DECARBONIZATION PATHWAYS

Natural Gas:

An Energy Transition Fuel for Asia

BLACK & VEATCH

More goes into infrastructure than most might think, but you cannot miss the difference it makes in the world. Black & Veatch makes the **Invisible, Invaluable**. Addressing net-zero power generation goals, our Decarbonization Pathways eBooks help our clients stay ahead of the curve so they can progress relevant and effective decarbonization strategies and help the world transition to net-zero.

About this eBook

With much dependence on coal throughout Asia, natural gas can play an important role in lowering carbon emissions. This eBook explores opportunities for natural gas as an energy transition fuel – from the production and supply of LNG through to the generation of electric power through turbine technology – and outlines how clients can go farther, faster and realize cost efficiencies by planning through the entire current and future natural gas value chain.

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Replacing Coal: Gas as a Transition Fuel

Large gas-fired power plants can provide **baseload energy, complementing variable energy sources** like wind and solar power.

How does the development and use of natural gas as an energy source align with a climate-centric view of our future? How can gas infrastructure be harnessed to replace coal without undermining many nations' energy security goals? And how do we plan out further so that any transition that harnesses natural gas is superseded in time by a transition to complete net-zero energy systems?

The case for natural gas as a transition fuel in Asia Pacific starts when we consider the role coal has on the base load of many power generation systems across the region today.

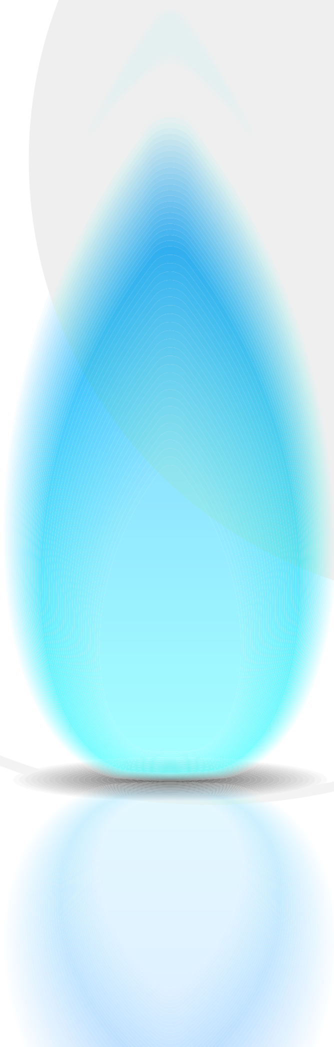
Almost 47 percent of the energy consumed in Asia Pacific in 2021 came from coal, according bp's Statistical Review of World Energy, 2022, while data from the Global Energy Monitor Coal Plant Tracker in January 2023 outlines that almost 77% of coal plant megawatts in operation reside in the region.

Countries such as Japan and South Korea and China have made pledges to end public support for new coal plants, meaning there are essentially no significant international public financiers remaining for new coal plants. That said, coal development continues, and China's pledge relates to international and not domestic development; in June 2022, the country announced further plans for more domestic coal development up until 2025 as it grapples balancing near term energy security issues alongside its longer-term decarbonization efforts.

Relatively speaking there is much less natural gas used in APAC compared to OECD nations today. According to bp's report, gas constitutes approximately 12 percent of APAC total energy consumption compared to 28 percent in the OECD.

Benefits of natural gas as part of integrated power grid systems:

- Large gas-fired power plants can provide baseload energy, complementing variable energy sources like wind and solar power
- Small gas-fired power plants can serve as peaker facilities that quickly ramp up and ramp down, helping stabilize power grids alongside other solutions such as battery systems
- Compared to coal plants of the same size, gas-fired combined cycle power plants are more efficient and emit less CO_2
- Most new turbine technology is capable of co-firing emissions-free hydrogen, with most original equipment manufacturers predicting new turbines will be 100 percent hydrogen capable by 2030



The following select findings from the *Black & Veatch 2022 Asia Electric Report.* Download the full report **here.**

This call for a transition will carry a burden on countries whose electricity supply depends on coal power, accentuated by regional economics and the lifespan of existing assets. For example, the average age of coal plants in Asia is only 12 years old while the lifespan of most coal facilities is approximately 30 years.

