Paper #2-1

WATER/ENERGY NEXUS

Prepared by the Environmental & Regulatory Subgroup
of the
Operations & Environment Task Group

On September 15, 2011, The National Petroleum Council (NPC) in approving its report, *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*, also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the study's Task Groups and/or Subgroups. These Topic and White Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

These Topic and White Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents, but approved the publication of these materials as part of the study process.

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached paper is one of 57 such working documents used in the study analyses. Also included is a roster of the Subgroup that developed or submitted this paper. Appendix C of the final NPC report provides a complete list of the 57 Topic and White Papers and an abstract for each. The full papers can be viewed and downloaded from the report section of the NPC website (www.npc.org).

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I. WATER/ENERGY NEXUS

Water is required for each stage of oil and gas production, including drilling, transport, refining and many end uses. The quantity of water that is required varies based on drilling technology, water reuse opportunities, water quality, and end use of the hydrocarbons. There is also a relationship between fuel development and water quality as the water quality can directly dictate energy needs for water purification, and can impact the quality of the hydrocarbons produced.

Water is also a by-product of oil, gas, and coal-bed natural gas production. The quality and quantity of the water can vary dramatically.[1]

Increasing population, shifting demographics, and natural variability are already straining the limited resources of fresh water. The potential impacts of climate change could add increased variability to fresh water supplies and quality. In addition, methods for reducing carbon emissions from the oil and gas life cycle might further increase the fresh water demand. As a result, the water footprint or demand of oil and gas production should be considered as part of any fuel mix decision as it can have important consequences on regional resources. This brief discussion is intended to highlight the top-level fresh water quantity and water quality issues relevant to oil and gas production to inform industry, stakeholders, and policymakers.

A. Water Quantity Issues

Understanding the difference between water consumption and withdrawal is important when planning for the impacts of water usage. Water consumption describes water that is taken from surface water or groundwater sources and not directly returned (e.g. it might be evaporated before it is returned). Water withdrawal pertains to water that is taken from a surface water or groundwater source, used in a process, and potentially returned to the source making it available for the same or other purposes. Water consumption is inherently a subset of water withdrawal, and it is possible to withdraw more water than is consumed.

1. Natural Gas

Natural gas can be produced through a number of methods. Historically, the water for natural gas production was not a significant issue. While some unconventional gas such as Coal Bed Methane may not require significant volumes of fresh water, many new or unconventional gas developments require new technologies, some of which are more water-intensive than before. Much of the water used for current gas production is used in the process of hydraulically fracturing the rock formations, usually shale. In this

[1] U.S. Department of Energy, Energy Demands on Water Resources: Report to Congress on the Interdependency of Energy and Water. December 2006 at p. 57. ("USDOE Energy Demands on Water") Accessed April 2011 at
http://www.sandia.gov/energy-water/docs/121-RptToCongress-EWwEIAcomments-FINAL.pdf

process, water with fluid additives is injected under high pressure to open and enlarge fractures in the rock and allow for increased production. This process can be water intensive, but actual quantities depend on a number of factors including the geologic properties of the shale.

The goal during hydraulic fracturing or fracing is not only to fracture the formation with water and pressure, but to deliver the sand or proppant, to keep the fractures open. The majority of water injected during hydraulic fracturing is to deliver the proppant rather than to create the fracture. If injected water is reduced, more energy must be used at the surface to force the large mass of proppant down into the formation to achieve equivalent fracturing and production. Thus, there is a tradeoff between reducing water use at the expense of increased energy use.

Today, an estimated 4 to 6 million gallons of water per well is used during the fracing and well development or production phase in a typical deep shale formation. The majority of the water is used early in well development and before production begins.[2] One producer has reported that the use of water for fracturing translates to 0.8-1.6 gallons of water per million British Thermal Units (MMBtu) of energy produced.[3] The amount of water per MMBtu for drilling and extraction for conventional or traditional natural gas wells is considered negligible.[4]

During the fracturing process, much of the fresh water use is consumptive, with estimates of 30% to 70% of the original frac fluid volume returning to the surface.[5] Some of the water remains in the formation, while the produced water (water from the formation or injected water returned to the surface) is either recycled or treated and disposed of as liquid waste. The significance of the water use in a region depends on the quantity needed and the quantity available, the level of well development in the area, the nature of the shale, the quality of the produced water (as it affects the ability to reuse the fluid) and local regulations for disposal.

