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Market Analysis for HTGR Technologies and Applications

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EXECUTIVE SUMMARY

This report provides supplemental information to the assessment of target markets provided in Appendix A of the 2012 Next Generation Nuclear Plant (NGNP) Industry Alliance (NIA) business plan [NIA 2012] for deployment of High Temperature Gas-Cooled Reactors (HTGRs) in the 2025 – 2050 time frame.

This report largely reiterates the [NIA 2012] assessment for potential deployment of 400 to 800 HTGR modules (100 to 200 HTGR plants with 4 reactor modules) in the 600-MWt class in North America by 2050 for electricity generation, co-generation of steam and electricity, oil sands operations, hydrogen production, and synthetic fuels production (e.g., coal to liquids). As the result of increased natural gas supply from hydraulic fracturing, the current and historically low prices of natural gas remain a significant barrier to deployment of HTGRs and other nuclear reactor concepts in the U.S. However, based on U.S. Department of Energy (DOE) Energy Information Agency (EIA) data, U.S. natural gas prices are expected to increase by the 2030 – 2040 timeframe when a significant number of HTGR modules could be deployed. An evaluation of more recent EIA 2013 data confirms the assumptions in [NIA 2012] of future natural gas prices in the range of approximately $7/MMBtu to $10/MMBtu during the 2030 – 2040 timeframe. Natural gas prices in this range will make HTGR energy prices competitive with natural gas, even in the absence of carbon-emissions penalties. **Exhibit ES-1** presents the North American projections in each market segment including a characterization of the market penetration logic. Adjustments made to the 2012 data (and reflected in Exhibit ES-1) include normalization to the slightly larger 625MWt reactor module, segregation between steam cycle and more advanced (higher outlet temperature) modules, and characterization of U.S. synthetic fuel process applications as a separate market segment.

This report also evaluates other selected markets which currently utilize high value oil and liquefied natural gas (LNG) fuels for process heat and electricity generation on a large scale. In markets where oil and LNG are being displaced, the HTGR is projected to be economically superior in the near term. These markets include:

- The State of Hawaii, which uses very expensive petroleum fuel to generate about 80% of its electricity.
- The Kingdom of Saudi Arabia (KSA) uses oil for both electricity generation and for most new increments of industrial process heat, but has published plans to displace subsidized domestic oil with nuclear and renewable energy in order to preserve its oil reserves for export and more value-added products.
- Japan and the Republic of Korea (ROK), which are the world's No. 1 and No. 2 importers of expensive liquefied natural gas (LNG). In both countries, the share of

electricity generation from LNG exceeds that from nuclear. In Japan this would be true even if all pre-Fukushima nuclear plants were on-line.

In addition, Japan and the ROK are the world's No. 2 and No. 3 steel producers (behind China). Because fossil fuels are presently used for iron-ore reduction, steel production is among the largest emitters of CO_2 in both countries. Japan and ROK have strong interest in HTGR technology and established HTGR programs focused on hydrogen production to displace fossil fuels for iron-ore reduction and to reduce CO_2 emissions.

Exhibit ES-1 *Market projections indicate that hundreds of SC-HTGR modules could be deployed in the North America to economically provide process heat, steam, and electricity to support synthesis of transportation fuels from low cost coal and natural gas feedstocks. Internationally and in Hawaii, the HTGR can provide lower cost electricity and process heat than the oil and LNG currently utilized.*

North American, U.S. & Selected International Markets for the HTGR					
Market Segments	**Potential Market (GWt)**	**Characterization of Estimation for Penetration of Potential Market from 2025 to 2050**	**HTGR (GWt)**	**Projected Steam Modules**	**Projected Advanced Modules**
1. North America: Process Heat, Steam & Electricity					
• Cogeneration	150	50% replace of existing U.S. CHP plants >900MWt	75	120	na
• Oil Sands/Oil Shale	72	25% of NA oil sands steam & electricity	18	30	na
• Merchant Hydrogen	144	25% of U.S. hydrogen production	36	6	52
• IPP Supply Electricity	1100	10% of nuclear power deployed in U.S. 2025 to 2050	110	176	na
2. U.S. Production Synthetic Fuels from Coal & Natural Gas					
• U.S. Transport Fuels	250	25% replacement of oil imports; producing ~2.3 Mbpd	250	40	361
3. Displacing Oil & LNG for Electricity Generation & Process Heat					
• KSA Electric Gen	100	12% of planned nuclear; arid sites & CHP apps	12	20	na
• KSA Process Heat	10	50% of process heat for ~2Mbpd oil refining	5	8	na
• Hawaii Electric Gen	5	~25% of oil-fired generation replaced w/HTGR	1	2	na

North American, U.S. & Selected International Markets for the HTGR					
Market Segments	**Potential Market (GWt)**	**Characterization of Estimation for Penetration of Potential Market from 2025 to 2050**	**HTGR (GWt)**	**Projected Steam Modules**	**Projected Advanced Modules**
• Japan Electric Gen	205	20% of LNG-fired generation & 10% of nuclear	51	82	na
• Japan Process Heat	80	50% supply of process heat & H_2 for steel making	40	13	51
• Korea Electric Gen	80	20% of LNG-fired generation replaced with HTGR	16	26	na
• Korea Process Heat	40	50% supply of process heat & H_2 for steel making	20	6	26
Totals	2251		644	532	na

CHP – Combined Heat & Power cogeneration; NA- North America; KSA- Kingdom of Saudi Arabia; Mbpd- Million barrels per day of crude oil or equivalent; Modules are 625 MWt, na-not applicable.

Target Markets Identified in the NGNP Industry Alliance 2012 Business Plan

As shown in **Exhibit ES-2** [NIA 2012], the most viable markets in North America for HTGR deployment were judged to be:

- Co-generation supply of steam and electricity to industrial processes and typically to the grid as well.
- Electricity generation as a merchant or regulated utility.
- Oil sands steam assisted gravity drainage (SAGD) bitumen recovery and upgrading operations.
- Coal to fuels and chemical feedstock.
- Hydrogen production.

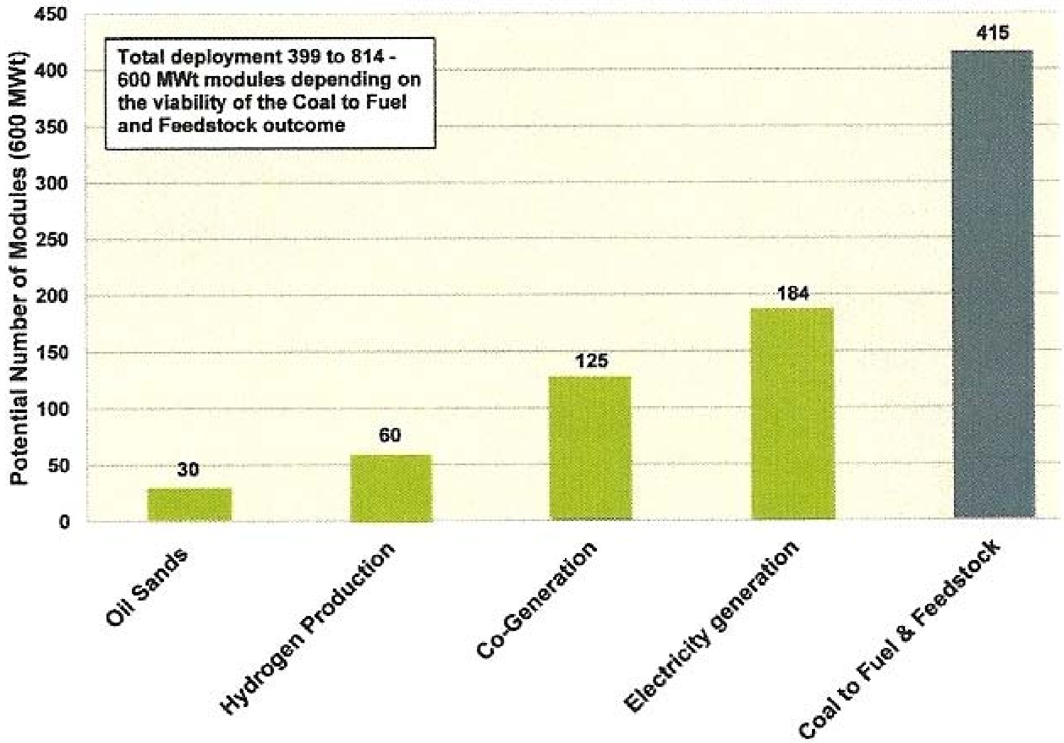

Exhibit ES-2. *The 2012 NGNP business plan quantified five North American applications for deployment of HTGR modules in the 2025 – 2050 time frame*

As noted in [NIA 2012], hydrogen production and carbon conversion (i.e. synthetic liquid fuel production) could utilize the Steam Cycle HTGR (SC-HTGR) to reduce CO_2 emissions. However, the complementary commercialization of high-temperature hydrogen production technology [e.g., high temperature steam electrolysis (HTSE) or thermochemical water splitting] is required to fully exploit the potential of HTGR technology for high-efficiency hydrogen production and the associated reduction of CO_2 emissions to levels below those characteristic of current natural gas steam-methane reforming (SMR) and crude oil refining.

The market penetration projections for the first applications were based on the size of the current market and projections for its growth. The synthetic transportation fuels and chemical feedstock market is essentially a new market driven primarily by the goal of utilizing low cost, domestic coal and natural gas feedstocks to substantially reduce U.S. imports of crude oil over the next four decades. Based upon the INL analysis, the SC-HTGR could become economically viable as a process heat/steam source for SMR and support of synthetic fuel production at crude oil prices of $70 to $100/bbl, depending upon the value attributed to by-product electricity. Future crude oil prices in the range of $140 to $200 per barrel would provide a compelling business case for synthetic transportation fuels production using advanced (higher temperature)

HTGRs to provide “drop in” transportation fuels while virtually eliminating CO_2 emissions during the refining process.

Additional Studies on HTGR Utilization for Synthesis of Transportation Fuels In the U.S.

After publication of the NIA business plan [NIA 2012], Idaho National Laboratory (INL) published two detailed case studies for integration of HTGRs with synthetic conversion processes in the states of Wyoming [INL 2012a] and Kentucky [INL 2012b]. The Wyoming and Kentucky studies confirm the technical feasibility and economics for using HTGRs with carbon conversion processes. A coal-to-liquids (CTL) plant producing 50,000 barrels per day of oil equivalent would require five, 600 MWt HTGR modules. These modules would provide approximately 1200 MWt and 90 MWe to the process and export ~640 MWe to the grid. Assessments were also performed for coal to gasoline (CTG), natural gas to gasoline (GTG) and natural gas to liquids (GTL) processes. Integration of HTGRs with carbon conversion processes reduces CO_2 emissions by 65% to 95%, utilizes indigenous sources of low value fossil fuel adding to national energy security, provides stable long-term energy costs, and increases the efficiency of converting carbon fuel by up to 95%. These attributes match the current administrations goals related to energy security, climate and jobs.

U.S. entry into a synthetic fuels industry can be phased through construction of process facilities using process heat and hydrogen from coal and natural gas in the near term with integration of SC-HTGRs in the 2025 to 2035 time frame. Subsequently higher temperature, hydrogen production HTGRs will provide process heat and hydrogen. HTGR integration will deliver the greatest environmental benefits while also providing a reliable and stable cost of process energy and hydrogen for the many decades of HTGR operation. Module deployment in **Exhibit ES-1** assumes that the initial 10% of the HTGRs deployed to power fuel synthesis will be steam cycle modules with the subsequent modules being more advanced, higher temperature HTGRs. As an example of the potential impact of this synthetic fuel industry, if by 2050 the current Wyoming coal production were to be redirected to making synthetic transportation fuels (e.g., gasoline and diesel) using facilities powered by advanced HTGRs, these facilities could supply over 50% of the current U.S. consumption of liquid hydrocarbon fuels. The cost of the synthetic transport fuels produced would be competitive with fuels produced from crude oil costing ~$140/bbl. The reference EIA projection for crude oil prices indicates that oil prices will exceed $140 by 2035 and will reach ~$160/bbl by 2040.

While current low domestic natural gas prices combined with the even lower (per unit energy) coal prices present an opportunity for the U.S. to synthesize these indigenously abundant low cost feedstocks into high value transportation fuels, including gasoline and diesel, the real long-term value comes from stable liquid fuel and other high value products produced utilizing stressed carbon sources, predominately coal. The HTGR is not required to deploy fuel synthesis facilities in the near term, but the process heat, and H_2 production, utilizing HTGR modules is the key to largely eliminating the substantial CO_2 emissions associated with using fossil fuels to provide the process heat for synthesis. Deployment of ~400 HTGR modules in the U.S. for fuel synthesis by 2050 would result in the following outcomes:

- Domestic production of ~2.3 million barrels per day of synthetic diesel and gasoline fuel.
- Reduction of crude oil imports by more than 25%, avoiding billions of dollars of wealth transfer from the U.S.
- Replacement of ~67 GWe of coal-fired generation while maintaining coal mining for feedstock.
- Reduction of CO_2 emissions by up to 500 million metric tons per year.
- Conversion of ~$20 billion/yr of domestic feedstocks into >$80 billion/yr of gasoline and diesel fuel while maintaining existing employment for mining of feedstocks and adding thousands of new jobs associated with the fabrication of components, and construction and continuing operations of the synthesis facilities, including the HTGRs.

The potential roles of HTGR technology in synthetic fuel production demonstrate its economic flexibility. If fossil fuel prices (particularly natural gas) rise then the HTGR becomes more economically attractive for both electrical generation and process heat. If fossil fuel prices remain low then the HTGR remains attractive as a non-carbon emitting process heat source to power transport fuel synthesis primarily from coal.

Displacing Oil Used for Electricity Generation and Process Heat in the Kingdom of Saudi Arabia (KSA) and Hawaii

The KSA projects a more than doubling of electricity demand from about 55 GWe to about 120 GWe by 2032 [Garwan 2013]. The largest portion of this demand is required for air conditioning. To meet this demand while reducing its current use of >2 million barrels of domestic oil per day for electricity generation, the KSA plans to use a combination of renewable energy (primarily photovoltaic and concentrated solar plants) and nuclear energy.

The KSA plan calls for nuclear energy to provide 17.6 GWe by 2030. Existing Generation III+ LWRs are expected to be initially deployed in the KSA, along the lines of the current collaboration between the United Arab Emirates and the ROK. However, modular HTGRs (which require much less cooling water and can be configured for dry-cooling operation) could provide a significant portion of the KSA demand, especially at inland locations with limited or no availability of cooling water. Assuming continued growth in the KSA, nuclear capacity could provide about 100 GWt by 2050. A 12% share of this market would correspond to about twenty

625-MWt HTGR modules. An additional eight HTGR modules are projected by 2050 to provide 50% of the process heat for KSA's current 2 million barrels per day refining operations. Further, while they have not publicly quantified the expected oil demands for new industrial process heat demand, KSA's current dearth of natural gas for these applications is already forcing the Kingdom to burn valuable oil, generally subsidized, to meet new increments of process heat demand.

In Hawaii, nine out of the ten largest electrical generating plants use expensive petroleum fuel, accounting for approximately 1,900 MWe and about 80% of the state's generating capacity. Plants with capacities greater than about 600 MWe are not considered to be practical for deployment on the islands. As a result of the high petroleum fuel cost, electricity is very expensive in Hawaii, with retail prices in the residential sector of approximately $0.30/kWe-hr and an average retail price of about $0.25/kWe-hr for the combined residential, commercial, and industrial sectors. These power plants account for the vast majority of emissions from electricity generation in Hawaii, including about 6.5 million metric tons of CO_2 per year. Approximately eight 625-MWt modular HTGR modules would be required to displace petroleum fuel for electricity generation in Hawaii. Initial deployment and NRC licensing of modular HTGRs in Hawaii could open the market for exporting this technology to the KSA, Asia, and other regions with high energy costs. Before modular HTGRs could be deployed in Hawaii, a significant change in public policy would have to occur, including changes to the state's constitution which currently bans nuclear power. However, the economic and environmental incentives for displacing petroleum fuels, possibly combined with other incentives from the federal government, could be sufficient to encourage consideration of the needed changes.

Additionally, Oahu hosts eight significant military bases and installations. DOD has been evaluating the use of nuclear energy to provide more secure energy sources at larger bases. An HTGR on one of Oahu's larger installations; such as Schofield barracks or a similar base, could provide the desired increased security of longer-term energy supply for the selected base as well as other Oahu bases connected on a military grid. Electricity costs could also be significantly reduced assuming FOAK costs are modest or covered by vendors and/or DOE. The HTGR would also provide excess electricity to the civilian grid under normal conditions. Similar economic opportunities exist for bases utilizing electricity generated using petroleum fuel such as Guam, Diego Garcia, Eielson AFB, etc. but, like the Oahu installations, bases alone do not require the ~230 MWe of capacity and may not have adjacent civilian demand to help defray the cost of the excess capacity not utilized by the military installation(s).

<u>Displacing LNG Used for Electricity Generation in Japan and Republic of Korea (ROK)</u>

This market study focused on Japan and the ROK because Japan and Korea are the world's largest importers of LNG and their LNG price (currently ~$15/MMBtu) is tied to the international oil price. These countries are also potential development partners for the U.S. and the NIA since:

- Both countries have well established commercial nuclear power programs with associated infrastructure and both countries have active HTGR/VHTR programs.
- Both countries participate in Generation IV International Forum HTGR/VHTR activities.
- Japan Atomic Energy Agency (JAEA) and Korea Atomic Energy Research Institute (KAERI) have collaborated with the DOE on NGNP-related R&D activities
- The NIA and the Korea Nuclear Hydrogen Alliance (KNHA) signed a Collaborative Agreement for development of HTGR/VHTR technology in April 2013.
- JAEA operates the High Temperature Engineering Test Reactor (HTTR), a 30 MWt VHTR prismatic-block prototype that can support R&D, design, and licensing activities for the HTGR FOAK development venture [Richards 2009].

China and India are also potentially large markets in Asia but were not selected for HTGR market assessment since they have limited utilization of high cost fuels for large-scale electricity generation and process heat. However, China is independently developing HTGR technology and has established the High Temperature Reactor – Pebble-bed Module (HTR-PM) project. The HTR-PM project has proceeded to the construction phase, with pouring of first concrete in December 2012. While possible, collaboration with the Chinese may be complicated for several reasons, including differences in fuel design.

As noted above, Japan and Korea are independently developing HTGR technology. In terms of supporting the NIA Business Plan for Commercialization [NIA 2012], collaborations with Japan and Korea could reduce the costs for the HTGR FOAK development venture. The cost reductions could be achieved through sharing of costs for technology development and areas of common design and common methods development/validation. It may also be possible to achieve cost and risk reductions for the HTGR deployment venture through international collaboration. An international collaboration model for HTGR development and deployment would require establishment of government-to-government agreements with Japan and/or Korea, and potentially others, that go beyond the current basic R&D collaborations and information exchange.

Japan and the ROK import nearly all of their natural gas as LNG which adds significant costs. LNG has historically been priced at about 60% parity to the oil Btu price plus transportation costs. As a result, LNG prices in Japan and Korea are currently ~$15 per million Btu, or a factor of 3 to 4 times the current price of natural gas in the U.S. As noted previously. Japan and the ROK are the world's No. 1 and No. 2 importers of LNG and 50% or more of the LNG is used for electricity generation in both countries. Because of the high cost of natural gas in Japan and Korea, HTGRs would be economically competitive today for electricity generation while also reducing CO_2 emissions and conserving natural gas for use as a chemical feedstock. The high thermal efficiency of HTGRs also results in lower cooling water requirements, which allows siting HTGRs at inland locations where many of their natural gas plants are located. When HTGRs are used as combined heat and power (CHP) for industrial heat applications and the excess electricity is put on the grid, typical cooling water requirements are even lower as the condensing load is further reduced as the industrial facilities take full advantage of the latent heat.

Natural gas electricity generation in Japan is expected to remain fairly constant through 2035 at about 75 to 77 GWe, assuming most of its nuclear plants are eventually restarted. In Korea, natural gas electricity generation is expected to increase from 26 GWe at present to about 32 GWe by 2035. One GWe corresponds to about four, 600-MWt HTGR modules, assuming a steam-cycle thermal efficiency of about 40%. In both Japan and Korea, the percentage of electricity generated from burning natural gas exceeds the percentage of electricity generated using nuclear power. Displacing high cost LNG imports could represent a significant market opportunity for HTGRs in both countries as quantified in Exhibit ES-1.

