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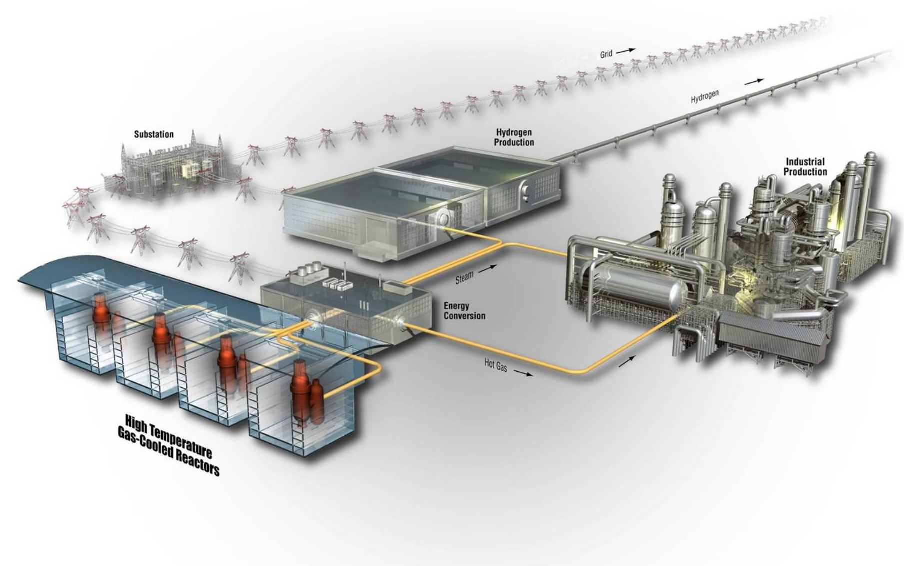
Revision 1

High Temperature Gas-Cooled Reactor Projected Markets and Preliminary Economics

August 2011



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Idaho National Laboratory
Next Generation Nuclear Plant Project
Idaho Falls, Idaho 83415

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Next Generation Nuclear Plant Project

High Temperature Gas-Cooled Reactor Projected Markets and Preliminary Economics

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August 2011

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ABSTRACT

This paper summarizes the: potential market for process heat produced by a high temperature gas-cooled reactor (HTGR), environmental benefits of reduced CO_2 emissions from the substitution of the emissions-free HTGR for traditional carbon-based energy supplies, benefits of a long term stable energy price free from the wide swings in energy pricing experienced over the last decade, and the typical economics of projects using these applications. It provides examples of HTGR technology applications to industrial processes for co-generation supply of process heat and electricity, the conversion of coal to transportation fuels and chemical process feedstock, and the production of ammonia as a feedstock for the production of ammonia derivatives, including fertilizer. It also demonstrates how uncertainties in capital costs and financial factors affect the economics of HTGR technology in the application of HTGR and high temperature steam electrolysis processes to produce hydrogen.

SUMMARY

The NGNP Project is developing and enabling the initial commercial deployment of the high temperature gas-cooled reactor (HTGR) technology to supply high temperature process heat to industrial processes as a substitute for the burning of premium fossil fuels, such as natural gas. Commercial applications for HTGR technology evaluated by the NGNP Project include electricity generation, supplying steam and high-temperature gas to a wide range of industrial processes, and the production of industrial gases (hydrogen and oxygen) for use in petrochemical, refining, coal-to-liquid fuels, chemical, and fertilizer plants. As a non-CO_2 emitting substitute for the burning of carbon fuels, the HTGR can offset significant quantities of industry-generated CO_2 emissions. The use of the HTGR technology as an energy substitute for natural gas in many of these applications and for conversion of coal to synthetic fuels and chemical process feedstock improves the security of the U.S. energy supply by reducing reliance on imports, reducing the energy price volatility that has been experienced over the last few decades (e.g., wide swings in the prices of oil, natural gas, and coal), and extending the life of nonrenewable energy resources for use within more productive and efficient applications where no current alternatives are available.

Market studies have identified a large market potential for the HTGR technology. The highest priorities include the displacement of natural gas and other hydrocarbons for process steam/electricity cogeneration applications (e.g., petrochemical production, petroleum refining, and ammonia production), enhanced oil recovery and upgrading (e.g., from oil sands and oil shale), synthetic transportation fuel and feedstock production from coal and biomass, hydrogen production supporting all the above potential applications, and metals production. Technical evaluations have been completed to show the viability of integrating the HTGR technology with conventional processes in these market sectors. Trade studies have shown the potential for integrating the HTGR technology into conventional processes for supplying steam, electricity, and high-temperature gas in co-generation applications; for production of hydrogen and for the use of it in the production of gasoline in methanol-to-gasoline processes; and production of diesel fuel in coal and biomass-to-liquid fuel conversion processes in the synthesis of ammonia.

The modular characteristics (e.g., module ratings from 200 to 625 MWt) and low water usage of the HTGR technology facilitate its application for electricity generation in areas with limited electric power transmission capacity, low cooling water availability, or other factors that would otherwise be unable to take advantage of nuclear energy. The thermal efficiency of the HTGR is also higher than that attainable with light water reactor technology (e.g., 40 to 45% net efficiency for an HTGR versus ~30% for an LWR). Accordingly, electricity generation is also potentially a very significant market for the HTGR technology.

These evaluations of the potential market and preliminary economics provide a foundation for making decisions on technical requirements for the HTGR module designs as the NGNP Project moves forward. The overall functional and performance requirements derived from these studies provide the basis for detailed design specifications to be developed by the nuclear systems suppliers in cooperation with the future HTGR plant owners. In contrast to LWRs for electric power generation, it is anticipated that as the high temperature process heat and related markets mature and the actual owners step forward to invest, a spectrum of designs will emerge that best fit each market. A primary objective of the NGNP Project is to envelop the most important of these functional and performance requirements in its supporting development work and in selecting a representative first-of-a-kind application that provides a demonstration that can be applied to broadest possible future markets.

Full realization of the NGNP Project estimate in penetrating the targeted markets for the HTGR technology over the time frame of mid-2020 to 2050 would result in:

- Deployment of ~488,400 MWt (megawatts thermal) of HTGR technology (~800 reactor modules rated at 600 MWt)
- Providing steam, electricity, and high-temperature gas to the process heat market, providing steam, electricity and hydrogen for bitumen recovery, water treatment, and upgrading from oil sands, producing hydrogen for the merchant market, and producing synthetic fuels and feedstock from coal and biomass
- Providing a significant fraction of non-greenhouse-emitting electricity generation on the national electrical grid
- Reducing the importation of ~2.4 million barrels of imported crude oil per day (~25% of the imported oil in 2009); replacing the equivalent in crude oil based gasoline and diesel fuels with synthetic transportation fuels produced from coal
- Implementing a beneficial and efficient use of coal without generating greenhouse gas emissions
- Reducing ~6.5 trillion scf in natural gas consumption in the United States, per annum
- Reducing CO_2 emissions of ~380 million metric tons per annum (reducing by ~7% the total CO_2 emissions in the United States).

Table ES-1 summarizes the distribution of the HTGR deployments in the potential markets evaluated in this paper.

Table ES-1. Summary of results.

Item	Power Requirement (MWt)	Number of 600 MWt Modules	CO_2 Emissions Reductions (million metric tons)	Natural Gas Usage Reductions (trillion cubic feet)
Co-generation and process heat	75,000	125	110	2.2
Hydrogen production	36,000	60	15	0.44
Oil sands	18,000	30	23	0.41
Coal/biomass to fuel and feedstock	249,000	415	80 to 410	N/A
Electricity generation	110,400	184	~150 replacing CCGT* or ~300 replacing coal plant	3.4 (if replacing 150 CCGT units)
TOTAL	488,400	814	378 to 858	6.45
* Combined cycle gas turbine.				

A broader based study of strategies for transforming the U.S. energy infrastructure show that the HTGR technology can be an even more significant asset in improving the energy security in the United States (reduce reliance on imported oil), stabilizing energy prices (insulating the price of energy and feedstock from the large variations seen in natural gas prices over the last decade), and reducing CO_2 emissions.[1]

Preliminary business models have been formulated and economic evaluations of these business models have been performed to establish the economic viability of these applications. These business models address the fundamental differences in the economics of a nuclear plant, which are sensitive to capital recovery, with a fossil fired plant (e.g., natural gas) whose economics are driven primarily by fuel costs. These business models also address, at a preliminary level, the potential differences in the economic criteria and financial parameters that apply to ownership of a nuclear plant versus that of a conventional industrial plant. They also provide flexibility in addressing varying scenarios of nuclear plant and industrial process ownership and operation, (e.g., a likely condition is that the nuclear plant will be operated by an entity with prior experience in operation of a nuclear plant rather than by the industrial plant owner. The industrial plant owner could own all, part, or none of the nuclear plant). These business models and the economic evaluations will evolve as the NGNP Project progresses and business cases for specific applications are developed.

Because of the preconceptual stage of design of the HTGR for these applications, there is large uncertainty in the capital and operating costs of the HTGR plant and, therefore, comparably large uncertainty in the results of the economic evaluations. However, the evaluations show that the HTGR technology can be competitive with traditional fossil fired processes, depending on the assumptions of capital and operating costs, financing, and the potential for governmental policies to put a cost on carbon emissions in the future. However, the real impact of the economic evaluations on the viability of the HTGR technology is not easily addressed generically. The end user of the technology may consider the long-term benefits of the technology such as security and stability in the price of this energy source and shelter from the potential costs of carbon emissions sufficient to justify a higher initial cost for that energy. How to account for this fact is being pursued with the end users and other stake holders in development of the HTGR technology.

To develop confidence in the technical and economic viability of the HTGR technology, the plant designs need to be progressed beyond their current preconceptual status to provide better estimates of performance and costs to construct and operate. The economic factors for financing and pricing of energy over the long operating lifetime of the HTGR plants need to be refined through further discussion with major financial institutions with an energy portfolio, current nuclear plant owners, and major industrial plant owners that can benefit from use of energy from the HTGR.

The NGNP Project is developing updated and more refined economic models for evaluating the viability of the business models for both the HTGR plant and the industrial plant for the processes evaluated to-date and for those for which evaluations are to be completed. As the designs of the HTGR plants evolve, better estimates of the capital and operating costs for these plants will be developed supporting higher confidence levels in the results of the economic models. This will, in turn, improve the confidence in the continuing evaluations of the technical and long term economic viability of HTGR applications.

FORWARD

This revision updates the evaluation of the sizes of the following potential markets:

- Co-generation supply of steam, electricity and hot gas to collocated industrial facilities
- Hydrogen supply to the Merchant Market
- Supply of steam, electricity, and hot gas for bitumen recovery and upgrading in oil sands.

CONTENTS

FIGURES

TABLES

ACRONYMS

AEO	Annual Energy Outlook
CCGT	Combined Cycle Gas Turbine
DOE	Department of Energy
EIA	Energy Information Agency
HTGR	High-Temperature Gas-Cooled Reactor
HTSE	High Temperature Steam Electrolysis
INL	Idaho National Laboratory
LPG	liquid petroleum gas
LWR	light water reactor
MTG	methanol to gasoline
NGNP	Next Generation Nuclear Plant
SMR	steam methane reforming

High Temperature Gas-Cooled Reactor Projected Markets and Preliminary Economics

1. BACKGROUND AND PURPOSE

The Next Generation Nuclear Plant (NGNP) Project was initiated at Idaho National Laboratory (INL) by the Department of Energy (DOE) as part of the Generation IV Nuclear Energy Systems technology roadmap and pursuant to the *2005 Energy Policy Act*.[2] The principal objective of the NGNP Project is to support commercialization of high temperature gas-cooled reactor (HTGR) technology. The HTGR is helium cooled with a graphite core that can operate at reactor outlet temperatures much higher than conventional light water reactor (LWR) technology. Accordingly, it can be applied in many industrial applications as a substitute for burning of fossil fuels, such as natural gas, in addition to producing electricity—the principal application of LWRs. Applications of the HTGR technology that have been evaluated by the NGNP Project for supply of process heat include supply of electricity, steam and high-temperature gas to a wide range of industrial processes, and production of hydrogen and oxygen for use in petrochemical, refining, coal-to-liquid fuels and synthetic feedstocks, chemical, and fertilizer plants.

As a non-CO_2 emitting substitute for the burning of fossil fuels in industrial applications the HTGR can offset significant quantities of CO_2 emissions attendant to the burning of these fuels. These emissions derive from both the direct combustion of these fuels in the industrial processes (e.g., providing steam, electricity for internal use, supplying high temperature gas) as well as the emissions associated with electrical power taken from the grid. This is one of the several benefits of the HTGR technology that have been explored by the NGNP Project with potential end users of this technology in the industrial sector. Several studies have been performed that demonstrate this benefit as well as the technical and economic viability of integrating the HTGR technology with specific applications, (e.g., co-generation of steam, electricity, and high temperature gas; coal-to-liquid transportation fuel conversion; bitumen extraction from oil sands using steam assisted gravity drainage and bitumen upgrading; chemical, ammonia, and ammonia derivative production).

The use of the HTGR technology as a substitute for burning of natural gas in many of these applications and for conversion of coal to synthetic fuels and chemical process feedstock improves the security of the energy supply in the United States by reducing reliance on offshore imports, reduces the impact of the volatility in energy prices that have been experienced over the last few decades on the economics of industrial processes (e.g., wide swings in the prices of oil, natural gas, and coal), and preserves our limited nonrenewable energy resources (e.g., instead of burning natural gas, it is used in more productive and irreplaceable feedstock applications for producing a broad range of chemicals).

This paper summarizes the potential market for HTGR process heat and its environmental benefits in reducing CO_2 emissions in these markets and the typical economics of projects in these applications and provides examples of the application of HTGR technology to industrial processes in typical co-generation supply of process heat and electricity, the conversion of coal to transportation fuels and chemical process feedstock, and the production of ammonia as a feedstock for the production of ammonia derivatives, including fertilizer. Finally, the effects of uncertainties in the capital costs and financial factors on the economics of the HTGR technology are demonstrated in application of HTGR and the high temperature steam electrolysis process for the production of hydrogen.

2. ASSESSMENT OF THE HTGR MARKET FOR SUPPLY OF PROCESS HEAT TO THE INDUSTRIAL SECTOR

2.1 General

Up to the time of this writing, the assessments of the potential markets and discussions with end users have focused on understanding the full energy needs of the targeted industries to inform the design requirements of the HTGR to meet these needs. As cited above, the targeted markets include established industries, such as co-generation, bitumen extraction from oil sands, and hydrogen production, and new markets such as the conversion of coal to synthetic fuels and feedstock whose development would be enhanced through application of the HTGR technology.

For the purposes of providing a basis for quantifying the benefits of using HTGR technology in these applications, the Project has assumed certain levels of penetration of these markets based on engineering judgment. The following sections summarize the approach applied in this market assessment and the results and conclusions of these assessments.

2.2 Identifying Potential Applications

NGNP Project trade studies have identified large, long-term markets that are judged viable for the HTGR technology. These studies first screened the industries to prioritize potential applications as shown in Table 1.[3] The energy requirements for the low priority industries, (e.g., wood, pulp, paper, textiles, and pharmaceuticals) are judged to not match the capabilities of the HTGR or are not large enough to justify use of a nuclear heat source.

Table 1. Prioritization of potential industrial applications of the HTGR technology.

Industry	Assessment	Priority
Petroleum Refining	Multiple refining processes have very high energy demands and suitable process temperatures.	High
Oil Recovery	In situ bitumen extraction has a high energy demand, suitable process temperature, and high growth expectations.	High
Coal and Natural Gas Derivatives	Syngas, hydrogen, and liquid fuel production from coal and natural gas has suitable process temperatures and high projected growth.	High
Petrochemicals	Multiple petrochemical production processes have very high energy demands and suitable process temperatures.	High
Industrial Gases (Hydrogen)	Steam methane reforming and advanced hydrogen production methods have high energy demands and suitable process temperatures.	High
Fertilizers (Ammonia, Nitrates)	Ammonia production has high energy demand and suitable process temperatures.	High
Metals	Direct-reduced iron (DRI) production has high energy demands, suitable process temperatures and strong global growth.	High
Polymer Products (Plastics, Fibers)	Certain polymers have large energy demands, suitable process temperatures, and strong global growth.	High
Cement	The current cement process temperatures are too high, but production is possible at suitable temperatures with technology development.	Low
Pharmaceuticals	The process energy needs of the pharmaceutical industry on a per plant basis are relatively low.	Low
Paper	The typical energy requirements for a mill is low and byproducts, having little value otherwise, are burned to provide half of the steam and electricity needs of paper products.	Low
Glass	Glass production process temperatures are too high.	Low

Figure 1 compares the temperature capabilities of the HTGR with the energy requirements of the higher priority industrial applications and the temperature capabilities of current LWR technologies. This figure shows the broad-based applicability of the HTGR technology in meeting the energy needs of the industrial sector, which cannot be met at the lower temperatures typical of current and advanced LWRs.

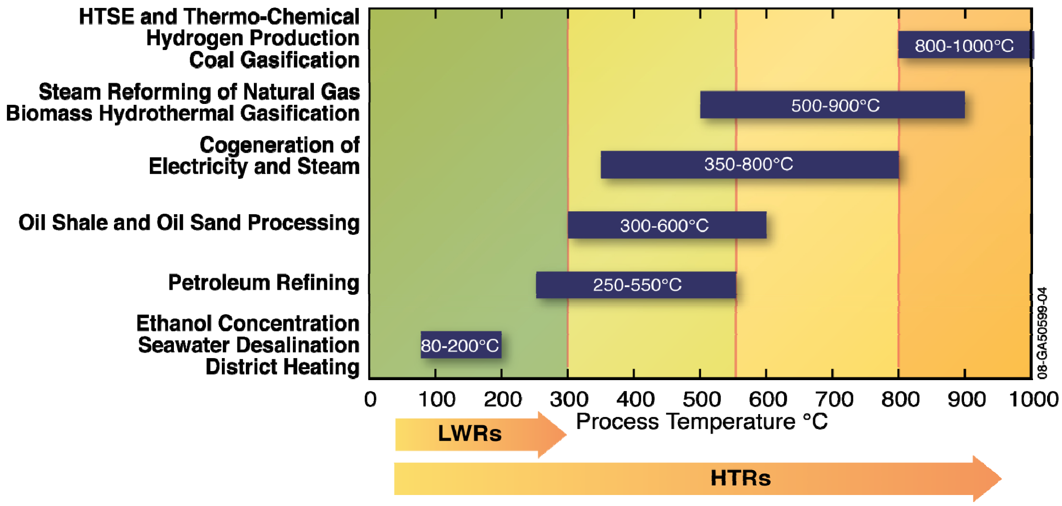

Figure 1. Process temperature requirements versus LWR and HTGR operating temperatures.

2.3 Characterizing the Potential Market

The NGNP Project estimated the characteristics and magnitude of the energy needs of selected high-priority processes. The U.S. energy consumption data summarized by the DOE Energy Information Agency (EIA) in Annual Energy Outlook (AEO) reports were used for this purpose. Table 2 shows the energy consumption in the United States by sector in 2009 & 2010. This data was obtained from the DOE-EIA AEO 2010 December 2009 update and AEO 2011 Early Release Tables, December 2010.[4] The applications identified as high and medium priority fall within the Industrial Sector. As shown, this sector was responsible for ~30% of the energy consumed in 2009 and 2010. For comparison this is about 3.5 times the total energy generated by the 104 nuclear power plants in the United States in 2009 and 2010 (8.4 quad Btu). The consumption of energy in 2009 by the industries that have been identified as having the highest potential for HTGR application within the Industrial Sector is summarized in Table 3.[a] Table 3 shows that the refining, chemical processing, iron and steel, aluminum, and plastics industries account for about 40% of the total energy consumed by the Industrial Sector. Also, about 60% of the energy consumption for the chemical industry is used for feedstock, typically natural gas. The HTGR could replace chemical industry feedstock by converting synthetic fuel such as coal to synthetic gas. Altogether, these are among the high priority applications identified in the early screening of potential applications for the HTGR technology. As shown in the last two columns of Table 3, except for the Refining sector, the DOE-EIA projections through 2035 show that the Industrial Sector energy consumption is not expected to change significantly (a growth rate of ~0.2%/annum is projected) over the next 20 years.

Table 2. U.S. energy consumption in 2009 & 2010 by sector.

	Quad Btu	
Sector	2009	2010
Residential	21.79	22.03
Commercial	18.56	18.32
Industrial	32.2	29.91
Transportation	27.98	27.47
Total	100.53	97.73

a. Table 3 data for 2010 was not available at the time of this writing. It is judged, however, that the relative usage by industry in 2010 would not be significantly different from that in 2009 based on the small change in total industrial energy consumption from 2009 to 2010 as shown in Table 2.

Table 3. Summary of selected industries' energy consumption in the industrial sector.

2009 Industrial Sector Energy Consumption (AEO 2010, December 2009)											
Total Consumption	*28.8*	*Quad*	Source	Electricity Quads	Emissions Mt	% of Total U.S. Emissions	On-site Generation		# 600 MWt modules equivalent	Projected Annual Change 2008 - 2035	Total Quads 2035
Industry	Total, Quads	% of Ind Sector Total					Own Use Elec, BKWh	Sales to Grid, BKWh			
Refining	3.797	13%	Table 34	0.174	263.2	4%	15.97	7.4	249	1.2%	5.257
Chemical	5.627	20%	Table 37	0.404	256.7	4%	43.12	9.23		-0.3%	5.823
	2.457	used for heat and power the rest is feedstock							161		2.515
Iron & Steel	0.709	2%	Table 40	0.065	64.8	1%	5.53	0.82	46	-1.7%	0.842
Aluminum	0.366	1%	Table 41	0.156	41.5	1%	4.57	1.6	24	-0.6%	0.299
Plastics	0.269	1%	Table 43	0.155	36.2	1%	N/A	N/A	17	0.5%	0.334
Quad = 1e15Btu	*Mt = million metric tons*						*BKWh = billion kilowatt hours*				

2.4 Estimating the Size of the Market

Figure 2 summarizes the projected penetration of the potential markets. The following discusses the development of this figure.

