Testimony
House Committee on Natural Resources
Subcommittee on Energy and Natural Resources
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Good morning Chairman Lamborn, Ranking Member Holt, and members of the committee.

I am Erik Milito, upstream director at the American Petroleum Institute. API has more than 500 member companies, which represent all sectors of America's oil and natural gas industry. Our industry supports 9.2 million American jobs and 7.7 percent of the U.S. economy. In fact, a recent report from the World Energy Forum concludes that from 2010 to 2011, oil and gas industry employment grew by 4 percent, adding approximately 150,000 total jobs to the economy, representing 9 percent of all jobs created in the U.S. in 2011. The industry also provides most of the energy we need to power our economy and way of life and delivers more than $86 million a day in revenue to the federal government.

Our nation can and should be producing here at home more of the oil and natural gas Americans need. At a time when the United States still must import half the oil it consumes, we should be adding to our supplies from our own ample domestic resources. This would strengthen our energy security and help put downward pressure on prices while also providing many thousands of new jobs for Americans and billions of dollars in additional revenue for our government.

The administration should encourage this, but we've seen a status quo approach to federal lands oil and natural development characterized more by delay and restriction than by rising project approvals. Policy leadership for creating and overseeing a more robust program of safe and responsible development has been absent. We continue to hear about an "all-of-the above" energy approach. An "all-of-the-above" approach makes sense, but all-of-the-above necessarily includes oil and natural gas. The administration's projections show that oil and natural gas will supply most of the nation's energy for decades to come. Yet while the Administration claims to support an "all-of-the-above" approach, we continue to see proposals to increase taxes on the industry, decisions that reduce opportunities for leasing and resource development, processes that string out permitting, and continued regulatory uncertainty. We have provided a three-page summary for the subcommittee's consideration that outlines more than 20 key decisions that propose new taxes or otherwise prevent, delay or obstruct oil and natural gas development.

This makes no sense. The United States has some of the largest reserves of oil and natural gas on the planet and we need a comprehensive energy policy that supports increased development – something most of the public supports. The industry has the capital, technology, and commitment to safe and responsible development to make it happen the right way.

The Administration continues to propose tax increases to the industry, which is completely contrary to its recent statements that suggest it supports U.S. oil and natural gas development. And we must be clear, these proposals would raise taxes on production by eliminating tax deductions – not subsidies – that are similar to or the same as those that many taxpayers – including companies like Apple Computer, the New York Times, and General Electric - avail themselves. We do not suggest increasing taxes on any particular company or sector; we simply believe these proposals amount to discriminatory tax policies against the oil and gas industry and would significantly hurt rather than help the U.S. economy. In fact, two recent studies by Wood Mackenzie conclude that it is through increased access to domestic oil and natural gas—rather than increased taxes on the U.S. oil and natural gas industry—that provides the best strategy for increasing government revenue, jobs and energy production.

U.S. oil and natural gas companies are a major force in our economy and, with the right policies in place, could drive even greater economic benefits. These companies produce most of the nation's energy, put millions of people to work and deliver billions in taxes and royalties to our state and federal governments. The studies show increased access to areas currently off-limits would create jobs, grow the economy and dramatically increase revenues to the Treasury, at a time when the U.S. deficit is of national concern, while increased taxes would take us backwards.

Increased access to American and Canadian supplies could (by 2020) create 1,100,000 jobs, deliver $127 billion more in revenue to the government, and boost domestic production by four million barrels of oil equivalent a day, according to the Wood Mackenzie study, "U.S. Supply Forecast and Potential Jobs and Economic Impacts (2012-2030)." A copy of this study is provided for consideration by the subcommittee. In an earlier Wood Mackenzie study, "Energy Policy at a Crossroads: An Assessment of the Impacts of Increased Access versus Higher Taxes on U.S. Oil and Natural Gas Production, Government Revenue and Employment," they found that raising taxes on the industry with no increase in access could reduce domestic production by 700,000 barrels of oil equivalent a day (in 2020), sacrifice as many as 48,000 jobs, and reduce revenue to the government by billions of dollars annually. An additional 1.7 million barrels of oil equivalent a day in potential production that is currently of marginal economic feasibility would be at greater risk of not being developed under the modeled tax increase. A copy of this study is provided as well.

Furthermore, the Congressional Research Service (CRS) recently concluded in a March 2, 2012 report entitled "Oil and Natural Gas Industry Tax Issues in the FY2013 Budget Proposal" that the Administration's tax proposals would "make oil and natural gas more expensive for U.S. consumers and likely increase foreign dependence." On Saturday, the President stated that a vote for his tax proposal would show that you "stand up for the American people." Yet it is this same tax proposal that would destroy domestic production, destroy jobs, destroy government revenue and, according to CRS, make oil and natural gas more expensive and make us more dependent on foreign energy. The American people get it, as poll after poll shows that the American public opposes increased taxes on America's oil and natural gas industry, with most Americans agreeing that increasing taxes would destroy jobs.

In addition to maintaining an effective tax structure and improving access to U.S. resources, we must also ensure that we have streamlined permitting and regulatory certainty to ensure continued job creation and a regulatory climate that encourages investment in U.S. projects.

However, the federal government has taken step after step to decrease leasing, decrease permitting, and introduce uncertainty into the regulatory process to effectively place a drag on both short-term and long-term energy production, in both onshore and offshore areas. With respect to BLM-managed lands in particular, the picture is not promising.

Lease sales in the West, which has been a very important region for U.S. oil and gas development, are down 70 percent in 2011 as compared to 2008. Some of the state-level examples are striking, with Interior offering a mere four parcels in Colorado in 2011 as compared to 241 in 2008, a mere 17 in Utah in 2011 as compared to 124 in 2008, and only 213 in Wyoming in 2011 as compared to 1,186 in 2008. Interior has not consistently met its statutory requirement of issuing leases within sixty days of the lease sale. On top of that, Interior has canceled or suspended numerous leases in Utah and Montana.

Permitting is also delayed and down on BLM-managed lands. Companies simply do not get permits to drill in a timely fashion. Permitting times have averaged more than 200 days in recent years, and depending on the field office, it can actually take more than two years to obtain a permit. The Energy Policy Act of 2005 mandated a thirty day deadline for processing applications for permits to drill and this deadline is largely ignored. The number of permits being issued by Interior dropped by 39 percent when comparing the total permits issued in 2009 and 2010 to the total permits issued in 2007 and 2008. The Administration is quick to point out that there are about 7,000 outstanding approved permits, but it conveniently neglects to explain that there are stipulation periods, lands that are now subjected to new planning requirements where development is prevented, lawsuits and other reasons that may prevent companies to utilize many permits. In addition, the uncertainty about when permits are approved means that companies may need to submit multiple applications in the hopes that some permits may actually get approved in a timely fashion. A copy of a January 2012 report by Grand Junction based EIS Solutions on the impact of current federal lands policies lays out the declining leasing and permitting trends on BLM-managed lands and is provided for the subcommittee.

Interior is also holding operations at bay through extremely long delays in completing the environmental analysis to support a project approval. This environmental analysis must occur before companies can apply for drilling permits. The Council on Environmental Quality's NEPA guidance states that Environmental Assessments (EA) should take three months to complete and Environmental Impact Statements (EIS) should take 12 months to complete. However, Interior routinely takes years to complete both EAs and EISs. A May 2011 report by SWCA Environmental Consultants, entitled "Economic Impacts of Oil and Gas Development on BLM Lands in Wyoming", demonstrated that six EISs were delayed in a range of one to five years. The impact of these delays is quite astonishing, with an estimated 17,000 total wells delayed due to the snail's pace of NEPA review by Interior. The estimated employment impacts from the delays in these 6 projects equate to 30,666 average job equivalents and $2.6 billion in earnings that would not be realized annually within the state of Wyoming. A copy of this report has been provided to the subcommittee for consideration.