<u>HTGRs for Nuclear Steel Manufacturing in Japan and Korea</u>

There will be continuing growth in steel production, particularly in developing areas such as Latin America, Asia, Africa, and the Indian sub-continent, where steel will be vital in raising the welfare of developing societies. In these regions, more than 60% of steel consumption will be used to create new infrastructure. This continued growth prevents the demand for steel being met by means of recycling of end-of-life steel products alone, hence making it necessary to continue converting virgin iron ore into steel.

On average, 1.8 metric tons of CO_2 are emitted for every metric ton of steel produced. As a result, the iron and steel industry is one of the largest CO_2 emitters and accounts for approximately 6.7% of total global CO_2 emissions. Because steel use is projected to increase 50% by 2050 from present levels, CO_2 emissions could increase by the same amount. CO_2 generated by the steel industry results mostly from the chemical interaction between carbon (from coal, oil, or natural gas) and iron ore in a blast furnace. This process is called ore reduction and produces hot metal which is then converted to steel. There is currently no large-scale commercially available substitute for carbon in steel making.

Both Japan and the ROK are major world steel manufacturers and both countries have been actively investigating processes for using hydrogen to replace carbon for ore reduction. The hydrogen would be produced without the use of fossil fuels by coupling high temperature heat from VHTRs to advanced hydrogen production processes under development in the U.S., Korea, and Japan, including thermochemical water splitting. The CO_2 emissions from the steel manufacturing plant would be practically eliminated, except from small auxiliary sources (e.g., long-term oxidation of the graphite electrodes used in the high-temperature furnaces). In addition, because both Japan and the ROK lack domestic fossil fuel resources, using domestic nuclear plants to provide the hydrogen, oxygen, and electricity required for steel production would significantly reduce fossil fuel imports.

Japan produces about 80 million metric tons of iron per year, resulting in about 140 million metric tons of CO_2 emissions per year. Assuming pre-Fukushima nuclear capacity, iron production in Japan contributes 10% - 12% of its CO_2 emissions and represents a significant portion of its fossil fuel imports. Eighty million metric tons of iron produced per year corresponds to about 130, 600-MWt HTGR modules, which represents a significant market opportunity in Japan as an economical option to significantly reduce both CO_2 emissions and fossil fuel imports. The ROK also represents a significant market opportunity for nuclear steel production, since iron production in the ROK is approximately half that of Japan and could support about 65, 600-MWt modules. Exhibit ES-1 summarizes projections that by 2050, ~50% of the hydrogen production, associated process heat and electricity for steel making in Japan and Korea could be provided by various versions of the HTGR. The initial modules deployed are assumed to be SC-HTGRs for SMR of LNG, process steam and electricity for steel making and is projected to be 20% of the modules to be deployed by 2050. The higher cost of LNG provides incentive for a higher rate of earlier deployment in Japan and Korea than in the U.S. The later 80% of the HTGRs are projected to be higher temperature modules.

Displacing Russia Natural Gas and Coal in Europe

While additional work is required to quantify this demand, the Nuclear Cogeneration Industrial Initiative (NC2I) and recent discussions with Poland both indicate that the HTGR presents potential opportunities for electricity generation and the production of process heat.

In more developed European countries, natural gas is tied, by in large, to oil parity with some European countries like Germany relying increasingly on Russia for imported gas. Poland has significant indigenous coal use and today relies on Russia for more than 60% of its natural gas supply. Both Eastern and Western European countries have, via the country and/or resident industry, initiated study efforts or expressed a strong interest in learning more about the HTGR.

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ACRONYMS AND ABBREVIATIONS

AEO	Annual Energy Outlook
AESJ	Atomic Energy Society of Japan
ASME	American Society of Mechanical Engineers
bpd	barrels per day
BF-BOF	Blast Furnace – Basic Oxygen Furnace
Btu	British thermal unit
BWR	Boiling Water Reactor
CHP	Combined Heat and Power
CTG	Coal to Gasoline
CTL	Coal to Liquids
DOE	U.S. Department of Energy
DRI	Direct Reduced Iron
DV&S	Design Verification and Support
EAF	Electric Arc Furnace
EIA	Energy Information Administration
GA	General Atomics
GTG	Natural Gas to Gasoline
GTHTR300C	Gas Turbine High Temperature Reactor, 300 MW, Co-generation (Japan)
GTL	Natural Gas to Liquids
FERC	Federal Energy Regulatory Commission
FOAK	First-of-a-Kind
HTGR	High-Temperature, Gas-Cooled Reactor
HTR-PM	High Temperature Reactor – Pebble-bed Module (China)
HTSE	High Temperature Steam Electrolysis
HTTR	High Temperature engineering Test Reactor
JAEA	Japan Atomic Energy Agency
KAERI	Korea Atomic Energy Research Institute
KNHA	Korea Nuclear Hydrogen Alliance
KSA	Kingdom of Saudi Arabia
LNG	Liquefied Natural Gas
LWR	Light Water Reactor
METI	Ministry of Economy, Trade and Industry (Japan)
MEXT	Ministry of Education, Culture, Sports, Science, and Technology (Japan)
MHR	Modular Helium Reactor
MMBtu	Million Btu
NGNP	Next Generation Nuclear Plant

NIA	NGNP Industry Alliance
OHF	Open Hearth Furnace
ROK	Republic of Korea
PWR	Pressurized Water Reactor
S-I	Sulfur-Iodine (thermochemical water splitting)
SMR	Steam-Methane Reforming
SC	Steam Cycle
SSC	System, Structure & Component
VHTR	Very High Temperature Reactor

1. UPDATE ON IMPACT OF NATURAL GAS SUPPLY IN NORTH AMERICA

The 2012 Next Generation Nuclear Plant (NGNP) Industry Alliance (NIA) business plan [NIA 2012] includes an assessment of natural gas as the primary competition to the deployment of High Temperature Gas-Cooled Reactors (HTGRs) for process steam/heat applications. This competitive assessment was based largely on the data provided by the U.S. Department of Energy (DOE) Energy Information Administration (EIA) in the 2012 version of their Annual Energy Outlook (AEO) Report. Based on this EIA data and some additional assumptions, the following conclusions were made:

- From the EIA data, the uncertainty band on natural gas prices in 2035 ranges from \$5.35/MMBtu to \$9.26/MMBtu based on potential positive and negative effects on shale gas extractions.
- The effect of early retirements on coal-fired plants due to EPA regulations on emissions could shift that band up to a high of \$10.26 MMBtu.
- Increased exports of natural gas due to favorable differentials between the U.S. and other countries could shift the band up by another \$2/MMBtu. It is assumed this shift would only affect the lower bound because an increase in price to \$12/MMBtu would have a negative impact on exports. Based on the above data and assumptions, natural gas prices in 2035 were projected to range from \$7.35/MMBtu to \$10.26/MMBtu.

The NIA business plan also identified trends that can significantly influence natural gas pricing include direct use for transportation fuel and the use for base load power (noted above) that both provide potentially inelastic uses, leading to price spikes when the last increments of any country use is provided by LNG imports with pricing tied to oil.

The AEO report was updated by the EIA in April 2013 [AEO 2013]. The 2013 report extends the projections to 2040. **Figure 1-1** shows a comparison of natural gas price projections from the AEO 2012 and 2013 reports for the reference case Henry hub spot price. The 2013 report projects somewhat lower prices (\$6.32/MMBtu in 2035 vs. \$7.37/MMBtu from the 2012 report). However, the 2013 report projects the price to increase to \$7.83 by 2040. Using the same assumptions given above and using [AEO 2013] year 2040 data as the reference point, natural gas prices in 2040 are projected to range from \$7.81/MMBtu to \$10.72/MMBtu. Given the modest differences in the projected ranges and the uncertainties in these projections, there is little need to update the 2012 business plan [NIA 2012] with regards to the impacts of natural gas supply and pricing on HTGR deployment on the North American market.

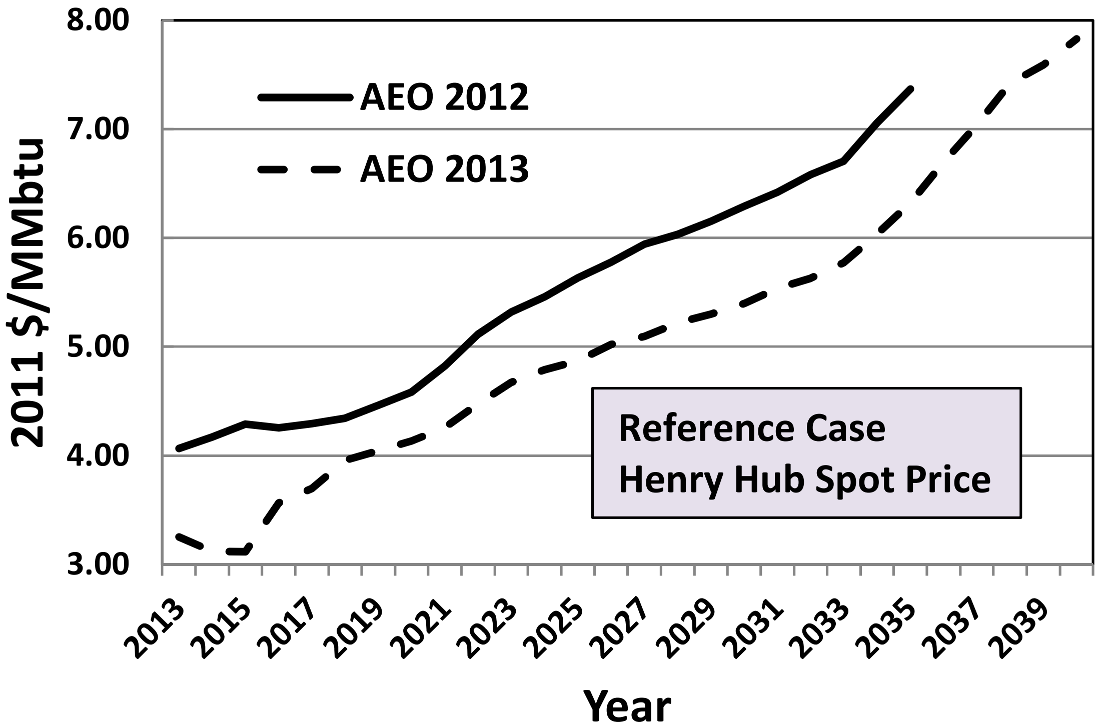


Figure 1-1. Comparison of Natural Gas Price Projections

The EIA AEO 2013 Report indicates a modest price reduction and extends the relatively low price projection to 2040.

2. HTGRs FOR POWERING SYNTHETIC LIQUID FUEL SYNTHESIS IN THE U.S.

As discussed in [NIA 2012], the synthetic transportation fuels and chemical feedstock market would be essentially a new market driven primarily by the goal of utilizing low cost fossil feedstocks (coal with supplemental hydrogen from natural gas) to substantially reduce imported crude oil over the next four decades. At current coal and natural gas prices in the U.S., INL has projected that synthesis of “drop in” transportation fuels and other liquid products is competitive with crude oil prices around $70/bbl and higher [INL 2011]. These projections note that for an additional modest cost (~$10 to $20/bbl) the SC-HTGR can be integrated into synthesis facilities to significantly reduce CO_2 emissions and provide power to the U.S. electrical grid. Ultimately, future crude oil prices in the range of $140 to $200 per barrel could provide a compelling business case for VHTRs to provide electricity, high temperature process heat and hydrogen to allow production of synthetic transportation fuels with essentially no CO_2 emissions from the synthesis process. This application could be the largest HTGR and VHTR market in North America, supporting the deployment of up to approximately 400, 600-MWt modules [NIA 2012] including modules with higher outlet temperatures. Market projections for the SC-HTGR assumed that the initial tranche of SC-HTGRs will be ~10% of the total to be deployed by 2050.

North America has an abundance of fossil fuel resources, especially coal and natural gas. While the current price for oil is ~$100/barrel (or ~$18/MMBtu), coal prices are in the $3/MMBtu range and natural gas is priced in the $5/MMBtu range at major hubs. However natural gas prices in U.S. regions with limited pipeline connectivity are as high as $10/MMBtu today Processes for producing transportation fuels and other high value hydrocarbons from coal and natural gas have been used for decades. While the older processes were not necessarily economically competitive with the lower oil prices of the past, modern equipment and modern processes hold the promise of allowing these low cost, domestic U.S. feedstocks to be converted to gasoline, diesel and other high value liquid fuels for total costs equivalent to oil at ~$60/barrel when these domestic fuels are used as both the feedstock and the process heat source. Though these coal-to-liquids and natural gas-to-liquids opportunities are projected to be economically superior to oil at current prices, they require large capital investment for equipment and facilities. These synthesis processes also result in significantly higher CO_2 emissions unless a non-fossil source of high temperature process heat (e.g. the HTGR) is available. Where natural gas is used there is also the risk of an economic link to oil in future demand scenarios. These coal and natural gas resources are also very good feedstocks for the synthesis of olefins and other high value products normally made from petroleum.

The EIA projects U.S. consumption of petroleum-based liquid fuels will remain relatively constant (around 20 million barrels per day equivalent) through 2040. Imports are currently ~9 million barrels per day but are projected to drop due to increased recovery of liquids from shale oil, increased natural gas use in transportation, increased biofuels production, and several other factors. During this same interval, the reference EIA case indicates that crude oil is expected to increase from the current ~$100/barrel to ~$160/barrel in 2040.

The economic analysis completed by INL indicates that at current U.S. coal and natural gas prices, liquid fuels can be synthesized for 10% to 25% lower cost than that from refining of imported $100/barrel crude oil, and with similar CO_2 emissions when the SC-HTGR is integrated into the process facilities to provide limited process heat/steam for CTL and steam-methane reforming (SMR). In the specific facility envisioned by INL over half the energy from the five, 600MWt HTGRs would be converted to electricity and sold/exported to the grid. Subsequently, such facilities would be powered by higher temperature HTGRs to increase the quantity of nuclear heat to be used in the process and eventually to power H_2 production via high-temperature electrolysis (HTSE) or other efficient, high temperature processes. This degree of economic competitiveness provides a reasonable basis for the projection that HTGR assisted fuel synthesis facilities will penetrate the market such that ~25% of current U.S. imported oil will be supplanted by these facilities by 2050. Such market penetration will require ~249 GWt or ~400 625-MWt HTGR modules, producing 2.28 million barrels per day oil-equivalent or ~12% of the total liquid fuel consumed by the U.S. each year. For the purposes of these market projections it has been estimated that the initial deployment of SC-HTGR will be ~10% of the total modules deployed by 2050. The remaining 90% will be higher temperature HTGRs.

Specific studies have been performed by INL for the potential of using coal and natural gas for synthetic fuel production in Wyoming [INL 2012a] and Kentucky [INL 2012b] and have shown that these states would: (1) benefit economically and expand employment as the result of commercial deployment of facilities to convert coal and/or natural gas to diesel and/or gasoline and other petrochemical products and (2) have an opportunity to avoid the projected decline in coal production and associated tax base and employment.

From the Wyoming study [INL 2012a], a coal to liquids (CTL) plant producing 50,000 barrels per day (bpd) of oil equivalent would require five 600 MWt HTGR modules. These modules would provide ~1,200 MWt and ~90 MWe to the process and export ~640 MWe to the grid. Assessments were also performed for coal to gasoline (CTG), natural gas to gasoline (GTG) and natural gas to liquids (GTL) processes (see **Table 2-1**). Integration of HTGRs with carbon conversion processes reduces CO_2 emissions by 65% to 95%, provides stable long-term energy costs, and increases the efficiency of converting carbon fuel by up to 95%.

Table 2-1. INL Conceptual Design of Characteristic Outputs for Several Synthetic Fuel Plants Powered by HTGRs

Carbon Conversion Plant	Equiv. Barrels per Day	No. 600 MWt HTGR Modules	Thermal Capacity (MWt)	Heat Supply to Process (MWt)	Electricity Supply to Process (MWe)	Electricity Supply to Grid (MWe)
GTG	40,000	5	3,000	387	115	963
GTL	50,000	5	3,000	479	0	1,038
CTG	60,000	5	3,000	1,112	60	706
CTL	50,000	5	3,000	1,201	91	637

Facility deployment scenarios include initial conversion facilities which are fired by natural gas for heating and for production of hydrogen via steam methane reforming to reduce the carbon footprint of the coal gasification process. Later, these natural gas-reliant processes for heat and hydrogen are designed to be replaced with HTGRs as soon as HTGRs are available. First with production of power and some process heat, but later higher temperature versions of the HTGR coupled with HTSE could provide the hydrogen required and further reduce (and essentially eliminate) CO_2 emissions from the synthesis process.

While the benefits to host states noted above will also accrue to the U.S., deployment of the processing facilities would provide additional benefits important to the nation as a whole including:

- Conversion of a low value coal into high value gasoline and diesel.
- The option to reduce foreign oil imports as much as desired while preserving U.S. oil reserves.
- Placing a ceiling on the price the U.S. pays for imported oil.
- Capturing the employment, added value, and infrastructure associated with conversion in the U.S. rather than buying or selling raw fuel resources internationally.

Evaluation of the fuel synthesis industry shows that deployment is technically feasible, would produce fuels at a production cost lower than, or competitive with, similar products from traditional industries, and generates returns on investment at these production costs that are expected to be consistent with industry objectives. Furthermore, a U.S. synthetic fuel industry will add substantive value to the local as well as the national economy. Deployment of this industry would better retain the value of these indigenous resources within the U.S. economy and increase the contribution from mining and processing of these resources to the gross domestic product.

Appendix A provides additional background information on the U.S. synthetic fuels market. Most of this information summarizes material in the Wyoming [INL 2012a] and Kentucky [INL 2012b] studies performed by INL.

3. HTGR MARKETS FOR DISPLACING OIL AND LNG USAGE INTERNATIONALLY, IN HAWAII, AND ON U.S. MILITARY BASES

3.1. Kingdom of Saudi Arabia

The energy policy for the Kingdom of Saudi Arabia (KSA) is based on sustainability, reliability, and extending the availability of their oil reserves for future export either as oil or in other higher value downstream products such as chemicals and their derivatives. Their current published projections [Garwan 2013] show the country moving from an oil exporter to an oil importer as early as 2032 if they do not introduce additional technologies and energy sources. Their goal is to minimize oil use for electrical generation, industrial process heat and desalination. These uses are forecasted to grow substantially to meet future demand from population growth, modernization and expected industrial growth. Nearly all of the present and newly committed electrical generation capacity utilizes hydrocarbon fuels, including natural gas (~23 GWe) and domestic petroleum (~32 GWe) that is heavily subsidized relative to oil export prices in order to maintain low domestic electricity prices. While natural gas is KSA's fuel of choice for electric generation, current sources are fully subscribed forcing the use of the more valuable oil. As shown in **Fig. 3.1-1**, the KSA projects a more than doubling of electricity demand from about 55 GWe to about 120 GWe by 2032. The largest portion of this demand is required for air conditioning. To meet this demand while saving its domestic oil reserves, KSA plans to use a combination of renewable energy (primarily photovoltaic and concentrated solar plants) and nuclear energy. **Figure 3.1-2** shows the KSA plan for deploying renewable and nuclear energy to reduce the share of fossil fuels for electricity production from the current ~100% to 50% by 2032.

