ALASKA NATURAL GAS TRANSPORTATION PROJECTS
OFFICE OF THE FEDERAL COORDINATOR

Government incentives help attract natural gas projects

Big energy projects routinely kindle collaboration between government and developers. Prospects of job growth, energy security, public revenues and other economic or social benefits can motivate governments to encourage energy development. Companies, no matter how large and financially robust, find offers of government assistance attractive for cutting costs and reducing risks.

Government incentives frequently factor into development decisions for liquefied natural gas and petrochemical plants, as sponsors face billions in upfront capital costs and governments foresee large benefits in the years ahead.

Source: Oyvind Hagen, Statoil

The LNG plant on the island of Melkoya is supplied by the offshore Snohvit gas field in Norway's Arctic.

As illustrated by five examples in this report, government help comes in various forms, including lower taxes, rebates for development costs or even assumption of responsibility for risks posed by new technologies, such as storing carbon dioxide underground:

- Russia reduced its mineral extraction tax (also considered a royalty) and cancelled

Governmental incentive programs for major energy projects

Direct Project Financial Assistance
- Grants
- Subsidies
- Capital Investments
- Funding of Development Costs
- Loans

Direct Project Assistance
- Dedication of governmental natural resources
- Guaranteed off-take
- Expedited permitting
- Use of state property
- Condemnation power

Indirect Project Financial Assistance
- Income tax incentives
- Loan guaranties
- Reduction state fiscal take
- Tax credits
- Waivers of property, use, sales, franchise, VAT
- Use of governmental bond authority

Indirect Policy Assistance
- R&D support
- Portfolio standards
- Demand incentives
- Fuel preference programs
- Labor initiatives
- Consumer financial incentives
- Building/zoning codes
- Interconnection planning
- Permitting standards

Government assistance for big energy projects can take many forms, said Houston-based energy attorney Bill Garner.

export duties on new offshore oil and gas projects developed in the Arctic.

- British Columbia dispenses royalty credits for oil and gas projects that include construction or upgrades of roads and pipelines.
- Australia and Western Australia agreed to assume future liability for any leaks from the Gorgon LNG development's carbon dioxide capture and storage project in northwest Australia.
- Norway removed a 50 percent tax on gas production profits from the Snohvit Arctic LNG project.
- Pennsylvania outbid two neighboring states by offering $1.65 billion in tax incentives to attract a petrochemical refinery that, if built, would source its feedstock from nearby natural gas fields.

As Houston-based energy attorney Bill Garner noted in 2011 during a presentation in Anchorage, government incentives also can include loans, grants, capital investments, support for research and development, workforce training, expedited permitting or promises to purchase a portion or all of the produced resource.

There are lessons to be learned from studying government incentives for big energy projects, Garner said, whether it's taking an equity stake in the project, providing upfront money for development costs or indirect assistance.

Alaska, for its part, provides tax credits to promote oil and gas drilling — some targeted, some general. The state in 2007-2008 also agreed to pay up to $500 million over a number of years toward preliminary design and environmental work for a large-volume pipeline to move North Slope gas to market.

It's not always about taxes and cash. The state of Western Australia's gas reservation policy, requiring companies to set aside up to 15 percent of production for domestic use, was discouraging to sponsors of the $34 billion Ichthys LNG project. They opted instead to build the processing plant in Australia's Northern Territory, despite it being farther from the gas field. The Northern Territory has no gas reservation requirement.

Governments try to strike a fine balance when offering fiscal incentives. They need to pinpoint terms that encourage projects to take root, but also generate budgetary returns that outweigh the cost of incentives. Governments might also take into account the need to be compensated for use of their land, permanent depletion of the resources and environmental degradation, weighed against gains in jobs and overall economic productivity.

Of course, whether companies ultimately decide to build a project depends on conditions governments can't entirely influence. Geology, geography, terrain, climate, technology, the cost of labor and materials, size of the resource base and market demand all play roles in promoting or destroying a project's economic viability. Government incentives can't always tip returns in favor of developing an LNG plant or other projects but, as the following examples illustrate, they do matter a great deal.

RUSSIA: MAKING A PLAY FOR ARCTIC LNG

A number of tax breaks helped ease the decision by Russia's Novatek and France's Total to push forward on Yamal LNG, a $20-plus billion greenfield project under development in the tough Arctic environment of northwest Siberia. The port, some living quarters, an airstrip and well pads are under construction, but work on the liquefaction plant — the most expensive component of an LNG project — has not begun.