Interior has taken various other specific steps that effectively add uncertainty to the BLM-regulatory process. In January 2010, Interior introduced a slew of new administrative requirements and processes to an already burdensome onshore leasing process. According the Western Energy Alliance, these policies add three additional layers to the existing five levels of regulation and analysis. In February 2011, Interior created a new category of wilderness called "wild lands." This runs counter to the Wilderness Act, which specifically provides Congress with the authority to designate Wilderness Areas – not Interior. Congress has effectively designated more than 100,000,000 acres as wilderness. However, the new "wild lands" policy has the potential to remove lands from multiple-use to one use, contrary to the directive of the Federal Land Policy Management Act. Interior also has chosen to severely limit the use of categorical exclusions as directed by Congress in Energy Policy Act 2005. Congress developed these five exclusions to address situations where the environmental impact is minimal or where additional review would be redundant, but Interior continues to ignore this Congressional mandate.

The Rockies have steadfastly delivered oil and natural gas to the nation through strong state-level regulation of drilling and production operations on both state and federal lands. The records of Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming are strong when it comes to developing and implementing oil and gas regulations. Yet despite all of this, Interior is moving forward with its own regulations for drilling operations. The Governors of the States of North Dakota and Utah recently sent letters to the Secretary of the Interior objecting to this regulatory effort. Copies of these letters are provided to the subcommittee. As stated by Governor Dalrymple of North Dakota, "I believe additional regulations regarding these issues are unnecessary and redundant in an area that is already effectively regulated by the states." We simply have not seen a demonstration of inadequacy in the states' regulatory systems. In fact, EPA Administrator Lisa Jackson has spoken on multiple occasions in acknowledgment of the effective job states are doing.

And we have seen the start of a similar pattern of obstruction with the U.S. Forest Service, which released a draft forest management plan that proposes a ban on horizontal drilling in the George Washington National Forest and which canceled a planned auction of public lands in the Wayne National Forest.

The industry stands committed to safe and environmentally responsible development. We're working very hard, for example, to ensure that shale oil and natural gas development occurs with as little impact on the environment and with as much transparency as possible. API has more than 200 industry standards related to exploration and production activities, including a series of hydraulic fracturing documents that assist operators in well construction and integrity, water management, surface impact mitigation and environmental protection. A copy of the hydraulic fracturing series of documents has been provided to the subcommittee for consideration.

We are aggressively promoting safe and responsible operations by holding a series of workshops across the country on the API hydraulic fracturing documents. Targeted to local audiences from industry, elected officials and other stakeholders, these workshops offer a high-level explanation of the API standards and our ANSI-accredited standards process, and demonstrate industry's commitment to working with communities, local elected leaders and state regulators. To date, API has completed seven of these half day workshops in Arkansas, North Carolina, Maryland, New Jersey, West Virginia, Ohio and New York. Each event has also given the audience of approximately 100 participants the opportunity to hear from state regulators, local officials and business people about the latest developments of shale energy in their region. Additional workshops are scheduled in Bismarck, ND, Cheyenne, WY, Denver, CO, Baton Rouge, LA, Traverse City, MI and Washington, DC. And we've also been working closely with state regulators as they've reviewed and updated their rules to ensure regulations are shaped to promote safe and responsible industry operations. We understand the need to do it right, and are working every day to make it happen.

And yet what we've seen on the federal level is a pulling back on new development on public lands. The administration has been restricting where oil and natural gas development may occur, leasing less often, shortening lease terms, going slow on permit approvals, and increasing or threatening to increase industry's development costs through higher taxes, higher royalty rates, higher minimum lease bids, and overlays of new regulations.

The administration likes to point out that oil production is up nationwide, but it is claiming credit for production gains taking place on private and state lands within which the federal government does not have control over leasing, permitting and regulation of operations. In the areas where the federal government is in control, oil production is down 7.9 percent when comparing 2011 to 2009 and natural gas production is down 14.7 percent over the same period. It is important to keep in mind that BLM-managed lands in the Rockies have historically been a strong producer of natural gas for the nation, yet we are a seeing a lag in production. And over the same period, natural gas production increased by 21 percent on nonfederal lands.

In his recently released book "The Quest", the Pulitzer-prize winning historian Daniel Yergin points out that "[p]olicies related to access to energy and its production can have major impact on the timeliness of investment and the availability of supply – and thus on energy security." With the right policies and right leadership, we could be doing far better in developing our own energy and bolstering America's economic and energy security. The results could be astounding. Within 15 years, American and Canadian energy supplies could provide 100 percent of U.S. liquid fuel needs with increased biofuels development and the implementation of four straightforward policies:

- Providing access to U.S. oil and natural gas reserves that are currently off-limits;

- Returning the Gulf of Mexico permitting rates to premoratorium levels, at a minimum;

- Resisting calls for imposition of unnecessary new regulatory requirements on oil and natural gas development; and

- Partnering with Canada to develop new pipeline capacity to export Canadian crude to the United States, including approval of the Keystone XL pipeline.

A document is provided that demonstrates how this level of energy security is achievable.

We urge the Congress and the administration to promote energy policies that consistent with this strategy to aid our economic recovery and reduce our debt.

Thank you. That concludes my statement.

Environmental Protection for Onshore Oil and Gas Production Operations and Leases

API RECOMMENDED PRACTICE 51R
FIRST EDITION, JULY 2009

Environmental Protection for Onshore Oil and Gas Production Operations and Leases

Upstream Segment

API RECOMMENDED PRACTICE 51R
FIRST EDITION, JULY 2009

Environmental Protection for Onshore Oil and Gas Production Operations and Leases

1 Scope

This standard provides environmentally sound practices for domestic onshore oil and gas production operations. It is intended to be applicable to contractors as well as operators. Facilities within the scope of this document include all production facilities, including produced water handling facilities. Offshore and arctic areas are beyond the scope of this document. Operational coverage begins with the design and construction of access roads and well locations, and includes reclamation, abandonment, and restoration operations. Gas compression for transmission purposes or production operations, such as gas lift, pressure maintenance, or enhanced oil recovery (EOR) is included; however, gas processing for liquids recovery is not addressed. Annex A provides guidance for a company to consider as a "good neighbor."

2 References

2.1 Normative References

This recommended practice (RP) includes by reference, either in total or in part, the following standards and publications. Users should investigate use of the appropriate portion of the most recent editions of the publications listed below.

API, *API Environmental Guidance Document: Onshore Solid Waste Management in Exploration and Production Operations*

API, *Guidelines for Commercial Exploration and Production Waste Management Facilities*

API Bulletin E2, *Bulletin on Management of Naturally Occurring Radioactive Materials (NORM) in Oil and Gas Production*

API Bulletin E3, *Environmental Guidance Document: Well Abandonment and Inactive Well Practices for U.S. Exploration and Production Operations*

API Specification 7B-11C, *Specification for Internal-Combustion Reciprocating Engines for Oil-Field Service*

API Recommended Practice 7C-11F, *Recommended Practice for Installation, Maintenance, and Operation of Internal-Combustion Engines*

API Recommended Practice 11ER, *Recommended Practice for Guarding of Pumping Units*

API Bulletin 11K, *Data Sheet for the Design of Air Exchange Coolers*

API Specification 11N, *Specification for Lease Automatic Custody Transfer (LACT) Equipment*

API Specification 12B, *Specification for Bolted Tanks for Storage of Production Liquids*

API Specification 12D, *Specification for Field Welded Tanks for Storage of Production Liquids*

API Specification 12F, *Specification for Shop Welded Tanks for Storage of Production Liquids*

API Specification 12J, *Specification for Oil and Gas Separators*

API Specification 12K, *Specification for Indirect Type Oilfield Heaters*

API Specification 12L, *Specification for Vertical and Horizontal Emulsion Treaters*

API Recommended Practice 12N, *Recommended Practice for the Operation, Maintenance and Testing of Firebox Flame Arresters*

API Specification 12P, *Specification for Fiberglass Reinforced Plastic Tanks*

API Recommended Practice 12R1, *Recommended Practice for Setting, Maintenance, Inspection, Operation, and Repair of Tanks in Production Service*

API Recommended Practice 49, *Recommended Practice for Drilling and Well Servicing Operations Involving Hydrogen Sulfide*

API Recommended Practice 53, *Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells*

API Recommended Practice 55, *Recommended Practices for Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide*

API Bulletin 75L, *Guidance Document for the Development of a Safety and Environmental Management System for Onshore Oil and Natural Gas Production Operations and Associated Activities*

API Recommended Practice 2350, *Overfill Protection for Storage Tanks in Petroleum Facilities*

API Publication 4663, *Remediation of Salt-Affected Soils at Oil and Gas Production Facilities*

NACE RP 0475 [1], *Selection of Metallic Materials to be used in All Phases of Water Handling for Injection into Oil-Bearing Formations*

NACE Standard MR 0175, *Petroleum and Natural Gas Industries—Materials for Use in H_2S-containing Environments in Oil and Gas Production—Parts 1, 2 and 3*

[1] NACE International (formerly the National Association of Corrosion Engineers), 1440 South Creek Drive, Houston, Texas 77218-8340, www.nace.org.