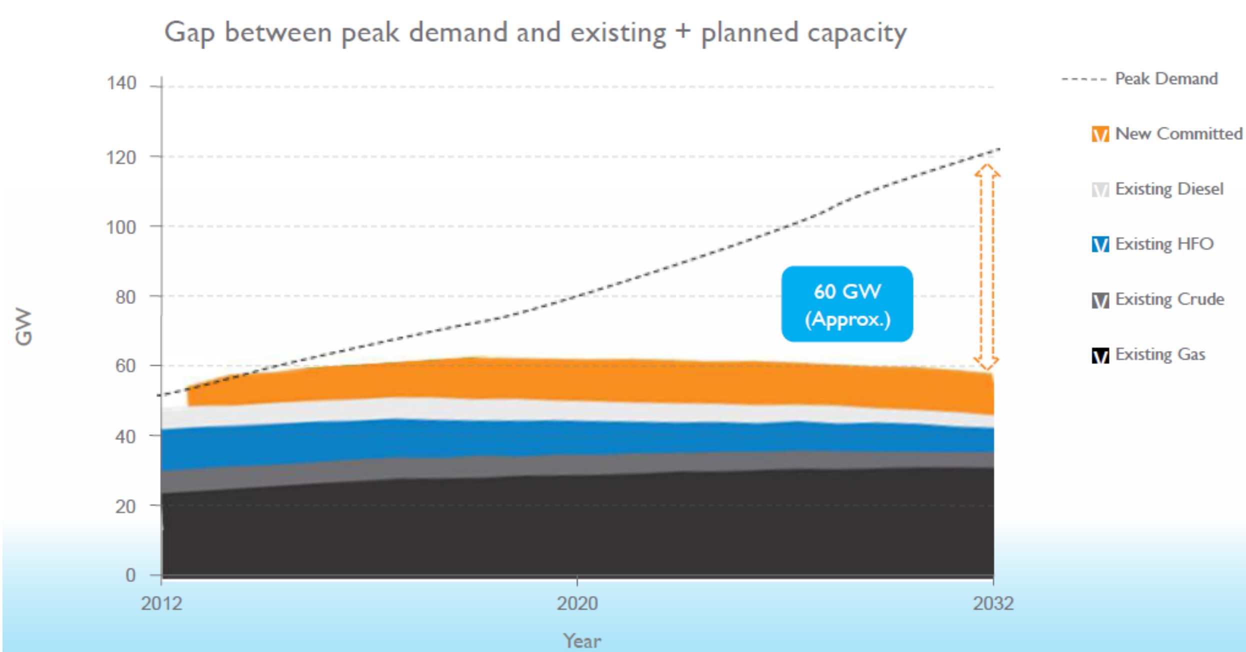


Figure 3.1-1. KSA Projects that Electricity Demand Will More than Double in the Next Twenty Years

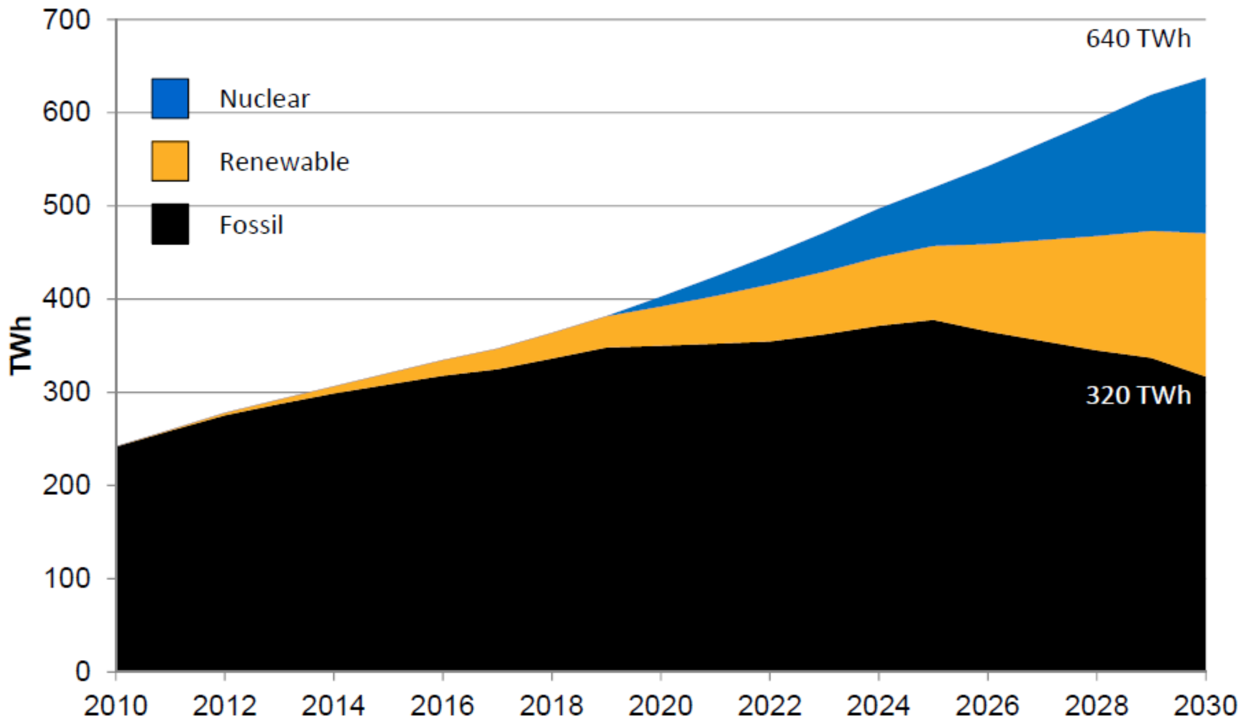


Figure 3.1-2. KSA Plan to Offset Fossil Energy with Nuclear and Renewable Energy

As shown in **Fig. 3.1-3**, the KSA plan calls for nuclear energy to provide 17.6 GWe by 2030. Commercially available Generation III+ LWRs are expected to be initially deployed in the KSA, along the lines of the current collaboration between the United Arab Emirates and the Republic of Korea (ROK). However, modular HTGRs could provide a significant portion of the KSA demand, especially at inland locations with limited or no availability of cooling water. In addition, the inherent safety features of the modular HTGR precludes the need for public evacuation plans regardless of the severity of any accident, which may be of increased importance for deployment in the KSA and other countries with limited nuclear energy experience. Assuming continued growth in the KSA, nuclear capacity could provide about 100 GWt by 2050. It is estimated that >12% of the potential KSA nuclear power plant sites will benefit substantially from the reduced water requirements, higher efficiency and process heat capability of the HTGR. A 12% share of the nuclear electricity market (12 GWt) would correspond to about twenty, 625-MWt HTGR modules.

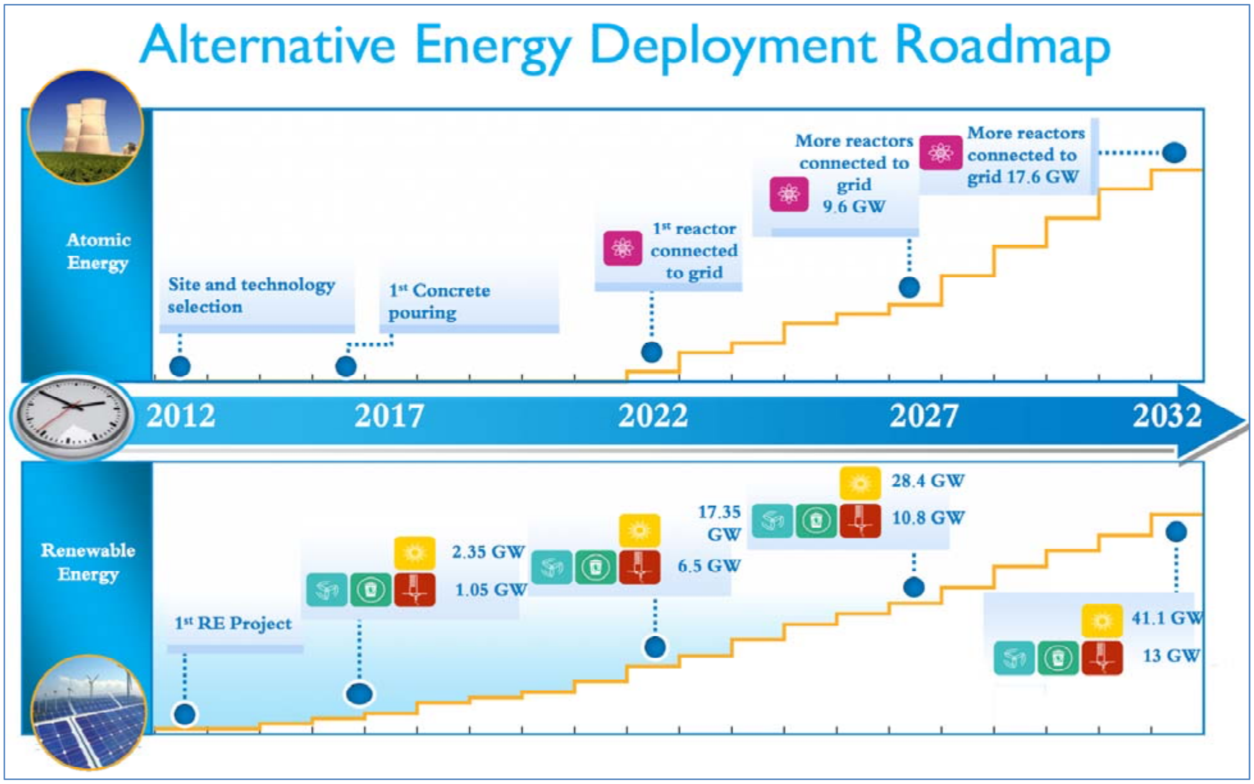


Figure 3.1-3. KSA Plan for Deployment of Nuclear and Renewable Energy Includes ~18 GWe of Nuclear Power and ~54 GWe of Renewables by 2032

Because of their high-temperature capability, modular HTGRs could also be used for other energy needs in the KSA, including petroleum refining. If over the next 40 years the HTGR were to displace 50% of the natural gas and petroleum liquids currently being consumed by the ~2 million barrel per day refining capacity of the KSA, an additional 2 to 5 GWt (or up to 8 modules) could be deployed by 2050. It also seems likely that as the HTGR becomes available it would be utilized to power a number of other large petrochemical facilities in KSA which consume oil for process heat.

The liquid petroleum fuels used for electricity generation are heavily subsidized relative to oil export prices in order to maintain low domestic electricity prices. KSA electrical prices (tariffs) currently vary from 5 to 26 Halala/kWh (or from 1.3 to ~7 cents/kWh) at the official exchange rate of 375 Halala/$. These prices suggest that the value assigned to the oil burned for electricity is well below $20/barrel or less than 20% of current international market price. Informal discussions with KSA officials suggest that government subsidies for oil result in utility costs of ~$4/bbl for the liquid fuels products which are used for electric generation. The ~2 million barrels per day of oil being burned for electricity is causing the KSA to forego ~$70 billion in oil export revenue annually.

While Gen III+ LWRs are expected to provide the majority of the KSA planned nuclear generation, the modular HTGRs could provide a modest portion of the KSA nuclear energy plans for the following reasons:

HTGR Advantages at Arid Sites: The higher outlet temperature allows the HTGR to tolerate higher ambient temperature and reduced water availability with a much smaller efficiency loss than LWRs. Analysis indicates that if the site requires dry cooling, LWR efficiency will be reduced such that net plant output will be reduced by 20% even assuming that additional equipment investment is made to mitigate the efficiency loss. Similar analysis for the HTGR indicates a <10% reduction in net output. **Figure 3.1-4** shows that much of the KSA grid and many of the generating facilities are at inland sites. Similar concerns apply to sites on the Persian Gulf due to the temperature restrictions driven largely by the limited circulation in the Gulf.

Figure 3.1-4. KSA Power Grid Has Many Facilities at Arid Inland Sites and Water Temperature Restricted sites on the Persian Gulf

- *Intrinsic Safety & Co-Location with Petrochemical Facilities:* Many of the KSA power plants are located with, or near, oil production or petrochemical facilities. HTGR intrinsic safety will minimize the investment risk for co-location with these facilities while also providing required process steam. Intrinsic safety is also likely to be very important for the KSA from a public acceptability point of view as KSA has no operating nuclear facilities today and the public is likely to be wary of nuclear post-Fukushima.

- *Opportunity for KSA Participation in HTGR Commercialization and Export:* The Generation III+ LWRs, and to a lesser degree LWR SMRs, have already been designed and have entrenched reactor vendors and suppliers for the systems and major components. In contrast, the HTGR provides a unique opportunity for KSA organizations to be involved in development of the technology, to gain an equity position in intellectual property, and to become suppliers of selected systems and components for both domestic and foreign projects. The modular HTGR may also be of interest to the KSA as an investment opportunity for a future energy export technology, with a significant level of KSA domestic supply localization that is consistent with other KSA goals. Specifically, the KSA has stated that they have targeted 60% localization of supply of nuclear equipment by 2030 (see **Fig. 3.1-5**). Western investors with whom members of the NIA have interacted have noted that KSA investment in development activities and projects slated for deployment in KSA is a fundamental consideration in their investment decision.

3.2. Hawaii & U.S. Military Bases

As shown in **Table 3.2-1**, 9 out of the 10 largest electrical generating plants in Hawaii use petroleum fuel, accounting for approximately 1,900 MWe and about 80% of the state's generating capacity. Plants with capacities greater than about 600 MWe are considered too large to be practical for deployment on the islands. The extensive use of oil-fired generation (fuel cost of ~$15 to $18/MMBtu) makes electricity costs in Hawaii the most expensive in the U.S. Retail prices in the residential sector are approximately $0.30/kWe-hr and an average retail price of about $0.25/kWe-hr for the combined residential, commercial, and industrial sectors. These power plants also account for the vast majority of emissions from electricity generation in Hawaii, including about 6.5 million metric tons of CO_2 per year.

Value chain localization potential by 2030: Nuclear energy

Technology	Industry	Services
Nuclear Localization Target by 2030 60%	Uranium mining	Construction
	Fuel fabrication	Engineering
	Piping	Operation and Maintenance
	Pumps	Radioactive Waste Management
	Valves	Spent fuel
	Non-Nuclear Grade components	R&D design (reactor design)

52

Figure 3.1-5. KSA Has a Stated Goal of 60% Localization of Nuclear Energy Components and Systems by 2030

Table 3.2-1. Nine of the Ten Largest Electrical Generating Plants in Hawaii are Fueled with Petroleum

Plant	Primary Energy Source or Technology	Operating Company	Net Summer Capacity (MWe)
Kahe	Petroleum	Hawaiian Electric Co Inc	582
Waiau	Petroleum	Hawaiian Electric Co Inc	457
Kalaeola Cogen Plant	Petroleum	Kalaeloa Partners LP	214
Maalaea	Petroleum	Maui Electric Co Ltd	205
AES Hawaii	Coal	AES Hawaii Inc	180
Campbell Industrial Park Generating Station	Petroleum	Hawaiian Electric Co Inc	113
Honolulu	Petroleum	Hawaiian Electric Co Inc	100
Port Allen	Petroleum	Kauai Island Utility Cooperative	90
Keahole	Petroleum	Hawaii Electric Light Co Inc	79
Hamakua Energy Plant	Petroleum	Hamakua Energy Partners LP	61

Electricity Generation on Oahu

Displacing petroleum-based generating plants with modular HTGRs could significantly lower electricity costs and reduce emissions in Hawaii. The modular size is consistent with existing generating and grid capacity and the intrinsic safety features preclude the requirement for public evacuation even for the most severe accidents, which is especially important for the islands. The island of Oahu with its larger population, industry, and generating capacity (see Fig. 3.2-1) is the most likely candidate for siting HTGR modules. Oahu also has two refineries which could displace petroleum-fired process heat with process heat and steam from the HTGR.

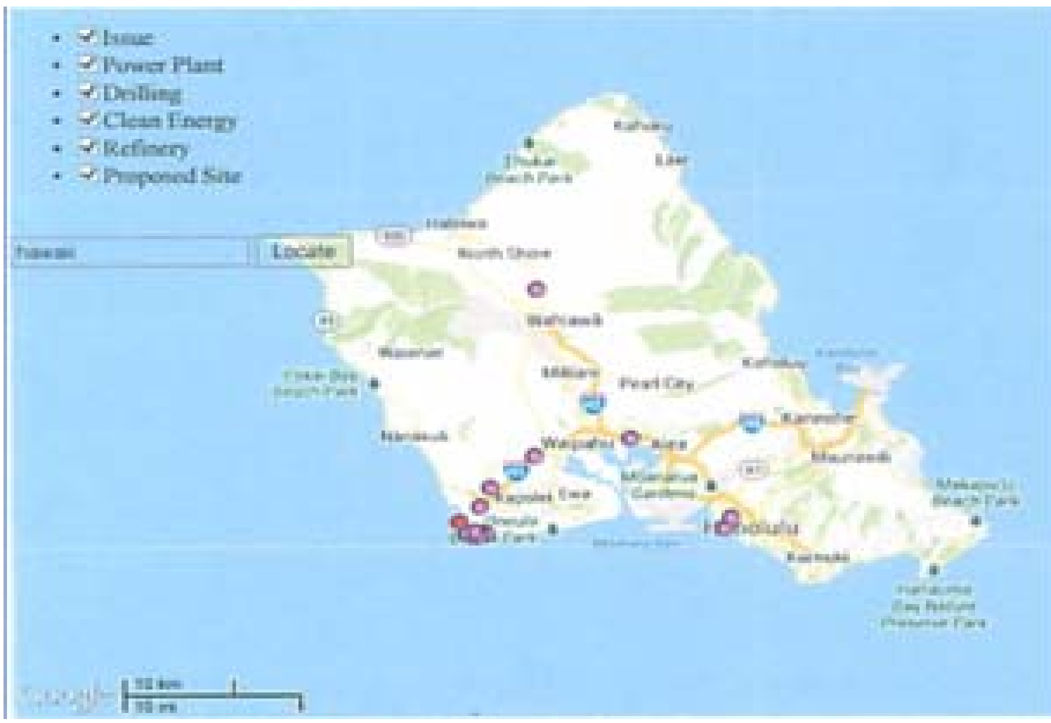


Figure 3.2-1. Oahu has Most of the Energy and Industrial Facilities in the Hawaiian Islands

Before modular HTGRs could be deployed in Hawaii, a significant change in public opinion and policy would have to occur, including changes to the state's constitution which currently bans nuclear power. However, the intrinsic safety and economic/environmental incentives for displacing petroleum fuels, possibly combined with other incentives from the federal government, might be sufficient to encourage consideration of needed changes. Approximately eight 625-MWt HTGR modules would be required to displace petroleum fuel for electricity generation in Hawaii. Market projections assume that two SC-HTGR modules will displace ~25% of the petroleum-fired electrical generation by 2050. Initial deployment and NRC licensing of modular HTGRs in Hawaii could also help open the market for exporting this technology to the KSA, Asia, and other regions with high energy costs.

Military Bases Powered by Petroleum-fired Generation on Oahu and Elsewhere

Most U.S. military bases meet their electrical needs through the local civilian power grid. While such power is often less expensive than dedicated on-base power plants, the base electrical supply is vulnerable to disruptions by off-base sabotage or natural events. The DOD has periodically studied options for using on-base nuclear power (with its longer interval before requiring new fuel) to reduce vulnerability to disruptions in the grid and fuel supplies. In a 2011 study "Feasibilty of Nuclear Power on U.S. Military Installations" it was noted that small modular reactors might be cost competitive on larger bases but only if FOAK costs did not have to be recovered in the electricity costs. This observation was based largely on the assumption that electricity costs were typical of continental U.S. electricity prices; i.e. in the four to fifteen cents per kwh range. Bases which purchase electricity from oil-fired grids can expect to pay 20 to 30 cents per kwh as they do in Hawaii, Guam, Diego Garcia and other locations where other fuels are difficult to procure, transport or use. Figure 3.2.-2 (from the same study) illustrates the fact that few bases require more than 60 MWe of capacity further complicating deployment of cost effective nuclear plants.

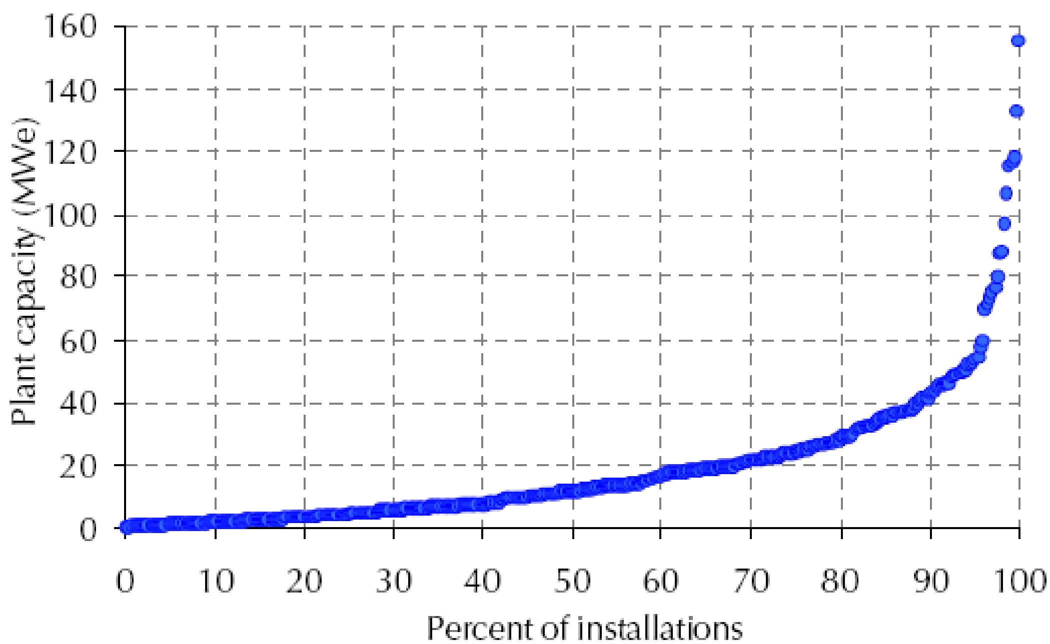


Figure 3.2-2. Most DOD Installations Require 60 MWe or Less of Generating Capacity

Since the proposed HTGR will generate ~230 MWe, it is best suited economically for larger bases which are also connected to a civilian grid that can utilize the excess capacity. The island of Oahu is such a location since it has several bases which require ~30 MWe and has a total generating capacity >1200 MWe, dominated by oil-fired plants. One or two HTGR modules located on the most appropriate base could provide electrical supply security for the base and other bases connected by a secure grid, while providing lower electrical prices for the base and the civilian population.

