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Unconventional Energy Resources: 2015 Review

American Association of Petroleum Geologists, Energy Minerals Division

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This paper includes 10 summaries for energy resource commodities including coal and unconventional resources, and an analysis of energy economics and technology prepared by committees of the Energy Minerals Division of the American Association of Petroleum Geologists. Unconventional energy resources, as used in this report, are those energy resources that do not occur in discrete oil or gas reservoirs held in structural or stratigraphic traps in sedimentary basins. Such resources include coalbed methane, oil shale, U and Th deposits and associated rare earth elements of industrial interest, geothermal, gas shale and liquids, tight gas sands, gas hydrates, and bitumen and heavy oil. Current U.S. and global research and development activities are summarized for each unconventional energy resource commodity in the topical sections of this report, followed by analysis of unconventional energy economics and technology.

KEY WORDS: Coal, coalbed methane, gas hydrates, tight gas sands, gas shale and liquids, geothermal resources, bitumen, heavy oil, oil shale, uranium, thorium, rare earth elements, energy economics, unconventional energy resources.

INTRODUCTION

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The Energy Minerals Division (EMD) of the American Association of Petroleum Geologists (AAPG) is a membership-based technical interest group having the primary goal of advancing the science of geology, especially as it relates to exploration, discovery, and production of unconventional energy resources. Research on unconventional energy resources changes rapidly, and exploration and development efforts for these resources are constantly expanding. Ten summaries derived from 2015 committee reports presented at the EMD Annual Meeting in Denver, Colorado in May 2015, are contained in this review. The complete set of committee reports is available to AAPG members at http://emd.aapg.org/members_only/. This report updates the 2006, 2009, 2011, and 2103 EMD unconventional energy reviews published in this journal (American Association of Petroleum Geologists, Energy Minerals Division 2007, 2009, 2011, 2014a).

Included herein are reviews of research activities in the U.S., Canada, and other regions of the world related to coal, coalbed methane, oil shale, U and Th deposits and associated rare earth elements of industrial interest, geothermal, gas shale and liquids, tight gas sands, gas hydrates, and bitumen and heavy oil. An analysis of energy economics and technology as related to unconventional resource commodities also is included. Please contact the individual authors for additional information about the topics covered in each section of this report. The following website provides more information about all unconventional resources and the AAPG-EMD: http://emd.aapg.org.

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COAL

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World Overview and Future Technology Issues

Coal still is the second largest energy commodity worldwide, exceeded only by oil. The world's top 10 coal-producing countries since 2012 account for about 90% of the world's total coal production, with China being the top coal-producing and -consuming country and Indonesia and Australia the top coal-exporting countries (Table 1). This report focuses on coal production in the top-three coal-producing countries (China, U.S., and India), which together represented ~65% of the world's coal production [~5.16 billion metric tons (5.68 billion short tons, or bst)] at the beginning of 2013 (EIA 2015a). Brief highlights of other leading coal-producing countries are featured at the end of this report.

Over 30% of the world's total energy demand and >40% of generated electricity comes from coal (World Coal Association 2015). The challenge for coal in the 21st century will be improving technology for electricity from coal to address increases in CO_2 emissions, while at the same time continuing to provide access to energy for developing countries. A large portfolio of technologies including advanced power generation (high thermal efficiency) and CCS (carbon capture and storage) must be demonstrated and deployed to realize significant GHG (greenhouse gas) reductions from coal use. Lowering CO_2 emissions from coal-fueled power plants will require an increase in thermal efficiency. The IEA roadmap for technology involving electricity generated from coal with CCS currently envisages slightly less than 280 gigawatts (GW) of CCS-equipped power plants worldwide by 2030. Roughly 630 GW of coal-fueled power plants with CCS would be required by 2050.

Coal Markets and Supply

A current global oversupply of coal, with surpluses at roughly 10 million metric tons [~11 million short tons (mst)] in 2014, has led to a downturn in global coal prices (Reuters 2014). This will move coal prices below profitable levels for many coal producers in 2015 and 2016, with the result of some mines having to close or suspend operations until more favorable prices return. Worldwide coal prices have been reduced by as much as 50% in the past 3 years because of increased production from exporters that include the U.S., Australia, South Africa, Indonesia, and Colombia. Reuters (2014) reported that the oversupply for seaborne steam (thermal) coal, used primarily for generation of electricity, was estimated by coal traders and analysts to range from 7 to 12 million metric tons (7.7–13.2 mst), and surplus coal could continue to be problematic into 2016. Demand for thermal coal in Asia, particularly in China, is slowing. Economic growth in China has recently slackened, and in combination with pressure from the government to use more natural gas to mitigate air-pollution problems, some coal mines may close. However, demand may pick up in 2016 as the thermal coal oversupply begins to fall as a result of coal mine closures. In other Asian markets, Indian utilities may require more imported coal if Coal India cannot meet demand. This could result in a 6% increase in demand to almost 790 million metric tons (~ 871 mst) by the end of fiscal year 2015.

China

China continues to be the number one producer and consumer of coal in the world (World Coal Association 2014), using more coal than the U.S., Europe, and Japan combined (Moore 2011; Vince 2012; Sweet 2013). China produced more than 4.2 billion metric tons (~ 4.37 bst) of coal in 2013 (EIA 2015b). China accounts for almost half of the world's coal consumption (~78 quadrillion BTUs [British Thermal Units]) and is the world's largest power generator (EIA 2015b). China possessed an estimated 122.5 billion metric tons (126 bst) of recoverable coal reserves in 2011, equivalent to ~13% of the world's total coal reserves. China, as of 2012, had more than 18,000 coal mines, of which 95% were underground mines producing primarily bituminous coal, anthracite, and lignite (World Coal Association 2015). Much of China's thermal coal resources occur in the north-central and northwestern parts of the country. In contrast, coking (metallurgical) coal reserves are found mostly in central and coastal parts of China.

Roughly two-thirds of coal in China is used for power generation (EIA 2015b). China has been a

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Table 1. Top Coal-Exporting Countries and Their Coal Exports in 2014, Projected Coal Exports in 2015, Coal Consumption for Electric Power in 2013 (Calculated from Sources Indicated Below), and Electric Power Generation Use Ratio in 2014

Top Exporters	2014 Exports (Million Metric Tons)	2015 Exports (Million Metric Tons)	2013 Electrical Consumption (Million Metric Tons)	2014 Power Generation Use Ratio
Indonesia	382.0 (a)	450.0 (b)	239.4 (c)	0.49 (d)
Australia	196.0 (e)	202.9 (f)	266.5 (g)	0.64 (h)
United States	97.3 (i)	87.9 (i)	341.4 (j)	0.39 (k)
South Africa	78.0 (l)	79.0 (b)	161.3 (m)	0.62 (n)
Colombia	77.6 (o)	80.0 (b)	0.5 (p)	0.06 (d)

Sources (a) Indonesia Investments (2015); (b) Slideshare (2015), based on sources from globalCOAL; (c) EIA (2015f); (d) Worldbank Data (2015); (e) Australia Department of Industry (2014); (f) Reuters (2015b); (g) World Coal Association (2014); (h) EIA (2015g); (i) EIA (2015c); (j) EIA (2015k); (k) EIA (2015l); (l) EIA (2015m); (m) EIA (2015h); (n) Republic of South Africa, Department of Energy (2015); (o) Dodson (2015); (p) EIA (2015n).

net coal importer since 2009, with recent increased imports resulting from increased demand as well as high internal coal transportation costs caused by bottlenecks in China's railway capacity. These factors have made imported coal economically viable, particularly along coastal regions that are distant from coal mined in western China. China is attempting to consolidate its coal industry, as it has ~10,000 minor local coal mines where inadequate investment, outmoded equipment, and poor safety procedures control inefficient resource development.

Electricity generation in China is operated by state-owned holding companies, although limited private and foreign investments have recently been made in the electricity sector. Chinese power generation growth in 2014 was the slowest since 1998 and growth in steel production was also the weakest in more than 30 years. China has expanded the construction of natural gas-fired and renewable power plants to introduce power to remote population centers.

China's coal production in 2014 is estimated to have dropped 2.5%, having produced 3.52 billion metric tons (3.88 bst) of coal in the first 11 months of 2014. China produced 3.7 billion metric tons (4.1 bst) in 2013. This is the first annual decline in coal production in China in more than a decade (Reuters 2015a). This decline is the result of weakening demand from industry and the power sector, oversupply, and initiatives from the government to reduce air pollution.

United States

U.S. coal consumption in 2014 showed no increase, with third-quarter production on par with that in 2013 (EIA 2015c). The average price of U.S. metallurgical and thermal coal exports during third-quarter 2014 was ~$95 per metric ton (~$86 per short ton) and ~$70 per metric ton (~$63.50 per short ton), respectively. Wyoming continues to be the top coal-producing state, with 85.7 million metric tons (~94.5 mst) of production from April to June 2014.

The decline in U.S. coal exports in 2014 was primarily controlled by a decrease in world coal demand, depressed international coal prices, and greater coal production in other coal-exporting countries. The EIA (2015d) projects coal exports will fall from 88 million metric tons (97 mst) in 2014 to an annual average of 73.5 million metric tons (81 mst) in 2015 and 2016. Coal consumption for electric power in the U.S. decreased by 0.8%, or 6.35 million metric tons (7 mst) in 2014. The EIA (2015d) predicts that power sector coal will decrease by 2.2% in 2015, mainly as a result of lower natural gas prices and coal plant retirements because of implementation of new air-quality and emission standards. An additional decline in coal consumption for electric power (0.5%) is projected in 2016.

Although U.S. coal production for exports continues to be strong, coal's share of the country's overall energy production is declining, primarily the result of expanded natural gas production (Humphries and Sherlock 2013). Lower demand for coal in U.S. markets is controlled by increasingly strict federal regulations, lower natural gas prices, and coal plant retirements. Reuters (2012), based on data from North American Electric Reliability Corporation (2011), estimated that market conditions and environmental regulations will contribute to between 59 and 77 GW of coal plant retirements by 2016. Greatest loss of coal-fired electricity

generation is projected to occur in the southeastern U.S., with 27–30 GW of plant retirements, followed by the northeastern U.S. (18–26 GW).

India

The coal industry in India was the world's third largest in terms of production and the fifth largest in terms of reserves in 2012 (EIA 2015e). Coal India has a near-monopoly on the coal sector, of which the power sector comprises most of its coal consumption. India continues to undergo regulatory, technical, and distribution difficulties that limit production and prevent efficient transportation of coal to demand centers. Moreover, coal mines in the country are distant from the high-demand markets in western and southern India. Because coal production has failed to keep up with demand, particularly from the power sector which accounted for 69% of coal consumption in 2011, India imported 162.4 million metric tons (179 mst) and was the third largest coal importer in 2012. India imports thermal coal primarily from Indonesia and South Africa, as well as metallurgical coal from Australia (EIA 2015e). The Indian coal ministry plans to scale down its production target of 795 million metric tons (876.4 mst) in the period from 2016 to 2017, owing to perceived problems in rail transport and compliance with environmental regulations (Thakkar 2014). India possessed 249 GW of installed electricity generation capacity in 2014. However, owing to fuel shortages and limited transmission capacity, India still experiences electricity shortages and blackouts typically lasting from several hours to days.

Other Leading Coal-Producing Countries

Other leading coal-producing countries include Indonesia, Australia, Russia, South Africa, Germany, Poland, and Kazakhstan. Indonesia and Australia are the world's largest and second largest exporters of thermal coal, respectively (Wulandari 2014; Cahyafitri 2014; Asmarini 2015; EIA 2015f, g). Although levels of coal production in Russia are modest, with 354 million metric tons (390 mst) in 2012, the country has inaugurated a long-term development plan for its flagging coal industry and is calling for an increase in coal production and electricity generation from coal (Dobrovidova 2014). Coal still represents >70% of South Africa's total primary energy consumption, although its coal production is expected to peak in the next decade (Ryan 2014; EIA 2015h). Germany plans to reduce greenhouse gas emissions by 40% (from 1990 levels) by 2020 (Destatis 2015), although coal accounted for 43% of electricity generation in Germany in 2014. Coal production in Poland is the second largest in Europe, exceeded by Germany (EIA 2015i). Of the 3.9 quadrillion BTU (~980 trillion kilocalories/kg) of Poland's primary energy consumption in 2012, coal represented 55%. Coal production in the same year was 143.3 million metric tons (158 mst), or ~20% of total coal production in Europe. Coal represented 63% of Kazakhstan's total energy consumption in 2012 (EIA 2015j). A coal-to-liquids (CTL) facility is underway in Akmola Oblast in Kazakhstan (Urazova 2015). The experimental facility for processing low-rank coal into gasoline and diesel fuel will employ low-temperature plasma in the Fischer–Tropsch process. For every ton of coal delivered from the Maikuben Basin, plans are to produce 0.223 tons of liquid fuel at a cost of 23 cents (42 tenge) per liter.

COALBED METHANE

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Introduction

The evaluation and production of natural gas from coal beds falls under two broad categories, depending on the context in which the resource is being assessed and produced:

- As an energy resource similar to other sources of natural gas, with the principal distinction being that the gas is coming from coal beds rather than conventional porous reservoir rocks. In this context, the produced gas is variously referred to as coalbed methane

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(CBM), coal bed natural gas, or coal seam gas (CSG).
- Gas produced in association with coal mining operations—termed coal mine methane (CMM).

CMM development is driven by three incentives: (1) increased mine safety through the reduction of methane being released into mine workings, (2) the energy value of the produced gas, and (3) the abatement of fugitive methane being released into Earth's atmosphere, where it acts as a potent greenhouse gas (GHG). In contrast, CBM development is driven largely by market forces related to its value as an energy resource, with additional governmental incentives occasionally being provided.

Much of the current interest in CMM is being sustained by programs sponsored through the United Nations, U.S. Department of Energy (DOE), U.S. Environmental Protection Agency (EPA), and other national organizations in countries including Australia, China, and Mexico.

The Global Methane Initiative web site (https://www.globalmethane.org/tools-resources/coal_overview.aspx) provides hyperlinks to resource over views for countries having significant resources of coal, CBM, and CMM. The web site https://www.globalmethane.org/coal-mines/index.aspx#action plans has a list of hyperlinks to action plans devel oped under the auspices of the Global Methane Initiative. The goal of this program is to find ways of reducing atmospheric emissions of methane arising from four major industrial sources: agriculture, coal mining, municipal solid waste, and oil and gas pro duction.

Overview of Current CBM Production and Reserves

Production and reserves of natural gas from coal beds in the U.S. have declined since 2008 due, in part, to the drop in price for natural gas, but it is still an important resource globally. Research on CBM remains active, however, as indicated by 61 technical papers published in 2014, including a book edited by Thakur et al. (2014) that contains the proceedings of the North American Coalbed Methane Forum's 25th Anniversary meeting. [The North American Coalbed Methane Forum celebrated 30 years of forums (1985–2015) at the meeting on May 20–21, 2015 (http://www.nacbmforum.com)]. Mastalerz (2014, her Fig. 7.3) provided a map showing world CBM resources, production, and exploration activities as of 2010. Global CBM resources and production are summarized in Tables 2 and 3.

Table 2. Coalbed Methane Resources by Country as of 2010 (Modified from Mastalerz 2014)

CBM Resources by Country	
Country	Resources (Tcf)
Russia	2824
China	1100
Alaska	1037
U.S. (minus Alaska)	700
Australia	500
Canada	500
Indonesia	435
Poland	424
France	368
Germany	100
UK	100
India	70
Ukraine	60
Zimbabwe	40
Kazakhstan	25

1 trillion cubic feet (Tcf) = 28.3 billion m^3.

Table 3. Annual Coalbed Methane Production by Country as of 2010 (Modified from Mastalerz 2014)

Annual CBM Production by Country	
Country	Production (Bcf)
U.S. (minus Alaska)	1886
Canada	320
Australia	190
China	50
Alaska	1
Russia	0.5
India	0.4
Kazakhstan	0.4

1 billion cubic feet (Bcf) = 28.3 million m^3.

Summaries of CBM Production for Selected Countries

United States of America. The EIA (2009a) shows a map of U.S. lower 48 states CBM fields (as of April 2009). U.S. annual CBM production peaked at 1.966 trillion cubic feet (Tcf; 55.67 billion m^3) in 2008 (Fig. 1). CBM production declined to 1.466 Tcf (41.51 billion m^3) in 2013, the lowest level since 2001, representing 5.5% of the U.S. total natural

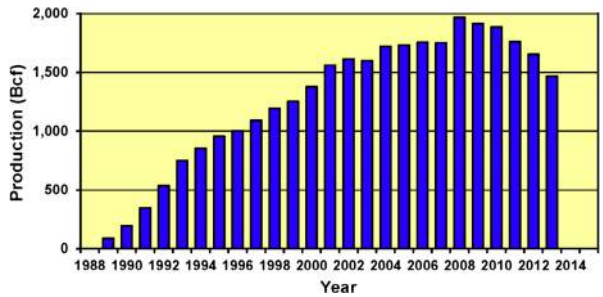

Figure 1. United States CBM production, 1989–2013 (compiled from EIA 2009b Table D11, 2010a Table 15, 2014a Table 15). 1 Billion cubic feet (Bcf) = 28.3 million m^3.

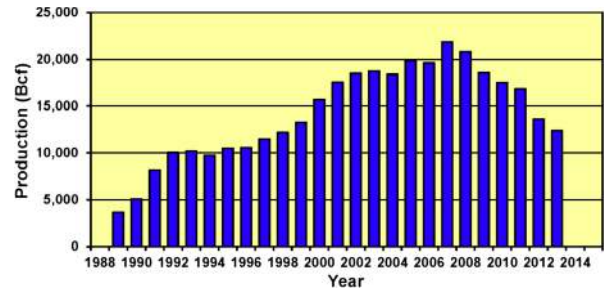

Figure 2. United States CBM proved reserves, 1989–2013 (compiled from EIA 2009b, 2010a, 2014a). 1 Billion cubic feet (Bcf) = 28.3 million m^3.

gas production of 26.5 Tcf (750.4 billion m^3). Note that U.S. CBM production in EIA (2014a, their Table 15) is different than in EIA (2014b, their Table 1). According to EIA (2014a), the top 8 CBM-producing U.S. states during 2013 (production in billion cubic feet, Bcf; or million m^3) were Colorado (444; 12.57), New Mexico (356; 10.08), Wyoming (331; 9.37), Virginia (93; 2.63), Oklahoma (65; 1.84), Alabama (62, 1.76), Utah (50; 1.42), and Kansas (30; 0.85). Annual CBM production by U.S. state (2008–2013) is available at EIA (2015o). Cumulative U.S. CBM production from 1989 through 2013 was 32 Tcf (0.91 billion m^3). CBM production continues even though few new wells are being completed, reflective of the very long productive lives of CBM wells. U.S. Geological Survey (2014) includes hyperlinks to their CBM assessment publications and web pages. Ruppert and Ryder (2014) included coal and coalbed methane resources and production in the Appalachian and Black Warrior Basins.

U.S. annual CBM proved reserves peaked at 21.87 Tcf (619 billion m^3) in 2007 and declined to 12.392 Tcf (351 billion m^3) in 2013, the lowest level since 1999, representing 3.5% of the U.S. total natural gas reserves of 354 Tcf (10,024 billion m^3) (Fig. 2). Annual CBM proved reserves by U.S. state (through 2013) are available at EIA (2015p).

Australia. Flores (2013, his Fig. 9.15) included a map showing coal seam gas (CSG) potential in Australia noting that the coal beds range in age from Permian to Tertiary in about 30 coal-bearing basins. Blewett (2012) included maps showing the distribution of demonstrated black coal and gas resources in Australia. CSG reserves in 2012 are divided into six coal basins in eastern Australia: Surat Basin (69%), Bowen Basin (23%), Gunnedah Basin (4%), Gloucester Basin (2%), Sydney Basin (1%), and Clarence-Moreton Basin (1%) (Flores 2013). The EIA (2015g) reported that economically recoverable CSG reserves in Australia were 33 Tcf (934 billion m^3) in 2012, primarily in the Surat and Bowen Basins in Queensland. Commercial CSG production in Australia began in 1996 and was 246 Bcf (6.97 billion m^3) in 2012 (~13% of total natural gas production).

China. A map showing coal basins and CBM resources in China is available at https://www.globalmethane.org/tools-resources/coal_overview.aspx. EIA (2015b) reported that CBM production from wells and underground coal mines in China was 441 Bcf (12.49 billion m^3) in 2012. Tao et al. (2014) indicated there were 12,574 CBM wells in China at the end of 2012; the Southern Qinshui Basin is the largest CBM-producing basin in China. The first CBM exploration well in China was drilled in 1991 (Zhang et al. 2014). Flores (2013) indicated that a significant amount of the CBM resources in China are from coal mine methane (CMM) with the first CMM project in 1991. Information on coal mine methane activity in China is available from U.S. Environmental Protection Agency (2015). According to Dodson (2014), "Chinese shale gas production fell so far short of expectations that the Asian behemoth quickly turned to CBM" and "CBM may well find itself relied on increasingly in China, as the country looks to offset its coal dependence."

Canada. CBM production in Canada comes mainly from Cretaceous and Tertiary coals in the Western Canada Sedimentary Basin (Flores 2013). According to the web site http://www.energy.alberta.ca/Natural

Gas/750.asp, there were 19,269 CBM wells in Alberta, Canada as of December 31, 2012. Most of the new production was from the Horseshoe Canyon Formation with some deep wells to the Mannville Formation coals.

OIL SHALE

Alan K. Burnham[9]

Oil shale is a kerogen-rich petroleum source rock that never got buried deep enough to experience the times and temperatures necessary to generate oil and gas. Worldwide, oil shale is a substantial potential energy resource that potentially could yield a trillion barrels (159 billion m^3) of oil and gas equivalent (Burnham 2015). Estimates of the resource vary considerably (Knaus et al. 2010; Dyni 2003; Boak 2013), but taking the highest value for each country from these estimates plus a contribution from a largely uncharacterized resource in Mongolia, (Oil & Gas Journal 2013) one obtains a potential resource of about 7.5 trillion barrels (1.2 trillion m^3). Most of that resource is in the U.S., and most of that is in the Green River Formation—about half the world total. Russia, China, Israel, Jordan, and DR Congo each have resources of at least 100 billion barrels (15.9 billion m^3). Recovery factors are hard to estimate due to grade variations and yet-unproven in situ technology required to process most of the resource, but even 20% recovery seems highly optimistic. A new assessment is sorely needed.

Prior to the discovery of commercial natural petroleum deposits, oil shale was a significant source of heating and lighting oil, particularly in Scotland in the 19th century. In the U.S., interest in oil shale awakens every 30 years or so with concerns about conventional petroleum prices and energy security then wanes with new discoveries and lower prices. Oil shale activities in other parts of the world are less variable due to a variety of economic factors. Prior to the most recent drop in oil prices (2014), the future of oil shale looked bright, at least in certain parts of the world. The current status is in flux, but it is too early to know whether we are seeing a repeat of the 1980s or a shorter-term correction.

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Although the U.S. has the largest oil shale (kerogen) resource, Estonia and China are currently the largest producers, processing it both for electric power by burning and for shale oil by retorting (destructive distillation). The unfortunate recent use of the term "shale oil" for oil produced by hydraulically fracturing mature petroleum source rocks and adjacent more permeable lithologies is a source of major confusion in both public and scientific circles, as the resources and production methods are completely different. The U.S. EIA (2015q) and most industry has adopted the term "tight oil" for what is sometimes called "shale oil" because it is a more appropriate description.

As shown in Figure 3, oil shale mining peaked in 1980 at ~43 million tons (47 short tons) per year, declined to ~16 million tons (18 short tons) per year in 2000, but has grown steadily since to ~33 million tons (36 million short tons) per year in 2014, of which 90% was split between China and Estonia. Brazil produced most of the rest. From the portion retorted, China averaged about 16,000 barrels of oil per day (bopd) (~2500 m^3/day), Estonia 14,000 bopd (~2200 m^3/day), and Brazil nearly 4000 bopd (640 m^3/day). The Chinese and Estonian numbers include new capacity added during 2014 and are projected to rise a little in 2015.

New oil shale development is proposed in the three currently producing countries and in Jordan, the U.S., Australia, Morocco, Mongolia, Israel, Canada, and Uzbekistan. How fast this expansion proceeds depends strongly on the price of crude oil, but it is likely that some research and development and incipient commercial production will occur in order to refine processing technology, environmen-

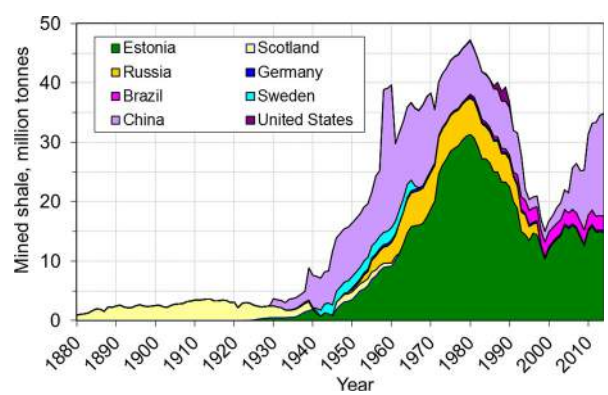

Figure 3. History of oil shale extraction updated from Dyni (2003) using a variety of industry and government sources. 1 metric ton = 1.1 short ton.

tal factors, and economics under the presumption that oil prices will go up during the years before significant commercial production. Projections prior to the recent oil price collapse were ~300 million tons (441 short tons) of oil shale mined per year and 400,000 bopd (64,000 m^3/day) by 2030 (Boak 2013).

The two primary extractive processes for producing shale oil are hot-gas retorts and hot-solids retorts (Burnham and McConaghy 2006; Crawford and Killen 2010). Many variations of each exist, with the Fushun, Kiviter, Petrosix, and Paraho processes being the dominant hot-gas types used in China, Estonia, Brazil, Australia, and the US and the Galoter, Petroter, Enefit and Alberta Taciuk Process (ATP) processes being the hot-solids types used in Estonia and China and potentially the US, Jordan and Morocco. New hot-solids retorts have achieved design throughput for Enefit (Eesti Energia) and VKG in Estonia and Fushun/ATP in China. Enefit is pursuing a commercial development in Utah on both private and US land (via its Bureau of Land Management Research, Development, and Demonstration (US BLM RD&D) lease) using its hot-solids technology.

The two new types of processes being researched are in-capsule and in situ heating (Burnham and McConaghy 2006). In-capsule heating is a new type of process invented by Red Leaf Resources (http://www.redleafinc.com/), in which shallow oil shale is mined and used to create stadium-sized rubble beds encapsulated by ben tonite-clay engineered earthen walls. The original concept was that oil shale would be heated indirectly to retorting temperatures by flowing hot gas through embedded tubes, with heat distributed by conduction and convection and the spent shale abandoned in place. In situ heating was resurrected from Swedish technology of the mid-20th century by Shell using more modern drilling technology and heating cables (Ryan et al. 2010), and several companies are researching variations of in situ heating in the U.S. and Israel. Shell recently abandoned its US BLM RD&D leases in preference for a demonstration of its in situ conversion process in Jordan, and it started in situ heating for a small pilot test in Jordan in 2015. Israel Energy Initiatives was recently denied a permit in Israeli to conduct a pilot test of a similar process and is considering its options.

The first commercial shale oil production in the U.S. will likely use Red Leaf's EcoShale in-capsule heating technology in a joint Utah project with Total S.A. Red Leaf obtained the necessary permits from the State of Utah and started construction on a 5/8th commercial-scale demonstration that would produce >300,000 barrels (>47,700 m^3) of oil over 400 days. However, the drop in crude oil prices has caused them to re-optimize the design, switching from indirect to direct hot-gas retorting, and then to restart construction in 2017. TomCo Energy also plans to use the EcoShale process in Utah.

ENERGY COMPETITION IN THE URANIUM, THORIUM, AND RARE EARTH INDUSTRIES IN THE U.S. AND THE WORLD: 2015

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Introduction

After the 2011 Fukushima tsunamis and damage to Japan's Daiichi nuclear power plant, uranium prices dropped about 60% in value over the ensuing years. But the decline in the price evident in Figure 4 appears to have run its downward course by mid-2014. As illustrated in the two charts in Figure 4, since bottoming near $28 in mid-2014, spot uranium prices gained nearly 40% to reach their current level around $38.50 (as of May 2015), see I2M Web Portal (I2M Web Portal 2015a) for recent discussions on future price expectations.

Energy Competition

Nuclear fuel prices represent a very small segment of the total cost to produce electricity by nuclear power relative to other energy sources. The supply of nuclear fuel is available from an increasing number of uranium mine sites today, and therefore, new nuclear plant construction is based more on its total plant cost and financing (including insurance costs), concerns about nuclear waste disposal and public opinion than with those impacting other competing energy sources, even if the latter have major impact on the environment.