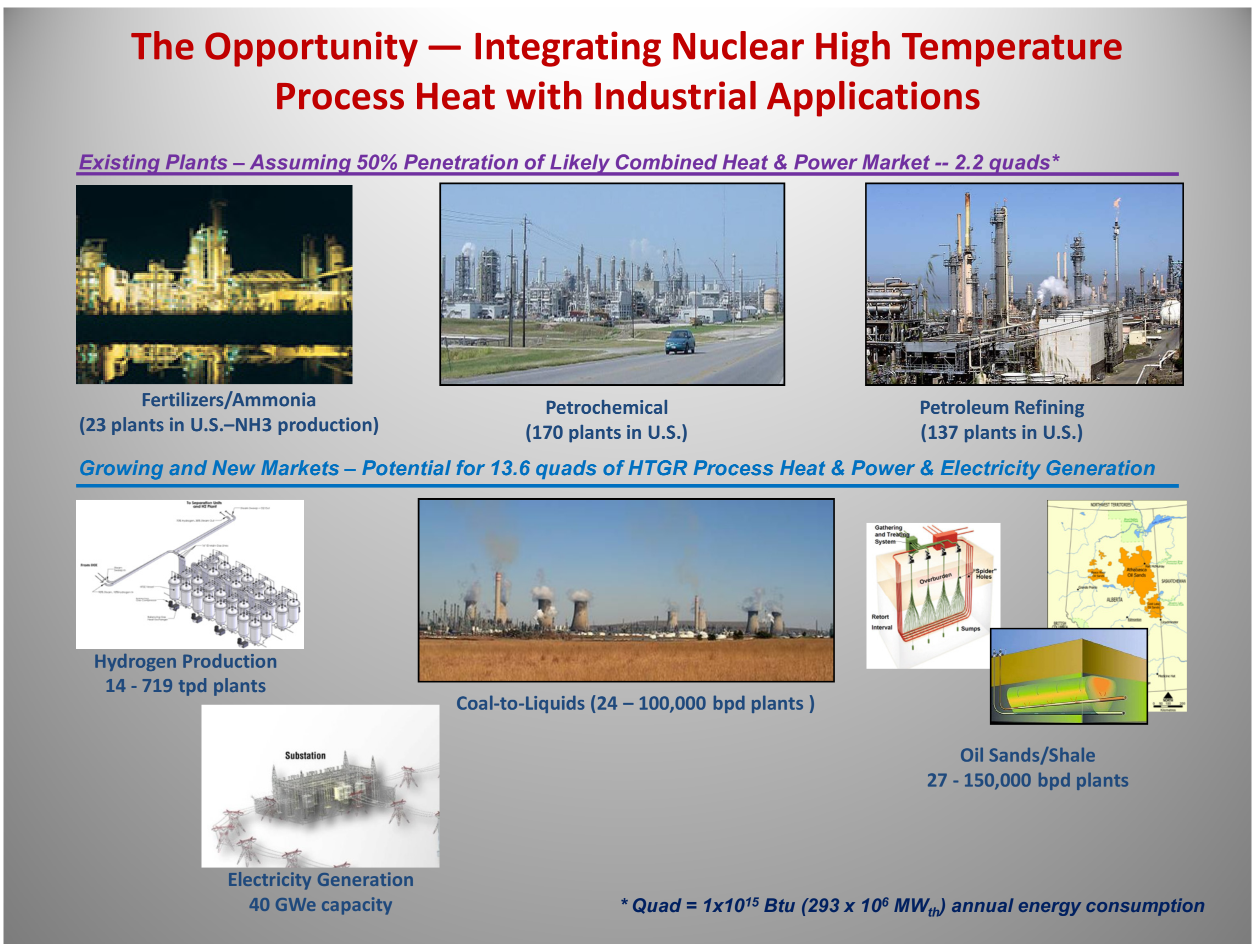

Figure 2. Projected penetration of the target markets.

The sections that follow identify the specific industries and processes targeted for application of the HTGR technology and summarize NGNP Project estimates of the potential scope for deployment of the HTGR technology as the energy supply for these industries and processes. These start with the cogeneration and process heat market covering the petrochemical, refining, ammonia/fertilizer production, iron and steel, aluminum, and plastics industries followed by the hydrogen production, oil and oil shale recovery, and conversion of coal to synthetic fuels and feedstock industries. The modular configurations and lower per module rating of the HTGR compared with large LWRs also allow HTGRs to be constructed in areas with limited transmission and distribution capacity, low cooling water availability or other factors that would otherwise be unable to take advantage of nuclear energy. The HTGR also has an advantage over LWRs with a higher thermal efficiency (e.g., 50 to 45% for the HTGR versus ~30% for the LWR). Electric generation is, therefore, a potentially important market for the HTGR technology covered below.

2.4.1 The Cogeneration Market in the United States

2.4.1.1 Data Source

The U.S. Department of Energy, Energy Information Administration (EIA), 2009 January to December EIA-923 Monthly Time Series File with Sources: EIA-923 and EIA-860 contains the following summary characterization of the sources of data in this file:

> This file contains the final 2009 data. During the year, the EIA-923 survey collected monthly data from approximately 1800 generating plants. These data were published each month as preliminary and subject to revision. The remaining out-of-sample power plants reported data annually. In this final 2009 database, the annual responses are proportionately distributed over the months using the ratio of collected monthly data to the sum of that monthly data. The entire set of data collected for 2009 is now final and shown below with plant-specific names and plant numbers. Plants that did not respond or data that could not be verified are estimated. The estimates are rolled-into state/fuel aggregates with a “99999” plant code. For additional information, see the documentation file on page 6 of this workbook.

Of the ~1800 entries in this database 818 are characterized as combined heat and power (CHP) plants. These are cogeneration plants that provide electricity and in most cases steam to industrial plants. The remaining ~1000 plants are primarily non-regulated suppliers of electricity to the grid. These latter plants are not considered co-generators for the purposes of this part of the HTGR market analysis. That part of the potential market for HTGR deployment is covered in the assessment of use of the HTGR as an Independent Power Producer (IPP) of only electricity sold to the grid. The full database and an abridged database of the CHP plants only is contained in Excel file “Co-Gen Examples.” Manipulation of the data within this file supported the evaluation of the cogeneration market for HTGR application.

The key variables reported in this database used in this analysis included[b]:

- Combined Heat and Power Plant Indicator (only those with a “Y” or “CHP” were used)
- Facility Name
- Operator Name
- State
- Reported Prime Mover, (e.g., steam turbine, gas turbine, gas turbine combined cycle)
- Reported Fuel Type, (e.g., natural gas, mixed gas, coal, products of the process)
- Total Fuel Consumed (MMBtu) – reported monthly

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b. The figures and tables in the following discussions were developed using data from this database in Excel File, “Cogen Examples,” 8/8/11

- Year to-date:
  - Total Fuel Consumption Quantity
  - Electric Fuel Consumption Quantity
  - Total Fuel Consumption MMBtus
  - Electric Fuel Consumption MMBtus
  - Net Generation (megawatthours).

The data collected by EIA in Form 923 covers only that energy consumed in CHP plants that include the generation of electricity and, in most cases, steam that is used by a co-located industrial plant. A fraction of the electricity is typically sold on the regional grid. In a majority of the cases the steam generated by the CHP plant does not cover all of the steam requirements of the industrial facility. These facilities use package or other type boilers that are fired by natural gas and waste gases from the processes to supply the balance of steam demand. EIA does not track the energy consumed by these boilers, but it does track estimated emissions from these plants, although translation of the emissions data into steam demand is not practicable for these purposes. In characterizing and categorizing the size of the CHP plants, this analyses assumed that the relative steam consumption from sources other than the CHP plant to be consistent with the size of the CHP plant. The Project has investigated several specific co-generation applications and this assumption has been confirmed in these investigations.

2.4.1.2 CHP Cogeneration Plant Statistics

A key parameter of interest in assessing the viability of substituting the HTGR technology for the current plants in the cogeneration category is the average annual consumption of energy for each CHP site. For each of the 818 sites the average annual energy consumption (in MMBtus) in 2009 was converted to an average equivalent CHP plant rating assuming a 100% capacity factor as

Equivalent Plant Rating, MWt = Average Annual Energy Consumption (MMBtus)/3.413 (MMBtus/MWt)/8760 (hours/year).

The Equivalent Plant Ratings (APR) for the 818 sites in 2009 covered the range 3,230 MWt to essentially zero. The zero ratings reflect the fact that some of the smaller plants did not operate much during 2009. For the purposes of this analysis it was assumed that the minimum equivalent average plant rating that may be viable for HTGR application is 600 MWt. 125 sites had EPRs at or above 600 MWt. Figure 3 shows the breakdown of this population of CHP sites by EPR.

Table 4 summarizes data for a limited cross-section of the 818 CHP cogeneration sites in the United States. Not all of these sites are judged to be HTGR applicable. Only 13 of the sites shown in Table 4 are covered by those in Figure 3. The data in Table 4 over the limited cross-section is shown to illustrate why only 125 out of the 818 are considered likely sites for HTGR application—the energy demand is too small. A variety of industrial applications are represented in this table including petrochemical plants, refineries, aluminum smelter, paper mill and biorefinery (see highlighted data). Most of the highlighted plants are part of an industrial facility, but one, (e.g., Louisiana 1) is owned by Entergy and supplies electricity and steam to the Exxon-Mobil Baton Rouge as a cogeneration facility independent from the refinery. This cogeneration plant is shown in relation to the Baton Rouge refinery in Figure 4.

The first 15 of the 22 plants in Table 4 are representative of the 125 sites with equivalent plant ratings >600 MWt covered in Figure 3. The final seven are smaller plants shown to provide a broader perspective on the total cogeneration sites in the United States. This table highlights some of the key characteristics of this market:

- Natural gas is the predominate principal fuel followed by coal.

- The ratio of energy consumed to generate electricity to that used for steam generation is in the mid-40% range. (Note: the table shows an average of 43.2% for the 18 plants shown; the average is 45.8% for the 125 sites that have equivalent plant ratings >600 MWt.
- On average ~25% of the electricity generated is sold off-site. Note that this is a larger fraction for the off-site "Co-Gen" plants because that is their principal product. Although it is not clearly stated in the EIA data the majority of the electricity is purchased by the co-located industrial facility, (e.g., Midland Cogeneration Venture sells power to a Dow Chemical plant).
- About 17% of the electricity consumed by the industrial plants comes from the grid. This is usually to make up for insufficient capacity of an onsite plant or if the grid electricity can be obtained for a lower cost than it can be generated onsite. Note that there are plants that do not generate any electricity, (e.g., Ponca City Refinery).
- The peak to average demand for energy was ~120% in 2009.
- The average capacity factor for the electricity generation for the facilities listed is ~60%. This was calculated using the nameplate ratings of all of the generators that were statused as operating and the total generation for 2009. The cogeneration facilities tend to have capacity factors higher than this average. The onsite facilities tend to have capacity factors lower than this value. As noted previously, onsite electricity generation may not be used if the electricity can be obtained at a lower price from the grid.

In visits to petrochemical, refinery, and ammonia plants and in discussions with personnel from these sites it was stressed that the steam supply from the cogeneration plants was more important to plant operation than the electricity supply. This is because these plants have ties to the regional grid and can obtain electric power from the grid as needed. That is not the case with steam. 100% availability of the steam source is required.

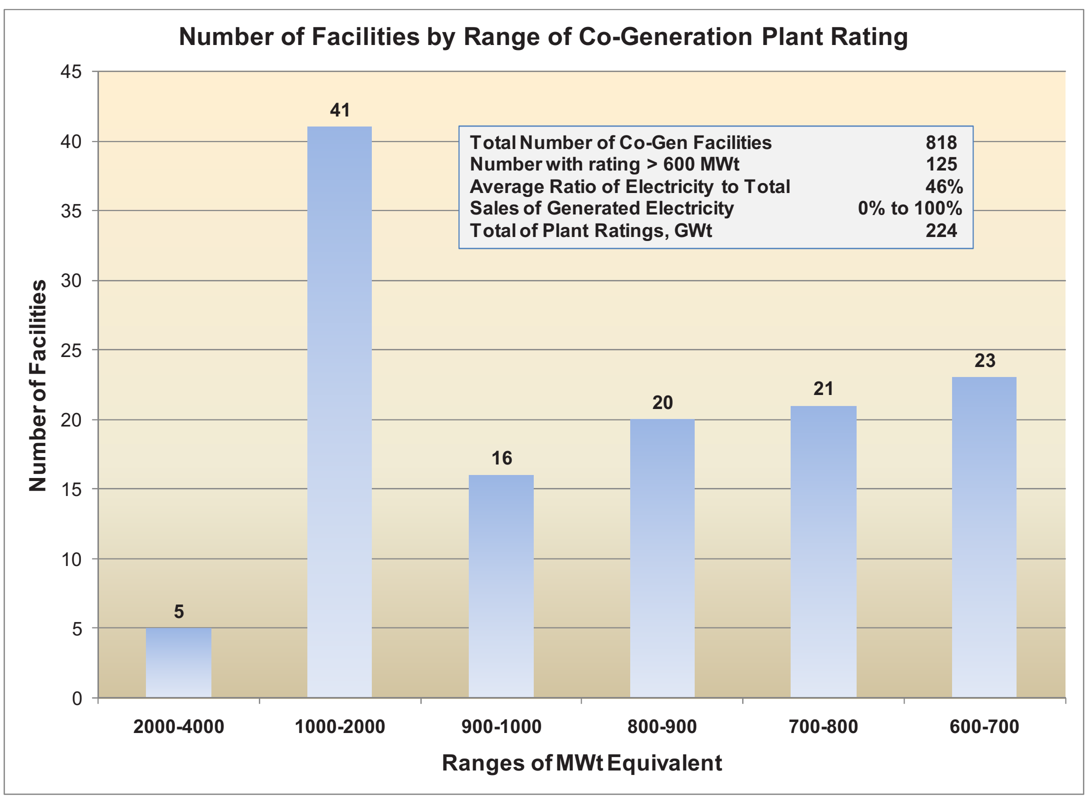


Figure 3. Number of CHP facilities ranked by equivalent plant rating (MWt).

Table 4. Summary data for a cross-section of cogeneration sites in the United States (2009).

Plant Name	Type	Refinery Capacity, Barrels/day	Location	Principal Fuel	Total Energy 2009, MMBtu	Energy to Generate Electricity 2009, MMBtu	Percent Electricity Generation, %	Percent Electricity Sold Off-Site, %	Percent Electricity from Off-Site, %	Average Energy Demand, Monthly MWt Equivalent	Peak Energy Demand, Monthly MWt Equivalent	Peak to Average Energy Demand	Peak to Minimum Energy Demand	Operating Electricity Generator Ratings	Capacity Factor
Red Shield Environmental Old Town Facili	Paper Mill /Bio-refinery	N/A	ME	BLQ	70,259,792	447,234	0.6%	8.2%	22.5%	2,958	3,217	1.09	1.19	29	38%
Alcoa, Warrick	Aluminum	N/A	IN	BIT	47,612,173	47,612,173	100.0%	14.4%	16.2%	1,627	1,808	1.11	1.18	778	72%
Alcoa, Warrick	Aluminum		IN	BIT	47,612,173	47,612,173	100.0%	14.4%	16.2%	1,627	1,808	1.11	1.18	778	72%
Dow Chemical Texas Operation	Petro-Chemical	N/A	TX	NG	46,235,852	21,322,266	46.1%	0.0%	39.7%	1,568	2,029	1.29	1.81	1,011	44%
Sweeny Cogen Facility	Co-Gen	247,000	TX	NG	40,859,167	16,331,212	40.0%	97.6%	0.0%	1,386	1,561	1.13	1.37	572	66%
Tennessee Eastman Operations	Petro-Chemical	N/A	TN	BIT	37,722,726	5,572,342	14.8%	0.0%	9.5%	1,279	1,367	1.07	1.13	194	69%
ExxonMobil Beaumont Refinery	Refinery	344,500	TX	NG	36,214,399	21,717,100	60.0%	45.2%	0.0%	1,228	1,433	1.17	1.37	670	56%
Taft Cogeneration Facility	CoGen		LA	NG	34,911,384	32,702,872	93.7%	68.5%	0.0%	1,159	1,414	1.22	3.26	894	59%
Midland Cogeneration Venture	Co-Gen	N/A	MI	NG	33,090,706	21,407,277	64.7%	95.9%	0.0%	1,120	1,646	1.47	1.93	1,469	24%
ExxonMobil Baytown Refinery	Refinery	560,640	TX	NG	59,894,980	27,269,837	45.5%	2.6%	7.4%	1,106	1,391	1.26	1.90	552	73%
Baytown Energy Center	Co-gen	N/A	TX	NG	32,531,570	31,653,775	97.3%	0.0%	0.2%	1,103	1,411	1.28	1.81	915	49%
Louisiana 1	Co-Gen	N/A	LA	NG	29,039,100	12,212,758	42.1%	13.6%	6.2%	985	1,284	1.30	1.58	250	108%
Oyster Creek Unit VIII	Co-Gen	N/A	TX	NG	27,334,978	22,564,159	82.5%	96.7%	0.0%	927	1,014	1.09	1.23	498	55%
Dow St Charles Operations	CoGen		LA	NG	22,562,622	15,175,000	67.3%	17.1%	5.0%	795	864	1.09	1.20	334	51%
Eastman Cogeneration Facility	Co-gen	N/A	TX	NG	20,377,408	12,743,280	62.5%	45.8%	0.8%	691	824	1.19	1.46	468	50%
Richmond Cogen	Co-Gen		CA	NG	9,897,803	4,537,477	45.8%	2.7%	6.6%	333	363	1.09	1.19	125	81%
Savannah River Mill	Paper Mill	N/A	GA	NG	9,739,420	2,789,338	28.6%	0.8%	9.8%	330	360	1.09	1.23	90	77%
Shell Chemical	CoGen		LA	NG	7,952,908	6,441,892	81.0%	32.1%	1.6%	283	345	1.22	1.58	80	84%
ExxonMobil Baton Rouge Turbine Generator	Refinery	504,500	LA	NG	6,920,307	2,630,381	38.0%	0.0%	0.0%	235	300	1.28	1.64	85	78%
Ponca City Refinery	Refinery	198,400	OK	OG	6,553,764	0	0.0%	0.0%	100.0%	222	246	1.11	1.31	4	0%
Port Arthur Refinery-Valero	Refinery	232,000	TX	NG	5,302,388	551,820	10.4%	6.8%	87.7%	180	222	1.23	1.53	37	39%
Richmond Refinery TG800	Refinery	245,271	CA	OG	4,806,656	639,995	13.3%	0.0%	0.0%	168	201	1.20	1.62	30	50%
Averages					28,974,194	16,087,926	51.6%	25.6%	15.0%	969	1,141	1.19	1.53	448	59%

Figure 4. Louisiana 1 cogeneration facility at the Exxon Mobil Baton Rouge Refinery.

Because the data used for this analysis does not necessarily include all of the steam demand for the CHP sites the categorizing the viability of each CHP site by its Equivalent Plant Rating is conservative. There are likely more sites that could be viable for HTGR application. For example, the latter two refineries listed in Table 4 have relatively small CHP facilities but likely have much higher overall energy demand than shown. Accordingly, the co-generation market size projected in this analysis is judged to be conservative.

The data in Table 4 informs needed characteristics of an average HTGR plant that would replace the existing fossil plants in these cogeneration applications:

- The plant must be capable of supplying steam demand at 100% availability. The steam demand on average is ~55% of the total energy demand on the CHP plant.
- The peak to average demand of total energy is ~120%; the plant must be sized to meet this swing in demand as a minimum.
- The plant must have the capability of supplying at least 45%of the energy in the form of electricity. About 25% of that electricity will be sold off-site. This is the primary mechanism by which the plant will absorb variations in the energy demand from the industrial plant.
- The availability of the plant on an annual basis must take into account outages for refueling, regular maintenance, major maintenance and un-scheduled outages. For an HTGR this is projected to result in an availability of 90% over the life of the plant.

These characteristics combine to form a factor that relates the Required Rating of the HTGR plant to the average Equivalent Plant Rating as determined above. This factor includes:

Peak to average = 1.2

Availability = 1/0.9 = 1.11

Total = 1.33

Accordingly, the HTGR plant rating must be one third larger than the average Equivalent Plant Rating as determined above. Figure 5 is a revision of Figure 4 applying this factor. As shown, the combined required plant ratings of the 105 sites at 900 MWt or above is ~156 GWt; the balance of 38 GWt is in the range 600 to 900 MWt.

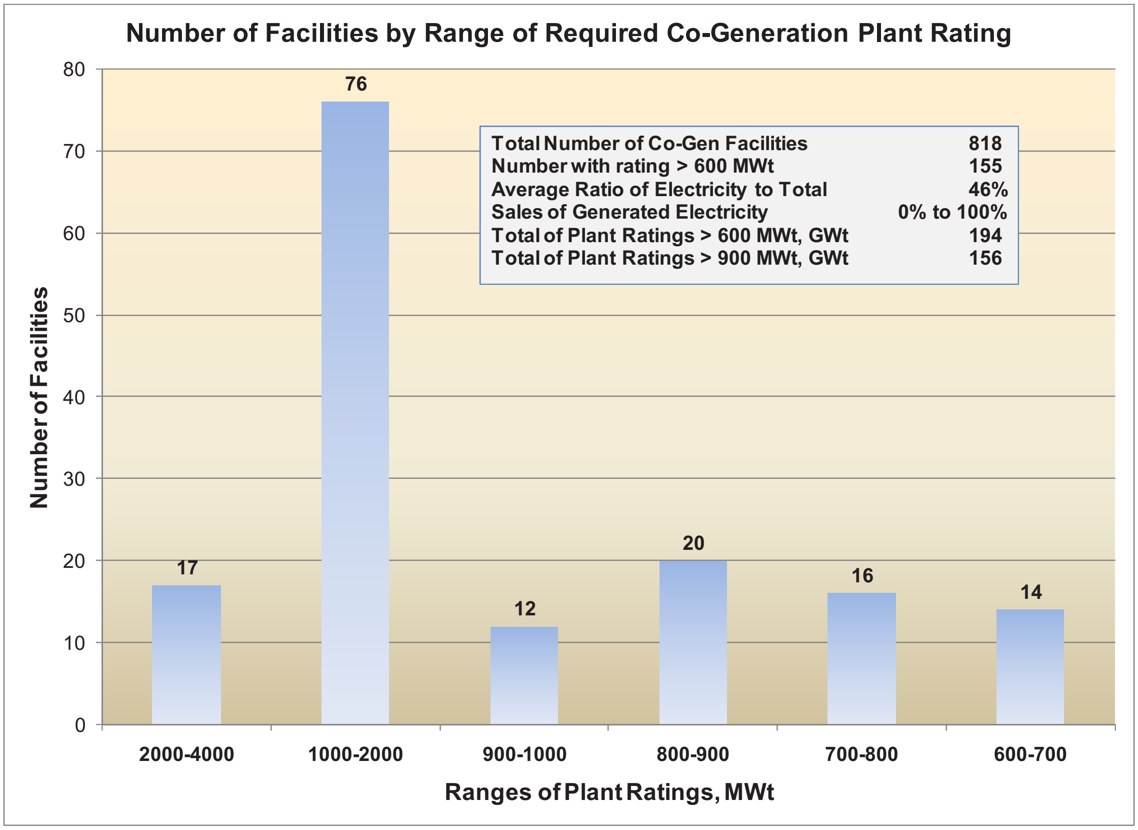


Figure 5. Distribution of required plant ratings for cogeneration plants >600 MWt.

Figure 6 shows the results of estimating the energy prices for an HTGR applied to cogeneration applications of varying plant ratings from 600 to 2,400 MWt using 600 MWt module ratings. Prior analyses have shown that the 600 MWt module rating has economic advantage over smaller module ratings. Figure 6 shows the variation in energy pricing with plant rating as equivalent natural gas price. Equivalent natural gas price is that price at which a conventional natural gas based plant would have the same product price, (e.g., for steam and electricity) as the HTGR plant. Data on actual electricity and steam prices as a function of natural gas price over a wide range of natural gas prices was obtained from General Atomics as part of their development of the Conceptual Design Report for a prismatic reactor based plant (SC-MHR),[5] see Figure 7. This metric is used since the majority of cogeneration plants currently use natural gas as the primary fuel. The HTGR pricing is also shown for internal rates of return (to the equity holders of the HTGR plants) of 10 and 15%. As shown, equivalent natural gas prices range from \$9.75/MMBtu for the 600 MWt plant rating and 15% IRR to \$5.55/MMBtu for the 2,400 MWt plant rating and 10% IRR. The curves show a marked reduction in equivalent natural gas price from 600 to 1,200 MWt. The sharp change in slope at 1,200 MWt is due to the coarseness of the intervals of plant rating used in the analysis. However, the trend is judged to be accurate.