As part of a package of alternative conversion and replacement solutions, including the scaling up of renewables and battery systems, replacing coal-fired electricity generation with gas-fired generation options will reap significant, initial gains in lowering carbon emissions.

According to the *Black & Veatch 2022 Asia Electric Report*, gas-fired power has a future as an investment class in Asia. More than a quarter of Asia's electric industry believe that combined cycle technology will help meet carbon/emissions reduction and/or clean energy goals looking out beyond the next 10 years (the same proportion of respondents as wind, 27 percent, and more than solar, 19 percent). The significant role of this technology in decarbonizing Asia's electric industry is further underlined by approximately 50 percent of respondents who believe that over the next five years there will 'more investment' in gas or LNG-to-power facilities combined with carbon capture while, separately, **46 percent of respondents believe gas-fired generation will remain an important part of the grid beyond 2035**. This contrasts clearly with coal where less than 4 percent expect to see 'more investment' over the next five years.

As we write, however, much geopolitical uncertainty continues to impact global gas trade, complicated by the pressure from governments' and major corporations' pledges to decarbonize. In this milieu, on one hand, gas developers must mobilize and monetize gas fields quickly and profitably while LNG consumers for power generation must secure affordable and sustainable supply contracts to ensure the success of their development projects.

What emerges is an intricate stakeholder map across multiple hundred-million-plus project financing deals. Given what is at stake in terms of energy security and climate change risks, it is critical that all stakeholders consider the full view of the gas value chain, and consider plans and opportunities across the value chain and life cycle of the assets under investment as other complementary decarbonization technologies become economically and technically feasible.

The Future of Natural Gas Technology in Asia's Electric Grid

*(*Only select technology options surveyed are featured below)*

Source: Black & Veatch

Which of the following methods do you expect will be included specifically to help meet your carbon/ emissions reduction and/or clean energy goals?

Source: Black & Veatch

	Beyond 10 years
Hydrogen	73.0%
Combined cycle	27.0%
Wind	27.0%
Solar	18.9%

For each of the following categories, how do you expect new generation capacity investments to change over the next five years in your region?

Source: Black & Veatch

	Much more investment than today	Somewhat more investment than today
Gas-fired/LNG to Power with CCUS	9.6%	40.4%
Coal-Fired Power	1.9%	1.9%

Is there a future for fossil fuel generation (utility-scale coal and gas generation) in your region(s) of operation beyond 2035?