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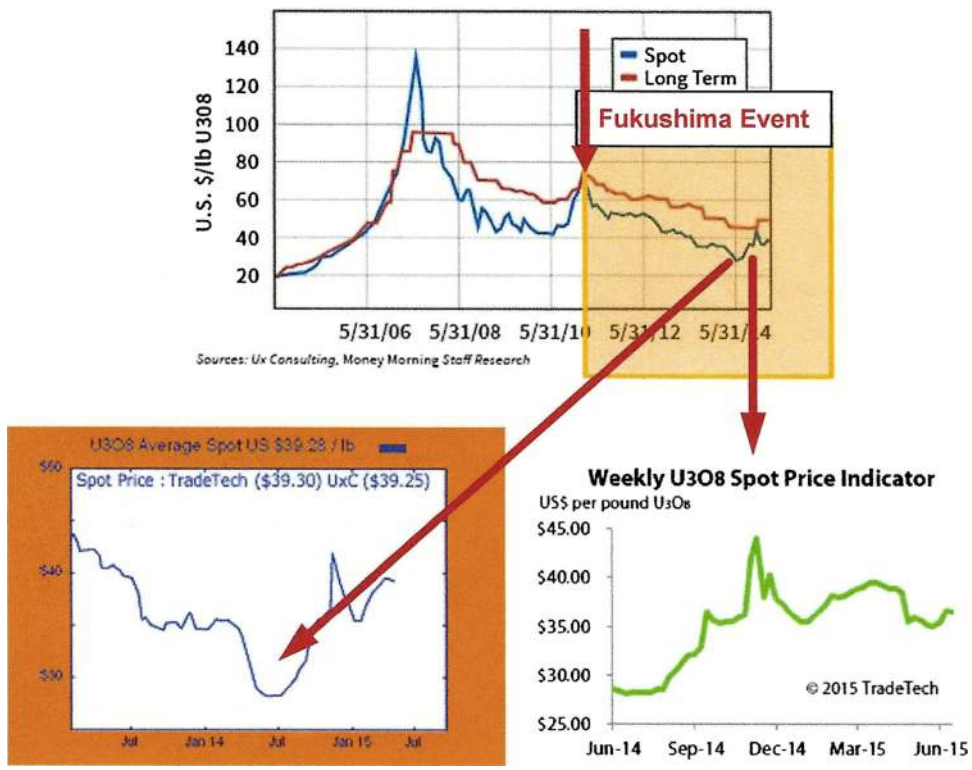

Figure 4. Yellowcake prices since Fukushima Tsunami. From U_3O_8.biz (2015) and TradeTech (2015). 1 pound (lb) = 0.453 kg.

In contrast, the technologies associated with the operation of renewable energy generation do not have established records in their operation and maintenance costs, within a scaled-up grid of significant size, without substantial state and federal subsidies.

Considering that the "fuel" costs to drive wind and solar are zero, albeit available at variable wind speeds and receiving radiation only during daylight, these technologies still involve moving parts to produce electricity that must be maintained by humans and/or stored in batteries or backed up by grid-power that is usually of lower cost than those of the renewables, such as produced by nuclear, hydroelectric and natural gas. For cost comparisons, see I2M Web Portal (2015b).

Energy Selection

Many favorable aspects underlie using nuclear heat to boil water to turn turbines to generate electricity that have supported the construction and continuous operation of more than 100 plants in the U.S. (Fig. 5) and nearly 400 plants worldwide for the past 50 years. Currently, the main criteria applied to select a source of energy are based on short-term economics and political influences. Because the nuclear plants have been built in fortress-like extended-life designs that cost billions of dollars to bring on line, many of them have now lasted decades and have produced electricity both reliably, safely, and at low relative cost over the past 50 years.

Factors that can be considered that impact energy-type selection, such as the costs of competing fuels, their safety records, public opinion, and media coverage, can even include sociological factors as far afield as the relationship of technology and employment needs to be addressed. In the present climate, these factors all bear heavily on the availability, price, and use of nuclear fuels, i.e., uranium and thorium, for the generation of electricity within nuclear power plants.

Energy Economics

There has been a remarkable resilience to the positive media views about nuclear power's

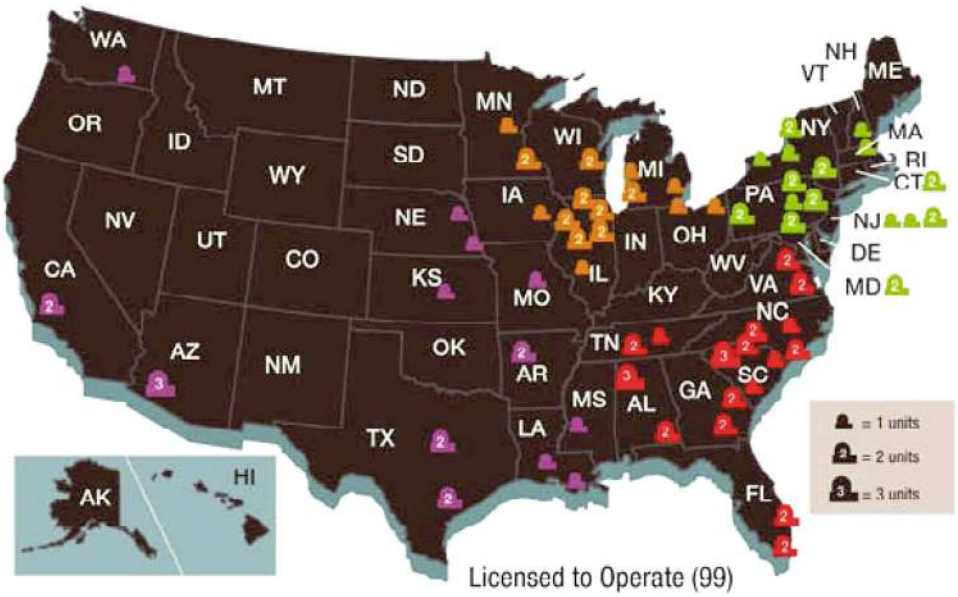

Figure 5. Currently operating U.S. Nuclear Power Reactors. U.S. Nuclear Regulatory Commission (NRC) (2015). NRC regions by color code.

resurgence in the U.S. and world today as the existing plants exceed their design lives, with an understanding that all plants will need to be replaced with new nuclear technology sooner or later. Another significant economic issue is the extensive storage onsite of nuclear waste, and the current lack of an offsite, long-term underground nuclear storage waste alternative. In addition, with the success of horizontal drilling and hydraulic fracturing technology in developing shale gas and oil deposits in the U.S. and around the world, new natural gas resources are reaching the markets and have driven down the cost of fuel for generation of electricity to levels that compete with nuclear power. With the glut of new oil and gas, the price has fallen so low that some U.S. shale oil and gas fields are becoming uneconomic to produce so natural gas prices will likely tend to fluctuate in the future. This over supply of oil and gas, developed by the petroleum industry and national policy, is already evident by the employment downsizing underway today in the oil and gas industry, especially in the smaller companies.

The U.S. is leaving the land acquisition, leasing, and delineation stages of shale gas production and is entering the consolidation stage where operations will become more efficient and fewer, but larger, companies will control the market. Price volatility will decrease and prices will increase just as the U.S. connects to the world market through development of the liquefied natural gas (LNG) infrastructure. Immediate markets will include Europe and Japan as long as the prices are attractive.

Added to this economic condition, and with the renewed interest in gas-fired power plants based on cheap natural gas, competition also comes from renewable energy resources that the general public, led by current national policies, associated federal agencies, and the media, have suggested as the answer to energy selection in the U.S. Nuclear adversaries and pro-solar and wind proponents have released media feeds promoting renewables and listing accomplishments sometimes without fully providing the economic evidence for such claims (Rosenbloom 2006; I2M Web Portal 2015c, d).

If the climate is to be a consideration and if the end cost of electricity, without government subsidies, is to be included in an assessment of the best approach to energy utilization, then nuclear power can prevail in delicate balance with natural gas between costs and the environment on the basis that nuclear power has been and continues to be a preferred energy resource, e.g., capacity factor (Fig. 6).

The Annual Report of the Uranium (Nuclear Minerals and REE) Committee or UCOM (American Association of Petroleum Geologists, Energy Minerals Division 2015) discusses these issues and others in more detail, and from which this summary

is drawn. This summary also draws on the I2M Web Portal (2015a), which provides links to abstracts and reviews of media articles and technical reports with a focus on current uranium prices, exploration, mining, processing, and marketing (I2M Web Portal 2015e), as well as on topics related to uranium recovery technology, nuclear power, economics, reactor design, and operational aspects (I2M Web Portal 2015f), and related environmental and societal issues involved in such current topics as energy resource selection, climate change, and geopolitics (I2M Web Portal 2015g). This report summary also draws from the 2014 UCOM Mid-Year Report (American Association of Petroleum Geologists, Energy Minerals Division 2014b) as support.

Current university and government research and recent industrial developments on thorium are also discussed in the 2015 UCOM Annual Report (American Association of Petroleum Geologists, Energy Minerals Division 2015, pp. 26–27), and captured by the I2M Web Portal (2015h). Other potential energy sources such Helium-3 (I2M Web Portal 2015i), and related environmental and societal issues are captured as well.

In addition, current university and government research and recent industrial developments in the rare earth industry are discussed in the 2015 UCOM Annual Report (American Association of Petroleum Geologists, Energy Minerals Division 2015, p. 30, 32), and captured by the I2M Web Portal (2015j). For the full list of coverage of the various sources of energy and associated topics, in the form of more than 4000 abstracts and links to media articles and technical reports to date (and increasing each day) from sources in the U.S. and around the world, see (I2M Web Portal 2015k).

Uranium Demand

Eighty-nine percent (89%) of the fuel requirements of the current fleet of nuclear reactors will be met by Canada, Australia, and Kazakhstan, and supplied from other sources, totaling some 377 million pounds U_3O_8 per year. As uranium prices rise, more in situ uranium mines in the U.S. will come on stream as Japan re-starts their reactors and other countries bring new construction on-line, such as China, India, and a number of others in the next few years. But other deposits now being developed in the world will also come on-line to compete on the world markets.

The U.S. is the largest consumer of uranium in the world, currently requiring more than 50 million pounds U_3O_8 annually, yet producing only about 4.7 million pounds domestically. China consumes 19 million pounds per year, expected to reach 73 million pounds by 2030. China currently produces about 4 million pounds U_3O_8 per year, and is planning to build additional nuclear power capacity, nearly tripling by 2020, to alleviate problems with air pollution created by mining, importing and burning coal to generate electricity.

Vietnam has committed to building a number of nuclear power plants in the north and in the south of Vietnam (World Nuclear Association 2015a). Vietnam has significant hydroelectric power, but currently still needs coal and natural gas for electric power.

India also is in the midst of a major build out of nuclear power generation. A 500-MW prototype fast breeder reactor (PFBR) at Kalpakkam in Tamil Nadu is targeted to produce power in 2015–2016 (India Business Standard 2015). The country's installed capacity is now at 5780 MW, but that is set to nearly double in the next 4 years to 10,080 MW, which also puts pressure on the world uranium demand and price. In mid-April 2015, Indian Prime Minister Narendra Modi visited Canada. While there, he signed a 5-year deal to buy 3000 tons U_3O_8 in order to fuel India's nuclear reactors (Market Oracle 2015). The agreement is worth C$350 million dollars, just over C$58.00/pound U_3O_8. Narendra's meeting was the first India–Canada governmental visit in 42 years and the first nuclear contract between these two nations.

Given the anticipated near-term demand for uranium, a significant rise in the uranium commodity price may drive stock prices up, which in turn will drive new rounds of mergers and acquisitions of uranium properties and the companies holding them, as well as driving new exploration and processing plant development.

Uranium Production in the U.S

U.S. production of uranium concentrate in the fourth quarter 2014 was 1,100,111 pounds U_3O_8, down 25% from the previous quarter and up 16% from the 4th Quarter 2013. During the fourth quarter 2014, U.S. uranium was produced at seven U.S. uranium facilities, one less than in the previous quarter (EIA 2015r). Uranium was produced by mill at White Mesa Mill in Utah, first operating-

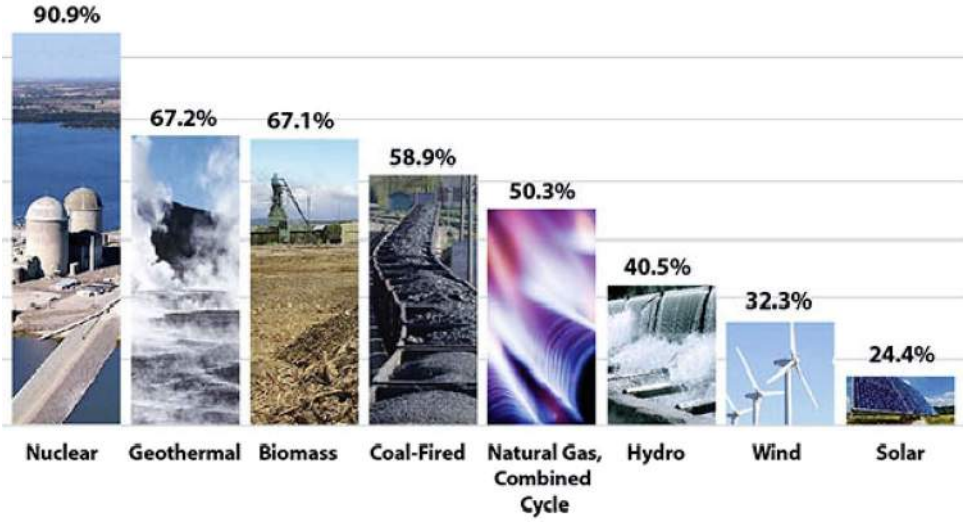

Figure 6. Comparative Energy Capacity Factors (Nuclear Energy Institute 2015a).

processing alternate feed in 4PthP Quarter 2014. Uranium was produced by in situ-leach plants at Alta Mesa Project (Texas), Crow Butte Operation (Nebraska), Hobson ISR Plant/La Palangana (Texas), Lost Creek Project (Wyoming), Nichols Ranch ISR Project (Wyoming), which started production in 2014, Smith Ranch-Highland Operation (Wyoming), and the Willow Creek Project (Wyoming). U.S. uranium concentrate production totaled 4,905,909 pounds U_3O_8 in 2014. This amount is 5% higher than the 4,658,842 pounds U_3O_8 produced in 2013. U.S. production in 2014 represented about 11% of the 2014 anticipated uranium market requirements of 46.5 million pounds U_3O_8 for U.S. civilian nuclear power reactors (EIA 2015s).

EIA (2015t) reported that U.S. uranium mines produced 4.9 million pounds U_3O_8 in 2014, 7% more than in 2013. Two underground mines produced uranium ore during 2014, one less than during 2013. Uranium ore from underground mines is stockpiled and shipped to a mill, to be milled into uranium concentrate (called yellowcake, a yellow or brown powder). Additionally, seven in situ-leach (ISL) mining operations produced solutions containing uranium in 2014 (one more than in 2013) that was processed into uranium concentrate at ISL plants. Total production of U.S. uranium concentrate in 2014 was 4.9 million pounds U_3O_8, 5% more than in 2013, from eight facilities. The Nichols Ranch ISR Project started producing in 2014. The ISL plants are located in Nebraska, Texas and Wyoming. Total shipments of uranium concentrate from U.S. mill and ISL plants were 4.6 million pounds U_3O_8 Rin 2014, 1% less than in 2013. U.S. producers sold 4.7 million pounds U_3O_8 of uranium concentrate in 2014 at a weighted-average price of $39.17 per pound U_3O_8.

The EIA (2014g) reported that although most of the uranium used in domestic nuclear power plants is imported, domestic uranium processing facilities still provide sizeable volumes of uranium concentrate to U.S. nuclear power plants. In 2013, the percentage of uranium concentrate produced was distributed among seven facilities in four states. Wyoming accounted for 59% of domestic production, followed by Utah (22%), Nebraska (15%), and Texas (4%).

Uranium is processed into uranium concentrate either by grinding up ore mined from an open pit or from underground and then processed into yellowcake, or by using oxygen and liquid mixtures to dissolve the uranium occurring in sandstone from depths of 300 feet to more than 1200 feet in the subsurface by a process known as in situ leaching.

Today, most plants incorporate in situ leaching; Utah's uranium mill serves a separate function involving upgrading the uranium product. The output of the mill and the leach plants is uranium concentrate, known as U_3O_8 or yellowcake, which is transported to conversion and enrichment facilities for further processing before being fabricated into the pellets used in nuclear fuel to generate the heated water that runs steam generators to produce electricity.

Uranium Exploration in the U.S

Uranium exploration data for 2014 reflected the lower price of uranium and were expectedly down substantially from previous years. In the meantime, Google search results (I2M Web Portal 2015l) show a multitude of mergers, acquisitions, and consolidations, and company downsizing of properties held are moving at a fast pace, while the price continues to look for support in the nuclear power industry markets for fuel (Uranium Investing News 2015a). Recent exploration can be monitored on-line (I2M Web Portal 2015e), and by using a more generalized term (I2M Web Portal 2015m), exploration for related commodities as well.

As reported by the EIA (2015t), total uranium drilling in 2014 was 1752 holes covering 1.3 million feet, 67% fewer holes than in 2013 and the lowest since 2004. Expenditures for uranium drilling in the U.S. were $28 million in 2014, a decrease of 43% compared with 2013. Therefore, total expenditures for land, exploration, drilling, production, and reclamation were $240 million in 2014, 22% less than in 2013.

Expenditures in the U.S

Expenditures for U.S. uranium production, including facility expenses, were the largest category of expenditures at $138 million in 2014 but were down by 18% from the 2013 level, as expected. Uranium exploration expenditures were $11 million and decreased 50% from 2013 to 2014. Expenditures for land were $12 million in 2014, a 21% decrease compared with 2013. Reclamation expenditures were $52 million, a 5% decrease compared with 2013.

All of these declines were in direct response to the decline in the price of yellowcake that was associated with the shutdown of the Japanese reactors and overall impact of the damage to the reactors caused by Fukushima tsunamis in 2011. However, the price is still expected to rise over the coming months (Money Morning 2008).

Significant Field Activities in the U.S

The Rapid City Journal (2015) reported that Powertech Uranium, now Azarga Uranium, and adversaries of a planned uranium mining operation in Custer and Fall River counties, South Dakota saw a recent NRC (U.S. Nuclear Regulatory Commission) decision as a victory for both sides. The lengthy decision came months after NRC's Atomic Safety and Licensing Board took testimony on a contested license the NRC granted to develop Azarga Uranium's Dewey-Burdock in situ leach uranium operations near Edgemont, South Dakota. The licensing board found in favor of Powertech on five of the adversarial challenges relating to water quality and quantity. It did, however, revise the Powertech license, instructing the company to improve efforts to find and properly abandon existing drill holes at the site to prevent contamination by rainfall draining into the subsurface. Recently, drilled holes have standard procedures in place for appropriate abandonment using cement and bentonite, if needed. The thousands of historical holes are to be sealed when encountered.

Dewey-Burdock Project Manager Mark Hollenbeck of Edgemont said that they were "very happy" with the science-based decisions that the Court made. Hollenbeck said that all of the licensing board's decisions upheld the Powertech scientific presentations and data on water quality and hydrology. The licensing board did rule in favor of the Oglala Sioux Tribe on the unspecified threat the mining operation would pose to Native American cultural, historic, and religious sites in the well-fields, but these could be easily managed with the cooperation of the Tribe.

Historical Uranium Reserves Estimates in the U.S

Currently known uranium reserves in seven western states are estimated to total nearly 340 million pounds U_3O_8 (EIA 2015u); about one-third of the reserves are in Wyoming. Other known reserves are in Arizona, Colorado, Nebraska, New Mexico, Texas, and Utah. Uranium deposits have also been identified in Alaska, North Dakota, and South Dakota, and in several other states, mostly in the western U.S. The largest known undeveloped uranium property in the U.S., and allegedly the seventh largest in the world, is located on private land at Coles Hill in south-central Virginia, near the North Carolina border. The deposit at Coles Hill is estimated to contain some 60 million pounds of uranium in a hard-rock environment, which would be mined by open pit and later by underground methods and processed onsite to produce U_3O_8. The development of this deposit has been stalled by local opposition.

Christopher (2007) prepared a technical report on the Virginia project. A geological summary of the deposit is provided by Dahlkamp (2010). It has yet to be confirmed that these reserves have been included in the EIA estimate of U.S. uranium reserves.

The EIA (2015u) estimated at the end of 2008 that U.S. uranium reserves totaled 1227 million pounds of U_3O_8 at maximum forward cost (MFC) of up to $100 per pound U_3O_8. At up to $50 per pound U_3O_8, estimated reserves were 539 million pounds of U_3O_8. Based on average 1999–2008 consumption levels (processed uranium into fuel pellets then inserted into assemblies loaded into nuclear reactors), uranium reserves available at up to $100 per pound of U_3O_8 represented about 23 years of operation (EIA 2015u). At up to $50 per pound U_3O_8, however, uranium available through in situ leaching was about 40 percent of total reserves, somewhat higher than uranium in underground mines in that cost category. ISL is the dominant mining method for U.S. production today. These estimates are likely conservative because proprietary industrial reserve information may be substantially greater than government estimates of economic tonnage and grade of particular deposits.

The EIA (2015t) announced that as of the end of 2014, estimated uranium reserves were 45 million pounds U_3O_8 at MFC of up to $30 per pound of U_3O_8. At up to $50 per pound, estimated reserves were 163 million pounds U_3O_8. At up to $100 per pound, estimated reserves were 359 million pounds U_3O_8. At the end of 2014, estimated uranium reserves for mines in production were 19 million pounds U_3O_8 at a maximum forward cost of up to $50 per pound. Estimated reserves for properties in development drilling and under development for production were 38 million pounds U_3O_8 at MFC of up to $50 per pound.

The EIA (2015t) claimed that the uranium reserve estimates from the 2015t report cannot be compared with the much larger historical dataset of uranium reserves published in the EIA (2015u). The earlier (EIA 2015u) reserve estimates were made based on data collected by EIA and data developed by the National Uranium Resource Evaluation (NURE) program, operated out of Grand Junction, Colorado, by DOE and predecessor organizations. The EIA (2015t) data covered Roughly 200 uranium properties with reserve estimates, collected from 1984 through 2002.

The NURE data covered roughly 800 uranium properties with reserve estimates, developed from 1974 through 1983. Although the EIA (2015t) data collected by the Form EIA-851A survey covered a much smaller set of properties than the earlier report (EIA 2015u), the EIA believes that within its scope the EIA-851A data provides more reliable estimates of the uranium recoverable at the specified forward cost than estimates derived from 1974 through 2002. In particular, this is because the NURE data have not been comprehensively updated in many years and are no longer a current data source. However, these data are very useful and suggest that there are many additional uranium properties in the U.S. that deserve additional exploration, the essential question of which revolves around just how many of these will be found to contain economic reserves of uranium. If history is any guide to the future, more reserves will be identified as prices begin to rise over the near future and beyond.

Employment in the Uranium Industry

The EIA (2015u) estimated total employment in the U.S. uranium production industry was 787 person-years in 2014, a decrease of 32% from the 2013 total and the lowest since 2006. Exploration employment was 86 person-years, a 42% decrease compared with 2013. Mining employment was 246 person-years, and decreased 37% from 2013. Milling and processing employment was 293 person-years, a 30% decrease from 2013. Reclamation employment decreased 19% to 161 person-years from 2013 to 2014. Uranium production industry employment for 2014 was in nine States: Arizona, Colorado, Nebraska, New Mexico, Oregon, Texas, Utah, Washington, and Wyoming.

Nuclear Power Plant Operations in the U.S

Ninety-nine nuclear reactors are currently licensed in the U.S. (Fig. 5), five of which have been recently closed or are in the process of being shuttered. Nuclear plants operate continuously and generate 63 percent of U.S. carbon-free electricity, but competitive electricity markets do not value these attributes and some may be shuttered on economic grounds. Vermont's only nuclear plant is a case in point. The company's operating revenues at the Yankee 604-megawatt plant were squeezed by a combination of sagging electricity demand, low

energy prices, and restructured markets that undervalue nuclear energy's contributions. Industry executives warned that more nuclear plants are under financial strain and could close—a prospect that is of concern to all regulators, especially since nuclear power is the preferred energy resource, e.g., capacity factor (Fig. 6). When a mid-size nuclear reactor in Vermont permanently and prematurely shuts down, it exacerbates instabilities in the energy markets of a community and region already impacted by economic uncertainties in that area. When Vermont lost its only nuclear power plant at the end of 2014, the region's electricity grid lost 604 megawatts of clean, around-the-clock generating capacity, and the area will see an increase in carbon dioxide emissions, a move that runs counter to national goals to reduce these emissions (Nuclear Energy Institute 2015b).

Small Nuclear Reactors

Small modular reactors (SMRs) are getting increased attention over the period, continuing an upward trend in developing SMRs for standby use in case of disasters, for remote areas, including off-world, as well as for operating sector grids in small towns or in large cities where a number of SMRs would be located around the city. Numerous research and development programs are underway on SMRs by many companies in the U.S. and overseas. Additional, updated information and media items on SMRs are compiled at I2M Web Portal (2015n) and described by World Nuclear Association (2015b).

Spent Fuel Storage

Spent nuclear fuel data are collected by the EIA for the Office of Civilian Radioactive Waste Management (OCRWM). The spent nuclear fuel (SNF) data include detailed characteristics of SNF generated by commercial U.S. nuclear power plants. From 1983 through 1995, these data were collected annually. Since 1996, these data have been collected every 3 years. The latest available detailed data cover all SNF discharged from commercial reactors before December 31, 2002, and are maintained in a database. Additional information on spent fuel storage is available from the Nuclear Energy Institute (2015c).

Nuclear Power Construction Overseas

Nuclear power plant construction is expanding rapidly in China, India, Russia, and more than ten other countries. In particular, for review of current reports on nuclear activities involving Russia readers are referred to (World Nuclear Association 2015b) and (I2M Web Portal 2015o); Ukraine (World Nuclear Association 2015c; I2M Web Portal 2015p), and Kazakhstan (World Nuclear Association 2015d; I2M Web Portal 2015q).

Thorium Activities

Ideas for using thorium as an energy resource have been around since the 1960s, and by 1973, there were proposals for serious, concerted research in the U.S. However, programs came to a halt due to the development of nuclear weapons.

The 1960s and 1970s were the height of the Cold War and weaponization was the driving force for all nuclear research. Nuclear research that did not support the U.S. nuclear arsenal was not given priority (Warmflash 2015). Conventional nuclear power using a fuel cycle involving uranium-235 and/or plutonium-239 was seen as meeting two objectives with one solution: reducing U.S. dependence on foreign oil, and creating the fuel needed for nuclear bombs. Thorium power, on the other hand, did not have military potential. And by decreasing the need for conventional nuclear power, a potentially successful thorium program would have actually been reported by some as threatening to U.S. interests in the Cold War environment.

Global leaders today are concerned about proliferating nuclear technology which has led several nations to take a closer look at thorium power generation of electricity, especially China and India, with technical assistance from the U.S. (Halper 2015). Hayes (2015) indicated that China, India, and a few others are actively pursuing research on a thorium-based nuclear fuel cycle for electricity production. This is based largely on the fact that India has not yet identified abundant uranium resources, but does have substantial thorium ores.

Scientists in Shanghai have been ordered to accelerate plans to build the first fully functioning thorium reactor within 10 years, instead of 25 years as originally planned (Evans-Pritchard 2015). China faces fierce competition from overseas and to get

there first will not be an easy task, says Professor Li Zhong, a leader of the program.

As reported in the technical and public press over the past few years, thorium shows promise as an economically viable fuel source someday, but the potential use of it in the U.S. does not appear to be likely in the near term. However, nuclear giant, Westinghouse, a unit of Toshiba, is part of an international consortium with Thor Energy (Uranium Investing News 2015b), a private Norwegian company, and continues to fund and manage further assessments of using thorium to replace uranium to generate the heat in nuclear power reactors.

Rare Earth Activities

There are two parallel themes to consider when discussing the topic of rare earth elements. One discusses the exploration and mining of REEs, and the other concerns the economic processing of the ores to provide a marketable product stream. Gerden (2015) reported that there have been some recent developments in the former by Russia. They have announced they are in the final stage of a company plan to focus on the development of the world-class Burannoey deposit of the Tomtorsky rare earth element trend, where reserves are estimated at 20 million tons of ore, valued at US$8 billion (either in-place, or on some unspecified basis of costs), with the development of other deposits in the trend when required. Operational lifetime of the Burannoey project alone is estimated at 40–50 years.

A joint venture of Rostec (a Russian state corporation established to promote development, production, and export of hi-tech industrial products for civil and defense sectors), and ICT Group, one of Russia's leading investment holdings, is developing the Burannoey project. The volume of investments in the project is estimated at 145 billion rubles (US$4.5 billion).

Successful implementation this project would make Russia one of the world's largest producers and exporters of rare earth metals when it reaches full operation. During Soviet times, the production of rare earth metals in the country was at the level of 8500 tons per year. Production took place in more than 30 regions of the USSR. However, since the collapse of the USSR in 1990 and the number of political and economic problems in the country, the production of REEs in Russia has almost stopped, while Russia became a net importer.

There have also been breakthroughs in processing that could reduce China's current control of the REE prices and product (Matich 2015), at least of those elements of the REE group that are highly sought after, but also very expensive (Frontier Rare Earths 2015). The company Rare Earth Salts (RES) announced that it has a defined path to near-term commercialization of its rare earth separation technology. Company CEO Allen Kruse has said that their low-cost technology will allow rare earth companies to directly compete with domestic Chinese pricing. The RES technical team claims to have demonstrated some of the lowest operating costs and highest efficiency in the industry with their environmentally friendly process, projected the cost to be below $4 per kilogram. Another key advantage is the functional independence of the RES separations technology with various rare earth concentrate feedstocks. Their technology allows them to reportedly combine concentrates from multiple partners and feedstock types without sacrificing separation effectiveness (Matich 2015).