2.2 References for Operations on Federal Lands

BLM [2], *Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development*, (*The Gold Book*), 2007

2.3 References for All Onshore Operations

IOGCC [3], *Adverse Impact Reduction Handbook*, 2007

3 Acronyms and Abbreviations

BOPE	blowout prevention equipment
E&P	exploration and production
EOR	enhanced oil recovery
ESD	emergency shutdown
IC	internal combustion
MSDS	material safety datasheet
NORM	naturally occurring radioactive materials
SOP	standard operating procedure
USDW	underground sources of drinking water

4 Government Agencies

4.1 General

Before drilling or construction, and, in some instances, before modification of onshore oil and gas production facilities, it may be necessary to obtain approvals from one or more government agencies. In addition to drilling and building permits, permits may be required because of air emissions, discharges to surface waters or sewer systems, injection activities, stormwater discharges (including during construction activities), impacts to threatened or endangered species or their critical habitat, impacts to wetlands and other environmental impacts, or impacts to other cultural resources. Operators should ensure that all necessary permits have been obtained before commencing operations. Operators should ensure that operations are conducted in accordance with local, state or federal regulatory requirements.

4.2 Surface Owners and Users

The footprint of drilling and production operations for oil and gas projects is variable and dependent upon the operator’s equipment and operational needs, and the mutual objectives established by the operator, appropriate regulatory agencies, and the owner of the surface rights. Operators will need to be familiar with land use plans, regulations and ordinances that have been adopted by federal, state, and (in certain cases) local governments. Different land uses may require operators to adjust their approaches during site preparation, construction, development or production to avoid or minimize impacts to existing land uses. The development of surface use plans will allow for more efficient use of the land while balancing protection of important local resources, by minimizing surface disturbance and mitigating those impacts that are unavoidable.

[2] U.S. Department of the Interior, Bureau of Land Management, 1849 C Street, NW, Room 5665, Washington, DC 20240, www.blm.gov.

[3] Interstate Oil and Gas Compact Commission, 900 NE 23rd Street, Oklahoma City, Oklahoma 73105, www.iogcc.state.ok.us/.

Before drilling or construction on lands on which the surface estate is privately held, it is recommended that the operator communicate with land owners or surface users concerning activities planned for the site and measures to be taken for safety, protection of the environment, and for minimization of impacts to surface uses. Additional recommendations may be found in API 75L, Annex B—"Good Neighbor Guidelines." Operators of federal oil and gas leases under private surface ownership are encouraged to consult the BLM publication, *Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development* (*The Gold Book*) for BLM guidance with respect to communication and recommended practices to address concerns of surface owners.

5 Lease Roads

5.1 Introduction

Lease roads are constructed and used to support various exploration and production (E&P) operations. The environmental impact of the construction of a roadway can have long lasting effects well beyond the limits of the right-of-way. Existing roads should be utilized, where feasible, to limit the extent of new road construction, when they meet regulatory standards, transportation and development needs, and safety and environmental objectives. When it is necessary to build new roadways, they should be developed in an environmentally acceptable manner consistent with landowner recommendations.

5.2 Planning

5.2.1 Road alignment and right-of-way selection is a multidisciplinary process. Goals of the planning effort should include affected resource values and safety, and avoidance of haphazard or unnecessary development of roads and associated utility corridors. The total infrastructure that may later be developed should be considered during the selection process. Government agencies, landowners, tenants, and other users may need to be consulted during the planning process.

5.2.2 Standards should be established for the road based on its short-term and long-term function considering geography, traffic density, and load expectations.

5.2.3 Alternative alignments should be developed considering the following parameters as appropriate:

a) topography;

b) hydrology, drainage, and watercourses, whether intermittent or permanent;

c) engineering properties of soils, erodible soils;

d) location and amounts of excavation and fill materials;

e) type and location of materials for road construction;

f) air, water, and noise pollution;

g) wetlands and wetland drainage;

h) consistency with community character and local government needs and plans;

i) proximity to dwellings or other permanent structures occupied or used by the public;

j) visual sensitivity;

k) power lines and pipelines;

l) other geotechnical factors, particularly in areas of complex terrain, such as landslide areas, subgrade conditions indicating a need for surfacing, potential cut slope problems, and subsurface or surface water problem areas.

5.2.4 Road alignments and potential environmental impacts should be reviewed. Routes and alignment should be selected to minimize erosion. Environmentally significant areas should be identified and avoided to the maximum extent practical, including:

a) sensitive wildlife and critical habitats;

b) areas with endangered and threatened animals and plants;

c) cultural and historical sites;

d) federal, state, or local areas of concern;

e) areas with the potential for flooding or snow drifting;

f) wetlands.

5.2.5 When required, mitigation strategies should be developed in the planning process, including:

a) road operation schedules and/or use of special designs to minimize any adverse impacts in areas with sensitive wildlife and fish habitats, wetlands, existing facilities, crops;

b) plans to take appropriate action on cultural and historic resources before changes are made;

c) maintenance of existing traffic patterns on highways and local access roads.

5.2.6 Interim reclamation plans and final restoration plans should be developed and incorporated into the planning process.

5.2.7 Stormwater and air (dust) permit requirements should be considered during the planning phase of the roadway.

5.3 Design and Construction

5.3.1 The design and construction of a road should be site-specific. Each road will have its own unique terrain, safety, operation, and maintenance requirements. Each area within a route will support a distinct ecology. When site conditions are appropriate, where suitable for the types of drilling or production operations anticipated, and where compatible with safety and operational concerns, primitive roads may be considered for use as a means to reduce resource impacts.

5.3.2 Design and construction documents, including plans and drawings, should be prepared during the planning and design phases before the construction of the project. Plans will enable proper and timely review of items of environmental concern. They will also be beneficial for later restoration work.

5.3.3 Construction work should be scheduled and the use of special designs and local construction practices should be considered to minimize or avoid undesirable effects on sensitive wildlife and fish habitats, wetlands, and designated federal, state, or local recreational areas. Seasonal restrictions such as freeze-thaw cycles, potential flooding, and wildlife migration should be considered.

5.3.4 The operator should confirm that the construction contractor has implemented an environmental and safety program, including the training of construction personnel. This program should include, where applicable, written procedures for a hazard communication program, hazardous material handling, spill reporting, emergency response, stormwater management, special environmental requirements within the project area, and blasting. The contractor should supply material safety datasheets (MSDSs) for all hazardous materials brought on site. Regulatory agencies often require performance bonds when roads are to be constructed in environmentally sensitive areas.

5.3.5 The operator should hold a preconstruction meeting with the contractor(s) to establish environmental and safety responsibilities along with desired objectives of the project.

5.3.6 Field inspections and lab analysis of soil samples may be used to assess soil erosion hazards and slope stability. Properties of soils, length and gradient of slopes, and vegetative cover contribute to soil stability. Fitting the profile to topography, locating roads on moderate slopes, providing adequate drainage, and stabilizing slopes decreases surface disturbance and reduces erosion and sedimentation.

5.3.7 Means and methods for erosion control are numerous and often site-specific. Revegetation with local species, rip-rap, gabions, woven jute, and energy dissipators are effective measures that may be used to reduce erosion.