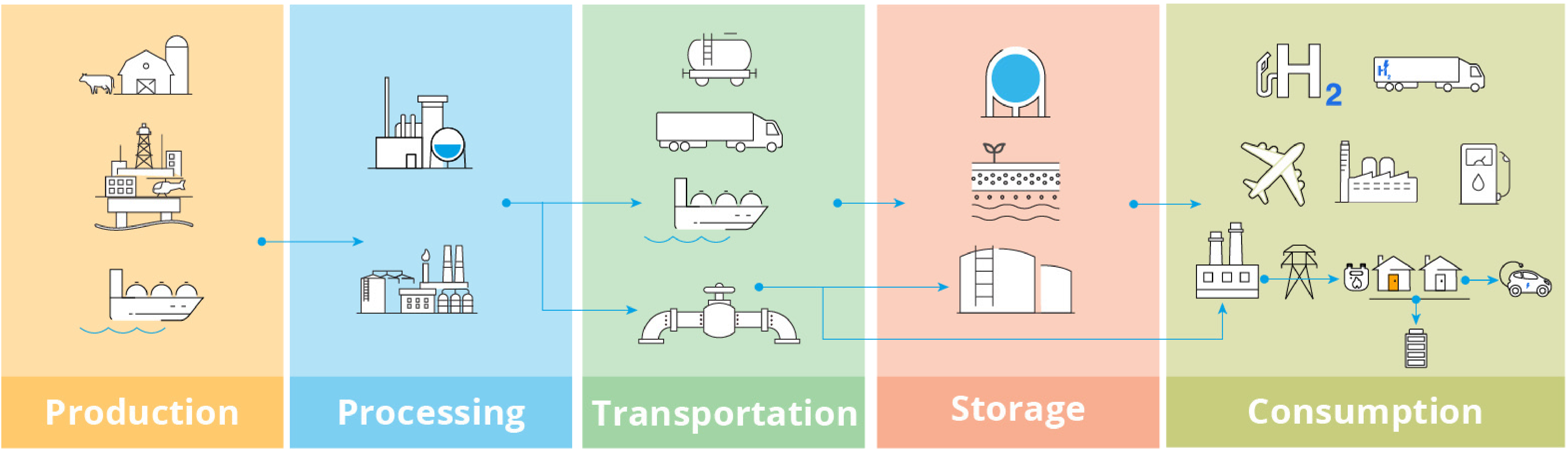
Source: Black & Veatch

Yes, both coal and gas will remain important components of the grid beyond 2035	15.4%
Yes, investment in gas will remain long term, however, coal will be gradually phased out with little new development	30.8%

3 Energy Transition Options for Existing Coal Asset Owners in Asia:

1. Full or partial fuel conversion to fuel sources like natural gas, hydrogen or biomass
2. Retrofitting emissions control equipment or adopting carbon capture, use and storage solutions
3. Decommissioning aged coal assets for re-purposing or repowering using integration with gas turbine.

Gas Value Chain



Black & Veatch brings a full view across every stage of the gas value chain. Our consultants, engineers and EPC contractor teams work with financiers and developers from conception stage right through to operations and maintenance helping our clients move further, faster.

Timely Consideration of LNG as a Global Commodity

As…nations consider the effectiveness of natural gas as an energy transition fuel, **demand for LNG will not subside in Asia.**

Moving gas remains a significant part of the puzzle for economies looking to harness natural gas as an energy transition fuel – the world's major supply centers are far away from the largest centers for demand. Three infrastructure options exist: point-to-point pipeline development, LNG infrastructure development as well as the transfer of power through grid systems

As the Ukraine crisis continues to play out (as at time of writing), the supply of gas via pipeline to Europe is significantly affected moving many European nations to consider additional and fast-track investments into LNG infrastructure. These developments will see a greater flow of LNG to Europe, undoubtedly challenging the dynamics of global LNG supply, competition and trade.

As populations grow, economies expand, living standards rise and nations consider the effectiveness of natural gas as an energy transition fuel, demand for LNG will not subside in Asia. Japan and Korea have long relied on LNG while in more recent years Bangladesh, China, India, Indonesia, the Philippines, Thailand and Vietnam have all become LNG importers. Asia needs large-scale power generation solutions that replace coal, keep pace with demand growth and are at a scale that is easier to achieve when compared with coordinating multiple renewable wind and solar project developments, large scale nuclear, regional intercountry grid networks or hydropower projects which are challenged by other development issues.

From conflict to energy security, governments and developers must consider many profound geopolitical and economic factors when considering LNG and gas infrastructure development. **A common theme underpinning these considerations is one critical development factor: time**.

Adapting LNG Infrastructure for a Decarbonized World

Looking over a longer investment period, there are opportunities to modify and adapt existing LNG infrastructure to receive future ammonia shipments as developments, scale and cost efficiencies are progressed in the green hydrogen economy.

Known for its role in fertilizer production, ammonia is gaining attention as a stable energy carrier for hydrogen whose volumetric energy density makes storage and transport technically and economically challenging. Ammonia is more energy dense than liquid hydrogen and is also easily liquified for storage and shipment in the same fashion as LNG.

In addition, planning for and complementing LNG infrastructure with Carbon Capture, Utilization and Storage (CCUS) capabilities as well as powering upstream processes with renewable energy are other ways gas developers can reduce overall carbon emissions from supplying natural gas.

Reducing Development Time: Advantages of Floating Technologies

Many importing countries in Asia are constrained in terms of land or capital for land-based facilities or lack funding for easy approval of expensive and complex development projects, including their associated pipelines. Storage facilities are also constrained or absent, with less appetite for investment.

