high pressure for their depth. These areas are formed by layers of clay that are deposited and compacted very quickly on top of more porous, absorbent material such as sand or silt. Water and natural gas that are present in this clay are squeezed out by the rapid compression of the clay, and enter the more porous sand or silt deposits. The natural gas, due to the compression of the clay, is deposited in this sand or silt under very high pressure (hence the term 'geopressure'). In addition to having these properties, geopressurized zones are typically located at great depths, usually 10,000-25,000 feet below the surface of the earth. The combination of all these factors makes the extraction of natural gas in geopressurized zones quite complicated.

Methane hydrates are the most recent form of unconventional natural gas to be discovered and researched. These interesting formations are made up of a lattice of frozen water, which forms a sort of 'cage' around molecules of methane. These hydrates look like melting snow and were first discovered in permafrost regions of the Arctic. However, research into methane hydrates has revealed that they may be much more plentiful than first expected. Estimates range anywhere from 7,000 trillion cubic feet (Tcf) to over 73,000 Tcf. In fact, the USGS estimates that methane hydrates may contain more organic carbon than the world's coal, oil, and conventional natural gas - combined.

Unconventional natural gas, despite existing in non-traditional forms, is usually included in estimations of the amount of natural gas available for use. To further confuse the definitions, as unconventional gas resources become economical to recover, they are often re-classified as conventional gas. For example, shale gas is considered unconventional gas, but because of the new technology to access shale gas it will likely become known as a conventional gas resource.

Discovered and Undiscovered Technically Recoverable Resources

Recoverable resources are the subset of the total resource base that is thought to be technically recoverable; the technology exists to make its extraction possible. This subset is further divided into discovered and undiscovered resources. *Discovered recoverable resources* are those in a known location. That is, those reservoirs that geologist have actually located through exploration. Discovered recoverable resources include current production, all past production, as well as the gas that is remaining to be produced.

Undiscovered resources are those deposits that have not been pinpointed, but are generally expected to exist based on geologic conditions. Geologists know, or at least have a good idea, that these natural gas reservoirs exist, although they are not able to pinpoint a specific location for a reservoir. In the U.S., the Department of the Interior and the U.S. Geological Survey (USGS) are responsible for estimating how much undiscovered recoverable natural gas there is in onshore areas and State governed offshore areas of the United States. Conversely, the Minerals Management Service, an agency with the Department of Interior, is responsible for estimating the undiscovered natural gas in Federal offshore areas. Each of these departments uses slightly different definitions, and terminology, when measuring and referring to undiscovered resources. However, as a general estimate, most agree that there is at least as much technically recoverable natural gas remaining to be found in the earth than has already been located to date.

Economically Recoverable Resources

Economically recoverable resources are those natural gas resources for which there are economic incentives for production; that is, the cost of extracting those resources is low enough to allow natural gas companies to generate an adequate financial return given current market conditions. However, it is important to note that economically unrecoverable resources may, at some time in the future, become recoverable, as soon as the technology to produce them becomes less expensive, or the characteristics of the natural gas market are such that companies can ensure a fair return on their investment by extracting this gas.

Those resources that have been discovered, and for which a specific reservoir location is known, can further be broken down into those resources that are economically recoverable, and those that are *economically unrecoverable*. This differs from technically unrecoverable resources, in that the technology exists (or is foreseeable in the near future) to get economically unrecoverable resources from the ground, but the economics do not exist to make the production of this natural gas profitable.

Reserves

Those discovered, technically and economically recoverable resources are further broken down into different types of *reserves*. Organizations measure reserves for their own use and for outside publication, often using different measuring and estimation techniques for the different types of reserves. However, in general, reserves can be broken down into two main categories - proved reserves, and other reserves.

Proved reserves are those reserves that geological and engineering data indicate with reasonable certainty to be recoverable today, or in the near future, with current technology and under current economic conditions. According to the Energy Information Administration (EIA, 'reasonable certainty' implies that there is a 90 percent probability that the natural gas actually recovered from those reserves will exceed the amount that is estimated beforehand to be recoverable.

The EIA further divides proved reserves into non-producing and producing reserves. *Producing proved reserves* are those reservoirs that are currently being produced, that is, natural gas is currently being extracted. These are probably the most certain of the estimates, as characteristics of the reserves become more apparent once a well is actually drilled, and natural gas is extracted. *Proved non-producing reserves* are further broken down into proved undeveloped reserves, and proved developed non-producing reserves. Of these two categories, *proved developed non-producing reserves* are more accurate. This means that pre-production work has been done on the reservoir and a well may have been drilled to prepare for natural gas extraction, but as of yet no natural gas has been produced. *Proved undeveloped reserves* are those where no well has been drilled, but for which there is still relative certainty surrounding the amount of natural gas they contain.

Other Reserves

Other reserves are those that are less well known than proved reserves. This classification goes by many names and it is also called probable reserves, possible reserves, indicated reserves, or inferred reserves. Because the quantity and characteristics of these reserves are less well known, the extraction of this natural gas is not completely assured, although there is a relatively high probability that they will be recoverable.

It is important to note that different methodologies and systems of classification are used in the various estimates. There is no single way that every industry player uses to quantify estimates of natural gas. Therefore, it is important to delve into the assumptions and methodology behind each study to gain a complete understanding of the estimate itself.

It is tempting to believe that the proved reserves would be the most accurate indicator of available gas. This might not be true however because the gas companies have economic incentives to not overstate these 'on the books' estimations of their reserves as this classification carries with it a high degree of certainty. In order to not overstate the actual amount of natural gas, many companies list a high percentage of their reserves as unproven. It follows then that most of the natural gas that exists in the United States does not fall under the proven reserves classification. It may be misleading, then, to look only at levels of proved reserves as an indication of how much natural gas there really is. Instead, the entire supply picture should be examined, including conventional and unconventional natural gas, discovered and undiscovered, and economically recoverable or unrecoverable.

There are a myriad of different industry participants that formulate their own estimates regarding natural gas supplies, such as production companies, independent geologists, the government and environmental groups, to name a few. While this leads to a wealth of information, it also leads to a number of difficulties. Each estimate is based on a different set of assumptions, completed with different tools, and even referred to with different language. It is thus difficult to get a definitive answer to the question of how much natural gas exists. In addition, since these are all essentially educated guesses as to the amount of natural gas in the earth, there are constant revisions being made. New technology, combined with increased knowledge of particular areas and reservoirs mean that these estimates are in a constant state of flux. Further complicating the scenario is the fact that there are no universally accepted definitions for the terms that are used differently by geologists, engineers, accountants, and others.

With this confusing array of definitions, let's look at the estimates of natural gas available. The Energy Information Administration (EIA) estimates that there are 2,587 trillion cubic feet (Tcf) of technically recoverable natural gas in the United States. This includes undiscovered, unproved, and unconventional natural gas. Others have estimated the total US reserves at 1,800 – 2,000 Tcf, with the difference being how the reserves are calculated.

Proved world natural gas reserves are estimated to be around 5,210 Tcf. As can be seen from the graph in Figure 1, most of these reserves are located in the countries that make up the former USSR as well as the Middle Eastern countries, such as Iran, Qatar, Saudi Arabia, UAE, and Iraq. The United States contains only about 4% of the world's proven gas reserves.