In addition to the use of water to extract natural gas, water is also needed for processing, transporting and in its ultimate use, including the use of gas for electricity generation or in its conversion to a transportation fuel. Water use is estimated in an average gas processing plant at 2 gal H2O/MMBtu and another 1 gal H2O/MMBtu for typical gas pipeline operations.[6] Use of water in power production can vary based on the type of technology at the plant for both cooling and power generation. A typical open-loop cooling system at a natural gas combined cycle plant would withdraw 7,500-20,000

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[2] Mantell, Mathew E., "Deep Shale Natural Gas and Water Use, Part Two: Abundant, Affordable, and Still Water Efficient," 2010 Ground Water Protection Council (GWPC) Water/Energy Symposium, Accessed April 2011 at www.gwpc.org/meetings/forum/2010/proceedings/20Mantell_Matthew.pdf

[3] Mantell 2010.

[4] USDOE Energy Demands on Water at p.57

[5] Ground Water Protection Council and ALL Consulting. 2009. *Modern Shale Gas Development in the United States: A Primer.* P. 66. Prepared for the DOE Office of Fossil Energy and National Energy Technology Laboratory (NETL). April 2009. Accessed April 2011 at http://www.netl.doe.gov/technologies/oil-gas/publications/epreports/shale_gas_primer_2009.pdf

[6] USDOE Energy Demands on Water at p. 59.

gallons of water per MWh of electricity, of which an average of 110 gal H2O/MWh is consumed.[7] Closed-loop cooling has average withdrawals of 240 gal H2O/MWh and consumption rates of 190 gal H2O/MWh.[8] Plant modifications such as carbon capture and sequestration would greatly increase water consumption per MWh delivered.

While natural gas vehicles (NGVs) are not currently widespread in the US, NGV usage could increase in the future. Worldwide there are approximately 7 million NGVs, with 150,000 in the US. When using electrical compressors, 0.06-0.10 kWh/mile is required for natural gas compression. The indirect water usage for electricity from the US grid mix is 0.06-0.07 gal H2O/mile consumption and 1.3-2.1 gal H2O/mile withdrawal. If using natural gas-powered compressors, approximately 6.5 SCF/mile of gas is used for compressing the natural gas, and the resulting water usage is approximately 0.03 gal H2O/mile for both consumption and withdrawal.[9]

2. Oil, Oil Shale and Oil Sands

Water requirements for oil production can vary depending on the source material and region. Traditional onshore drilling uses about 0.8 to 2.2 gal H2O/MMBtu during the period of initial drilling and production.[10] Oil shale and oil sands present one of the more direct substitutions for conventional petroleum wells and are often placed into a category of fossil resources called 'unconventional oil.' Often, the 'unconventional' nature of these resources pertains to the fact that they require new techniques and/or considerably more input of energy and/or materials (e.g. CO2, water/steam, electricity, or heat) to extract and/or process the fuel.[11]

Oil shale and oil sands require water and heat to either extract them from the ground using in-situ (in place, underground) processes, or to process it after surface or underground mining. Without considering future technological reductions in water usage, mining and processing of oil shale and extracting and upgrading oil sands consumes a large amount of water.

Oil shale is commonly defined as a fine-grained sedimentary rock containing organic matter that yields substantial amounts of oil and combustible gas upon destructive distillation (decomposition by heating).[12] Oil shale water budgets are estimated at 7 to 22 gallons of water per MMBtu (based on water usage of 1 to 3 gallons of water per barrel