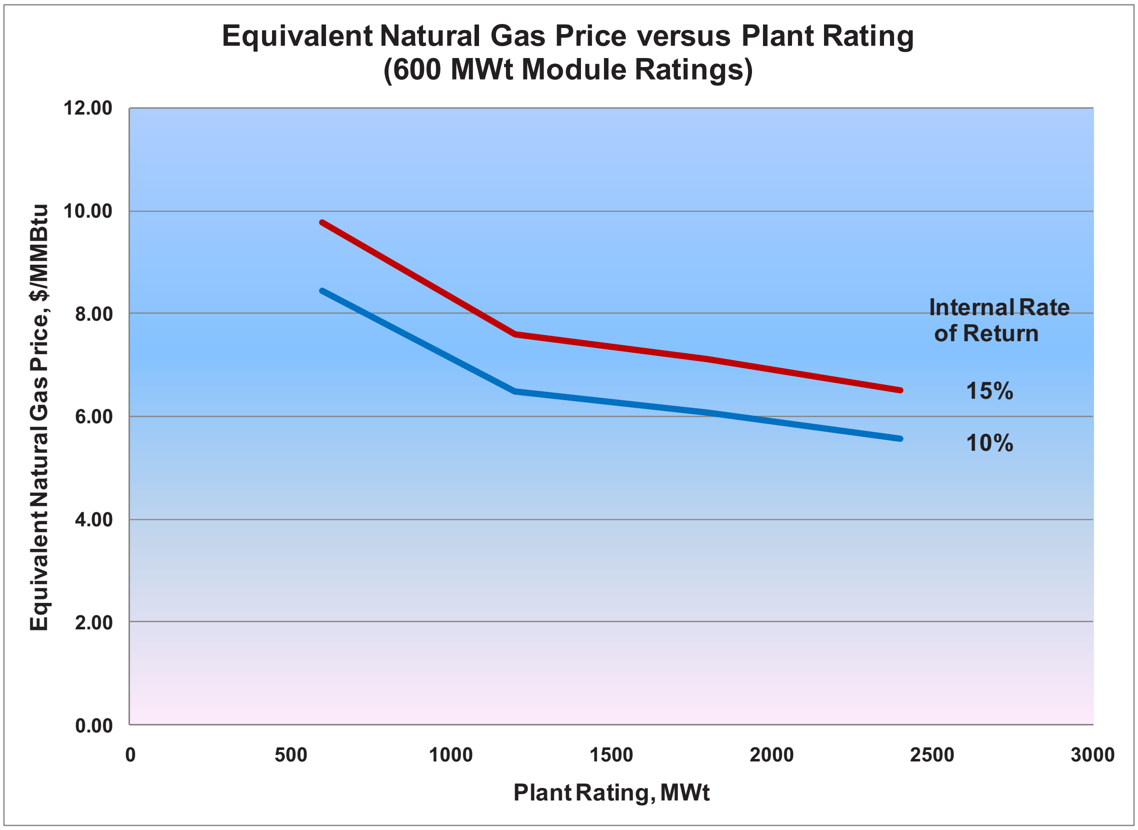


Figure 6. Equivalent natural gas price versus plant rating.

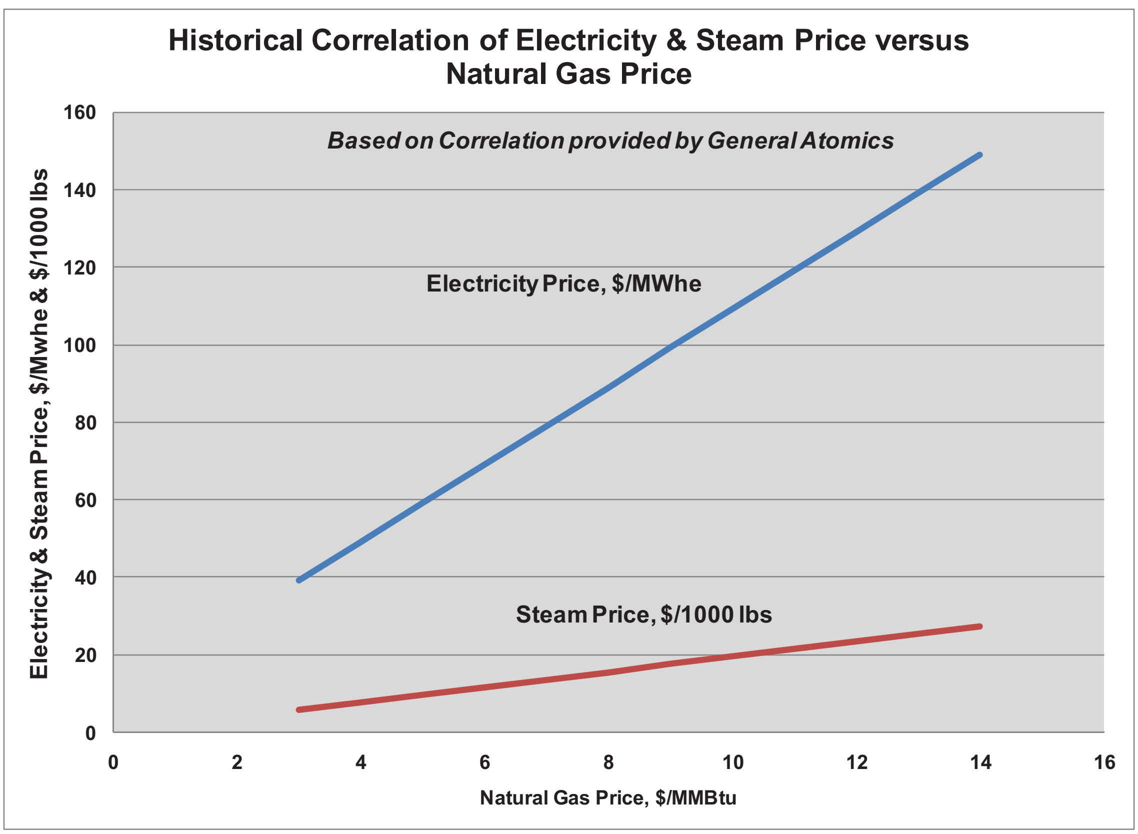


Figure 7. Historical electricity and steam prices as a function of natural gas price (this figure extracted from Excel file, "HTGR Co-gen and Electricity Only Parametric and Tornado 4-5-11").

It is judged that without imposition of costs for carbon emissions that the HTGR needs to have projected energy prices in a range equivalent to ~$8/MMBtu.

Assuming that Figure 6 is representative of projected prices of HTGR energy as a function of plant rating, the $8/MMBtu price falls between ~750 and ~1100 MWt depending on the IRR assumed. It is judged that sites with plant ratings at or above 900 MWt would be economically viable without a carbon cost and are the most likely market for HTGR application. Those between 600 and 900 MWt may require a carbon cost to be competitive and, therefore, may not be viable targets. As shown in Figure 5 the required combined plant rating of the sites at 900 MWt or above is ~156 GWt. Assuming that 50% of these are replaced with HTGR plants the total projected market for HTGR deployment in this area of cogeneration applications is ~75 GWt.

2.4.2 Hydrogen Production

The HTGR combined with high temperature steam electrolysis (HTSE) is an effective non-CO_2 emitting process for producing hydrogen. Demonstration of hydrogen production was cited as an objective for development of the HTGR technology in the *Energy Policy Act of 2005*.

The majority of the generation and use of hydrogen in the United States is in the refining industry. Based on EIA data,[6] refineries in the United States had hydrogen generation capacity of 2,985 million cubic feet per day in 2010; equivalent to 2,590 thousand metric tons per year at 100% capacity factor. This compares with a capacity of 3,100 million cubic feet per day in 2007; equivalent to 2,723 metric tons per year at 100% capacity factor. Table 5 shows that refinery hydrogen generation was 2,723 thousand metric tons in 2006. This is the last data available that estimates actual generation. In comparison with the capacities in 2007 and in 2010 it is concluded that these refineries run the onsite hydrogen plants essentially at 100% capacity.

Table 5. U.S. Hydrogen Production Capacity, 2003 and 2006.

Capacity Type	Production Capacity (Thousand Metric Tons per Year)	
	2003	2006
On-Purpose Captive[a]		
Oil Refinery	2,870	2,723
Ammonia	2,592	2,271
Methanol	393	189
Other	18	19
On-Purpose Merchant[a]		
Off-Site Refinery	976	1,264
Non-Refinery Compressed Gas (Cylinder and Bulk)	2	2
Compressed Gas (Pipeline)	201	313
Liquid Hydrogen	43	58
Small Reformers and Electrolyzers	<1	<1
Total On-Purpose[a]	**7,095**	**6,839**
Byproduct		
Catalytic Reforming at Oil Refineries	2,977	2,977
Other Off-Gas Recovery[b]	462	478
Chlor-Alkali Processes	NA	389
Total Byproduct	**3,439**	**3,844**
Total Hydrogen Production Capacity	**10,534**	**10,683**

[a] "On-purpose" are those units where hydrogen is the main product, as opposed to "byproduct" units where hydrogen is produced as a result of processes dedicated to producing other products.

[b] From membrane, cryogenic and pressure swing adsorption (PSA) units at refineries and other process plants.

Sources: The EIA-820 Refinery Survey, The Census Bureau MA28C and MQ325C Industrial Gas Surveys, SRI Consulting, The Innovation Group, Air Products and Chemicals, Bilge Yildiz and Argonne National Laboratory (Report # ANL 05/30, July 2005), and EIA analysis.

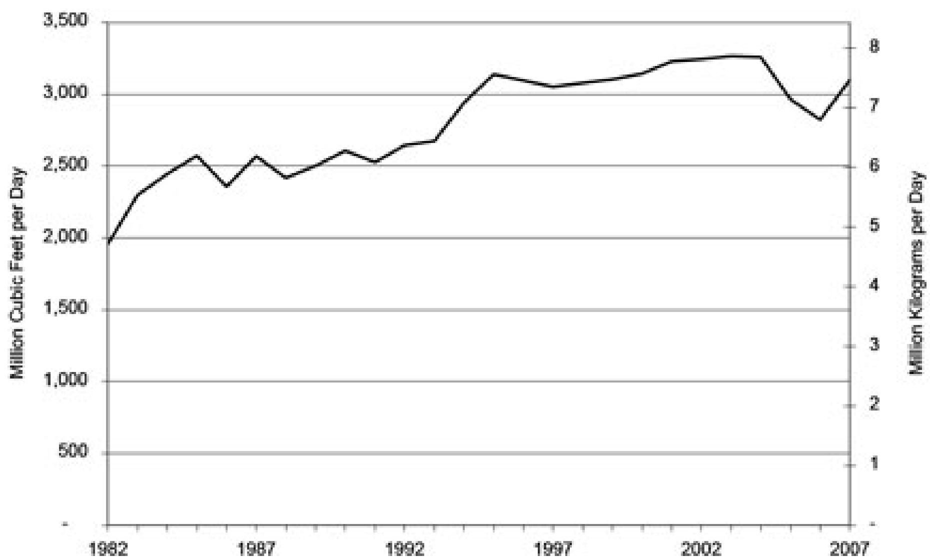
As shown in Table 5 ammonia plants also produced significant quantities of hydrogen in 2003 and 2006. However, review of recent data indicates that ammonia plants in the United States have been operating at low capacity factors for several years due to competition from offshore. Ammonia generation is, therefore, not judged to be a viable market for HTGR hydrogen at this time. This market will continue to be evaluated and if it reverses recent trends it will be factored into the market projections.

The potential market for deployment of HTGR technology for hydrogen generation is judged to be the merchant market. As shown in Table 5 merchant plants supplied a little over 20% of the direct ("on-purpose") generation of hydrogen in 2003 and 2006.

Table 5 was extracted from a 2008 EIA assessment of the effect of hydrogen generation on greenhouse gas emissions. This assessment presented the following conclusions[7]:

> "As illustrated in Figure C.2, the refinery demand for hydrogen is increasing in order to satisfy the growing demand for hydrocarbon transportation fuels and the tightening environmental restrictions on vehicle exhaust emissions. Since 1982, there has been a 59% expansion of onsite refinery-owned hydrogen plant capacity—an average growth rate of about 1.2% per year. Prior to 2006 the United States hydrogen industry had been growing at a rate of about 7 to 10% per year and is projected to grow another 40% over the next five years. Within the refinery sector, the near-term average annual growth rate of hydrogen consumption is projected to be about 4% per year. The merchant share of hydrogen to refineries is estimated to grow at an annual rate of about 8 to 17% per year."

Figure C.2. United States Refinery On-Site Hydrogen Production Capacity



Source: Energy Information Administration, Form EIA-820.

This prediction has, however, not been borne out through 2010, likely because of the downturn in the U.S. economy starting in 2008. Table 6 and Figure 8 show the total and merchant market production of hydrogen worldwide and in the United States for 2005 through 2010. The merchant market accounted for 15 to 20% of the total U.S. production over this period. Figure 9 shows the industries serviced by the merchant market in 2003 and 2006. The market was dominated by refineries in these years. Based on the location of most of the major producers near refineries (see Table 9) it is judged that this is still the major market for merchant hydrogen production.

Table 6. Hydrogen Production Data, 2005–2010.[a]

	Production Figures in Million Metric Tons/Year					
	2005	2006	2007	2008	2009	2010
Worldwide Total Production[b]	23.158	24.098	28.917	31.327	36.146	31.327
Worldwide Merchant[c] Production	2.499	2.892	4.097	4.579	4.579	4.820
U.S. Total Production	15.447	16.145	19.037	19.760	19.760	20.122
U.S. Merchant Production	1.598	1.783	2.535	2.856	2.892	3.012
U.S. Large Merchant Production	1.513	1.687	2.410	2.716	2.819	2.928
U.S. Small Merchant Production	0.084	0.096	0.125	0.140	0.084	0.084
U.S. Small Merchant Delivery Modes						
Liquid Tanker	90%					
Compressed Gas Tube Trailer	7%					
Compressed Gas Cylinder	3%					

a. Source: CryoGas International, February 2006; February 2007; February 2008; February 2009; April 2010; February 2011.

b. Excludes hydrogen production from syngas, byproduct gases, and onsite plants not owned and operated by the end-user.

c. "Merchant" hydrogen production is defined here to mean any hydrogen produced by one company for consumption by another company. Large merchant production is usually delivered to the customer via pipeline as a compressed gas. The merchant plant may be on the customers property, adjacent to the customer's property (commonly referred to as "over the fence") or a few hundred miles away in regions (e.g., Texas Gulf Coast) served by hydrogen pipeline networks. Merchant production is a subset of total production.

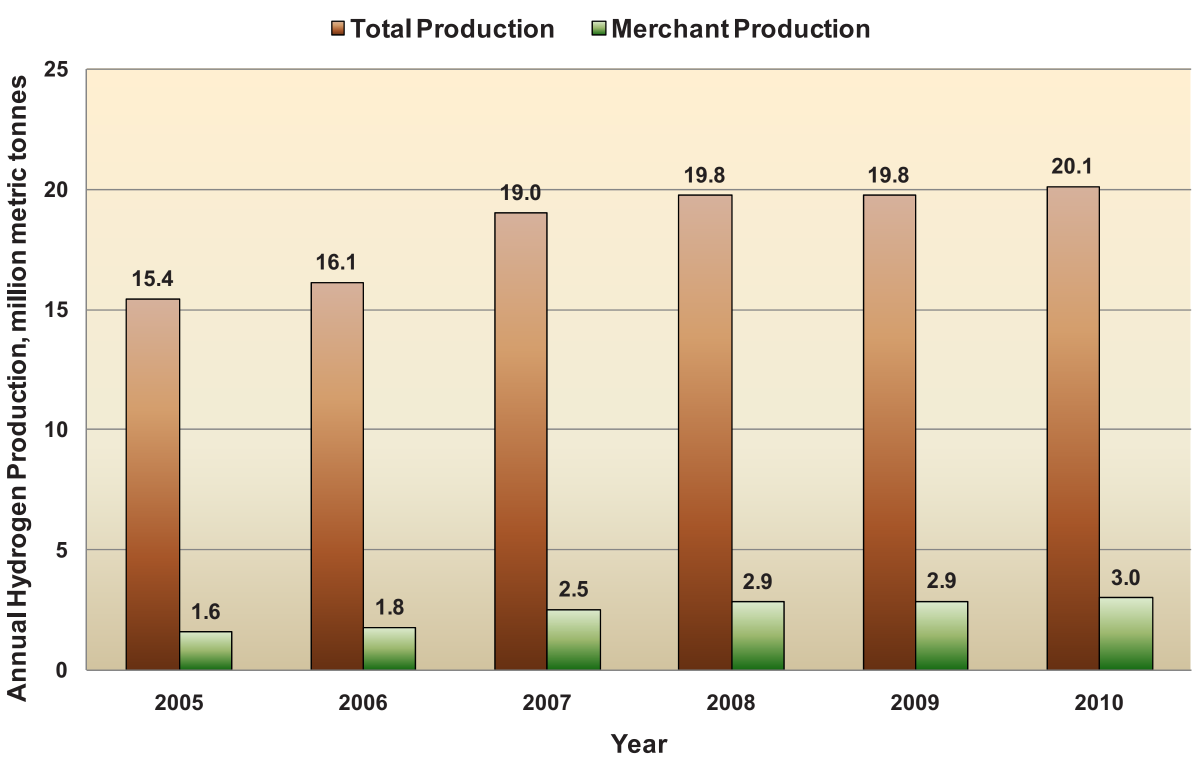


Figure 8. Total and Merchant Hydrogen Production 2005–2010.

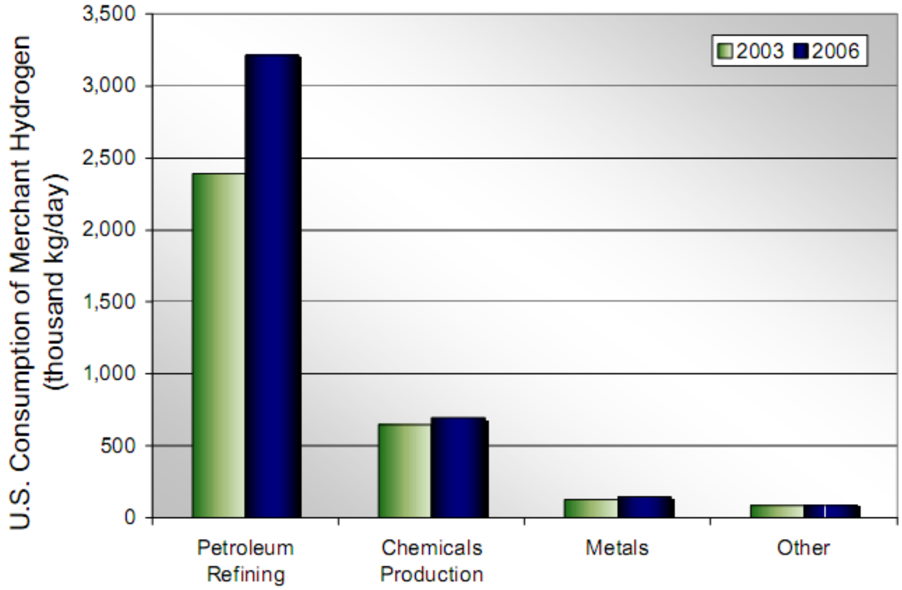


Figure 9. Merchant and nonmerchant hydrogen production in the United States; 2005 through 2008.[8]

Based on data reported by the Hydrogen Resource Center, the merchant market for generation and supply of gaseous hydrogen is dominated by the four U.S. companies shown in Table 7. These four companies account for 97% of the merchant market hydrogen capacity in the United States. Table 7, Figure 8, and Table 8 all show a merchant market production rate of ~3 million metric tonnes in 2010, reflecting a greater than 100% capacity factor for that market.

Table 7. Principal merchant hydrogen production companies in the United States.

Company	Capacity, kg/day	% of Total
Air Products	3,890,347	48
Praxair	2,532,228	31
Air Liquide	888,878	11
BOC-Linde	540,803	7
TOTAL	8,100,481	97
	2957	Metric tons/year

A significant amount of hydrogen is also produced in the United States as a byproduct of refinery and petrochemical processes. Table 5 showed that byproduct production accounted for 35 to 40% of the total hydrogen production capacity in 2003 and 2006. It is judged that this percentage has been maintained through 2010.

Steam methane reforming is the principal method used in refineries and by the merchant market to produce hydrogen. INL analyses[9] show that the ratio of hydrogen produced to natural gas input in the steam reforming process is ~2.5 and ~25 tons of CO_2 is produced for every million standard cubic feet (Mscf) of hydrogen produced. These analyses also project that ~70% of the CO_2 could be captured and sequestered, see Figure 10.

If it is assumed that 60% of the hydrogen produced in 2010 (~12 million metric tonnes, ~5 mscf) was produced using conventional steam methane reforming[c] ~2 trillion cubic feet of natural gas were consumed and 115 million metric tons of CO_2 were generated.

c. This accounts for that produced from by-products and other processes.

Table 8. Summary of hydrogen production capacity in the United States (Hydrogen Analysis Resource Center: Merchant Liquid and Compressed Gas Hydrogen Production Capacity in the United States and Canada by Company and Location).