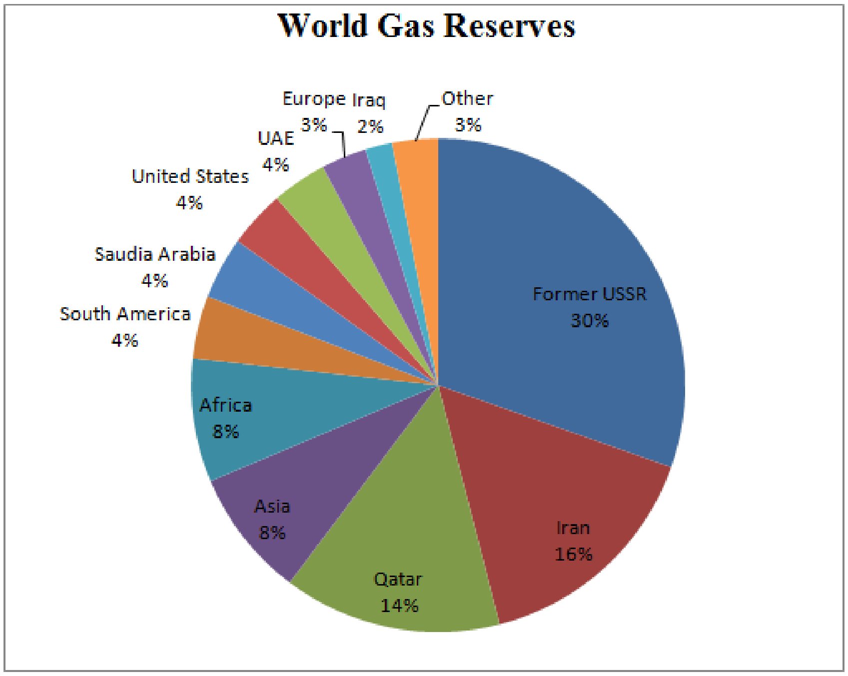
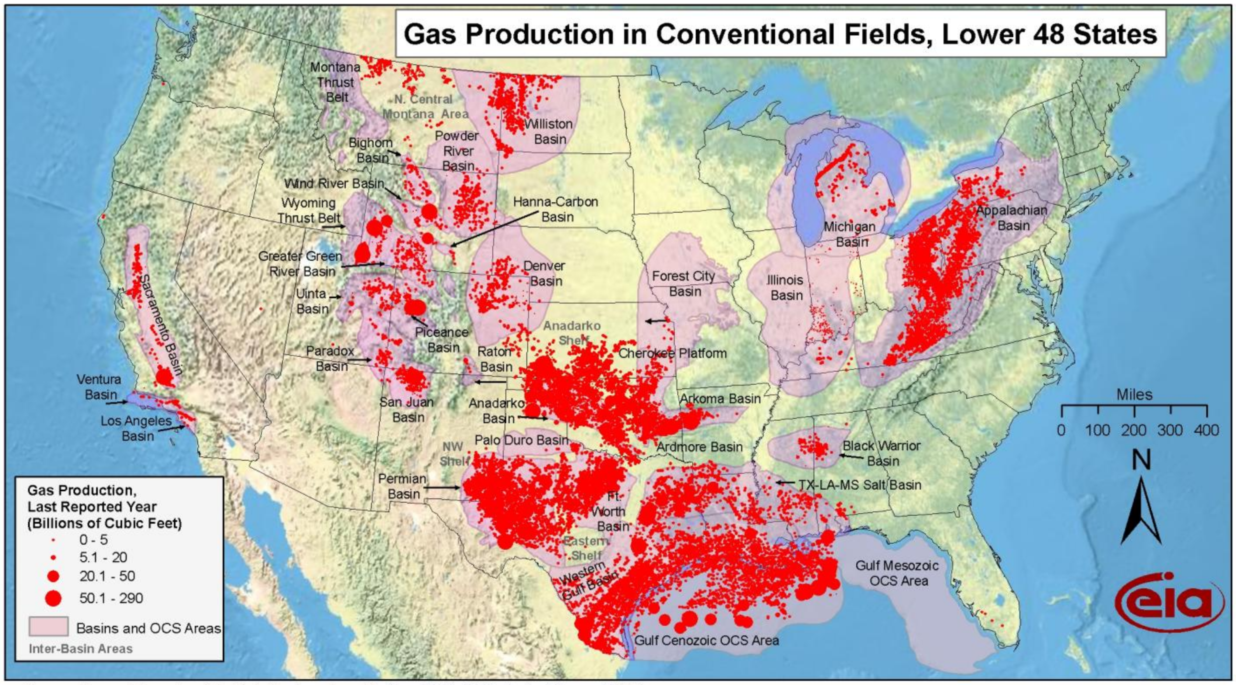


Figure 1

United States Natural Gas Fields

Most of the natural gas that is found in North America is concentrated in relatively distinct geographical areas, or basins. Given this distribution of natural gas deposits, those states that are located on top of a major basin have the highest level of natural gas reserves. As can be seen on the map in Figure 2 below, the U.S. natural gas reserves historically have been concentrated around Texas and the Gulf of Mexico.



Source: Energy Information Administration based on data from HPDI, IN Geological Survey, USGS
Updated: April 8, 2009

Figure 2

Off shore production on natural gas is primarily located in the Gulf of Mexico, with some off the coast of California, as shown is Figure 3 below.

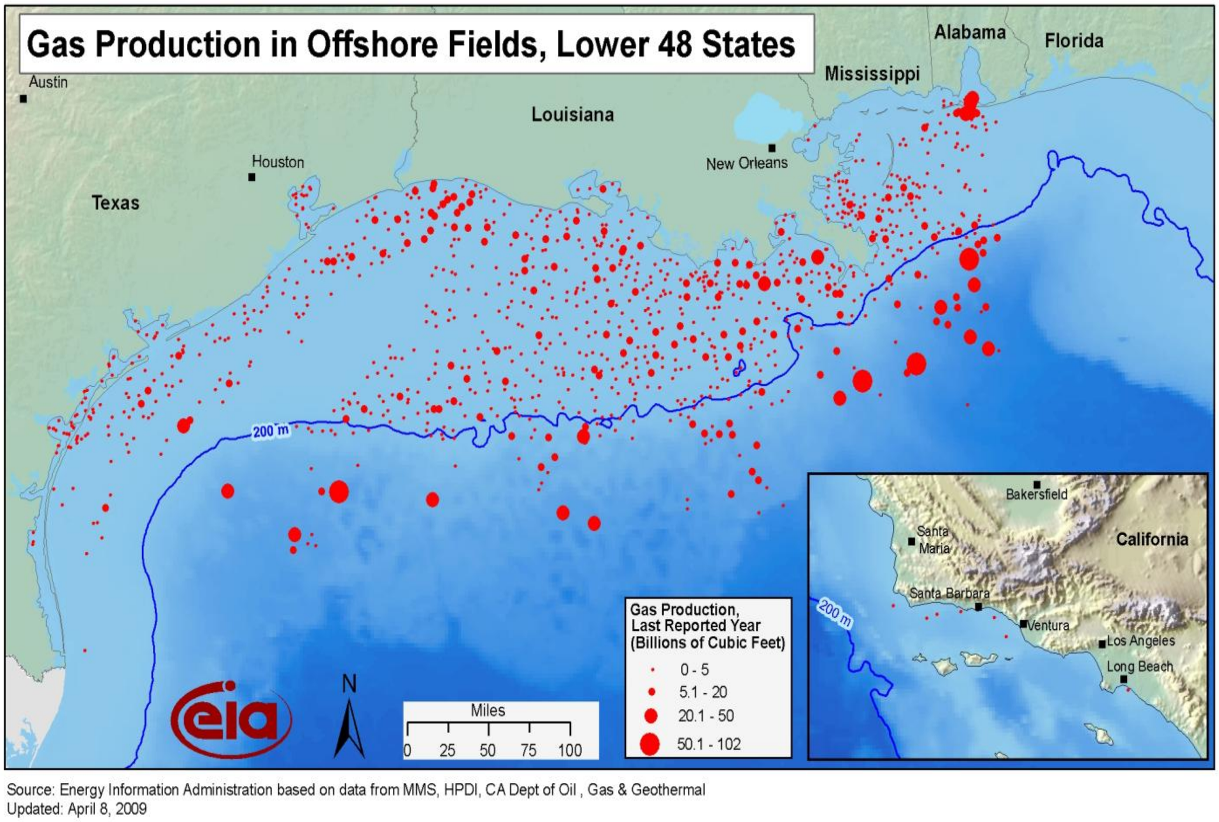


Figure 3

Shale Gas

As previously mentioned, gas shales are fine grained, organic-rich, sedimentary rock formations that trap natural gas. Gas shale rock has characteristically small pores that are relatively impermeable to natural gas flow unless they are naturally or artificially fractured to create channels connecting the pores. Shale rock is considered so impermeable that geologists sometimes say it makes marble feel "spongy" in comparison.

Shale gas is present across much of North America in basins of both extreme and moderate size. Currently most shale development in the United States is concentrated in the Marcellus (Appalachia), Barnett (Texas), Haynesville (Louisiana), Fayetteville (Arkansas), and Woodford (Oklahoma) shale plays. As of 2010, there are at least 22 major shale plays in the U.S., spread diversely over more than 20 states. See Figure 4 below.