Military bases on Guam require over 40 MWe but the total generating capacity of the island is only slightly more than 100 MWe. The lack of a market for the additional capacity would reduce the cost effectiveness of a 230 MWe HTGR located on Anderson AFB, NAVBASE Guam or another large base on Guam. Despite the higher cost, such an installation might be attractive given its safety, security and oil-displacement characteristics even at some selected bases which do not have access to a larger civilian electrical market.

3.3. Displacing LNG in Asia

For this study, potential markets are focused on developed economies in Asia, specifically Japan and the ROK. These markets are of interest since both countries are large users of imported LNG for electricity generation and process heat and their LNG prices are linked to the international energy price for oil. In addition Japan and Korea are expected to be receptive to HTGR technology and potentially receptive to joint development initiatives because:

- Both countries have well established commercial nuclear power programs with associated infrastructure and both countries currently have active HTGR/VHTR programs.
- Both countries participate in Generation IV International Forum HTGR/VHTR activities.
- Japan Atomic Energy Agency (JAEA) and Korea Atomic Energy Research Institute (KAERI) have collaborated with the DOE on NGNP-related R&D activities. In addition, JAEA, Fuji Electric Systems, Toshiba Corporation, and KAERI have participated on development of the NGNP Pre-Conceptual and Conceptual Designs.
- The NIA and the Korea Nuclear Hydrogen Alliance (KNHA) signed a Collaborative Agreement for development of HTGR/VHTR technology in April 2013.
- JAEA operates the High Temperature Engineering Test Reactor (HTTR), a 30 MWt VHTR prismatic-block prototype that can support R&D, design, and licensing activities for the HTGR FOAK development venture [Richards 2009]. In October 2012 (coinciding with the HTR 2012 Conference in Tokyo), JAEA President Atsuyuki Suzuki met with the NIA and KAERI at the JAEA Tokyo office and expressed his strong support for HTGR/VHTR technology.

China and India are also potentially large markets in Asia but were not selected for HTGR market assessment since they have limited utilization of high cost fuels for large-scale electricity generation and process heat. However, China is independently developing HTGR technology and has established the High Temperature Reactor – Pebble-bed Module (HTR-PM) project. The HTR-PM project has proceeded to the construction phase, with pouring of first concrete in

December 2012 [Sun 2013]. While possible, collaboration with the Chinese may be complicated for several reasons, including differences in fuel design.

In terms of supporting the NIA Business Plan for Commercialization [NIA 2012], collaborations with Japan and Korea provides an opportunity to reduce the costs for the HTGR FOAK development venture. U.S. cost reductions could be achieved through sharing of costs for technology development and areas of common design and common methods development/validation. An assessment of JAEA facilities and test programs to satisfy NGNP Design Data Needs (DDNs) is provided in [Richards 2009]. In addition, a comprehensive engineering development plan was prepared as part of the NGNP conceptual design [Hanson 2010]. This plan identifys potential areas for cost sharing. One such area is design verification and support (DV&S) for critical systems, structures, and components (SSCs) that fall into three categories: (1) development tests supporting the designs of FOAK components, including equipment qualification tests; (2) pre-commissioning tests on component assemblies; and (3) validation tests to satisfy ASME code cases for components operating at higher temperatures than previously approved. The topical areas in the DV&S discipline are:

- Reactor Internals
- Neutron Control System
- Reactor Service Equipment
- Main Circulator
- Steam Generator
- Shutdown Cooling Circulator
- Shutdown Cooling Heat Exchanger
- Reactor Cavity Cooling System
- Fuel Handling System
- Instrumentation and Control Plan
- High Temperature Isolation Valves

While the overall plant designs and applications in the U.S., Japan, and Korea have differences, there should be sufficient commonality among the designs to use many of the same major key components in the above list.

It may also be possible to achieve cost and risk reductions for the HTGR deployment venture through international collaboration. Joint HTGR development and deployment would require establishment of government-to-government agreements with Japan and/or Korea that go beyond the current basic R&D collaborations and information exchange. For this study, the scope is limited to identifying the potential markets in Japan and Korea that could support international collaborations for both development and deployment ventures.

3.3.1. Displacing LNG Used for Electricity Generation

In the U.S., natural gas prices are at historic lows as the result of increased supply from hydraulic fracturing. **Figure 3.3.1-1** shows the U.S. natural gas prices for electricity production with projections to 2040 [AEO 2013]. However, Japan and the ROK import nearly all of their natural gas as liquefied natural gas (LNG) which adds significant costs. As shown in **Fig. 3.3.1-2**, LNG prices in Japan and Korea are on the order of $15 per million Btu [FERC 2013] due to their link to the price of oil (currently ~60% of energy cost of oil) plus liquefaction and transportation costs (~$5 to $7/MMBtu). Japan and the ROK are the world's No. 1 and No. 2 importers of LNG and 50% or more of the LNG is used for electricity generation in both countries. Because of the high cost of natural gas in Japan and Korea, HTGRs are projected to be economically attractive for electricity generation while also reducing CO_2 emissions and conserving natural gas for use as a chemical feedstock. The high thermal efficiency of HTGRs results in lower cooling water requirements, which allows siting HTGRs at inland locations where many natural gas plants are located.

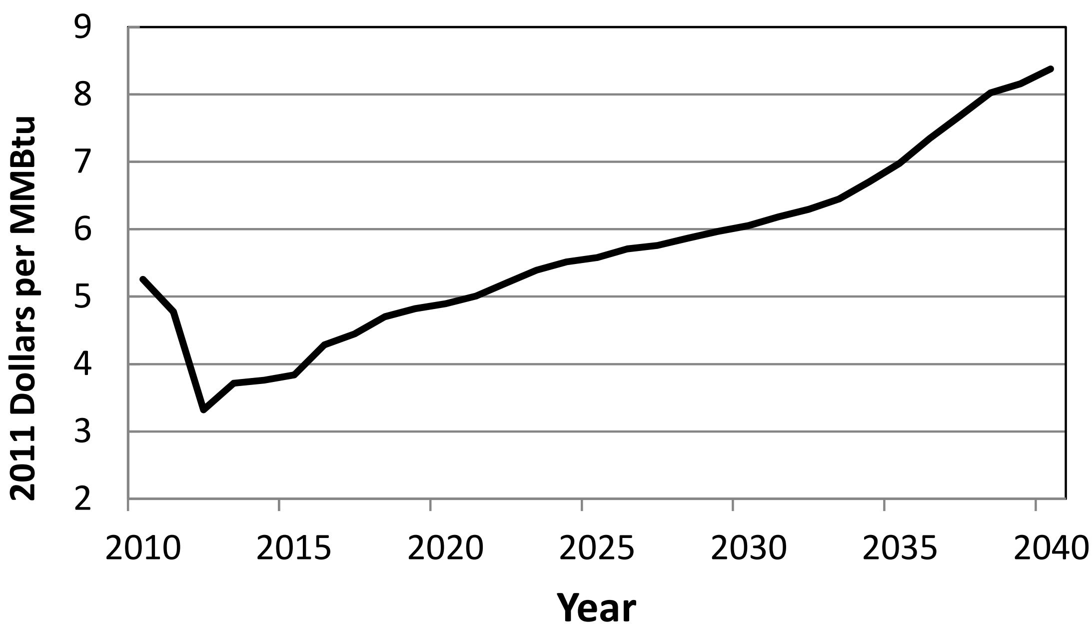


Figure 3.3.1-1. Natural Gas Price for Electricity Generation in the U.S. Is Projected to Increase Slowly

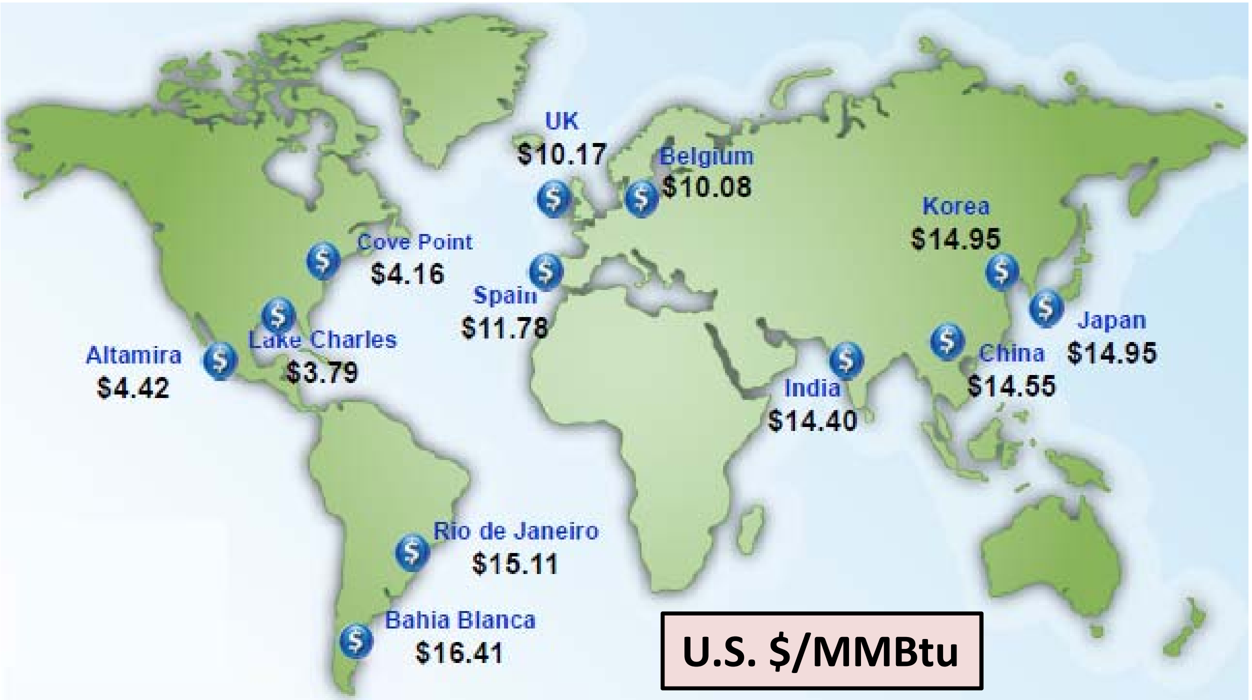


Figure 3.3.1-2. May 2013 World LNG Landed Prices at Selected Locations

Figure 3.3.1-3 shows the electricity generation mix in Japan and Korea for 2012 and as projected for 2035. The values for Japan reflect the national energy policy prior to the Fukushima accident. Natural gas electricity generation in Japan is expected to remain fairly constant through 2035 at about 75 to 77 GWe. In Korea, natural gas electricity generation is expected to increase from 26 GWe at present to about 32 GWe by 2035. (One GWe corresponds to about four, 600-MWt class HTGR modules, assuming a steam-cycle thermal efficiency of about 40%.) In both Japan and Korea, the percentage of electricity generated from burning natural gas exceeds the percentage of electricity generated using nuclear power. Displacing LNG imports for electricity generation represents a significant market opportunity for HTGRs in both Japan and Korea. The data presented suggests that the potential HTGR market for replacing LNG generated electricity is approximately 190 GWt in Japan and 80 GWt in Korea. Based on the cost advantage over LNG and the siting flexibility of the SC-HTGR, a market penetration of ~20% has been projected for both Japan and Korea as shown in **Exhibit ES-1**. Additional opportunity for penetration into the nuclear electricity generation in Japan is discussed in the following section.

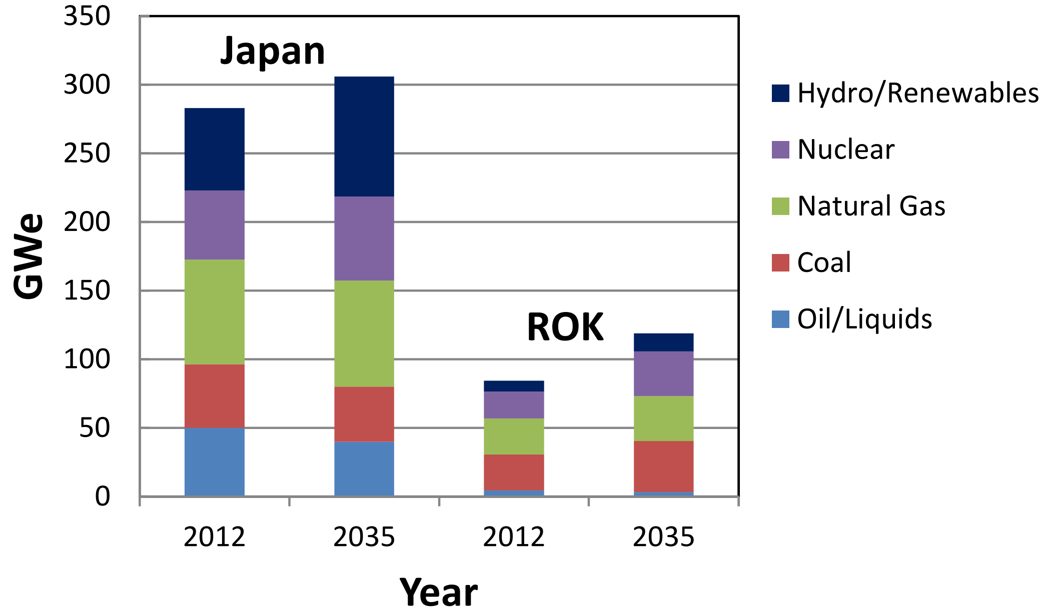


Figure 3.3.1-3. Electricity Generation Mix Projections in Japan and the ROK Indicate Expanded use of LNG for Next 20 Years

Potential Opportunities for Early HTGR Deployment in Japan

The Great East Japan Earthquake of March 2011 and the resulting tsunami led to unprecedented severe accidents with multiple core meltdowns at the Fukushima Dai-Ichi nuclear plant complex. The earthquake and ensuing damage also resulted in an immediate shutdown of 12,000 MWe of generating capacity at four nuclear power stations. Other energy infrastructure such as electrical grid, refineries, and gas and oil-fired power plants were also affected by the earthquake, though some of these facilities have been restored. Between the 2011 earthquake and May 2012, Japan shutdown all of its nuclear capacity due to scheduled maintenance and the detailed safety reviews required to obtain government approvals to return to operation. Japan is substituting the loss of nuclear generation with additional natural gas, low-sulfur crude oil, and fuel oil.

With the loss of Fukushima Units 1 through 4, Japan currently has 50 nuclear reactors with a total installed generating capacity of 46 GWe, down from 54 reactors with 49 GWe of capacity in 2010 (see **Table 3.3.1-1** and **Fig. 3.3.1-4).** All of these reactors are light water reactors (LWRs), with a mix of pressurized water reactors (PWRs) and boiling water reactors (BWRs). In its 2010 energy policy plans, Japan intended to increase nuclear electricity generation from 24 percent in 2008 to 40 percent by 2017 and to 50 percent by 2030, according to the Ministry of Economy, Trade and Industry (METI). Post-Fukushima energy policy is still undecided. In a February 13, 2013 speech to Parliament, Prime Minister Shinzo Abe pledged to restart the idled LWR fleet under tougher safety standards being adopted by a new independent watchdog agency, the Nuclear Regulation Authority. Only the Oi (also referred to as Ohi) Units 3 and 4 have been restarted. It is likely that some of the older LWRs will be decommissioned rather than be restarted.

Prior to the Fukushima accident, Japan had invested heavily in development of Sodium Fast Reactors (SFRs) and the associated reprocessing and fuel manufacturing technologies to support a sustainable, closed fuel cycle. Japan has also made a significant investment in developing HTGR/VHTR technology and technologies for nuclear hydrogen production [Richards 2007]. The intrinsic safety features of the HTGR/VHTR (which may help address post-Fukushima concerns in Japan) and its siting flexibility (as the result of its higher thermal efficiency and lower cooling water requirements) away from coastal areas subject to flooding from typhoons or tsunamis could elevate its role in future Japan energy policy. Recently, the Government of Japan provided a significant increase in funding to support nuclear hydrogen production at JAEA. An effort has also been initiated between JAEA and the Atomic Energy Society of Japan (AESJ) to establish a safety standard for the HTGR/VHTR [Sato 2013].

Commercial deployment studies of HTGR/VHTR technology in Japan have been primarily focused on the 600-MWt GTHR300C for co-generation of electricity and hydrogen (**see Fig. 3.3.1-5**) [Kunitomi 2007]. The GTHTR300C requires development and demonstration of the technologies for helium Brayton cycle power conversion and hydrogen production using the S-I process. Earlier deployment of commercial HTGR technology in Japan could be achieved using the conventional steam-cycle power conversion system for electricity production consistent with the NIA design. Steam-cycle HTGRs in Japan could help replace the electricity from the permanently lost Fukushima Units 1-4 and older LWRs that are likely to be decommissioned rather than re-started, which could represent 5 or 6 or more GWe of capacity (or approximately 15 GWt). This strategy would allow demonstration of the basic HTGR reactor system technology in Japan for evolution to direct Brayton cycle power conversion and nuclear hydrogen production. Such an evolutionary strategy would also be consistent with the phased approach adopted by the NIA for HTGR deployment, and would be conducive for international collaboration that could lower costs for both the development and deployment ventures.