Russia, which depends heavily on the energy industry as a tax base, has one of the most aggressive oil and gas tax regimes in the world for both production and exports with, for example, a stiff export duty on oil that tracks the price of Urals crude blend on the Mediterranean and Rotterdam markets. As of May, the export duty was estimated at close to $50 a barrel on Urals crude selling at an average $100 a barrel, according to a Bloomberg News report. The law allows a top rate of 65 percent, calculated monthly.

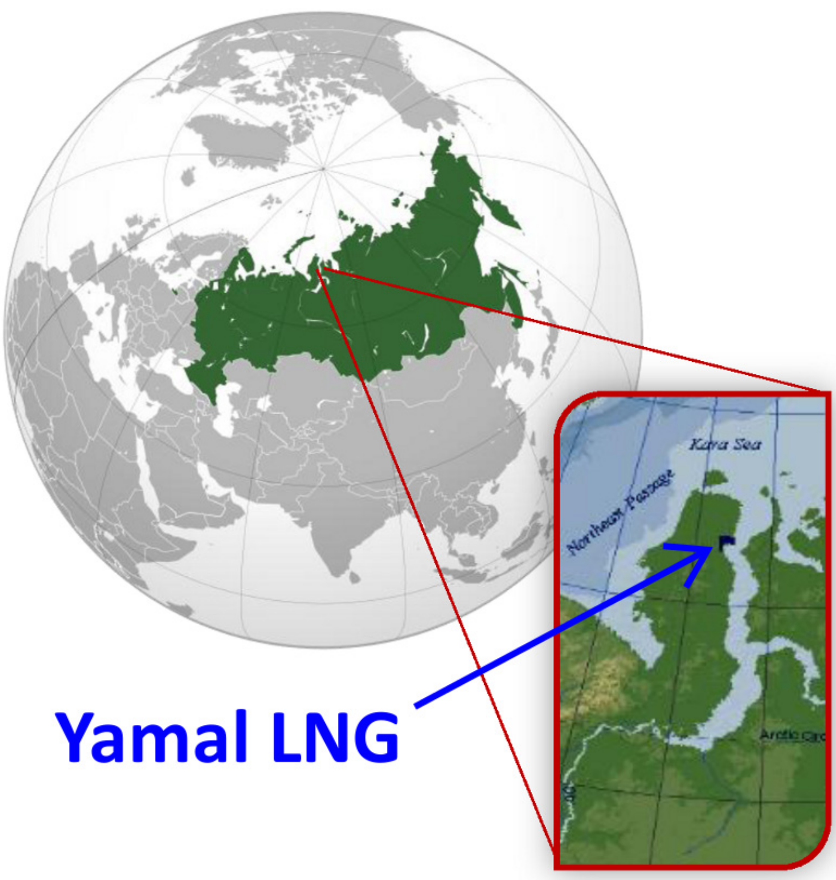
Lately, however, Moscow has promised to do away with the export duty and scale back its mineral extraction tax to stimulate development of shale and tight oil, offshore oil and other difficult plays, including natural gas in the Arctic.

Russia’s incentives for Arctic gas

- Waiver of export duty and reduction in mineral extraction tax.
- No mineral extraction tax on gas used exclusively for Yamal LNG.
- Government financing of Yamal port, dredging, pipelines, icebreakers and airport.
- Lower regional government property taxes and corporate taxes.

Yamal LNG is located on a peninsula jutting north into Russia's Kara Sea about midway between Iceland and Nome, Alaska. The sponsors have yet to finalize the offtake contracts they would need to come to an investment decision and attract financing. They also are waiting on approval from Moscow for companies other than state-owned Gazprom to export gas.

The recent government tax policies and other promises of assistance, however, signal support for the project, as does President Vladimir Putin's recent announcement during a speech in St. Petersburg that the government would gradually lower restrictions on LNG exports.



Source: Gazprom

The proposed Yamal LNG project is on a peninsula jutting out into Russia's Arctic waters, about midway between Iceland and Nome, Alaska, near the top of the world.