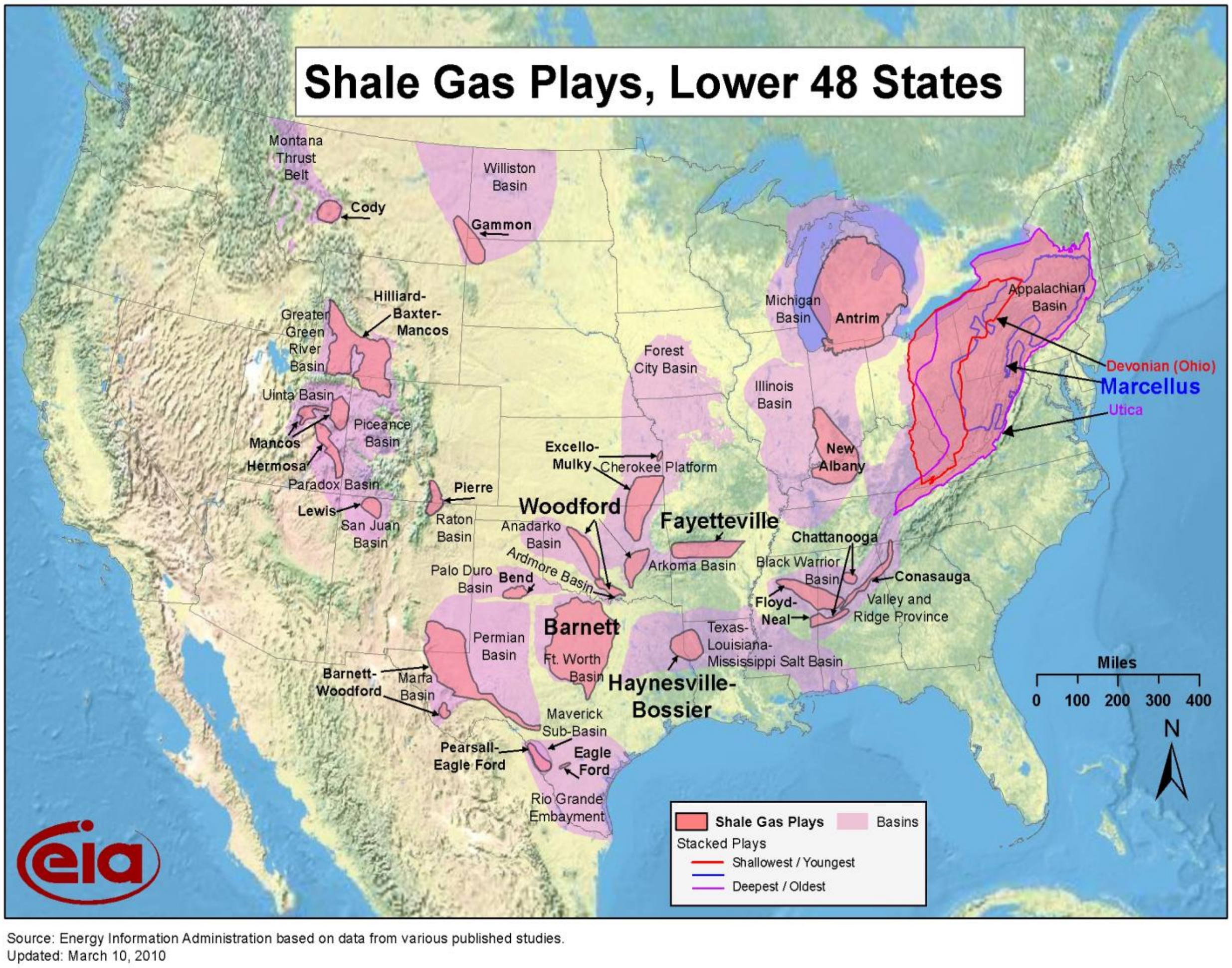


Figure 4

Geologists have known of the presence of natural gas in shale rock for years, but until recently, could not cost-effectively extract it. Two factors came together in recent years to make shale gas production economically viable:

(1) Advances in horizontal drilling; and
(2) Advances in hydraulic fracturing.

Together, these factors have transformed shale formations from marginal sources of natural gas to substantial contributors to the natural gas supply portfolio, ushering in a robust resurgence in domestic natural gas production. Looking at Figure 5, we can see that shale gas will likely play a prominent role in new natural gas deliveries in the future. From this chart we see that shale gas, which was only 14% of gas production in 2009, may compromise up to 45% of the natural gas production in the United States by 2035.

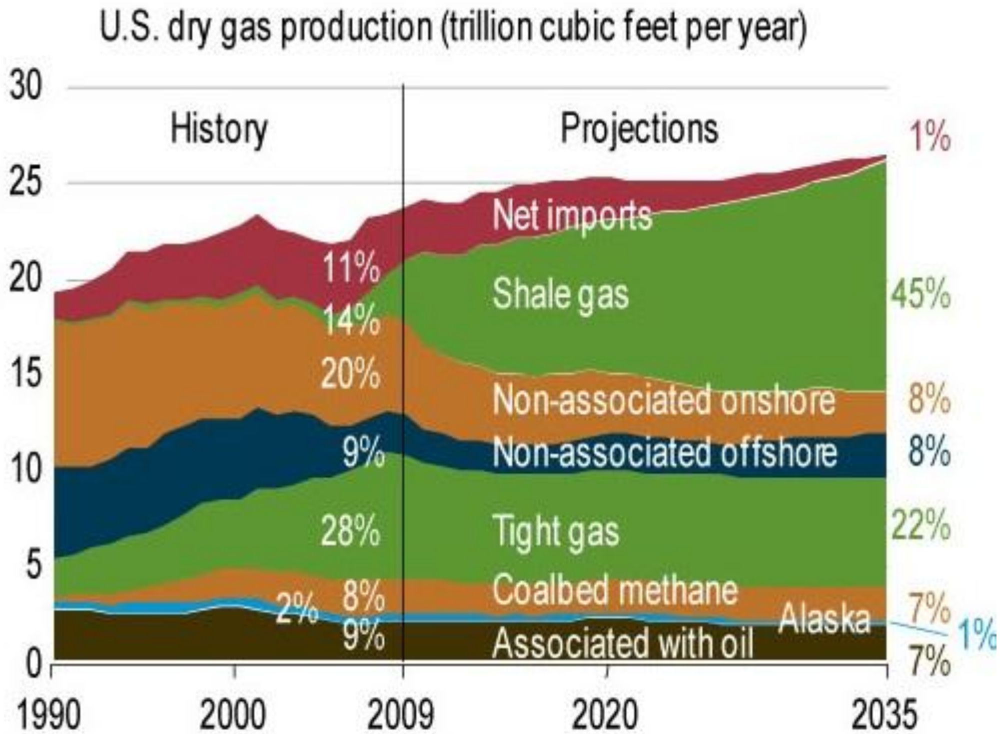


Figure 5

With the onset of shale gas development, production has been diversified across the country and supply is closer to various demand centers. For example, the Marcellus Shale basin covers portions of New York, Pennsylvania, West Virginia and Ohio. As a result, supply is less susceptible to weather disruptions in the Gulf of Mexico. The geographic diversity of U.S. shale gas resources and advances in technology helps ensure a stable and deliverable natural gas supply.

Biogas

Another developing form of natural gas is from *Biogas*. When methane-rich gases are produced by the anaerobic decay of non-fossil organic matter (biomass), these are referred to as biogas. Sources of biogas include swamps, marshes, and landfill, as well as sewage sludge and manure by way of anaerobic digesters, in addition to enteric fermentation particularly in cattle.

Methane released directly into the atmosphere would be considered a pollutant. However, methane in the atmosphere is oxidized, producing carbon dioxide and water. Methane in the atmosphere has a half life of seven years, meaning that every seven years, half of the methane present is converted to carbon dioxide and water.

Other sources of methane, the principal component of natural gas, include landfill gas, biogas and methane hydrate. Biogas, and especially landfill gas, is already used in some areas, but their use could be greatly expanded. Landfill gas is a type of biogas, but biogas usually refers to gas produced from organic material that has not been mixed with other waste.

Landfill gas is created from the decomposition of waste in landfills. If the gas is not removed, the pressure may get so high that it works its way to the surface, causing damage to the landfill structure, unpleasant odor, vegetation die-off and an explosion hazard. The gas can be vented to the atmosphere, flared or burned to produce electricity or heat.

Once water vapor is removed, about half of landfill gas is methane. Almost all of the rest is carbon dioxide, but there are also small amounts of nitrogen, oxygen and hydrogen. There are usually trace amounts of hydrogen sulfide and siloxanes, but their concentration varies widely. Landfill gas cannot be distributed through utility natural gas pipelines unless it is cleaned up to less than 3% CO_2, and a few parts per million H_2S, because CO_2 and H_2S corrode the pipelines. It is usually more economical to combust the gas on site or within a short distance of the landfill using a dedicated pipeline. Water vapor is often removed, even if the gas is combusted on site. If low temperatures condense water out of the gas, siloxanes can be lowered as well because they tend to condense out with the water vapor. Other non-methane components may also be removed in order to meet emission standards, to prevent fouling of the equipment or for environmental considerations. Co-firing landfill gas with natural gas improves combustion, which lowers emissions.

Biogas is usually produced using agricultural waste materials, such as otherwise unusable parts of plants and manure. Biogas can also be produced by separating organic materials from waste that otherwise goes to landfills. Such method is more efficient than just capturing the landfill gas it produces. Using materials that would otherwise generate no income, or even cost money to get rid of, improves the profitability and energy balance of biogas production.

Mining

Although there are several ways that methane, and thus natural gas, may be formed, it is usually found underneath the surface of the earth. As natural gas has a low density, once formed it will rise toward the surface of the earth through loose, shale type rock and other material. Some of this methane will simply rise to the surface and dissipate into the air. However, a great deal of this methane will rise up into geological formations that 'trap' the gas under the ground. These formations are made up of layers of porous, sedimentary rock (kind of like a sponge that soaks up and contains the gas), with a denser, impermeable layer of rock on top.

This impermeable rock traps the natural gas under the ground. If these formations are large enough, they can trap a great deal of natural gas underground, in what is known as a reservoir. There are a number of different types of these formations, but the most common is created when the impermeable sedimentary rock forms a 'dome' shape, like an umbrella that catches all of the natural gas that is floating to the surface.

There are a number of ways that this sort of 'dome' may be formed. For instance, faults are a common location for oil and natural gas deposits to exist. A fault occurs when the normal sedimentary layers 'split' vertically, so that impermeable rock shifts down to trap natural gas in the more permeable limestone or sandstone layers. Essentially, the geological formation, which layers impermeable rock over more porous, oil and gas rich sediment, has the potential to form a reservoir. To successfully bring these fossil fuels to the surface, a hole must be drilled through the impermeable rock to release the fossil fuels under pressure. Note that in reservoirs that contain oil and gas, the gas, being the least dense, is found closest to the surface, with the oil beneath it, typical followed by a certain amount of water. With natural gas trapped under the earth in this fashion, it can be recovered by drilling a hole through the impermeable rock. Gas in these reservoirs is typically under pressure, allowing it to escape from the reservoir on its own.