5.3.8 The use of geotextiles and geosynthetics should be considered in road planning and construction. These materials offer a variety of applications, aid in stabilizing the road, and minimize the utilization of road bed and surface materials.

5.3.9 An adequate drainage system should be incorporated into the design and construction of the road. This system should efficiently intercept, collect, remove, and discharge water from roads. A drainage system that is inadequate or blocked will result in excessive erosion, failures, and higher maintenance costs.

5.3.10 The number of river, stream (including ephemeral streams), lake, and wetland crossings should be minimized, where possible. Bridges, culverts, and other drainage structures should be incorporated to ensure the free flow of water when drainage ways are intersected. Different flood stages should be considered for the design and construction of the crossings.

5.3.11 The use of snow fences should be considered in areas with snow drifting characteristics. Minimization of snow buildup will reduce the use of deicers on the roadway and will also reduce the problems associated with the disposal of the bladed snow/salt mix during maintenance operations.

5.3.12 Clearing widths should be kept to a minimum. These limits should be delineated and marked in the field. Sensitive areas or features should be marked or fenced as required.

5.3.13 Where practical, topsoil should be salvaged and stockpiled in a safe and accessible location and be protected from erosion. The stockpiled material should be utilized for revegetation and reclamation purposes.

5.3.14 Revegetation should be done with local plants, seeds, and grasses species. Means and methods will be dependent upon seasonal considerations, the specific project area, and government agency requirements.

5.3.15 Areas of excavation should be approved before the start of construction. Permits are required for opening pits on federal land and may be required on other public lands. Pit layout and restoration should be planned before opening of the pit.

5.3.16 Environmental impacts during coarse/fine borrow material extraction should be minimized. The following should be considered:

a) use of recycled road surface material from abandoned roads and locations,

b) use of existing mineral material sites,

c) selecting new sites that minimize environmental impacts,

d) developing upland sites to maximize potential for revegetation and minimize adverse visual impact and possible erosion,

e) maintaining a buffer of undisturbed vegetation between borrow pits and highways or other sites.

5.3.17 Warning signs should be provided to comply with local requirements. The signs may include road crossings, animal crossings, speed limit, road hazards, pipelines, etc.

5.3.18 Existing pipelines and other subsurface facilities should be identified before construction. These facilities should be protected to prevent accidental damage during the construction and operation of the road.

5.3.19 Measures should be taken to ensure proper and adequate procedures for waste disposal, general housekeeping. An effective emergency response plan should be in place before initiating construction. The plan may simply be a listing of telephone numbers to call should a utility or product line be damaged. Many times, the existing emergency response plan for the field area may be adequate. Construction personnel should be familiar with these plans.

5.3.20 Construction activities should be carried out as described in the construction documents, including plans and specifications.

5.3.21 Construction supervision should be provided throughout operations. Many potential problems associated with incorrect interpretation of construction documents, spills, waste disposal, poaching, and hunting can be avoided through proper supervision.

5.4 Primitive or Nonconstructed Roads and Routes

5.4.1 Where site conditions are appropriate, and where approved by a surface owner or surface management agency, the establishment and use of "primitive," two-track roads or overland route corridors may be appropriate for an operator's needs and to facilitate later reclamation of the site. Primitive roads and route corridors may serve as appropriate access to exploration drilling locations where it is not certain if the well will be productive, or to producing wells where vehicle traffic is infrequent due to the use of off-site production facilities and automated well monitoring. Traffic and load expectations for primitive roads should be evaluated. If the expectations are exceeded during the project, the road should be evaluated for upgrades.

5.4.2 The appropriateness of primitive roads and routes is both site-specific and use-specific and is typically based on many factors, such as anticipated dry or frozen soil conditions, seasonal weather conditions, flat terrain, low anticipated traffic, service company's/driller's/operator's access needs.

5.4.3 Primitive roads or routes necessitate low vehicle speeds and are typically limited to four-wheel drive or high-clearance vehicles. They can consist of existing or new roads with minor or moderate grading; two-track roads created by the operator's direct vehicle use with little or no grading; overland routes with a defined travel corridor leaving no defined roadway beyond crushed vegetation; or any combination along the route. Operators should not flat-blade roads. Drainage must be maintained, where appropriate, to avoid erosion or the creation of a muddy, braided course of vehicular travel.

5.4.4 Primitive or two-track roads and routes must be used and established in a safe and environmentally responsible manner and are not intended for use as all-weather access roads. Resource damage must be repaired as soon as possible and the operator must consult with the surface management agency to determine if all or a portion of the road needs to be upgraded to an all-weather access road. When used and maintained appropriately, nonconstructed roads and routes have the advantage of reducing construction, maintenance and reclamation costs and reducing resource impacts.

5.4.5 Approval of a surface resource agency is generally required for use of nonconstructed roads on other than privately owned lands.

5.5 Maintenance

5.5.1 Proper road maintenance is critical for the performance of the road and to prevent and control erosion and sedimentation. Maintenance personnel should be made aware of environmentally difficult and sensitive areas.

5.5.2 Maintenance work should be scheduled and the use of special designs and maintenance programs should be considered to minimize undesirable effects on sensitive wildlife and fish habitats, wetlands, and designated federal, state, or local recreational areas.

5.5.3 When performing scraping and leveling operations, care should be exercised to avoid disrupting ditches and shoulders, and creating undesirable berms with the bladed material.

5.5.4 Ditches, culverts, and drains should be regularly cleaned of debris and sediment to allow the free passage of water. Periodic inspections of all culverts should be conducted. Culverts found to be blocked should be cleared.

5.5.5 Borrow and surface materials should be readily accessible to be utilized during maintenance operations. Pits opened during construction should be used as a source for maintenance material, where feasible.

5.5.6 The use of dust control materials or measures should be evaluated before their utilization. The materials should not be detrimental to health, vegetation, wildlife, or water quality.

5.5.7 Cutting back weed and hedge growth is essential for road safety. This maintenance operation should be done with light equipment. Critical review should occur before herbicides or other chemicals used for weed control are applied.

5.5.8 There should be continuous monitoring of drainage and erosion control structures. They should be maintained and revised, as required, to provide for the intended function.

5.5.9 Erosion should be prevented and controlled. Areas should be revegetated, and slopes and soils should be stabilized.

5.5.10 There should be an environmental emergency response plan ready to be placed in action during construction and maintenance operations. The plan should include emergency procedures to be followed in the event major drainage ways are blocked, fail, or do not perform as required during or immediately after major storm events.

5.6 Reclamation and Abandonment

5.6.1 Abandonment procedures should comply with regulatory requirements, contractual obligations, and lessor and landowner requirements. Consideration should be given to cost-effective measures that will minimize environmental impacts. Interim reclamation should be undertaken for portions of the road or areas disturbed during construction of the road that are not required for vehicle travel. In interim or final reclamation, wherever possible, cut slopes, fill slopes, and borrow ditches should be recontoured, covered with topsoil and revegetated to restore habitat, forage and scenic resources, and to reduce soil erosion.

5.6.2 Abandonment procedures may include the following considerations:

a) restoration;

b) abandonment in place;

c) restoration of original or improved drainage;

d) agreement on maintenance requirements, if any, after discontinued use, to be reached between the operator and new user;

e) agency approval requirements.

5.6.3 Restoration plans should be prepared in detail and should consider methods such as:

a) priority of stabilization and revegetation of disturbed areas,

b) use of native plant species,

c) stockpiling soils where reclamation would be enhanced,

d) use of agency approved designs and seed mixes.

6 Producing, Injection/Disposal Wells

6.1 Completion, Stimulation, and Workover Operations

6.1.1 Planning

For a new well site, an effective planning process should be carried out and should incorporate the latest guidelines for waste management, pit location and construction, handling of water discharges, and waste disposal. The location and size of new pits and pads for completion and workover equipment should be selected so as to minimize disruption of the surface resources and retain the potential for reclamation of the site. Refer to *API Environmental Guidance Document: Onshore Solid Waste Management in Exploration and Production Operations* for environmental aspects of reserve pit construction, operation and closure.