With much volatility and uncertainty in the market, final investment decisions can stall when facing such large and multi-faceted facility construction or expansion, and, as contracts expire and suppliers strive to be agile in procuring the best price for their limited LNG supply, heavy facility investments become less and less feasible in the absence of effective means to reduce risks, costs and development timelines.

For this reason, floating LNG (FLNG) liquefaction facilities – for developers looking to monetize gas fields – and floating storage and regasification units (FSRUs) – for developers importing natural gas supplies – are increasingly seen as key optimization options to complement existing onshore assets and eventually replace them. FLNG and FSRU facilities can help create more controllable projects, functioning essentially as alternative and proven delivery mechanisms to accelerate production and monetize gas fields, or expedite the importation of new gas supplies, meeting project requirements with less investment.

As bankable and re-deployable solutions, FLNG vessels can offer more flexibility and enable the monetization of smaller and mid-sized natural gas fields as well as gas in remote areas and underdeveloped markets. What's more, applying a modular approach to FLNG facility design and construction can expedite the development. In recent years, FLNG facilities have moved from attractive concepts to proven solutions, with several shipyards today experienced in delivering barge, ship and converted LNG carriers.

There exists scalable, motion insensitive and innovative technologies for low-cost FLNG modular configurations that drive deck space utilization down, provide ease of operations and maintenance, and deliver smaller environmental footprints than onshore facilities. Offsite fabrication, including pre-commissioning work in fabrication yards, minimizes onsite time and a phased approach means trains from 1 to 2 million tons per year (MTPA) can be produced in parallel to match any capacity requirement.

There are dozens of FSRUs in operation around the world since the first vessel coming online in 2005 and, like FLNG vessels, they can either be brand new vessels, with the regasification unit completely integrated during the design phase, or a converted LNG carrier, where the regasification unit is added to an existing vessel. The same technology that is used onshore is used onboard with seawater used either directly or indirectly to warm the LNG. Moving the regasification unit onboard a vessel avoids the extensive process of building a land-based LNG terminal, which both reduces cost and shortens the schedule; typical onshore terminals take four years to complete compared to two to three years for FSRUs, depending on the approach taken.

Other advantages of more agile, fast-track FSRU development can include options such as designing down-the-line expansion capacity of the regasification unit while keeping the storage volume low and making initial project costs more manageable. Then, as the market grows, a floating storage unit can be used to increase the terminal storage capacity, matching the downstream market needs with minimal additional investment.

Powering the Sea

On 1 January 2020, the International Maritime Organization (IMO) lowered the global regulatory limits on sulfur in maritime fuel, reducing the limit from 3.5 percent to 0.5 percent (by mass). With the most widely used fuel for commercial vessels being heavy fuel oil, with a sulfur content of 3.5 percent, the maritime industry is undergoing a major transition to using LNG as a marine fuel, and by 2025 as many as 60 percent of all ships on order may be LNG-powered. Ferries, cruise ships, cargo ships, and potentially military vessels will be impacted by this shift. Ports around the world are bolstering their LNG bunkering capabilities as more major shipping companies seek to decarbonize their operations. Other alternative such as ammonia and methanol are also being explored as alternative maritime fuels.

Right from the Start: Orchestrating Bankable Gas Generation Projects

With hundreds of millions of dollars of capital under consideration or at play, managing and reducing project risks at inception and throughout the development and delivery of the multiple gas project assets is critical. Major underlying causes for the project management challenges experienced are generally price volatility, supply uncertainty, disruption of shipping routes, presence and dynamics of different global gas markets and hubs, state of the purchasing and selling economies (e.g., inflation, taxation, trade policy, etc.) and force majeure events.

Another set of causes, over which the project company has better control, include cargo planning and scheduling, commercial contracts management, consumption pattern changes, disposing or reselling of unconsumed cargo and other project development related challenges such as Commercial Operations Date (COD) slippage. All these factors make managing risks associated with the gas supply chain a complex task, which requires real time (or frequent) monitoring and calibration efforts related with project management activities during the entire lifecycle of the project.