Producer	City	State/ Province	Capacity (Nm^3/hr)	Capacity (Mscf/day)	Capacity (kg/day)	Year Opened
Air Products	Sacramento	CA	2,568	2,300	5,542	1986
Air Products	New Orleans	LA	29,918	26,800	64,582	1966
Air Products	Sarnia	Ontario	12,838	11,500	27,712	1983
BOC	Magog	Quebec	6,586	5,900	14,218	1989
HydrogenAl	Becancour	Quebec	4,689	4,200	10,121	1987
Praxair	McIntosh	AL	12,838	11,500	27,712	1995
Praxair	Ontario	CA	9,489	8,500	20,483	1962
Praxair	East Chicago	IN	12,838	11,500	27,712	1997
Praxair	Niagra Falls	NY	16,745	15,000	36,146	1982
Total Merchant Cryogenic Liquid			108,508	97,200	234,229	
Air Gas	Kapolei	HI	241	216	521	2008
Air Liquide	El Segundo	CA	100,015	89,592	215,896	2004
Air Liquide	Rodeo	CA	122,797	110,000	265,074	2008
Air Liquide	Honolulu	HI	8	7	17	unknown
Air Liquide	Rockport	IN	804	720	1,735	unknown
Air Liquide	Lake Charles	LA	56	50	120	1957
Air Liquide	Portland	OR	223	200	482	unknown
Air Liquide	St. Marys	PA	324	290	699	unknown
Air Liquide	Bayport	TX	111,634	100,000	240,976	2006
Air Liquide	Corpus Christie	TX	55,817	50,000	120,488	1998
Air Liquide	Dallas	TX	927	830	2,000	unknown
Air Liquide	Freeport	TX	16,745	15,000	36,146	1997
Air Liquide	Ingleside	TX	781	700	1,687	unknown
Air Liquide	La Porte	TX	1,116	1,000	2,410	unknown
Air Liquide	Odessa	TX	184	165	398	unknown
Air Liquide	Anacortes	WA	23	21	51	2004
Air Liquide	Kalama	WA	324	290	699	unknown
Air Products	Edmonton	Alberta	79,260	71,000	171,093	2006
Air Products	Edmonton	Alberta	117,215	105,000	253,025	2008
Air Products	Carson	CA	111,634	100,000	240,976	1999
Air Products	Martinez	CA	139,542	125,000	301,221	1995
Air Products	Wilmington	CA	178,614	160,000	385,562	1996
Air Products	Delaware City	DE	1,675	1,500	3,615	unknown
Air Products	Joliet	IL	20,094	18,000	43,376	2006
Air Products	Tuscola	IL	837	750	1,807	1992
Air Products	Butler	IN	2,009	1,800	4,338	unknown
Air Products	Catlettsburg	KY	37,955	34,000	81,932	2004
Air Products	Convent	LA	122,797	110,000	265,074	2006
Air Products	Geismar	LA	39,072	35,000	84,342	1999
Air Products	Lake Charles	LA	111,634	100,000	240,976	2004
Air Products	New Orleans	LA	44,653	40,000	96,391	2003
Air Products	Plaquemine	LA	33,490	30,000	72,293	unknown

Producer	City	State/ Province	Capacity (Nm^3/hr)	Capacity (Mscf/day)	Capacity (kg/day)	Year Opened
Air Products	Taft	LA	23,443	21,000	50,605	1995
Air Products	West Lake	LA	111,634	100,000	240,976	2004
Air Products	Midland	MI	837	750	1,807	2000
Air Products	Hannibal	MO	1,072	960	2,313	unknown
Air Products	Cincinnati	OH	2,568	2,300	5,542	unknown
Air Products	Sarnia	Ontario	89,307	80,000	192,781	2006
Air Products	Gallatin	TN	837	750	1,807	unknown
Air Products	Baytown	TX	78,144	70,000	168,683	2006
Air Products	Clear Lake	TX	30,141	27,000	65,064	unknown
Air Products	LaPorte	TX	58,049	52,000	125,308	1996
Air Products	Mont Belvieu	TX	32,374	29,000	69,883	unknown
Air Products	Pasadena	TX	89,307	80,000	192,781	1997
Air Products	Port Arthur	TX	117,215	105,000	253,025	2001
Air Products	Port Arthur	TX	122,797	110,000	265,074	2006
Air Products	South Charleston	WV	4,019	3,600	8,675	unknown
BOC-Linde	Decatur	AL	11,163	10,000	24,098	unknown
BOC-Linde	Mobile	AL	11,163	10,000	24,098	2007
BOC-Linde	New Castle	DE	1,675	1,500	3,615	unknown
BOC-Linde	Honolulu	HI	8	7	17	unknown
BOC-Linde	Lemont	IL	16,745	15,000	36,146	2003
BOC-Linde	Crawfordsville	IN	1,206	1,080	2,603	unknown
BOC-Linde	Lima	OH	14,177	12,700	30,604	2000
BOC-Linde	Lima	OH	22,327	20,000	48,195	2006
BOC-Linde	Toledo	OH	133,960	120,000	289,172	2006
BOC-Linde	Asbestos	Quebec	7,875	7,055	17,000	2000
BOC-Linde	Salt Lake City	UT	29,025	26,000	62,654	2006
BOC-Linde	Weirton	WV	1,206	1,080	2,603	unknown
Markwest Javelina	Corpus Christi	TX	39,072	35,000	84,342	unknown
Equistar	Channelview	TX	89,307	80,000	192,781	unknown
General Hydrogen	Proctor	WV	558	500	1,205	unknown
Holox	Augusta	GA	447	400	964	unknown
Industrial Gas Products	Sauget	IL	1,675	1,500	3,615	unknown
Praxair	Richmond	CA	290,247	260,000	626,539	2008
Praxair	Norcross	GA	4,443	3,980	9,591	unknown
Praxair	Seymour	IN	848	760	1,831	1998
Praxair	Whiting	IN	22,327	20,000	48,195	2006
Praxair	Geismar	LA	106,052	95,000	228,928	1997
Praxair	Lake Charles	LA	140,658	126,000	303,630	1999
Praxair	Westlake	LA	39,072	35,000	84,342	unknown
Praxair	Ecorse	MI	1,608	1,440	3,470	unknown
Praxair	Butte	MT	324	290	699	unknown
Praxair	Belvidere	NJ	480	430	1,036	unknown
Praxair	West Leechburg	PA	2,143	1,920	4,627	1995
Praxair	Channelview	TX	44,653	40,000	96,391	unknown
Praxair	La Porte	TX	27,908	25,000	60,244	unknown

Producer	City	State/ Province	Capacity (Nm^3/hr)	Capacity (Mscf/day)	Capacity (kg/day)	Year Opened
Praxair	Mont Belvieu	TX	32,374	29,000	69,883	unknown
Praxair	Port Arthur	TX	111,634	100,000	240,976	2004
Praxair	Texas City	TX	111,634	100,000	240,976	2004
Praxair	Texas City	TX	111,634	100,000	240,976	2006
Praxair	Texas City	TX	77,027	69,000	166,274	2000
Praxair	Texas City	TX	44,653	40,000	96,391	1996
Praxair	Belle	WV	3,349	3,000	7,229	unknown
Prime Gas	Delaware City	DE	223	200	482	unknown
Tessenderlo	Westlake	LA	39,072	35,000	84,342	unknown
T&P Syngas Supply	Texas City	TX	44,653	40,000	96,391	1996
Total Merchant Compressed Gas			3,752,591	3,361,525	8,100,481	
Total Merchant Product			3,861,098	3,458,725	8,334,711	

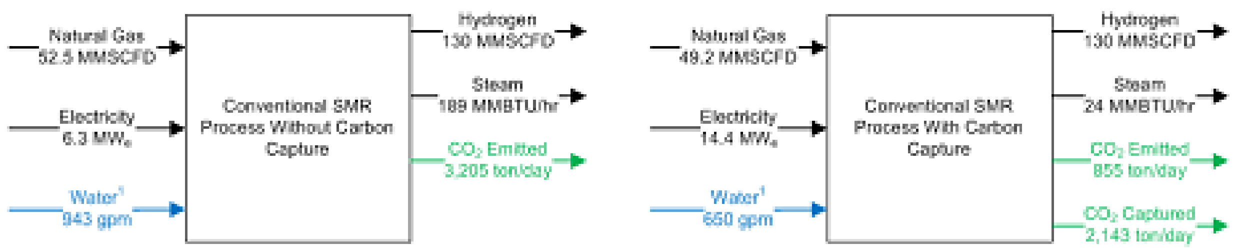


Figure 10. Components of hydrogen production using conventional steam methane reforming.

The HTGR/HTSE plant produces hydrogen with no emissions and with no natural gas fired conserving this limited natural resource for more productive uses such as feedstock for petrochemical processing.

It is assumed that as the economy recovers and for the reasons cited in the 2008 EIA assessment report the 4% per annum increase in refinery consumption of hydrogen will resume and the merchant market will attain the 8 to 17% projected growth rate. The assumption on the growth rate for the merchant market is also considered justified because none of the analyses cited so far consider the potential for an expanded use of hydrogen as a transportation fuel. The 2008 EIA report evaluated scenarios for penetration of the light duty vehicle market with fuel cell vehicles that projected hydrogen consumption in the 2030 to 2050 range of 2 to 14 quads[d] per annum. This is equivalent to 15 to 75% of the total hydrogen production in 2010. The shift to hydrogen as a transportation fuel has not proceeded as quickly as has been projected by the 2008 EIA report or by others, (e.g., National Hydrogen Association, DOE) because of the economics of distributing the hydrogen on a scale comparable to gasoline today. However, the high and volatile prices of gasoline over the last few decades, including the recent increase into the $4/gallon range, provide incentives to develop viable alternative transportation fuels that are not subject to the volatility of crude oil. Hydrogen will likely be one of several alternatives that will emerge to take the place of gasoline over the next few decades; along with hybrid vehicles, electric cars, cellulosic ethanol, etc. A non-greenhouse emitting source of hydrogen will be a key element in supporting hydrogen in this market.

For the purposes of analysis it is assumed that the hydrogen merchant market will grow at a rate of 5% per year. The HTGR/HTSE process will be applied in about half of the projected growth of the merchant market—5% per year. A total merchant market growth rate of 5% from 2006 to 2020 and

d. A quad is 1×10^{15} Btus.

beyond would project a merchant market of ~3 million metric tons per year in 2020. If the HTGR/HTSE process was deployed at a rate such that 25% of this market was supplied by HTGR/HTSE production within the first 10 years of deployment (2020 to 2030) and then continued at that percentage of the market through 2050, ~36,000 MWt of HTGR/HTSE technology (~60 reactor modules rated at 600 MWt) would need to be deployed over the 2020 to 2050 time frame. Figure 11 shows the HTGR/HTSE annual production by year over this deployment period.

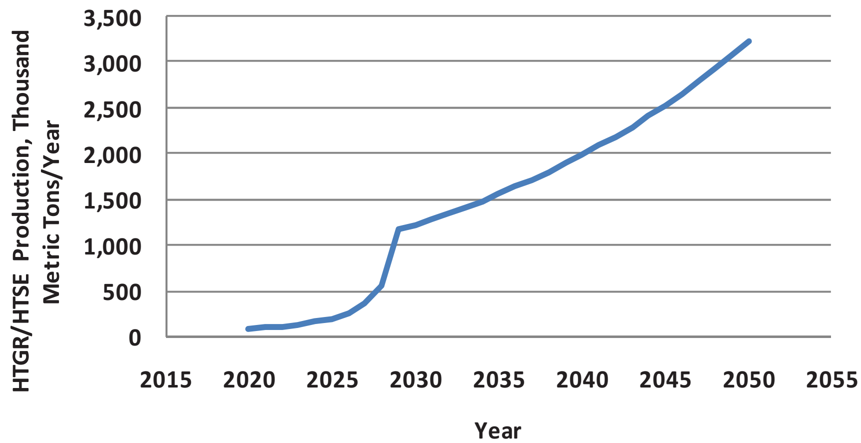


Figure 11. HTGR/HTSE hydrogen production by year.

Since, as noted above, the SMR process consumes ~2.9 tons of natural gas and generates ~4.7 tons of CO_2 for every ton of hydrogen produced,[10] the application of the HTGR/HTSE process as a substitute for SMR for this annual rate of production would reduce the natural gas consumption by ~10 million tons and reduce CO_2 emissions by ~15 million tons per annum in 2050. Over the 30-year period (2020 to 2050) the assumed deployment of the HTGR/HTSE technology for SMR production of hydrogen would have reduced CO_2 emissions by ~220 million metric tons and natural gas consumption by ~135 million tons (~5.9 trillion scf).

As an alternative to use of the HTGR to support HTSE hydrogen production, INL has performed analyses that show benefit in the use of HTGR heat as a substitute for natural gas firing in the SMR process.[9] In this application HTGR high temperature heat is substituted for natural gas firing in the primary and secondary reformers. In the application natural gas usage is reduced by 12 to 15% and emissions by 15 to 40%. The range of reductions reflects an option of including carbon capture and sequestration in the HTGR/SMR process. These reductions in natural gas consumption and CO_2 emissions are much lower than achievable by applying the HTGR/HTSE process. However the HTGR energy requirements are also much lower than required to support HTSE; ~90% lower. If the same level of penetration of the merchant hydrogen market as assumed for the HTSE process is assumed for the HTGR/SMR process by 2050, only ~4 GWth of HTGR energy would be required; equivalent to 7- 600 MWt HTGR modules. The total CO_2 reductions would be 20 to 30% of that achievable with HTSE and the reduction in natural gas usage for hydrogen production would be minimal.

Use of the HTGR in support of hydrogen production in the SMR process could be technically and economically viable in selected applications when the energy supplied to the SMR process is part of a facility that is providing energy to other applications in other forms such as steam and electricity. If the application of HTGR energy is to have a major impact on emissions reductions and on reducing natural gas usage in the merchant hydrogen market, it must be combined with either the HTSE or other hydrogen production process that have no emissions and do not use natural gas.

2.4.3 CTL and Oil Sands

As noted previously, there are additional applications for the HTGR technology in emerging industries. These include production of transportation fuels and feedstock from coal, natural gas, and biomass, and enhanced oil recovery from oil sands and oil shale.

2.4.3.1 Oil Sands

The HTGR technology can be applied for steam production in support of steam assisted gravity drainage (SAGD) extraction of bitumen from the Canadian oil sands, treatment of the water extracted with the bitumen, upgrade of the bitumen to synthetic crude using hydrogen generated by the HTGR plant, and electricity production. The Canadian Association of Petroleum Producers projects an increase in oil sands production in the 2015 to 2025 time frame as shown in Figure 12.[9] In situ (SAGD) production is expected to dominate this growth and result in an increase from 500,000 bpd (barrels per day) in 2015 to ~2,000,000 bpd in 2025 as shown in Figure 13. If the latter rate of increase (~50,000 bpd for years 2022 to 2025) of in situ production is maintained, this process will be producing 3,250,000 bpd by 2050.

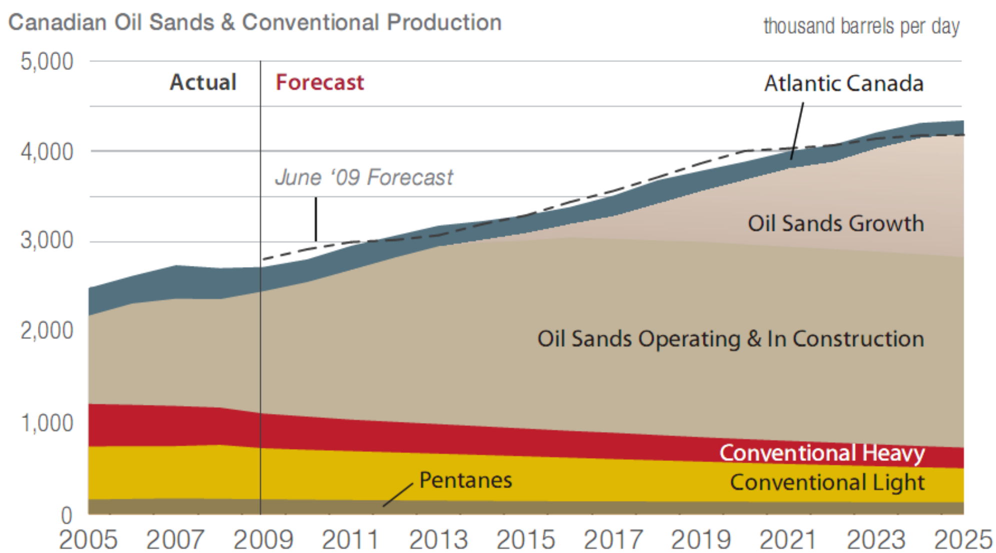


Figure 12. Oil sands production by year.

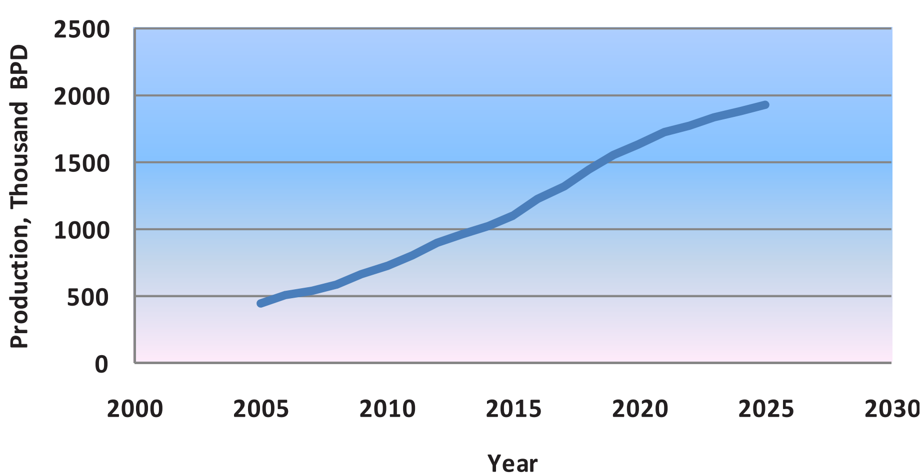


Figure 13. In situ production by year. (Generated in Excel file, "Basis for SAGD Projections in Market Study")

At the time of this writing the NGNP Project is evaluating the application of the HTGR technology for supply of the energy requirements for bitumen recovery, water treatment, upgrading and electricity supply to the oil sands area.[11] The objectives of this study are (1) to establish the technical and functional requirements for a central energy supply facility that would perform these functions, (2) confirm that the HTGR technology functional and performance requirements are sufficient to supply these energy needs, and (3) develop a notional HTGR central energy supply plant design to fulfill these requirements. The preliminary results show that it is technically feasible to site such a plant in areas of the oil sands with rich bitumen reserves sufficient to utilize the energy supply from this plant for bitumen extraction, water treatment, bitumen upgrading and electricity generation for at least 60 years.

For the purposes of analysis it was assumed that deployment of these centralized HTGR plants will begin in 2020 and by 2030 will account for supply of 25% of the projected energy consumption in the oil sands. This level of energy supply (25% of consumption) will be maintained as oil sands production and energy consumption increases through 2050. This would result in deployment of ~18,000 MWt of HTGR technology or~ 30 reactor modules rated at 600 MWt by 2050. Figure 14 shows the projected HTGR deployment strategy along with the projected growth in the oil sands production through 2050.

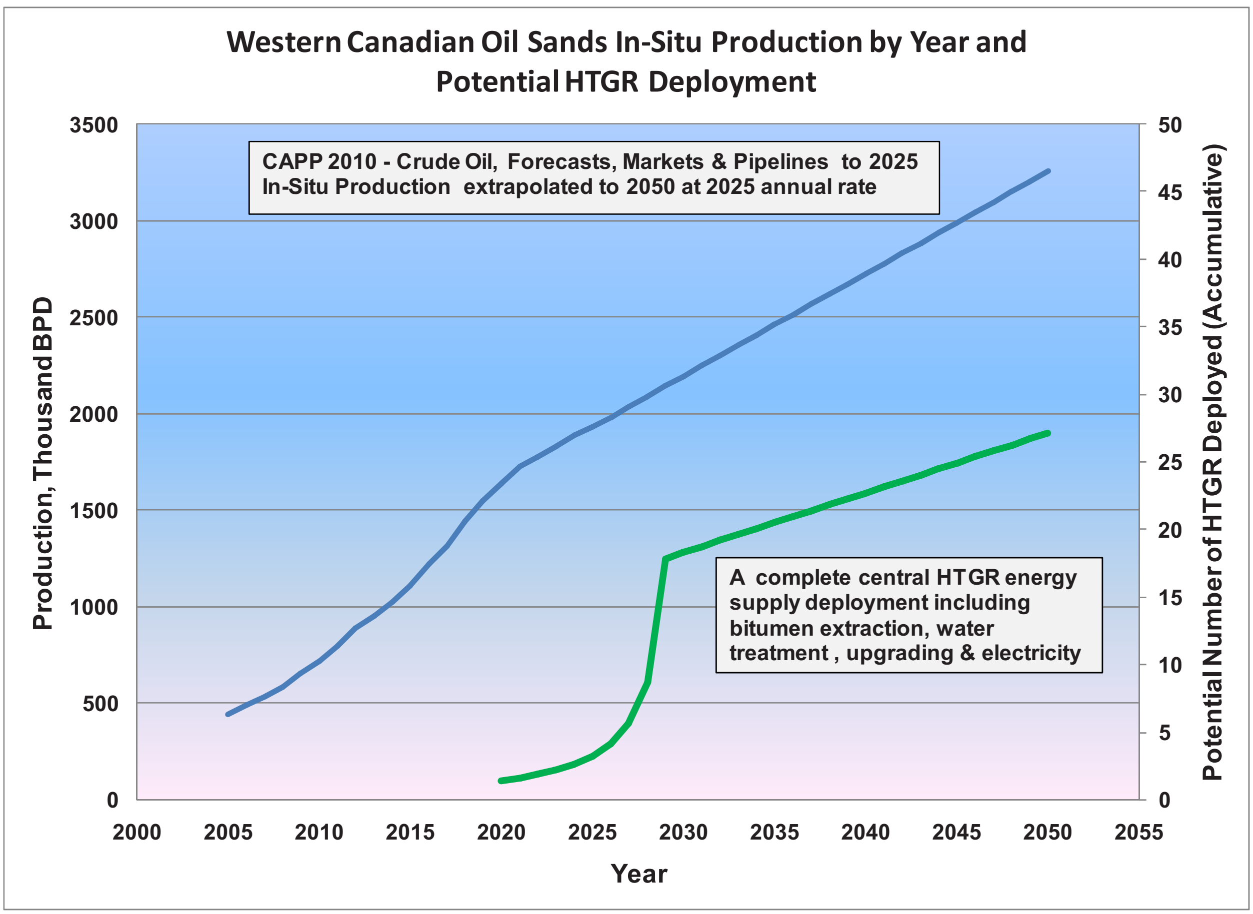


Figure 14. Deploying HTGR technology in the oil sands. (Generated in Excel File, "Backup Calculations for Industrial Energy Emissions & Consumption & CTL Plant_8-2-11")

By 2050 this deployment of the HTGR technology would reduce CO_2 emissions by ~23million metric tons and natural gas consumption by 406 billion scf per year.

There was no comparable estimate available for support of oil shale oil recovery at the time of this writing. This is a potential market yet to be defined.

2.4.3.2 Coal to Synthetic Fuel and Feedstock Production

If synthetic fuels and feedstock production is to make a significant contribution to improving energy security, it is assumed that it should offset at least 25% of the current U.S. imports of crude oil. Based on DOE-EIA data, the United States imported 9.12 million barrels of crude oil per day in 2009. Offsetting 25% of this would require, for example, deployment of twenty-four 100,000 bpd coal/biomass-to-liquid fuel plants, which would require ~249,000 MWt (415 reactor modules rated at 600 MWt) of HTGR energy to supply the energy and hydrogen required by these plants. In comparison with conventional crude oil refining, this would reduce CO_2 emissions by ~80 million metric tons per annum.[1] In comparison to a conventional coal to liquids plant, the use of the HTGR technology would reduce CO_2 emissions by ~410 million metric tons per annum with a carbon conversion efficiency of more than 90% compared with a ~35% carbon efficiency of the conventional plant.[12] Figure 15 compares the life cycle emissions for conventional crude oil refining, a conventional coal-to-liquids plant, and an HTGR coal-to-liquids plant.