For an existing well site, the planning process is just as important to provide for safe and environmentally acceptable completion and workover operations. Existing facilities, such as pits and production equipment, should be reviewed and assessed to determine whether the facility is suitable in its present condition for the intended well operations or if modifications are required. For both new and existing well sites, a waste management plan for handling and storing all waste materials generated during completion and workover activities should be developed. Refer to *API Environmental Guidance Document: Onshore Solid Waste Management in Exploration and Production Operations*, for information on how to develop such a plan. The waste management plan should address the specific wastes which are expected to be produced by the particular operations being performed, as well as provide guidelines concerning the actions to be taken in the event that unexpected waste materials, including hazardous materials, are encountered during the operations. In addition to safe handling and storage of waste materials on the well site, provisions should also be made for each type of waste to be disposed of. Refer to API 55 and API 49 for planning and conducting operations involving hydrogen sulfide. Refer to API E2 for information regarding management of naturally occurring radioactive materials (NORM).

Since much of the work on producing and injection wells is performed by contract or service company personnel, the operating company should confirm that the contractor’s personnel have appropriate safety training, including hazard communication training, and are aware of requirements of the site-specific waste management plan. Consideration should also be given to requiring performance bonds, if appropriate. The operator should also confirm that the contractor’s personnel are aware of all applicable safety and environmental requirements of the operator.

6.1.2 Equipment Selection

Temporary equipment required to carry out well completion and workover operations should be included in the overall operation plan. Equipment should be installed in a manner so as to utilize the smallest practical area for prudent operations. Equipment should be maintained to present an acceptable appearance.

6.1.3 Producing Wells

Producing wells should be completed so production zones and drinking waters zones are isolated and cannot be contaminated by other formations. The well must be cased and cemented properly to provide this protection.

6.1.4 Injection/Disposal Wells

Injection/disposal wells should be completed so the injected fluids enter the desired formations and do not enter other formations or drinking water zones. Typical injections are completed with three levels of protection for drinking water formations:

1) surface casing and cement,
2) long string casing and cement, and
3) tubing and packer.

Also, the area around the injection should be reviewed to see of any wells (active, inactive or abandoned) were drilled through the injection/disposal zone. If wells were drilled close to the injection/disposal well that penetrated the injection/disposal formation and those wells did not isolate those zones, the injected fluids could flow from the injection zone through the improperly plugged or completed well to other oil and gas zones or drinking water zones.

6.1.5 Remedial Cementing

For both new and existing wells, the known and anticipated needs for remedial cementing to protect underground sources of drinking water (USDW) should be considered in the planning stage.

Excess cement, cement returns, and water used to wash cementing equipment should be contained and disposed of in an environmentally sound manner. Refer to *API Environmental Guidance Document: Onshore Solid Waste Management in Exploration and Production Operations* for additional information.

6.1.6 Selection, Use, and Storage of Fuels and Completion Fluids

Completion fluid selection should take into account the safety and logistics of transporting, handling, storing, and disposing of clean and contaminated fluid.

For both new and existing well sites, all fuels, treatment chemicals, completion brines, and other similar liquids should be properly stored in labeled containers intended for that purpose. Containment should be constructed so spilled fuels or chemicals do not reach the ground.

Wherever practical, tanks or existing drilling pits should be used for completion and workover operations. Completion brines and other potential pollutants should be kept in lined pits, steel pits, or storage tanks. If a new earthen pit is necessary, it should be constructed in a manner that prevents contamination of soils, surface water, and groundwater, both during the construction process and during the life of the pit. Consideration should be given to the use of tanks or lined pits to protect soil and groundwater, especially for brines and oil-based fluids.

Normal operations should preclude oil in pits. However, in the event that well completion operations dictate use of pits containing oil for a brief period of time, they should be fenced, screened, netted and/or flagged, as appropriate, to protect livestock, wild game, and fowl. Refer to the Migratory Bird Treaty and Enforcement Improvement Act for additional guidance. Oil accumulated in pits should be promptly removed and recovered, recycled, or disposed.

All liquids and other materials placed in pits should be recovered, recycled, or disposed in an environmentally acceptable manner (determined by the constituents in the material and the environmental sensitivity of the location).

When operations are completed, pits not required for well operation should be closed in accordance with the environmental sensitivity of the location. The surface area should be restored to a condition compatible with the uses of the adjacent land area. Any pit retained should be of minimum size commensurate with well operations. Refer to *API Environmental Guidance Document: Onshore Solid Waste Management in Exploration and Production Operations* for additional information and permitting requirements.

6.1.7 Stormwater Runoff

Natural drainage patterns of the area should be considered in the location of equipment, pads, and pits so that stormwater runoff does not create an environmental hazard by erosion of base material, which could lead to equipment instability, or by flooding of pits, which could cause a discharge of oil or other fluids into the local surface waters.

Discharges of stormwater from inside E&P facilities such as bermed areas around tank batteries (including oil and gas exploration, production, processing, or treatment operations or a transmission facility), which can reach waters of the United States, require a stormwater discharge permit and submittal of a stormwater pollution plan to the EPA. Contamination includes stormwater that comes into contact with any overburden, raw materials, or waste products on the site.

Construction designs should include installation of erosion and sedimentation control systems. Site construction should be inspected routinely and after each significant storm event. Any repairs to the control systems should be completed promptly. During the drilling and completion phases, all raw materials should be stored in a manner to prevent contaminating the natural runoff of precipitation. Temporary containment and liners should be used to minimize the impact of spills and to prevent impacted precipitation from affecting surface or groundwater.

6.1.8 Blowout Prevention Equipment (BOPE)

All BOPE should be selected, installed, and properly maintained in order to prevent uncontrolled releases to the environment. Refer to API 53.

All BOPE should have a working pressure rating that exceeds the maximum expected surface pressure.

Training exercises or drills should be held as necessary to ensure crew familiarity and that the BOPE is in good working order.

6.1.9 Control of Noise and Other Nuisances

Engines and production equipment should be provided with noise abatement measures, if appropriate, to reduce noise levels to the extent practical, considering the local environment. Other nuisances such as odors and dust should be controlled as considered appropriate for the location. Consideration should be given to minimizing traffic in general, particularly in or near urban areas.

6.1.10 Solids Removal or Capture

All produced fluids, drill cuttings, cement, cement returns, NORM scale, and other solids should be captured and classified, then reused, recycled, or disposed. Hazardous waste should be segregated in order to prevent contamination of nonhazardous materials.

6.2 Well Operations

6.2.1 Equipment Operation and Maintenance

All well-producing equipment should be kept neat, clean, painted and in good working order. Equipment should be painted to blend into the surroundings, if required or appropriate, and kept clean to present an acceptable appearance. Selected moving equipment may be painted different colors to enhance visibility.

Safety guards necessary to protect humans, livestock, wildlife, and promote public safety should be maintained around equipment. Refer to API 11ER for information on guarding of pumping units. Equipment lockout/tagout procedures should also be developed and implemented.

Drip pans should be provided under equipment and storage containers potentially subject to minor leaks. These drip pans should be monitored on a routine basis to recover and recycle or dispose of accumulated oil and other liquids.

Bulk storage, recyclable, and reusable containers should be considered in order to reduce the number of containers that must be maintained and disposed. All reusable containers should be well marked to denote contents and the fact that they are to be reused.

The installation or use of double stuffing boxes, leak detectors, and shutdown devices should be considered in areas of particular environmental sensitivity.

Well cellars should be kept clean, dry, and guarded to prevent accidental falls. Well cellars should be filled if they may fill with sour gas and present a safety hazard to people.

6.2.2 Metallurgy and Corrosion

All equipment should be manufactured from materials which are suitable for the environment in which they are to operate. NACE MR 0175 and NACE RP 0475 should be consulted for more information.

Equipment operating in known corrosive conditions should be inspected on a routine basis for signs of corrosion, with corrective action taken, as needed, to assure the equipment continues to operate in an environmentally acceptable manner.