Storage and transport

Because of low density, it is not easy to transport or store natural gas. Many existing pipelines in North America are close to reaching their capacity. Natural gas is often stored underground inside depleted gas reservoirs from previous gas wells, salt domes, or in tanks as liquefied natural gas. The gas is injected in a time of low demand and extracted when demand picks up. Storage nearby end users helps to meet volatile demands, but such storage may not always be practicable.

One solution for the difficulty in transporting natural gas is to convert it into a liquid. Cooling natural gas to about -260°F at normal pressure results in the condensation of the gas into liquid form, known as *Liquefied Natural Gas* (LNG). LNG can be very useful, particularly for the transportation of natural gas, since LNG takes up about1/600th the volume of gaseous natural gas. While LNG is reasonably costly to produce, advances in technology are reducing the costs associated with the liquification and regasification of LNG. Because it is easy to transport, LNG can serve to make economical those stranded natural gas deposits for which the construction of pipelines is uneconomical.

LNG, when vaporized to gaseous form, will only burn in concentrations of between 5 and 15 percent mixed with air. In addition, LNG, or any vapor associated with LNG, will not explode in an unconfined environment. Thus, in the unlikely event of an LNG spill, the natural gas has little chance of igniting an explosion. *Liquificatio*n also has the advantage of removing oxygen, carbon dioxide, sulfur, and water from the natural gas, resulting in LNG that is almost pure methane.

The increased use of LNG is allowing for the production and marketing of natural gas deposits that were previously economically unrecoverable. Although it currently accounts for only about one percent of natural gas used in the United States, it is expected that LNG imports will provide a steady, dependable source of natural gas for U.S. consumption. According to the EIA, the U.S. imported 0.17 Tcf of natural gas in the form of LNG in 2002. LNG imports are expected to increase at an average annual rate of 15.8 percent, to levels of 4.80 Tcf of natural gas by 2025.

LNG is typically transported by specialized tanker with insulated walls, and is kept in liquid form by auto-refrigeration, a process in which the LNG is kept at its boiling point, so that any heat additions are countered by the energy lost from LNG vapor that is vented out of storage and used to power the vessel.

LNG that is imported to the United States comes via ocean tanker. The U.S. gets a majority of its LNG from Trinidad and Tobago, Qatar, and Algeria, and also receives shipments from Nigeria, Oman, Australia, Indonesia, and the United Arab Emirates. LNG carriers transport liquefied natural gas (LNG) across oceans, while tank trucks can carry liquefied or compressed natural gas (CNG) over shorter distances.

Gas is turned into liquid at a liquefaction plant, and is returned to gas form at regasification plant at the terminal. Ship borne regasification equipment is also used. LNG is the preferred form for long distance, high volume transportation of natural gas, whereas pipeline is preferred for transport for distances up to 2,500 miles over land and approximately half that distance offshore.

The ability to convert natural gas to LNG, which can be shipped on specially built ocean-going ships, provides U.S. consumers with access to vast natural gas resources worldwide. LNG is an odorless, non-toxic and non-corrosive liquid, and if spilled, LNG would not result in a slick. Absent an ignition source, LNG evaporates quickly and disperses, leaving no residue.
There is no environmental cleanup needed for LNG spills on water or land.

Liquefied natural gas (LNG) imports represent an increasingly important part of the natural gas supply picture in the United States. LNG takes up much less space than gaseous natural gas, allowing it to be shipped much more efficiently.

Chapter 2
Combustion Turbines

Historically, turbines have been developed as aero derivatives using jet propulsion engines as a design base. Some turbines have been designed specifically for stationary power generation or for compression applications in the oil and gas industries. A combustion turbine is a device in which air is compressed and a gaseous or liquid fuel is ignited. The combustion products expand directly through the blades in a turbine to drive an electric generator. The compressor and turbine usually have multiple stages and axial blading. This differentiates them from smaller microturbines that have radial blades and are single staged.

Photo Credit: DOE

A gas turbine, also called a combustion turbine, is a rotary engine that extracts energy from a flow of combustion gas. It has an upstream compressor coupled to a downstream turbine, and a combustion chamber (or burner) in-between. Gas turbine may also refer to just the turbine component. Energy is added to the gas stream in the combustor, where fuel is mixed with air and ignited. In the high pressure environment of the combustor, combustion of the fuel increases the temperature. The products of the combustion are forced into the turbine section. There, the high velocity and volume of the gas flow is directed through a nozzle over the turbine's blades, spinning the turbine which powers the compressor and, for some turbines, drives their mechanical output. The energy given up to the turbine comes from the reduction in the temperature and pressure of the exhaust gas.

Combustion Turbine Energy

2/3's Required to turn the compressor

1/3 Available for power generation

The gas turbine is an internal combustion (IC) engine employing a continuous combustion process. About two-thirds of the shaft power produced by the turbine is used to run the compressor, leaving about one-third available to turn a generator to produce electrical power.

Theory of Operation

A gas turbine that is configured and operated to closely follow the *Brayton cycle* is called a simple cycle gas turbine. The schematic in Figure 6 shows a simple diagram of a combustion turbine.

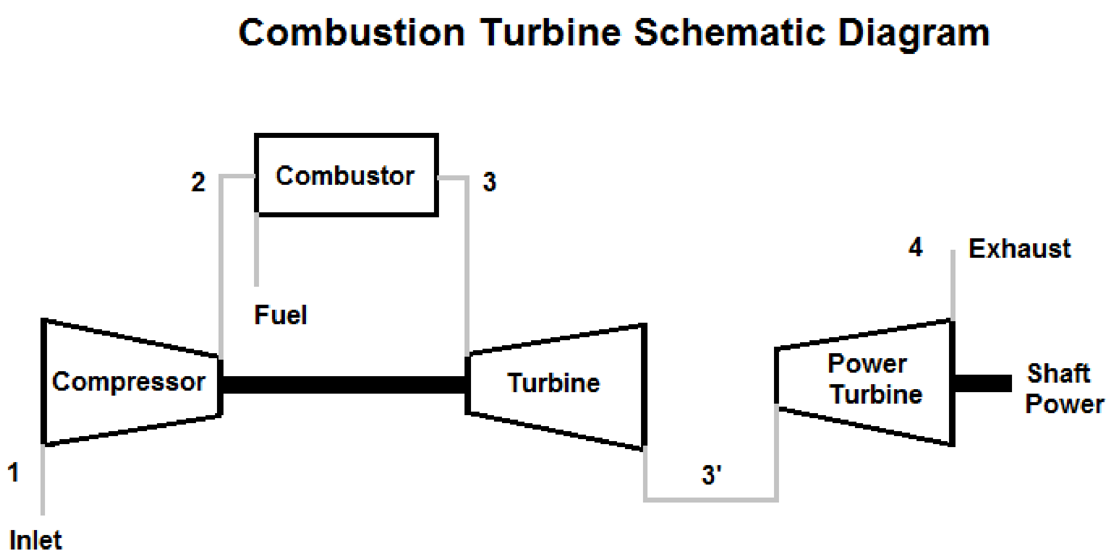


Figure 6

A cycle describes what happens to air as it passes into, through, and out of the gas turbine. The cycle usually describes the relationship between the space occupied by the air in the system (called volume, V) and the pressure (P) it is under.

The Brayton cycle, shown in graphic form in Figure 7 as a pressure-volume diagram, is a representation of the properties of a fixed amount of air as it passes through a gas turbine in operation. These same points are also shown in Figure 6.

Let’s follow the process by using the PV diagram in Figure 7.