Table 3.3.1-1. LWRS in Japan

Name	Location	Type	Rating (MWe)	Date Operational	Utility
Fukushima I-1 (lost)	Futaba, Fukushima	BWR	439	March 1971	TEPCO
Fukushima I-2 (lost)		BWR	760	July 1974	
Fukushima I-3 (lost)		BWR	760	March 1976	
Fukushima I-4 (lost)		BWR	760	October 1978	
Fukushima I-5		BWR	760	April 1978	
Fukushima I-6		BWR	1067	October 1979	
Fukushima II-1	Naraha, Fukushima	BWR	1067	April 1982	
Fukushima II-2		BWR	1067	February 1984	
Fukushima II-3		BWR	1067	June 1985	
Fukushima II-4		BWR	1067	August 1987	
Genkai-1	Genkai, Saga	PWR	529	October 1975	Kyūshū Electric
Genkai-2		PWR	529	March 1981	
Genkai-3		PWR	1127	March 1994	
Genkai-4		PWR	1127	July 1997	
Hamaoka-1	Omaezaki, Shizuoka	BWR	515	March 1976	Chūbu Electric
Hamaoka-2		BWR	806	November 1978	
Hamaoka-3		BWR	1056	August 1987	
Hamaoka-4		BWR	1092	September 1993	
Hamaoka-5		ABWR	1380	January 2005	
Higashidōri-1	Higashidōri, Aomori	BWR	1067	December 2005	Tōhoku Electric
Ikata-1	Ikata, Ehime	PWR	538	September 1977	YONDEN
Ikata-2		PWR	838	March 1982	
Ikata-3		PWR	846	December 1994	
Kashiwazaki-Kariwa-1	Kashiwazaki, Niigata	BWR	1067	September 1985	TEPCO
Kashiwazaki-Kariwa-2		BWR	1067	September 1990	
Kashiwazaki-Kariwa-3		BWR	1067	August 1993	
Kashiwazaki-Kariwa-4		BWR	1067	August 1994	
Kashiwazaki-Kariwa-5		BWR	1067	April 1990	
Kashiwazaki-Kariwa-6		ABWR	1315	November 1996	
Kashiwazaki-Kariwa-7		ABWR	1315	July 1997	
Mihama-1 (old)	Mihama, Fukui	PWR	320	November 1970	KEPCO
Mihama-2 (old)		PWR	470	July 1972	
Mihama-3		PWR	780	December 1976	
Ōi-1	Ōi, Fukui	PWR	1120	March 1979	
Ōi-2		PWR	1120	December 1979	
Ōi-3 (restarted)		PWR	1127	December 1991	
Ōi-4 (restarted)		PWR	1127	February 1993	
Onagawa-1	Onagawa, Miyagi	BWR	498	June 1984	Tōhoku Electric
Onagawa-2		BWR	796	July 1995	
Onagawa-3		BWR	798	January 2002	
Sendai-1	Satsumasendai, Kagoshima	PWR	846	July 1984	Kyūshū Electric
Sendai-2		PWR	846	November 1985	
Shika-1	Shika, Ishikawa	BWR	505	July 1993	RIKUDEN
Shika-2		ABWR	1358	March 2006	
Shimane-1	Kashima, Mitsue, Shimane	BWR	439	March 1974	Chūgoku Electric
Shimane-2		BWR	789	February 1989	
Takahama-1	Takahama, Fukui	PWR	780	November 1974	KEPCO
Takahama-2		PWR	780	November 1975	
Takahama-3		PWR	830	January 1985	
Takahama-4		PWR	830	June 1985	
Tokai-2	Tokai, Ibaraki	BWR	1056	November 1978	JAPC
Tomari-1	Tomari, Hokkaido	PWR	550	June 1989	HEPCO
Tomari-2		PWR	912	April 1991	
Tsuruga-1 (old)	Tsuruga, Fukui	BWR	341	March 1970	JAPC
Tsuruga-2		PWR	1115	February 1987	
Total Installed Capacity (MWe)			48,362		

TEPCO: Tokyo Electric Power Company
YONDEN: Shikoku Electric Power Company
KEPCO: Kansai Electric Power Company
RIKUDEN: Hokuriku Electric Power Company
JAPC: Japan Atomic Power Company
HEPCO: Hokkaido Electric Power Company

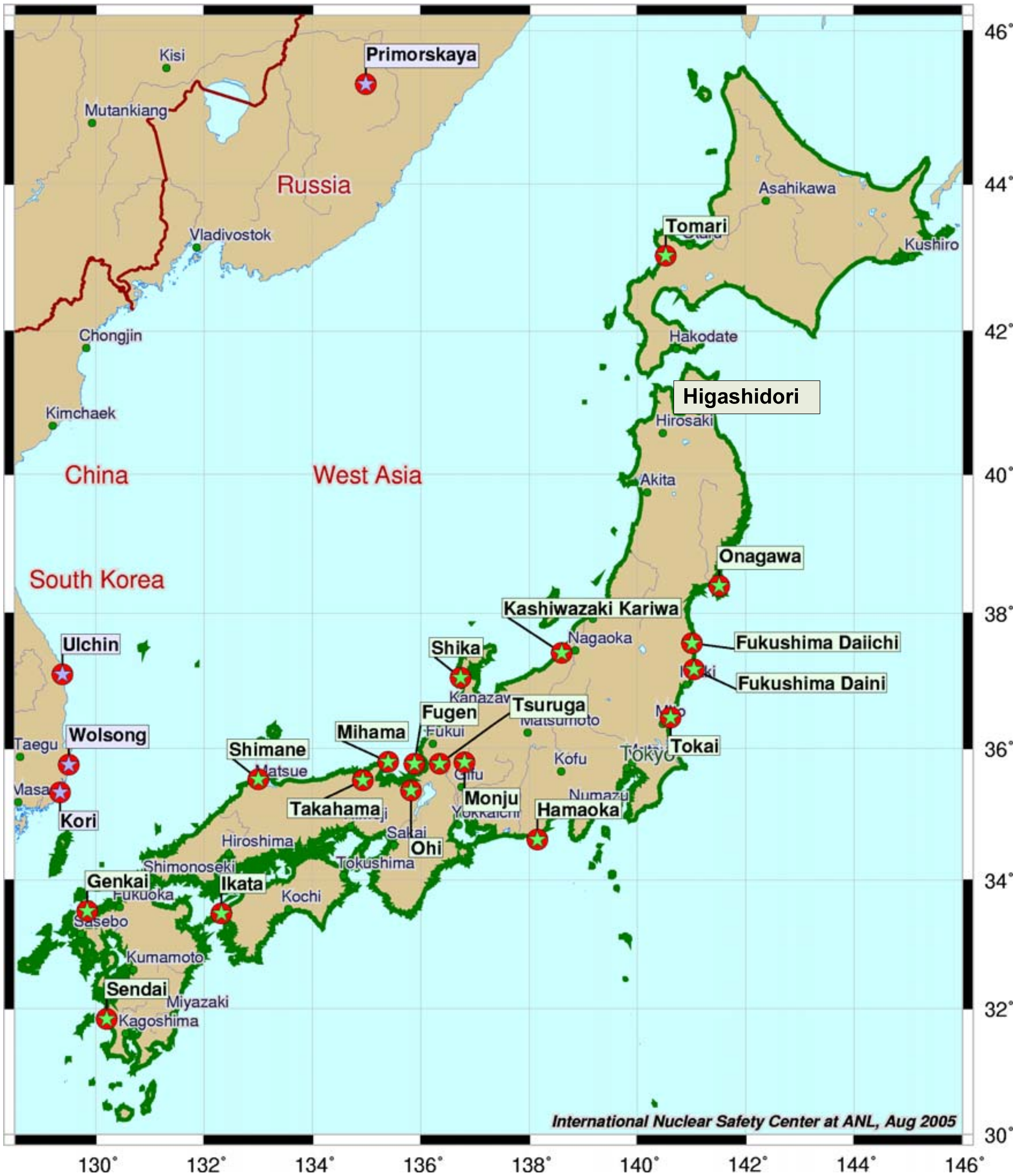
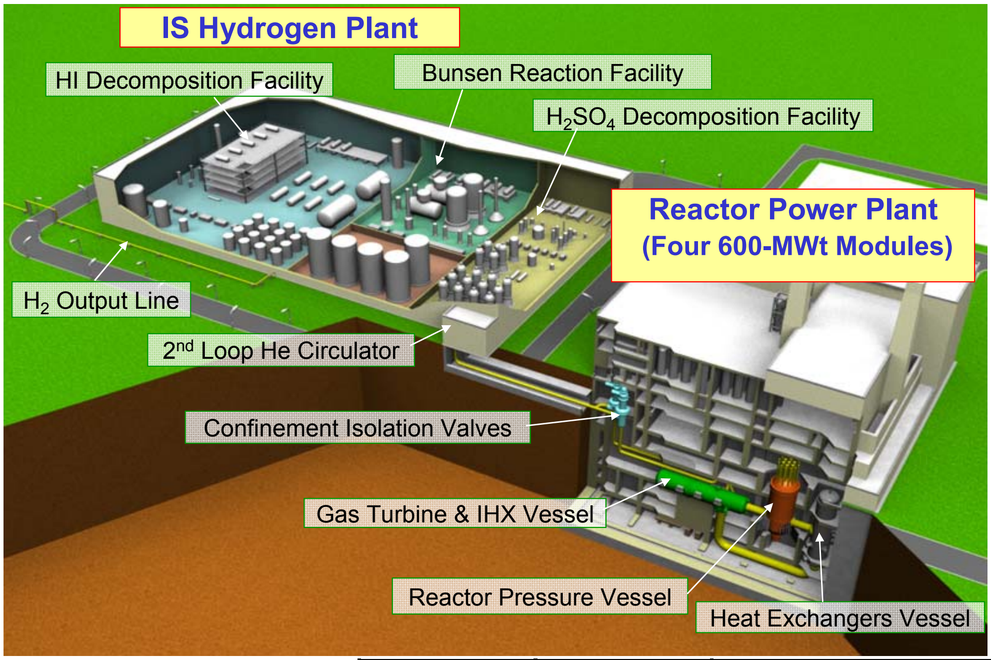


Figure 3.3.1-4. Almost all of Japan's Nuclear Power Plants are located Near the Coast



	GTHTR300	GTHTR300C(1)	GTHTR300C(2)
Operating Mode	Electricity Generation	Cogeneration	Cogeneration with Higher H_2 Production Capacity
Module Thermal Power (MW)	600	600	600
IS Process Thermal Power (MW)	–	170	371
Primary Coolant Flow Rate (kg/s)	439	322	322
Coolant Inlet Temperature (°C)	587	594	594
Coolant Outlet Temperature (°C)	850	950	950
RPV Material	SA533	SA533	SA533
RPV Inner Diameter (m)	7.6	7.6	7.6
Primary Coolant Pressure (MPa)	6.9	5.1	5.1
Average Core Power Density (W/cm^3)	5.4	5.4	5.4
Average U-235 Enrichment (%)	14.3	14.5	14.5
Number of Enrichment Zones	8	7	7
Average Fuel Burnup (GWt-d/t)	120	120	120
Refueling Interval (d)	720	540	540
Brayton Cycle Pressure Patio	2.0	2.0	1.47
Thermal Efficiency for Electricity Generation (%)	45	47	38
Electricity Generation Rate (MWe)	274	202	87
Thermal Efficiency for Hydrogen Production[a] (%)	–	50	50
Electricity Required for Hydrogen Production and House Loads (MWe)	4	40	87
Electricity Supplied to Grid (MWe)	270	162	–
Hydrogen Production Rate (kg/s)	–	1.43	2.11

Figure 3.3.1-5. JAEA GTHTR300/300C Commercial Design Concept for Coupling VHTR to IS Process

3.3.2. Nuclear Steel Manufacturing

Steel is essential to the modern world, and its use is critical in enabling man to move towards a sustainable future. Steel is also necessary for new, highly efficient power stations and the construction of smart electrical grids, transport infrastructure development, energy-efficient residential housing and commercial buildings. More than 1.5 billion metric tons of steel were manufactured in 2012, with 47% being produced in China. There will be continuing growth in steel production, particularly in developing areas such as Latin America, Asia, Africa, and the Indian sub-continent, where steel will be vital in raising the welfare of developing societies. In these regions, more than 60% of steel consumption will be used to create new infrastructure. This continued growth prevents the demand for steel being met by recycling of end-of-life steel products alone, making it necessary to continue converting virgin iron ore into steel.

Steel Production Routes [Worldsteel 2012]

Globally, steel is produced primarily via two main routes: the blast furnace-basic oxygen furnace (BF-BOF) route and electric arc furnace (EAF) route, which are shown in **Fig. 3.3.2-1**. The key difference between these routes is the type of raw materials they consume. For the BF-BOF route these are predominantly iron ore, coal, and recycled steel, while the EAF route produces steel using mainly recycled steel and electricity. Depending on the plant configuration and availability of recycled steel, other sources of metallic iron such as direct-reduced iron (DRI) or hot metal can also be used in the EAF route. About 70% of steel is produced using the BF-BOF route. First, iron ores are reduced to iron, also called hot metal or pig iron. Then the iron is converted to steel in the BOF. After casting and rolling, the steel is delivered as coil, plate, sections, or bars.

Steel made in an EAF uses electricity to melt recycled steel and/or DRI. Additives, including alloys, are used to adjust the final product to the desired chemical composition. Electrical energy can be supplemented with oxygen injected into the EAF. Downstream process stages, such as casting, reheating and rolling, are similar to those found in the BF-BOF route. About 29% of steel is produced via the EAF route.

Another steelmaking technology, the open hearth furnace (OHF), makes up about 1% of global steel production. The OHF process is very energy intensive and is in decline because of its environmental and economic disadvantages. Only four furnaces of this type are known to be in operation.

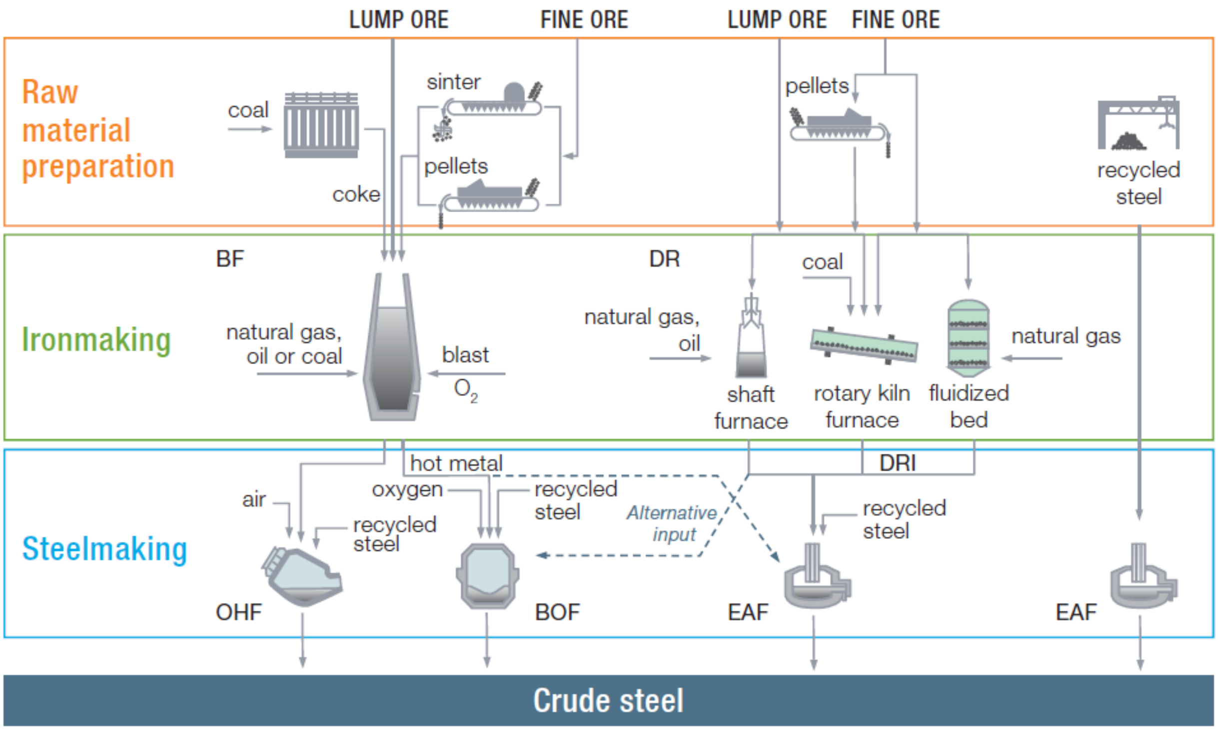


Figure 3.3.2-1. One of Two Routes are Used for most Steel Production

Most steel products remain in use for decades before they can be recycled. Therefore, there is not enough recycled steel to meet growing demand using the EAF method with recycled steel alone. Demand is met through a combined use of the BF-BOF and EAF production methods. All of these production methods can use recycled steel scrap as an input. Most new steel contains some recycled steel.

Figure 3.3.2-2 shows the quantities of iron and steel produced in 2012. Total iron production was 1,110 million metric tons and total steel production was 1,520 million metric tons. The countries shown on **Fig. 3.3.2-2** account for 97% of the world iron production and 91% of the world steel production. China dominates iron and steel production, accounting for 47% of the world's steel production and 59% of the world's iron production in 2012. The U.S. produced 89 million metric tons of steel in 2012, but 64% of this production was from recycled steel. As discussed below, both Japan and the ROK are major iron and steel producers, and both countries have shown an interest in coupling HTGRs/VHTRs to the steel manufacturing process to reduce their CO_2 emissions and fossil fuel imports.

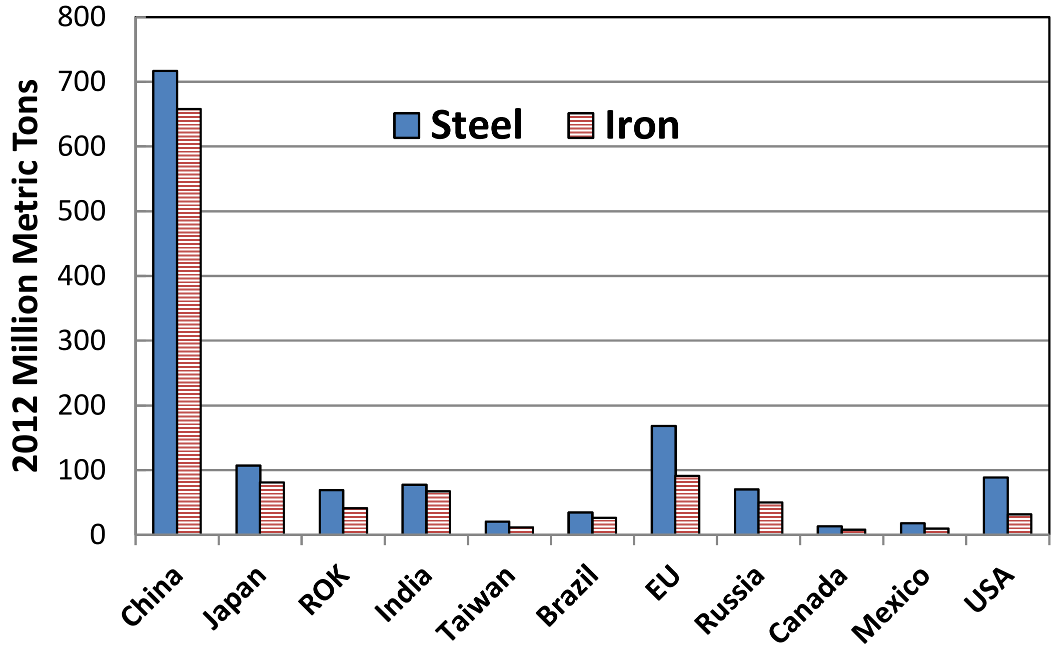


Figure 3.3.2-2. Iron and Steel Production in 2012 was Dominated by China but with Substantial Production in Japan and Korea

Carbon Dioxide Emissions from Steel Manufacturing

The greenhouse gas of most relevance to the world steel industry is CO_2, as it makes up approximately 93% of all steel industry greenhouse gas emissions. CO_2 emissions vary by production route. On average, 1.8 metric tons of CO_2 are emitted for every metric ton of steel produced. As a result, the iron and steel industry is one of the largest CO_2 emitters and accounts for approximately 6.7% of total global CO_2 emissions. Because steel use is projected to increase 50% by 2050 from present levels, CO_2 emissions could increase by the same amount. CO_2 generated by the steel industry results mostly from the chemical interaction between carbon (from coal, oil, or natural gas) and iron ore in a blast furnace. This process is called ore reduction and produces hot metal which is then converted to steel. There is currently no large-scale commercially available substitute for carbon in steel making.

Both Japan and the ROK are major world steel manufacturers and both countries have been actively investigating processes for using hydrogen to replace carbon for ore reduction. The hydrogen would be produced without the use of fossil fuels by coupling high temperature heat from VHTRs to advanced hydrogen production processes under development in the U.S., Korea, and Japan, including thermochemical water splitting. The CO_2 emissions from the steel manufacturing plant would be practically eliminated, except from small auxiliary sources (e.g., long-term oxidation of the graphite electrodes used in the high-temperature furnaces). In addition, because both Japan and the ROK lack domestic fossil fuel resources, using domestic nuclear plants to provide the hydrogen, oxygen, and electricity required for steel production would significantly reduce fossil fuel imports.

Steel Manufacturing in Japan Using Nuclear Energy

JAEA has performed a study for coupling their commercial GTHTR300C design to a steel manufacturing plant [Yan 2012]. The concept is illustrated in **Fig. 3.3.2-3**. The GTHTR300C produces both high temperature heat and electricity. The high temperature heat is supplied to a thermochemical water splitting plant [based on the Sulfur-Iodine (SI) process] to produce hydrogen and oxygen for the steel manufacturing process. Electricity is produced using a direct Brayton cycle with a helium gas turbine. A single 600 MWt GTHTR300C module provides the hydrogen, oxygen, and electricity to produce 0.63 million metric tons of steel per year. Figure **3.3.2-4** shows the material and energy balance for production of 1 million metric tons of steel. As shown in **Fig. 3.3.2-5**, JAEA is continuing to develop the S-I process and plans to conduct continuous operation tests at high temperature and high pressure with real engineering materials in 2014 [Sato 2013].