In July 2011, Russia's then-President Dmitry Medvedev signed a law exempting from the country's minerals extraction tax any natural gas used exclusively for LNG production "in areas located entirely or partially in the Yamal peninsula." According to international tax consultancy Ernst & Young, the minerals extraction tax on natural gas in 2012 was about 21 cents per thousand cubic feet. The tax exemption could save the project more than $40 million a year per production train running at nearly full capacity.

Yamal LNG additionally would benefit from a recent policy that exempts LNG from the export duty Russia applies to fossil fuels. The export duty for natural gas is 30 percent. The Russian government has pledged to further assist the project by financing construction of a port, an airport, gas pipelines, icebreakers and dredging work to build a navigable channel to the Sabetta port, for a total estimated cost of at least $9 billion.

The regional government is supporting the project with a property tax exemption and lower corporate profit tax rate.

The national and regional incentives will apply for no more than 12 years from the start of production. The tax breaks will expire earlier if the total volume of extracted gas reaches 8.8 trillion cubic feet or if extracted gas condensate reaches 180 million barrels, whichever comes first.

Novatek holds an 80 percent stake and Total owns 20 percent of Yamal LNG. The sponsors have awarded a tender to Technip of France and JGC Corp. of Japan for project construction, engineering, procurement, supply and commissioning.

Yamal LNG aims to have its first production train running by the end of 2016, followed by a second in 2017 and a third in 2018. Each train will have an average capacity of about 700 million cubic feet a day.

As with most other LNG export projects, Yamal LNG is targeting the market in Asia, but is also exploring the possibility of sales to Europe during the seven months when ice clogs the sea route heading east. Shipping lanes to the west are clear enough year-round for transit with specially designed tankers.

In one of the hurdles the project still must overcome, President Vladimir Putin opposes the sale of LNG to Europe, as it would compete with pipeline gas from state-owned Gazprom.

BRITISH COLUMBIA: ROYALTY CREDITS FOR ROADS & PIPE

Mountains and muskeg are major obstacles to developing the oil and gas deposits that pockmark the province of British Columbia.

Developers need nudging to sink capital and take heavy equipment into the rugged and remote reaches of Canada's westernmost province, so in 2004 British Columbia's government began offering royalty credits to oil and gas explorers whose plans included construction of roads. The province expanded the program in 2005 to include pipelines.

In a nod to the province's budding LNG industry, Premier Christy Clark unveiled this year's Infrastructure Royalty Credit Program in February at British Columbia's first international LNG conference, held in Vancouver. The program — essentially the same one dating to 2004 — is open to all oil and gas projects, not just those devoted to LNG, though the province is pushing hard these days for investment in LNG export projects.