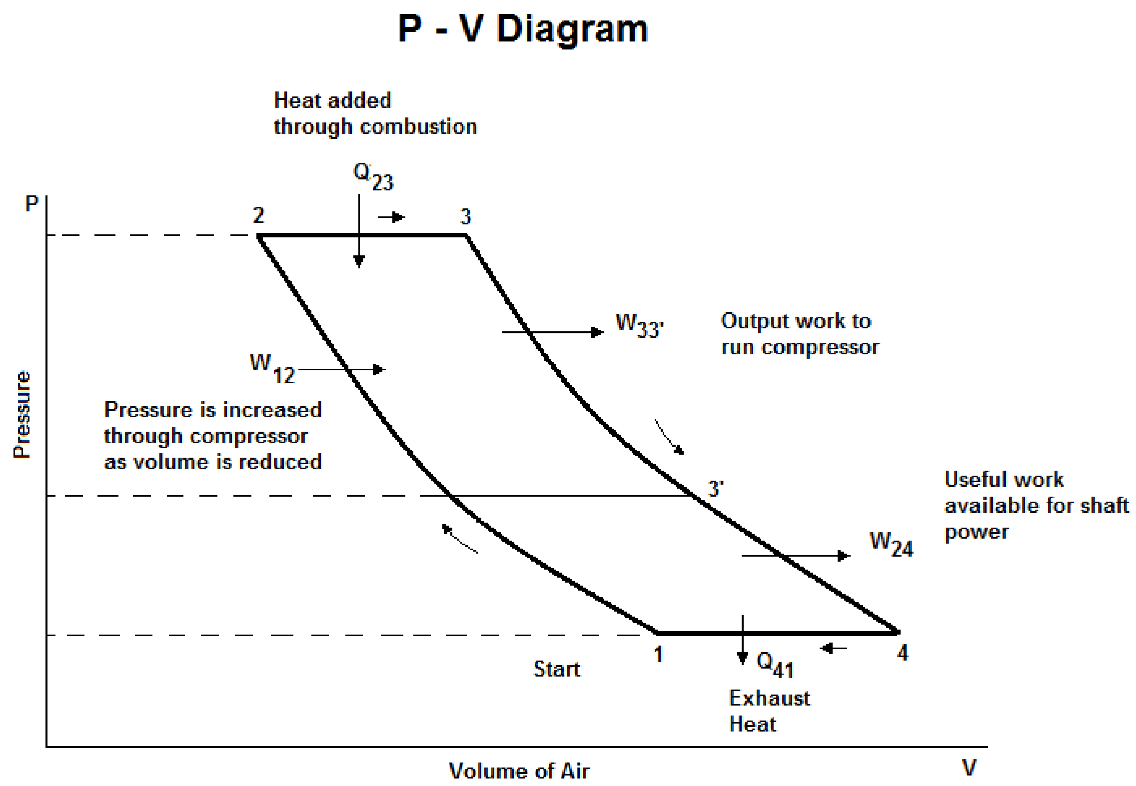


Figure 7

Air is compressed from point 1 to point 2. This increases the pressure as the volume of space occupied by the air is reduced.

The air is then heated at constant pressure from 2 to 3. This heat, denoted as Q_{23}, is added by injecting fuel into the combustor and igniting it on a continuous basis.

The hot compressed air at point 3 is then allowed to expand (from point 3 to 4) reducing the pressure and temperature and increasing its volume. In the engine, this represents flow through the turbine (the work is denoted as $W_{33'}$) to point 3' and then flow through the power turbine ($W_{3'4}$) to point 4 to turn a shaft to a generator. The Brayton cycle is completed by a process in which the volume of the air is decreased (temperature decrease) as heat is absorbed (Q_{41}) into the atmosphere.

Gasses passing through an ideal a gas turbine undergo three thermodynamic processes. These are isentropic compression, isobaric (constant pressure) combustion and isentropic expansion.

> In an **isentropic process**, the system neither absorbs nor gives off heat.

In a practical gas turbine, gasses are first accelerated in either a centrifugal or radial compressor. These gasses are then slowed using a diverging nozzle known as a diffuser; these processes increase the pressure and temperature of the flow. In an ideal system this is isentropic. However, in practice energy is lost to heat, due to friction and turbulence. Gasses then pass from the diffuser to a combustion chamber, where heat is added. In an ideal system this occurs at constant pressure (isobaric heat addition). As there is no change in pressure the specific volume of the gasses increases. In practical situations this process is usually accompanied by a slight loss in pressure, due to friction. Finally, this larger volume of gasses is expanded and accelerated by nozzle guide vanes before energy is extracted by a turbine. In an ideal system these are gasses expanded and leave the turbine at their original pressure. In practice this process energy is lost to both friction and turbulence.

If the device has been designed to power to a shaft as with an electrical generator the exit pressure will be as close to the entry pressure as possible. In practice it is necessary that some pressure remains at the outlet in order to fully expel the exhaust gasses.

Combustion Turbine Configurations

Additional equipment can be added to the simple cycle gas turbine, leading to increases in efficiency and/or the output of a unit. Three such modifications are regeneration, intercooling and reheating.

Regeneration involves the installation of a heat exchanger (recuperator) through which the turbine exhaust gases pass. The compressed air is then heated in the exhaust gas heat exchanger, before the flow enters the combustor. Figure 8 shows the simple cycle gas turbine with regeneration.

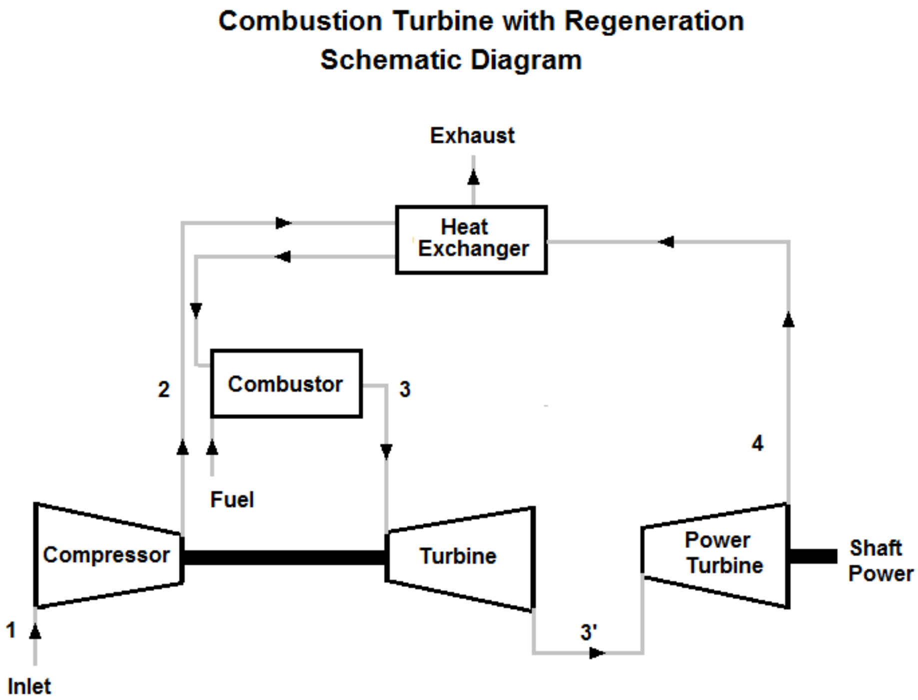


Figure 8

If the regenerator is well designed (i.e., the heat exchanger effectiveness is high and the pressure drops are small) the efficiency will be increased over the simple cycle value. However, the relatively high cost of such a regenerator must also be taken into account. Regenerated gas turbines increase efficiency 5-6% and are even more effective in improving part-load applications.

Intercooling also involves the use of a heat exchanger. An intercooler is a heat exchanger that cools compressor gas during the compression process. For instance, if the compressor consists of a high and a low pressure unit, the intercooler could be mounted between them to cool the flow and decrease the work necessary for compression in the high pressure compressor. The cooling fluid could be atmospheric air or water. The effect of an intercooler is a slight increase in the output of the gas turbine.

Figure 9 shows the simple cycle gas turbine with intercooling.

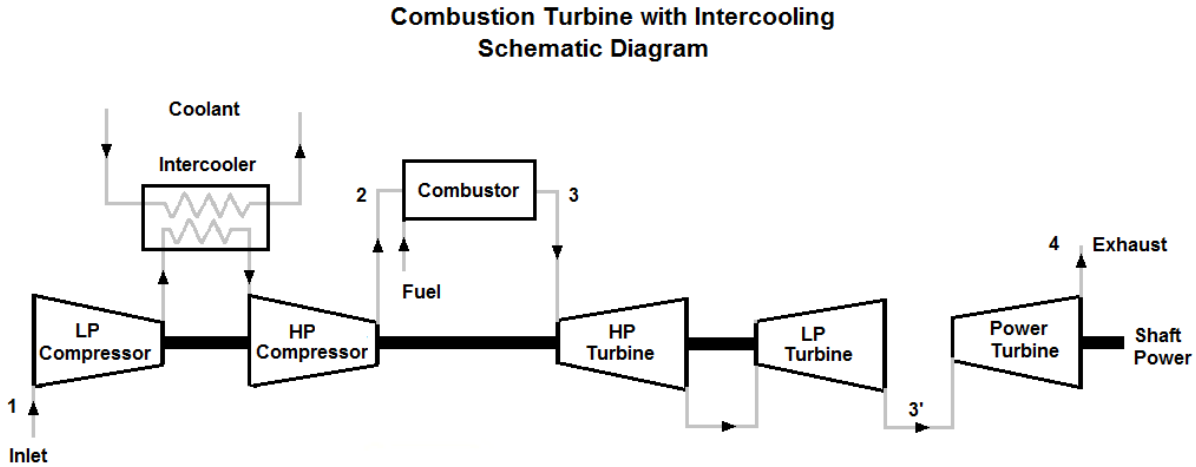


Figure 9

Reheating is a way to increase turbine work without changing compressor work or melting the materials from which the turbine is constructed. If a gas turbine has a high pressure and a low pressure turbine at the back end of the machine, a reheater (usually another combustor) can be used to "reheat" the flow between the two turbines. This can increase efficiency by 1-3%.

An example of reheating is the afterburner in a jet engine. Reheat in a jet engine is accomplished by adding an afterburner at the turbine exhaust, thereby increasing thrust, at the expense of a greatly increased fuel consumption rate. Figure 10 shows the simple cycle gas turbine with reheating.