As part of its study, JAEA commissioned an economic analysis using two major nuclear plant vendors in Japan [Yan 2012]. The two vendors estimated nearly identical hydrogen production costs at \$2.42 and \$2.45/kg of H_2. These estimates are in good agreement with the estimate of \$2.26/kg-H_2 developed by General Atomics (GA) as part of the NGNP Pre-Conceptual Design [GA 2007]. **Figure 3.3.2-6** shows the estimated steel cost as a function of hydrogen production cost. The estimated steel production cost using conventional processes is approximately \$670/metric ton. The cost using nuclear-supplied electricity, hydrogen, and oxygen is somewhat lower at approximately \$630/metric ton. This estimate includes credit for sale of surplus oxygen at a conservative value of \$0.13/Nm^3-O_2. Performance parameters for this concept are summarized in **Table 3.3.2-1**. CO_2 emissions for this concept are reduced to a negligible value of about 13.8 kg per metric ton of steel.

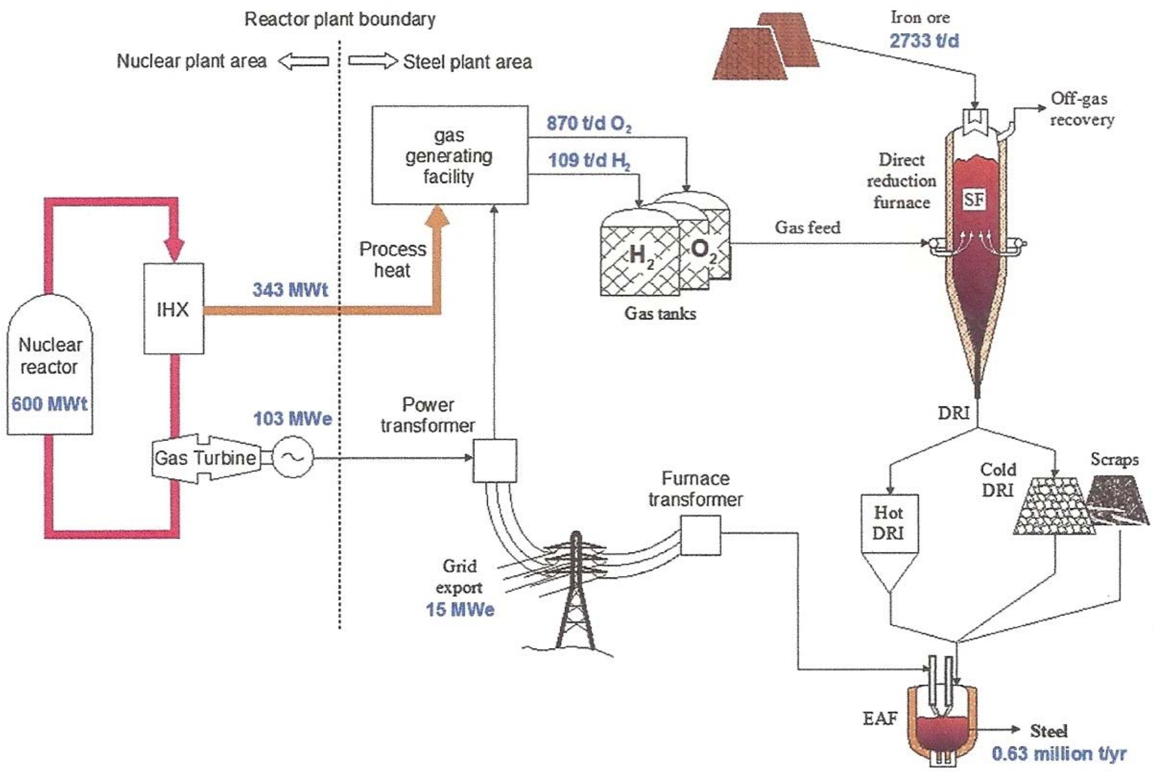


Figure 3.3.2-3. Concept for Nuclear Steel Manufacturing Includes High Temperature Heat for Hydrogen Production as well as Electricity [Yan 2012]

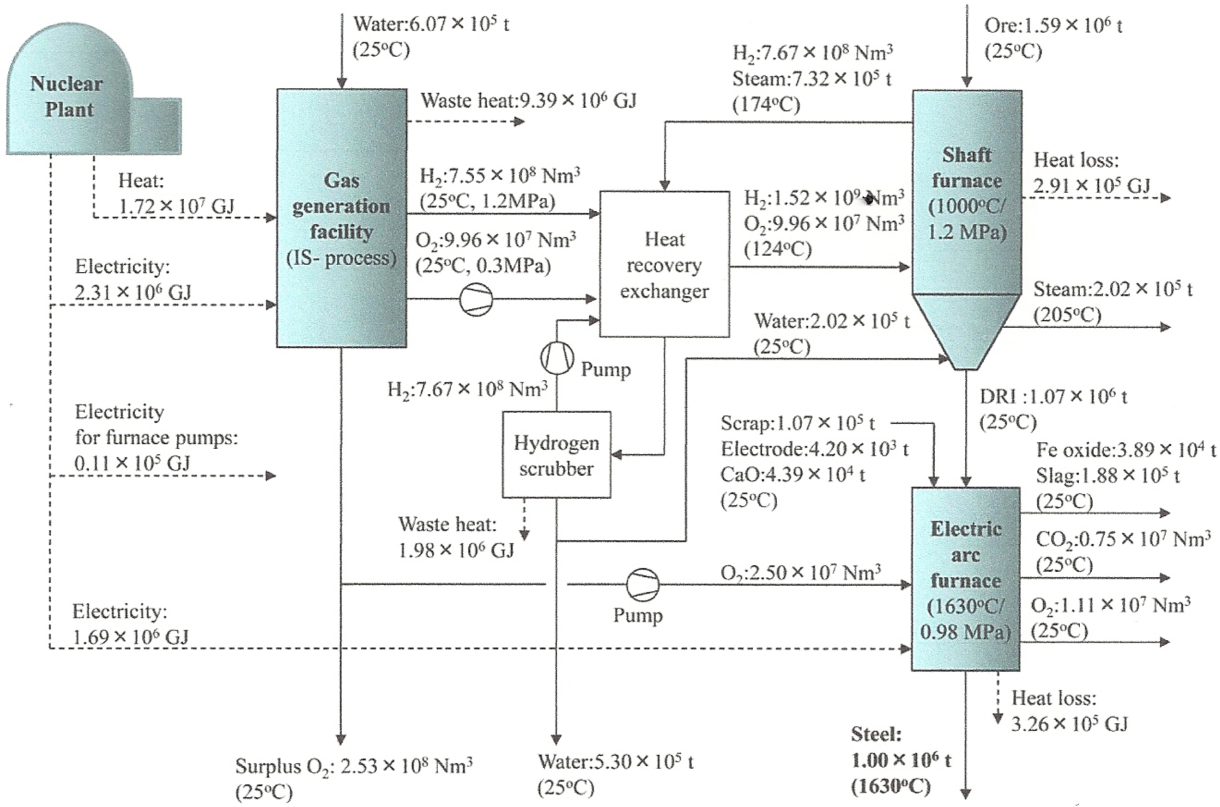


Figure 3.3.2-4. Flowsheet Has Been Developed for Producing 1 Million Metric Tons of Steel Using Energy from VHTR [Yan 2012]

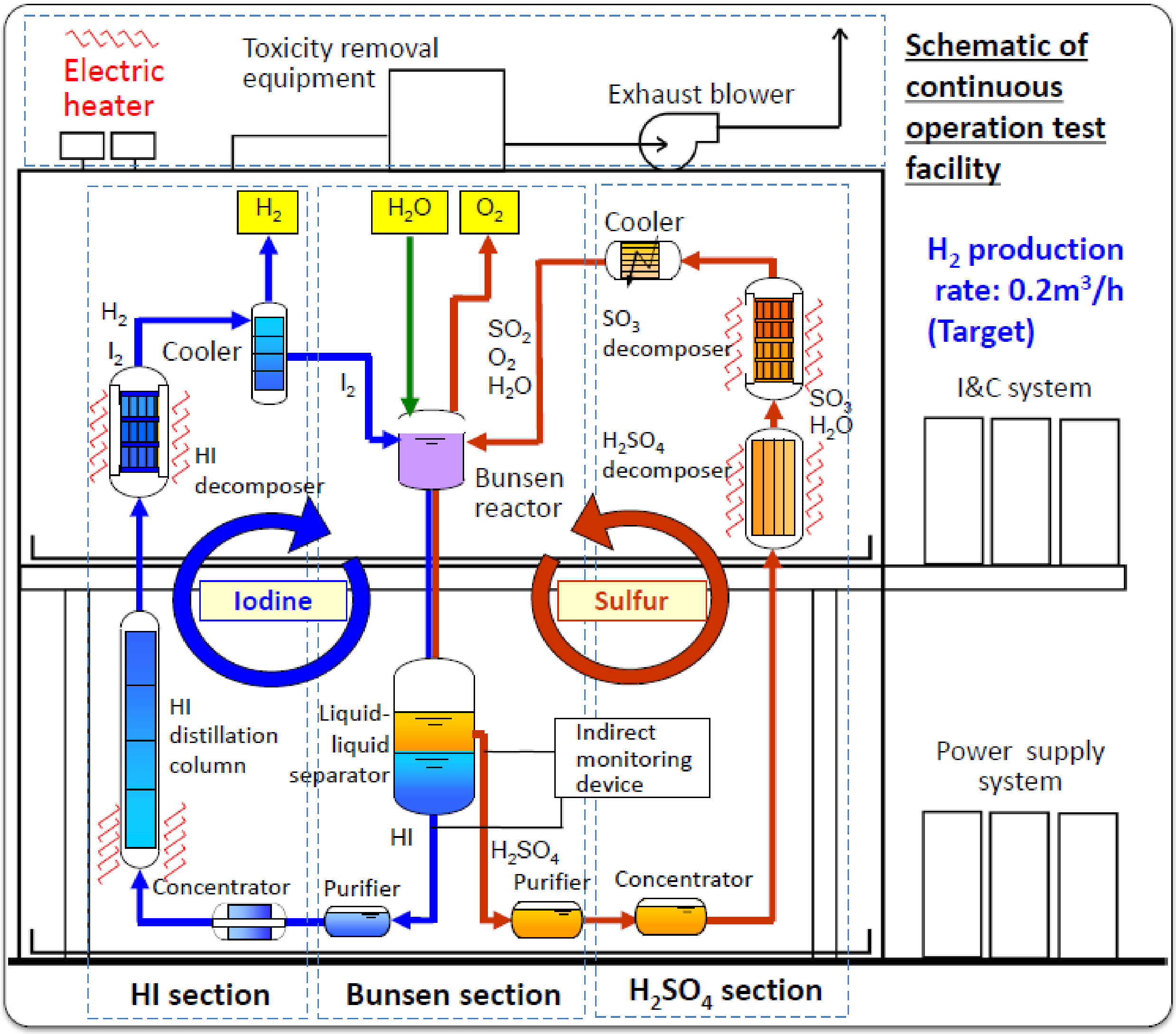


Figure 3.3.2-5. Continuous Operation Test of S-I Process Planned by JAEA [Sato 2013]

As part of its study, JAEA commissioned an economic analysis using two major nuclear plant vendors in Japan [Yan 2012]. The two vendors estimated nearly identical hydrogen production costs at $2.42 and $2.45/kg of H_2. These estimates are in good agreement with the estimate of $2.26/kg-$H_2$ developed by General Atomics (GA) as part of the NGNP Pre-Conceptual Design [GA 2007]. **Figure 3.3.2-6** shows the estimated steel cost as a function of hydrogen production cost. The estimated steel production cost using conventional processes is approximately $670/metric ton. The cost using nuclear-supplied electricity, hydrogen, and oxygen is somewhat lower at approximately $630/metric ton. This estimate includes credit for sale of surplus oxygen at a conservative value of $0.13/Nm^3-$O_2$. Performance parameters for this concept are summarized in **Table 3.3.2-1**. CO_2 emissions for this concept are reduced to a negligible value of about 13.8 kg per metric ton of steel.

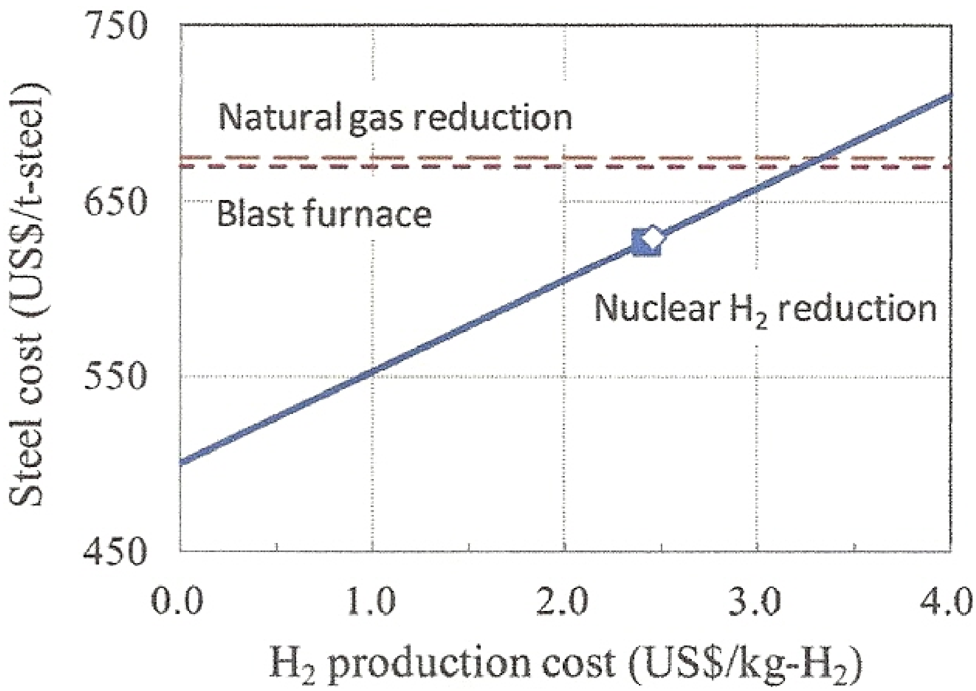


Figure 3.3.2-6. Cost Comparison of Steel Production Methods Illustrates Sensitivity to Hydrogen Production Costs [Yan 2012]

Table 3.3.2-1. Nuclear Steel Manufacturing Performance Parameters [Yan 2012]

Reactor Power	600 MWt
Reactor Helium Outlet Temperature	950°C
Reactor Helium Coolant Pressure	5.2 MPa
Turbine Inlet Temperature	750°C
Heat Supplied to S-I Process	343 MWt at 900°C
Electric Power Generation	103 MWe
Hydrogen Production	109 metric tons/day
Oxygen Production	870 metric tons/day
Steel Production	0.628 metric tons/year
Steel Production Cost	$628/metric ton
CO_2 Emissions	13.8 kg/metric ton of steel

As shown in Fig. **3.3.2-2**, Japan produces about 80 million metric tons of iron per year, resulting in about 140 million metric tons of CO_2 emissions per year. Assuming pre-Fukushima nuclear capacity, iron production in Japan contributes 10% - 12% of its CO_2 emissions and represents a significant portion of its fossil fuel imports. Eighty million metric tons of iron produced per year corresponds to about 130, 600-MWt GTHTR300C modules (or about 80 GWt), which represents a significant market opportunity in Japan as an economical option to significantly reduce both CO_2 emissions and fossil fuel imports.

Steel Manufacturing in the ROK Using Nuclear Energy

KAERI has been working on HTGR/VHTR technology and nuclear hydrogen production for over a decade. Figure **3.3.2-7** shows an overview of the project elements and schedule. An R&D program has been established to develop key technologies and design codes/methods for nuclear hydrogen production. In 2012, the Nuclear Heat and Hydrogen (NuH_2) design project was initiated in collaboration with Korean industry. The industrial consortium is headed by POSCO, the world's 4th largest steel manufacturer. Other industry participants include Hyundai Engineering and Construction, Hyundai Heavy Industries (HHI), and STX Heavy Industries. In addition, a Korea Nuclear Hydrogen Alliance (KNHA) has been established that includes additional industry participants. The first element of the NuH_2 project is the ongoing VHTR System Concept Study. The project structure for this study is shown in Fig. **3.3.2-8**.

As a means of reducing CO_2 emissions, POSCO has been investigating processes similar to that described in the JAEA study [Yan 2012] for coupling nuclear hydrogen, oxygen, and electricity to steel manufacturing. The POSCO concept is illustrated in Fig. **3.3.2-9**, which utilizes three 600-MWt VHTR modules to supply the energy needs for a 2 metric ton per year steel manufacturing plant. Two modules are used to generate hydrogen and oxygen using the S-I process and the third module is used to supply electricity. The overall energy and mass balances are nearly identical to that of the JAEA study [Yan 2012].

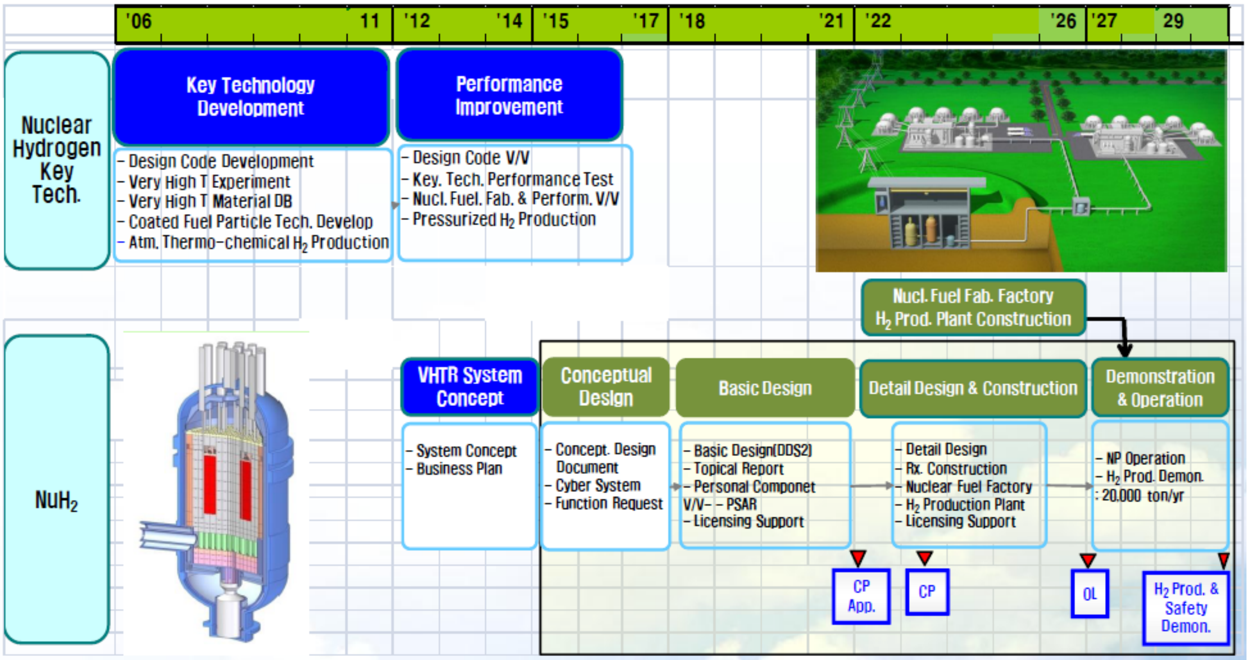


Figure 3.3.2-7. ROK Continues Plan to Develop Nuclear Hydrogen Programs Based on the VHTR