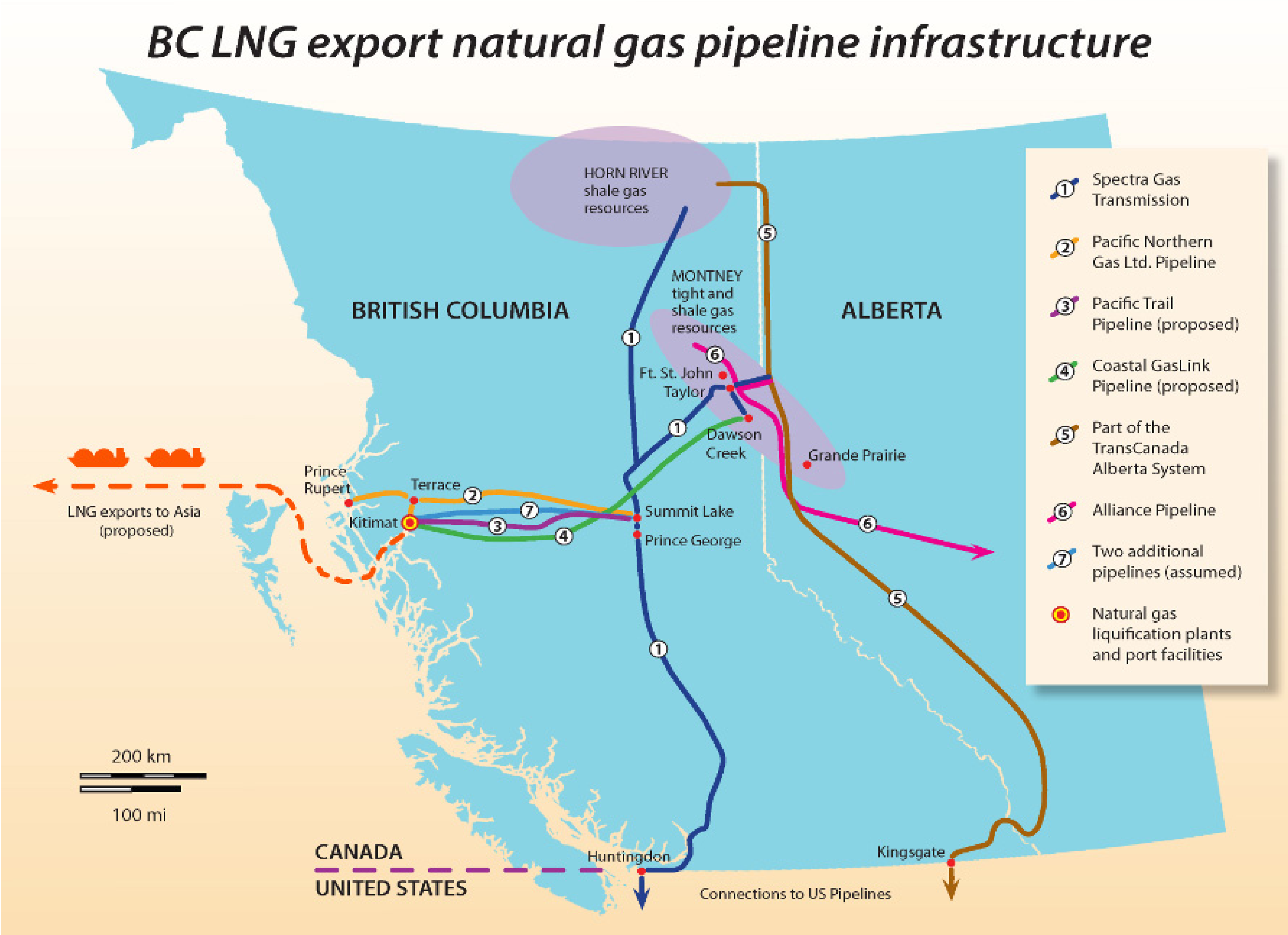
The province is offering a total of $120 million (Canadian dollars) in royalty credits in 2013. After starting production, an oil or gas developer can potentially receive up to 50 percent in royalty credits for the original cost estimate for building or upgrading pipelines and/or roads. For example, a developer that spends $50 million on a pipeline expansion could receive up to a $25 million credit against production royalties owed to the province. The government selects projects that offer the highest economic benefits to British Columbia.

Since the program began, the province has offered a total of $840 million (Canadian dollars) in royalty credits. The total amount that companies actually received is lower as some projects were cancelled, are still in the works or came in with lower-than-expected costs. The province reports that the program is intended to generate about $2.50 in additional royalties for every dollar issued in credits.

The road network in hydrocarbon-rich areas was designed to support the general public and forestry, not the pressures of multi-ton vehicles and loads typical of oil and gas activities. In many places, though, there are no roads, no pipelines and, consequently, no fossil fuel development.

As of June 2013, the program had supported 78 new resource roads totaling 1,243 miles, and 128 new pipeline projects totaling 1,304 miles of pipe. The projects represent more than $1.7 billion in capital investments.

LNG projects could benefit from the royalty credit program since most gas fields that would supply the coastal liquefaction plants are located in remote areas of northeast B.C. The Ministry of Energy, Mines and Natural Gas is reviewing



Source: Fraser Institute

Project developers have proposed LNG liquefaction plants and marine terminals at Prince Rupert and Kitimat, B.C., and new pipelines to supply the plants with gas from the Montney and Horn River shale and tight-gas plays in northeast British Columbia.