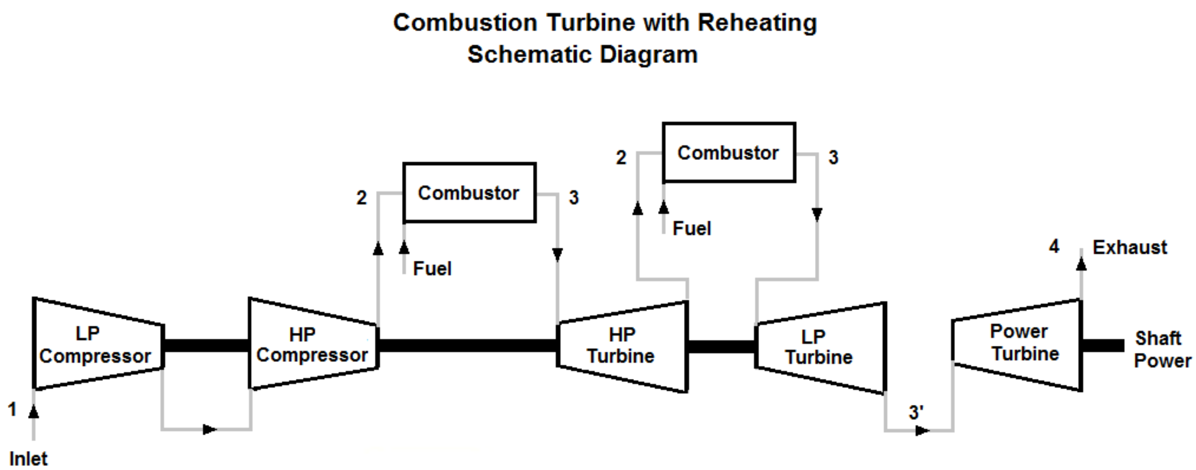


Figure 10

Efficiency

Turbine efficiency and total capacity is highly variable with the inlet air temperature and local altitude/atmospheric conditions. Turbine capacity can fluctuate as must as 20% from summer (the lowest) to winter (the highest output time), due to cold, denser air. Combustion turbines without heat recovery are likely to have heat rates in the 15,000 BTU/kWh range, which is much higher than coal-fired steam plants and combined cycle plants.

Simple cycle turbines have efficiencies generally in the range of 20 - 45%. Heavy frame turbines have slightly lower efficiencies (20 - 35%) than the aero derivative turbines (25 - 45%). While several factors influence efficiency, it generally scales proportionately with size; the larger the turbine the higher the efficiency. Single or simple cycle turbines have an efficiency of 25% for smaller, un-recuperated units to 45% for larger units with recuperators. The standard measurement is called the Heat Rate, or the BTUs input to make one kWh of electric output.

To estimate efficiency based on the Heat Rate, use the formula:

$$\text{Eff} = \frac{3413}{\text{Heat Rate}} * 100$$

Where,
Eff = Efficiency, percent.
Heat Rate = Heat Rate of the combustion turbine, BTU/kWh.

For example, with a heat rate of 11,000 BTU, the efficiency is 3,413/11,000 = 31% electrical efficiency.

To estimate total efficiency, we must add in the BTUs recoverable in the exhaust stream at the temperature and flow conditions of the application if any are used. Typical combined thermal and electric efficiency of combustion turbine plants is in the 60% range; higher if lower temperature thermal energy can be used, such as direct ducting of exhaust into a process. A duct burner can increase over-all system efficiency, as they operate at near 100% efficiency due to the high temperature of their inlet air supply.

Types of gas turbines

There are several different types of gas turbines, depending on their specific application. A few of the major types are described below.

Jet engines

Air breathing jet engines are gas turbines optimized to produce thrust from the exhaust gases, or from ducted fans connected to the gas turbines. Jet engines that produce thrust primarily from the direct impulse of exhaust gases are often called turbojets, whereas those that generate most of their thrust from the action of a ducted fan are often called turbofans.

Gas turbines are also used in many liquid propellant rockets, the gas turbines are used to power a turbo pump to permit the use of lightweight, low pressure tanks, which saves considerable dry mass.

Aero derivative gas turbines

For electric power generation, a form of jet engine is usually adapted to the application. These *Aero derivatives* are used due to their ability to startup, shut down, and handle load changes quickly.

Industrial Gas Turbines

Industrial gas turbines differ from aero derivative in that the frames, bearings, and blading is of heavier construction. Industrial gas turbines range in size from truck-mounted mobile plants to enormous, complex systems. They can be particularly efficient—up to 60%—when waste heat from the gas turbine is recovered by a heat recovery steam generator to power a conventional steam turbine in a combined cycle configuration. They can also be run in a cogeneration configuration: the exhaust is used for space or water heating, or drives an absorption chiller for cooling or refrigeration. Such engines require a dedicated enclosure, both to protect the engine from the elements and the operators from the noise.

Microturbines

Microturbines are becoming widespread for distributed power and combined heat and power applications. They are one of the most promising technologies for powering hybrid electric vehicles. They range from small units of less than a kilowatt, to commercial sized systems of several hundred kilowatts.

Part of the success of microturbines is due to advances in electronics, which allows unattended operation and interfacing with the commercial power grid. Electronic power switching technology eliminates the need for the generator to be synchronized with the power grid. This allows the generator to be integrated with the turbine shaft, and to double as the starter motor.

Microturbine designs usually consist of a single stage radial compressor, a single stage radial turbine and a recuperator. Recuperators are difficult to design and manufacture because they operate under high pressure and temperature differentials. Exhaust heat can be used for water heating, space heating, drying processes or absorption chillers, which create cold for air conditioning from heat energy instead of electric energy.

Typical microturbine efficiencies are 25 to 35%. When in a combined heat and power cogeneration system, efficiencies of greater than 80% are commonly achieved.

External combustion

Even though most gas turbines are internal combustion engines it is also possible to manufacture an external combustion gas turbine which is, effectively, a turbine version of a hot air engine. These systems are known as *Externally Fired Gas Turbines* (EFGT) or *Indirectly Fired Gas Turbines* (IFGT.)

External combustion turbines have been fired with pulverized coal or finely ground biomass as the fuel. In the indirect system, a heat exchanger is used and only clean air with no combustion products travels through the power turbine. The thermal efficiency is lower in the indirect type of external combustion, however the turbine blades are not subjected to combustion products and much lower quality fuels can be used. Indirectly fired systems are now commercially available.

Operating Cycle

Mechanically, gas turbines can be considerably less complex than internal combustion piston engines. Simple turbines might have one moving part: the shaft/compressor/turbine/alternative-rotor assembly, not counting the fuel system. However, the required precision manufacturing for components and temperature resistant alloys necessary for high efficiency often makes the construction of a simple turbine more complicated than piston engines.

As with all cyclic heat engines, higher combustion temperatures can allow for greater efficiencies. However, temperatures are limited by ability of the steel, nickel, ceramic, or other materials that make up the engine to withstand high temperatures and stresses. To combat this many turbines feature complex blade cooling systems.

As a general rule, the smaller the engine the higher the rotation rate of the shaft needs to be to maintain tip speed. Blade tip speed determines the maximum pressure ratios that can be obtained by the turbine and the compressor. This in turn limits the maximum power and efficiency that can be obtained by the engine. In order for tip speed to remain constant, if the diameter of a rotor is reduced by half, the rotational speed must double. For example large Jet engines operate around 10,000 rpm, while micro turbines spin as fast as 500,000 rpm.

Thrust bearings and journal bearings are a critical part of design. Traditionally, they have been hydrodynamic oil bearings, or oil-cooled ball bearings. These bearings are being surpassed by foil bearings, which have been successfully used in micro turbines and auxiliary power units.

Other performance related items for combustion turbines include:

- Partial load efficiencies are approximately 25% lower than full-load efficiencies.
- Start up times range from 2 to 5 minutes.
- Combustion turbines require natural gas pressure range from about 160 psig up to about 610 psig, depending on the manufacturer, type, and size of turbine.
- Most combustion turbine applications require a gas compressor which reduces the plant power output by 2 - 4%.
- Combustion turbines are rated based on standard conditions at sea level. Output and fuel consumption will decrease about 3.5% for every 1,000 feet above sea level.
- Combustion turbines are rated at a nominal temperature of 15C, and their output decreases by 0.25% per °C increase in ambient temperature.
- Heat rate increases about 0.1% for every 1C increase in turbine inlet temperature.

Let's now look at the complete operating cycle for a typical combustion turbine power plant from the air intake to the exhaust system. Please refer to Figure 11 on the next page to follow the discussion.