To review current reports, media items, and other information compiled for the rare earth industry, see (I2M Web Portal 2015r) and U.S. Geological Survey (2015).

GEOTHERMAL ENERGY

Paul Morgan[12]

Introduction

Geothermal Energy contributes to the global energy economy through electrical power production, direct heat and cooling, and as a convenient thermal reservoir for heat pumps. Electrical power production is most commonly associated with geothermal energy but residential and commercial buildings account for more than one-third of the total energy consumption in the U.S. and most of that energy is used for space heating and cooling, and hot water. In many places, geothermal resources can provide hot water and heating and cooling more efficiently than other energy resources, and ground-source heat pumps provide electrical energy savings of 75–80% or more for heating and cooling over the

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direct use of electricity for conventional heating and cooling. The direct use of geothermal hot water for district heating systems is growing, especially in Europe, and there is a steady growth in the use of ground-source heat pumps in Europe and the U.S. The thermal energy output/savings of these systems is very large, but difficult to quantify in the U.S. because national data have not been compiled. In examples where geothermal water is cascaded from power generation to district heating, the thermal energy recovered is typically several times larger than the electrical energy generated because the thermal energy can be recovered at a lower temperature and there are no losses in energy conversion. Direct-use and ground-source heat pumps remain underused geothermal resources. However, although they have global relevance, they have local application. This report focuses on the primary use of geothermal resources for power production and other transportable products.

One of the benefits of geothermal electrical power production with respect to wind or solar is that it provides base-load electricity providing power without the fluctuations of wind or the diurnal and seasonal cyclicity, and weather fluctuations of wind and solar. Most geothermal power plants have a capacity factor of >90%, equaling or exceeding the capacity factors of nuclear power plants because they are very simple with no fuel or boilers. They typically have multiple turbines and wells so that maintenance of individual components can take place while the system is operating. Lower capacity factors are only common during development or expansion stages of operation, or if the internal load factors of the systems, such as well pumps, are included in the capacity factor calculations (counting pumps integral to the system against the capacity factor of a geothermal system is equivalent to counting the mining, refining and disposal energy of uranium or CO_2 against the capacity factor of a nuclear or coal-fired power plant). Most power plants (coal, oil, nuclear) cannot be started quickly and there is a problem accommodating the fluctuating power delivery from wind and solar. To some extent, this fluctuating power delivery may be accommodated by transferring solar and wind power from one part of a grid where it is being generated to another part of a grid where generation is lacking. However, this requires excess power capacity and flexibility in switching power around a grid that may not be available because of limitations in line capacities. The main current solution to pick up rapid shortfalls in power generation is gas-fired power plants; these plants can change their generating load relatively rapidly (hydroelectric power plants are also very flexible but opportunities to build new hydroelectric power plants are limited). However, the rapid growth in wind and solar has required an almost one-to-one building of gas-fired power plants to back-up these fluctuating renewable resources.

Geothermal power plants have traditionally been run at or near full generating capacity because the plants were designed to operate most efficiently in that mode. However, within limits, the resource is not required to be withdrawn at the full capacity of the generating plant, and, with changes in design, plants can be constructed to provide power to the grid as needed up to the capacity of the system. Such a mode of operation lowers the efficiency of the geothermal power generation, but provides an alternative solution to standby gas-fired power plants. Flexible geothermal operations have recently been demonstrated by several projects, including the Puna Geothermal Venture plant which generates 38 MW, and has contracted 16 MW of flexible capacity in Hawaii (Nordquist et al. 2013; GEA 2015a). (Operators in the Geysers field, located in northern California, operated in various modes in the past, including traditional base load, peaking, and load-following. However, flexible operations ceased in the early 1990s in response to low demand and lower costs of generation within the utility's system from hydro, coal, and natural gas power plants.) Most growth in geothermal power production is for base-load electricity, especially in countries where geothermal is primary growth in the nations' electricity system. This report concentrates growth in base-load, geothermal electrical power production. A major source of information for this summary has been reports from the GEA, with special reference to the 2015 Annual U.S. & Global Geothermal Power Production Report (GEA 2015b).

United States Geothermal Development 2014–2015

The overall geothermal installed generating, or nameplate capacity was about 3.5 GW with about 2.7 GW net capacity in 2014–2015. As discussed in the introduction, the difference in these two numbers is primarily in energy used to operate pumps used to produce and dispose of the geothermal fluids: the net capacity rather than the nameplate

capacity should be used when calculating capacity factors for geothermal power plants. There was little significant growth in online geothermal generating capacity in the U.S. market in 2014–2015 but there was about 1250 MW of geothermal power under development with about 500 MW in limbo awaiting power-purchase agreements (PPAs). There was an increase in the number of states in which geothermal projects were under development (Fig. 7). Expansion of geothermal in the U.S. market was limited by almost no growth in demand for new power, and uncertainties and unbalanced mechanisms for valuing new power in terms of tax credits and other financial incentives. The uncertain U.S. geothermal market resulted in consolidation and restructuring of a number of companies in the U.S. market. The U.S. geothermal industry will be closely watching the final result of the U.S. Environmental Protection Agency Clean Power Plant rule and individual state actions that encourage clean power that supplies base-load power and balances intermittent supplies of clean energy. The developing planned and installed geothermal capacities by state and number of developing projects by state are shown in Figures 8 and 9. The locations of these geothermal power plants are shown in Figure 10.

U.S. Department of Energy Geothermal Programs

The U.S. Department of Energy is currently funding two programs associated with geothermal. The first program is a play fairways exploration program, following the play fairways concept in hydrocarbon exploration. The purpose of this program is to develop concepts of geothermal exploration models for different types of geothermal resources in type geological/tectonic/geothermal settings. The second program is to assist in developing technologies for mineral recovery from geothermal brines with a particular emphasis on rare earth, strategic, and other valuable minerals. The Frontier Observatory for Research in Geothermal Energy (FORGE) is a third program for which participant teams have been selected and funding is scheduled to start in later 2015. The first two phases of this program are to select a site for the ''observatory.'' The third phase is to develop a crystalline basement Enhanced Geothermal Systems (EGS) system that will serve as a research test site for scientists and engineers.

The budget for the Department of Energy Geothermal Technologies Office increased by more than 20% from FY2014 to FY2015. The presidential budget requests a further 74.55% increase for FY2016 (Table 4). However, indications at the time of writing this report (June 2015) are that the Congressional Budget Committee will reduce the geothermal budget to something close to the FY2014 level rather than approve an increase. A more optimistic outlook at this time is level funding for FY2016.

International Geothermal Development

For the third consecutive year, the global power industry sustained a 5% growth rate. The world market reached 12.8 GW of geothermal power operational through 24 countries with primary growth in Turkey, Kenya, Indonesia, and the Philippines (Figs. 11, 12). There are also 11.5–12.3 GW of planned capacity additions in 80 countries and 630 projects as of the end of 2014. Fourteen of those 80 countries are expected to bring 2 GW of power online over the next 3–4 years based on current construction and the GEA predicts that the global market will reach between 14.5 and 17.6 GW by 2020 (Figs. 11, 13).

Two factors are spurring the growth in the international geothermal market both in terms of the installed capacity and in the number of participating countries. The first factor is that geothermal energy is a cost-competitive green renewable energy source and part of the solution toward lowering the emissions that contribute to global climate change. This factor allows the World Bank's Energy Sector management Assistance Program (ESMAP) to mobilize assistance through the Clean Technology Fund toward scaling up geothermal energy. The second factor is that geothermal energy is a domestic resource that is available in many countries that are lacking in other energy resources: high-grade geothermal resources are generally concentrated on active plate boundaries that lack mature sedimentary basins rich in fossil fuels. The World Bank and other multi-lateral organizations focused on early-risk mitigation has funded a number of programs to initiate development in a number of geothermal-rich/fossil-fuel poor nations where surface exploration has been completed but additional financing is

Figure 7. States with operational and/or developing geothermal generating projects. Source GEA (2012).

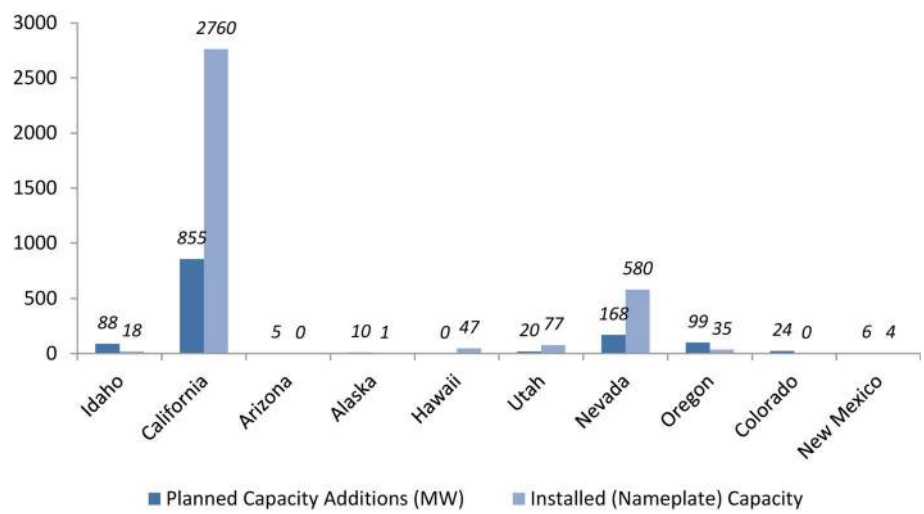


Figure 8. Planned capacity additions under development and installed nameplate capacities in the U.S. by state. Planned capacity additions are the estimated installed capacities in MW of the power plants. Source GEA (2015b, Fig. 7).

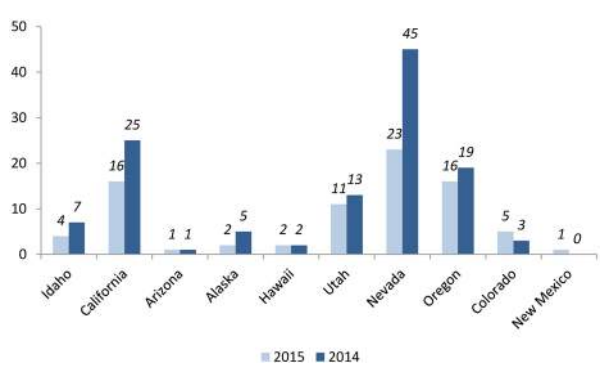


Figure 9. Number of U.S. developing geothermal generating projects by state. During the past few years, demonstration and exploration projects have occurred in additional states such as Washington, Texas, North Dakota, Louisiana, Montana, Mississippi, and Wyoming. Source GEA (2015b, Fig. 8).

needed to confirm the commercial viability of the geothermal resources. ESMAP estimates that as many as 40 countries could meet a large proportion of their electricity demand through geothermal power (World Bank 2014). Some of this development is illustrated in Figures 14, 15.

Job Creation

Geothermal development requires a wide range of skills and hundreds of people are typically employed in the siting and building of a geothermal power plant. This number decreases to tens in the actual operation and maintenance of the plant. In common with many natural assets, most geothermal resources have unique local characteristics so that exploration for the resources, engineering the sustainable development of the resource, and even power plant design are tailored to the specific physical and chemical qualities of the resource. Scientific and technical professionals with degrees, such as geologists, geochemists, geophysicists, and

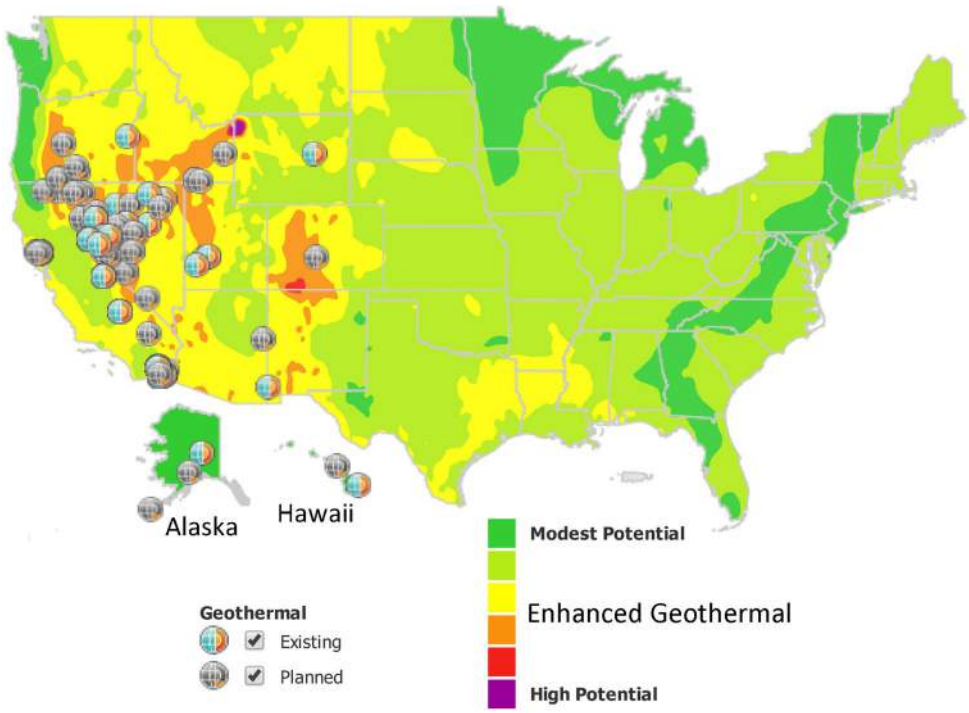


Figure 10. Existing and planned geothermal power plants in United States (modified from NRDC (2015). Colors show the relative potential for enhanced geothermal resources (i.e., recovered through the creation of engineered geothermal systems) in the basement.

Table 4. Enacted Budgets from the Department of Energy for the Geothermal Technologies Office for FY2014 and FY2015 and the Requested Budget to FY2016

(Dollars in Thousands)	FY 2014 Enacted	FY 2015 Enacted	FY 2016 Request
Enhanced geothermal systems (EGS)	27,084	32,100	45,000
Hydrothermal	10,285	12,500	36,500
Low temperature and coproduced	4708	6000	9000
Systems analysis	3698	3900	5000
NRfcLSitewide	0	500	500
Total, geothermal technologies	45,775	55,000	96,000

Source U.S. Department of Energy (2015).

engineers are essential in resource exploration, development, and operation. In the development of the resources, trained technical workers, such as drill-rig operators, welders, mechanics, and safety managers, are the main players. Behind the scenes, an additional professional workforce of project managers, assembly workers, administrative staff, archeologists, sales managers, and lawyers provide support services for the development of renewable resources (Jennejohn 2010). An example of the types of skills required in the different stages of the development of a geothermal resource is shown in Figure 16, together with the typical number of persons employed in each stage of development for a 50 MW power plant. Many resources are not initially developed to their full potential and additional capacity is added to the geothermal field after a few or more years of successful operation. Therefore, the high rate of employment during the development and building stage of a power plant may be extended by a decade or more as more capacity is added to the exploitation of a geothermal system.

Global Technology and Manufacturing

There are three basic common types of geothermal electrical power generation: dry steam,

flash, and binary. With dry steam, the resource is sufficiently hot that there is no water associated with the geothermal fluid. Steam is delivered directly into a turbine to rotate a generator to make electricity. Condensed steam is reinjected to replenish the geothermal reservoir. Resources associated with flash power plants are either a mixture of water and steam or superheated water and flashed to steam and water when the pressure is reduced at the surface. The steam is separated, delivered to a turbine to generate electricity as with the dry steam plant. The water is eventually reinjected to maintain the reservoir fluid. Binary plants use the lowest temperature resource of the three types of plant, and the geothermal fluid is used to heat a secondary fluid, with a lower boiling temperature than water, in a heat exchanger. The geothermal fluid is then returned to the geothermal reservoir to be reheated. The secondary fluid is vaporized in the heat exchanger and is used to turn a turbine or screw-expander, which is used to rotate a generator to produce electricity. As the secondary fluid exits the turbine or screw-expander, it is cooled and condensed and pumped back to the heat exchanger to be recycled. Two types of secondary fluids are commonly used: organic fluids (Organic Rankine Cycle type power plants), and a mixture of ammonia and water (Kalina power plants).

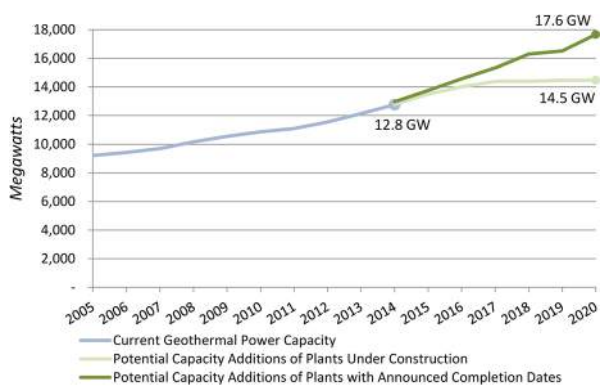


Figure 11. International geothermal power nameplate capacity (MW) from 2005 to 2014 (actual) and projected to 2020. Planned capacity additions, pilot plants, and utility-scale geothermal plants built in the first half of the 20th century and then decommissioned are excluded in the time series. Source GEA (2015b, Fig. 1).

The cost of the power plants per megawatt of electricity generated increases as the temperature of the geothermal fluid decreases, as shown in Figure 17. The primary reason for this increase in cost is the decrease in efficiency of generation as the temperature decreases: the efficiency roughly depends on the difference between the input and output temperature of the fluid entering and exiting the turbine or screw-expander. However, this simply translates into a slower amortization of the exploration and development costs with low-temperature resources. The fuel is essentially free. Efficiencies may be improved by multiple-stage or hybrid plants in which superheated water is flashed first to a pressure greater than atmospheric pressure and then a second time to atmospheric pressure with steam

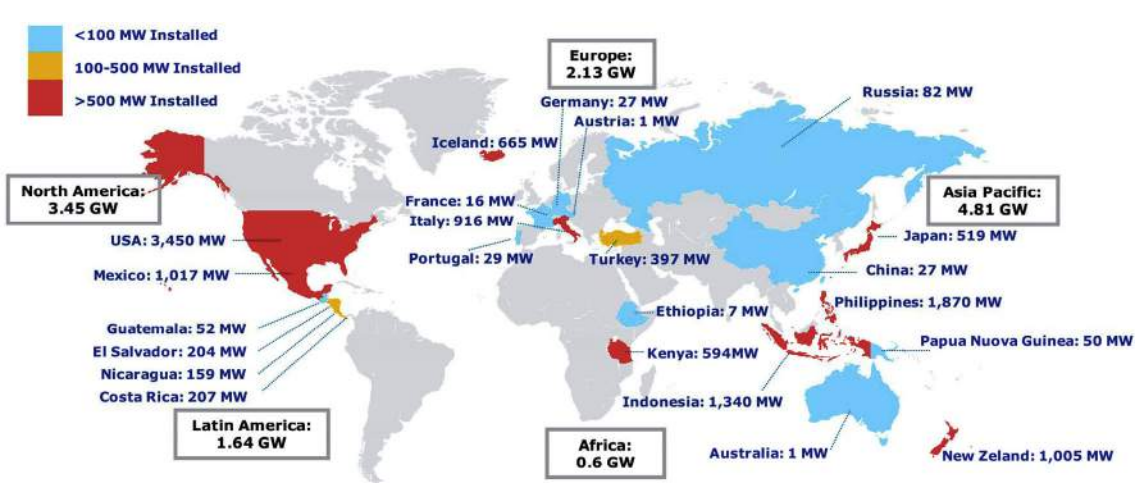


Figure 12. 2015 geothermal installed capacity (nameplate). Source Bertani (2015).

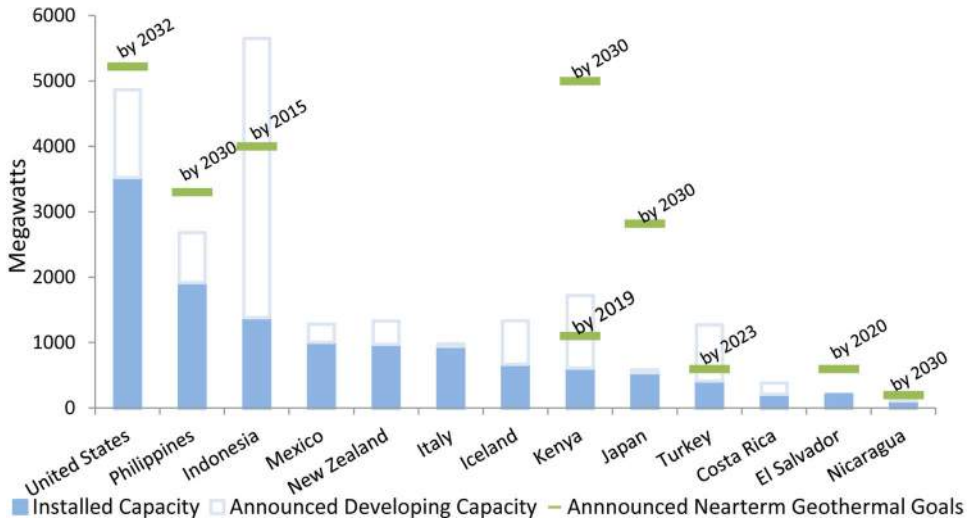


Figure 13. Major international geothermal markets, installed capacity, announced developing capacity, and announced near-term geothermal goals which include government and private sector development goals. Mexico has set a general renewable energy goal of 35% from renewables by 2024; however, this goal is not geothermal specific. The U.S. goal is the Imperial Irrigation District's objective of building out geothermal capacity at the Salton Sea Resource Area by 2032. Estimates are rounded to nearest 5 MW and ''net capacity'' was used when nameplate capacity was not available. Source GEA (2015b, Fig. 2).

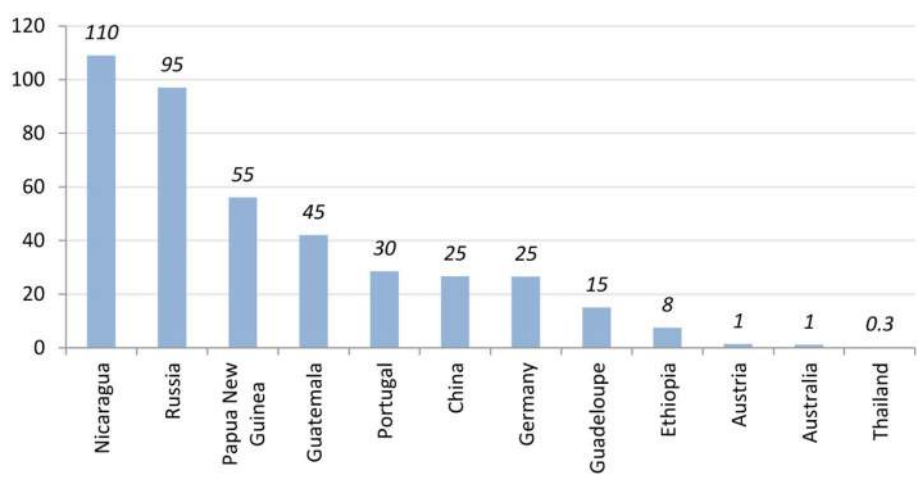


Figure 14. Totals of developing nameplate capacities in MW in developing markets. Estimates are rounded to the nearest 5 MW and ''net capacity'' is used when nameplate capacity was not available. Source GEA (2015b, Fig. 4).

used to turn a turbine at each flashing stage. Alternatively, hot water from a flash power plant may be directed to a binary power plant for power generation in a hybrid power plant. There are many options of improving the efficiency of single-stage power plants, the most simple of which is to use condensed hot water from the turbine for direct use, a common practice in northern Europe.

Developing nations with high-temperature geothermal resources are primarily building flash power plants. The manufacture of equipment for this market is dominated by Japanese companies, such as Mitsubishi, Toshiba, Fuji, and Ansaldo/Tosi. General Electric has a small, but significant share (5–6%). In Europe and the U.S., most new plants are binary power plants and are of the Organic

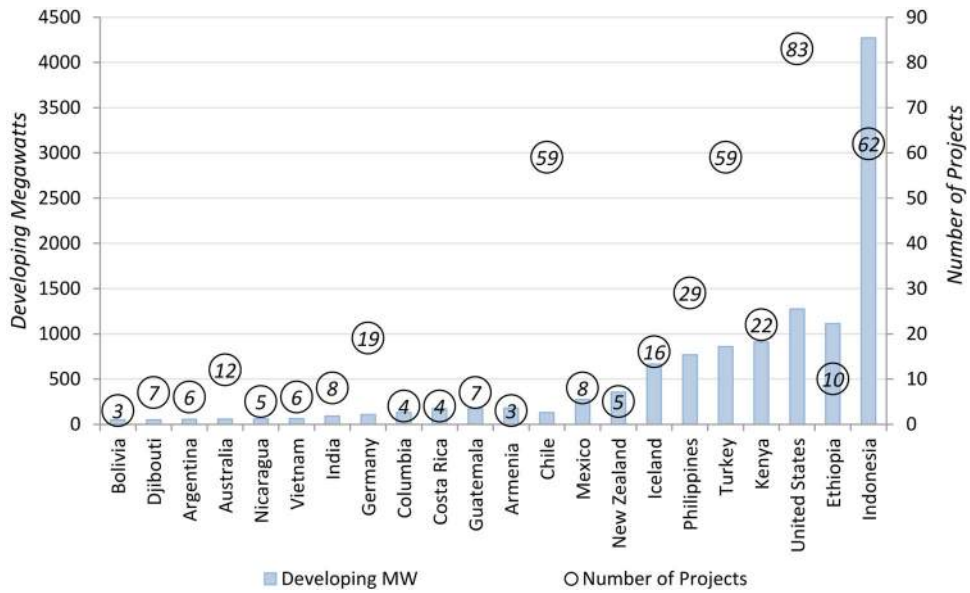


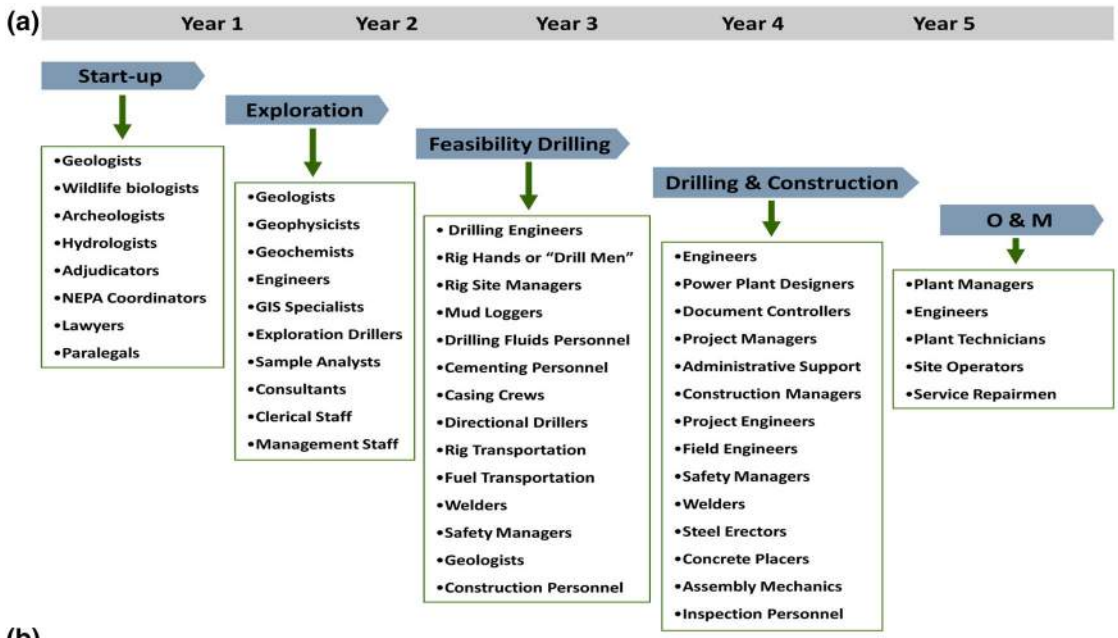
Figure 15. Totals of developing capacity and numbers of projects by country or territory. The large amount of developing capacity for Indonesia could be the result of a backlog of projects stalled by prolonged power-purchase agreements, delayed permits related to the use of conservation or protected areas and resistance from local communities. Source GEA (2015b, Fig. 5).

Rankine Cycle type. This market is dominated by Ormat. A current breakdown of equipment suppliers is given in GEA (2015b).

Concluding Remarks

The international geothermal energy market is enjoying steady sustained growth and that growth is expected to continue. The growth is based primarily on countries with the domestic availability of high-grade geothermal resources but a lack of other fuel resources from which to generate electricity. In other countries, growth in the use of geothermal resources is more erratic and more dependent on baseline energy prices, reliability of supply of fossil-fuel resources (short- and long-term), and government policies and incentives. For example, in most of Europe, geothermal resources are low grade, but energy prices are high, and there are incentives, either through individual countries or through European Economic Community grants to develop alternative energy resources. Germany currently receives most of its natural gas supplies from Russia and would like to reduce its dependence on this source. It has an aggressive program to use alternative energy sources. It has installed about 27 MWe geothermal electricity generating capacity, but about 150 MWt thermal geothermal district heating capacity using resources with insufficient temperature to generate electricity (Agemar et al. 2014).