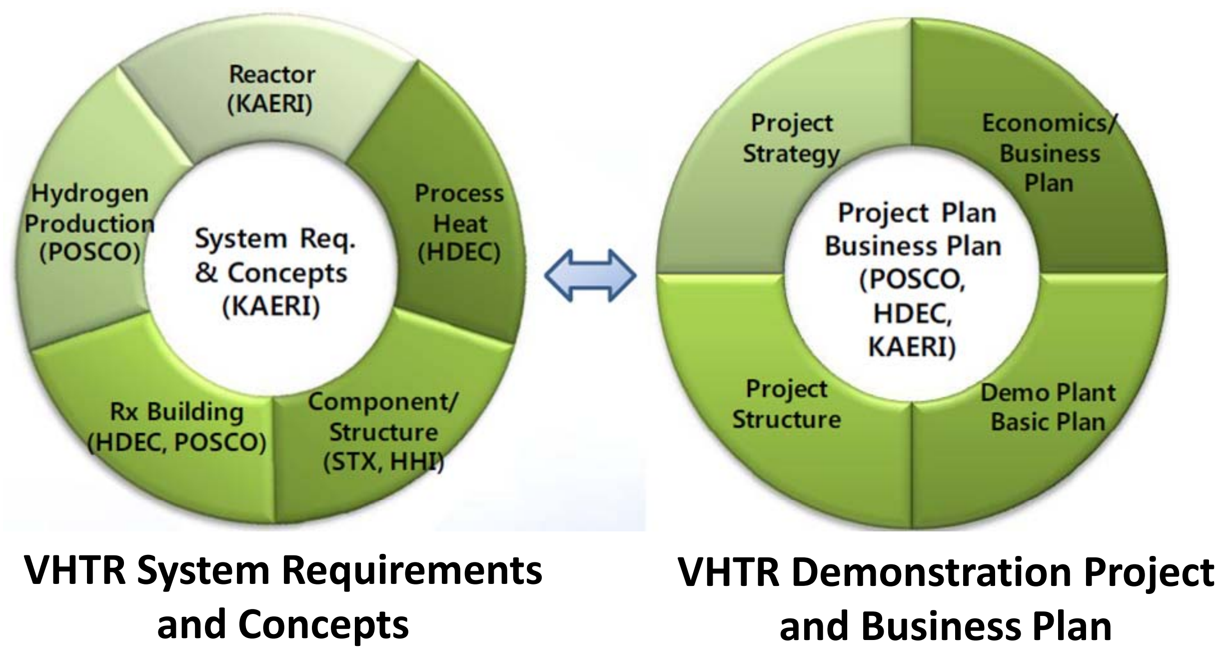


Figure 3.3.2-8. VHTR System Concept Study Project Structure Exploits Capabilities in ROK Labs and Industry

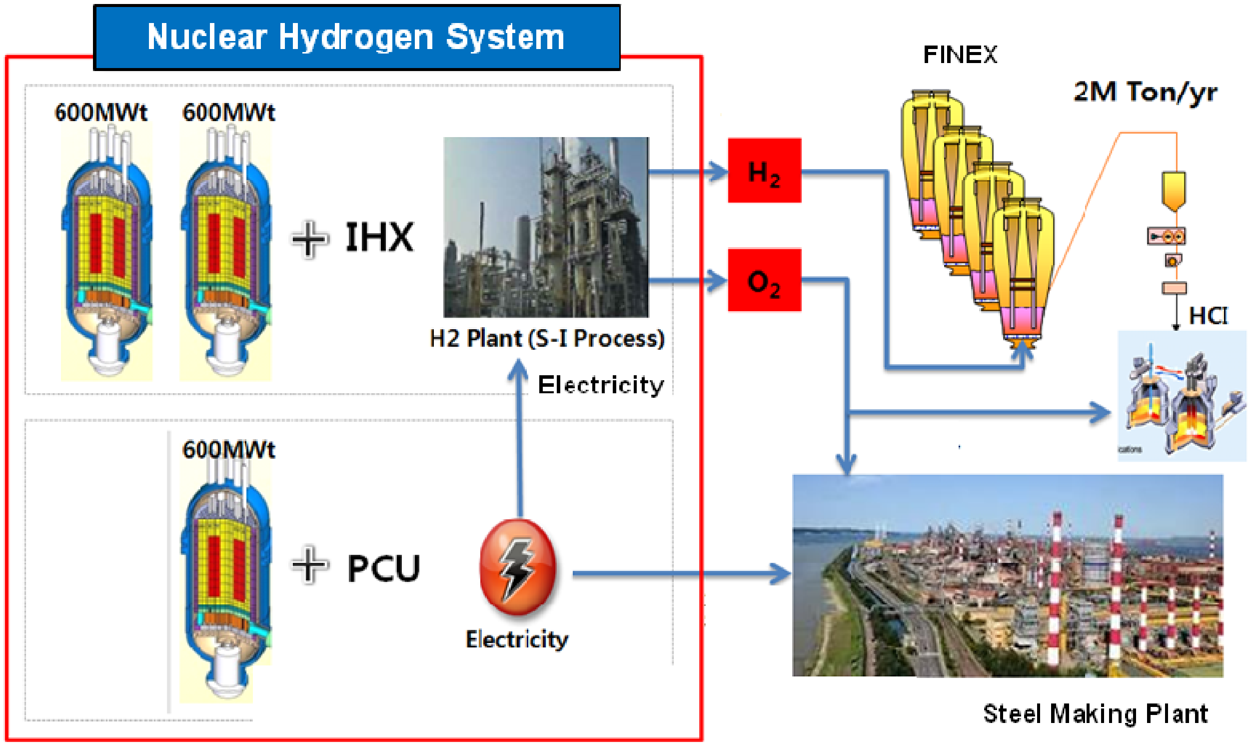


Figure 3.3.2-9. POSCO Concept for Nuclear Steel Manufacturing Utilizes Three, 600MWt VHTR Modules

As shown in Fig. **3.3.2-2**, the ROK produces about 40 million metric tons of iron per year, resulting in about 70 million metric tons of CO_2 emissions per year. 40 million metric tons of iron produced per year corresponds to about 65, 600-MWt VHTR modules (about 40 GWt), which represents a significant market opportunity in the ROK as an economical option to significantly reduce both CO_2 emissions and fossil fuel imports.

<u>HTGR & VHTR Projections of Market Penetration Supporting Steel Making in Japan and ROK</u>

As noted in the potential market for nuclear powered steel making is (and presented in Exhibit ES-1) the summarizes projections that by 2050, ~50% of the hydrogen production, associated process heat and electricity for steel making in Japan and Korea will be provided by various versions of the HTGR. The initial modules deployed are assumed to be SC-HTGRs for SMR of LNG, process steam and electricity for steel making and is projected to be 20% of the modules to be deployed by 2050. The higher cost of LNG provides incentive for a higher rate of earlier deployment in Japan and Korea than in the U.S. The later 80% of the HTGR modules are projected to be VHTRs.

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APPENDIX A – Synthetic Fuels Market Background Information

<u>Availability & Pricing of Natural Gas & Coal in North America</u>

The availability and low cost of natural gas and coal in North America is a substantial hurdle for development and/or deployment of other advanced energy systems for electricity or process heat. On the other hand the projected long-term availability of these commodities at low prices offers an economic opportunity to utilize coal as the primary feedstock for the production of much higher value liquid transportation fuels and chemicals. Until other hydrogen production techniques are available, low cost natural gas would be used to provide hydrogen utilizing steam methane reforming (SMR)s.

EIA's 2013 projections [AEO 2013] for U.S. natural gas supply are presented in **Exhibit A-1** and suggest a bountiful supply largely driven by the continuing development of "fracking" in shale oil. The price which EIA projects for this production level was shown for the reference case price being in the $4 to $6/MMBtu range between 2020 and 2035.

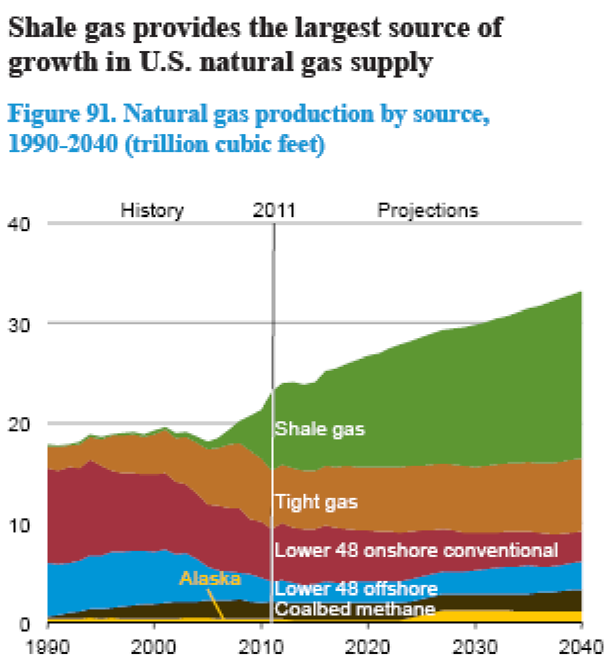

Exhibit A-1. *U.S. natural gas supplies are expected to increase through 2040*

More importantly, when these projections are correlated with similar oil projections EIA concludes that the cost per unit energy for oil will remain much higher than the cost of natural gas. Specifically, the ratio of the oil to natural gas price in $/MMBtu will remain around 4 from 2020 through 2040 as shown in **Exhibit A-2.** While natural gas prices are projected by EIA to remain low, it must be noted that such projections for energy commodities (and especially natural gas) cannot adequately address either short-term market excursions or long-term discontinuities in demand or supply. Dramatically increased LNG exports, rapid transition from coal to natural gas for electrical generation, unpredicted growth in direct use of compressed natural gas as a transportation fuel or other inelastic uses could result in higher long-term prices and market volatility.

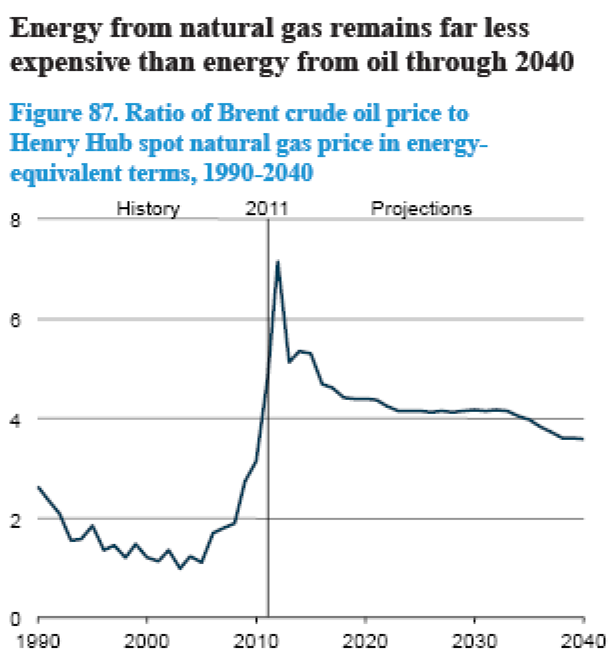

Exhibit A-2 *U.S. natural gas is expected to remain a relatively inexpensive feedstock for transport fuel synthesis*

Similarly, the price of coal currently averages ~\$2/MMBtu in the U.S. and below \$1/MMBtu at the mine mouth in many locations as compared to ~\$18/MMBtu (or ~\$100/bbl) for oil. While coal prices are projected by EIA to increase by ~50% by 2040 as shown in **Exhibit A-3,** oil prices are projected to increase by a similar fraction **(Exhibit A-4).**

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Expected declines in mining productivity lead to further increases in average minemouth prices

Figure 106. Average annual minemouth coal prices by region, 1990-2040 (2011 dollars per million Btu)

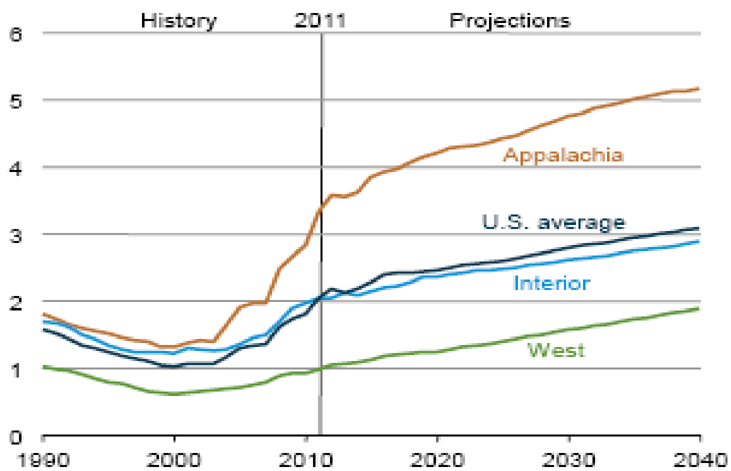

Exhibit A-3 *U.S. coal prices will make coal economically attractive as a feedstock for synthetic transportation fuels for decades*

The result is the ratio of energy value for oil to coal is projected to be maintained at ~9 to 10 through 2040 in the EIA reference case.

Figure 21. Annual average spot price for Brent crude oil in three cases, 1990-2040 (2011 dollars per barrel)

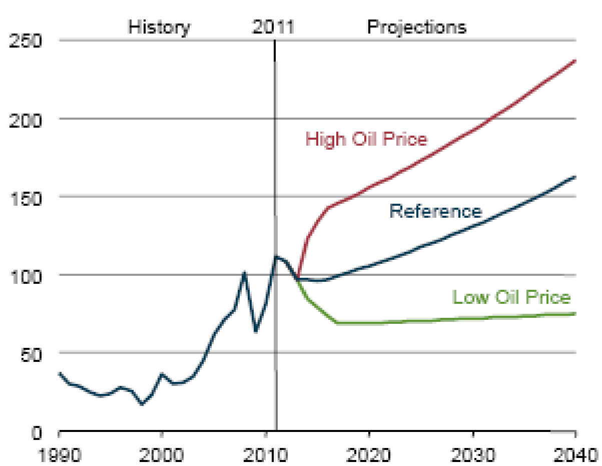

Figure 22. World petroleum and other liquids supply in three cases, 1990-2040 (million barrels per day)

Exhibit A-4 *Reference EIA oil price is projected to increase from $18/MMbtu ($100/bbl) in 2013 to ~$29/MMbtu ($160/bbl) in 2040*

Based on these 2013 projections the attractiveness of synthesizing oil in the U.S from coal and natural gas feedstocks has increased in the past year. The long-term projections for the costs of the feedstocks ($2 to $8/MMBtu) and the price of the drop-in liquid transport fuel products ($18 to $29/MMBtu) suggest that transport fuel synthesis from U.S. coal and natural gas will be economically attractive for at least several decades and is likely to remain attractive much longer.

Process Alternatives

As part of broad collaborative efforts with business interests in Wyoming and Kentucky, the NGNP Industry Alliance and the INL, performed separate studies for each state ([INL 2012a] and [INL 2012b]) to identify and formulate opportunities for expanding the market and increasing the value of the indigenous coal and natural gas resources. The investigations focused on the deployment of a carbon conversion industry and the potential use of nuclear energy to satisfy the long term energy needs in the State. These investigations (1) identified carbon conversion processes that match up with the characteristics of the coal and natural gas in each state and the market for the products from these processes (2) established the role of nuclear energy with emphasis on the HTGR technology to be integrated with the carbon conversion processes and as a part of the replacement mix for existing coal-fired electricity generation, and (3) identified the alternatives that meet the objectives of each collaborative effort and are technically and economically viable. The following information summarizes much of the information in the Wyoming and Kentucky studies.

The various chemical synthesis processes evaluated are identified in **Exhibit A-5** which summarizes the attributes and nomenclature for the processes evaluated in by INL.

Exhibit A-5 *A wide range of processes was evaluated for synthesis of coal and natural gas to liquid transportation fuels.*

Table 3-1. Carbon conversion alternatives evaluated.

Acronym	Process
Coal to Liquids (CTL)[7,8] -- *producing diesel, naphtha and liquefied petroleum gas*	
CTL	Conventional CTL using the Fischer-Tropsch (FT) process
CTL w/SMR	Conventional CTL with steam methane reforming (SMR) supplying hydrogen to the coal gasifier
CTL w/SMR & HTGR	CTL with SMR (CTL w/SMR) with HTGR supplying heat and electricity to the steam methane reformers
CTL w/HTGR & HTSE	CTL with HTGR and high temperature steam electrolysis (HTSE) supplying hydrogen to the coal gasifier
Natural Gas to Liquids (GTL)[4] – *producing diesel, naphtha and liquefied petroleum gas*	
GTL	Conventional natural GTL using the FT process
GTL w/HTGR	1 GTL with HTGR supplying heat to the primary reformer
Natural Gas to Gasoline (GTG)[8] – *producing gasoline and liquefied petroleum gas*	
GTG	Conventional natural GTG using the methanol to gasoline process (MTG)
GTG w/HTGR	GTG with HTGR supplying heat to the primary reformer
Coal to Gasoline (CTG)[5] – *producing gasoline and liquefied petroleum gas*	
CTG	Conventional CTG using MTG process
CTG w/SMR	Conventional CTG with SMR supplying hydrogen to the coal gasifier
CTG w/SMR & HTGR	CTG with SMR (CTG w/SMR) with HTGR supplying heat and electricity to the steam methane reformers
CTG w/HTGR & HTSE	CTG with HTGR and HTSE supplying hydrogen to the coal gasifier
Coal to Chemicals[9] -- *including olefins such as ethylene and propylene*	
CTO	Conventional coal to olefins (CTO)
CTO w/HTGR & HTSE	CTO with HTGR and HTSE supplying hydrogen to the coal gasifier
Direct Coal Liquefaction -- *producing diesel, naphtha and liquefied petroleum gas*	
DCL	Direct coal liquefaction (DCL) based on Bergius-Pier process

Syngas Generation

All of the processes evaluated and listed in **Exhibit A-5** involve conversion of coal and/or natural gas into some combination of diesel, naphtha, LPG, gasoline and commodity chemicals (e.g., ethylene and propylene). In all cases, except for the DCL process, the first step in the process is the conversion of the feedstock to synthetic gas composed of a specific ratio of H_2 and CO, see **Exhibit A-6**.

With coal as the feedstock the synthetic gas is produced in a gasifier at high temperature. There is insufficient hydrogen in the coal to achieve the required ratio of CO to H_2 in the syngas; hence, another supply of hydrogen is required. Most commercial gasifiers generate hydrogen by injecting steam and using the water shift reaction; i.e. $CO + H_2O \rightarrow CO_2 + H2$. This reaction is a major source of CO_2 generation, sending about 2/3rd of the incoming carbon out as CO_2 with only a third ending up in the actual syn fuel. For natural gas feedstock, syngas is produced through a reforming process, splitting the carbon and hydrogen in the gas and adding oxygen to produce the H_2 and CO components. This process is endothermic. Heat is supplied by burning natural gas which is a major source of CO_2 generation.

The quantities of CO_2 produced in the coal gasification process are significantly higher than that for the natural gas reformer. In both cases, however, the majority of the CO_2 generated in these processes can be captured, compressed and transported for sequestration or enhanced oil recovery (EOR). However, sequestration is costly, there are important uncertainties regarding the viability of sequestration, the financial insurance risk for sequestration impacts (re-release or impacting regional existing gas and oil resource production through displacement, etc.) and there is insufficient capacity in EOR to make that a viable long term disposal pathway. In most regions, the first 2 or 3 major carbon conversion plants would saturate the EOR demand. EOR is not a viable solution for a major penetration of synthetic fuel production. Pending government regulation of CO_2 emissions may also make release economically unattractive. Accordingly, there is advantage to reducing the amount of CO_2 generated in the syngas processes.

Exhibit A-6 *Syngas generation is an intermediate step in almost all synthetic fuel processes*

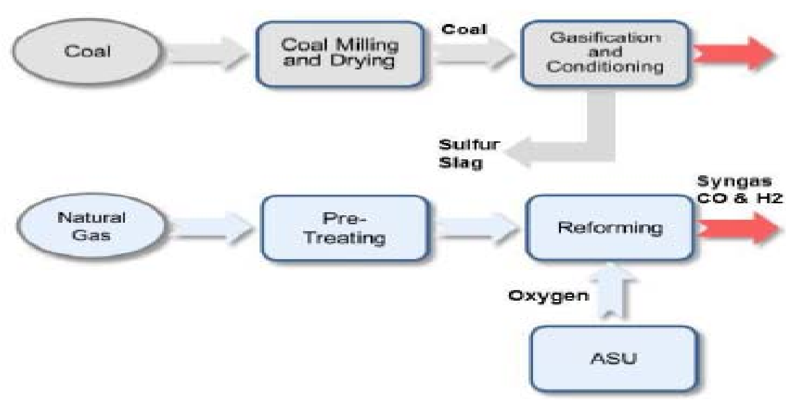

Figure 3-1. Syngas generation.

INL evaluated four different options for providing an external supply of hydrogen to the coal gasifier as a substitute for the water shift reaction to produce the required H_2 to CO ratio, as follows:

- Steam Methane Reforming (SMR); steam methane reforming is a common process used in the United States to produce hydrogen from natural gas and water. This process is used throughout the petro-chemical industry with good success. Use of SMR reduces the CO_2 generated in the process by ~60% compared to a process using water gas shift to produce hydrogen.

- SMR with HTGR heat; conventional steam methane reforming burns some of the natural gas to supply the heat required for the endothermic reaction. This and the reaction itself produce about 9 tons of CO_2 for every ton of hydrogen produced. Adding high temperature heat from the HTGR reduces CO_2 generation by 83% and also generates about 15% more hydrogen for the same feed rate of natural gas.
- HTGR and HTSE; the HTGR supplies heat and electricity to the HTSE process to produce hydrogen with no CO_2 emissions. This is the most effective process for reducing CO_2 emissions in the gasification process.
- Natural Gas Reforming, wherein the addition of HTGR heat to the reformer in the natural gas to syngas process reduces the generation of CO_2 by 23% and reduces the amount of natural gas required for the process by ~10%.