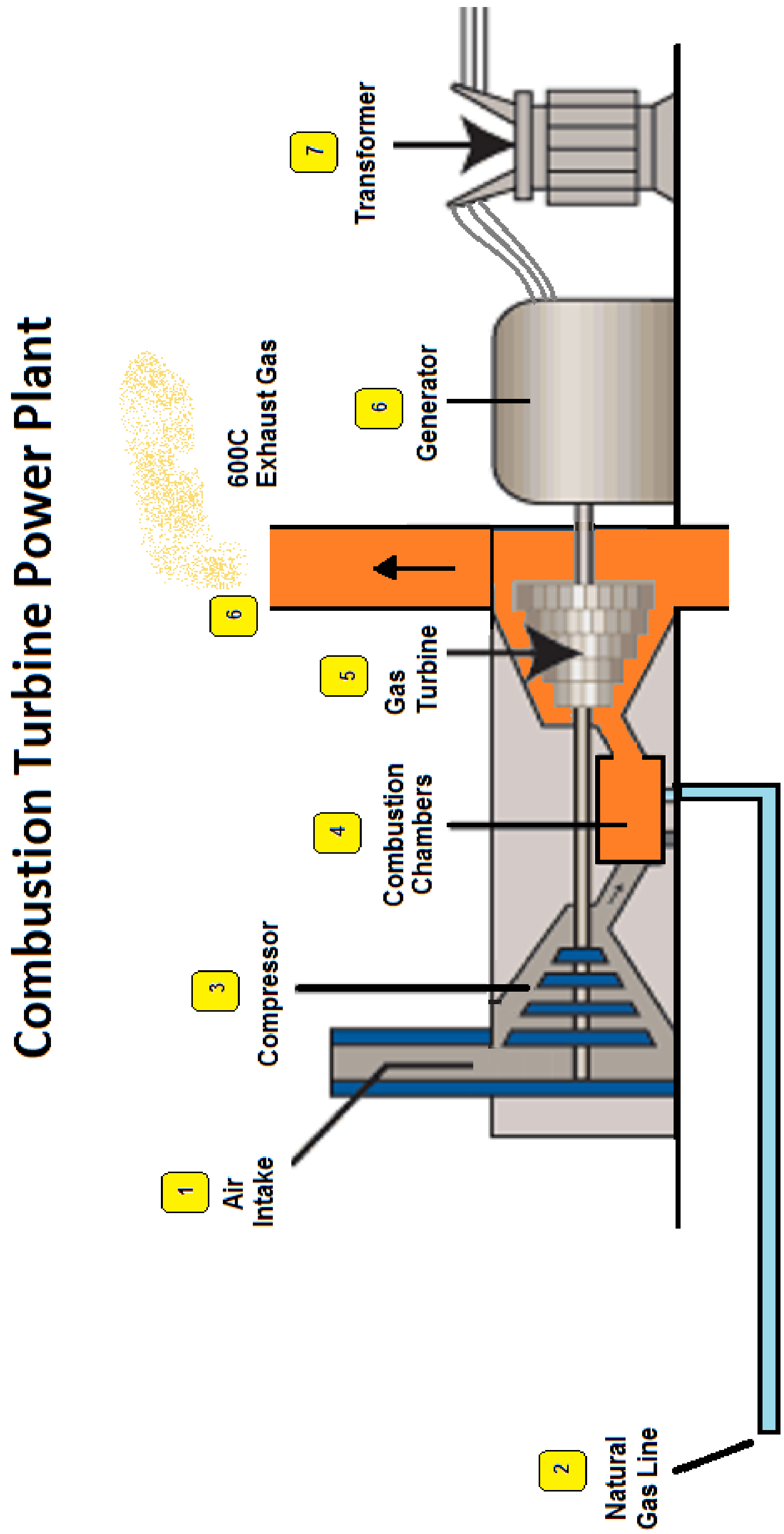

Combustion Turbine Power Plant
1
Air Intake
2
Natural Gas Line
3
Compressor
4
Combustion Chambers
5
Gas Turbine
6
600C Exhaust Gas
6
Generator
7
Transformer

Figure 11

The numbers in this section correspond to the labels on the drawing in Figure 11.

1. Air Inlet

Air is drawn though the large air inlet section where it is cleaned, cooled and controlled, in order to reduce noise.

2. Fuel

Gas turbines accept most commercial fuels, such as gasoline, natural gas, propane, diesel, and kerosene. However, when running on kerosene or diesel, they will typically be unable to start without the assistance of a more volatile product, such as propane gas. Most central station electric generation gas turbines are fueled by natural gas.

The natural gas fuel comes from a high pressure natural gas pipeline. A turbine may consume up to 2,000 MMBTU of natural gas per hour. Gas compressors pump the natural gas though the facilities' fuel gas system where it is delivered to the gas turbine. Combustion turbines require natural gas pressure range from about 160 psig up to about 610 psig, depending on the manufacturer, type, and size of turbine.

3. Compressor

Air enters the compressor where it is compressor using energy from the shaft of the gas turbine.

4. Combustor

The compressor air from the compressor than enters the combustor where it is mixed with natural gas and ignited, which causes it to expand.

5. Combustion Turbine

This expanding air then moves into the actual turbine section. The pressure created from the expansion spins the turbine blades, which are attached to a shaft and a generator, creating electricity. The combustion turbine shaft is also connected to the compressor and provides the work for the compression of the air. Items 3, 4, and 5 in this discuss are generally considered in total to be the "combustion turbine".

6. Exhaust Stack

The combustion turbine produces enormous amounts of waste heat that is vented into the atmosphere unless the unit is part of a combined cycle power plant.
The gas exhaust from the gas turbine then exits through the exhaust stack.

To control the emissions in the exhaust gas so that it remains within permitted levels as it enters the atmosphere, the exhaust gas may pass though a Selective Catalyst Convertor (SCR). There may be one catalyst to control Carbon Monoxide (CO) emissions and another catalyst to control

Nitrous Oxide (NOx) emissions. In addition to the SCR, some plants use aqueous Ammonia (a mixture of 22% ammonia and 78% water), injected into system, to even further reduce levels of NOx.

7. Generators and Transformers

The gas turbine generator produces power at relatively low voltages, typically less than 25,000 volts. Transformers are used to step the voltage up to transmission voltages of between 115,000 and 230,000 volts.

A small amount of generation is directed to *Auxiliary transformer*, which convert the generated voltage to a lower voltage, so it may be used by the plant to power pumps, fans, and motors.

Chapter 3
Environmental Issues

The primary pollutants from gas turbines are oxides of nitrogen (NOx), carbon monoxide (CO), and volatile organic compounds (VOCs). Other pollutants such as oxides of sulfur (SOx) and particulate matter (PM) are primarily dependent on the fuel used.

It is important to note that the gas turbine operating load has a significant effect on the emissions levels of the primary pollutants of NOx, CO, and VOCs. Gas turbines typically operate at high loads. Consequently, gas turbines are designed to achieve maximum efficiency and optimum combustion conditions at high loads. Controlling all pollutants simultaneously at all load conditions is difficult. At higher loads, higher NOx emissions occur due to peak flame temperatures. At lower loads, lower thermal efficiencies and more incomplete combustion occurs resulting in higher emissions of CO and VOCs.

Natural gas produces far lower amounts of sulfur dioxide (SO_2) and nitrous oxides (NO_X) than any other fossil fuel. Still NOx, along with carbon monoxide (CO) are the primary environmental concerns with natural gas-fired combustion turbines.

Nitrous Oxide (NO_X)

The principal environmental concerns associated with gas-fired turbines are emissions of nitrogen oxides (NOx) and carbon monoxide (CO). Because the turbine combustors in a gas turbine operate at very high temperatures the units produce high levels of NOx.

Nitrogen oxide abatement is accomplished by use of "dry low-NOx" combustors and a selective catalytic reduction system. Limited quantities of ammonia are released by operation of the NOx SCR system. CO emissions are typically controlled by use of an oxidation catalyst. No special controls for particulates and sulfur oxides are used since only trace amounts are produced when operating on natural gas.

Uncontrolled emission levels for combustion turbines are approximately 150 - 300 ppm NOx, but domestic regulations prevent such units from operating in the United States. Emissions of NOx are in the range of 9 to 25 ppm at 15% O_2 with new efficient combustion methods employed on new turbines. These levels can be reduced with the addition of selective catalytic reduction. Emission control systems are used to reduce NOx emissions to approximately 6 ppm for natural gas turbines. See Table 3 for NOx emissions from natural gas-fired combustion turbines.

Table 3 **NOx Emissions**	
Natural Gas Turbine	**NOx Emissions (ppmv - 15% O_2)**
Uncontrolled	150 – 300
Dry Low NOx	25
Dry Low NOx plus SCR	˜ 6

Regulations require that NOx be limited to no more than nine parts per million and modern power plants typically achieve NOx emissions of less than two parts per million.

The most common control methods for NOx is water injection to reduce combustion temperature, and Selective Catalytic Reduction (SCR) an after-treatment to remove NOx.

For environmentally sensitive applications where extremely low NOx emissions are required, selective catalytic reduction (SCR) can be readily adapted to gas turbines. SCRs require a gas temperature range lower than the gas turbine exhaust gas temperature so they are installed in a heat recovery steam generator in the appropriate zone to suit their operating temperature range.

Selective Catalytic Reduction

Selective catalytic reduction is the most common after-treatment method used to control NOx emissions from natural gas.

An SCR system consists of ammonia storage, feed, and injection system, and a catalyst and catalyst housing. Selective catalytic reduction systems selectively reduce NOx emissions by injecting ammonia (either in the form of liquid anhydrous ammonia or aqueous ammonium hydroxide) into the exhaust gas stream upstream of the catalyst. Nitrogen oxides, NH_3, and O_2 react on the surface of the catalyst to form N_2 and H_2O. For the SCR system to operate properly, the exhaust gas must be within a particular temperature range. The catalyst determines the temperature range.