If well production or injection conditions change in terms of hydrogen sulfide or carbon dioxide content, pressure, water cut, or any other parameter, the metallurgy of the well equipment should be reassessed to assure its suitability for the new conditions.

6.2.3 Leak Detection

All equipment should be inspected on a routine basis for signs of leakage, with corrective action taken, as needed, to assure the equipment continues to operate in a safe and environmentally acceptable manner.

All injection and disposal wells equipped with tubing and packed should periodically monitor the tubing casing annulus pressure to test the integrity of the tubing and packer. If a well is not completed with a packer, then other methods should be used, such as tracer logs or temperature logs to ensure the fluids injected are properly controlled and are going into the proper injection/disposal formation. Frequency of testing is dependent on the operating conditions. For example, if an area has a high number of corrosion failures, testing for the mechanical integrity of the well should be frequent.

6.2.4 Inspection and Certification

Equipment should be manufactured, refurbished, inspected, and installed according to manufacturer, API or other industry standards, and legal requirements.

6.3 Well Testing

6.3.1 Venting and Flaring

Venting and flaring should be restricted to a safe location. Where possible, the flare or vent should be located downwind considering the prevailing wind direction at the well location. When possible, all gas resources of value should be captured and used. If not possible, then this gas should be flared.

6.3.2 Flare Pits

Flare pits, sometimes called blowdown or emergency pits, should not be used for storage or disposal. The primary purpose of a flare pit is to catch any incidental fluid that might be associated with the gas stream that does not burn. Fluids in a flare pit should be removed daily, or as quickly as practical.

Siting and construction of flare pits should minimize the risk of surface and groundwater contamination. The size of the flare pit should be proportionate to the volume of liquid effluent that might be expelled from the gas flare. Use of a knockout vessel should be considered.

6.3.3 Control of Noise and Other Nuisances

Flares may need to be provided with noise abatement measures to maintain noise levels compatible with the local environment. The noise intensity, duration, location relative to public areas and natural resources, as well as the flare/vent exit design should be considered, where applicable.

Other nuisances, such as light emittance from a lighted flare, odors, and dust, should be controlled as considered appropriate for the location.

6.4 Plugging and Abandonment

6.4.1 General

Permanent abandonment is done when the wellbore has no further utility and is permanently sealed against fluid migration. Temporary abandonment operations may be performed when a wellbore has future utility, such as for EOR projects, and must be maintained in a condition where routine workover operations can restore a wellbore to service. The same environmental concerns exist in both cases. Refer to API E3.

6.4.2 Subsurface

6.4.2.1 General

Several environmental concerns related to well abandonment should be addressed. The primary environmental concerns are protection of freshwater aquifers and USDW, as well as isolation of downhole formations containing hydrocarbons or used for injection. Additional issues, which should be evaluated, are the protection of surface soils and surface waters, future land use, and permanent documentation of abandoned wellbore locations and conditions.

6.4.2.2 Plugging Purpose

The purpose of plugging wells is to prevent interzonal migration of fluids; the contamination of freshwater aquifers, surface soils, and surface waters, and to conserve hydrocarbon resources either in the production interval or potential production intervals. Generally, contamination by an improperly plugged and abandoned well can occur in two ways:

a) the abandoned well can act as a conduit for fluid flow between penetrated strata, into USDW, or to the surface;

b) contaminated water can enter the abandoned wellbore at the surface and migrate into USDW.

Such contamination is prevented when a well is properly plugged. Not only do the plugging operations prevent an abandoned well from becoming a conduit for contamination to occur, but well construction and completion methods also contribute to the prevention of contamination.

Well plugging operations are focused primarily on protecting USDW, isolating downhole formations productive of hydrocarbons or used for injection, and protecting surface soils and surface waters. A surface plug prevents surface water runoff from seeping into the wellbore and migrating into USDW cement plugs isolating hydrocarbon and injection/disposal intervals and a plug at the base of the lowermost USDW accomplish this primary purpose. Surface water entry into an abandoned well is a concern because the water may contain contaminants from agricultural, industrial, or municipal activities. API E3 recommends that operators set a cement plug at the base of the lowermost freshwater aquifer or USDW during plugging and abandonment operations applicable to the well.

NOTE The cement plugs also work to protect surface soils and water from wellbore fluids by confining those fluids in the well.

In addition to the cement plugs described herein, many state and federal regulatory agencies require cement plugs across the base of the surface casing and in, or between, each producing and potential producing zone.

6.4.2.3 Fluid Confinement

It is essential that all formations bearing usable quality water, oil, gas, or geothermal resources be protected and/or isolated. The prevention of gas or fluid migration to other zones or to the surface is of primary importance. Open-hole plugs, casing plugs, or cement squeezed through casing perforations will isolate the target formations in most cases. However, special procedures, such as perforating casing and circulating cement, may be necessary to isolate that potential production or injection formations existing behind uncemented casing. It is important to prevent interzonal flow in an abandoned well so that such cross-flow does not interfere in the commercial exploitation of the zones through nearby wellbores.

6.4.3 Surface

6.4.3.1 General

The cleanup and remediation of the surface may include cutting off the surface casing below ground level, restoring the surface to conditions near those that existed prior to the well being drilled, and marking the surface of the wellbore by installing an upright marker. The operator should restore the well site consistent with the criteria presented in *API Environmental Guidance Document: Onshore Solid Waste Management in Exploration and Production Operations*. However, the landowner should be consulted before beginning well site remediation. Some states require that the landowner be notified that a well is to be plugged. The landowner may have a right to use the well for a freshwater source.

6.4.3.2 Cleanup and Remediation

Assuming the landowner elects not to use the well as a freshwater source, the operator should set the required surface plugs; remove the wellhead; weld a steel plate on the surface casing stub, if required; fill in the well cellar, rat hole and mouse hole; and level the area. Casing strings left in the well should be cut off 3 ft to 6 ft below ground level, or deeper if required by the landowner.

Pits should be emptied and reclaimed to a condition similar to the rest of the reclaimed pad area. Pits should be allowed to dry or be solidified in situ before filling. The pit area may be mounded to allow for settling. Before removing or abandoning pipelines or flowlines, fluid displacement and line purging should be considered and fluid reclaimed, recycled, or properly disposed of according to fluid type.

Open burning can be used in some areas to dispose of nonhazardous, hydrocarbon-containing wastes that are unsuitable for recycling. Burning should be restricted to materials such as oily sorbents and paraffin and should be conducted only with approval of state or local air pollution regulatory agencies. Burning should be conducted during daytime hours and with due regard to wind direction and velocity. The results should not cause a nuisance that could result in black smoke or particulates.

Off-site commercial facilities should be used for other nonhazardous and hazardous waste disposal. The off-site facilities should be permitted and care should be taken with site selection. Refer to *API Environmental Guidance Document: Onshore Solid Waste Management in Exploration and Production Operations*, API 4663 and API's *Guidelines for Commercial Exploration and Production Waste Management Facilities*.

6.4.3.3 Soil Erosion

Disturbed areas, such as roads, pits, and well sites, may need to be further remediated depending on lease agreements.

6.4.3.4 Inspection

Final abandonment is complete only after all surface equipment is removed, all pits are closed, and the surface is restored. A vertical steel monument may be considered that indicates the well location, operator, and well number. Thereafter, the abandoned well site can more easily be located and the former operator determined.

7 Lease Gathering and System Lines

7.1 Introduction

In planning lease gathering and system lines, including electrical distribution systems, it is important to consider the impact that construction operations and maintenance activities will have on people, animals, plants, and the land itself, both surface and shallow subsurface. The impact on current use, as well as possible future uses, should be evaluated along with potential future facilities expansion. Because pipelines can be buried, and the surface reclaimed, long-term surface disturbance associated with pipelines can be avoided. The placement of pipelines should avoid steep hillsides and watercourses where feasible. Also, where feasible, pipeline routes should take advantage of road corridors to minimize surface disturbance. Also, when clearing is necessary, the width disturbed should be kept to a minimum and topsoil material should be stockpiled to the side of the routes where cuts and fills or other disturbances occur during pipeline construction. Retaining topsoil for replacement during reclamation can significantly accelerate successful revegetation.