Given the nature and inter-relation of challenges in the gas supply management process, early adoption of the broadest view of the project's development has proven significant in guiding numerous global gas projects through to commercial success. This is achieved through a well-developed analytical model, addressing quantitative and qualitative aspects of the gas supply chain, which forecasts and identifies risks. Such analytic models are usually multi-layered and include evaluations such as:

- **Sale Purchase Agreement evaluation and comparison model:** used to shortlist potential gas/LNG suppliers, based on predefined techo-commercial requirements.
- **Buying model assessment:** integrating mix of different markets and price indices for formulating an optimal buying model, anchored on project requirements and the risk mitigation plan. (This approach of sourcing a gas mix from various markets supports the management of risks such as geo-political developments, economic changes and shipping route disruptions.)
- **Price volatility management:** forecasting landed-buying-price with the help of projections provided by different gas price indices.
- **Bespoke scenario modelling:** analyzing various probabilities of uncertain events or variables such as a delay in the project's COD or an occurrence of a force majeure event; these can then be assessed using deterministic models using static input variables with different cases / scenario formation, or stochastic models based on iterative processes for variables demonstrating or expected to perform in a certain range of values (e.g., a Monte-Carlo simulation).
- **Commercial sell-purchase plan:** additional development of commercial sell-purchase plans for gas cargos using the analytical model, determining with greater accuracy the quantum and scheduling of these cargos as per project needs.
- **Sensitivity analysis:** more detailed undertaking performed on several critical parameters which have the greatest impact on the project.

Co-location of LNG and Gas Power Infrastructure

As governments and developers conceive and plan around new LNG/Gas to Power projects across Asia, the desire to optimize cost, increase efficiency, and minimize environmental impacts is imperative.

The integration of LNG terminals and other facilities – power generation or chemical – is a proven way to achieve efficiencies across the entire value chain improving returns for investors from the LNG receiving and power-generation assets, as well as presenting potential additional revenue opportunities from the production of a high value natural gas liquid (NGL) product where local gas regulations require reductions in the gas's heat content.

The minus 164° Celsius (C) LNG that arrives at the LNG Receiving Terminal needs to be warmed to about 5° C for send-out. This regasification or vaporization process is a major step at the LNG Receiving Terminal facility and means either energy is used for heating (with air emissions impacts) or seawater is used (with water ecosystem impacts). Both methods carry significant capital cost impacts, can impact the environment, and suffers from the fact that **the 'cold energy' available from the LNG is wasted.**

Seawater

This heating is typically accomplished by warming the gas against seawater using an open rack vaporizer (ORV) or shell and tube vaporizer (STV). The result is a large seawater flow of about 15,000 metric tons per hour to vaporize 1 BCFD (billion cubic feet per day). The cost of this overall system is very site dependent and can add significantly to the overall facility cost. Also, the thermal impact of discharging the cooled seawater is an environmental impact which must be addressed.

Heating

The LNG can be warmed in a fired heater, normally a submerged combustion vaporizer (SCV). The SCV consumes about 1.5 percent of the inlet gas to accomplish this vaporization. The gas combustion is a major operating cost for these facilities. For a 1 BCFD terminal this cost can be well over $40 million per year. In addition, these units will be a major emissions source for the terminal.

Using cold energy

1. Cryogenic Facilities

Facilities which can use the cold at low temperatures are preferable as they can take full advantage of the cold available from the LNG. Air separation units, for example, are often considered due to the direct use of the low temperatures in the process. The LNG cold is used in the chilling of the inlet air and other intermediate streams in the air separation plant. Typically, two heat transfer loops are needed to establish this integration.

Many of these schemes can result in a 50 percent reduction in power consumption in the air separation plant. The two critical constraints with planning for this type of cryogenic integration is the need to locate the facility adjacent to the terminal to achieve close coupling of the processes and for the facility to run at design capacity continuously to support the terminal operation.

As regional and global food security issues remain prominent on national agendas, exploring the co-location of food storage and cold chain applications may improve the overall commercial prospects of integrated LNG and power projects.