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[7] USDOE Energy Demands on Water at p. 65.
[8] Ibid.
[9] King, Carey W., and Webber, Michael E., "Water Intensity of Transportation," *Environ. Sci. & Tech.,* September, 2008, pp 7866–7872. Accessed April 2011 at http://pubs.acs.org/doi/full/10.1021/es800367m
[10] USDOE Energy Demands on Water at p. 57.
[11] King and Webber
[12] Dyni, J.R., 2006, Geology and resources of some world oil-shale deposits: U.S. Geological Survey Scientific Investigations Report 2005–5294, 42 p. Accessed April 2011 at http://pubs.usgs.gov/sir/2005/5294/pdf/sir5294_508.pdf

of oil and energy content of 5.8 MMBtu/bbl oil).[13] Additional water is required for refining and end use. Specifically, the water consumption for converting oil shale to gasoline for use in light duty vehicles (LDVs) is in the range of 0.15-0.37 gal H2O/mile.[14] If the oil shale industry were to produce 2.5MMBbl/d, the water usage equates to between 105 and 315 million gallons of water per day.[15] This estimate includes water for mining the shale as well as water for on-site needs such as power generation, dust control and heating processes.[16]

Distinct from oil shale resources, "tight oil" from low permeability shale is produced using the same hydraulic fracturing techniques as in extraction of natural gas from shale. Thus, similar quantities of water per well are needed during fracturing.

Oil sands are naturally occurring mixtures of sand, clay, water, and an extremely dense and viscous form of petroleum called bitumen. The extraction is done by surface mining if the resources are close to the surface or by using drilling and various technologies underground or in situ. In North America, most of the productive oil sands are in Canada.

Earlier technologies reported using 8 tons of water for one ton of product, and the water budgets were estimated at 20 - 50 gal H2O/MMBtu (also based on energy content of 5.8 MMBTU/bbl oil).[17] Thus, the water consumption for converting mined oil sands to gasoline for use in light duty vehicles (LDVs) is a little higher than oil shale, at 0.20-0.46 gal/mile.[18] This higher value is due to the water intensity of the mining and processing practices in the McMurray Formation in the Athabasca River Basin of the province of Alberta, Canada.

The best current practices for an in-situ oil sands extraction process, steam assisted gravity drainage (SAGD), requires withdrawal of approximately 0.5 barrels of water for every barrel of oil produced, or 3.6 gal H2O/MMBtu. The oil sands extraction projects in northern Alberta now report that it takes an average of two to four barrels of water to produce one barrel of bitumen from a mine.[19] The recent mining related extraction of oil sands requires withdrawal of 14 - 29 gal H2O/MMBtu (more than 50% of which is now non-fresh or saline water[20]) while recycling or reusing between 80 - 95% of the water.[21]

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[13] U.S. Department of Energy, Fact Sheet: Oil Shale Water Resources, 2007. ("USDOE Fact Sheet: Oil Shale Water Resources "). Accessed April 2011 at www.fossil.energy.gov/programs/reserves/npr/Oil_Shale_Water_Requirements.pdf
[14] King and Webber
[15] USDOE Fact Sheet: Oil Shale Water Resources.
[16] Ibid.
[17] USDOE Energy Demands on Water, citing Gleick, 1994.
[18] King and Webber
[19] Canadian Association of Petroleum Producers (CAPP), Dialogue: The Facts on Oil Sands March 2011. Accessed April 2011 at www.capp.ca/UpstreamDialogue/OilSands/Pages/default.aspx#PXcqBN4RLsBC
[20] Canadian Association of Petroleum Producers (CAPP), Responsible Water Management in Canada's Oil and Gas Industry, 2010-0018, June 2010. Accessed April 2011 at www.capp.ca/getdoc.aspx?DocID=173950
[21] CAPP, Dialogue: The Facts on Oil Sands.