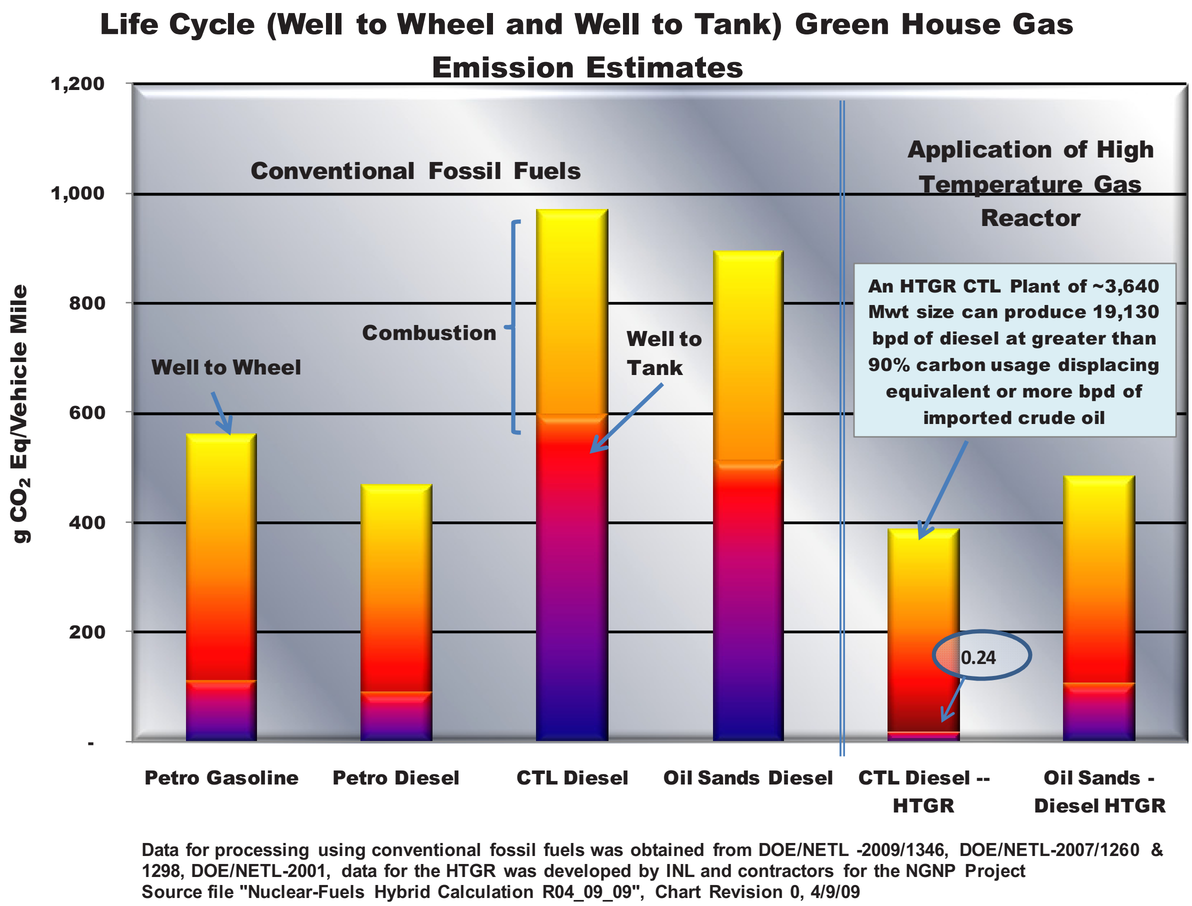


Figure 15. Comparison of life cycle emissions of HTGR based applications with conventional fossil based applications for transportation fuel production.

2.4.4 Electricity Production

Table 9 summarizes data from DOE-EIA on the costs of several forms of electricity production.[13] As is discussed in detail below the HTGR is competitive with LWRs and other non-greenhouse emitting sources of electricity production. Reference 13 shows that nuclear power will need to play a significant role if the government takes actions to reduce CO_2 emissions from electrical production on the national grid. An addition of up to 450 GW(e) of nuclear power has been projected by 2050 in Reference 9 and in EPA assessments of the impact of pending Congressional energy legislation[13] to meet government emissions reduction objectives.

Table 9. Summary of electrical generating plant costs.[13]

Technology	Nominal Capacity (kilowatts)	Heat Rate (Btu/kWh)	Overnight Capital Cost (2010 $/kWe)	Fixed O&M Cost (2010 $/kWe)	Variable O&M Cost (2010 $/MWhe)	Years to Construct	Capacity Factor (from EIA 2009 Data)	Fuel Price, $/MMBtu	$/Mwhe
Single Unit Advanced PC	650,000	8,800	3,167	35.97	4.25	3	0.85	2.27	109.40
Single Unit Advanced PC with CCS	650,000	12,000	5,099	76.62	9.05	3	0.85	2.27	136.20
Conventional NGCC	540,000	7,050	978	14.39	3.43	1	0.87	5.71	66.10
Advanced NGCC	400,000	6,430	1,003	14.62	3.11	1	0.87	5.71	63.10
Advanced NGCC with CCS	340,000	7,525	2,060	30.25	6.45	1	0.87	5.71	89.30
Conventional CT	85,000	10,850	974	6.98	14.70	1	0.30	5.71	124.50
Advanced CT	210,000	9,750	665	6.70	9.87	1	0.30	5.71	103.50
Dual Unit Nuclear	2,236,000	10,000	5,335	88.75	2.04	7	0.90	0.90	113.90
Biomass BFB	50,000	13,500	3,860	100.50	5.00	2	0.83	2.74	112.50
Onshore Wind	100,000		2,438	28.07		1	0.34		97.00
Offshore Wind	400,000		5,975	53.33		2	0.34		243.20
Solar Thermal	100,000		4,692	64.00		1	0.18		311.80
Large Photovoltaic	150,000		4,755	16.70		1	0.25		210.70
Hydro-electric	500,000		3,076	13.44		3	0.52		86.40
From EIA Updated Plant Costs 2010									

A 2,400 MWt HTGR plant using a Rankine steam turbine generator produces about 975 MWe. If the HTGR were assumed to account for 10% of the total nuclear power deployment on the grid in the time frame 2020 to 2050, forty-six 2,400 MWt plants (184 reactor modules rated at 600 MWt) would be required. If the HTGR plants were replacing only natural gas fired plant, the reduction in CO_2 emissions in 2050 would be ~150 million metric tons per annum and natural gas consumption would be reduced by 3.4 trillion cubic feet per annum. If the HTGR plants were substituted for coal plants the reduction in CO_2 would be ~300 million metric tons per annum.

2.4.5 Summary of Deploying HTGR Technology

Table 10 summarizes the results of the assumed deployment of HTGR technology in the four sectors described above.

Table 10. Summary of results.

Item	Power Requirement (MWt)	Number of 600 MWt Modules	CO_2 Emissions Reductions (million metric tons)	Natural Gas Usage Reductions (trillion cubic feet)
Co-generation and process heat	75,000	125	110	2.2
Hydrogen production	36,000	60	15	0.44
Oil sands	18,000	30	23	0.41
Coal/biomass to fuel and feedstock	249,000	415	80 to 410	N/A
Electricity generation	110,400	184	~150 replacing CCGT* or ~300 replacing coal plant	3.4 (if replacing 150 CCGT units)
TOTALs	488,400	814	378 to 858	6.45
* combined cycle gas turbine.				

Full realization of this estimate in penetrating the targeted markets for the HTGR technology would result in:

- Deployment of 488,400 MWt of HTGR technology (~800 reactor modules rated at 600 MWt)
- Providing steam, electricity, and high temperature gas to the process heat market; providing steam and hydrogen for bitumen recovery and upgrading from oil sands; producing hydrogen for the merchant market; and producing synthetic fuels and feedstock from coal and biomass
- Providing a significant fraction of non-greenhouse-emitting electricity generation on the national electrical grid
- Reducing the importation of ~2.4 million bpd of imported crude oil (~25% of the imported oil in 2009); replacing the equivalent in crude-oil-based gasoline and diesel fuels with synthetic transportation fuels produced from coal
- Implementing a beneficial and efficient use of coal without generating greenhouse-gas emissions
- Reducing ~6.5 trillion scf in natural gas consumption in the United States, per annum
- Reducing CO_2 emissions by ~400 million metric tons per annum (reducing by ~8% the total CO_2 emissions in the United States).

3. SCHEDULE AND BENEFITS TO DEPLOYMENT OF HTGR TECHNOLOGY

Based on the current NGNP Project schedule the first-of-a-kind HTGR module is targeted to begin operation in the 2023 time frame. This is anticipated to be the first module in a multi-module plant supplying energy to an industrial process. It is assumed that the subsequent deployment of HTGR technology to achieve the broad range of applications targeted by the NGNP Project would occur in the mid-2020 to 2050 range. The NGNP Project has evaluated the impact of this potential deployment of the HTGR technologies in combination with other initiatives of U.S. energy infrastructure transformation to address energy security, price volatility, natural resource management, and CO_2 emission reductions.[1] This referenced evaluation assumed a larger deployment of the HTGR technology than is described herein, concluding that in addition to effecting a reduction in the need to import crude oil, full deployment of the HTGR technology would reduce projected annual CO_2 emissions in 2050 by ~915 million metric tons. This is ~16% of the total reductions in CO_2 emissions in 2050 that are required to meet the emission reduction objectives of the Administration and Congress.[14]

In summary, there are several benefits in pursuing all of the potential applications identified for use of the HTGR technology:

- Application of the HTGR in all of the potential industrial process applications preserves our limited natural resources. Many of these processes use significant quantities of natural gas (e.g., for steam production and generation of hydrogen). The use of the HTGR technology in place of natural gas preserves this nonrenewable natural resource for more beneficial purposes.
- Application of the HTGR supports improving the energy security of the United States by reducing the need to import crude oil and natural gas.
- The use of coal and biomass as feedstock for transportation fuel production with the HTGR as the source of process heat and cogeneration supports the beneficial use of one of the most abundant forms of energy in the United States. Coal and biomass can also be converted to feedstock for petrochemical processes, thereby reducing the usage of natural gas for this purpose and improving the security of this feedstock supply.
- Changes in the long-term operating costs for production of energy from an HTGR will be affected only by traditional inflationary factors affecting personnel wages, utilities, and commodities. They will not be subject to the volatility experienced in the prices of fossil fuels over the last decade as with natural gas.

Figure 16 shows the volatility of natural gas by plotting the historical and projected prices of natural gas since 1990 and projected to 2035 by DOE-EIA.[15] Three projections from 2009, 2010, and 2011 of natural gas prices are shown on this figure. The large variation in price projections reflects the volatility of natural gas prices and the emergence of recovery of large shale gas reserves in the United States over the last several years. Figure 17 shows the projections by EIA for the increase in production of shale gas that is the underlying factor that led to the lower projected price of natural gas in EIA AEO 2011. There are many factors that can affect both the projections of shale gas production and pricing that add uncertainty to these projections, (e.g., high demand and pricing offshore that leads to increased export of natural gas and increased domestic pricing, energy parity with other carbon fuels such as oil, environmental concerns with shale gas fracking, government regulation of carbon emissions).

Although energy pricing from the HTGR supply will be affected by market conditions the inherent stability in its operating costs will support establishing longer term stability in energy pricing to improve confidence in the long term planning of the supplied industrial processes. This not only helps to insulate these processes from energy price volatility, but also from potential disruption of sources of fossil fuels.

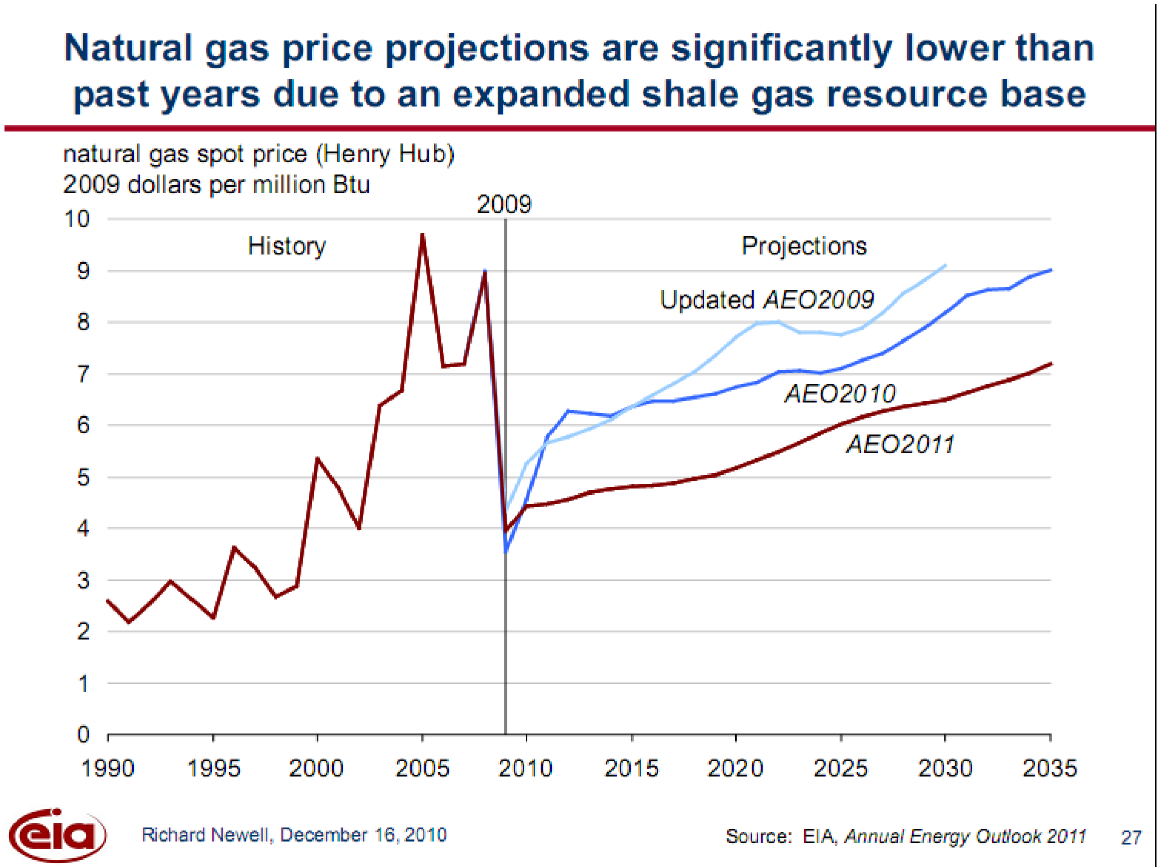


Figure 16. History and projections of utility user natural gas prices for 1970 to 2030.

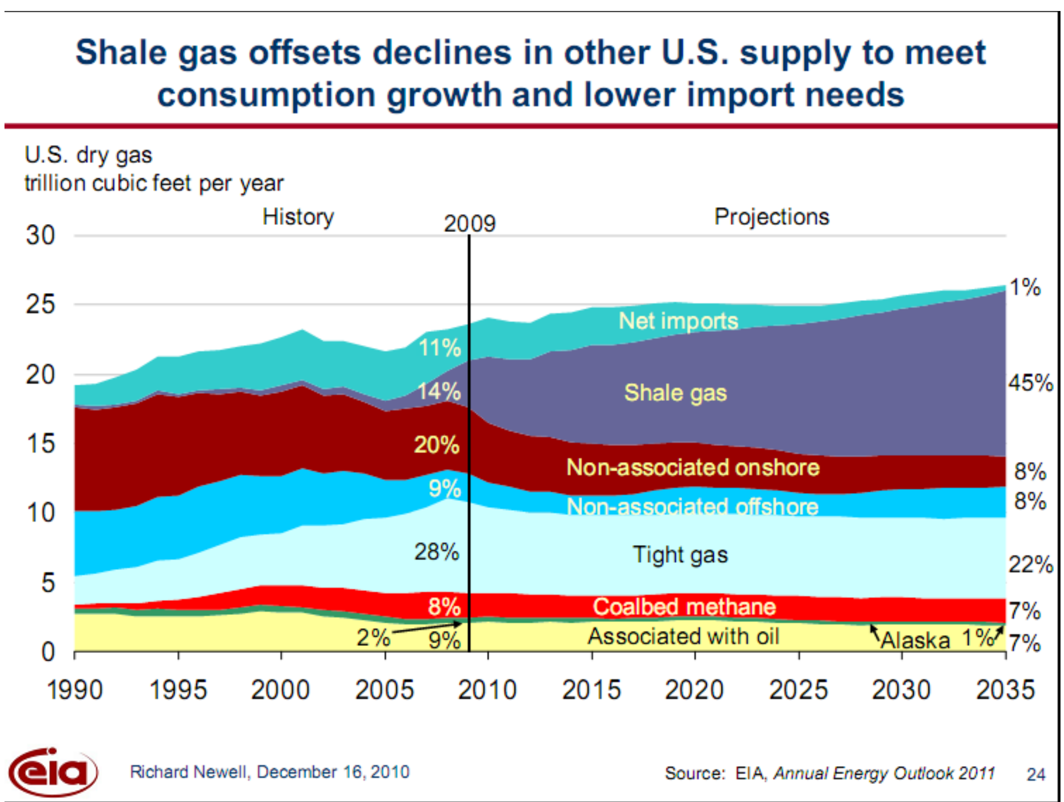


Figure 17. EIA Projections of the Sources of Natural Gas Production through 2035

Use of the HTGR technology in these applications eliminates the significant amounts of greenhouse gas emissions released by traditional processes. A comparison of the CO_2 emissions of conventional processes for coal-to-liquids production and traditional crude oil refining with that supported by the HTGR technology for the production of transportation fuels is shown above in Figure 15. As can be seen, the HTGR essentially eliminates CO_2 emissions from the production phase (well to tank). This avoids cost pressures that may evolve from future governmental actions to curb carbon emissions.

4. TECHNICAL AND ECONOMIC EVALUATIONS OF HTGR TECHNOLOGY INTEGRATION WITH INDUSTRIAL PROCESSES

The NGNP Project has performed technical and preliminary economic evaluations of integrating the HTGR technology with several conventional processes.[16] These evaluations cover the specific processes within the applications discussed in the characterization and sizing of the potential HTGR markets above, as well as the others identified in the following:

- Co-generation applications supplying steam, electricity, and hot gas as well as for electricity only production.
- Bitumen recovery and upgrading in the Canadian oil sands
- Coal and natural gas derivatives production including ammonia from coal and natural gas, converting natural gas and coal to liquid fuels such as gasoline and diesel, and converting coal to substitute natural gas
- Petrochemicals production such as supplying steam, electricity, and hot gas to support conversion of natural gas to chemical products
- Production of hydrogen such as substituting HTGR hot gas for combustion of natural gas in the SMR process, eliminating natural gas burning and feedstock through the use of HTSE for the production of hydrogen and oxygen
- Production of ammonia and ammonia derivatives (e.g., Urea, fertilizers) using HTGR steam and hot gas as a substitute for burning natural gas or to supply pure hydrogen and nitrogen directly to the ammonia synthesis reactor using the HTGR and HTSE
- Shale oil recovery applying the ex-situ and in-situ processes
- Coke/steel production
- Sensitivity of the technical viability of using HTGR heat in the Steam Methane Reforming process as a function of the HTGR reactor outlet temperature Biomass conversion to gas or liquids
- Methane hydrates.

The medium category processes identified in Section 2 include those that require higher temperatures than the HTGR technology can currently supply. As noted for cement production, however, it is possible that revisions to the process could reduce the temperature requirements to be compatible with HTGR temperatures and improve the efficiency of the processes. These will be explored in the future as the next set of priorities for the project or as specific potential end users in these areas are consulted.

5. BUSINESS CONSIDERATIONS IN APPLYING THE HTGR TECHNOLOGY TO INDUSTRIAL APPLICATIONS

5.1 The Business Model

The integration of the HTGR technology with industrial processes involves the transport of energy from the modular reactors to the processes in the form of steam, electricity, high temperature gas, or other heat transport fluid (e.g., molten salt), and could include hydrogen and oxygen, depending on the process needs and the plant configuration. This is similar to current co-generation arrangements in many industrial processes wherein a central plant co-located with the process will provide energy to the process. Many of the current co-generation plants use natural gas or waste gas to generate the energy. These co-generation plants may be owned and operated by the owner/operator of the process or by a separate entity. In the latter case, the energy is delivered under contract “over the fence.” For a nuclear co-generation plant, it is judged to be unlikely that a traditional owner/operator of an industrial plant (e.g., petrochemical, refining, ammonia/fertilizer) would undertake operation of the nuclear plant, because of their lack of experience with its licensing and operating requirements. Accordingly, an entity with nuclear plant operating experience, separate from the industrial plant owner/operator, could operate the nuclear plant. The owner of the nuclear plant would enter into a contract with the industrial plant for supply of energy in the required forms “over the fence” to the processes.

Figure 18 shows a possible business model. It illustrates the likelihood that there would be several “owners” (i.e., equity holders) of the HTGR plant. The principal owner of the plant may or may not be the operator. The HTGR could also be supplying energy to more than one industrial facility and have multiple energy supply agreements. It is also assumed that the plant would be selling excess generated electricity to the grid. As noted in the prior discussion of the co-generation application selling excess electricity to the grid is a common arrangement for these plants.

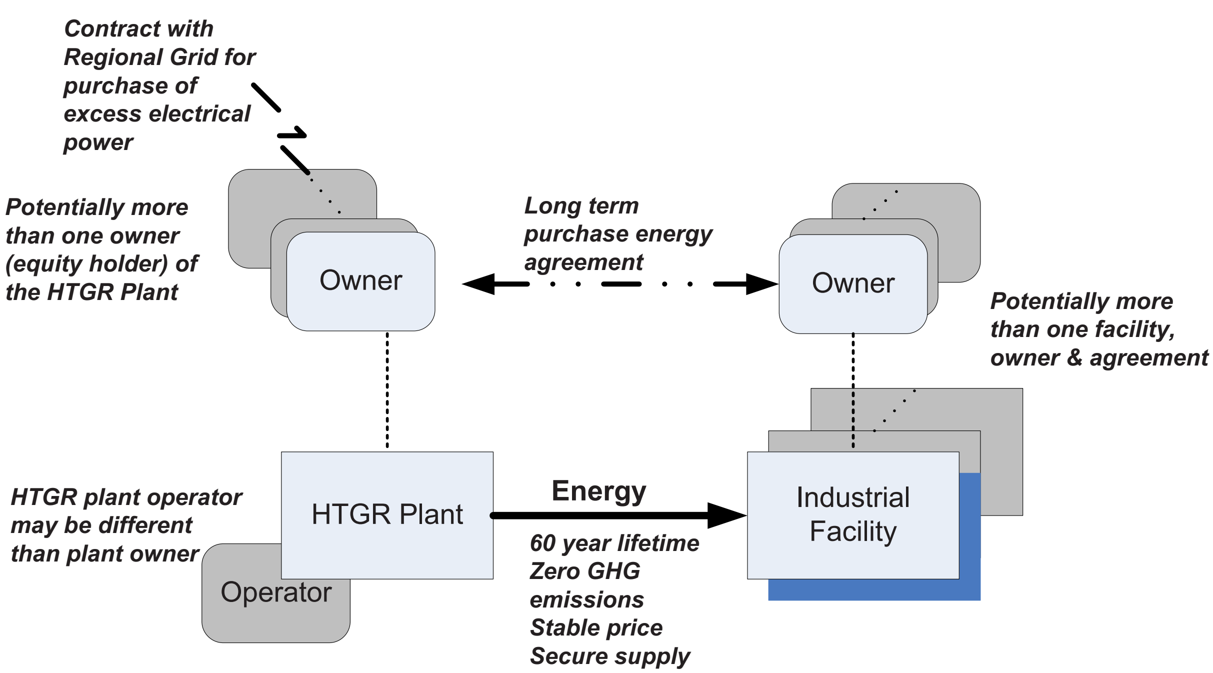


Figure 18. Business Model

The “business model” used in the economic analyses performed for each of the potential markets varies depending on the market. For the cogeneration market the prices for the steam, electricity and hot gas supplied to the industrial facility are calculated. A prospective industrial plant would evaluate whether those prices are judged to be competitive with traditional fossil sources of energy over the long term (60 years or more). In this case the HTGR plant is supplying energy "over the fence" and is, therefore, not tightly coupled with the process. In this model there is a distinct division between the HTGR plant and the industrial facility.