2. Chemical Facilities

The LNG cold can be used beneficially in many other process facilities. The LNG vaporization is typically accomplished with a heat medium such as glycol or water. This medium is then used for process cooling in an adjacent process facility. Using this heat medium means that the seawater intake, large piping and outfall facilities can be eliminated. The heat medium can be designed with a much larger temperature differential, such that the flow rates handled in this type of system is much smaller than a typical seawater ORV system.

3. Power Generation

Integrating the LNG terminal with a combined cycle power generation facility makes use of the power plant as a sink for the LNG cold and typically uses a glycol or water heating loop to capture the cold energy and use it in the power cycle:

- Turbine inlet air can be chilled to 10° C with the glycol or water medium which can produce about 10 percent additional power in warm climates. The only additional cost to the power plant is inlet chillers which are a small investment when considering the scale of the overall facility.
- The glycol or water medium can replace cooling water in the steam condensers. This means that the cooling water system (i.e., cooling towers, pumps, etc.) can be eliminated or significantly reduced. Also, usually in this scenario, the heat medium is usually available at a lower temperature and can achieve an additional boost of 1 to 2 percent power.

An additional power generation option can be explored using the expansion of the vaporized LNG or a Rankine cycle system with an intermediate heat transfer fluid. These systems exist at some of the Japanese terminals and generate approximately 10 megawatts (MW) of power. That said, the systems can be quite complex, and expensive to install and operate.

Other integration synergies and benefits:

- Direct supply of fuel for power generation from the LNG terminal
- Integration of operating and maintenance staff, digital systems, utilities and infrastructure
- **Opportunities to explore the co-location of other infrastructure such as the provision of cooling at (as well as power for) data centers or the use of steam, waste heat and water reclamation at industrial facilities**

Hydrogen Liquefaction: Harnessing Cold Energy

Clean energy applications of the future are prompting increased demand for liquid hydrogen. Advancements in large-scale processing are leading to reductions in hydrogen liquefaction costs while increasing energy efficiency and minimizing risk.

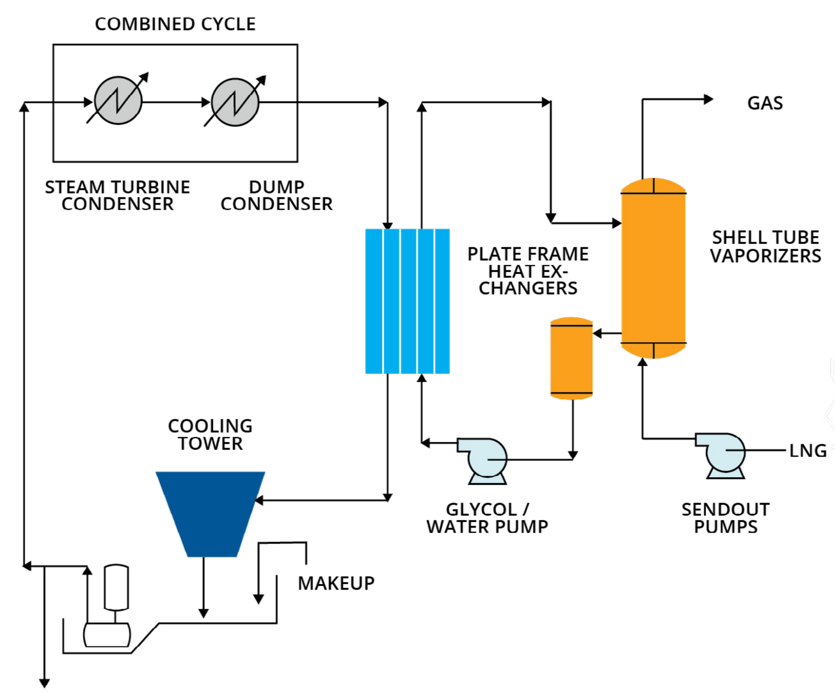
By reusing cold energy (a byproduct of re-gasifying LNG at the terminal) for a portion of the hydrogen cooling load, producers can realize eco-friendly, cost-effective production of liquid hydrogen. Black & Veatch's expertise in LNG liquefaction utilizing our PRICO technology can also drive down power consumption of the initial cooling steps of the hydrogen liquefaction process as the scale of facilities grows in the future.