In calculating the water withdrawal for using oil shale or oil sands converted to gasoline to power LDVs, the additional water consumption for mining or SAGD processing is added to the water withdrawal amount used for petroleum refining. This addition results in water withdrawal rates of 0.71-0.86 gal H2O/mile for oil shale and 0.76-0.95 gal H2O/mile for oil sands.[22]

Considerable amounts of water are also required in the oil refining process to convert the oil to the end products such as gasoline and diesel, whether the oil is extracted through traditional drilling or from oil sands. Large industrial refineries can use 3 to 4 million gallons of water a day,[23] much of which is lost to evaporation, meaning that 60-70% of water used is consumptive. Total water consumption for refining is 7 - 18 gallons of water for every MMBtu.[24]

3. Tertiary and Enhanced Oil Recovery Processes

Most formations require additional techniques to maximize production over the life of a well. These efforts are called tertiary recovery and Enhanced Oil Recovery or EOR. EOR often injects water to flood the formation and force residual oil out of the reservoir. This process can use substantially more water than the primary hydrocarbon recovery processes. Depending on the formation and other conditions, EOR requirements are approximately 14 gal H2O/MMBtu for production. More water intensive processes can increase this number to 2,400 gal H2O/MMBtu. A number of factors can impact this number, such as on-site water recycling and use of CO_2 for EOR can reduce water use considerably. Additional water is needed for refining and combustion.

[22] King and Webber.
[23] USDOE Energy Demands on Water, citing CH2M Hill, 2003.
[24] USDOE Energy Demands on Water, citing Gleick, P. 1994.

Resource	Water consumption range (gallons/MMBtu)			
	Drilling	Completion/ Stimulation/ Enhancement/ Extraction	Production Processing & Refining	Generation
Natural Gas				
Conventional - Flowing	< 1 gal/MMBtu [1]		~ 2 gal/MMBtu [2]	110-190 gal/MWh [2]
Conventional – Fracture Stimulation	< 1 gal/MMBtu [1]	1-3 gal/MMBtu [2]		
Non-Conventional – Tight Gas (Rock/sand) - Fracture Stimulation	< 1 gal/MMBtu [1]	< 3 gal/MMBtu [1]		
Non-Conventional – Tight Gas (Shale) – Horizontal Well w/ Fracture Stimulation	0.02-0.10 gal/MMBtu [3]	0.8-1.6 gal/MMBtu [3]		
Non-Conventional – CBM				
Oil				
Conventional - Flowing	< 1 gal/MMBtu [1]	0.8-2.2 gal/MMBtu [2]	7 – 18 gal / MMBtu [2]	
Conventional – Fracture Stimulation	< 1 gal/MMBtu [1]			
Non-conventional – Oil (Tar) Sands - Mined		14 - 29 gal/MMBtu [4]		
Non-conventional – Oil (Tar) Sands – in situ Extraction	< 1 gal/MMBtu [1]	~ 3.6 gal/MMBtu [4]		
Non-conventional – Oil Shale- Mined		7 - 22 gal/MMBtu [5]		
Non-conventional – Oil Shale – in situ Extraction	< 1 gal/MMBtu [1]	7 - 22 gal/MMBtu [5]		
Non-conventional – Enhanced Oil Recovery (EOR) – Nitrogen or Steam Injection				
Non-conventional – Enhanced Oil Recovery (EOR) – Water injection		14 – 2,500 gal/MMBtu [2]		
Non-conventional – Enhanced Oil Recovery (EOR) – CO2 Injection		≥ 172 gal/MMBtu [2]		
Non-conventional – Enhanced Oil Recovery (EOR) – WAG (water alternating gas) Injection				
Non-conventional – Tight Shale Oil – Horizontal Well w/ Fracture Stimulation	0.02-0.10 gal/MMBtu [6]	1.6 – 3.6 gal/MMBtu [6]		

[1] *Assumed*
[2] *USDOE Energy Demands on Water*
[3] *Mantell 2010*
[4] *Extrapolated from water use figures taken from CAPP, Upstream Dialogue: The Facts on Oil Sands 2010.*
[5] *USDOE Fact Sheet: Oil Shale Water Resources*
[6] *preliminary non-published Chesapeake Energy Data from Eagle Ford Shale, 2010*