Nitrogen oxide formation is strongly dependent on the high temperatures developed in the combustor. Selective catalytic reduction (SCR) systems selectively reduce NOx emissions by injecting ammonium (NH_3) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, NH_3, and O_2 react on the surface of the catalyst to form N_2 and H_2O. The exhaust gas must contain a minimum amount of O_2 and be within a particular temperature range (typically 250C to

450C) in order for the SCR system to operate properly. The temperature range is dictated by the catalyst material, which is typically made from metal oxides such as vanadium and titanium, or zeolite-based material. Exhaust gas temperatures greater than the upper limit (450C) cause NOx and NH_3 to pass through the catalyst un-reacted. Ammonia emissions, called *NH_3 slip*, may be a consideration when specifying an SCR system and are often limited by air permitting. Ammonia, either in the form of liquid anhydrous ammonia, or aqueous ammonia hydroxide is stored on site or injected into the exhaust stream upstream of the catalyst.

Sulfur Oxides (SOx)

The sulfur content of the fuel determines emissions of sulfur compounds, primarily SO_2. Gas turbines operating on de-sulfized natural gas or distillate oil emit relatively insignificant levels of SOx. In general, SOx emissions are greater when heavy oils are fired in the turbine. SOx control is thus a fuel purchasing issue rather than a gas turbine technology issue. Particulate matter is a marginally significant pollutant for gas turbines using liquid fuels. Ash and metallic additives in the fuel may contribute to particulate matter in the exhaust.

Carbon Dioxide Emissions

Carbon dioxide, a greenhouse gas, is an unavoidable product of combustion of any power generation technology using fossil fuel. The carbon dioxide production of a gas-fired combustion turbine, on a unit output basis, is much lower than that of other fossil fuel technologies. A typical power plant produces about 0.8 lb CO_2 per kilowatt-hour output, whereas new coal-fired power plants produce about 2.0 lb CO_2 per kilowatt-hour.

Natural gas is often described as the cleanest fossil fuel, producing less carbon dioxide per unit of energy delivered than either coal or oil, and far fewer pollutants than other fossil fuels. However, in absolute terms it does contribute to global carbon emissions, and this contribution is projected to grow.

From Figure 12 we see that, in 2004, natural gas produced about 5,300 Mt/yr of CO_2 emissions, while coal and oil produced 10,600 and 10,200 respectively, which means natural gas is about 20% of the total from these three sources.

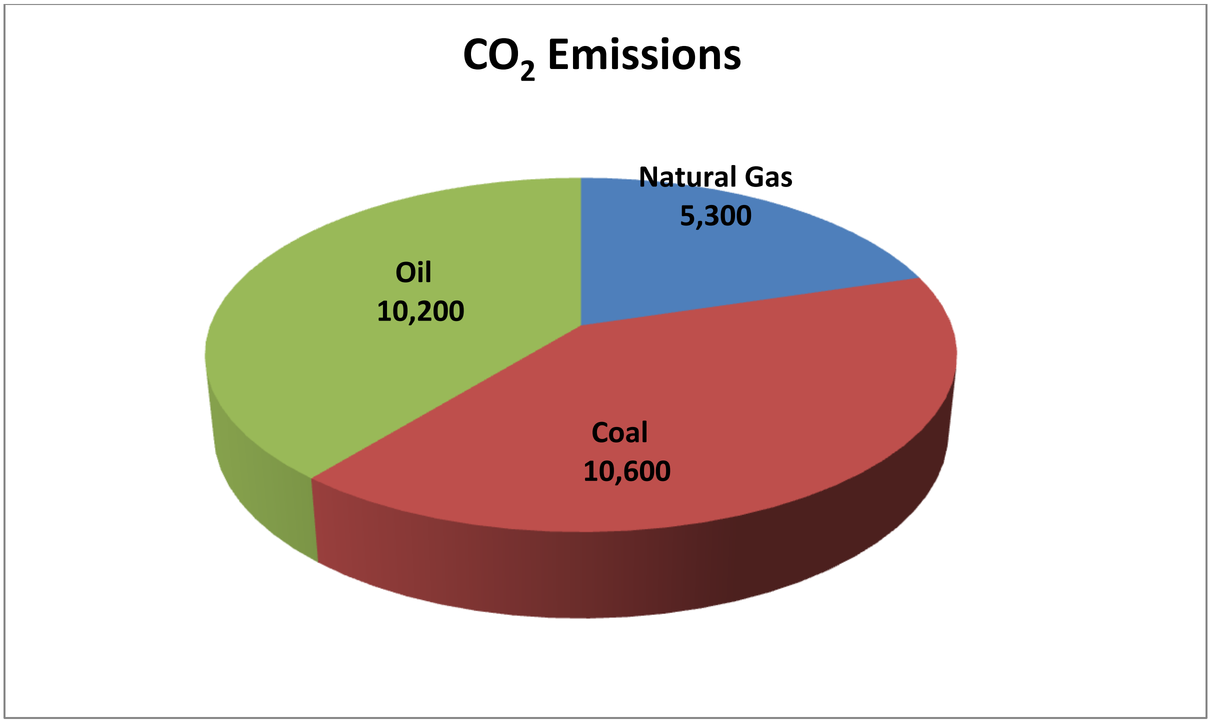


Figure 12

However, by 2030 natural gas may be the source of 11,000 Mt/yr, or 30% of the total from these three sources, compared to coal and oil at 8,400 and 17,200 respectively (see Figure 13).

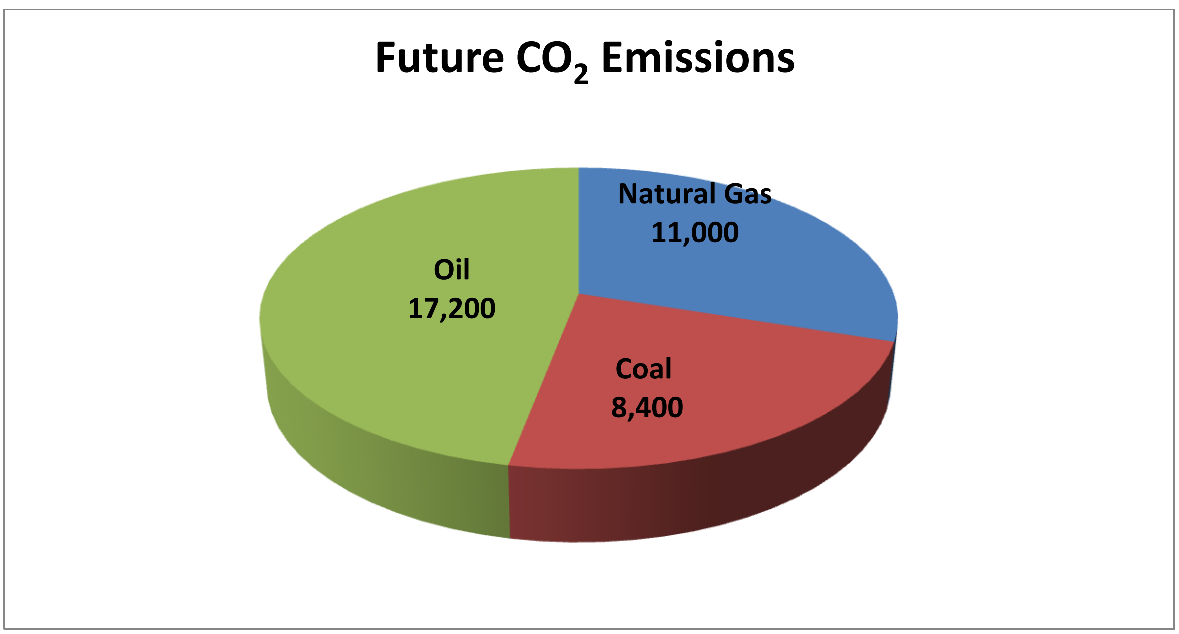


Figure 13

In addition, natural gas itself is a greenhouse gas far more potent than carbon dioxide when released into the atmosphere, although released in much smaller quantities. Natural gas is mainly composed of methane, which has a radiative forcing twenty times greater than carbon dioxide. This means one ton of methane in the atmosphere traps in as much radiation as 20 tons of carbon dioxide. Carbon dioxide still receives the lion's share of attention over greenhouse gases because it is released in much larger amounts. Still, it is inevitable in using natural gas on a large scale that some of it will leak into the atmosphere.

Summary

Natural gas is a vital fuel for maintaining America's thriving, robust economy and new natural gas resources will continue to allow natural gas to be a choice fuel for electric power generation for many years. To meet growing demand and to diversify our energy supply, the United States needs to continue to exploit the benefits of shale gas as well as bring in natural gas from overseas in the form of liquefied natural gas (LNG).

Combustion turbines offer low capital costs, quick installation, high-temperature exhaust for steam generation, and high reliability. The units suffer from high operating costs and have relatively low efficiencies compared to other central station power plants. However, when combined with a heat recovery steam generator and used in a combined cycle power plant, combustion turbines offer a major advantage for future central station electric power generation.

Proximity to natural gas mainlines and high voltage transmission is the key factor affecting the siting of new combustion turbine power plants.

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