The U.S. continues to lead the world in installed geothermal generating capacity and annual geothermal electricity production. However, growth was stalled in 2015, and despite pressure for increased green generating capacity in the U.S., there are few incentives from the federal and state governments for geothermal development and many regulations that slow development. Programs pursued by the Department of Energy Geothermal Technology Office look far into future, perhaps too far into the future. Most of the funds from this office in past years have been used for studies of EGS: the feasibility of this technology was demonstrated at Fenton Hill, New Mexico, by scientists at the Los Alamos National Laboratories in the 1970s and 80s,



(b)

Stage of Development	No. of jobs
Start-up	10 – 13
Exploration	11 – 22
Drilling	91 – 116
Plant Design and Construction (EPC)	383 – 489
Operation and Maintenance	10 – 25
Power Plant System Manufacturing	192 – 197
Total	**697 – 862**

Figure 16. A. Job types through the project timeline for the exploration and development of a new geothermal field. B. Typical numbers of jobs involved in the different stages in the project timeline for the exploration of a new geothermal field and development of a 50 MW power plant. Source Jennejohn (2010, Fig. 1 and Table 2).

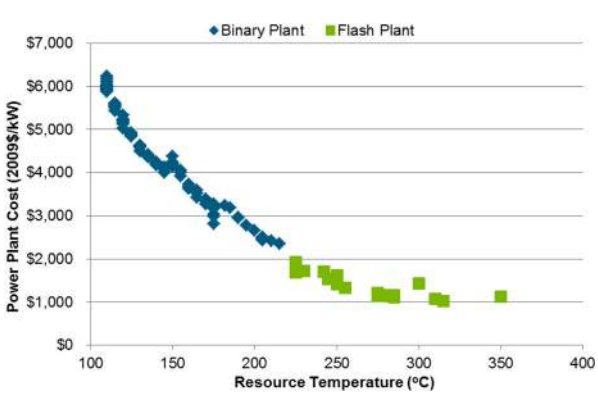


Figure 17. Power plant capital costs (2009$/kW) estimated by Geothermal Electricity Technology Evaluation Model and used in RE Futures for hydrothermal power plants. Source NREL (2012, Figs. 7–5).

but it was far from economic. Experiments in the U.S. and around the world during the past 30 years have made little improvement on the economics. There have been great improvements in geothermal power plant technologies, however, that allow electricity to be generated with lower temperature resources than was possible in the 1980s. Thirty years ago, sedimentary basins were not fertile grounds for generating electricity. Today the low hanging fruit for a new horizon for geothermal resources is sedimentary basins as electricity can be generated at temperatures in the high-end of the oil and gas window. This horizon is the perfect interface for hydrocarbon developers and geothermal as it is the backyard for oil and gas drilling.

SHALE GAS AND LIQUIDS

Neil Fishman,[13] with contributions from Kent Bowker, Harris Cander, Brian Cardott, Marc Charette, Kenneth Chew, Thomas Chidsey, Russell Dubiel, Sven Egenhoff, Catherine Enomoto, Ursula Hammes, William Harrison, Shu Jiang, Julie LeFever, Jock McCracken, Stephen Nordeng, Richard Nyahay, Stephen Sonnenberg, Michael D. Vanden Berg

Introduction

As the source rocks from which petroleum is generated, organic-rich shales have always been considered an important component of petroleum systems. Over the last few years, it has been realized that in some mudrocks, sufficient hydrocarbons remain in place to allow for commercial development, although advanced drilling and completion technology is typically required to access hydrocarbons from these reservoirs. Tight oil reservoirs (also referred to as continuous oil accumulations) contain hydrocarbons migrated from source rocks that are geologically/stratigraphically interbedded with or occur immediately overlying/underlying them. Migration is minimal in charging these tight oil accumulations (Gaswirth and Marra 2014). Companies around the world are now successfully exploiting organic-rich shales and tight rocks for contained hydrocarbons, and the search for these types of unconventional petroleum reservoirs is growing. Unconventional reservoirs range in geologic age from Ordovician to Tertiary (Silverman et al. 2005; EIA 2013a).

North America

The significance of production of petroleum from shale gas/oil and tight oil reservoirs is nowhere more clearly illustrated than in North America (Figure 18). Some of the largest oil and gas fields currently under production in the U.S. are producing from these types of unconventional reservoirs (EIA 2015v). Production from these reservoirs has been instrumental in a recent ranking of the U.S. as the World's leading nation in production of petroleum and other liquids (EIA 2014c). Steep increases in shale gas and tight oil production in the U.S. since 2007 (EIA 2014d) have been realized (Figs. 19, 20), and overall, six tight oil and shale plays (e.g., Eagle Ford Formation, Bakken Formation, Niobrara Formation, various rocks in the Permian Basin, Haynesville Shale, and the Marcellus Shale) are collectively responsible for almost 90% of the growth in U.S. oil and gas production (EIA 2014d). Projections (Figs. 21, 22) indicate that shale gas and tight oil production will increase into the coming decades (EIA 2014d).

Although now booming, unconventional reservoir production has been occurring for almost 200 years in the U.S. The first documented production of natural gas from shales was that from Devonian rocks in New York in 1821 (Hill et al. 2008). The gas was used to light street lamps in at least one town (Roen, 1993). Although this early production proved that gas could be successfully exploited from mudrocks, shale gas production remained low. It was not until 2005 that shale gas production became a significant and growing component of the total gas produced in the U.S. (Fig. 21). By 2013, roughly 40% of gas produced in the U.S., almost 12 Tcf (339.6 billion m^3), was from shale, surpassing that produced from non-shale wells (EIA 2014e). Experts project that, by 2040, roughly 50% of domestic gas production will be from shales (Fig. 21).

Examples of how shales have contributed to overall increases in production in some states in the U.S. can be seen in Figure 23. In Texas, for example, exploitation from the Mississippian Barnett Shale resulted in the statewide increase in gas production starting in 2004 (EIA 2012), even though Barnett production began more than 10 years earlier (Steward 2007). The additional statewide jump in gas production observed in 2011 for Texas was caused by exploitation from the Cretaceous Eagle Ford Formation as well as the Jurassic Haynesville Shale (EIA 2014d). The Haynesville is also responsible for the statewide increase in gas production in Louisiana, whereas production from the Mississippian Fayetteville Shale (Fig. 19) resulted in the statewide increase for Arkansas. The Devonian Marcellus Shale is responsible for the significant increase in gas production in Pennsylvania and West Virginia (EIA 2013b), and production from the Ordovician Utica/Point Pleasant Formations in Ohio and Pennsylvania is noteworthy. Shale gas development in Canada, although in its infancy, is also underway from the Devonian Horn River Formation and the Triassic

[13] Hess Corporation, 1501 McKinney Street, Houston, TX 77010 USA; Chair, EMD Gas Shale and Liquids Committee .

Figure 18. Locations of shale and tight oil plays in North America. From EIA (2011).

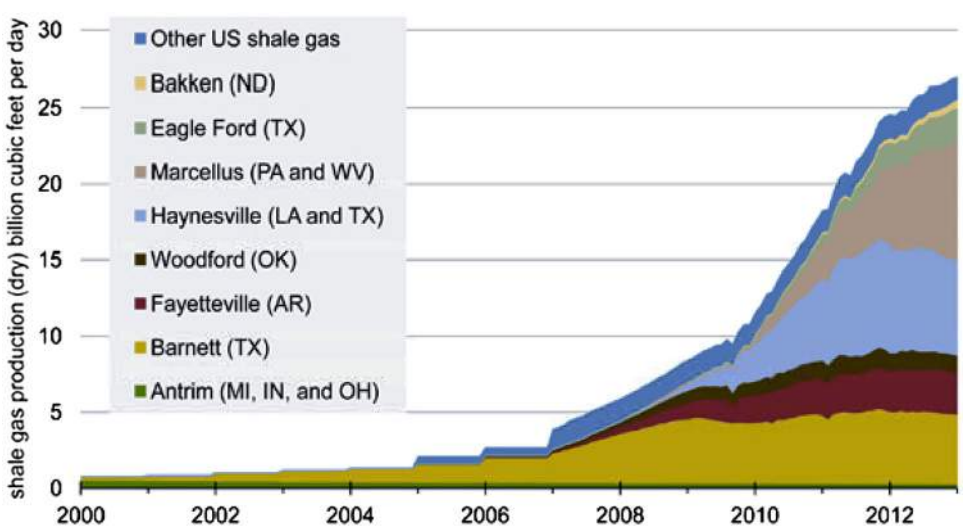


Figure 19. Shale gas production for various shales in the U.S. from 2000 to the present. (ND, North Dakota; TX, Texas; PA, Pennsylvania; WV, West Virginia; LA, Louisiana; OK, Oklahoma; AR, Arkansas; MI, Michigan; IN, Indiana; OH, Ohio). From EIA (2014e). 1 billion cubic ft = 28.3 million m^3.

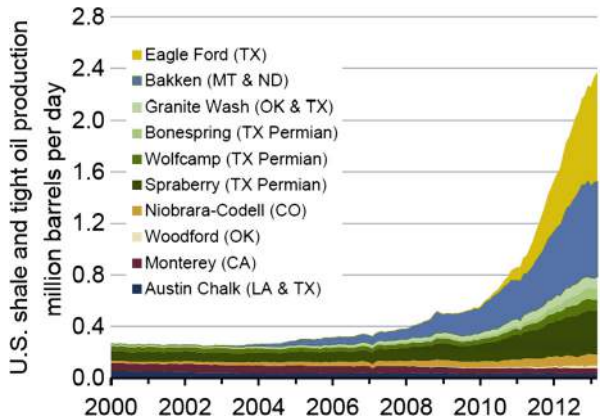


Figure 20. Tight oil production for various rocks in the U.S. from 2000 to the present. (CA, California; CO, Colorado; LA, Louisiana; ND, North Dakota; MT, Montana; LOK, Oklahoma; TX, Texas). From EIA (2014e). 1 million barrels (oil) = 158,987 m^3.

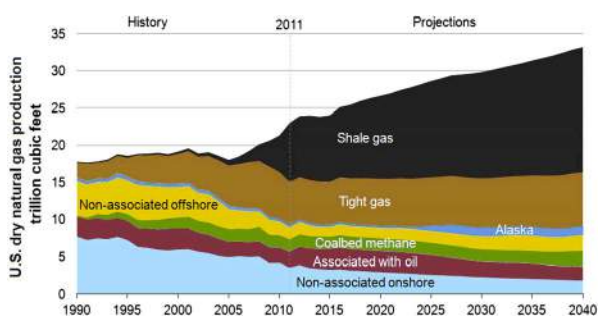


Figure 21. Historical production from U.S. of natural gas reservoirs through 2011, and then projection of gas production through 2040. Note that shale gas production becomes significant by 2010, and is projected to dominate by 2040 (EIA 2014e). 1 Trillion cubic feet (Tcf) = 28.3 billion m^3.

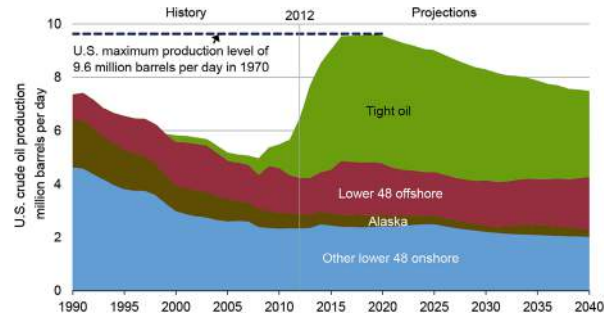


Figure 22. Historical crude oil production in the U.S. through 2012, and then projection of through 2040 (EIA 2014e). 1 million barrels (oil) = 158,987 m^3.

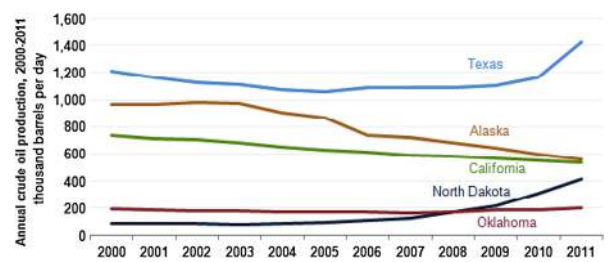


Figure 23. Shale crude oil production for various states in the U.S. during 2000–2011. The increase in production is Texas in 2011 is due to exploitation of the Eagle Ford Formation. The increase in oil production in North Dakota since 2005 is largely due to exploitation of the Bakken Formation. From EIA (2012). 1 thousand barrels (oil) = 159 m^3.

Montney Formation in western Canada (Jock McCracken, written communication 2015).

After a general decline that began in 1970 (EIA 2015w), production of oil from tight plays in the U.S. has contributed to the observed reversal in domestic oil production (EIA 2014f). The increase in production of tight oil is most apparent in North Dakota, because of exploitation of the Late Devonian-Early Mississippian Bakken Formation. Oil and condensate production from the Eagle Ford Formation in Texas (Fig. 23) also has contributed significantly to an overall increase in domestic production in the U.S. (EIA 2014d). The Bakken Formation in Manitoba and Saskatchewan is also producing oil (Jock McCracken, written communication 2015). Oil produced from the Late Devonian-Early Mississippian Woodford Shale has helped to keep production levels up in Oklahoma over the past decade (Fig. 20). The production of tight oil from various reservoirs in the Permian Basin of Texas and New Mexico continues to contribute significantly to overall domestic production increases in the U.S.

Although there is active exploration elsewhere in the world for unconventional gas and oil, successful exploitation is limited. Active commercial production from shales and tight oil reservoirs is occurring in only four countries, the U.S., Canada, Argentina, and China (EIA 2015x). The Upper Jurassic/Lower Cretaceous Vaca Muerta Formation in Argentina has seen some limited oil production (Fig. 24) and has the potential for both shale gas and shale oil (EIA 2013a). Cretaceous organic-rich rocks

in Columbia, including the Cretaceous La Luna Formation, also have potential as unconventional shale gas and oil reservoirs (EIA 2013a), but exploration and exploitation of these reservoirs is not as mature as that in North America. The Silurian Longmaxi Shale has seen some commercial success in the Sichuan Basin of China (EIA 2015x). Overall, Europe remains relatively unexplored compared to North America, with Paleozoic and Mesozoic organic-rich rocks as potential exploration targets. Nevertheless, decisions to scale back exploration efforts have made it difficult to evaluate what the future holds for European shale gas and tight oil exploitation (Ken Chew, written communication 2015). As with Europe, many parts of Asia remain relatively unexplored for shale gas and tight oil, but interest in these unconventional reservoirs remains high. Australia, China, New Zealand, India, and Japan all have an interest in exploration for shale gas and oil (Shu Jiang and Jeff Aldridge, written communication 2013).

TIGHT GAS SANDS

Dean Rokosh,[14] Shar Anderson[15]

Executive Summary

Tight gas is an unconventional hydrocarbon resource within reservoirs that are low permeability (millidarcy to microdarcies range) and low porosity. Extracting gas from these reservoirs in economic quantities requires technological effort to artificially enhance the permeability of the reservoir (fracturing and/or acidizing the formation). Tight gas sand plays are being tested and developed in many countries outside of the U.S., including Canada, Australia, China, and the Ukraine. McGlade et al. (2012) use prior publications and estimate 54.5 Tcm (1914 Tcf) of technically recoverable tight gas from 14 regions or countries in the world. The following summary represents a few of the tight gas sands worldwide, beginning with the U.S. (Fig. 25).

[14] Alberta Energy Regulator, Alberta Geological Survey, Edmonton, AB T6B 2X3, Canada; Chair, EMD Gas (Tight) Sands Committee.

[15] Alberta Energy Regulator, Alberta Geological Survey, Edmonton, AB T6B 2X3, Canada.

United States

Dew–Mimms Creek Field, East Texas Basin, U.S.. The Bossier Formation sandstones in the Dew–Mimms field are part of the Jurassic Cotton Valley Group that underlies most of the northern coastal plain of the Gulf of Mexico. The Dew–Mimms Creek field produces from a series of stacked, discontinuous, and lenticular sand-shale successions at depths of 12,400–13,200 feet (3780–4023 m) containing 75–100 feet (23–30 m) of net sand with average porosity ranging from 6 to 10%. Estimated ultimate recoveries (EURs) per well vary from 1 to 4 Bcf (28.3–113.2 million m^3).

Jonah Field, Green River Basin, Wyoming, U.S. The Upper Cretaceous Lance Formation sands are the main producing interval in the Jonah field, northwestern Green River Basin, Wyoming with a thickness ranging from 2000 feet (609 m) in the southwest to 3000 feet (914 m) in the northeast. What distinguishes the Jonah field are the large net pay thickness of the low-permeability sandstones, a ''clear structural component to the gas accumulation'' (Harris et al. 2013) and the large areal extent of the field. The Jonah field is delineated on a structural feature that has converging faults along flanks of the Pinedale anticline with up-dip trapping against boundary faults. The Jonah field contains a succession of 20–50 fluvial channel sands each 10–25-feet (3.0–7.6 m) thick that are stacked into sequences up to 200 feet (61 m) thick at a depth of 11.000–13,000 feet (3353–3962 m). Porosity ranges from 5 to 14%. Initial well rates ranged from 1.3 to 6.1 MMcfd (36,812–172,733 m^3) with EURs ranging from1.5 to 5.7 Bcf (4.25×10^7–1.614×10^8 m^3) per well.

Mamm Creek Field, Piceance Basin, Colorado, U.S. This field is located in the structurally deepest part of the Piceance Basin (Cumella and Ostby 2003). The main producing interval is the 2000-foot-(610 m) thick, overpressured, and faulted Upper Cretaceous Williams Fork Formation which consists of discontinuous (30–70 acres; 12–28 ha), lenticular fluvial to marine sands at a depth of 4500–8500 feet (1372–2591 m). An additional contribution to production comes from the more continuous marine sandstones of the Corcoran, Cozzette, and Rollins Members at 7000 feet (2130 m) deep. Cumella and Ostby (2003) estimated porosity at about 6–12% and permeability from 0.1 to 2 μD (0.0001 to 0.02 mD).

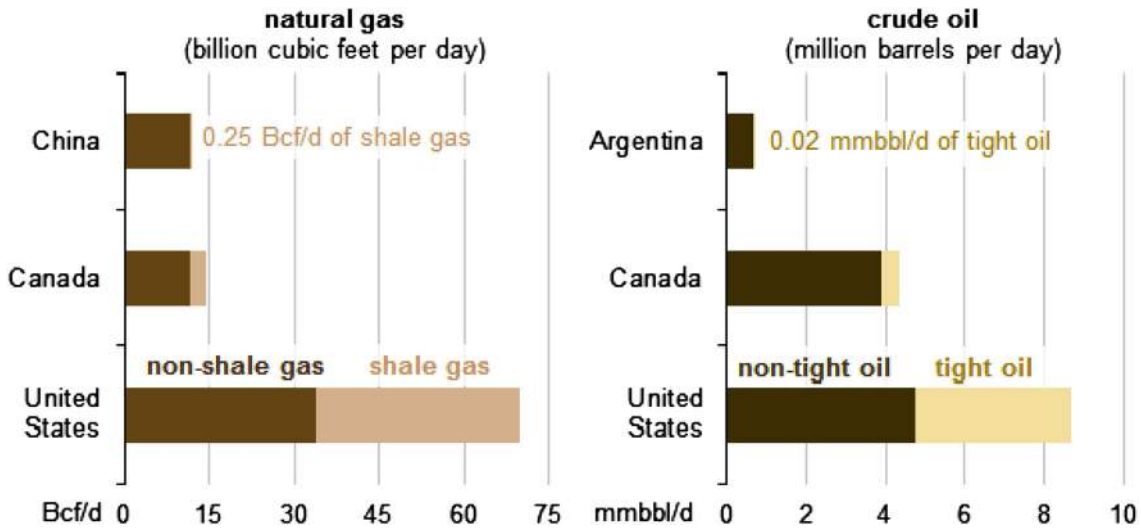


Figure 24. Production of natural gas from both shale and non-shale reservoirs in the U.S., China, and Canada as well as production of crude from tight oil reservoirs in the U.S., Canada, and Argentina (EIA, 2015x). 1 billion cubic ft = 28.3 million m^3; 1 million barrels (oil) = 158,987 m^3.

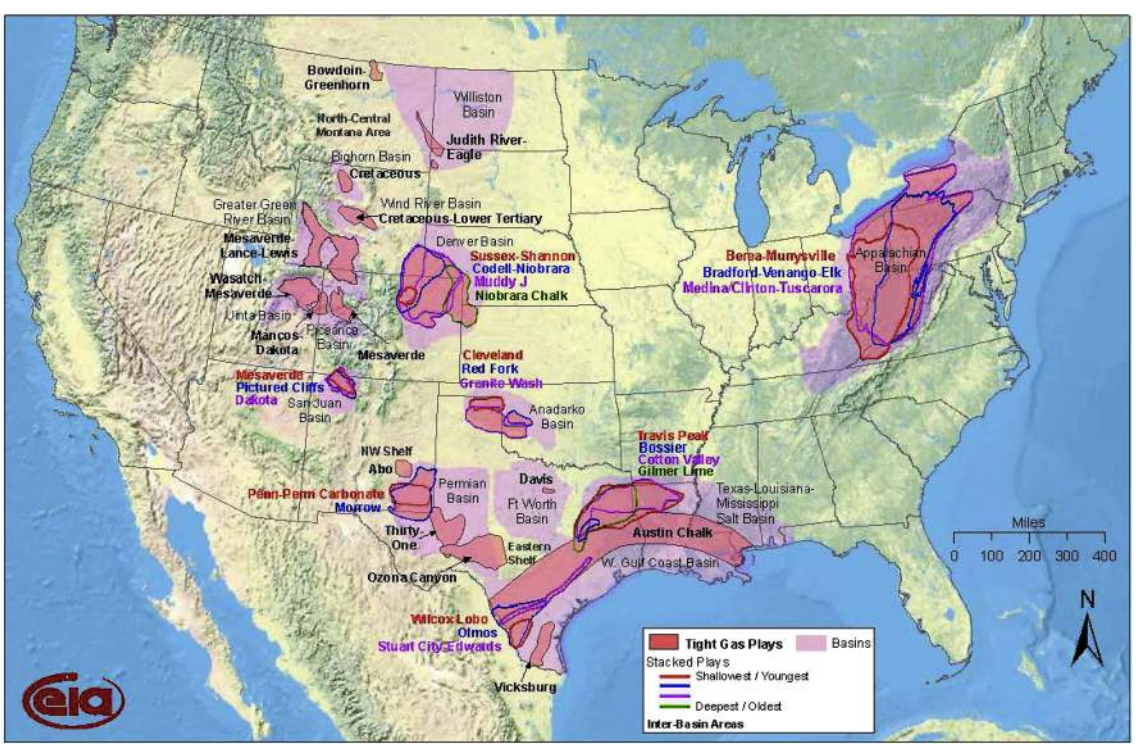


Figure 25. Major tight gas plays in the USA. From EIA (2010b).

Wamsutter Development Area, Green River Basin, Wyoming, U.S. This area in the greater Green River Basin of Wyoming contains an estimated 50 Tcf (1.42 trillion m^3) of OGIP. The reservoir consists of stacked marine and fluvial sands of the Upper Cretaceous Almond Formation, Mesaverde Group, and numerous turbidites within the Lewis Shale. The Almond Formation ranges from 250 to >500 feet (76–152 m) thick, with variations in thickness and lithologies related to basement block-fault structures. In the Wamsutter field, the Upper Almond Formation is generally encountered between depths of 8500 and 10,500 feet (2590 and 3200 m) with a porosity of 8–12% porosity and an average net pay from 50 to 80 feet (15–24 m) per well. Completion depths range from 7000 feet (2133 m) for Lewis Shale wells to 12,200 feet (3718 m) for Almond wells. A typical initial gas rate for a fracture stimulated well is 1 MMcfd (28.3 thousand m^3 per day) with an average recovery of 2 Bcf (56.6 million m^3) per well.

Western Canada Sedimentary Basin, Alberta, Canada

Unconventional technologies are being used for basin-centered accumulations, and enhanced recovery within and surrounding older conventional fields. Horizontal multistage fractured (HMSF) gas/liquid well completions increased from 626 to 846 wells from 2013 to 2014, while HMSF oil well completions decreased from 1612 to 1506 during the same period.

Cardium Formation, Alberta. This formation with >10 billion barrels (>1.59 billion m^3) of oil-in-place has cumulative production (1957–2009) of ~1.75 billion barrels (280 million m^3). It spans about 36 square miles (9320 ha^2) or 23,040 acres in central and southern Alberta. Sandstone reservoirs are largely in three-stacked successions of largely marine sandstones occurring between 3937 and 9186 feet (1200–2800 m) depth and contain mainly light oil with varying amounts of dissolved gas, along with more gas-rich pools toward the north. Conventional sand and conglomerate reservoirs are relatively thin (13–32 feet or 4 10 m) and a porosity of 6–15%.

A sharp increase in horizontal drilling occurred in 2009 largely focused on the fringe or halo areas of existing pools. Halo or tight fringe refers to the area surrounding a conventional field. These areas are developed using unconventional technology; for example, the Pembina (Fig. 26) field of central Alberta, where the Cardium occurs at 4265 feet (1300 m) depth. Estimated ultimate recovery typically ranges from about 50,000 barrels (7950 m^3) to >100,000 barrels (>15,900 m^3) with an upper limit of about 250,000 barrels (39,750 m^3) equivalent per well.

Nikanassin Formation, NE British Columbia and NW Alberta. This formation has thinner (5–15 m) fluvial channel and thicker (>50–500 m; >164–1640 ft) incised-valley-fill reservoir sandstones, with porosities of 6–10%, and permeability of 0.01–1 l D. Reservoir sandstones are quartz-rich, highly cemented, brittle, and, where productive, extensively fractured. The Nikanassin is a structural play where thrust-belt tectonics has fractured the brittle sandstones to enhance porosity/permeability. Gas was generated in the associated coals with regional conventional trapping. Nikanassin development fairways are along the leading edges of the NW–SE trending thrust faults. Early returns show production up to 3.2 Bcf (90,000,000 m^3) per well (Oil and Gas Inquirer 2012).

Montney Formation, NE British Columbia and NW Alberta. This Triassic formation continues to be a focus of activity in British Columbia and Alberta even in a lower price environment. The resources in this formation are classified as both shale gas (British Columbia) and tight gas (Alberta) because there is a discrepancy between the formation definitions across the provincial boundaries and each province is producing from different facies within the formation.

The Montney Formation is a thin-bedded succession of mixed siliciclastic lithologies up to 820–984-feet (250–300 m) thick. Lower shoreface/distal delta fringe deposits, trending east to west, of stacked siltstone and very fine sandstone overlie a deeper basinal facies of fine-grained, organic-rich mudstone/shale, cut by low stand turbidite sandstones. The delta fringe/shelf siltstones and shale in British Columbia have an estimated gas-in-place of 25–40 Bcf (0.71–1.1 billion m^3)/section, with the lower Montney turbidites having gas-in-place of 30–50 Bcf (0.85–1.4 billion m^3)/section. Porosities in these unconventional reservoirs are typically <3–10%, with <millidarcy permeabilities. Most recent drilling is focused on oil-bearing or gas/liquid-rich successions.

China

China Tight Gas Sands. Tight gas drilling and production in China is booming (Reuters 2013) with tight gas production currently accounting for about a

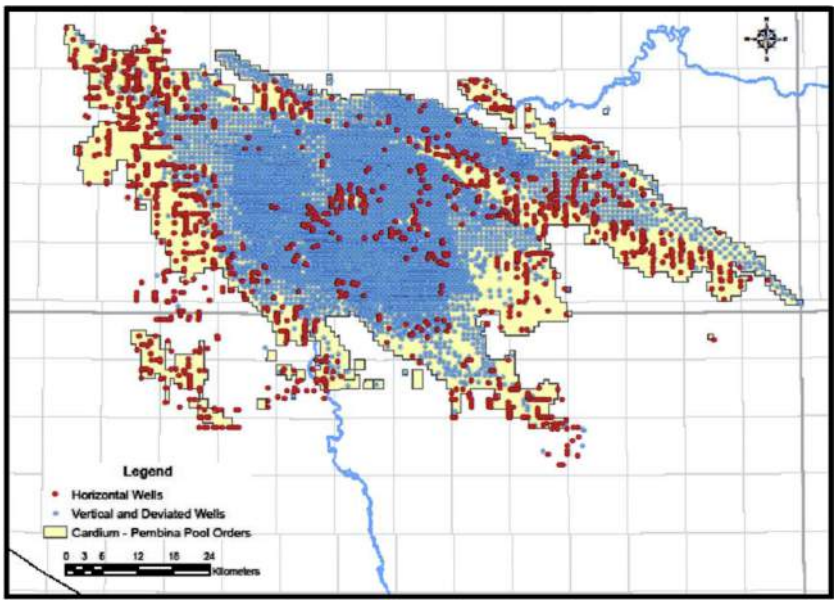


Figure 26. Horizontal wells into the 'halo' zones of one of the Cardium Formation fields in Alberta, Canada.

third of the total gas output. Present tight gas output of 30 billion m^3 (1.06 Tcf) is forecast to increase to 80 billion m^3 (2.82 Tcf) by 2020 and perhaps to 100 billion m^3 (3.53 Tcf) by 2030.