Benefits of integrated power and terminal facilities

Based on a series of facility development studies conducted by Black & Veatch, we can extrapolate that for each 100 MW of power generation about 3.5 MMTPA of LNG can be vaporized which can lead to immediate capital saving of at least $10-15 million. Inlet chilling can be added to the integration scheme with the same glycol/water loop. To inlet chill 100 MW of generation capacity, about 0.25 MMTPA of LNG can be vaporized. In most of the installations we have examined, substantial power plants can provide all the necessary heat for LNG terminals.

In addition, building both a gas-fired power plant and LNG regasification terminal opens further commercial opportunities to potentially market LNG to regional enterprises through a hub-and-spoke concept. Such opportunities may accelerate as industrial customers seek to switch from diesel to less carbon-intensive gas.

Integration of Power and Terminal Facilities



Gas as Part of Asia's Future Grid Mix

Unprecedented amounts of renewable energy are being integrated into the grid as Asia shifts to a zero-carbon future. Southeast Asia economies, for instance, have collectively pledged to achieve a 23 percent share of renewable energy in Total Primary Energy Supply, as well as 35 percent share in installed power capacity by 2025.

While solar and wind power helps resolve the climate crisis by replacing fossil energy with zero-emissions electricity, these resources are intrinsically variable by nature. Accommodating increased variable renewable generation will require Asia to expand integrated solutions such as gas-fired generation and energy storage to enhance grid efficiencies and resilience.

Asia's lower-carbon energy systems will need highly flexible, dispatchable generation to maintain future grid reliability and resiliency. This shift towards load correction plants will see gas engine-based plants or smaller gas turbine-based plants gain traction in the region soon.

In addition, today's advanced gas turbines in a simple cycle configuration can supply more than 400 MW to the grid in 10 minutes and are designed to reach full combined cycle load in 30 minutes to one hour. New gas turbine technologies can now operate at very low loads of less than 25 percent of their baseload capacity in some cases and ramp at 10 to 15 percent of their full load capacity per minute.

As grids demand more flexibility from gas-fired power plants due to increasing renewable deployments, plant startup profiles will become more crucial and initial design should incorporate appropriate measures to allow fast start and higher load ramping capabilities.

Accompanied by the right planning, design and integration, gas turbine generation has a place in Asia's fuel mix for years to come as a high efficiency, reliable baseload source, as well as by serving as a complement to systems with wind and solar generation.

Key to this futureproofing investment into these gas assets starts by designing in the flexibility to operate across services ranging from energy storage to baseload generation while also considering revenue opportunities in ancillary and grid reliability services.

Gas turbine investments are set to yield significant returns for investors for many years in Asia. Thinking ahead, considering the new functionality of gas infrastructure, and building in greater levels of adaptability to future market conditions – such as planning for even further integration with other large electricity users such as data centers – will be critical in the early project development stages to maximize these operational advantages.

Green Hydrogen and Green Ammonia in Vietnam

Black & Veatch and The Green Solutions (TGS) have signed a Memorandum of Understanding (MoU) to advance the production and supply of green hydrogen and green ammonia in Vietnam. Together, the companies are targeting to produce 180,000 tons of green ammonia and 30,000 tons of green hydrogen per year to support regional decarbonization efforts.

TGS has also appointed Black & Veatch to study the production and storage of green hydrogen in Vietnam utilizing solar or wind power supplied through the grid. The study also includes development of a green ammonia production plant as well as plant configuration and technology review, technology evolution risk and tentative mitigation, conceptual design, order of magnitude cost estimates, and financial analysis.

BESS technology is now approximately **75 percent less expensive** than it was **ten years ago**.

Designing Operational Flexibility

As electric grids introduce greater volume of variable generation and as large baseload generating facilities are taken offline, utilities in Asia will need to build in greater operational flexibility to their grid systems. This means rethinking grid operations infrastructure such as applying greater consideration of smaller, fast-reacting back-up power systems to overcome temporary grid issues caused by resultant grid instability.