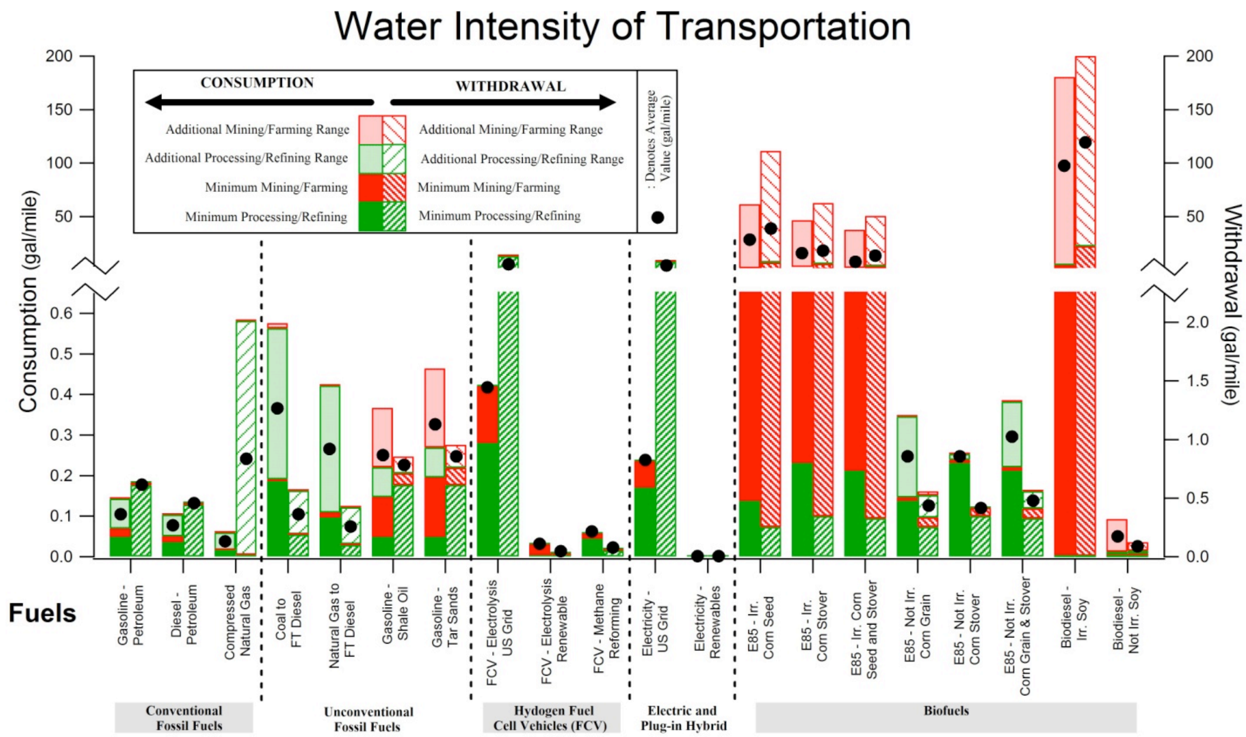

Figure 1. The water consumption and withdrawal (gallons of water per mile traveled) varies considerably depending upon the life cycle of the fuel (update from King and Webber (2008)).

B. Water Quality Issues

There is a direct relationship between water quality and energy requirements particularly as related to hydraulic fracturing and EOR processes. Poor quality source water needed for production must be treated if it contains high concentrations of scaling parameters, bacteria, or sulfates. Poor quality water can cause swelling of formations and production of unwanted corrosive compounds which impair the formation. Purification of poor quality water takes energy. A certain level of salts can be accommodated during the fracturing process; however, as the concentration increases, additional treatment is necessary.

An additional balance that must be met is the ratio of water mass used in hydraulic fracturing as compared to the mass of chemicals in the water. Energy and water needs can be reduced through the use of these additional chemicals to reduce friction; however, these constituents may raise additional environmental concerns. Also, each of these chemicals has its own water and energy inputs as part of their production and transport. Fully understanding the water impact for the various levels of injected water, proppant, and chemicals requires a lifecycle evaluation of the tradeoffs.

Decisions for injected water sourcing must be based on regional needs and local water availability. Each situation is unique and a “one size fits all” solution is not viable. In some regions, an appropriate technique may be to reduce chemical and energy inputs via additional water use. In regions with greater concerns about water-scarcity and lower concerns about water quality, stakeholders may favor minimization of water withdrawal and consumption.