Tight gas sandstones are widely distributed in a number of basins including the Ordos, Hami (including the Taibei Depression, located in the Tuha Basin, also called the 'Turpan-Hami' Basin), Sichuan, Songliao, Tarim, and deeper parts of the Junggar Basin (Fig. 27; Table 5), with the favorable prospective areas exceeding 300,000 km^2 (116,000 mi^2).

China National Petroleum Corporation (CNPC 2010) reports that more than 5000 wells have been drilled into the Sulige Tight Gas Field in the Ordos Basin of Inner Mongolia, north-central China. The field has a potential area of 40,000 km^2, (15,400 mi^2) cumulative proven gas-in-place of 1.68 Tcf (48 billion m^3)and an upper potential of about 2.5 Tcf (70 billion m^3) (CNPC 2010). Sulige Gas field is reported to be a stratigraphic trap developed in Permian sandstone at a depth ranging from 3200 to 3500 m (10,500–11,500 ft).

The Lower Jurassic Shuixigou Group sands in Taibei Depression, Hami Basin (part of the Tuha Basin) in the Kekeya area of China contains three-stacked successions of tight gas sandstones within braided delta-front reservoirs. Burial depths range from 9186 to 14,108 feet (2800–4300 m). The field produces from a series of sand-pebbly sand, with porosity of 4–8.4% and permeability of 0.077–3.61 millidarcies. Individual sand reservoirs range from 59 to 180 feet (18–55 m), with a gross thickness of the stacked successions between 344 and 919 feet (105–280 m). The play seeks to exploit fractured reservoirs micro- and macro-scale) with the highest production from (reservoirs on structural highs. Single well gas production varies from 1.9 to 7.6×10^4 m^3/d (671–2.68 MMcf/d).

GAS HYDRATES

Arthur H. Johnson[16]

United States

From 2011 through 2015, the U.S. Gas Hydrate program at the Department of Energy (DOE) had been functioning at a low level compared, with the period 2001–2010, as the DOE has moved away from fossil energy. That approach has changed under Energy Secretary Ernest Moniz, and fossil en-

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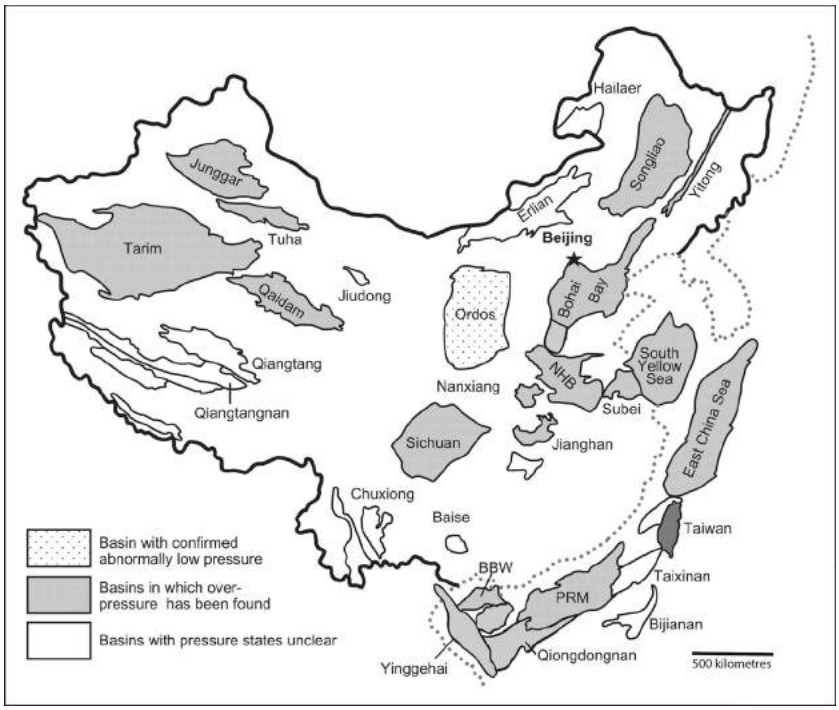

Figure 27. China's major sedimentary basins. From Hao et al. (2007). *NHB* Nanhuabei Basin, *BBW* Beibuwan Basin, *PRM* Pearl River Mouth Basin.

Table 5. Characteristics of the Main Tight Gas Sandstone Reservoirs in China (from Yukai et al. 2011)

Basin	Depth (m)	Amount of Resources (TCM)
Ordos basin	2500–4500	8.4
Sichuan basin	1500–4500	3.5
Faulted depression beneath the Songliao Basin	1500–6000	Not estimated
Southern deep layer in the Junggar Basin	4000–7000	Not estimated

1 trillion cubic meters (TCM) = 35.3 Tcf.

ergy is now being included in the federal ''All of the Above'' philosophy of energy.

Areas of gas hydrate focus are continuation of the characterization of gas hydrate in the Gulf of Mexico and a production test in Alaska. A solicitation is being released from DOE regarding the Alaska test, and the State of Alaska is working with DOE to identify a site for the test on state lands west of Prudhoe Bay Field. Industry participation will be necessary.

On October 22, 2014, the DOE announced the selection of a multi-year, field-based research project designed to gain further insight into the nature, formation, occurrence, and physical properties of methane hydrate-bearing sediments in the Gulf of Mexico for the purpose of gas hydrate resource appraisal. Under this program, the University of Texas at Austin, along with The Ohio State University, Columbia University-Lamont Doherty Earth Observatory, the Consortium for Ocean Leadership, and the U.S. Geological Survey, will characterize and prioritize known and prospective drilling locations with a high probability of encountering concentrated methane hydrates in sand-rich reservoirs. The 4-year program includes $41,270,609 of DOE funding and a cost share of $17,030,884.

The U.S. program has a two-pronged approach, focusing on both the North Slope of Alaska and the Gulf of Mexico. The next U.S. field test is being developed under the leadership of the University of Texas at Austin, in partnership with The Ohio State University, Columbia University-Lamont-Doherty Earth Observatory, the Consortium for Ocean

Leadership and the U.S. Geological Survey. Their 4-year exploratory program will characterize prospective drilling locations in the Gulf of Mexico, then in 2018 drill and collect pressure cores and well logs as well as conducting short-duration pressure drawdown tests.

The Gulf of Mexico project includes a focused drilling program that will acquire conventional cores, pressure cores, and downhole logs; measure in situ properties; and measure reservoir response to short-duration pressure perturbations. The field program will also serve to deploy and test several coring and hydrate characterization tools developed through previous DOE-supported research efforts. Post-cruise analyses will determine the in situ concentrations, the physical properties, the lithology, and the thermodynamic state of methane hydrate-bearing sand reservoirs. The goal of the project is to improve the ability to estimate the occurrence and distribution of marine gas hydrates and lay the groundwork needed to simulate production behavior from sand-rich reservoirs.

On the North Slope, the program is pursuing two options with Japan for a long-term test. The program is evaluating unleased acreage the State of Alaska has set aside temporarily for this test, and is also exploring the possibility of testing within one of the producing units. Prior DOE programs in Alaska have explored gas hydrate reservoir potential and alternative production strategies, and additional testing programs are in development.

A new Methane Hydrate Advisory Committee has been established and met in Galveston March 27–28, 2014. The Committee advises the Secretary of Energy on potential applications of methane hydrate, assists in developing recommendations and priorities for the methane hydrate research and development program, and submits to Congress one or more reports on an assessment of the research program and an assessment of the DOE 5-year research plan. The Committee's charter stipulates that up to 15 members can be appointed by the Secretary of Energy, representing institutions of higher education, industrial enterprises and oceanographic institutions and state agencies.

Japan

Following the successful drillstem test in 2013, Japan's gas hydrate program continues to evolve. In a move to become a commercial rather than governmental project, a new industrial joint venture corporation was formed on October 1, 2014. The ''Japan Methane Hydrate Operating Company'' (JMH) was formed with the agreement and capital participation of 11 companies engaging in oil and natural gas development and in plant engineering. Commercial production of natural gas from hydrate is expected to commence from the Nankai area on Japan's Pacific margin by 2018.

Japan has expanded its gas hydrate program beyond the Nankai area and is funding programs to explore the Sea of Japan and conduct an assessment. The areas being explored in the Sea of Japan are off the Joetsu region and off of the Akita and Yamagata regions (Fig. 28). Based on the initial results of a June 2014 drilling program, the assessment is focused on ''shallow'' hydrates, the term used by Japan's Agency for Natural Resources and Energy (ANRE) for chimney/fracture-fill occurrences. This represents a new development since throughout the world, all commercial considerations for production of gas from gas hydrate have involved hydrate-bearing sands. It is unclear whether a viable production technology for fracture-fill hydrate is being investigated.

India

The second leg of India's gas hydrate drilling program commenced in February 2015, utilizing the drillship D/V Chikyu. Roughly 170 days of operations are planned, with 20 deep LWD holes and 10 core sites in the northern Bay of Bengal. The program is targeting hydrate-bearing sands with a focus on reservoir delineation and resource assessment. The goal is to identify an optimal site for a future production test.

Results of India's first gas hydrate drilling program were published in December 2014 in Marine and Petroleum Geology. That program included a 113.5-day voyage from April 28 to August 19, 2006, during which the expedition cored or drilled 39 holes at 21 sites (one site in the Kerala-Konkan Basin, 15 sites in the Krishna-Godavari Basin, four sites in the Mahanadi Basin, and one site in the Andaman deep offshore areas). The drilled holes penetrated a total of more than 9250 m (30,348 ft) of sedimentary section, and recovered nearly 2850 meters (9350 ft) of core. Twelve holes were logged with logging-while-drilling (LWD) tools and an additional 13 holes were wireline logged.

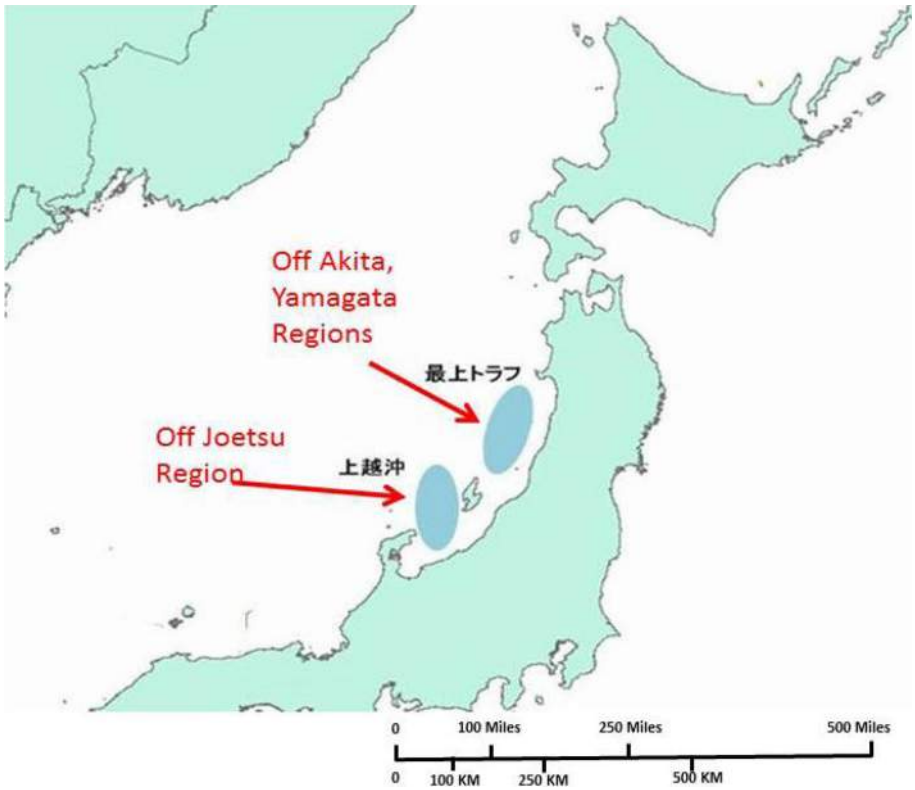

Figure 28. Basins drilled by the Japanese Agency for Natural Resources and Energy (ANRE) expedition in 2014.

South Korea

As a part of the Korean National Gas Hydrate Program, a production test in the Ulleung Basin had been planned for 2015 but its current status is uncertain. The targets are the gas hydrate-bearing sand reservoirs that were found during the Second Ulleung Basin Gas Hydrate Drilling Expedition (UBGH2) in 2010.

European Union

The European Cooperation for Science and Technology (COST) has initiated MIGRATE (Marine Gas Hydrates: An Indigenous Resource of Natural Gas for Europe), a program to integrate the expertise of a large number of European research groups and industrial players to promote the development of multidisciplinary knowledge on the potential of gas hydrates as an economically feasible and environmentally sound energy resource. In particular, MIGRATE aims to determine the European potential inventory of exploitable gas hydrates, to assess current technologies for their production, and to evaluate the associated risks. National efforts will be coordinated through Working Groups focusing on (1) resource assessment, (2) exploration, production, and monitoring technologies, (3) environmental challenges, (4) integration, public perception, and dissemination. Study areas will span the European continental margins, including the Black Sea, the Nordic Seas, the Mediterranean Sea and the Atlantic Ocean.

MIGRATE will examine the potential of gas hydrates as an economically feasible and environmentally sound energy resource. Stefan Bünz, associate professor at Centre for Arctic Gas Hydrate, Environment and Climate (CAGE) at The Arctic University of Norway, was elected the Vice Chair of the action. Three working groups have been established in MIGRATE: resource assessment; exploration, production and monitoring technologies; and environmental and geohazard challenges.

Figure 29. New Zealand's gas hydrate provinces.

Turkey

After many years of planning, Turkey has begun an extensive evaluation of the nation's gas hydrate potential in the Black Sea. The program is being led by Dokuz Eylül University in conjunction with the Turkish National Oil Company (TPAO). This comprehensive program includes depositional modeling that integrates onshore and offshore studies, hydroacoustic and geophysical surveys (multibeam, sonar, chirp, high-resolution seismic acquisition, and bathymetry surveys), water column sampling, sediment sampling, laboratory studies, and computer modeling. The initial cruise began in March and data collection will continue for more than 1 year.

After 3 years, a second phase is planned that will include 3D seismic and electromagnetic data acquisition, along with evaluation and development of production technology.

New Zealand

As part of a larger project focused on understanding the dynamic interaction of gas hydrates and slow moving active sediment mass flows, a joint New Zealand–German research team mapped a large area of hydrate-bearing sediment off New Zealand's eastern coast in April and May 2014 (Fig. 29). The project utilized 3D and 2D seismic data and found evidence of gas hydrate along with 99 gas plumes venting from the seafloor. The plumes formed columns extending up to 250 m (820 ft) into the water column. The venting and the presence of gas hydrate have significant implications for slope failure along New Zealand's coastal margin.

New Zealand also has an active research program investigating the resource potential of New Zealand's gas hydrate deposits. The program is led by GNS Science, in collaboration with National Institute of Water and Atmospheric Research (NIWA), the University of Otago, and the University of Auckland; with funding from the Ministry of Business, Innovation, and Employment. The current program builds on a 2010–2012 pilot program funded by the Foundation for Research, Science, and Technology.

The key objectives for the resource assessment program are to study the regional distribution of gas hydrate and to characterize individual gas hydrate reservoirs. The initial area of investigation is a zone outside of the Hikurangi Margin. This characterization effort is utilizing analysis of seismic data to improve the understanding of gas hydrate reservoir rocks and investigation of gas hydrate formation mechanisms. Initial production modeling has been completed as well as a first assessment of seafloor communities that may be affected by gas hydrate production. The overarching goal within the current program is to identify targets for scientific exploration drilling.

United Nations Environmental Programme

Researchers at the DOE Office of Fossil Energy's National Energy Technology Laboratory (NETL) were part of an international team, including the United Nations Environmental Programme (UNEP) that contributed to a newly released report explaining the prospect of gas hydrate as a potential worldwide energy source that can contribute in the transition to the low-carbon energy systems of the future. ''Frozen Heat: A Global Outlook on Methane Hydrates'' details the science and history of gas hydrate, evaluates the current state of gas hydrate research, and explores the potential impacts of gas hydrate on the future global

energy mix. The report notes that gas hydrate contains an immense quantity of methane gas that, when combusted, emits up to 40 percent less carbon dioxide than coal and 20 percent less than oil. According to the report, there may be regions in the world that realize meaningful production of natural gas from gas hydrates in the next 10–20 years.

Other National Programs

Gas hydrate characterization programs are also underway in Brazil, Colombia, Iran, Mexico, South Africa, Uruguay, and Vietnam. As Japan achieves full commercial production within the next several years, it is likely that other nations with deepwater coastal margins will initiate programs to assess the gas hydrate resource potential off their shores.

BITUMEN AND HEAVY OIL

Steven Schamel,[17] Sharleen Overland,[18] Ravil Ibatullin[19]

Introduction

This commodity commonly consists of bitumen and heavy oil principally in unlithified sand. Heavy oil reservoirs can also include porous sandstone and carbonates. Oil sands petroleum includes those hydrocarbons in the spectrum from viscous heavy oil to near-solid bitumen, although these accumulations also can contain some lighter hydrocarbons and even gas. These hydrocarbons are denser than conventional crude oil and considerably more viscous (Fig. 30), making them more difficult to recover, transport, and refine. Heavy oil is just slightly less dense than water, with specific gravity in the 1.000–0.920 g/cc range, equivalent to API gravity of 10°–22.3°. Bitumen and extra-heavy oil are denser than water, with API gravity less than 10°. Extra-heavy oil is generally mobile in the reservoir, whereas bitumen is not. At ambient reservoir conditions, heavy and extra-heavy oils have viscosities greater than 100 centipoise (cP), the consistency of maple syrup. Bitumen has a gas-free viscosity greater than 10,000 cP (Danyluk et al. 1984; Cornelius 1987), equivalent to molasses. Many bitumens and extra-heavy oils have in-reservoir viscosities many orders of magnitude large. There are a variety of factors that govern the viscosity of these high-density hydrocarbons, such as their organic chemistry, the presence of dissolved natural gas, and the reservoir temperature and pressure. The viscosity of a heavy oil or bitumen is only approximated by its density.

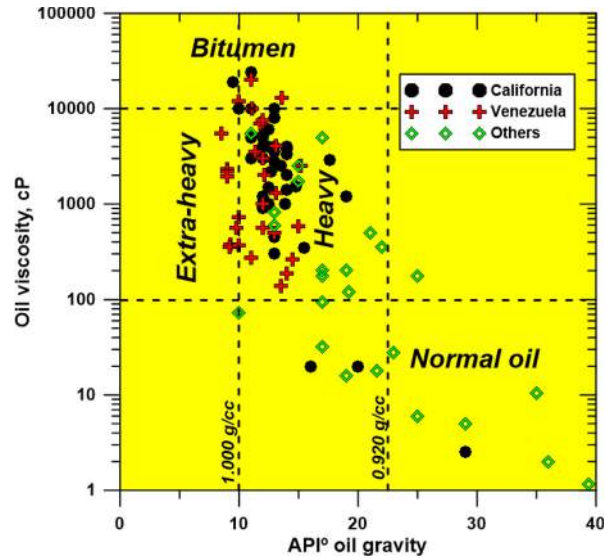

Figure 30. Cross-plot of oil density versus viscosity indicating the fields represented by bitumen, heavy and extra-heavy oils. Actual properties are plotted for a variety of oils from producing oil sand accumulations. From Koottungal (2012).

Some heavy oils are the direct product of immature (early) oil generation. However, bitumen and most heavy oils are the products of in-reservoir alteration of conventional oils by water washing, evaporation (selective fractionation) or, at reservoir temperatures below 80°C (176°F), biodegradation (Blanc and Connan 1994), all of which reduce the fraction of lower molecular weight components of the oil. These light-end distillates are what add commercial value to a crude oil. Thus, in addition to being more difficult and costly to recover and transport than conventional oil, heavy oil and bitumen have lower economic value. Upgrading to a marketable syncrude requires the addition of hydrogen to the crude to increase the H/C ratio to values near those of conventional crudes. Heavy oil and bitumen normally contain high concentrations of NSO compounds (nitrogen, sulfur, oxygen) and heavy metals, the removal of which during upgrad-

[17] GeoX Consulting Inc., Salt Lake City, UT, USA; Chair, EMD Bitumen and Heavy Oil Committee.

[18] Alberta Energy Regulator, Calgary.

[19] Tal Oil Ltd., Calgary.

Table 6. Estimated Global In-Place Heavy Oil and Bitumen Resources, Technically Recoverable Reserves, and Percentage of Global Reserves per Region (from Meyer and Attanasi 2003)

Region	Heavy Oil (BBO)			Bitumen (BBO)		
	Resources	Reserves	%	Resources	Reserves	%
N. America	185.8	35.3	8.1	1659.1	530.9	81.6
S. America	2043.8	265.7	61.2	1.1	0.1	0.0
Europe	32.7	4.9	1.1	1.4	0.2	0.0
Russia	103.1	13.4	3.1	259.2	33.7	5.2
Middle East	651.7	78.2	18.0	0.0	0.0	0.0
Asia	211.4	29.6	6.8	267.5	42.8	6.6
Africa	40.0	7.2	1.7	430.0	43.0	6.6
Western Hemisphere	2315.4	301.0	69.3	1659.4	531.0	81.6
Eastern Hemisphere	1025.4	133.3	30.7	920.8	119.7	18.4
World total	3340.8	434.3		2580.1	650.7	

The heavy oil category includes extra-heavy oil. BBO = billion barrels of oil. 1 barrel = 0.159 m^3.
BBO billion barrels of oil.

ing and refining further discounts the value of the resource. Heavy and some extra-heavy oils can be extracted in situ by injection of steam or super-hot water, CO_2, or viscosity-reducing solvents such as naphtha. Bitumen normally is recovered by surface mining and processing with hot water or solvents.

Resources and Production

Global. The International Energy Agency (2014) estimates the total world crude oil resources are between 9 and 13 trillion barrels (1.4–2.1 trillion m^3), of which just 30% is conventional crude oil. The remaining 70% is unconventional crude, which is divided 30% oil sands and bitumen, 25% extra-heavy oil, and 15% heavy oil. Heavy oil and bitumen deposits occur in more than 70 countries across the world. Meyer et al. (2007) observed that heavy oils are found in 192 sedimentary basins and bitumen accumulations occur in 89 basins. However, these unconventional oils are not uniformly distributed (Table 6). The global in-place resources of bitumen and heavy oil are estimated to be 5.9 trillion barrels (938 billion m^3), with more than 80% of these resources found in Canada, Venezuela, and the U.S. (Meyer and Attanasi 2003; Hein 2013). The largest oil sand deposits in the world, having a combined in-place resource of 3.05 trillion barrels (484.9 billion m^3), are along the shallow up-dip margins of the Western Canada sedimentary basin and the Orinoco foreland basin, eastern Venezuela. Western Canada has several separate accumulations of bitumen and heavy oil that together comprise 1.85 trillion barrels (294.1 billion m^3). The Orinoco Heavy Oil Belt is a single extensive deposit containing 1.2 trillion barrels (191 billion m^3) of extra-heavy oil. Both basins have extensive world-class source rocks and host substantial conventional oil pools in addition to the considerably larger resources within shallow oil sands.

Globally, there is just over 1 trillion barrels (159 billion m^3) of technically recoverable unconventional oils (Table 6), 434.3 billion barrels (69.1 billion m^3) of heavy oil, including extra-heavy crude, and 650.7 billion barrels (103.5 billion m^3) of bitumen (Meyer and Attanasi 2003). South America, principally Venezuela, has 61.2% of the heavy oil reserves and North America, mainly western Canada, has 81.6% of the bitumen reserves.

Heavy oil, in general, is more easily produced, transported, and marketed than bitumen. Consequently, it tends to be in a more advanced stage of development than bitumen deposits. Countries with very large reserves of conventional crude oil, particularly Saudi Arabia and Kuwait, have been slow to develop their heavy oil resource, whereas countries with small or dwindling conventional oil reserves are exploiting heavy oil to a greater degree.

Table 7. Summary of Alberta's Energy Reserves, Resources, and Production at the End of 2014 (Alberta Energy Regulator 2015)

	Crude Bitumen		Crude Oil		Natural Gas[a]		Raw Coal	
	(Million m^3)	(Billion Barrels)	(Million m^3)	(Billion Barrels)	(Billion m^3)	(Trillion Cunic Feet)	(Billion tons)	(Billion Tons)
Initial in-place resources	293,125	1845	12,927	81.3	9805	348	94	103
Initial established reserves	28,092	177	3010	18.9	5590	198	34.8	38.4
Cumulative production	1661	10.4	2722	17.1	4677	166	1.60	1.76
Remaining established reserves	26,431	166	288	1.8	913[b]	32.4 [b]	33.2	36.6
Annual production	133.7	0.841	34.2	0.215	104.9[e]	3.7[e]	0.030[c]	0.033[c]
Ultimate potential (recoverable)	50,000	315	3130	19.7	6276[d]	223[d]	620	683

[a]Expressed as "as is" gas, except for annual production, which is 37.4 megajoules per cubic meter; includes coalbed methane.
[b]Measured as field gate.
[c]Annual production is marketable.
[d]Does not include unconventional natural gas.
[e]Includes unconventional gas.

Canada. Nearly all of the bitumen being commercially produced in North America is from Alberta, Canada. Canada is an important strategic source of bitumen and of the synthetic crude oil (SCO) obtained by upgrading bitumen. Bitumen and heavy oil are also characterized by high concentrations of nitrogen, oxygen, sulfur, and heavy metals, which results in increased costs for extraction, transportation, refining, and marketing compared to conventional oil (Meyer and Attanasi 2010). Research and planning are ongoing for transportation alternatives for heavy crude, bitumen, and upgraded bitumen using new and existing infrastructure of pipelines and railways. Such integration has been called a virtual "pipeline on rails" to get the raw and upgraded bitumen to U.S. markets (Perry and Meyer 2009). SCO from bitumen and (or) partially upgraded bitumen is being evaluated for potential long-distance transport to refineries in the Midwest and Gulf states of the U.S. and to existing or proposed terminals on the west coast of North America. Associated concerns include effects on the price of crude oil, and the environmental impacts that are associated with land disturbance, surface reclamation, habitat disturbance, and oil spills or leaks with associated potential pollution of surface and ground waters.

Excellent sources of information on Alberta oil sands and carbonate-hosted bitumen deposits are the resource assessments and regulatory information by the Alberta Energy Regulator (AER 2015). Estimated in-place resources for the Alberta oil sands are 1845 billion barrels (293.4 billion m^3) (AER 2015, p. 3). Estimated remaining established reserves of in situ and mineable crude bitumen are 166 billion barrels (26.4 billion m^3). Only 5.9% of the initial established crude bitumen has been produced since commercial production began in 1967 (Table 7) (AER 2015). Cumulative bitumen production for Alberta in 2014 was 10.4 billion barrels (1.65 billion m^3). The bitumen that was produced by surface mining was upgraded; in situ bitumen production was marketed as non-upgraded crude bitumen (Energy Resources Conservation Board of Alberta 2012). Alberta bitumen production has more than doubled in the last decade, and is expected to increase to greater than 4 million barrels per day (0.6 million m^3 per day) by 2024. Over the last 10 years, the contribution of bitumen to Alberta's total primary energy production has increased and in 2014 represented over half of Alberta's primary energy production. A breakdown of production of energy in Alberta from all sources, including renewable sources, is given in Table 7.

Crude bitumen is heavy and extra-heavy oil that at reservoir conditions has a very high viscosity such that it will not naturally flow to a well bore. Administratively, in Alberta, the geologic formations (whether clastic or carbonate) and the geographic areas containing the bitumen are designated as the Athabasca, Cold Lake or Peace River oil sands areas (Fig. 31). Most of the in-place bitumen is hosted within unlithified sands of the Lower Cretaceous Wabiskaw-McMurray deposit in the in situ development area (Table 8), followed by the Grosmont carbonate-bitumen deposit, and the Wabiskaw-McMurray deposit in the surface mineable area (Table 8).

A number of factors (including economic, environmental, and technological criteria) are ap-

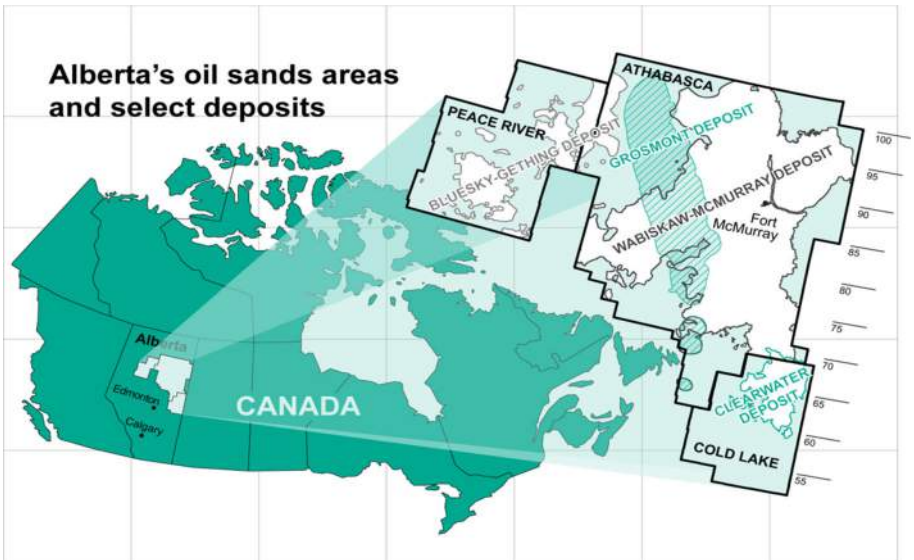

Figure 31. Alberta's Peace River, Athabasca and Cold Lake oil sands areas, highlighting the main deposits (AER 2015).