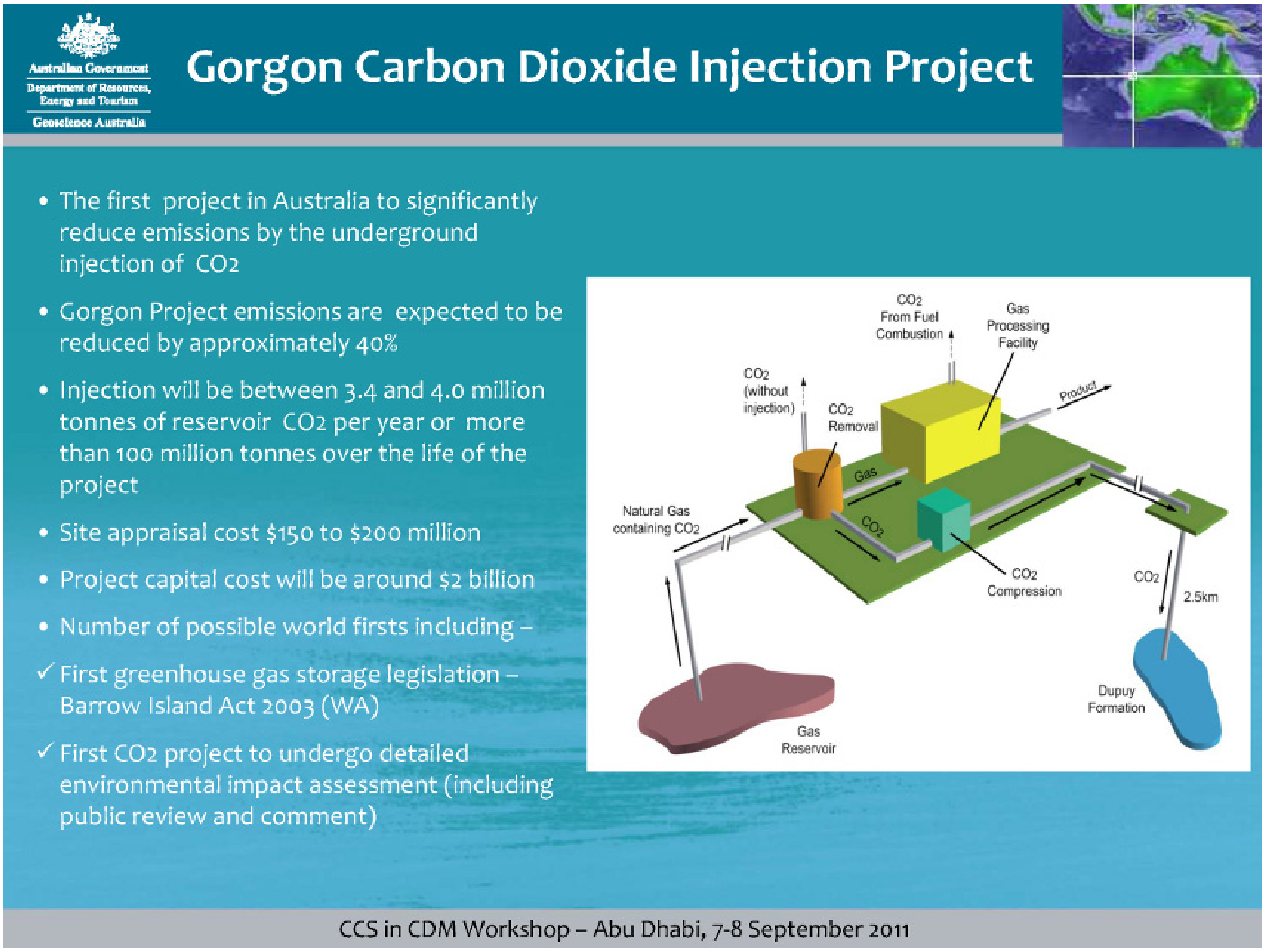
applications, and successful projects will be notified later this year. The province keeps confidential the names of the winning applicants.

The province is hoping LNG will boost B.C.'s fortunes. Premier Clark, during her successful re-election campaign this spring, told voters that the LNG industry would pay tens of billions of dollars in royalties and business taxes. The LNG industry, meanwhile, has voiced concern about the stability of the B.C. government's fiscal regime and is waiting to see the details of a proposed export tax on gas.

AUSTRALIA: CARBON SEQUESTRATION LIABILITY

Resolving the question of liability for a carbon capture and storage project was a decisive step for the $52 billion Gorgon LNG development off the coast of Western Australia. Already one of the world's priciest energy projects, it will also include one of the largest carbon sequestration efforts ever attempted.

Australia, whose carbon emissions per person are among the highest in the world, has pledged to unconditionally reduce its carbon pollution to



Source: Australian Government, Department of Resources, Energy and Tourism

The injection project at Gorgon LNG will remove carbon dioxide from the gas stream and inject it deep underground for permanent storage.