In other markets, (e.g., hydrogen generation) the HTGR can be tightly coupled with the process and the projected price of the product, (e.g. hydrogen) is calculated and compared with projected prices using conventional processes. This can blur the line between the owners of the HTGR plant and the owners of the industrial plant. In these cases the costs for construction and operation of both the HTGR plant and the industrial plant are combined in the economic analyses.

5.2 HTGR Plant Economics versus CCGT Economics

There are fundamental differences in the economics of a nuclear plant as the energy supplier to a process compared with that of a natural gas fired combined cycle gas turbine (CCGT) plant. The latter is a common co-generation application in the industrial sector. As shown in Figure 19, in a natural gas fired plant the fuel costs account for the majority of the annual operating costs. These plants can, therefore, be cycled without major economic penalty. Much of the combined cycle plant equipment is also more "portable" than nuclear plant equipment and could be re-located if the original energy market becomes no longer available.

As shown in Figure 19, the nuclear plant costs are comparatively capital recovery intensive with low operating costs. The nuclear plant will also have a longer lifetime (e.g., 60 years) than the typical fossil based CCGT plant, (e.g., 20 to 30 years). The recovery of capital accounts for approximately 70% of the annual costs of operating a new nuclear plant compared to about 30% for a CCGT plant. Since the capital recovery is a fixed annual cost the nuclear plant must run at a high capacity factor to be economic compared to the CCGT plant. The nuclear plant also requires a long term stable energy market. This puts a premium on developing and sustaining an energy demand profile for the nuclear plant that maximizes its long term availability and capacity factor.

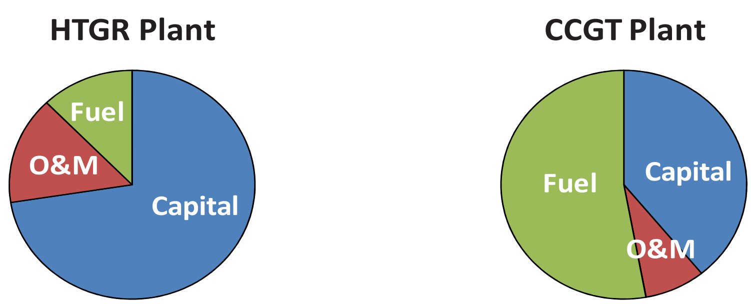


Figure 19. Comparison of the operating cost elements of an HTGR with a CCGT plant. (Developed in Excel file, "CCGT (7FA) steam & elec 5-24-11")

5.3 Example of Possible HTGR and Industrial Plant Business Cases

When the HTGR plant is supplying energy "over the fence," (i.e., is a separate entity from the industrial facility) there are two business cases that must be compatible to make integrating the HTGR technology with the industrial application economically viable: (1) that of the HTGR plant owner who will set a price for the delivered energy that fulfills his project economic criteria (e.g., return on the equity investment), and (2) that of the industrial plant owner who must be able to meet his economic criteria at that price of energy (e.g., setting a price for his product that is competitive and provides the requisite return and provides a hedge on feedstock real escalation and/or volatility). Evaluations of specific applications of this nature have shown that it is important to separate these two business cases because there are substantive differences in the economic factors such as debt ratio, period of financing, interest rates, and required return on investment typically applied by these two entities.

There are other factors that need to be considered in assessing the economic viability of the application.

- The HTGR plant may need to be oversized from that size required to meet the basic energy needs of the industrial process so that availability requirements for supply of the energy can be assured. Close to 100% availability requirements are typical for much of the energy supply for an industrial process. The HTGR plant owner could be expected, therefore, to assess whether there are other potential markets to which any excess energy can be offloaded. The local electrical grid is a potential taker of any excess energy. The viability of this alternative is driven by the economics of the regional electricity generation market.
- The nuclear plant owner will evaluate whether there are other industrial plants in the area or needs of the regional grid that would permit deploying an even larger plant. There are economies of scale that can accrue from siting a larger rated plant.
- The HTGR plant owner will evaluate both the regional electrical grid and other industrial plants as potential long-term alternatives for delivery of the energy if, over the longer term, the primary industrial plant is shuttered or production curtailed because of evolving economic conditions or other factors.

In a back-fit project, the owner of the industrial plant will need to assess how much, if any, of the original energy production equipment to retain in operation as backup to the HTGR plant. This may be a phased activity—less backup equipment is retained as more confidence in the reliability of the HTGR plant is developed.

For either a back-fit or Greenfield application, the owner of the industrial plant may include other factors than the price of the delivered energy in evaluating the viability of the HTGR plant as a long term energy supply. Some of these factors could include:

- The HTGR plant provides a long term (60 years or more) stable cost of energy; separating the costs of production from the significant volatility of fossil fuel prices experienced over the last decades, thus adding more certainty to future planning.
- The HTGR plant integrated with carbon conversion processes provides a long term secure and dedicated source of energy carriers and feedstock; eliminating concerns with disruption of energy carrier and feedstock supply from the traditional fossil sources.
- The HTGR plant is a non-greenhouse gas emitting source of energy, eliminating concerns with the effects of potential government policies that result in a cost for carbon emissions contributing to the volatility of the price of fossil energy.
- Fossil energy sources currently used for energy production (e.g., oil, natural gas, coal) may have more financial benefit as feedstock to the process. For example, the waste gases that were formerly burned in the power houses may be convertible to revenue producing products. When waste gas is used to provide energy to an industrial process, the differential between the cost of imported sources of the fossil fuel (e.g., natural gas) and the market price of the product that could be produced from the waste gas and the cost of processing the waste gas are key factors in the economics of such a conversion. In the conventional processes reviewed by the Project, these factors lead to the decision to burn the waste gas rather than process it. The factors affecting the economics of such conversion will be different with an HTGR energy source, and may be more favorable.
- For future Greenfield applications, improved efficiencies and economics are expected in the processes by reengineering them for integration with the nuclear plant.
- The schedule for initial deployment of an HTGR plant is expected to be in the mid- to late-2020s, assuming a focused and stable NGNP Project is established. While there is high uncertainty in predicting the sources, forms, and costs of energy that far into the future, the national commitment to secure the option as a hedge for such uncertainties needs to be established now.

6. EXAMPLES OF APPLICATION OF THE HTGR TO INDUSTRIAL PROCESSES

The following sections discuss the results of NGNP Project evaluations of the application of the HTGR technology to supplying all or some of the energy needs of industrial processes. The first—co-generation—is judged by the Project and the HTGR suppliers to have low technical risk, a large potential market, significant energy price stability, energy security and environmental benefits, and economic viability. This judgment is based on the nature of the energy needs of this application; principally steam, electricity, and hot gas with modest temperature requirements, (e.g., 700 to 850°C).

The latter two processes (conversion of coal to transportation fuels and ammonia and ammonia derivative production), which are discussed below, represent applications of the HTGR technology that address principally energy security by providing alternatives to imported crude oil and natural gas as feedstocks. These are more developmental than co-generation, relying, in some cases, on the development of the HTSE process for hydrogen production and higher HTGR operating temperatures to optimize the performance of that process. The economic evaluations of these two applications are, therefore, more uncertain. In any event, they are judged to be applications that require continued development to ensure that the benefits of HTGR technology in securing our energy sources, stabilizing our energy costs, preserving our natural resources, and reducing CO_2 emissions are fully realized. The NGNP Project has received support for this continued development in discussions with major companies involved in these applications.

The economic evaluations discussed below use engineering, procurement and construction (EPC) cost estimates and operating cost estimates for a mature HTGR plant that have been developed by the NGNP Project.[17] These cost estimates were developed by review of prior HTGR plant design work, (e.g., General Atomics designs of the MHTGR, NPR and GT-MHR, NGNP Project FY07 Pre-conceptual design work), special studies conducted for the NGNP Project by HTGR suppliers, current costs for common power plant components, (e.g., circulators, steam turbine generators, pumps) and bottoms up estimates of major components, (e.g., vessels). The cost estimates vary depending on the rating of each HTGR module, the reactor outlet temperature of the reactor, the rating of the multi-module plant and the plant configuration, (e.g., includes steam generators and/or intermediate heat exchangers, type and number of power conversion systems). Correlations were developed from the basic data to facilitate developing a cost estimate for a specific plant design considering module rating, plant rating, reactor outlet temperature and plant configuration. These cost estimates and correlations also consider three possible states for plant deployment; these are: as a first-of-a-kind demonstration plant, during the "learning curve" transition from the costs for a demonstration first-of-a-kind plant to an Nth-of-a-kind plant and as an Nth-of-a-kind plant). All of the analyses discussed below were performed for an Nth-of-a-kind plant status.

It should be noted that because the Project is still in the preconceptual design phase, there is large uncertainty in these costs. The Project is progressing into the conceptual design phase wherein more certain estimates of capital costs for the mature plant will be developed. The economics will be updated, as necessary, as the cost estimates become more certain.

6.1 Co-generation

This application involves the supply of energy to an industrial process typically in the form of steam, electricity, and/or hot gas from a power plant located either outside the industrial facility or embedded in the facility. The power plant may be owned and operated by an entity separate from the owner/operator of the industrial facility or be a part of the facility itself. A large number of these power plants in the United States are fired using natural gas or coal and waste gas from the industrial processes. These plants typically include some combination of steam boilers, steam turbine generators, and natural gas combined cycle (NGCC) plants. In a back fit application, the HTGR would replace or augment the installed equipment. In a Greenfield application, the HTGR would be the principal energy supply. As noted previously the schedule for commercial deployment of the HTGR plant is currently projected for the mid-2020s. By this time it is anticipated that there will be some governmental action on control of carbon emissions. Accordingly, whether the deployment of the HTGR is in a Brownfield or Greenfield application the most likely alternative energy supply that the HTGR would be compared with would be an advanced NGCC (higher efficiency than current models) with carbon capture and sequestration (CCS). The energy costs for the HTGR in a co-generation application are compared below with those of an Advanced NGCC w/CCS.

As noted in previous sections, it is likely that the HTGR plant would not be operated by the owner of the industrial plant, but rather by an entity with nuclear plant operating experience such as a current nuclear power plant owner/operator. The NGNP Project and the HTGR suppliers have worked with several owner/operators of industrial plants and with an owner/operator of nuclear electrical power plants to develop business cases for this co-generation application.

Figure 20 shows a comparison of the prices of electricity and steam from a new HTGR plant with that of a new advanced natural gas fired combined cycle gas turbine plant with carbon capture and sequestration (ADV NGCCw/CCS) as a function of the price of natural gas. Also shown on this Figure are historical electricity prices as a function of the price of natural gas. The HTGR plant is sized at ~2400 MWt—the rating required to supply a modest sized industrial plant with steam and electricity. It is compared with an Advanced NGCC w/CCS plant using EIA data on projected costs of generating electricity with several different technologies.[12] The historical data for the price of electricity and steam as a function of natural gas price was provided by General Atomics as part of preparing a conceptual design report of a prismatic reactor co-generation plant.[5] These comparisons are made for varying costs of natural gas in $/MMBtu. This variation with natural gas price is shown because, as noted previously, the fuel costs dominate the costs of operating a natural gas fired plant. Two curves are shown for the HTGR illustrating the change in the costs when varying the internal rate of return on equity from 10 to 15%

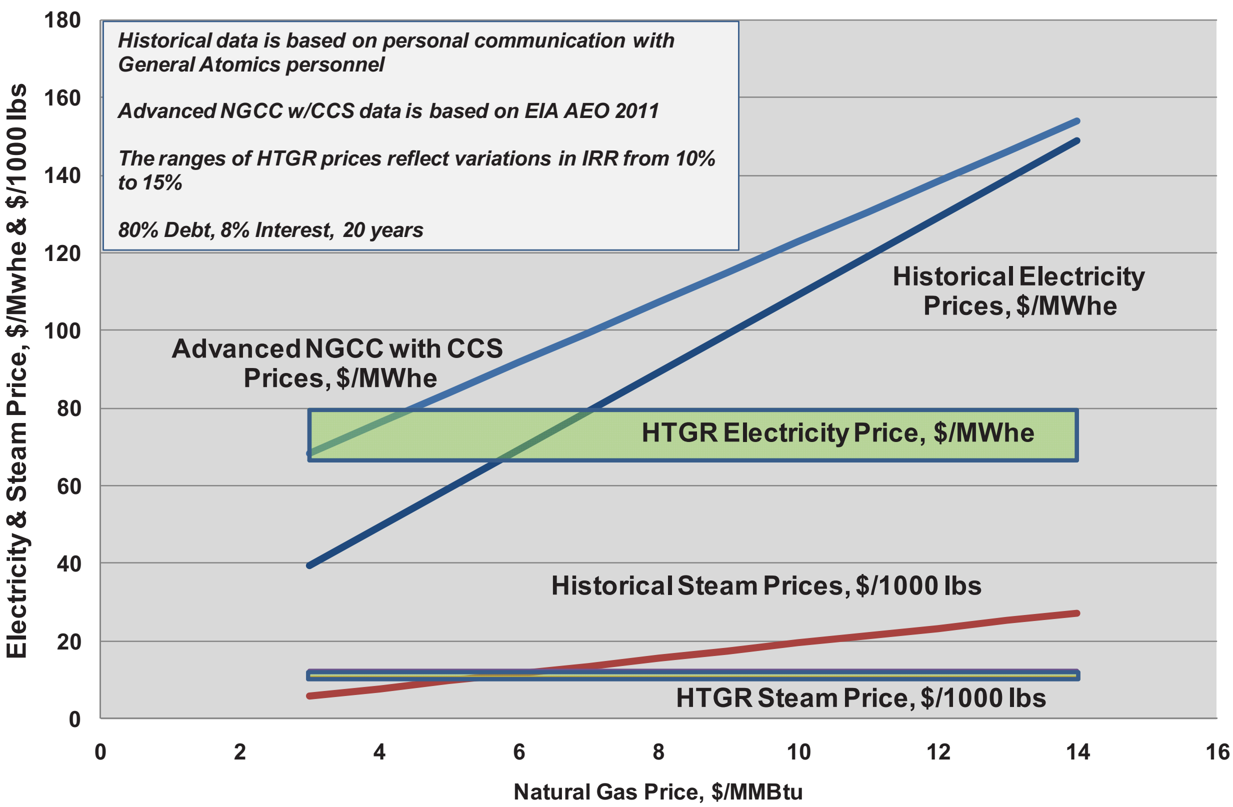


Figure 20. Comparing the price of electricity and steam for HTGR and NGCC plants (2009$). (Developed in Excel file, "Baseline Co-gen Plant – 4-600 MWt_8-04-11")

As shown in Figure 20 the price for the HTGR plant electricity and steam is equivalent to that of the Advanced NGCC w/CCS plant at natural gas prices in the range \$3 to \$7/MMBtu, depending on whether the comparison is made with historical prices or Advanced NGCC w/CCS prices and the IRR used for the HTGR plant. As shown in Figure 16, over the last 5 years, natural gas prices have ranged from a low of ~\$4/MMBtu to a high of ~\$13/MMBtu with high volatility. As also shown in Figure 16, the EIA projects a natural gas price in the \$7/MMBtu (2009\$) range in the time frame for deployment of HTGR plants, (i.e., mid-2020s and in the competitive range for the HTGR).

The HTGR will also reduce the use of natural gas burning for this purpose, thereby preserving this limited natural resource for more beneficial uses. The HTGR also eliminates the CO_2 emissions that result from the burning of natural gas. Based on the EIA data, a base loaded (87% capacity factor) 340 MWe NGCCw/CCS plant would burn ~20 billion cubic feet of natural gas (~1000 million lb) and emit ~1,040,000 metric tons of CO_2 per year. Two of these NGCCw/CCS plants plus augmenting steam generators (also fired on natural gas or waste gas) would be required to meet the steam and electricity supply of the HTGR plant. The steam generators would also contribute to the emissions of CO_2 and, when fired on natural gas, the consumption of natural gas.

6.2 Conversion of Coal to Gasoline

One of the processes evaluated by the NGNP Project in the HTGR Integration with Industrial Process Task[11] is the conversion of coal to gasoline using the methanol to gasoline (MTG) process. Liquid petroleum gas (LPG) is also produced in this process. In each of these evaluations of the potential for integration of the HTGR in the process, the conventional process is first modeled to determine where the HTGR could be used and to define the specific requirements for the HTGR application (e.g., heat input, electricity generation, hydrogen production). The conventional MTG process modeled for this evaluation is shown schematically in Figure 21.

Figure 22 shows the process with an HTGR energy source. The proposed process includes the same unit operations as the conventional coal-to-MTG process with the following exceptions: the cryogenic air separation unit and water gas shift reactors (a part of the gasification and syngas conditioning block) are replaced by high temperature steam electrolysis (HTSE) to provide oxygen and hydrogen for the process.

Figure 23 summarizes the results of the evaluation. In both cases ~67,000 bpd of gasoline and LPG are produced. As shown in this figure, the use of the HTGR energy source to supply heat and hydrogen reduces CO_2 emissions from the conventional process by a net amount of 100 to 31,000 tons per day (0.04 to 10 million tons per year) depending on the amount of CO_2 that can be captured in the conventional process.

Figure 24 summarizes the economic evaluation of this HTGR application. This figure shows the production price of gasoline for the conventional and HTGR integrated processes required to meet the economic criteria summarized on the figure as a function of the cost of CO_2 emissions. As shown, the HTGR plant is competitive with the conventional process for costs of CO_2 emissions in the \$75/ton range. The historical range in the price of gasoline in 2008 is also shown on this figure for information. Use of the coal-to-MTG process for production of gasoline using either the conventional or HTGR integration approach falls within the upper end of this range.

Figure 25 shows the gasoline pricing for the conventional and HTGR integrated process and for crude oil refining as a function of crude oil price in \$/bbl. The price of crude oil has varied considerably over the last decade (~\$25/bbl in January 2000, ~\$130/bbl in July 2008). As shown, the conventional coal to MTG process is competitive with crude oil refining at crude oil prices in the range of \$80/bbl (note the price range of crude oil at the time of this writing was in the range of ~\$100/bbl) with no cost associated with CO_2 emissions. At a cost of \$50/metric ton of CO_2 emissions, the price of crude oil would have to be in the \$110/bbl range for the conventional coal to MTG process to be competitive with crude oil refining. Similarly, the HTGR integrated process would be competitive with crude oil refining in the \$125/bbl range.

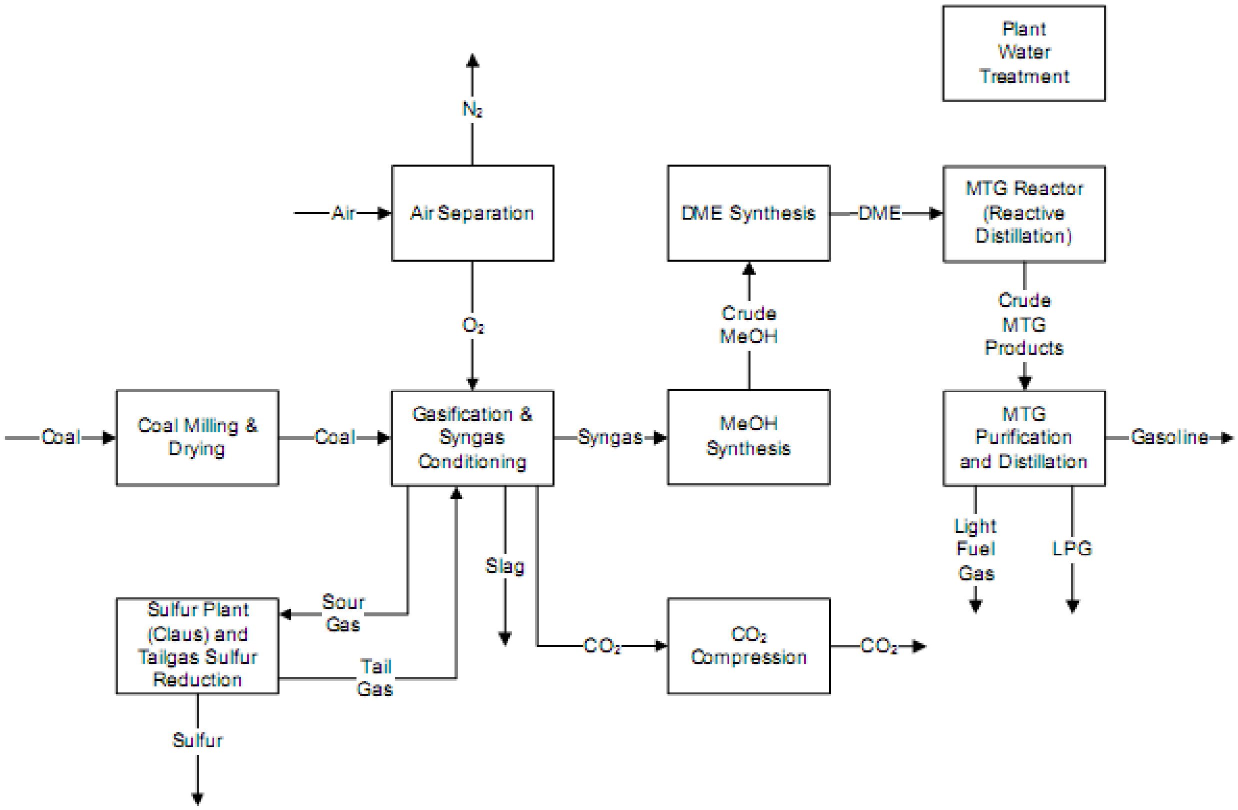


Figure 21. Block diagram of conventional coal to MTG process.