Table 8. Initial In-Place Volumes of Crude Bitumen as of December 31, 2014 (Alberta Energy Regulator 2015)

Oil Sands Area Oil Sands Deposit	Initial Volume In-Place (10^6 m^3)	Area (10^3 ha)[a]	Average Pay Thickness (m)	Average Reservoir Parameters		
				Mass (%)	Pore Volume Oil (%)	Average Porosity (%)
Athabasca						
Upper Grand Rapids	5817	359	8.5	9.2	58	33
Middle Grand Rapids	2171	183	6.8	8.4	55	32
Lower Grand Rapids	1286	134	5.6	8.3	52	33
Wabiskaw-McMurray mineable)	20,823	375	25.9	10.1	76	28
Wabiskaw-McMurray (in situ)	131,609	4694	13.1	10.2	73	29
Nisku	16,232	819	14.4	5.7	68	20
Grosmont	64,537	1766	23.8	6.6	79	20
Subtotal	242,475					
Cold Lake						
Upper Grand Rapids	5377	612	4.8	9.0	65	28
Lower Grand Rapids	10,004	658	7.8	9.2	65	30
Clearwater	9422	433	11.8	8.9	59	31
Wabiskaw-McMurray	4287	485	5.1	8.1	62	28
Subtotal	29,090					
Peace River						
Bluesky-Gething	10,968	1016	6.1	8.1	68	26
Belloy	282	26	8.0	78	64	27
Debolt	7800	258	25.3	5.1	66	18
Shunda	2510	143	14.0	5.3	52	23
Subtotal	21,560					
Total	293,125					

1 m^3 = 35.3 ft^3; 1 hectare (ha) = 2.47 acres; 1 m = 3.28 ft.

plied to the initial in-place volumes of crude bitumen to attain the established reserves. In Alberta, there are two types of reserves for crude bitumen—those that are anticipated to be recovered by surface mining techniques (generally in areas with <65 m (<213 ft) of overburden in the Athabasca

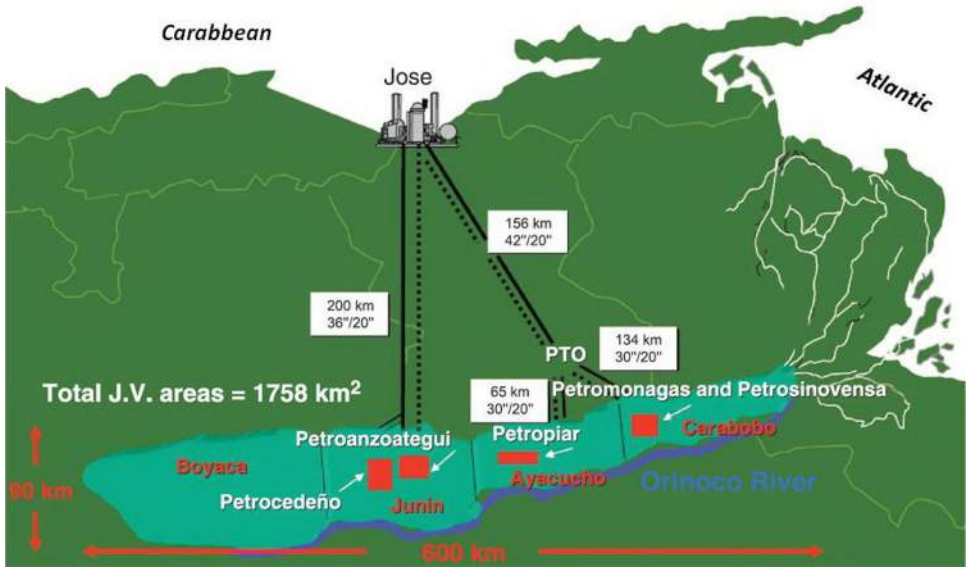

Figure 32. The Faja Petrolifera del Orinoco in eastern Venezuela (light green) showing the four production units (red text), four current production projects (white text), and pipelines connecting the projects to the Jose upgrading facility on the coast. From Villarroel et al. (2013). 1 km = 0.6 mi; 1 km^2 = 0.386 mi^2).

area), and those to be recovered by underground in situ and largely thermal technologies in areas with >65 m (>213 ft) of overburden. The principal technology of choice for Athabasca is Steam-Assisted Gravity Drainage (SAGD), for Cold Lake, it is Cyclic Steam Stimulation (CSS), and for Peace River, it is thermal and primary recovery.

In situ oil sands production continues to be the largest growth area. Compared to surface mining, in situ operations, such as SAGD, involve lower capital costs, a smaller ''footprint'' and reduced environmental impacts. A modest increase in both conventional and tight-formation development is expected, largely due to improvements in multistage hydraulic fracturing from horizontal wells that are targeting these previously uneconomic, but potentially large, resources. In 2012, in situ recovery overtook mining as the favored means of bitumen recovery, according to the Alberta Energy Regulator.

Crude oil prices began to fall in June 2014 and continued to decline for the rest of the year. Despite falling oil prices, upgraded and non-upgraded bitumen production from oil sands continued to grow at a steady pace in 2014. With the decrease in oil prices, economic returns of crude bitumen projects are expected to be affected. Even with this low price environment, oil sands projects under construction continue to move ahead while producers continue to evaluate the viability of new oil sands projects.

Venezuela. The Faja Petrolifera del Orinoco (Orinoco Heavy Oil Belt) in eastern Venezuela is the world's single largest oil accumulation. The total estimated oil-in-place is 1.2 trillion barrels (191 billion m^3) of which 310 billion barrels (49.3 billion m^3) are considered technically recoverable (Villarroel et al. 2013). The Faja is 55,314 km^2 (21,357 mi^2) in size and extends 600 km (373 mi) in an east–west arcuate band that is up to 90 km (56 mi) wide (Fig. 32). The deposit lies immediately north of the Orinoco and Arauca Rivers in the southern portions of the states of Guarico, Anzoategui, and Monagas. The Faja follows the extreme up-dip edge of the foreland basin of the young Serrania del Interior thrust belt, the source of the oil, where Neogene-age sediments overlie the crystalline basement of the Guayana Shield. To the north, in the foothills of the Serrania del Interior, there are numerous conventional oilfields, the majority in structural traps within the thrust belt.

Extra-heavy oil having an average API gravity of 8.5° is reservoired in stratigraphic traps within the highly porous and permeable sands of the lower and middle Miocene Oficina Formation. These sands were carried off the Guayana Shield by river systems flowing north and northeastward to be deposited in fluvio-deltaic and estuarine complexes on the south rim of the foreland basin (Martinius et al. 2013). Upper Miocene marine shales of the Freites Formation form the top seal to the Faja oil accumula-

tion. The net thickness of oil-impregnated sands is highest within the paleo-deltas, giving rise to a highly irregular distribution of resource richness within the Faja.

At present, there are four active heavy oil recovery projects operating in the Faja (Fig. 32), each begun in successive years between 1998 and 2001. Petroleos de Venezuela (PDVSA) is the sole owner/operator of Petroanzoategui and is the senior joint venture partner in the other three projects with a partner as the operator: BP in Petromonagas, Chevron in Petropiar, and Total with Statoil in Petrocedeño. In what is referred to as the ''first stage'' of development, the four projects are now producing collectively about 640,000 bopd (101,760 m^3/d) using cold production methods (Villarroel et al. 2013). These methods are possible due to the highly porous and permeable properties of the reservoir sands and the gas-charged and foamy character of the extra-heavy oil. The dissolution of dissolved natural gas in the oil during production aids in propelling the oil from the sand and towards the wellbore. The foaming of the oil and reservoir temperatures of about 50°C (122°F) helps overcome its viscosity, which is on the order of thousands of centipoise. The oil is extracted from horizontal wells as long as 1.5 km (0.9 mi) with the aid of downhole progressive cavity pumps and multi-phase pumps at the well head. A major challenge is the optimal placement of the long horizontal wells in these complex heterogeneous fluvial-deltaic sands (Martinius et al. 2013).

To enhance production, a 50° API naphtha diluent is commonly injected into the horizontal wells to further decrease viscosity. The recovery factor for this cold production is about 10%. The naphtha-charged oil is transported by pipeline about 200 km (124 mi) to the Jose upgrading facility on the Caribbean coast (Fig. 32). Here the naphtha is separated from the oil and returned to the projects via dedicated diluent pipelines (Fig. 32). The oil is upgraded in one of four delayed coking units to a 32° API syncrude that is exported as ''Zuata Sweet.'' As the projects prepare for the next phase of development, a variety of established enhanced oil recovery (EOR) technologies are being tested in pilots, including thermal methods (SAGD, CSS) and reservoir flooding using polymer-viscosified water.

To increase the rate of extra-heavy oil production by expanding operating areas, PDVSA has entered into joint venture agreements with various national or quasi-national oil companies. However, at present, more heavy crude is being produced than can be processed in the Jose upgraders, which are more than a decade old. The lack of investment funds has prevented PDVSA from adequately maintaining and expanding the pipelines and upgrading facilities. This situation has been exacerbated by the recent drop in global oil price.

United States. The goal of the U.S. to move towards greater energy independence could include production from existing U.S. oil sands deposits using surface mining or in situ extraction. Current U.S. bitumen production is mainly for local use on roads and similar surfaces. This is due mainly to the different character and scale of the deposits compared to Canada and Venezuela, but in part it is because, outside of heavy oilfields in California and Alaska, the U.S. has not developed the infrastructure required to produce oil sands as a commercially viable fuel source. Schenk et al. (2006) compiled total measured, plus speculative, estimates of bitumen in-place of about 54 billion barrels (8.6 billion m^3) for 29 major oil sand accumulations in Alabama, Alaska, California, Kentucky, New Mexico, Oklahoma, Texas, Utah, and Wyoming (Table 9). However, these older estimates of total oil sand resources provide only limited guidance for commercial, environmentally responsible development of the oil sand deposits. Additionally, the estimates do not factor in commercially viable heavy oil resources. The resources in each of the states have distinct characteristics that influence current and future exploitation.

California has the second largest heavy oil proved reserves in the world, second only to Venezuela (Hein 2013). California's oilfields, of which 52 each have reserves greater than 100 million barrels (15.9 million m^3), are located in the central and southern parts of the state (Fig. 33). As of the beginning of 2014, California's proved reserves were 2878 million barrels (457.6 million m^3) (EIA 2014a). The dominantly heavy oilfields of the southern San Joaquin basin have 2014 proved reserves of 1813 million barrels (288.3 million m^3). Most of the fields were discovered and put into primary production in the period 1890–1930. However, with the introduction of water flooding, thermal recovery, and other EOR technologies starting in the 1950s and 1960s, oil recoveries improved dramatically and the proved reserves increased several fold (Tennyson 2005).

Nearly all of the oil is sourced from organic-rich intervals within the thick Miocene Monterey diato-

Table 9. Previous Estimates of Bitumen–Heavy Oil Resource-In-Place, Measured and Total, Including Speculative, in the United States

State	No. Deposits	°API Range	Measured (MMB)	Total (MMB)
Utah	10	−2.9 to 10.4	11,850	18,680
Alaska	1	7.1 to 11.5	15,000	15,000
Alabama	2	na	1760	6360
Texas	3	−2.0 to 7.0	3870	4880
California	6	0.0 to 17.0	1910	4470
Kentucky	4	10	1720	3410
New Mexico	1	12	130	350
Wyoming	2	na	120	145

Data from Schenk et al. (2006). 1 MMB = 158,987 m^3.
MMB million barrels.

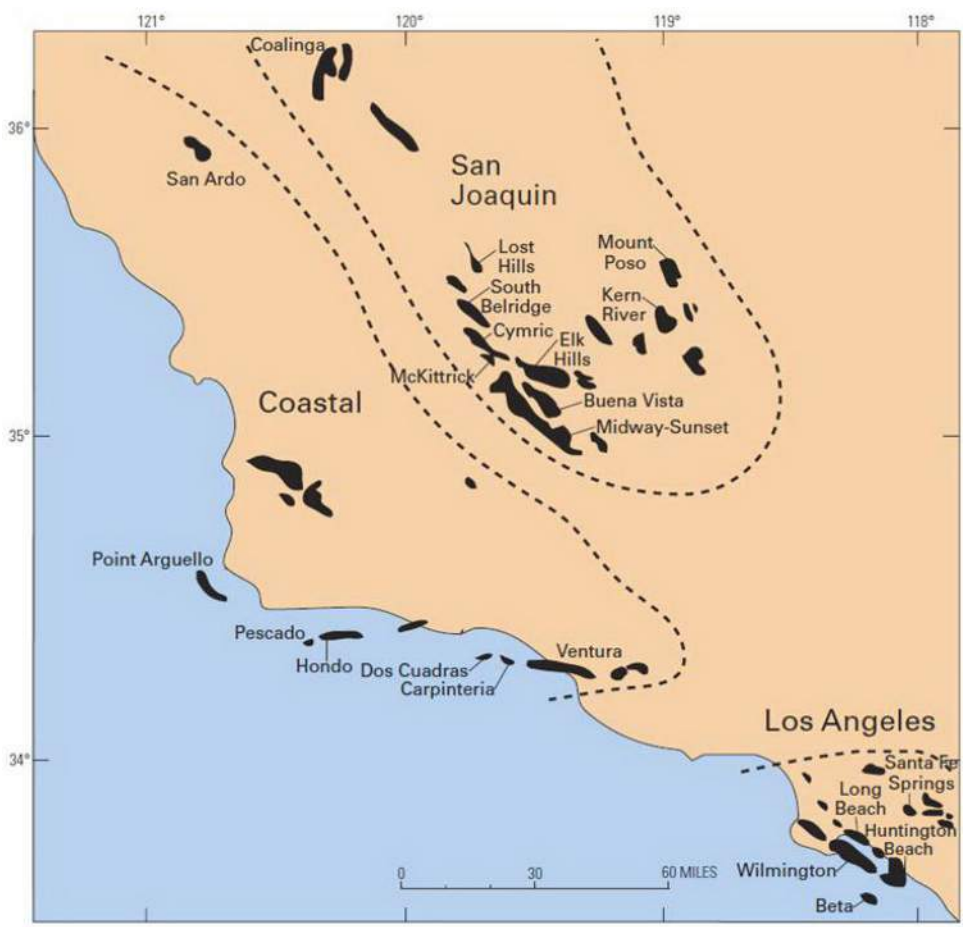

Figure 33. Principal oilfields of California. From Tennyson (2005). 1 mile = 1.6 km.

mite, diatomaceous mudstone and carbonate. Due to a combination of Type IIS kerogen, modest burial and thermal heating, and generally shallow depths of oil pools, the oil tends to be heavy and relatively viscous. These are thermally immature, partially biodegraded oils. Roughly 40% of the oil is produced by steam flooding, cyclic steam stimulation, or other thermal recovery methods. Thermally produced oil comes mainly from fields in the San Joaquin basin (Fig. 33). In general, the reservoirs are poorly or un-consolidated sandstones intercalated within or overlying the Monterey Formation. In

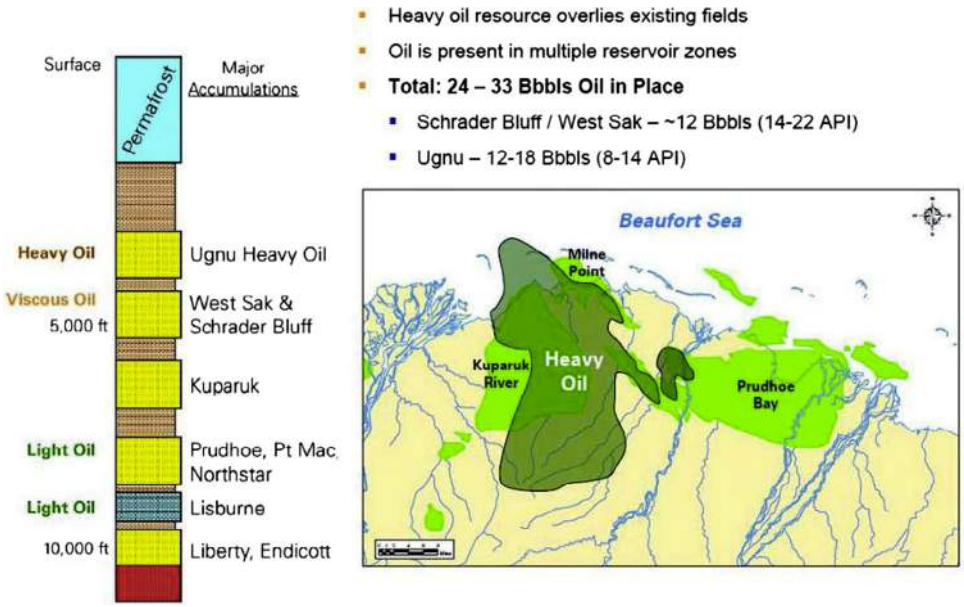

Figure 34. Location of shallow, heavy oil accumulations on the North Slope of Alaska. Heavy oil deposits overlie the Kuparuk field and parts of the Prudhoe and Milne Point fields and occur in sands within the Ugnu, West Sak, and Schrader Bluff formations. From Pospisil (2011). 1 ft = 0.3 m; 1 barrel (oil) = 0.159 m^3.

addition to the heavy oil accumulations that are being produced, California has numerous shallow bitumen deposits and seeps that are not currently exploited. The total resource is estimated to be as large as 4.7 billion barrels (747.3 million m^3) (Kuuskraa et al. 1987). Five of the six largest oil sand deposits are in the onshore Santa Maria basin (central Coastal zone in Fig. 33), covering a total area of over 60 square miles (155 km^2).

The California heavy oils are exceptional in that they sell with little or no discount compared to the WTI benchmark. From 2011 through mid-2014, the price of benchmark Midway-Sunset 13° API crude had remained near \$100/barrel (\$100/0.159 m^3) (EIA 2015y). The oil price dropped to a low of \$42.93 in January 2015, but then gradually increased to \$57.48 in early May 2015. In the existing heavy oilfields of California, where natural gas burned to generate steam is the principal operational cost factor, a dramatic drop in both oil and gas price may reduce new capital expenditures, but not ongoing oil production. During the past decade, oil production in California has steadily declined (EIA 2014a). The rate of decline is being slowed, and in some fields reversed, through the application of fully integrated reservoir characterization and improved recovery technologies that are resulting in higher recovery factors (Dusseault 2013; Beeson et al. 2014), up to 70–80% in some fields.

Alaska's heavy oil and bitumen deposits on the North Slope are very large (24–33 billion barrels, or 3.8–5.2 billion m^3) and they hold promise for sustained commercially successful development. Since early 1980s (Werner 1987), two very large, shallow heavy oil-impregnated sands have been known to overlie the Kuparuk River field and underlie a 1800-ft (549 m)-thick permafrost (Fig. 34). These are the Ugnu Sands (8°–12° API) at depths of 2000–5000 ft (610–1524 m) and the West Sak Formation (16°–22° API) at 2300–5500 ft (701–1676 m). The size of the deposits is well defined with the numerous wells tapping the underlying conventional oilfields. For the Lower Ugnu Sands and West Sak Formation, the resources are 12–18 billion barrels (1.9–2.9 billion m^3) and 12 billion barrels (1.9 billion m^3), respectively. The reservoirs are fluvial-deltaic sands de-

Table 10. Estimated Resource and Richness of Principal Bitumen Deposits in Utah (from Schamel 2013a, b)

Bitumen-Heavy Oil Deposit	Resource Estimate MMB	Areal Extent Square Miles	Richness, Average (MB/acre)	°API Gravity	Reservoir Unit
P.R. Spring -Hill Creek	7790	470	25.9	5.9 –13.8	Lower Green River ss
Sunnyside	3500–4000	122	45–51	7.1–10.1	Lower Green River ss
Sunnyside 'core'	1160	2.7	638.3		Lower Green River ss
Asphalt Ridge	1360	16	132.9	10.0–14.4	Mesaverde ss (U Cret.)
Whiterocks	98	0.45	338	11.4–13.5	Navajo Ss (Tr.-Jr.)
Tar Sand Triangle	4250–5150	198	33.5–40.6	−3.6 to 9.6	White Rim Ss. (L. Perm)
TST 'core'	1300–2460	30–52	67.7–73.9		White Rim Ss. (L. Perm)

1 MMB = 158,987 m^3; 1 MB = 159 m^3; 1 square mile = 259 hectares. 1 acre = 0.4049 hectares.
MMB million barrels, *MB* thousand barrels.

posited during the Late Cretaceous–earliest Paleocene across the north and northeast prograding Brooks Range coastal plain (Hulm et al. 2013).

Production of viscous (50–5000 cP) oil from the West Sak pools began in the early 1990s, reaching the current level of 4000–5000 barrels (636–795 m^3) of oil per day in 2004. To date, over 100 million barrels (15.9 million m^3) have been recovered from the formation using a combination of vertical wells and water flood. The heavy oil in the Ugnu Sands presents a much greater technical challenge due to its higher viscosity (5000 to >20,000 cP) and the friability of the reservoir sand (Chmielowski 2013). A pilot project at Milne Point using the CHOPS ('cold heavy oil production with sand') recovery process (Young et al. 2010), although technically successful, has been suspended, at least for the present.

Utah's bitumen and heavy oil deposits are found throughout the eastern half of the state (Schamel 2009, 2013a, b). In northeast Utah, the largest accumulations are located along the southern margin of the Uinta Basin underlying vast portions of the gently north-dipping East and West Tavaputs Plateaus. This highland surface above the Book and Roan Cliffs on either side of the Green River (Desolation) Canyon is supported by sandstone and limestones of the Green River Formation (lower Eocene). Here the resource-in-place is at least 10 billion barrels (1.59 billion m^3), nearly all of it reservoired in fluvial-deltaic sandstone bodies within the lower member of the Green River Formation. On the northern margin of the Uinta Basin, heavy oil occurs in a variety of Mesozoic and Tertiary reservoirs on the hanging wall of the Uinta Basin Boundary Fault. The proven resource is <2 billion barrels (<0.32 billion m^3), but the potential for additional undiscovered heavy oil and bitumen is great. In both areas, the source of the heavy oil is organic-rich lacustrine calcareous mudstone in the Green River Formation. These naphthenic oils have API gravities in the 5.5°–17.3° range, are only weakly biodegraded in the subsurface, and are sulfur-poor (0.19–0.76 wt%). The known oil sand reservoirs are lithified and oil-wet.

New resource-in-place estimates for the major deposits are determined from the average volume of bitumen/heavy oil measured in cores distributed across the deposit, as delineated by wells and surface exposures (Table 10). The deposits on the south flank of the basin are extensive and large, but the actual concentrations (richness) of resource are small. For the vast P. R. Spring–Hill Creek deposit, the average richness is just 25.9 thousand barrels per acre (4.1 thousand m^3 per 0.4 ha); it is only slightly higher for the entire Sunnyside accumulation west of the Green River. However, a small portion of the Sunnyside deposit having unusually thick reservoir sands within a monoclinal structure trap has measured average richness as large as 638.3 thousand barrels (101.5 thousand m^3) per acre. The two principal deposits on the north flank of the basin, Asphalt Ridge and Whiterocks, are relatively small, but they contain high concentrations of heavy oil (Table 10).

In the southeast quadrant of Utah, there are numerous shallow bitumen accumulations on the northwest and west margins of the Pennsylvanian–Permian Paradox Basin. The deposits are hosted in rocks of late Paleozoic and early Mesozoic age. With the exception of the Tar Sand Triangle and Circle Cliffs deposits, most accumulations are small and/or very lean. Normally, the oils are heavier than 10° API and highly biodegraded. In contrast to the Uinta Basin deposits, this bitumen is derived from a marine source rock and is aromatic with high sulfur

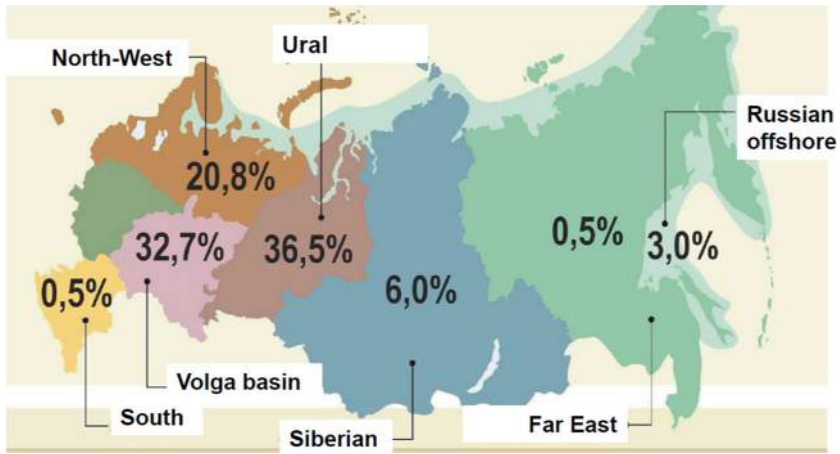

Figure 35. Russian heavy oil and bitumen reserves regional distribution. From Prischepa et al. (2013).

Table 11. Russian Heavy Oil and Bitumen Resources

Basin	Region	Resource (B m^3)	Resource (BBO)	Share of Total Heavy Oil (%)
West Siberian	Tyumen	2.45	15.41	38.10
Volga-Ural	Tatarstan	1.163	7.32	18.10
Volga-Ural	Udmurt	0.299	1.88	4.70
Volga-Ural	Samara	0.293	1.87	4.70
Volga-Ural	Perm	0.263	1.65	4.10
Volga-Ural	Bashkortostan	0.159	1.00	2.50
Timan-Pechora	Komi	1.52	9.62	23.80
		6.162	38.75	96.00

B m^3 billion cubic meters, *BBO* billion barrels of oil.

content (1.6–6.3 wt%), but low nitrogen (0.3–0.9 wt%).

The Uinta Basin heavy oils and bitumens are highly viscous; the Tar Sand Triangle bitumen is only slightly less viscous. Both groups of oils have viscosities that are orders of magnitude greater than that of the 13° API heavy oil produced by steam flood in the southern San Joaquin Basin, California. So far, the Utah oil sands have resisted attempts at commercial development. However, two projects are scheduled to be operational before the end of 2015. The Calgary-based U.S. Oil Sands PR Spring commercial demonstration project at Seep Ridge is designed to produce liquids from surface-mined oil sand using a closed-loop solvent extraction process. The mine and processing site was prepared in 2014, and the process extraction equipment modules are scheduled to be delivered and assembled mid-year 2015. The mine and extractor could be operating by October 2015. Toronto-based MCW Energy Group Limited has announced plans to build two 2500 bopd (400 m^3 per day) closed-loop solvent extractors at the existing Temple Mountain mine at the south end of Asphalt Ridge.

Russia. Heavy oil constitutes roughly 13.1% of the total Russian oil reserves, which official estimates place at 22.5 billion m^3 (141.8 billion barrels). Recoverable heavy oil occurs in three principal petroleum provinces: (1) the southern, up-dip portion of the West Siberian Basin, (2) the Volga-Ural Basin, and (3) Timan-Pechora Basin, on the southwest and northwest foreland (Ural Mountains), respectively (Fig. 35; Table 11). Resource and reserve summaries of the deposits within the three principal petroleum provinces are described herein.

In the southern up-dip portion of the West Siberian basin, heavy oils occur in Jurassic–Cretaceous sandstone where oil pools have been infiltrated by meteoric water and biodegraded. Additionally, bitumen deposits have been discovered along the southeast flank of the Ural Mountains. West Siber-

ian basin's reserves are mainly represented by the Russkoye, Tazovskoye, and Vanyeganskoye heavy oilfields.

The heavy oil and bitumen accumulations of the Volga-Ural province, Russia's second largest oil producing region, are within Carboniferous–Permian age reservoirs on or flanking the enormous Tatar dome. There are 194 known heavy oil-bitumen fields, most of which are reservoired within shallow Permian rocks in the central and northern parts of the province. Tatarstan holds Russia's largest natural bitumen resources; there are 450 deposits in Upper Permian sandstones with 1.163 billion m^3 (7.3 billion barrels) of resource-in-place. The heavy oil and bitumen of this province have high sulfur content (up to 4.5%) and contain transition metals (Ni, Mo). A very large portion of the total oil reserves is heavy oil.

In the Timan-Pechora basin, the heavy oil and bitumen resources occur in shallow pools on the Timan arch forming the southwest margin of the basin and in shallow anticlinal traps within the basin center. Several known accumulations are in production. The Yaregskoye oilfield is located in East-Pechora Swell and the Usinskoye oilfield is located in the Kolvino Swell. The Yaregskoye field in Komi Republic, containing about 375 million m^3 (2358 million barrels) of heavy oil proved recoverable reserves in Devonian formation, is the largest field in the Timan-Pechora petroleum province. The second largest is the Usinskoye oilfield which contains OOIP around 67.9 million m^3 (425 million barrels) of heavy oil in Permian–Carboniferous age reservoirs.