5 percent below 2000 levels by 2020 and aims to scale back the country's carbon emissions by 80 percent of year 2000 levels by 2050. Gorgon's CO2 storage project is part of a suite of strategies, including a carbon pricing policy and investments in clean energy, intended to turn these commitments into reality.

The gas stream at the Gorgon field is 14 to 16 percent carbon dioxide, which must be removed before the flow enters the liquefaction plant. Lead sponsor Chevron estimates carbon capture and storage will cut Gorgon's overall greenhouse gas emissions by about 120 million metric tons over the lifetime of the field, equivalent to about 40 percent of carbon emissions from the LNG plant.

There are no guarantees that this relatively new approach to keeping carbon dioxide out of the atmosphere will work, though the Intergovernmental Panel for Climate Change estimates that more than 99 percent of captured carbon is "very likely" to remain sequestered for upward of 100 years in a properly selected site.

Oil companies have been reinjecting CO2 to pressurize fields for decades, but whether the greenhouse gas will stay permanently trapped in the subterranean rock formation chosen beneath an island near Gorgon is unknown, given that the region has a history of seismic activity. Oil and gas wells that already penetrate the formation will need monitoring to prevent carbon from escaping.

CO_2 leakage to the surface could harm animals inhabiting the world-class nature reserve on Barrow Island (where the carbon capture and storage project is located) by asphyxiation should carbon dioxide concentrations in the air become too high. The odds that people would be affected are low, since the island has no permanent human inhabitants and no aboriginal land claims.

The chances of gas escaping through natural clay and cement seals and reaching Barrow's surface are "unlikely," Gorgon General Manager Colin Beckett told Bloomberg News in August 2012.

Although the economics of the Gorgon project allowed for main sponsors Chevron, ExxonMobil and Royal Dutch Shell to take the lead on designing and building the injection facility, the risk of future liabilities linked to CO_2 leakage was not one they were eager to assume.

To ensure Gorgon went forward, Australia's federal government agreed to shoulder 80 percent of the liability arising from any successful claim against the carbon capture and storage segment of the project, as long as the state of Western Australia covered the remaining 20 percent. Gorgon's offshore production activities will take place in federal waters, while the liquefaction and shipping facilities on Barrow Island fall under state jurisdiction.

Although the assumption of liability is not a fiscal policy in the pure sense, it could affect Australia and Western Australia's fiscal situations in the years to come as the governments will need to conduct continuous monitoring and could find themselves in legal disputes over leakage.

"That was a very big point that needed to be covered," George Kirkland, Chevron's executive vice president for upstream and gas, told Bloomberg News in September 2009.

An undersea pipeline from offshore fields will take production to a processing plant on Barrow Island. The carbon dioxide will be separated from the methane, compressed and injected more than 1.2 miles below the island into a formation comprised of sandstone saturated with brackish water and overlaid by several layers of shale and siltstone.

The companies will be responsible for storing Gorgon's carbon emissions during the project's estimated operating lifetime of 40 years plus an additional 15 years. They plan to monitor for carbon leakage near the surface and use repeated seismic investigations farther underground to plot the CO_2 plume. After that, all responsibility passes to the Australian national and state governments provided that they are satisfied with the state of the stored carbon dioxide.

Norway already provides unlimited liability for carbon capture and storage projects run by StatoilHydro in Norway and Algeria.

"No company can take on unlimited liability for 1,000 years," Olav Kaarstad, senior adviser on carbon dioxide for Statoil, told Bloomberg News in 2009.

The Australian government also committed $60 million from its Low Emissions Technology Demonstration Fund to the $2 billion CO_2 injection project, with the Gorgon joint venture contributing the rest.

Source: Harald Pettersen, Statoil

The Hammerfest liquefaction plant on Melkoya Island started operations in 2007.

NORWAY: LOWER TAXES FOR SNOHVIT

Tax breaks were a must for developing Norway's Snohvit gas field in the Barents Sea, 340 miles north of the Arctic Circle.

The government decided to support Europe's first LNG export project by waiving a portion of the combined 78 percent tax on profits from gas sales. For the oil and gas industry, Norway applies a special corporate income tax rate of 50 percent on profits from offshore production — there is no onshore oil and gas production in the country — in addition to the 28 percent corporate income tax rate charged every business in the country.