C. Produced Water

Produced water, a byproduct of oil and natural gas (energy) development, plays a key role in the energy/water nexus. While produced water is extracted alongside the production of oil and gas, energy also plays a key role in determining the best way to manage produced water. For the purposes of this discussion, *produced water* is all water that is returned to the surface through a well borehole and is made up of water injected during the fracture stimulation process, as well as natural formation water. (This would include what is sometimes referred to as *flowback,* which is a term for the *process* of excess fluids and sand returning through the borehole to the surface from fracture stimulations.) In order to successfully develop these fuel resources, produced water should be effectively managed.

Produced water is typically produced during the lifespan of a well, although quality and quantity vary significantly by region. Produced water quality can also vary tremendously from brackish (not fresh, but less saline than seawater) to saline (similar salinity to seawater) to brine (which can have salinity levels multiple times higher than seawater). Depending on the formation being developed, produced water quality can even vary tremendously from within the same formation. In addition to very high levels of natural salts, produced water may contain suspended solids, hydrocarbons, dissolved minerals and other compounds that have dissociated from the target hydrocarbon reservoir.

Historically, the common methods for produced water management from oil and gas operations has been disposal by injection into the producing reservoir to maintain pressure or enhance recovery (EOR), or via underground injection into EPA approved Class II Salt Water Disposal (SWD) wells. Injection in SWD wells is still a viable option in most oil and gas producing areas. However, water conservation measures and lack of disposal capacity in new areas have focused more attention and research on recycling and reuse of produced water.

The amount of energy required to effectively manage produced water quality is dependent on two sets of parameters which require very different water treatment. The first set includes suspended solids, oil and grease, hardness compounds, and other non-dissolved parameters. These constituents are often treated with conventional water treatment processes including flocculation, coagulation, sedimentation, filtration, and lime softening. These processes utilize chemicals, which may require significant energy input in their development. The technologies can be energy intensive, but are typically *much less* energy intensive than the salt separation treatments.

The other set of constituents include dissolved solids, primarily consisting of chlorides and salts, but also may include dissolved barium, strontium and some dissolved radionuclides. These dissolved parameters are much more difficult and energy intensive to treat, and can only be separated through reverse osmosis membranes, thermal distillation, evaporation, and/or crystallization processes. In addition to being energy intensive, treatment and disposal of dissolved solids can be expensive.

These water treatment processes typically require that the conventional treatment processes listed above for the first set of non-dissolved parameters be completed prior to treatment for the second set of dissolved parameters. This is required to ensure that most of the non-dissolved parameters are removed prior to the dissolved solids treatment process.

The water/energy relationship must be considered when discussing possible reuse options for produced water. Much discussion and technology development has focused on treatment technologies that can treat produced water so it is suitable for reuse in oil and gas operations, municipal, agricultural, and/or industrial operations. Produced water having less total dissolved solids (TDS) (< 30,000 ppm TDS) may be feasible for treatment to reuse outside of oil and gas operations. Higher dissolved solid produced waters (> 30,000 ppm TDS) should only be reused where the high salt/salinity content can be kept in solution (to avoid the intense energy input to separate salts). Operators have successfully demonstrated produced water reuse by using conventional treatment processes on high TDS waters, then managing the TDS by blending the fluids in hydraulic fracturing operations.

The feasibility of relying on high TDS produced waters for potential municipal or agricultural water supply might not make sense from an energy, economic, or environmental perspective due to the availability of alternative low quality water resources that could be treated to acceptable standards with far lower energy inputs. These streams include municipal wastewater, brackish groundwater, and even seawater when logistically feasible. Furthermore, oil and gas operations that keep dissolved solids in solution and use the fluid in completion operations for subsequent wells can effectively reduce the volume of fresh water needed for future operations by significant amounts. Specifically, the shale gas industry has recently been very successful in utilizing conventional, low energy treatment systems to remove suspended solids from produced water and in using this water in hydraulic fracturing operations. From an energy efficiency standpoint, this is a much more efficient use of energy and water than treating produced water to drinking water standards. Any decisions regarding reuse should consider these trade-offs as well as regional requirements.