7.2 Route Selection

7.2.1 The following environmental factors should be considered in planning lease gathering and system lines.

a) Proximity to lakes, streams (including dry washes and ephemeral streams), wetlands, drainage and irrigation ditches, canals, flood plains, and shallow water wells. These features should be evaluated in terms of disturbances during construction and routine operations, and in the event of accidental releases.

b) Depth to, and quality of, groundwater. The potential impact to groundwater, particularly from any releases from buried lines should be considered.

c) Removal of trees, disturbances to dikes, levees, and terraces, and destruction of growing crops. These impacts should be evaluated with a focus on construction and routine maintenance activities.

d) Impacts to migratory bird habitat or critical habitat of threatened or endangered plant and animal species, including noise and dust.

e) Proximity to buildings or other facilities occupied or used by the public. Particular consideration should be given to homes, churches, schools, and hospitals.

f) Impact on cultivated lands.

g) Areas of special historical, archeological, recreational, biological, or scenic significance.

h) Land ownership.

i) Location of recently active shallow faults.

7.2.2 The selection of routing for lease gathering and EOR injection and produced water disposal system lines, consistent with production, EOR and disposal requirements and overall economics, should consider the following:

a) foreseeable uses of surfaces areas by either the landowner or tenant;

b) possible exposure to future construction and excavation work;

c) topography, when it is an important factor in:

   1) line design,

   2) right-of-way maintenance,

   3) possible land erosion,

   4) emergency response and containment of releases;

d) location of existing rights-of-way;

e) location of existing roads.

7.3 Design

7.3.1 In design of lease gathering and system lines, appropriate industry codes should be followed.

7.3.2 Lease gathering and system line design should consider the following.

a) Estimated life of the line.

b) Line environment (nature of the soil, presence of water-saturated soil, alkaline flats, depth of frost, etc.).

c) Nature and quantity of product throughput, initially and as production matures, including the potential for EOR processes.

d) Impacts on existing facilities.

e) Consequences of possible line failure. Release of oil, water, or gas should be qualitatively evaluated. Consideration should be given to installing block valves to isolate line segments located in or near environmentally sensitive areas (such as wetlands), on either side of stream crossings, and in close proximity to areas occupied by the public. Consideration should also be given to sleeving lines or using heavier walled pipe in these areas.

The qualitative evaluation should consider the following:

1) public impact,

2) environmental impact (including potential natural resource damage assessment liability),

3) damage to crops and domesticated animals,

4) cleanup costs,

5) political or regulatory impacts.

f) Corrosion inhibition measures (external and internal). All equipment should be manufactured from materials which are suitable for their operating environment. NACE MR 0175 should be consulted for further guidance, as applicable.

g) Burial to optimum depth to reduce exposure to hazards such as plowing, freezing, and other construction.

h) Provisions for various crossings (roads, streams, and other lines).

i) Optimum location for blowdown tanks, valves, etc.

j) Noise abatement (where appropriate).

k) Miscellaneous variable factors including operating pressures, temperature changes, line expansion, and desired safety factors.

l) If electrical distribution lines are to be installed in areas where raptors are likely to use them as perches, consideration should be given to installing wooden perch guards or cross members on the poles above the lines to prevent the birds from coming in contact with the charged lines.

7.4 Construction and Installation

7.4.1 Lease line routes and applicable rights-of-way should utilize the smallest practical surface area, consistent with prudent operations.

7.4.2 Unnecessary damage to trees and other vegetation adjoining lease line routes should be avoided.

7.4.3 If contractors are used to install lines, the operator should verify that the contractor has implemented a safety program that includes a written hazard communication program. The contractor should supply MSDSs for all hazardous materials brought on site.

7.4.4 Appropriate inspections should be performed during construction to ensure design specifications are met.

7.4.5 Upon completion, lines should be inspected and pressure tested for possible leaks in accordance with state and local codes. Pressure test fluids should be collected and disposed. Refer to the *API Environmental Guidance Document: Onshore Solid Waste Management in Exploration and Production Operations* for recommendations for disposal of these test fluids.

7.4.6 After installation of a new line, all lease line routes and rights-of-way should be cleaned up and restored to conditions compatible with existing land use, unless other arrangements have been made with the landowner. Disposal of all waste should be in accordance with the *API Environmental Guidance Document: Onshore Solid Waste Management in Exploration and Production Operations*.

7.4.7 Line routes and burial depth should be adequately documented to aid in preventing ruptures and/or accidental leaks during future excavation activities. Crossings should be marked.

7.5 Operation and Maintenance

7.5.1 All applicable personnel (both company and contractor) should receive training to provide for proper operation and maintenance of the lines. This training should include start-up and shutdown procedures, normal operating procedures, and emergency response procedures, in the event of a leak or spill of a hazardous substance.

7.5.2 Line routes and facilities should be inspected at intervals dictated by evaluation of exposures and/or failures.

7.5.3 Appropriate steps should be taken to prevent surface and environmental damage from the use of hot oil, chemicals, and other treatments that are used to maintain lease gathering and system lines.

7.5.4 Proper maintenance practices should be exercised with respect to crossing markers, blowdown tanks, venting equipment, and corrosion protection equipment. Blowdown fluids should be collected and placed in the production system to recover hydrocarbons. Waste materials should be recycled, reclaimed, or disposed. Refer to *API Environmental Guidance Document: Onshore Solid Waste Management in Exploration and Production Operations*.

7.5.5 Pressure tests, profile surveys, and other means should be considered to meet operating safety requirements.

7.5.6 Operating procedures should provide for early identification of developing corrosion problems, failure-prone equipment, and malfunctions so that corrective action can be taken before environmental or safety consequences occur. Frequency of failure analysis should be considered to aid in scheduling line replacements.

7.5.7 Appropriate industry codes should be followed with respect to maintenance of records, repairs, reporting of leaks, etc.

7.5.8 Whenever modifications are made to existing lines or there are significant changes in physical parameters (temperature, pressure, composition, etc.), the changes should be considered for evaluation pursuant to management of change principles. Where appropriate, facility drawings should be updated to show modifications and the superseded drawings should be destroyed.

7.6 Abandonment of Gathering and System Lines

7.6.1 All surface lines should be removed. Lines should be purged before removal.

7.6.2 Surface and subsurface equipment connected to buried lines should be removed to a depth consistent with subsequent land use or, preferably, to the depth of the buried lines.

7.6.3 Harmful or hazardous materials should be displaced from any lines abandoned in place.

7.6.4 Where appropriate, each outlet of abandoned lines should be permanently sealed.

7.6.5 All crossing markers and other line markers should be removed.

7.6.6 The location of abandoned lines should be identified on facility maps.

7.6.7 Upon completion of abandonment activities, all disturbed surface areas should be cleaned up and restored to conditions similar to the adjacent lands.

7.6.8 Dispose of all waste per *API Environmental Guidance Document: Onshore Solid Waste Management in Exploration and Production Operations*.

8 Production and Water Handling Facilities

8.1 Requirement Determination (Preplanning Considerations)

The overall basis for siting, designing, constructing, and operating oil, gas, and water production, handling, and disposal/injection facilities should be to minimize adverse effects on the environment, consistent with providing an economical means of accumulating well, lease, or unit production from primary, secondary, or tertiary recovery methods and producing the ultimate recoverable reserves. Impacts on local population, land, surface and subsurface waters, air quality, and animal and plant species, including habitat, should be considered.

Water handling facilities are typically located adjacent to, or within, production facilities. Initial planning for these facilities within a field should consider future development potential in order to minimize surface disturbance. When practical and economic, central field locations should be considered to avoid the use of multiple facilities. Facility sizing should consider future throughput increases to minimize the need for additional tankage and treating vessels.

Production and water handling facilities should be planned to utilize the smallest practical surface area consistent with safe, prudent, and economic operations. In addition, produced water may be saline and corrosive. Therefore, special care should be taken to minimize the possibility of environmental damage due to equipment upsets, spills, and leaks.