These methods can provide an external supply of hydrogen and heat and help reduce CO_2 production.

<u>Indirect Processes for Carbon Conversion</u>

The syngas can be used to synthesize many different products. The INL study [INL 2012a] evaluated several indirect processes including:

- **Coal Liquids using Natural Gas to produce Hydrogen** producing diesel fuel, naphtha and LPG using the conventional Fischer-Tropsch (FT) process.
- **A CTL alternative** of converting the naphtha to higher value products including gasoline and olefins.
- **Coal and Natural Gas to Gasoline** using the methanol to gasoline (MTG) process.
- **Coal to chemicals** (e.g., olefins such as ethylene, propylene) using the coal to methanol to olefins (CTO) process.

<u>Direct Coal Liquefaction (DCL)</u>

The DCL process was developed early in the twentieth century and has been studied for coal conversion to transportation fuels by NETL and others for several decades. It is generally accepted that the liquids produced are valuable feedstocks for fuels and chemicals and that production of transport fuels is technically feasible. A DCL plant is currently successfully operating in Shenhua China. DCL interest in the U.S. has been limited by several concerns including:

- Relatively high CO_2 emissions
- Relatively modest thermal conversion (~65%) efficiencies

- Most work has been on high sulfur coal

This alternative may be more attractive for the higher sulfur coal in the eastern U.S.

Plant Capacities

All of the processes evaluated can be deployed in facilities comprised of multiple trains or modules of 10,000 to 20,000 bpd capacities. For the purposes of the analyses herein total plant capacities of ~50,000 bpd to ~60,000 bpd have been considered; comprised of four modular trains each with 25% of the full plant capacity.

Comparison of CO_2 Emissions for Indirect Processes

The quantity of CO_2 generation and emissions is a distinguishing characteristic of these processes as shown in **Exhibit A-7**. The benefits of generation and emissions reductions through the incorporation of SMR, HTGR and HTSE technologies are apparent in this exhibit. The exhibit shows that a substantial percentage of the emissions generated by all of the processes can be captured for sequestration or EOR. However, there are substantive operational costs associated with capture and transport of these emissions that add to the production costs of these processes. The potential to reduce the generation of emissions through incorporation of these technologies is a key element in selection of the processes to be deployed to address the effects on production costs of current and potential regulations of CO_2emissions by Environmental Protection Agency (EPA).

There is insufficient information available on the CO_2 generation in modern DCL processes but it seems apparent that DCL will require incorporation of effective carbon management.

Exhibit A-7 *Carbon generation & emissions vary by factors of 10 to 100 for alternative synthesis processes. Utilization of the HTGR can significantly reduce carbon generation.*

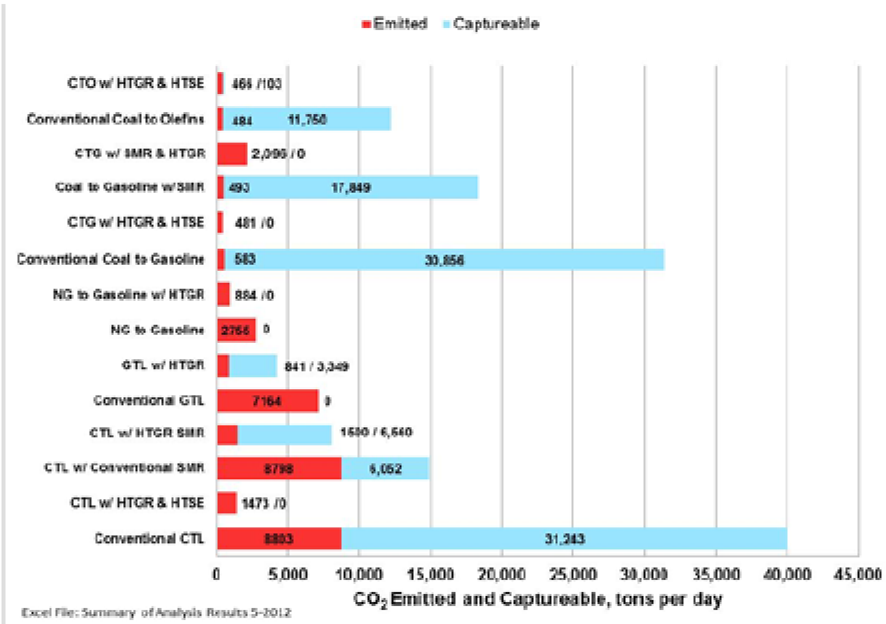

Figure 3-8. Comparison of CO_2 emissions of alternative processes.

Alternative Process Economics

Production Costs of Synthetic Transportation Fuels

The economic viability of the candidate processes was evaluated by comparing the calculated production costs for each process with the production costs for the products using other more traditional processes (e.g., the production cost for refining crude oil or generating chemicals from natural gas liquids). These calculations were made for consistent economic factors (e.g., return on investment, debt to equity ratio, interest rates and terms) and were made for the conventional carbon conversion processes and those in which the HTGR and, where applicable, the HTSE technologies were incorporated. The results of those calculations are summarized in **Exhibits A-8 and A-9.**

Exhibit A-8 summarizes the production cost of diesel fuel for the six coal and natural gas to diesel alternative processes evaluated compared with the historical costs of refining diesel from crude oil as a function of the price of crude oil. This historical data was extracted from DOE

Energy Information Agency data bases for the period May 2002 through March 2012. The line through the data was produced using a linear regression analysis. **Exhibit A-9** shows a similar comparison of the production costs for the six coal and natural gas to gasoline processes evaluated with the production costs of refining gasoline from crude oil. On both figures Energy Information Administration (EIA) projections of the price of crude oil in the 2023 to 2035 time frame is shown. In all cases the projections on the costs of production for the alternatives fall within the EIA projections of crude oil prices over time (i.e., the production cost of diesel and gasoline produced using carbon conversion processes can compete with those products produced by conventional crude oil refining processes). This range is very wide, however, and all but those alternatives that use the combined HTGR and HTSE technologies for the hydrogen supply are grouped in a lower range, $58 to $85/bbl, that is more closely aligned with the range of variations experienced over the last five years (see **Exhibit B-10**) and are significantly less than the reference EIA projection through 2040.

Exhibit A-8 *Preliminary economic analysis indicates that U.S. coal supplemented by hydrogen from natural gas can be used as feedstock (and process heat source) to synthesize diesel fuel at a cost competitive with oil at $60 to $70/bbl. Utilization of the HTGR as the process heat source will increase costs equivalent to ~$66 to $85/bbl but will significantly reduce carbon emissions*.

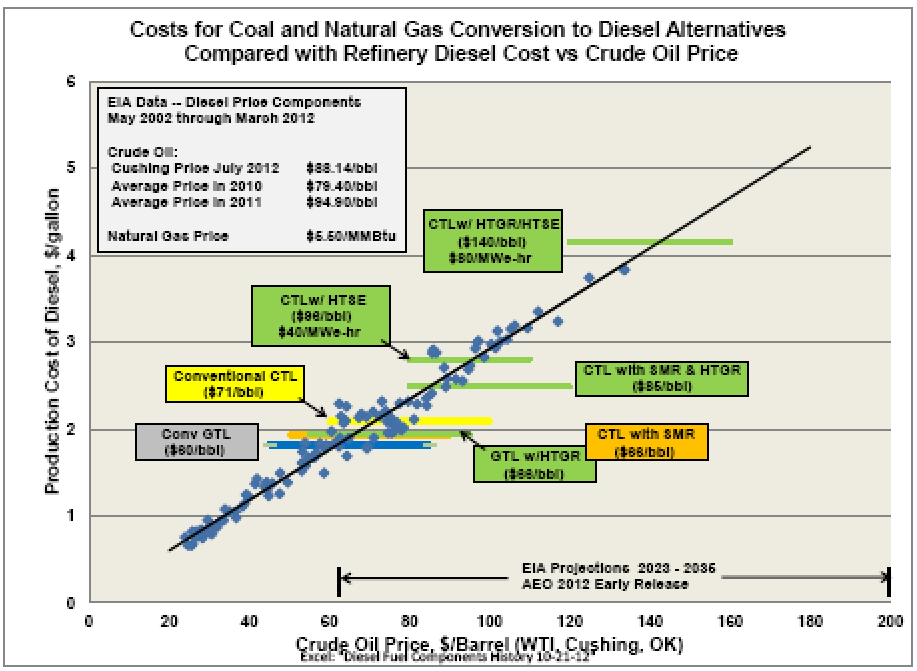

Figure 3-9. Comparison of the production costs of conventional carbon conversion processes with the production cost of diesel refined from crude oil versus the price of crude oil.

Exhibit A-9 *Preliminary economic analysis indicates that U.S. coal can be used as feedstock (with natural gas SMR) to synthesize gasoline at a cost competitive with oil at $70/bbl. Utilization of the HTGR as the heat source will increase costs equivalent to $77/bbl but will significantly reduce carbon emissions.*

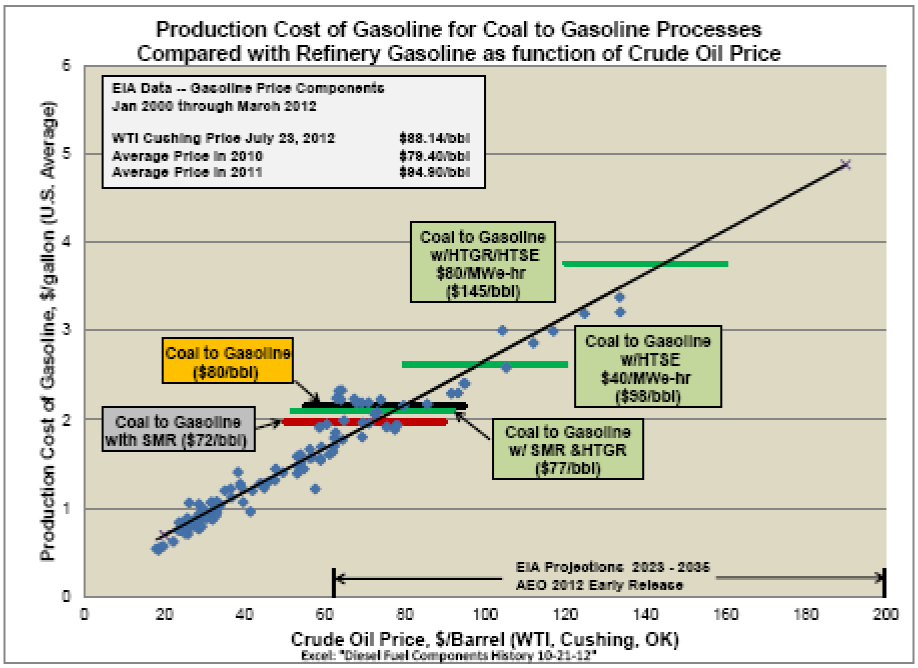

Figure 3-10. Comparison of the production costs of conventional carbon conversion processes with the production cost of gasoline refined from crude oil versus the price of crude oil.

The production costs for the processes using HTSE in **Exhibit A-8** and **Exhibit A-9** are shown for electricity prices ranging from $40/MWe-hr to $80/MWe-hr. The higher production costs (equivalent to crude oil prices in the $140/bbl range) are associated with supply of electricity using the HTGR which has an equivalent price of ~$80/MW(e)-hr. If electricity can be obtained in the range of $40/MW(e)-hr, the production costs become more competitive with other alternatives. Although the lower prices for electricity are in the range currently available to industrial users in coal producing states with open pit mining, they are highly dependent on coal-fired generation that may not be available over the long term for the reasons cited earlier in this report. Over the long term, such low prices for electricity may be available off-peak or from generation that has been fully amortized and dedicated to the plant

It is important to note, however, that independent of costs, the HTSE option for hydrogen production could become a necessary alternative to steam methane reforming if government regulation leads to, for example, any or all of the following: prohibition on CO_2 emissions, EOR is not available and costs for capture, compression and transport for sequestration are prohibitive (e.g., equivalent to $100/ton CO_2). In this event the HTSE supported process would have to be competitive with crude oil refining. The price of crude oil would need to be in the range of $100/bbl or higher for the HTSE supported process to be competitive. Since the price of crude oil is set internationally, it is judged conceivable that both high crude oil prices and high costs for CO_2 generation could be concurrent. With overall net efficiencies at least a factor of two better than conventional low temperature electrolysis and with projected hydrogen production prices significantly lower than for alternative high temperature developmental chemical processes, HTSE is a viable option for non-GHG emitting hydrogen production.

Effect of Natural Gas Cost Variations and CO2 Costs on Production Costs

Other factors that affect the viability of alternative processes are the costs of carbon (either a tax on emissions and/or the costs for capture and transport for sequestration or EOR) and the cost of natural gas.

Analysis by INL indicates that while the impact of a carbon tax on the cost of production of gasoline from crude oil is small; i.e. ~$0.10/gallon at $50/ton CO_2, the cost for CTG ranges from ~$0.70/gal for conventional CTG to <$0.10/gal for CTL which uses the HTGR for process heat with SMR. Similarly, the production cost of gasoline increases ranges (for each $1/MMBtu in natural gas price) from ~$0.12/gal for CTL with SMR to ~$0.08/gal for CTL/SMR powered by the SC-HTGR. Such sensitivities strongly favor deployment of the HTGR for synthetic fuel production in scenarios where CO_2 costs are high and natural gas prices may increase.

Despite these sensitivities, synthetic fuel production from U.S. coal and/or natural gas is projected to be economically competitive or superior to oil at $100/bbl for all CTG with SMR, with $50/ton CO2 costs, as long as the price of natural gas is <$12/MMBtu. Similarly, gasoline production from natural gas is competitive with $100/bbl oil at natural gas prices up to ~$10/MMBtu.

Comparison of the Production Costs of All Alternatives

Exhibit A-10 compares the production costs for all of the alternatives evaluated and shows the costs of CO_2 that would make the production costs for conventional processes equal to a process where CO_2 reducing technologies are incorporated (HTGR and HTSE technologies). In those cases where natural gas is either the primary feedstock or used for SMR to produce hydrogen, a cost of $5.50/MSCF has been used. This was the average cost of natural gas to industrial users in 2009. As shown, the CO_2 costs for incorporating HTGR and HTSE are high; \$95 to \$125/ton in the CTL and CTG processes. However, the coal to gasoline process with SMR and the HTGR supplying heat and electricity requires only a \$17/ton cost of CO_2 to be equal to the production cost without it.

Projections on the cost of CO_2 capture, compression and transport for sequestration and EOR range from a low of ~\$20/ton to >\$100/ton depending on the location and nature of the process.

Exhibit A-10 *Synthetic fuel production from U.S. coal and natural gas is economically competitive with fuel production utilizing \$100/bbl crude oil. The HTGR increases production costs somewhat but also reduces CO_2 generation significantly.*

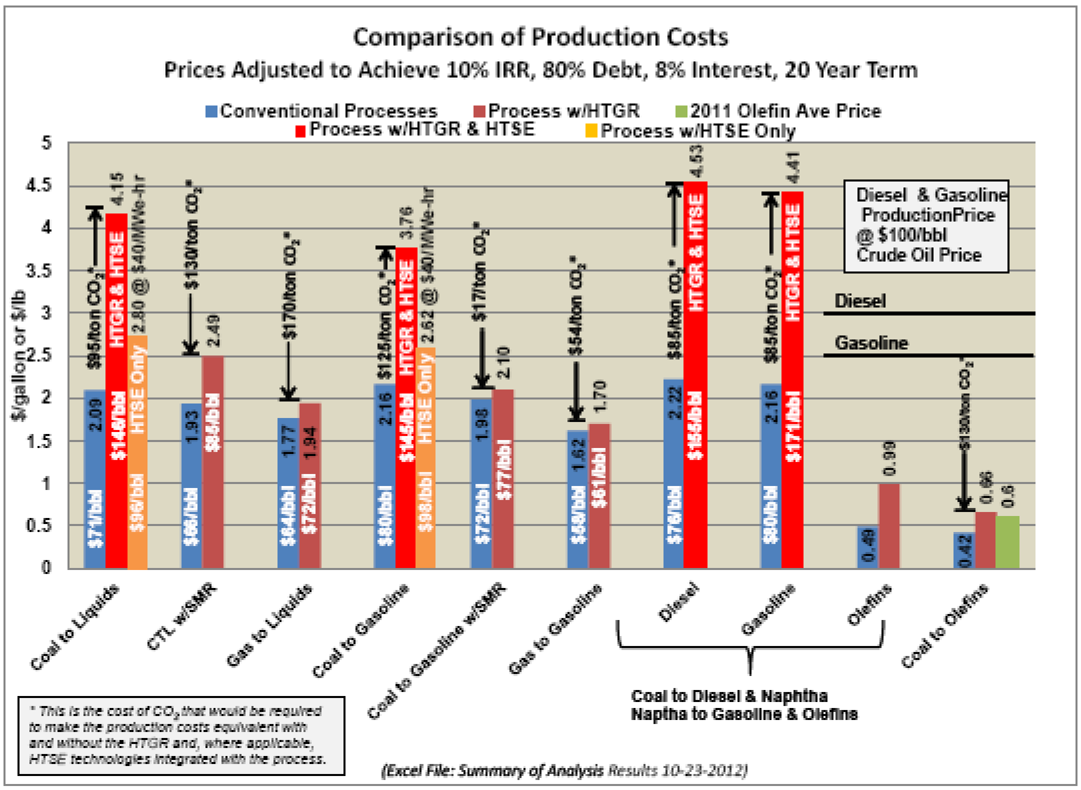

Figure 3-15. Comparison of production costs for all alternatives.

Exhibit A-10 Illustrates the effect of electricity costs on the production costs for processes using HTSE for hydrogen production. These processes are distinguished in this figure by red bars which show production costs where HTGR technology is providing the electricity required for the HTSE process (designated with the phrase "Includes HTSE") and orange bars where the electricity is supplied from another lower cost source (designated as HTSE @ \$40/MW(e)-hr). This lower value is about half the equivalent price of electricity supplied by the HTGR; ~\$80/MWe-hr. As noted previously the lower cost of electricity is typical of the average cost to industrial users in coal producing states such as Wyoming.

Selection of the Processes for Evaluating Deployment of a Synthetic Transport Fuel Industry

To quantitatively assess how a synthetic transport fuel industry might be deployed in the U.S., four processes (see **Exhibit A-11**) which are projected to be competitive with $100/bbl oil were chosen for scenario analysis. The facilities for each of these processes are assumed to be designed to operate initially using natural gas and/or coal for both feedstock and process heat but to allow integration with the HTGR as soon as it becomes available.

Exhibit A-11 *Synthetic fuel processes selected for deployment analysis are competitive with $100/bbl oil and will have modest CO_2 emissions following integration of HTGR.*

Table 3-2. Characteristics of the notional Wyoming carbon conversion industry process plants.

Type	Capacity bpd	Products	Natural Gas Consumption MMSCFD	Coal Consumption short tons per day	Cost, $MM (2011$)	Annual Revenue $MM (2011$)
GTG	40,000	Gasoline & LPG	290	---	1,900	1,050
GTL	50,000	Diesel, Naphtha & LPG	430	---	2,400	1,860
CTG	60,000	Gasoline & LPG	290	11,845	5,900	2,100
CTL	50,000	Diesel, Naphtha & LPG	280	7,720	3,900	1,860
Totals	**200,000**		**1,290**	**19,565**	**14,100**	**6,870**

Nominal schedules indicate that with a decision in 2013, early non-nuclear production could begin in 2018 with the HTGR beginning to support fuel production 8 to 10 years later. A four module HTGR is assumed to be utilized to power each facility to produce the process steam and electricity as shown in **Exhibit A-12**.

Exhibit A-12 *A five module HTGR facility will provide necessary process heat and electricity for the selected process facilities and provide electricity to the grid*

Integrated with	Thermal Capacity MW(t)	Number of Modules	Heat Supply to Process MW(t)	Electricity to Process MW(e)	Electricity to the Grid MW(e)
GTG	3,000	5	387	115	963
GTL	3,000	5	479	0	1038
CTG	3,000	5	928	60	706
CTL	3,000	5	1201	91	637
Totals	**12,000**	**20**	**2,995**	**266**	**3,344**