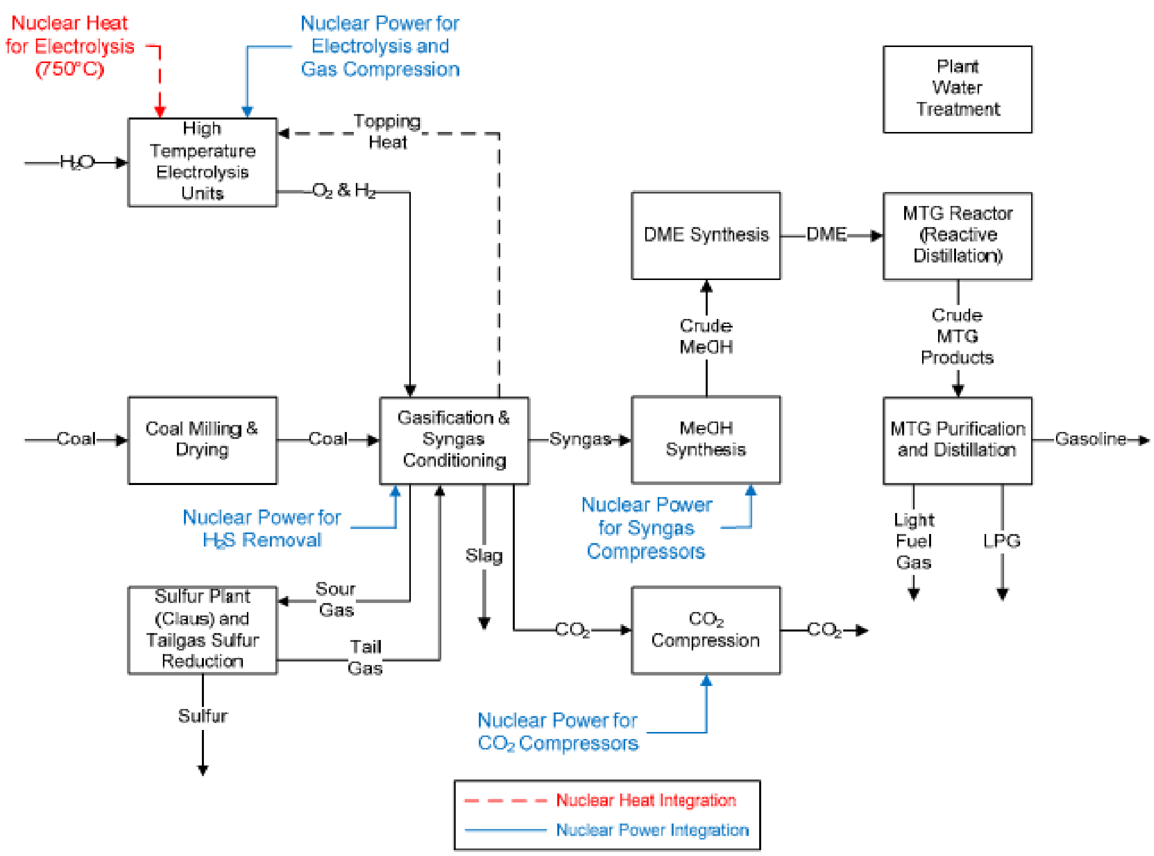
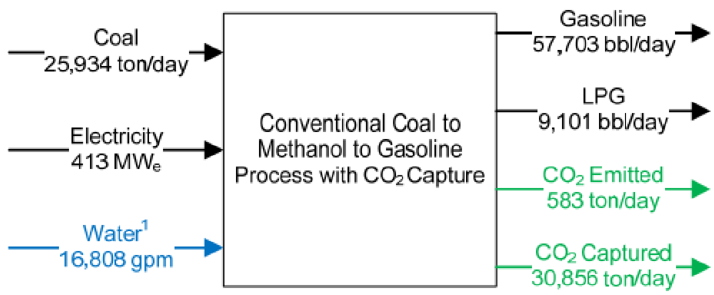


Figure 22. Block diagram of the HTGR integrated coal to MTG process.



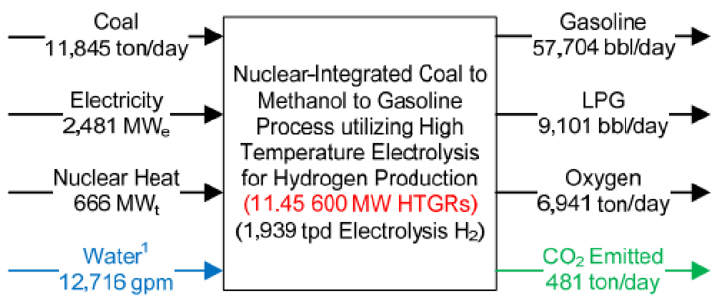


Figure 23. Conventional coal-to-MTG process compared with HTGR integrated coal-to-MTG process.

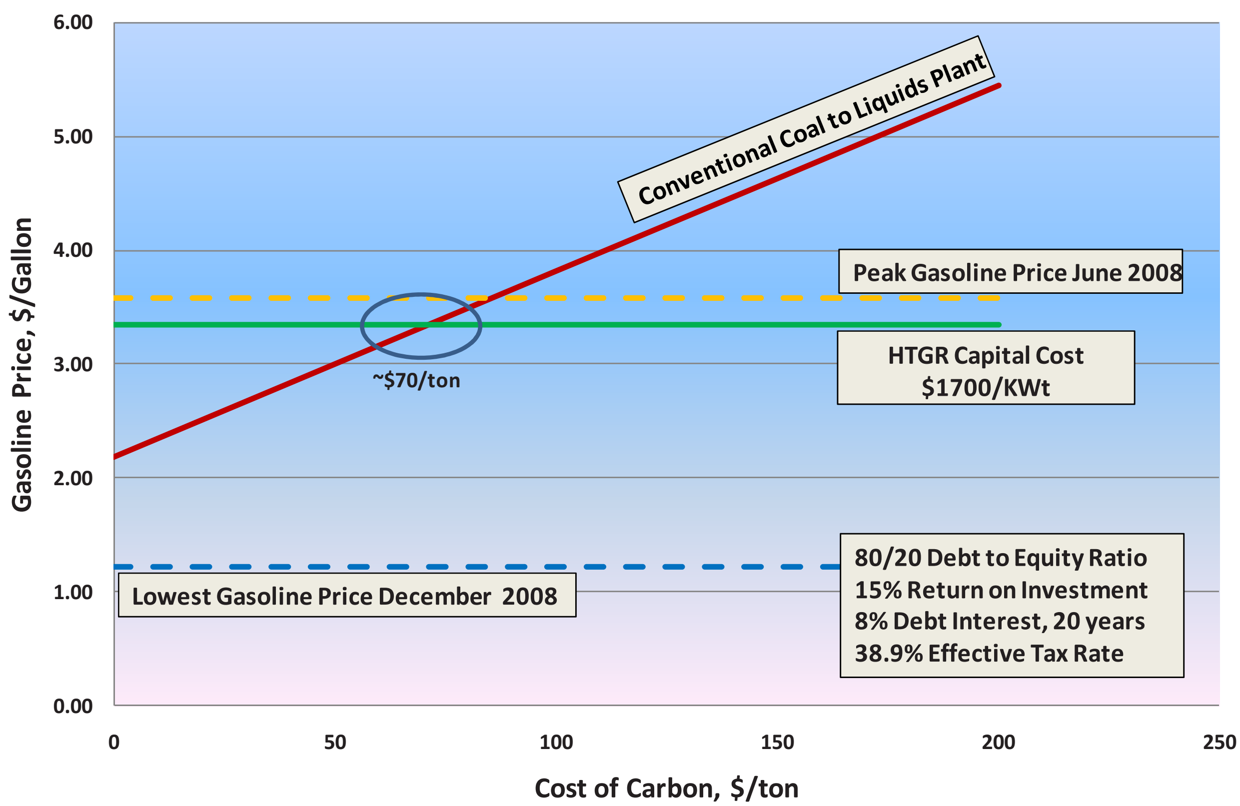


Figure 24. Results of the economic evaluation of conventional and HTGR integrated coal-to-MTG plants. (Gasoline price: well to tank; Peak and Low $/gal between 2000 and 2009, developed in Excel file, "Backup Calcs on Industrial Sector Emissions & Energy Consumption and CTL Plant")

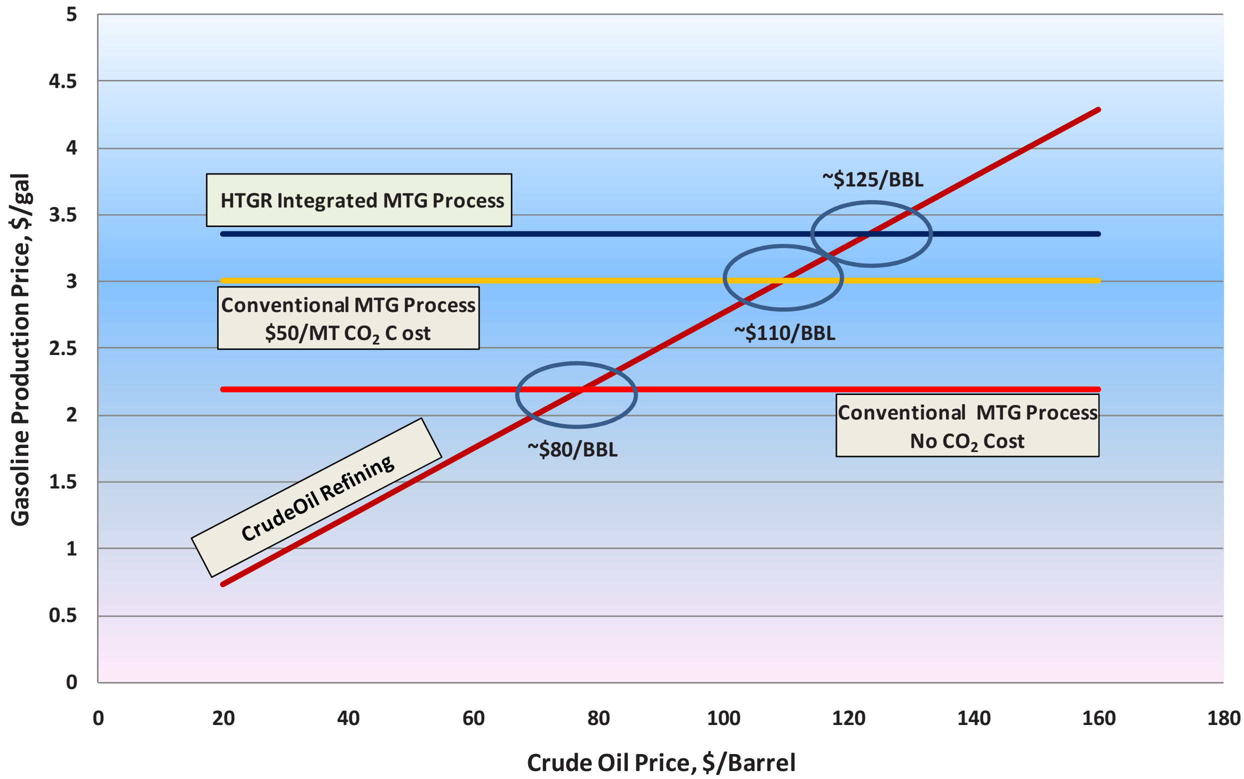


Figure 25. Comparison of the production price of gasoline for crude oil refining, conventional coal to MTG and HTGR integrated coal to MTG processes. (Developed in Excel file, "Backup Calcs on Industrial Sector Emissions & Energy Consumption and CTL Plant")

These results indicate that the application of the HTGR technology to coal-to-MTG production of gasoline is marginally economic for the reference financial and economic factors, even when compared with the conventional process when subjected to additional costs for CO_2 emissions. The large capital cost investment required for the HTGR plant in production of hydrogen, oxygen, and process heat provides a disadvantage when compared with the relative low capital cost for the conventional plant. Additionally, the supply of hydrogen, oxygen and process heat in this case does not significantly reduce the complexity of the MTG plant and eliminate significant components and systems. Therefore, the additional costs of the HTGR plant add to rather than substitute for the majority of the conventional plant costs. The viability of this alternative would also be affected by governmental actions that prescribe the pursuit of substitute transportation fuels.

As the HTGR technology develops the technical and economic viability of the technology for this application will be revisited and continued to be evaluated with potential end users.

6.3 Integration of the HTGR Technology in an Ammonia Production Plant

The NGNP Project has developed detailed process flow sheets for integration of HTGR process heat into processes for production of ammonia and ammonia derivative products such as urea used in the production of fertilizer. These flow sheets were validated by ammonia equipment and system designers, meetings with producers of ammonia, and a tour of an operating plant. Scoping evaluations were also initiated with the objective of comparing the economics of the HTGR integrated plant with the economics of a conventional plant. These analyses were performed for a typical plant producing 2,500 tons per day of ammonia.

In discussions on applying HTGR technology as a source of process heat and reviews of evaluations of integrated processes, a major producer of ammonia and ammonia derivatives recommended that the evaluations focus on just the production of ammonia. The information from that evaluation will facilitate the industry's evaluation of the viability of the output of that process for use of the ammonia as feedstock for further processing. To that end, two different applications of an HTGR integrated plant for the production of ammonia were evaluated. The first used HTGR process heat to offset the burning of natural gas in the primary reforming stages of a conventional process. A simplified flow sheet for this process is shown in Figure 26.

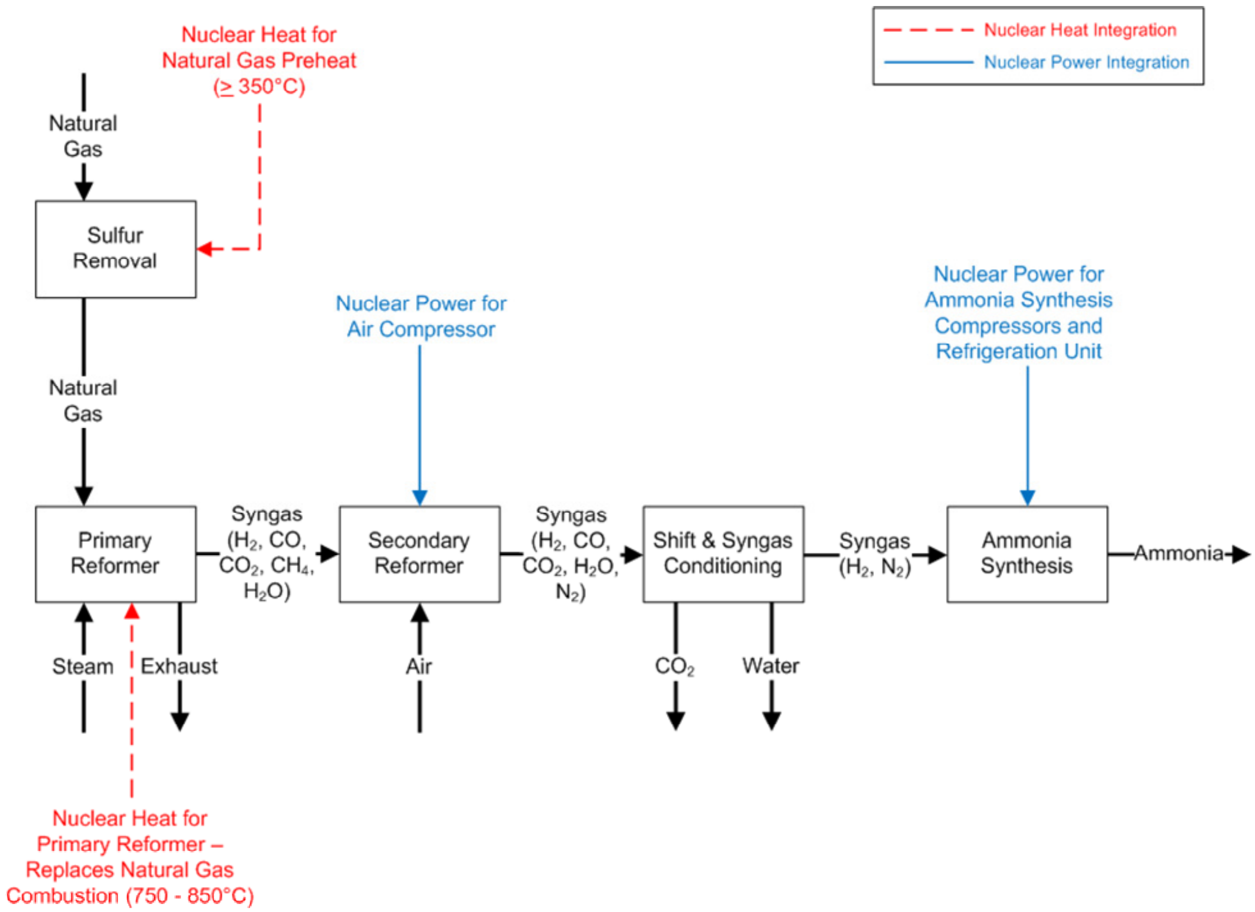


Figure 26. Use of the HTGR instead of natural gas firing in the primary reforming stages.

In the second case, the HTGR plant produces high purity hydrogen and oxygen using the HTSE process. The high purity hydrogen is delivered directly to the ammonia synthesis reactor along with nitrogen produced from a cryogenic air separation unit powered by HTGR generated electricity. A simplified flow sheet for this process is shown in Figure 27. This latter use of the HTGR plant eliminates all of the reforming and purification equipment required to supply the hydrogen from decomposition of natural gas in a conventional process. This reduces the capital investment and operating costs of the ammonia plant, making the use of hydrogen and nitrogen directly for ammonia synthesis potentially more economically attractive.

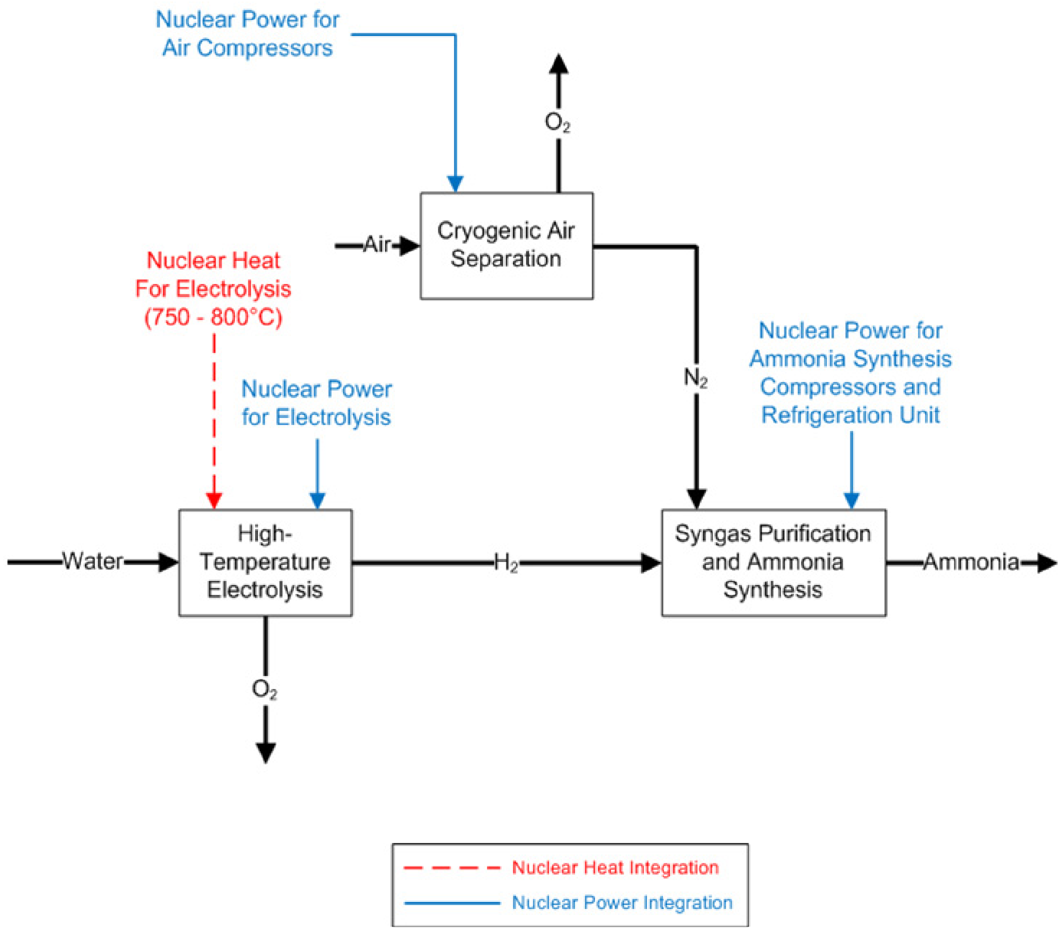


Figure 27. Use of the HTGR for supply of hydrogen directly to the ammonia syntheses reactor.

Both of these uses of the HTGR energy source result in significant reductions in CO_2 emissions compared with the conventional process. Figure 28 summarizes the outputs for the two HTGR cases with the conventional plant. Depending on the case, the emissions that would be emitted from a conventional process are reduced by 22% (Case 1, ~1,000 tons of CO_2 emissions per day) to 98% (Case 2, ~3850 tons of CO_2 emissions per day).

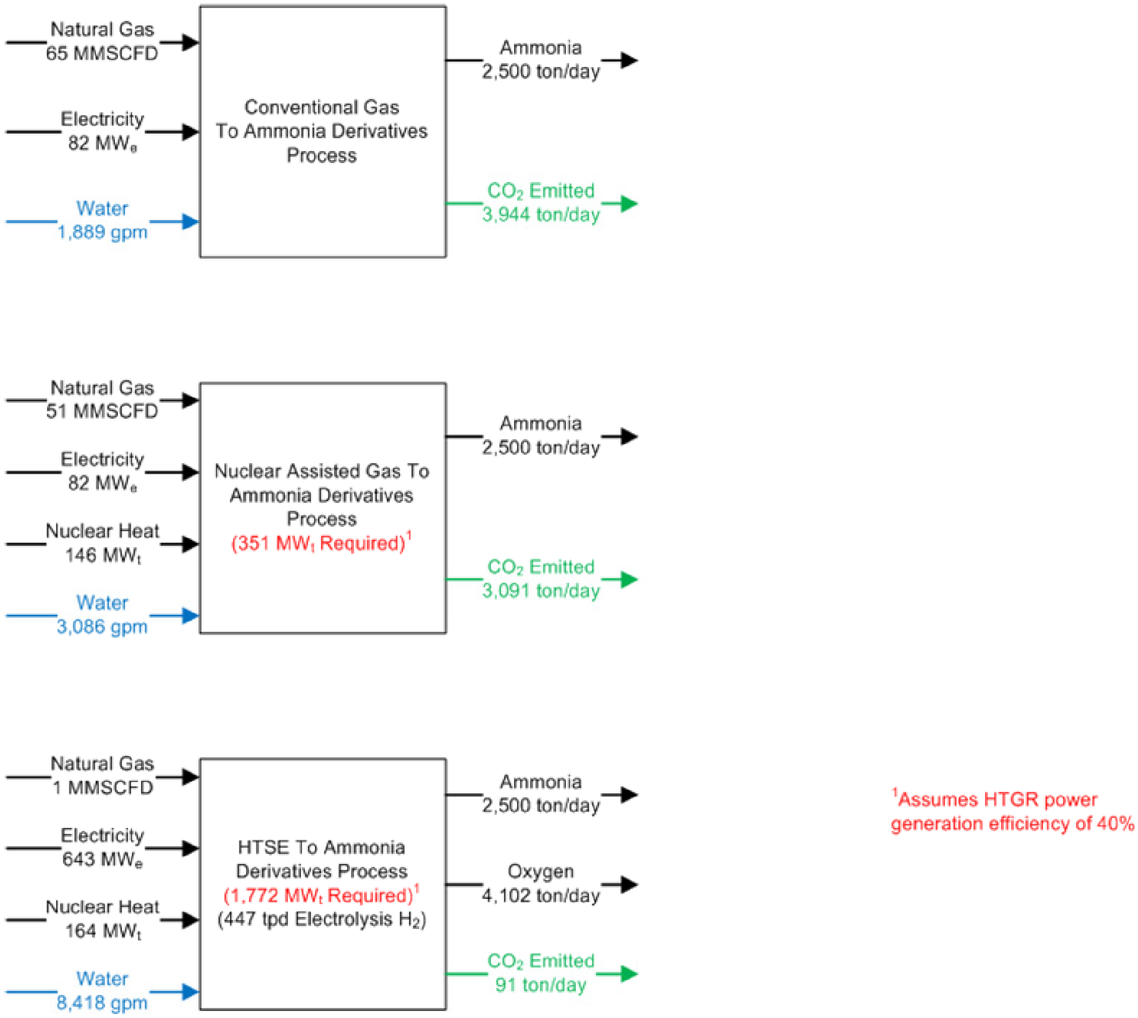


Figure 28. Summary of results for use of the HTGR for ammonia production.