Environmental Issues

The primary environmental issues relate to the balance among greenhouse gas emissions and water/energy usage and the recovery, production, and upgrading of bitumen. Specifically, the critical environmental focus is how to cleanly, efficiently, and safely extract, produce, and upgrade the bitumen. Goals include reducing (1) energy required to heat the water to steam and (2) CO_2 emissions. Current greenhouse gas emissions are decreasing and remaining emissions are compensated for by carbon trading and (or) CO_2 sequestration; and (3) improving the economics and processes of extraction, production, and upgrading of the bitumen. Some of the areas of focus include:

- Land reclamation in surface mining.
- Tailings and consolidated tailings disposal and reclamation.
- Bitumen upgrading and co-production of other products from tailings (such as vanadium, nickel, and sulfur).
- In situ recovery.
- Underground refining.

The growing size or ''footprint'' of the surface mines and their tailings ponds is an environmental problem needing to be addressed. To this end, Syncrude Canada Limited is preparing to build a C$1.9 billion centrifuge plant at its Mildred Lake mine, which when operational in 2015 will reduce the waste slurry from the separators to a less-hazardous, near-dry sediment requiring far less surface storage (Curran 2014).

Oil sand developers in Canada largely have been successful in reaching the goal of reducing CO_2 emissions by 45% per barrel (45% per 0.159 m^3), as compared to 1990 levels. Also in Canada, developers are legislated to restore oil sand mining sites to at least the equivalent of their previous biological productivity. For example, at development sites near Fort McMurray, Alberta, the First Nation aboriginal community, as part of the Athabasca Tribal Council, and industry have worked together to reclaim disturbed land (Boucher 2012) and industry has reclaimed much of the previous tailings pond areas into grasslands that are now supporting a modest bison herd (about 500–700 head).

ENERGY ECONOMICS AND TECHNOLOGY

Jeremy Platt[20]

Opening Comment: US Oil Hits the World Stage

2014 is the year attention shifts to oil, as obviously this was the year of the oil price collapse. Yet this is, improbably and surprisingly, actually a hydraulic fracturing story. Shale oil's growth over 3 years, exclusively enabled by high volume hydraulic fracturing, created oversupply in the world oil market. Ironically, it was oversupply of shale gas and

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natural gas' price collapse that drove developers to wetter gas and shale oil prospects in the first place. Now all eyes across the global energy spectrum are focused on how U.S. industry will respond.

Oil Price Collapse

The collapse of oil prices took industry participants and market observers almost completely by surprise. Seventy-five dollars per barrel [$12.90/million Btu (mmBtu)] was anticipated by some, as reported at the end of March 2014, yet it was a future envisioned within 5 years or as soon as 3 years, not just 6 months. Gene Epstein of Barron's remarked on this on March 29, 2014, citing Citigroup's Edward Morse regarding a decline within 5 years and citing University of California's Amy Jaffee and Rice University's Mahmoud El-Gamal regarding their proposition of a decline within as few as 3 years. The collapse of oil prices echoes the punishing price collapse of 1986. Adam Sieminski, Administrator of the U.S. EIA, graphed historical constant dollar–oil prices on December 11, 2014, in a hearing on U.S. oil export policy (Fig. 36; House Subcommittee on Energy and Power). Then at $60/barrel ($10.34/mmBtu), the collapse had not yet reached its nadir of $44.80/barrel ($7.72/mmBtu) on January 26, 2015, and $43.39/barrel ($7.48/mmBtu) on March 17, 2015. By mid-May 2015, prices had climbed above $60/barrel. Among the starkest differences between the decade of the Oil Crises and now is the pattern of U.S. oil imports. Between 1970 and 1977, oil imports' share of U.S. consumption rose from 21 to 46%. Between 2008 and 2014, it dropped sharply from 59% (its all-time peak was 60% in 2006) to below 29%. Like virtually everything to do with the phenomenon of high volume hydraulic fracturing, this is a stunning accounting. Today's import share now matches the lows experienced over several years in the early to mid-1980s.

Various reasons have been cited to explain the oil price collapse, including the slowdown of economic growth in China and anemic economic recovery across Europe. While these are certainly contributing factors, a review of recent global statistics points to surging and resurgent U.S. supplies as the greatest factor affecting the oil supply–demand imbalance over the past 4 years and more so over just the past 2 years (e.g., through the first quarter of 2015). (See also Figure 44.)

U.S. Shale Oil in a Global Context

The greatest changes in global oil supply and demand since 2011 are shown in Table 12, drawn from International Energy Agency (2015) data. Growth of ''Americas Production'' is shown alongside total supply and trends in demand. ''Americas Production'' includes ''light tight oil'' (e.g., North Dakota's Bakken region and Texas' Eagle Ford formation), Permian Basin production, Canadian oil sands, and other regions with growing or declining production. World production grew 5.9 million barrels per day (mmb/d) (938,100 m^3/d) between 2011 and 2015 (first Quarter). ''Americas'' grew 5.0 mmb/d (795,000 m^3/d). World demand grew at about half this pace, +3.0 mmb/d (477,000 m^3/d) over the full period. The mismatch was made up in growing global stocks, particularly over the past 2 years. Europe's demand remained lackluster (small negative changes 4 years in a row), but did not show any large declines in the past 3 years. China's recent, steady pattern of 300,000–400,000 barrels/d (47,700–63,600 m^3/d) demand increases simply went to zero, not negative, in the first quarter of 2015. OPEC production stopped falling by 2014 (it had declined 800,000 barrels/day (1.27 million m^3/d) the year before) and increased slightly going into 2015 (up 300,000 barrels/d, 47,700 m^3/d).

North Dakota and Texas account for the bulk of ''Americas Production'' growth—3 million barrels per day (477,000 m^3/d) between December 2011 and December 2014 (and >4 million barrels per day (>636,000 m^3/d) growth since January 2007). The EIA's new series of Drilling Productivity Reports (EIA 2015z) give drilling data and production for the principal new oil and gas plays. The leading shale oil plays (plus the Niobrara, but not the Utica due its much smaller production) are shown in Figure 37 and Table 13.

Canada's contribution to ''Americas Production'' growth has been steady in recent years, but very modest by comparison. Canadian crude plus liquids production grew 1 mmb/d (159,000 m^3/d) since 2009 (the total reached 4.4 mmb/d (700,000 m^3/d) in 2014 (EIA 2015aa). Oil sands production accounted for 2.3 mmb/d (370,000 m^3/d) in 2014; the National Energy Board has forecast oil sands growth of about 200,000 barrels/d per year (31,800 m^3/year) from 2014 to 2018 (National Energy Board 2015). An independent forecast suggests the oil price collapse will force an offsetting dip in Canadian conventional, tight and shale oil produc-

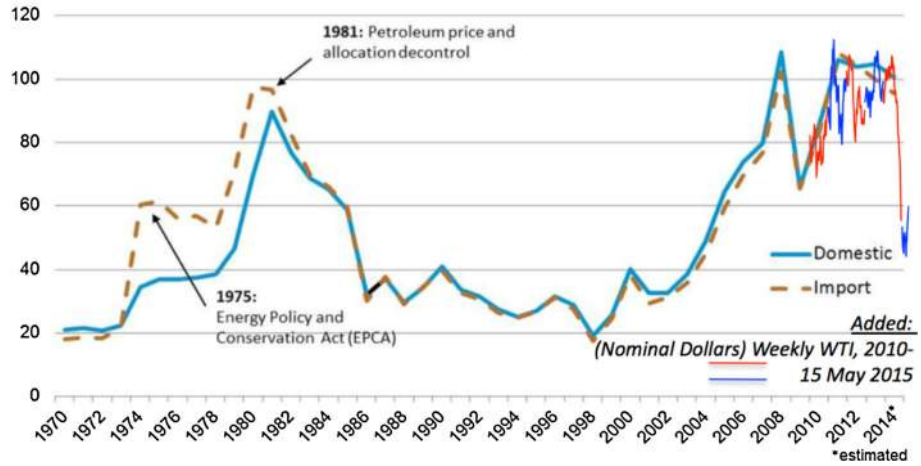

Figure 36. U.S. oil prices 1970–May 2015 (refiner acquisition costs by year, 2014 dollars per barrel; West Texas Intermediate (WTI) spot prices by week, 2010–May 2015). 1 barrel (oil) = 0.159 m^3. From Sieminski (2014).

Table 12. World oil Supply–Demand Trends (from International Energy Agency 2015)

Million Barrels Per Day	Changes by Year 2012–2015-1Q					Changes by Period	
	2011	2012	2013	2014	2015 (1Q)	2011–2015	2013–2015
World Production	88.6	+2.1	+0.7	+2.1	+1.0	+5.9	+3.1
Americas Production	14.6	+1.2	+1.3	+1.7	+0.8	+5.0	+2.5
OPEC Crude and NGLs	35.8	+1.7	−0.8	0.0	+0.3	+1.2	+0.3
World Demand	89.5	+1.1	+1.3	+0.6	+0.5	+3.0	+1.1
OECD Europe Demand	14.3	−0.5	−0.1	−0.2	−0.2	−1.0	−0.2
China Demand	9.4	+0.4	+0.3	+0.3	0.0	+1.0	+0.3
Other Asia Demand[a]	11.2	+0.4	+0.3	+0.2	+0.6	+1.5	+0.8
Stockchanges		+0.2	−0.5	+1.0	+1.6		

[a]Asia excl. China, Japan, Korea. Extracted and modified from IEA Oil Market Report: World Oil Supply and Demand.
1 million barrels (oil) = 158,987 m^3.

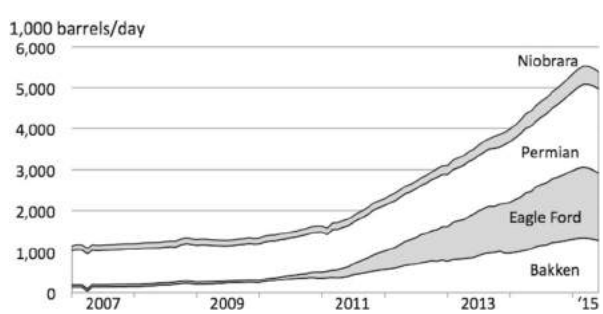

Figure 37. U.S. oil production since 2007 by principal growth region. From EIA (2015z). 1 barrel (oil) = 0.159 m^3.

tion of as much as 175,000–180,000 barrels/d (27,800–28,600 m^3/d) during 2016–2017, prior to a recovery (Howard 2015). The outcome would be a flatlining of Canadian production as the world waits to see what happens in the Lower 48.

These data underscore how much annual U.S. regional oil production increases, on the order of 1–1.5 mmb/d (159–238,000 m^3/d) out of 90 mmb/d (14.3 million m^3/d) global production, upended global price formation once these injections neared 5% of global supply. In this context, Saudi Arabia's decision to not cut back its own production was less a trigger than a recognition of the new global oil market imbalance.

EIA's new international energy statistics "portal" (http://www.eia.gov/beta/international/) allows ready analysis of global energy trends and easier tracking of individual country statistics than the IEA's regional groupings presented above. The top producing countries are shown in Figure 38. The scale of Saudi Arabian cutbacks had reached >5 mmb/d (>0.8 m^3/d) in the years preceding the Saudi led price collapse of 1986, when it was able to in

Table 13. Shale Oil Play Production Statistics, Selected Months (from EIA 2015q)

	Bakken	Eagle Ford	Permian	Niobrara	Total
Jan-07	132	54	843	113	1142
Dec-11	550	426	1097	174	2247
Dec-14	1274	1647	1868	421	5210
June 2015 (est.)	1267	1644	2056	411	5378
Peak	Mar-15	Mar-15	Still climbing	Mar-15	

est. estimated.

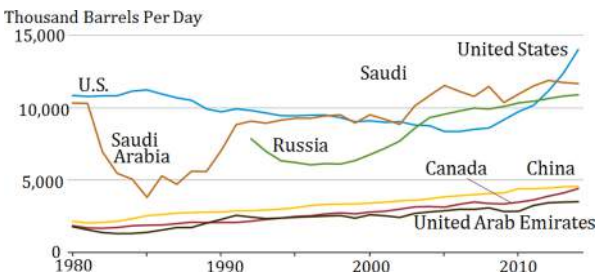

Figure 38. Oil and liquids production, 1980–2014: top producing countries. From EIA (EIA 2015ab). 1 thousand barrels (oil) = 159 m^3.

crease production by little over 1 mmb/d (159,000 m^3/d)—to dramatic effect on global oil prices. The skyrocketing climb of US production is even more remarkable in this historic context.

How Important is the Strength of the US Dollar?

Financial economists are scrutinizing relationships between currency movements and oil prices, bringing into the picture information about equity markets, investor risk aversion behavior and ''fights to safety'', and the ''financialization'' of the energy markets. The latter, represented by great increases in open interest in the oil futures markets, is one of the chief factors underlying closer linkage between daily oil price movements and currency changes. Authors from the European Central Bank (ECB) issued one of the most thorough examinations of this topic in their July 2014 paper ''Oil Prices, Exchange Rates and Asset Prices'' (Fratzsher et al. 2014). Unfortunately, the oil price collapse predated their paper by months—yet this will come under scrutiny in a follow-up paper (Van Robays, personal communication, 14 April 2015). Financial players are principally interested in daily price movements as part of trading strategies. Our interest is longer term, e.g., how much might the dollar's overall strengthening contribute to major changes in the oil price.

While the ECB authors have a great deal to say, one of their principal findings concerns a two-way dollar–oil price relationship: ''a 10% increase in the price of oil leads to a depreciation of the U.S. dollar effective exchange rate by 0.28% on impact, while a weakening of the U.S. dollar by 1% causes oil prices to rise by 0.73%.'' The long-term inverse dollar–oil price pattern (based on monthly data) is shown in Figure 39. Taken to the extreme (and outside the calendar of data incorporated in the July 2014 study), a strengthening of the dollar by 20% might cause a weakening of oil prices by 14.6% (or strengthening by 18% would cause weakening by 13.1%). As a point of fact, the dollar (against major currencies) strengthened 18% between June and July of 2014 and February–April 2015, and Brent oil spot prices weakened 46%. This roughly suggests that about 28% of the overall Brent oil price decline might be explained by currency considerations. Van Robays (personal communication, 14 April 2015) expects the greatest influences on the recent collapse will squarely be shown to be the supply–demand fundamentals, supplemented by European financial weakness.

LNG Connection: Oversupply of Natural Gas Drives Export Plans While Oversupply of Oil Undermines Export Revenues

For nearly 4 years from December 2010 through September 2014, spot oil prices occupied an almost uninterrupted plateau averaging $96.30/barrel ($16.60/mmBtu) (West Texas Intermediate, with standard deviation of $6.70/barrel) or $109/barrel ($18.80/mmBtu) (Brent Crude, with standard

deviation of $6.75). The Japan Customs Cleared or ''Crude Cocktail'' prices are in the same ballpark as Brent crude. While small differences in long-term Asian LNG pricing may be negotiated, the prices are discounted to oil prices with a three month lag. Resulting Asian prices averaged about $17/mmBtu over this same period, whereas U.S. Henry Hub prices averaged $3.50/mmBtu.

The Asian pricing formula is not strictly based on oil Btu parity, yet results in the equivalent of about an 8–14% discount to parity, depending on the particular formula. An East Asian LNG futures market index price has emerged and a relatively small volume of shipments in Asia trade on the spot market. Recent price trends are shown in Figure 40. Against the backdrop, the attraction of imports of U.S. LNG to Asia and Europe is diminished. U.S. facilities are expected to add supplies by the end of 2016 (Cheniere's Sabine terminal). U.S. pricing is based on a 15% markup to Henry Hub (HH) prices plus liquefaction costs (initially $2.25 and reported as $3.00 or $3.50 in recent BG Group materials (Hill 2014) plus shipping (reported as $3.00 to Asia, less to Europe). At HH prices of $4–5/mmBtu, deliveries to Asia would be about $11.10–$12.25/mmBtu. In the short to intermediate term, U.S. LNG offers only modest advantages, perhaps principally in destination and pricing flexibility compared to traditional sources. In the longer run, the U.S. stands as one of the behemoths bringing new liquefaction facilities into the world market.

Global liquefaction capacity has been at a standstill since 2011. Massive supplies from Australia will be added 2016–2018, with U.S. facilities in line for 2016–2019 (Sabine Pass, Freeport, Cameron, Cove Point and Corpus Christi under construction; others proposed). BG Group (2015a, b) describes the next period as one of volatility as the market absorbs these ''lumpy'' capacity additions. U.S. facilities now appear to face knife edge risk balancing recovery of oil prices and strengthening of natural gas prices, a prospect which may be enhanced by the oil price collapse's drag on oil industry revenues and investments.

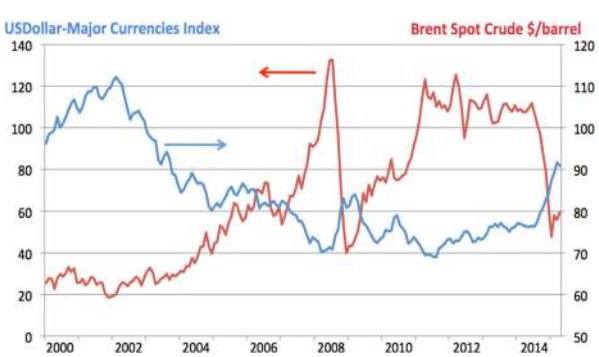

Figure 39. Inverse relation of US dollar value and oil prices (monthly data, 2000–April 2015). From Federal Reserve Bank (2015) and EIA (2015ac). 1 barrel (oil) = 0.159 m^3.

From a consumer point of view, the collapse of oil prices and thus LNG price could not come too soon, especially for Japan which saw its post-Fukushima (March 11, 2011) LNG import bill escalate about 40% due to the new plateau of high oil prices and another 25% due to heightened requirements (e.g., from 71 million metric tons per year to 87–89 million metric tons per year during 2012–2014). This led to a 75% total cost increase by 2012 from 2010 levels (Chyon 2014). Subsequently, riding oil price–LNG price linkage down to the equivalent of $65/barrel ($11.20/mmBtu, Brent crude) from its 2014 highs ($109/barrel or $18.80/mmBtu) should reduce Japan's total cost by 40% or about $30 billion/year. Taking advantage of selected spot shipments in the $7.00/mmBtu range, cost reductions could be even somewhat greater. Japan is, therefore, a noteworthy example of the scale of social and economic benefits arising from the oil price collapse, the injection of oil shale production into the global market, and ultimately from the enabling technologies of hydraulic fracturing. The entry of U.S. LNG exports will add to this effect.

Anti-gravity Strikes Again: Echoes of 2010 and 2011

Analysts first encountered the new math of unconventional drilling during the price-driven natural gas rig collapse of 2010–2011. At that time, it made almost no sense that total production first climbed 1.9 Bcf/d (53.8 million m^3/d) in 2010, when the industry was crawling back slightly from a greater-than-50% rig cut in 2009. With little change in the rig count, production the next year climbed another 4.3 Bcf/d (121.8 million m^3/d). This pattern (Fig. 41) has continued, supported in part by natural gas associated with the turn to oil.

Explanations for this ''gravity defying'' response to weak prices and drilling activity included drilling to hold leases by production, drill ''carries'' whereby companies could buy into properties by drilling, hedging, enabling companies to receive higher prices than otherwise, and gradual improvements in

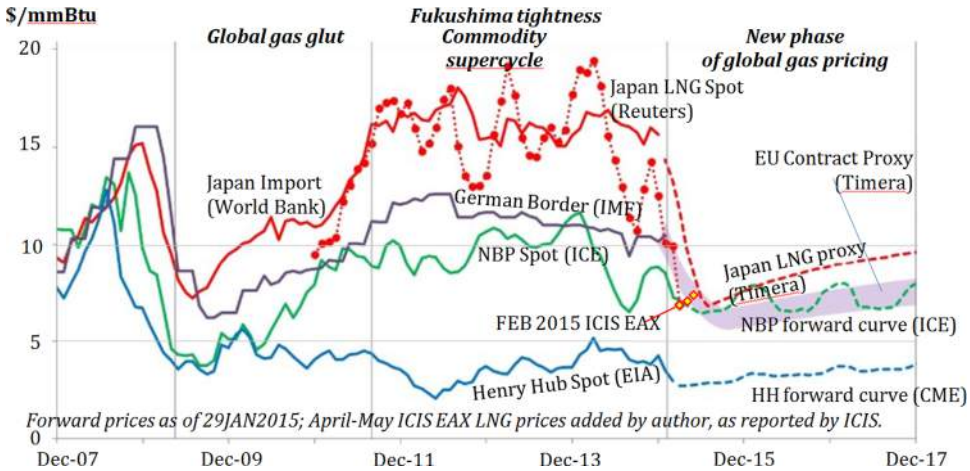

Figure 40. Global oil, LNG, and natural gas price trends. From Stokes et al. (2015). *LNG* liquefied natural gas, *IMF* International Monetary Fund, *NBP* National Balancing Point, UK, *IMF* International Monetary Fund, *ICE* Intercontinental Exchange, Inc., *ICIS EAX* ICIS [formerly Independent Chemical Information Service] East Asia Index for spot LNG prices, *EIA* U.S. Energy Information Admiration, *EU* European Union, *HH* Henry Hub, *CME* CME Group [formerly Chicago Mercantile Exchange & Chicago Board of Trade].

drilling practices and technology. A similar phenomenon is taking place today in the oil patch, without the emphasis on drill carries and supplemented by some combination of technology improvements and high-grading the portfolio, i.e., concentrating efforts on the most favorable locations. Likewise, a large number of wells are ''waiting on completion'' (so-called WOCs, or DUCs, drilled but uncompleted). Some 880 wells in North Dakota are estimated to be in this category (Helms 2015). Well completions are a key signpost, in addition to rig activity. In North Dakota, these had fallen to 63 by December, to 42 in January, and jumped to 189 in March. One hundred ten to 120 per month are necessary to maintain production at 1.2 million barrels/d (190,000 m^3/d).

Technology and strategy changes are captured over time in EIA's calculations of ''new-well oil (or gas) production per rig.'' This history is shown for some principal fields (Fig. 42). Gains in the Permian show a recent sharp uptick. The Bakken and Eagle Ford have made steady gains over 4 years and both appear to have accelerated in 2014 through April 2015 (most recent data as of end of May 2015). Marcellus' gains mostly predated 2014, occurring while the rig count dropped most sharply. Haynesville's earlier history showed gains accelerating during rig count declines and with sharp gains at minimal rig counts in 2014.

The oil price collapse is considered a ''good news, bad news'' situation. Revenues are down sharply, forcing producers and oilfield services companies to cut budgets and staff, but costs of oilfield services have been coming down as well, often cited to be in the 20–30% range.

The March of Technology

Naturally, the investment community has considerable interest in companies' performance and whether reported efficiencies are due to well design and technology practices, and thus likely to be more permanent, or are instead due to competitive repricing from drilling and service companies or from lower materials costs (e.g., fuel, mud, proppant, guar). Collectively, leading producers in the Eagle Ford, Bakken, Permian, Niobrara, Marcellus, Fayetteville, and other shales offer insights into costs and well productivity via their investor presentations and comments on their First Quarter 2015 financial performance. These are readily available from the companies themselves and in some cases from companies that offer transcripts of officers' remarks such as Seeking Alpha. While the oil price collapse dominates decisions to cut back on rigs, the more interesting story concerns adaptive practices which hold great promise for increasing, not decreasing, ''core'' acreage (meaning better quality acreage) and for increasing well Estimated Ultimate Recoveries (EURs) and companies' entire reserve/resource picture.

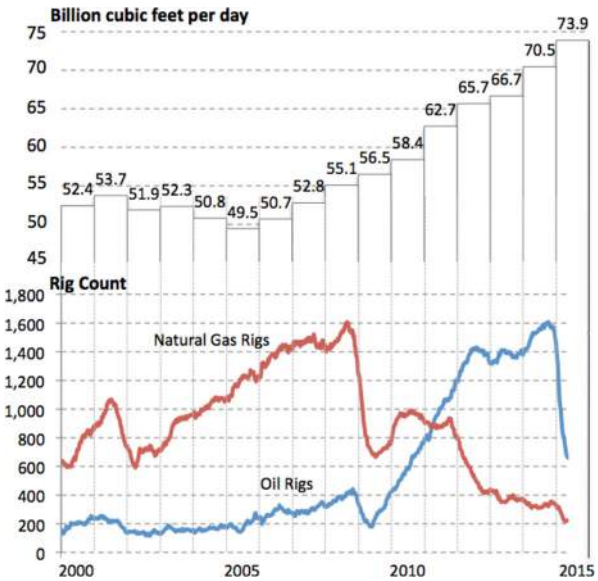

Figure 41. Rig activity and natural gas production. Weekly drilling through May 22, 2015. Annual production through 2014 and January–February levels for 2015. From Baker Hughes (2015) and EIA (EIA 2015ad). 1 billion cubic ft = 28.3 million m^3.

Among the recent changes reported are the following: *drilling and completing faster* (a company operating in the southern Marcellus forecast 26 days per well but achieved 19 days; innovations include casing design and the use of dissolvable plugs, the latter avoiding an extra step to drill out the plugs; a crew is reported to have completed as many as 12 stages in a day), *longer* [increasing from 5000 foot to 7500 foot [1524–2286 m) laterals, and now testing and completing 10,000 to 12,000 foot (3014–3658 m) laterals], *cheaper* (a consequence of the preceding and reduced costs of materials and services), *smarter* (concentrating on the best quality rock and on the best completion designs, using "G&G" or geological and geophysical, and petrophysical, knowledge), *drilling wells more closely together* ("down-spacing"; provided tighter placement avoids fracture system interference, this can greatly enhance recovery from existing acreage), *completing wells more intensely* by using more (possibly shorter) stages per well and more perforations or "contact points" and fracing these in tighter clusters (an enabling step to control fracture paths is cementing the full lateral), *optimizing fluids* (such as reducing use of more costly crosslinked gels or hybrid fluids and applying slickwater fracs), *increasing proppant volumes* (companies have tested the limits and backed off after learning the point of decreasing returns), and *monitoring and controlling regional drilling operations* through operational control centers.

Companies report more or less continuous improvements across measures such as costs and EUR per well or per lateral foot from 2011 or 2012–2014. Bucking the evolving negative impacts of price declines, these performance measures continued to show marked improvements through the first quarter of 2015 or in estimates of average 2015 well performance.

U.S. Shale Gas Accounts for Half of US Supply, the Resource Continues to Grow, and the Hydraulic Fracturing Backlash Continues

The buildup of shale gas production is updated in monthly and reported in EIA's Natural Gas Weekly. The EIA issued a chart (Fig. 43), converting reported data to dry gas production.

Since 2012, the contribution of Marcellus' gas has been phenomenal, followed by steady increases from the Eagle Ford. The share of shale gas exceeded 40% of total supply by February 2012 and has exceeded 50% of total U.S. production since February 2014, closing the year at 53.7%. The climb is highlighted in 10% increments (Fig. 44). Since September 2014, the annual production rate of shale gas from the Marcellus has been greater than the entire U.S. residential sector's consumption during 2014. Likewise, this formations' production rate as of April 2015 (5.71 Tcf/year; 161.2 billion m^3/year) would match 95% of all natural gas consumed in the region, comprising its home turf of New York, New Jersey and Pennsylvania, Virginia and Maryland, the five New England states (which are notoriously deficient in pipeline access), Ohio and Indiana. At the rate of production in April 2015 (42.04 Bcf/d or 15.3 Tcf/year; 1.2 million m^3/d or 435 billion m^3/year), total U.S. shale gas supplies are equivalent to 92% of all natural gas consumption in Japan, Canada, Germany, the United Kingdom, and Italy (15.9 Bcf/d; 450 billion m^3/d). It is easier to tally and juggle these statistics than to actually comprehend their significance.

As of April 2015, the Potential Gas Committee (PGC) issued its 2014 biennial resource estimate (Potential Gas Committee 2015). PGC's estimates since 1990 are shown in Figure 45. Shale gas began to alter the outlook in 2006, principally following from developments in the Barnett Shale of Texas.