For example, original equipment manufacturers have smaller scale turbine technologies that can be deployed as stationary or mobile packages and are designed to produce back-up power in as little as two minutes and reach full output in under 10 minutes. These can range from around 25 MW to 150 MW, and can be used to complement larger baseload facilities on the grid or by large industrial electric users (e.g., data center providers, mining operators, energy-intensive manufacturing, etc.) for mission-critical back-up power.

In addition, whether new investments or upgrading existing baseload gas-fired facilities, there are number of benefits from integrating battery energy storage systems (BESS). BESS technology is now approximately 75 percent less expensive than it was ten years ago and projected to be less than half of today's price by the end of the decade.

Benefits of integrating BESS include:

1. Grid Optimization. Adding battery energy storage systems (BESS) at existing gas-turbine plant substations is an effective means to provide rapid Automatic Generation Control and frequency regulation with milder ramp rates, shorter run times and fewer starts and stops for the gas turbine fleet. Automatic Generation Control systems adjust generation and load variations to achieve optimal grid performance.

2. Improved Performance. The efficiency of a gas turbine diminishes when running above or below its optimal point. With battery storage-augmented gas turbines, the storage performs as a new kind of reserve that springs to life immediately to smooth and optimize turbine performance levels, a scenario that will be increasingly required as more variable generation is added to the grid. Such systems can eliminate the need to operate with high rates of duct firing and provide a means of displacing higher heat rate dispatch during the hottest part of the day when gas turbine efficiency is lowest.

3. Grid Hardening. BESS can also serve as a black start resource to harden the grid against extreme weather events like storms (black start is the reboot of the power system after it suffers a complete collapse).

Major Coal to Gas-Fired and Hydrogen-Capable Conversion Project

Intermountain Power Agency's (IPA) Intermountain Power Project (IPP) Renewal Project is one of the earliest installations of combustion turbine technology designed to use a high percentage of green hydrogen. The IPP Renewal Project involves retiring IPA's original coal-fueled facility in Utah, which Black & Veatch designed in the early 1980s, and replacing it with an 840 MW combined cycle power plant that uses natural gas and hydrogen blended fuel by 2025.

The plant will generate power with advanced thermal efficiencies across its full operating range and is being designed with high flexibility that will allow it to quickly ramp up and down in response to California's challenging "duck curve", a 24-hour view of the grid imbalance between solar power generation and electricity demand timings. In addition, the two 1x1 MHPS M501JAC single-shaft turbines will be commercially guaranteed capable of blending 30-percent green hydrogen at start-up in 2025, with plans to increase hydrogen utilization to 100-percent hydrogen by 2045.

As Owner's Engineer, Black & Veatch is assisting the IPA with multiple areas of project execution, including system studies, technology selection, design, procurement and construction. Black & Veatch is also delivering the engineering, procurement and construction (EPC) contract for the adjacent Advanced Clean Energy Storage project, which will be the world's largest industrial green hydrogen production and storage facility.

Sustainable Alternative Fuels

In addition to the interest in ammonia as a fuel due to its zero-carbon content, there are additional fuels that are also gaining interest. These include methanol, dimethyl ether (DME), and Fischer Tropsch liquids that can produce diesel and jet fuels.

These fuels are best suited for transportation fuels and promise pathways that could unlock carbon free aviation, for example. In the case of methanol and DME, they are being studied with either natural gas as a feedstock with carbon capture or combining CO_2 with hydrogen generated through renewable electricity via electrolysis. The CO_2 for the process can either come from existing CO_2 capture processes or direct air capture. While Fischer Tropsch liquids can in theory be produced with CO_2 and H_2 also, most researchers are looking at them in terms of gasification of renewable resources, such as biomass or municipal solid waste.

Let's Talk

Black & Veatch brings a full view across every stage of the gas value chain (and the entire emerging hydrogen and ammonia value chain, too). Our consultants, engineers and EPC contractor teams work with financiers and developers from conception stage right through to operations and maintenance helping our clients move further, faster. Ultimately, when selecting an engineer or a contractor for a major new power generation or LNG development project, in addition to safety, every owner desires three key features: cost, schedule and performance certainty. By partnering with you at every stage, we ensure you achieve this value.

Let's find ways to help you, too.

Learn more
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