Figure 29 summarizes the results of scoping economic comparisons of the two HTGR integrated plants with a conventional ammonia production plant as a function of the costs for CO_2 emissions in $/ton emitted. The comparison shows the ammonia prices in $/ton that would need to be charged to meet the criteria summarized on this figure (e.g., a 15% internal rate of return on invested equity with a 80% debt-to-equity ratio). The calculations assume a base price of $6.5/MMBtu for the natural gas supply.

The use of the HTGR process heat plant as a substitute for some of the burning of natural gas in a conventional plant has pricing that varies in a manner similar to that of the conventional plant (see Figure 29). Because this case only offsets a fraction of the natural gas combustion, the required pricing increases with the costs of carbon emissions at a rate slightly lower than that for the conventional process. The ammonia pricing for the HTGR process heat plant is comparable to that of the conventional plant at costs of $50/ton of CO_2 emissions.

Figure 29 also shows the results for the option wherein the HTGR hydrogen plant supplies pure hydrogen that is combined directly with nitrogen generated from an ASU in the ammonia synthesis reactor. Ammonia pricing for the economic conditions shown in the HTGR hydrogen plant is projected to be comparable to that of the conventional plant at CO_2 emission costs of ~$160/ton. The economics for this case are based on designs and performance of the HTGR and HTSE plants developed in the NGNP Project FY 2007 preconceptual design task. The Project is continuing to support development and optimization of the HTSE process and the full capabilities of the HTGR technology. As these technologies develop the technical and economic viability of the HTGR technology will be revisited and discussed with potential end users.

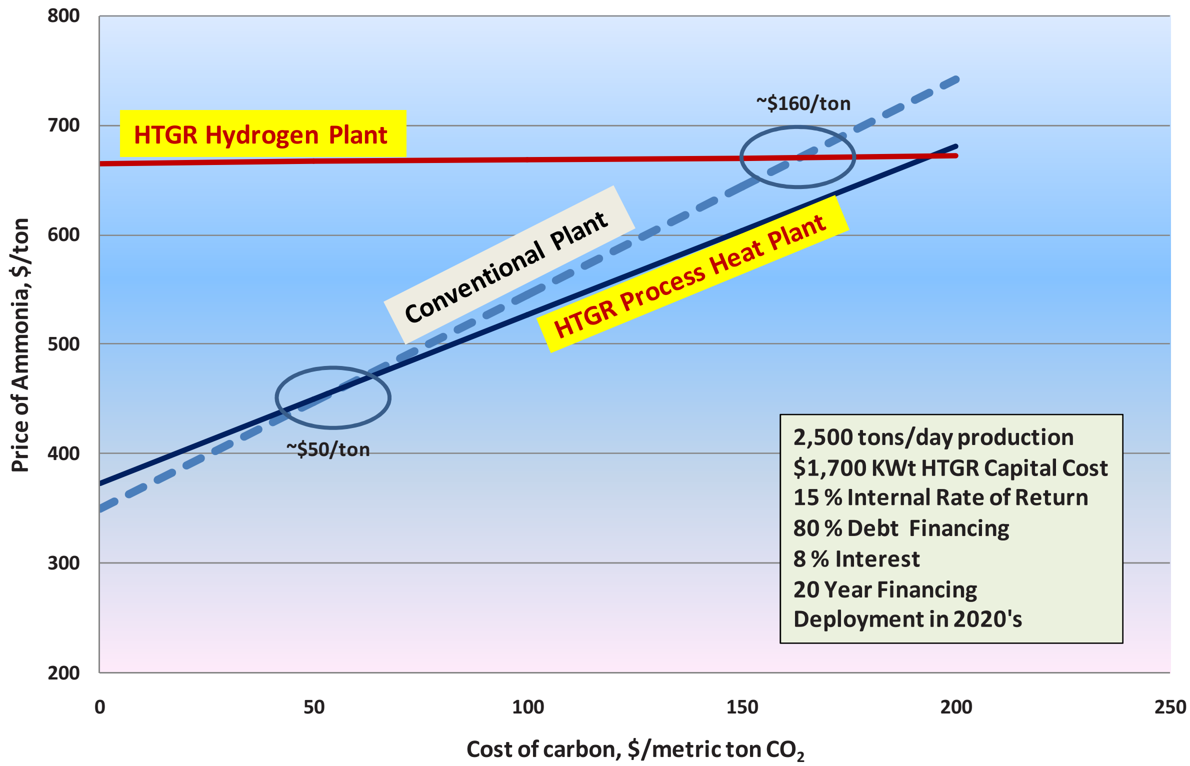


Figure 29. Comparison of conventional and HTGR integrated plant urea pricing vs. costs for CO_2 emissions. (Developed in Excel file, "Ammonia Economics – Separating the Process from the HTGR 8-02-10").

6.4 Hydrogen Generation and Effect of Uncertainties on Economic Evaluations

The economics of integrating the HTGR and the HTSE hydrogen plant with the coal-to-MTG and ammonia production processes are very sensitive to the price of hydrogen produced by the HTGR/HTSE plant. The hydrogen price is similarly affected by the assumptions used in the calculation. The economic calculations presented in Figures 24, 25, and 29 reflect a hydrogen price in the $3.2/Kg range. This is judged to be representative of current knowledge of the costs and performance of the HTGR and HTSE plants. However, because HTGR design development is still in the preconceptual phase, there is a large uncertainty in the factors applied to calculate this price. To establish the impact of this uncertainty on the price of hydrogen, sensitivity analyses were performed to determine the effect of variations in the principal assumptions applied to calculate this price. The results of these sensitivity analyses are summarized in the tornado chart of Figure 30, which shows the effect of variations in the debt-to-equity ratio, required internal rate of return, plant overnight cost, financing term, operating costs, and interest rates such as interest during construction and financing interest. The variation in each parameter investigated in the sensitivity analyses and the baseline value for each parameter are shown on this chart.

As expected, the first three parameters have the most effect on the results. The total variation shown on the chart ranges from a low of $2.36/Kg to a high of $4.25/Kg, driven by the variation in debt-to-equity ratio investigated (90 to 0%). Note that it is not appropriate to sum up all of the extremes shown on a tornado chart to estimate the full range over which the price of hydrogen could vary. These variations will actually combine in a more random way. To provide an assessment of the full range of expected variation in hydrogen pricing for the ranges assumed for the parameters, a Monte-Carlo analysis was performed using triangular distributions of these factors over the ranges shown in Figure 30. Figure 31 shows the results of this analysis as a probability distribution for the hydrogen price. The mean of the analysis ($3.18/Kg) conforms well with the baseline price of Figure 29. The wide swing in the 1-sigma span ($2.69/Kg to $3.68/Kg) reflects the large uncertainty in the pricing.

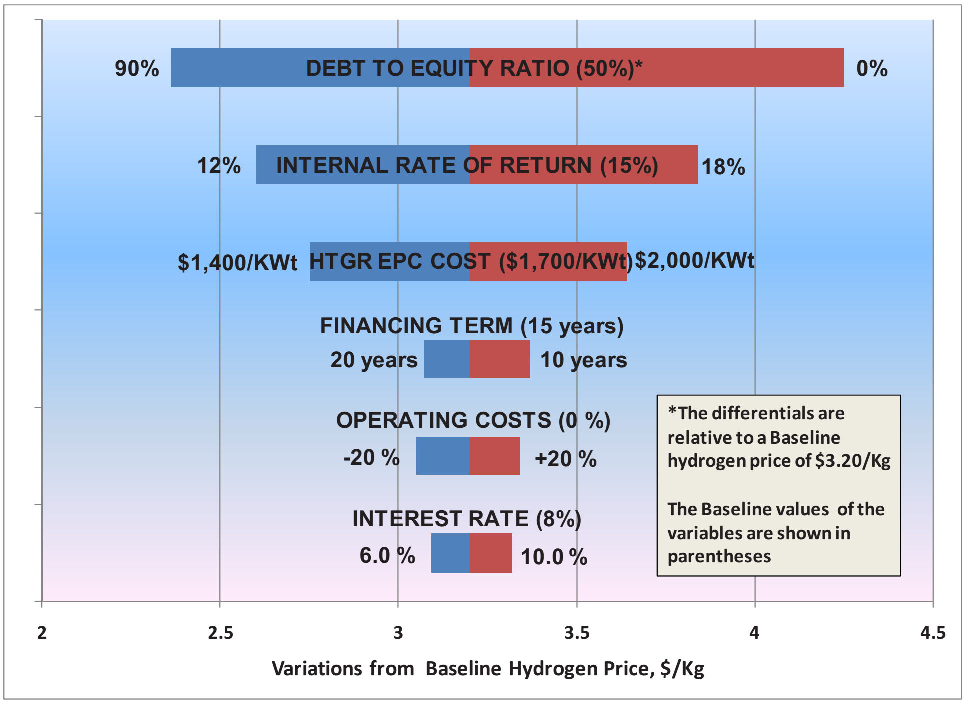


Figure 30. Effect of variations in financial parameters on hydrogen pricing. (Developed in Excel file, "HTGR H_2 Tornado Chart Development 7-22-10").

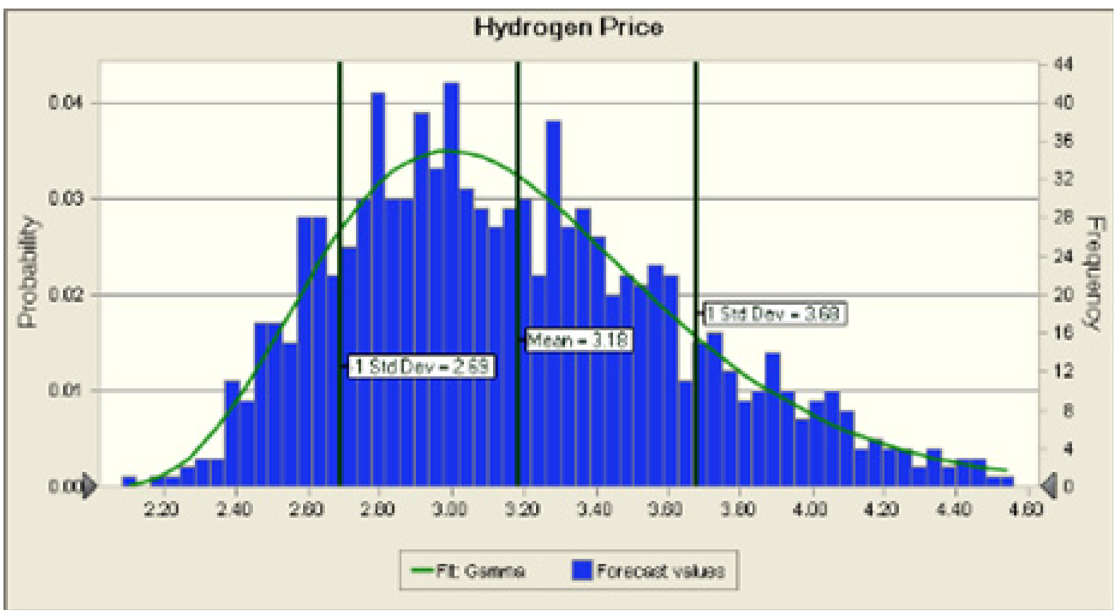


Figure 31. Probability distribution of hydrogen pricing. (Developed in Excel file, "HTGR H2 Cost Monte Carlo Analysis using Crystal Ball 6-9-10").

As cited previously, the majority of non-refinery hydrogen is produced using natural gas as the feedstock and energy source in the SMR process. The price of hydrogen using the SMR process is therefore a strong function of the price of natural gas. Figure 32 presents this variation assuming a new SMR process installation, the financial factors used in the economic evaluations presented above, and typical operating costs, excluding the cost of natural gas. The evaluation was completed for a plant generating ~35,000 lb/day of hydrogen with a natural gas usage of 121,000 lb/hour.[18] The Hydrogen pricing for the SMR process is shown as a function of the price of natural gas ($/MMBtu) and the cost of carbon emissions ($/MT of CO_2).

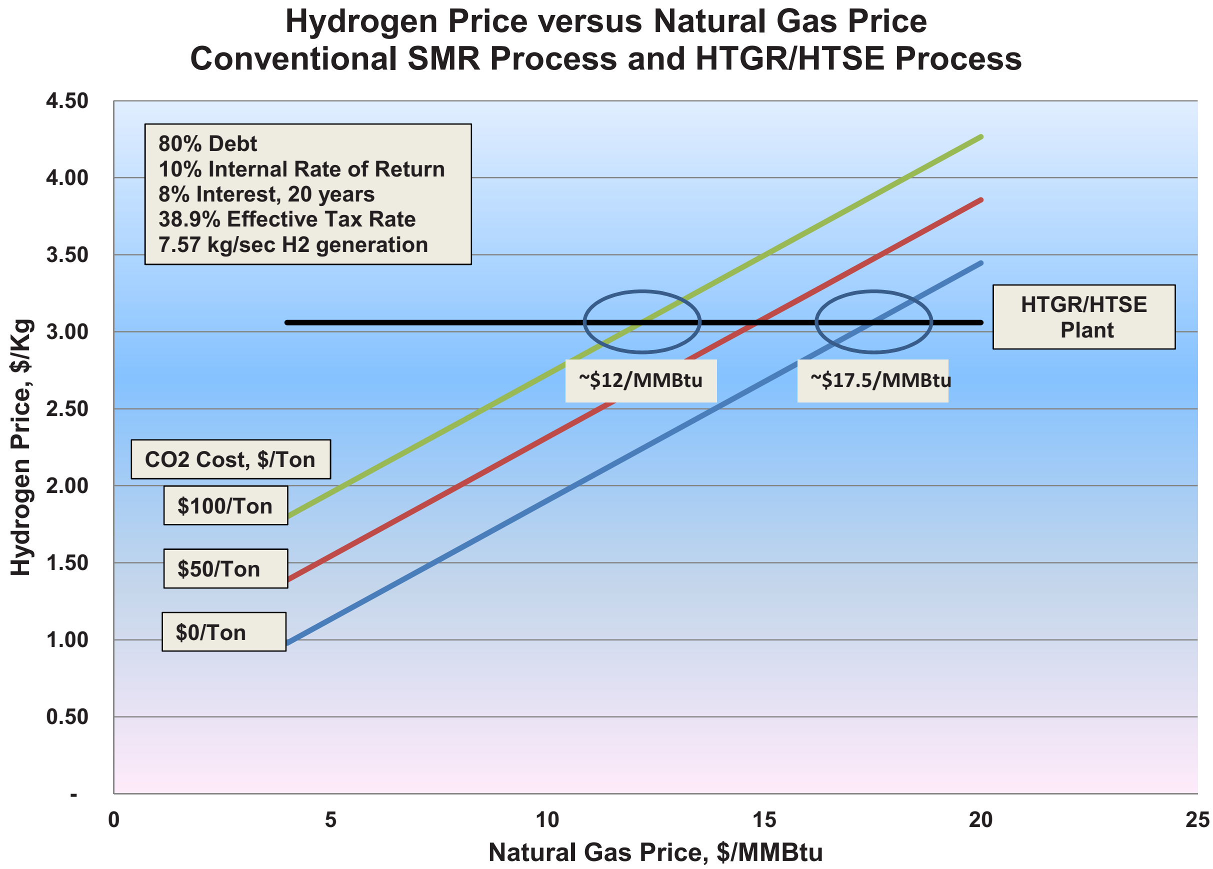


Figure 32. Comparison of hydrogen pricing using SMR and HTGR/HTSE technologies. (Developed in Excel file, "Backup calcs on Industrial Sector & Emissions and CTL Plant 6-7-10 & Baseline Hydrogen Plant – 5-600 MWt, 7.57 Kg/sec 8-16-11").

The price of hydrogen for the HTGR/HTSE process is for a HTGR plant cost of ~ $1,700/kWt and nominal financial factors assumed by the Project for a mature plant installation, (80% debt, 10% IRR). As shown in Figure 32, the HTGR/HTSE process intersects with the SMR pricing at natural gas prices from $12/MMBtu to $17.5/MMBtu depending on the cost of carbon emissions.

As cited previously the NGNP Project evaluated the application of HTGR energy as a substitute for burning of natural gas in the Steam Methane Reforming process.[9,19] Although the reductions in CO_2 emissions and natural gas consumption are not as favorable for this application of the HTGR technology for hydrogen production the economics are better. Figure 33 compares the price of hydrogen generated using the conventional with the HTGR-integrated SMR processes as a function of the price of natural gas. As shown the HTGR/SMR process is more economic for natural gas prices above $6.5/MMBtu.

At the time of this writing the supply to demand ratio of natural gas is sufficient to establish a price at the lower end of the range of prices experienced over the preceding decade. At this price the economics of the HTGR in comparison with a comparable natural gas fired plant are not favorable. However, the supply to demand ratio is trending to support a higher price because of uses of natural gas for base-loaded electricity production and initiation of significant export. These factors may drive the price of natural gas to the point where the HTGR economics are more favorable. It should also be noted that the HTGR technology is slated to become available for commercial application in the mid-2020s and has a design lifetime of 60 years. As shown in Figure 16, over the past 40 years the price of natural gas has shown an average escalation of 2% above inflation. It is not likely that the price of natural gas will remain near its current historical low or buck this historical trend in price escalation into the time frame in which the HTGR technology is available for deployment.

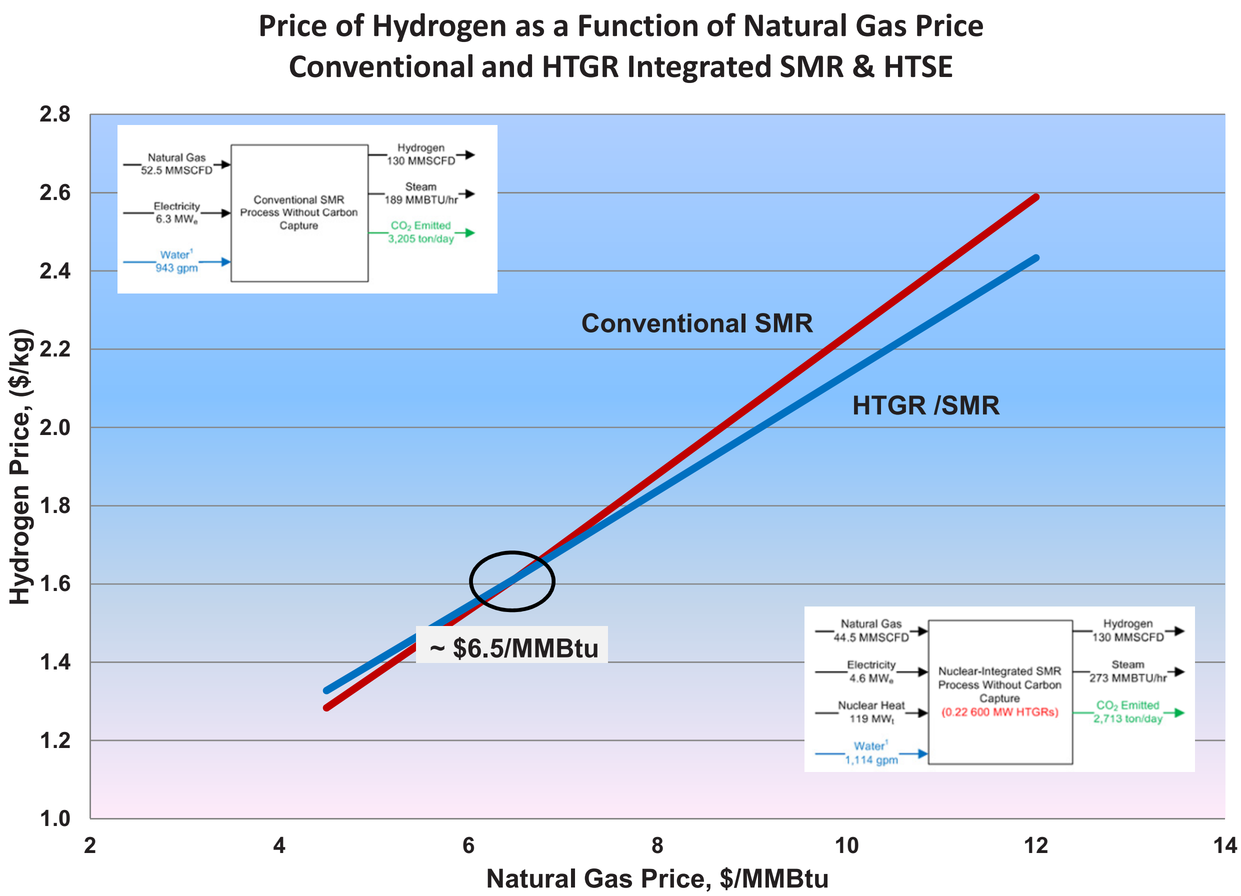


Figure 33, Price of Hydrogen as a Function of Natural Gas Prices for Conventional and HTGR-Integrated Steam Methane Reforming Processes (Developed from Excel file, "H_2 from SMR & SMR w_HTGR Plotting for Presentations" & Reference 19).

6.5 Conclusion on Application Economics

To develop confidence in the technical and economic viability of the HTGR technology, the design of the plants needs to be developed to provide better estimates of performance and costs to construct and operate. The economic factors for financing and pricing of energy over the long operating lifetime of HTGR plants need to be refined through further discussions with major financial institutions with an energy portfolio, current nuclear plant owners, and major industrial plants that can benefit from use of energy supplied from the HTGR. Additionally, the long term financial benefit of this technology to the end user has not been quantified in the evaluations performed to-date. The benefits of a long term secure and stable price of energy have been summarized qualitatively in this report. These factors may combine to permit the end user to accept a higher than current market cost that will be stable over the long term. This factor has not been accounted for in economic evaluations of the technology presented in this report. How to account for this fact is being pursued with the end users and other stake holders involved in the development of the HTGR technology.

The NGNP Project is developing updated and more refined economic models for evaluating the viability of the business models for both the HTGR plant and the industrial plant for the processes evaluated to-date and for those for which evaluations are to be completed. As the HTGR plant designs evolve, better estimates of the capital and operating costs for these plants will be developed that support higher confidence levels in the results of the economic models. The scoping economic analyses performed to-date do show that the HTGR technology has the potential to be competitive with many conventional industrial processes while offering significant benefit in stabilizing energy prices, providing secure energy sources, and reducing CO_2 emissions. The HTGR process may be favored in specific applications if there are governmental regulations that make it more attractive, lower costs and better financing were available, and other factors, such as stability in energy supply and pricing, were major factors.

As the technology develops and as U.S. energy policies and/or direction become better defined, the technical and long term economic viability of the HTGR applications will continue to be reevaluated and reviewed.

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