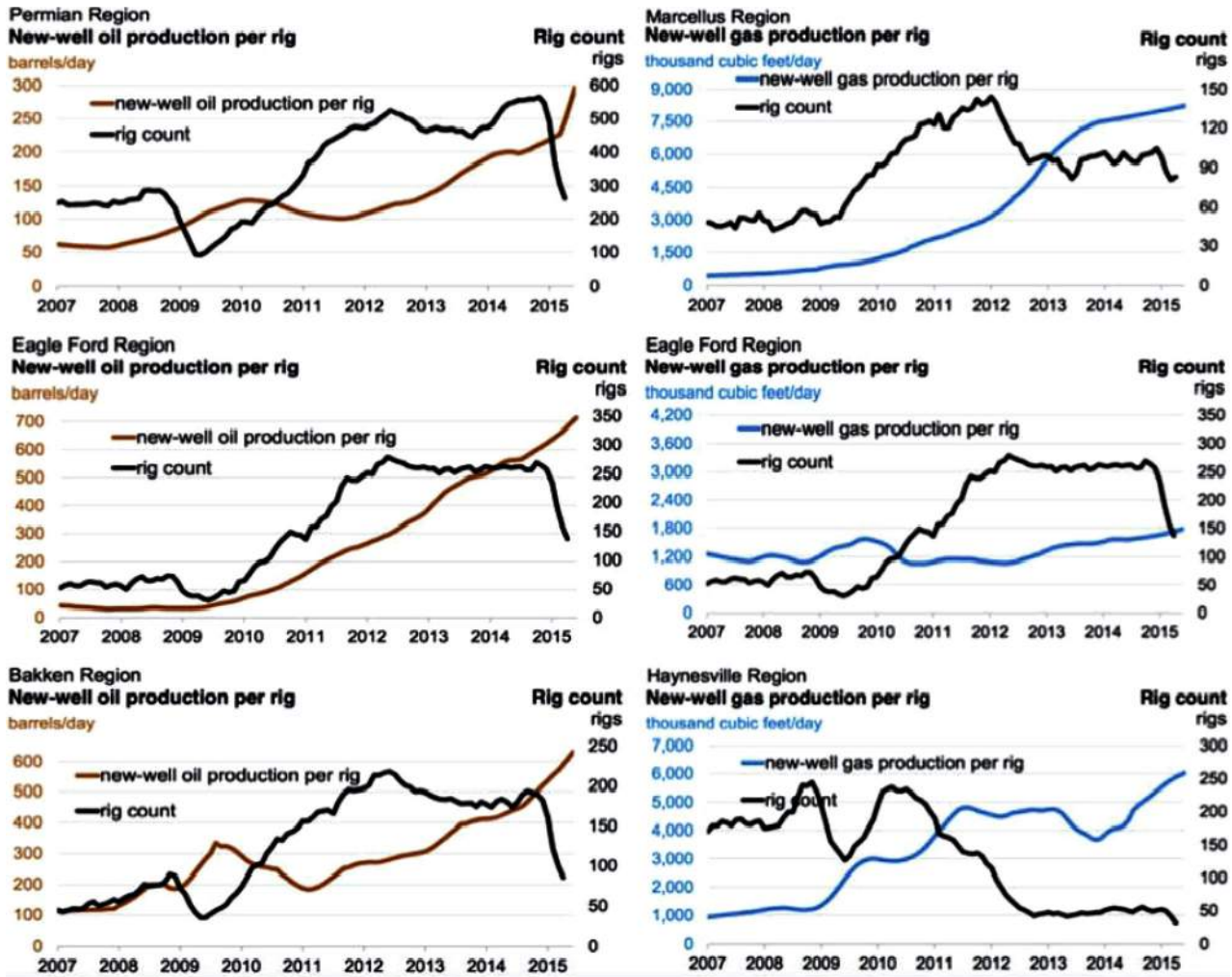

Figure 42. Rig productivity gains change the meaning of rig counts. From EIA (2015z). Drilling data through April 2015, production through June 2015.1 barrel (oil) = 0.159 m^3; 1 thousand cubic ft = 28.3 m^3.

1253 Tcf (35 trillion m^3) or half of the total resource of 2515 Tcf (71 trillion m^3) is now attributed to shales. The resource estimates follow the facts on the ground, as information has been obtained year after year. The generous resource numbers and abundant every-day supplies now coming from shale gas paint a far more encouraging picture for U.S. energy security and affordability than imagined in the lifetime of most energy experts over the past half century, yet this compelling new reality does not eliminate uncertainty in market prices, nor treacherous risk in business planning, nor controversies in the political and regulatory sphere.

Tracking the Hydraulic Fracturing Backlash

Strident calls to ban hydraulic fracturing ''fracking'' showed no letup, even as a year has gone by with half of U.S. natural gas supplies coming from natural gas and tight oil shales, i.e., reliant on technologies of hydraulic fracturing. The anti-fracking movement has been a source of consternation to many in the industry. Political measures can have substantive repercussions on industry activity, discussed below, and it requires not just scientific but sociological inquiry to understand the backlash. A fruitful path may be to draw from research into

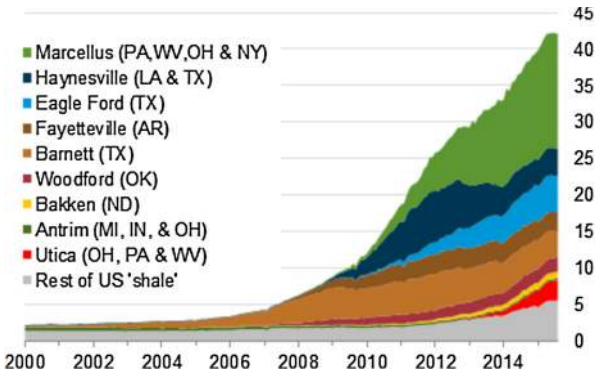

Figure 43. U.S. shale gas production (billion cubic feet per day. From EIA (EIA 2015ae). Derived by Energy Information Administration from state administrative data collected by DrillingInfo Inc. Data through August 2015. 1 billion cubic ft = 28.3 million m^3.

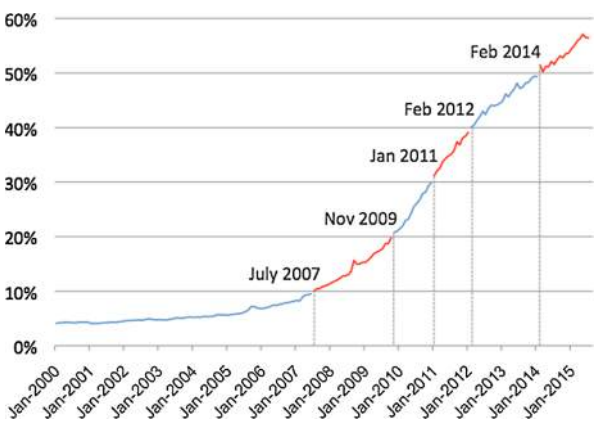

Figure 44. Shale gas as percent of total U.S. natural gas production (dry). From EIA (2015ae). Derived by Energy Information Administration from state administrative data collected by DrillingInfo Inc. Author calculation of shale gas percent of dry gas production. Data through July 2015.

''anti-science'' causes, as a National Geographic author has done in a March 2014 issue of the magazine. In his article ''Why Do Many Reasonable People Doubt Science?,'' Joel Achenbach looked into such diverse phenomena as vaccinations, fluoridation, genetically modified organisms (GMOs), evolution and climate change—not hydraulic fracturing (Achenbach 2015). Peoples' identities get caught up in what they believe and how selectively they sort information. The attraction and tenaciousness of belief systems is captured in Achenbach's observation: ''For some people, the tribe is more important than the truth; for the best scientists, the truth is more important than the tribe.'' Yet there is more to this than simply characterizing such movements has ''anti-science.'' On the subject of ''fracking,'' a Pew Research Center poll which included responses from members of the American Association for the Advancement of Science found that it was the scientists and not the general public who were more leery of ''fracking'' (Pew Research Center 2015). The intensity of passions around hydraulic fracturing, seemingly independent of scientific familiarity, highlights the dimensions of public fear and, for industry, the importance of impeccable execution. The intensity of the anti-fracking debate does not give great assurance that ''cooler heads will prevail.'' It highlights the dimensions of public fear and, for industry, the importance of impeccable execution.

Recent legislative activity and ballot initiatives convey the intensity and emotionality of concerns around hydraulic fracturing, particularly as these extend to actions of a purely symbolic nature. Athens and Yellow Springs, Ohio; Berkeley and Mendocino County, California; and the states of Vermont and Hawaii (Big Island, in 2013) are among the places with zero oil and gas prospects to have banned hydraulic fracturing (Athens and Mendocino County in 2014). The current review draws on the legislation tracking website http://ballotpedia.org/Main_Page, discussed further below. Also in the category of little potential is Maryland, which remains under a moratorium until 2017, and Florida, which is developing bills to ban or restrict fracking during 2015. California's Santa Cruz and San Benito counties enacted hydraulic fracturing bans in 2013 and 2014. The latter lacks hydraulic fracturing, but steam injection restrictions will arrest real prospects. Of greater significance is New York's statewide ban issued by the governor December 2014. Southern tier counties and cities will be affected, but Appalachian geologists have indicated to me that the loss will not place a large dent in the Marcellus Formation's overall potential.

Atop the Barnett Shale and home to 270 natural gas wells, Denton, Texas might have been expected to be the last place to ban hydraulic fracturing, yet it did so in the November 2014 election. In early 2015, this measure became the target of state legislation to ban hydraulic fracturing bans. Ballot measures continue to be mounted in different jurisdictions even as several local bans in Colorado (Fort Collins) and New Mexico (Mora County) were struck down in 2013 and January 2015 on legal grounds for

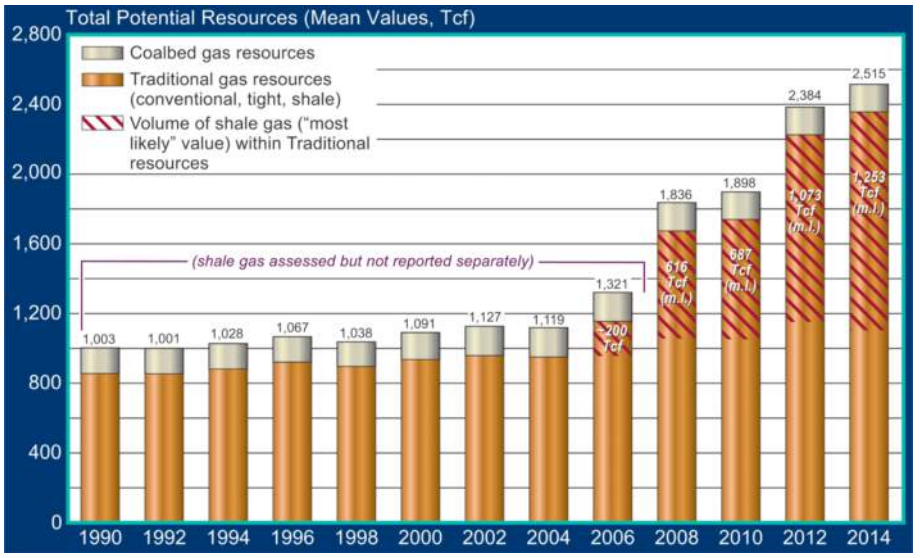

Figure 45. Progression of potential gas committee US natural gas resource estimates. From Potential Gas Committee (2015). 1000 Trillion cubic feet (Tcf) = 28.3 trillion m^3.

superseding state or federal interests. Longmont, Colorado's ban remains in legal limbo while appeals move forward into early 2015. Colorado has become a major battleground. It headed off the challenge from seven statewide ballot initiatives spanning hydraulic fracturing and local control issues after forming a multi-stakeholder task force to recommend policies. Michigan is another veteran state, considering its long history of production from the Antrim Shale, where activists are nevertheless mounting a 2016 ballot initiative to ban hydraulic fracturing.

Information sources on anti-fracking measures often convey a spin. A useful and seemingly balanced source is http://ballotpedia.org/Main_Page, which tracks fracking measures and policies by state, locality, year, and outcome (Ballotpedia 2015). It should be noted that the various bans, moratoria, and restrictions often extend to acidification proce dures and to disposal of flowback brines.

A complementary method to track the public pulse is the history of searches using Google Trends (https://www.google.com/trends/). Doing this for ''fracking'' and ''hydraulic fracturing'' shows 3 years of much heightened levels extending through the 2014 election cycle and extending to regions where impacts are occurring from proppant sand mining (e. g., Wisconsin). The first sizeable drop-off in 10 years of trending occurred in just the latest months prior to this publication, July–September 2015.

Clues to How Tighter Ozone Standards Could Affect Oil/Gas Development

On December 17th 2014, EPA proposed lowering ozone (03) emission standards from 75 to 65–70 ppb (parts per billion). Oil and gas supply is vulnerable because infrastructure to tap oil and gas shales occurs in areas that could be classified as ''non-attainment.'' Natural background levels of ozone, particularly in the rural intermountain western states, are already close to, or may often exceed, existing and proposed standards. Permitting of wells and permitting and operation of separators, compressors for pipelines, and gas processing facilities are among the critical infrastructure affected by tighter standards. Impacts include longer timetables for development, higher capital and operating costs (although state of the art procedures such as ''greenwell completions'' are already being adopted), and burdensome paperwork particularly with regard to documenting ''exceedances'' caused by natural and uncontrollable causes. (Spikes in ozone have been ascribed to stratospheric ozone intrusions, transport from international sources, wildfires, vegetation, lightning, and elevation.)

A major concern is how to obtain required ''offsets,'' i.e., emission reduction credits, for any final emissions, even after installing state of the art control technologies. These are hard to come by in rural areas lacking large point sources whose over-

compliance can generate credits. Without offsets, tighter standards could act as a brake on increasing gas development. The irony of this is that greater electric generation from natural gas combined cycle units is by far the largest ''building block'' of CO_2 emissions reductions under the Administration's Clean Power Plan proposed on June 2, 2014 (also known as Sect. 111(d) of the Clean Air Act) (Environmental Protection Agency 2014a).

The proposed rule is available from the Federal Register and from regulations.gov under ''National Ambient Air Quality Standards for Ozone'' (Environmental Protection Agency 2014b). Public comments were solicited through March 17, 2015, and posted at the latter site. Of all the comments received, macroeconomic studies by NERA Economic Consulting (formerly NERA) (NERA-EC) for the National Manufacturers Association (NAM) are repeatedly cited for guidance on the magnitude of broad economic impacts and hardships (NERA-EC 2014, 2015). NERA-EC examined impacts of a possible 60 ppb standard in a July 2014 report, giving particular attention to possible consequences for natural gas supply, demand, and price. By November, EPA announced its intention to revise the standard to 65 ppb. NERA-EC's analysis of this was released in February 2015. It was unable to update the impacts on natural gas, so the earlier results for the more stringent standard must be viewed for insights into possible directional effects. Neither study addressed impacts of tighter ozone standards on oil supplies and pipelines although their fates are intertwined in the newer unconventional plays. Selected findings from NERA-EC are given in Table 14.

Referring to 65 ppb standard, while notably more lenient than 60 ppb, one of the NERA authors described the ozone standard compliance costs as ''beyond what we have ever estimated for any other EPA regulation'' (NAM 2015). Illustrative findings from the two studies show that energy sector impacts are potentially serious (massive coal-fired generation retirements) or critical (stalled growth of natural gas supply, dramatic step-jump in prices). Impacts on other industries such as petrochemicals and fertilizer, both relying on low-cost natural gas to launch an historic resurgence while facing headwinds from suddenly cheap international oil, may add to the impacts tallied here.

The most telling result is that constraining gas production to 28.9 quadrillion Btu (~28 trillion ft^3; or 790 billion m^3) under a 60 ppb ozone standard in 2023 would drive Henry Hub prices to $9.10/mmBtu compared to $5.25/mmBtu with no further changes in ozone standards. Without further analysis, it is not clear whether and how much the more lenient 65 ppb standard later proposed could constrain natural gas production growth. The final EPA rule, released during the editorial preparations for this article on October 1, 2015 (http://www3.epa.gov/ozonepollution/pdfs/20151001fr.pdf), is a standard of 70 ppb.

A Glimpse into North Dakota

Visually impressive maps of the density of drilling, individual well paths and drilling patterns, and average individual well production are available from the North Dakota Industrial Commission. An example is shown in Figure 46. These sorts of fine-grained maps illustrate what is different about the shale plays, their promise and their risk. North Dakota is responding to additional, special challenges, including:

1. Revenue impacts from both falling prices and North Dakota Sweet's discount to the West Texas Intermediate (WTI) benchmark, $14 ($2.40/mmBtu) below WTI's $60/barrel price ($10.30/mmBtu) in early May 2015.
2. Meeting ''gas capture'' targets to greatly reduce gas flaring and modifying oil (''conditioning'') to strip off gas in the field and reduce its vapor pressure to 13.7 psi (0.9 bars). The latter rule was issued on December 9, 2014, and went into effect April 1, 2015.
3. Transportation. As of the first months of 2015, about 68% or 700,000–800,000 barrels/d (111,000–127,000 m^3/d) of 1.1 mmb/d (175,000 m^3/d) were shipped via rail.

A Logic for Natural Gas Price Formation in the Aftermath of the Oil Price Collapse

The price of oil is determined in a global market. The price of natural gas is much more regional, although it is a matter of debate whether global prices would be transmitted to the U.S. (netted back) at sufficiently high levels of LNG exports. Energy Ventures Analysis, Inc. (EVA) has proposed a mechanism for thinking about natural gas price formation in the U.S. (EVA 2014). Vast numbers of liquid-rich wells are seeing substantial revenue decline. From a revenue perspective (Fig. 47), the

Table 14. Economic Impacts of Tighter Ozone Standard: 2017–2040 (NERA Economic Consulting 2014, 2015)

	60 ppb (2013$, July 2014)	**65 ppb** (2014$, Feb 2015)
Compliance Costs		
Total	$2.24 T (vs. EPA $0.9T)*	$1.05 T (vs. EPA ~$167 B)*
Annual	$150-190 B (Capex, O&M) (ramps to $300 B by 2022)	$80-100+ B (Capex, O&M)
Coal Gen. Retirements	101 GW (52% decline in coal sector output)	34 GW; additional capacity is also affected, does not generate)
GDP Reduction 2017-2040		
Total	$3.39 T	$1.72 T
Annual	$270 B	$140 B
Labor Income Loss**	2.9 M Job-equivalents	1.4 M Job-equivalents

Natural Gas Impacts **60 ppb** (2013$, July 2014)

NERA examined natural gas impacts for the 60 ppb standard, not the 65 ppb standard, by designing a "sensitivity case" which froze US natural gas production at ~28 Tcf/yr in 2023 and thereafter. This case is likely more severe but indicative of effects when petroleum industry impacts are taken into consideration.

GDP Reduction 2017-2040	
Total	$4.48 T
Annual	$360 B
Labor Income Loss**	4.3 M Job-equivalents

Natural Gas Production and Price

Henry Hub Average Price, 2017-2040

1. Reference Case, Unchanged Ozone Standard:	$6.02/mmBtu (matches AEO2014)
2. 60 ppb Ozone Standard, NG not constrained:	$6.65/mmBtu
3. 60 ppb Ozone Standard, NG constrained:	$9.92/mmBtu

Results for 2023	**NG Production (Quads)**	**NG Price (Henry Hub)**
1. Reference Case	31.3 Q (10*15 Btu)	$5.25/mmBtu
2. NG not constrained	34.6 Q	$6.02/mmBtu
3. NG constrained	28.9 Q	$9.10/mmBtu (by 2026: >$12.00)

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* Net Present Value, 2017-2040, at 5% real discount rate; cost of coal plant retirements not included.
** Labor losses are net of positive gains in pollution control businesses. "Job-equivalents" is indicator of impact, not a count. It is total labor income loss divided by average annual income per job.

1 quad Btu = approx. 1 trillion cubic feet. 1 trillion cubic feet (Tcf) = 28.3 billion m^3.
AEO2014 Energy Information Administration Annual Energy Outlook 2014 (EIA 2014g), *NG* natural gas, *T* trillion, *B* billion, *Q* quadrillion (quad).

collapse of NGL prices has caused about a 30% decline for a Marcellus well. If oil and thus NGL prices stay at the January low level, it would take about a 30% increase in NG price, say from $3.65 to $4.75/mmBtu, to restore the lost revenues. ''Need'' alone is hardly a basis for price formation, but this

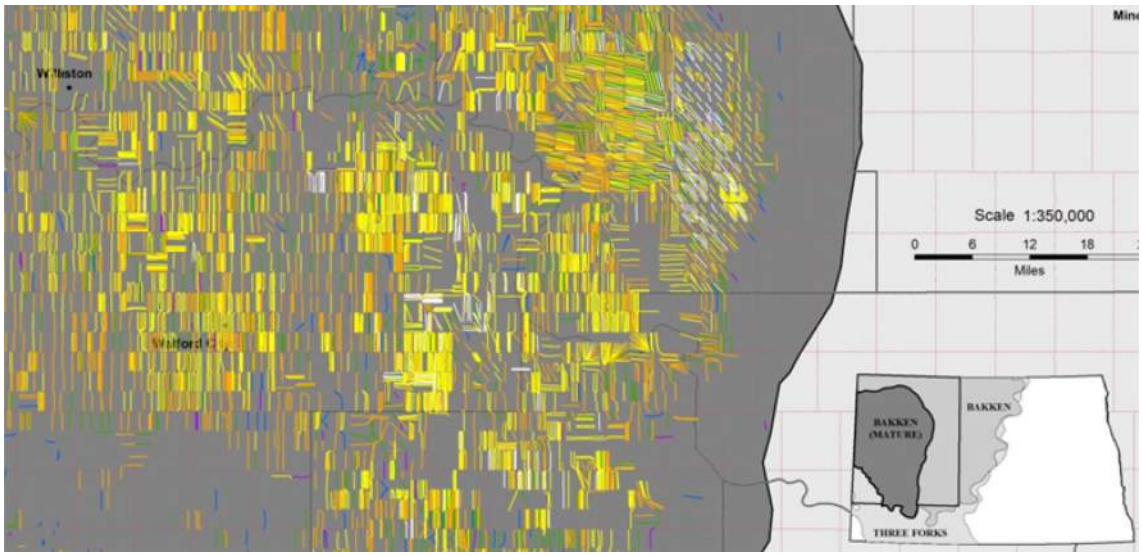

Figure 46. The zig zag heart of the Bakken. Well productivity for first 60 days average production is denoted in descending order white (>1000 bbls/d), yellow (>500), orange (>250), green (>125), blue (>50) and purple (<50). From North Dakota Department of Mineral Resources (2015). 1bbl/day = 0.159 m^3/day; 1 mi = 1.6 km.

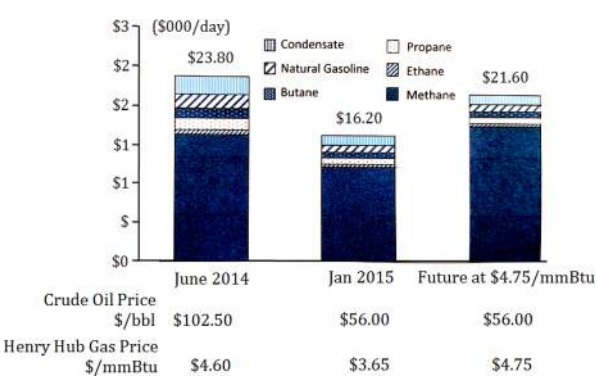

Figure 47. Net revenue for a liquid-rich Marcellus well (6 MMcf/d flow rate and 15% royalty). From Energy Ventures Analysis, Inc. (2015). 1 barrel (oil) = 0.159 m^3; 1 million cubic ft = 28,317 m^3.

calculation illustrates where natural gas prices might have to go for the industry to maintain gas-directed drilling at substantial levels. EVA does not foresee a recovery before ''late 2016 at the earliest,'' due to high storage levels.

Additional Issues

This discussion scratches the surface of changes taking place across the energy industries. It is looking like the period 2014–2015 is a pivotal time in the aftermath of the great commodities ''super-cycle'' of 2006–2008, the slowdown of the pace of China's growth, and the collapse of iron ore prices. It is pivotal in the sense that it lies between the unquestioned $100/barrel plateau and a less generous but presumably more balanced period—the balance being the balance between producer and consumer interests. Such a perspective would not have been possible at midnight on the last day of 2014, but it does seem warranted after a recovery from the price depths seen in January and February 2015.

The principal theme of this review, with its luxury of looking back at 2014 from a number of months into 2015, is that the first shocks of the oil price collapse and the search for individual triggers is past, allowing us to look at the dominant ''agent of change''—the scale of oversupply created by high volume hydraulic fracturing. As always, the tensions between how the last few percent of supplies and requirements come to balance define the market. This said, there is a host of additional issues which deserve and have not received attention in this commentary. Some of these are itemized here and represent good fodder for inquiry going forward.

The Harsh Winter of 2013–2014. This winter brought record cold, particularly to the Midwest. Natural gas storage was drawn down to record lows.

Natural gas prices, seemingly miraculously, did not spike except in infrastructure-constrained areas (this principally means New England). It all might look like an incredible success story and in many ways it was, but for two additional considerations. Propane supplies were totally insufficient in the face of early cold weather going into the winter and heightened crop-drying requirements. For students of price spikes, propane makes for an interesting case study. Second, coal-fired generating units slated to retire by 2016 in efforts to meet standards imposed by Mercury and Air Toxics legislation played a vital role where gas supplies were constrained. Some would say the country ''dodged a bullet.'' Yet part of the story is what took place next, a record stock build enabling the country to face the next winter in good shape.

Financial Adjustments in the Petroleum Industry. Reduced revenues are one thing, cutting cash flow and forcing reduced capital expenditures. Another part of this is how lower prices erode asset value in response to financial accounting and securities reporting principles. These tend to require valuing a company's assets based on a string of prior first-of-the-month settlement prices, a kind of ''looking forward through the rear view mirror'' approach. With time, the new lower prices will be what define value, reducing the collateral behind a company's debt. How companies adjust to these circumstances will be important news throughout 2015. A second consideration is that cutting back on drilling comes with a cost of breaking or renegotiating drilling contracts. These drilling commitment penalties may extend for several years.

Break-Even Prices. Calculations of ''break even prices'' for different regions and plays are a staple of financial analysts' reports, company investor presentations, consultancy reports, and some academic research. Break-even prices are prices high enough to stay in business and may principally represent prices high enough to recover operating costs. The number varies from portfolio to portfolio across wells and fields with varying characteristics and across companies with varying balance sheets, debt exposure, and cost efficiencies. Making and interpreting these calculations is of interest to most stakeholders in the industry.

Drilling and Completion Costs. Part of the break-even calculation, the interplay of field selection (high-grading), advances in technology and practices, and cost-pressures within the drilling and oilfield services sectors is a useful topic in its own right. Greater transparency in cost indices would be helpful to all concerned. It would also be useful to know what changes will continue, and are thus structural in nature, and what changes will expire once the best prospects are depleted. The performance of re-fracing is a topic of growing interest. Underlying all these cost and survival issues is an understanding of the complexity and variance of fields and plays.

Technology Performance. Due to the sensitivity of well performance, one of the few and best indicators of technology changes and costs is the financial information reported by companies. While companies are motivated to present themselves in the best possible light, the progression of changes and innovations that surface in these presentations is vital to learning what's going on. Companies in the business learn from what other companies in the business tell Wall Street. Or to put it differently, one is not likely to learn about companies' technical performance and cost efficiencies unless they have already told it to Wall Street. This information resource sheds light across the spectrum of financial adjustments, break-even prices, drilling and completion costs and technology performance.

Natural Gas Demand Response: Industrial. New and expanded fertilizer and petrochemical facilities are being announced. What comprises the ''pipeline'' of major new projects which will contribute to industrial demand? What prices will these facilities require and what defines the prices that they will be able to tolerate as prices increase?

Natural Gas Demand Response: Electric Power. Regulations and not simple market forces have much to do with electric power fuel consumption trends. Many foresee a complementary rather than oppositional balance occurring between the role of natural gas combined cycle generating units (the basic ''go to'' technology choice for efficient, clean, cost-competitive, and dispatchable power) and societal requirements imposing renewable generation. How will regulations to force greater dispatch of existing natural gas units affect gas demand, delivery, storage, and both natural gas and electric supply reliability?

Comparison of Forecasts: 100 Bcf/d World?. How many serious investigators are predicting a world in which U.S. natural gas production reaches 100 Bcf

per day (2.83 billion m^3/day)? Is this where the ''smart money'' is going, or is this a ''tulip mania,'' a bubble of straight line upward forecasting? What has to happen for this to occur on both the supply and demand side of the market, especially price?

The Societal Value of Shale Gas. This topic has received some formal scrutiny, in which economists have attempted to assess what is the value of shale gas to date. This sort of work calculates value to consumers, based on how much cheaper gas is than it would have been without shale gas, and value to producers, based on their lost earning because gas is cheaper than it would have been. Despite the formalities and rigors of such calculations, what gets left out? How is the chain of value in new infrastructure and industrial facilities represented?

Good Reads

This is a highly subjective and purposefully short list, representing both the opportunities and omissions of the author. BG Group's Andrew Walker (for LNG) (BG Group 2015a), investor presentations from innumerable companies, statistical reviews (e.g., British Petroleum Petroleum's well-known annual Statistical Review of World Energy), academic institutions, and other agencies and organizations are among the many informative references not receiving extensive commentary in this article.

Energy Information Administration. The variety and authority of a broad spectrum of information from the EIA makes for ''must read'' status. One of the new products is its series of Drilling Productivity Reports released monthly since October 2013 (EIA 2015z). These give equal treatment to both the new oil plays and the gas plays (although the Barnett Shale has not yet fallen into the scope). EIA is also the place to go to track gas storage.

The U.S. Shale Oil Revolution: The Test of the Business Model is Underway. A report issued by the Centre Energie at Institut Francais des Relations Internationales (Cornot-Gandolphe 2015) provides insight into what the rest of the world sees in U.S. ''light tight oil.''

Outlook for Natural Gas Supply and Demand for 2014–2015 Winter. The Natural Gas Supply Association has issued reports looking ahead at either summer or winter market conditions since 2008. Prepared by Energy Ventures Analysis, Inc., these are systematic and accessible analyses of supply, pipelines, demand (including major industrial facilities), and LNG. The full reports are characterized by detailed documentation.

North American Natural Gas Market Outlook: Year-End 2014: A View to 2035. Navigant Consulting issued a long-term market assessment in March 2015 (Navigant 2015). Considering that Navigant was one of the first organizations to recognize the emergence of shale gas, it is worth monitoring Navigant's perspectives.

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