(In an attempt to stimulate growth outside the fossil fuel industry, the government in May 2013 announced a proposal to raise the petroleum industry tax to 51 percent and lower the general corporate income tax to 27 percent.)

To help make Snohvit economic, the government, with the blessing of the European Free Trade Association's Surveillance Authority, did away with the offshore production profit tax. The surveillance authority monitors the three members of the association — Norway, Iceland and Liechtenstein — that do not belong to the European Union to ensure they follow the agreement that underlies European commerce.

Without the corporate profits tax on offshore petroleum, Snohvit is taxed at just 28 percent. The government essentially allows the producers to allocate the profit of the offshore-produced natural gas to the LNG plant, which is shore-based and therefore exempt from the 50 percent offshore levy.

Norway also allows all oil and gas producers to recover their capital costs relatively quickly with a six-year depreciation schedule for tax purposes (faster than the cost-recovery deductions the U.S. government and Alaska allow in corporate income taxes).

Snohvit was discovered in 1984 and took 23 years to bring online, for good reason.

Harsh Arctic conditions and the remoteness of the field, 90 miles from land in frigid and stormy waters more than 1,000 feet deep, presented cost-boosting technical challenges that required new approaches to offshore development. Instead of traditional rigs, Statoil's engineers installed production equipment on the seafloor that sends gas by pipeline to a processing and liquefaction facility on a small island off the city of Hammerfest.

In addition to promoting gas development in a physically and financially risky environment, the government opted for the lower tax rate as an incentive to create jobs onshore in a region where the fishing industry was in decline. Construction of the liquefaction plant involved 22,000 workers, one of the largest industrial projects in Europe, and cost nearly $10 billion, up from the estimate of $6 billion when the project started in 2002.

The International Institute for Sustainable Development estimated that without Snohvit, Norway's revenues from oil and gas in 2010 would have been 13.2 percent lower, employment 0.7 percent lower and carbon dioxide emissions 2.4 percent lower.

Though built to send much of its output to the U.S. East Coast, Snohvit's owners — Norway's Statoil, Petoro and RWE Dea Norge, and France's Total and GDF SUEZ — have had to improvise because shale gas flooded the U.S. market. Some of the LNG goes to Europe and some to Asia. The plant has the capacity to liquefy almost 750 million cubic feet of gas per day, though recent technical problems have cut into production.

PENNSYLVANIA: WOOING SHELL CHEMICAL

Generous fiscal terms ensured Pennsylvania's success last year over two neighboring states in attracting a petrochemical plant that would source natural gas from the Marcellus shale.

In a bidding war against Ohio and West Virginia, Pennsylvania offered Shell Chemical a tax credit of up to $1.65 billion over 25 years (up to $66 million a year). The credit helped propel the state to the top of Shell's list for siting an estimated $2 billion facility that will turn ethane found in natural gas into ethylene, a common building block for plastics.

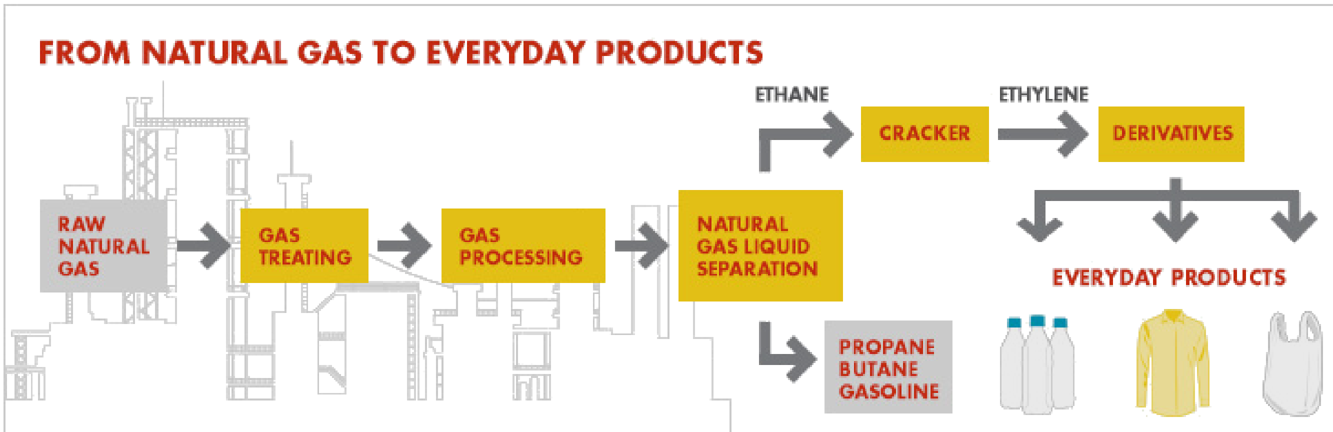
Spearheaded by Republican Gov. Tom Corbett, the Pennsylvania Resource Manufacturing Tax Credit is contingent on the company making a capital investment of at least $1 billion and creating the equivalent of at least 2,500 full-time construction jobs.

The Pennsylvania legislature easily passed the tax credit in July 2012, with the House voting 140-56 and the Senate voting 48-1. Critics, however, pointed to the fact that Corbett cut state spending for schools and social services, while offering generous tax breaks to large corporations.

The state's Department of Revenue called the program "a powerful incentive" that will "revitalize Pennsylvania's manufacturing industry, create thousands of good-paying Pennsylvania jobs and secure long-term economic benefits" for the state.

The terms of the credit mesh well with Shell's already-stated plans, although they apply to any company that meets certain criteria.

Any manufacturer purchasing natural gas containing ethane as a petrochemical feedstock at a facility within Pennsylvania could be eligible for a tax credit equal to five cents per gallon



Source: Shell Chemicals

Natural gas liquids, including ethane, propane and butane, are the feedstock for making plastics and other everyday products.

($2.10 per barrel) of ethane purchased and used in manufacturing ethylene. Shell's cracker plant won't be eligible for the tax credit until it produces a threshold of 85,000 barrels of ethane daily. At $2.10 per barrel, that would generate almost $66 million in tax credits. The credit applies to ethane purchased between Jan. 1, 2017, and Dec. 31, 2042.

Whatever credits a manufacturer cannot use to reduce its tax bill to the state it can sell to suppliers of natural gas containing ethane or manufacturers of products that use ethane or ethane derivatives.

The state also granted Shell a 15-year tax amnesty as part of its Keystone Opportunity Zone program, which reduces or eliminates state taxes, including the corporate net income tax, and local taxes, including property tax. The value of the additional tax breaks will not be known publicly, as Pennsylvania signed a non-disclosure agreement with Shell.

Ohio had offered Shell tax incentives worth about $1.43 billion, while West Virginia lawmakers had approved a 25-year property tax break worth an estimated $300 million.

Shell has not yet made an investment decision and is conducting technical and environmental reviews at the site of a still-operating zinc processing plant in Monaca, Pa., about 26 miles down the Ohio River from Pittsburgh. Shell had been expected to make its purchase decision on the land by late June, but Horsehead Corp., the Pittsburgh-based landowner, recently extended the deadline to the end of December.

Shell last year listed the merits of the 300-acre parcel: good pipeline access to liquids-rich natural gas; water; nearby road and rail transportation; power grids; and enough room for a world-scale petrochemical complex, as well as potential expansions. Shell said, however, a full commitment to the project would first require the company to secure ethane feedstock supply contracts, complete engineering and design work, confirm customer demand, receive all the necessary permits and evaluate the project's economic feasibility.

U.S. petrochemical production for decades has been based near ethane sources on the Gulf Coast in Texas and Louisiana. Shell produces ethylene and related chemicals at plants in Deer Park, Texas, and Norco, La.

But the enormous natural gas deposits of the Marcellus Shale, which spans New York state to Virginia, are attracting the attention of Shell and others targeting petrochemical markets in the northeastern United States.

"Shell is very meticulous in its planning and wouldn't be considering this magnitude of a plant unless [it] really believed supplies would be there for the long term," said Geoffrey Styles, a consultant to the oil and gas industries, in an article published February 2012 by the law firm Duane Morris.

In addition to the ethane "cracker," as these types of plants are known, Shell is also considering production of other chemicals that would supply industries in the Northeast. They include polyethylene, the most common type of plastic, and mono-ethylene glycol, used in numerous consumer products including carpets, kitchenware, synthetic fleece and polyester clothing.

For more information, please visit our website: www.arcticgas.gov

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