Baseline conditions and past land-use in the area should be documented. At a minimum, drinking water supplies should be identified and sampled before any development. Water usage should be determined during the planning phase so that water rights can be secured and disposal options evaluated and selected.

8.2 Site Selection Considerations

8.2.1 Land Use

Topographic, population, environmental hazard, zoning, and other maps should be consulted, where applicable, to locate sensitive or high exposure areas [such as churches, schools, hospitals, residential areas, surface waters, freshwater wells, flood zones, active fault areas, threatened and endangered plants and animals (including habitat), migratory bird habitat, wetlands, archeological, recreational, biological, or scenic areas]. Where feasible, the site should be located away from these sensitive areas. The potential impact from upset conditions, such as oil or produced water spills and leaks, should be considered.

Final well patterns should be considered, if possible, to minimize right-of-way requirements for roads and lease lines. Existing roads and rights-of-way should be utilized to the maximum extent possible.

The land owner and/or surface tenant should be consulted to consider present and future uses of affected and adjacent land.

Production and water handling facilities should be planned to utilize the smallest practical surface area consistent with safe and prudent operations. Future expansion possibilities should be considered.

On federal or state administered lands, appropriate agencies should be consulted in advance with respect to land use and environmental issues.

8.2.2 Erosion and Drainage

A site should be selected that minimizes the amount of surface terrain alteration to reduce environmental and aesthetic damages. Cuts and fills which pose possible landslide or slump problems should be avoided. Consideration should be given to stock piling topsoil, if feasible.

The natural drainage patterns of the land should be considered in selecting the site. Adequate culverts and drainage ditches should be provided, as required by the terrain. Soil stabilization, such as sod or grass seeding, should be provided to prevent erosion. Unnecessary removal of trees or alteration of other natural features should be avoided.

8.2.3 Water Resources

The proper management of water resources during the development and operations phases of oil and gas production is directly related to minimizing surface disturbances. Water can be used to create optimal soil moisture conditions to allow for proper compaction of soils, thereby, minimizing surface degradation caused by vehicular traffic and the occurrence of erosion events. Water is also important to help suppress dust and is necessary for drilling, completion and hydraulic fracturing activities. Since a large volume of water is often generated during the oil and gas production process, especially for coalbed natural gas production, additional surface disturbances may result without proper produced water management plans. For example, additional surface water can affect water quality, cause changes to channel morphology in nearby streams, or cause damage to access roads. The release of produced water typically can be controlled to prevent surface disturbances by utilizing management practices appropriate to the location or circumstances. Depending on the region, local geology and water quality, produced water may be used to support livestock/wildlife watering or for use in irrigation systems. Where it is allowed by regulatory authorities, the water can also be discharged into appropriate water systems or reinjected into suitable reservoirs.

8.2.4 Subsurface Soil Conditions

Subsurface soil conditions should be considered for adequate foundation support of buildings, pumps, engines, tankage, and equipment used in the construction process.

Soil characteristics should be evaluated for construction of dikes, firewalls, and emergency containment areas. Lining of containment areas with compacted clay or synthetic liners should be considered where porous soil conditions exist or groundwater could be impacted.

Soil corrosiveness or resistivity should be evaluated to determine whether coating or wrapping of lease lines will be necessary to prevent or control corrosion. Cathodic protection should be considered for highly corrosive conditions or sensitive areas.

8.2.5 Fire Protection

Production and water handling facilities should not be located where the equipment will create a potential fire hazard. As applicable, proper fire safety equipment should be stored nearby.

8.2.6 Public Exposure

In noise control planning, production and water handling facilities should be located as far as practical from buildings or facilities occupied or used by the public.

Facilities should be located to minimize risk of public exposure from potential hazardous material releases, considering prevailing winds and topographic elevations to the maximum extent practicable.

8.3 Facility Design

8.3.1 Equipment Sizing, Specifications, and Design

Consideration should be given to the following items in designing and constructing production facilities.

a) Production-related equipment should be sized and designed to provide appropriate safety and utility. Future development and exploration plans should be considered when sizing equipment. Where appropriate, the facilities should be sized to handle current and future production to minimize retrofitting and improper use of equipment. Equipment should be designed with appropriate spill control devices, such as high-/low-level indicators or high-/low-pressure indicators, to improve safety and protection of the environment.

b) The anticipated time the equipment is expected to remain active should be considered. Proper design and installation can minimize future equipment failures and downtime.

c) Equipment and foundations should be designed and installed giving consideration to adverse natural conditions common to the area, such as floods, excessive snow and rain, earthquakes, tornadoes, hurricanes, and dust storms.

d) Equipment installations should comply with industry standards. Air pollution control facilities should be installed whenever practical, economical, and technically feasible. Flaring vs venting should be evaluated based on gas volume and composition, safety, economics, and local environmental impact.

e) Pressure requirements for vessels, lines, and other equipment should be considered. Any variance from the manufacturer's recommended rates or pressures should be evaluated thoroughly. Refer to API 12J for information on sizing and designing lease pressure vessels.

f) The following items should be considered in installing fired lease vessels.

1) Consideration should be given to surrounding facilities when selecting the placement of fired lease vessels.

2) Manufacturer's recommendations should be followed. Any variances from these recommendations should be evaluated thoroughly.

3) Fired lease vessels should not be located immediately adjacent to oil, gas, or any other flammable or explosive storage facilities. Facilities should have a grade established so that releases of flammable fluid drain away from fired equipment.

NOTE Some states have minimum distance requirements between fired vessels and storage facilities.

4) Vessels should be well maintained and free of unnecessary debris or flammable products.

5) Fencing or some form of guarding should be considered to protect the public, livestock, and wildlife.

6) Refer to API 12K and API 12L for some information on selecting and designing fired lease vessels.

7) Consideration should be given to air permitting requirements for fired lease vessels.

g) The following items should be considered in installing bulk storage and loading facilities.

1) Adequate fire/retaining walls or other containment measures should be provided around tanks, where necessary to comply with regulatory requirements, in order to contain accidental discharges and prevent environmental damage. No open pipes should extend from within the firewalls which might allow contaminated fluids to be drained or siphoned from inside the containment area.

2) Installation of impervious foundations or liners under storage tanks should be considered to allow detection and containment of fluid releases.

3) Installation of high-level alarms and/or monitors should be considered on tankage.

4) Installation of drip pans or other containment should be considered at truck or barge loading/unloading hose connections to contain any spillage.

5) Emission permits should be obtained based on the highest anticipated production rates and equipment specifications before installation of the facilities or commingling well production to central facilities.

6) The following API recommended practices and specifications should be considered in designing storage and loading facilities:

i) API 11N,

ii) API 12B,

iii) API 12D,

iv) API 12F,

v) API 12N,

vi) API 12P.

h) The following items should be considered in installing internal combustion (IC) engines and compressor facilities.

1) Consideration should be given to minimizing noise disturbance. IC engines and compressor facilities should be located as far as practical from areas accessible to the general population. If feasible, alternate types of prime movers, such as electric motors, should be considered.

2) The emissions generated by the engine(s) exhaust should be of concern. Appropriate lead-time for permitting should be allowed, as it may require from six (6) months to one (1) year to permit compressor facilities. All required construction and emissions permits must be obtained before construction, modification, or relocation of an engine is initiated. The type of fuel should be selected to minimize pollutants. Electric power should be considered, where feasible.

3) Consideration should be given to installing drip pans or placing engines and compressors on impervious pads to minimize the impact of potential oil and chemical drips and spills. If drip pans or impervious pads are used, special attention should be given to ensuring that they are kept clean and that any oil or chemical collected is removed, recovered, and recycled or disposed in a timely and proper manner.

4) Piping for the relief valves of compressors should be of adequate size and piped to an appropriate vent or flare.

5) Placing fences, guard walls, or buildings around all engines and compressors should be considered for the protection of the public and any livestock or wildlife.

6) The following API standards and publications should be considered when installing and maintaining IC engines and compressor facilities:

i) API 7B-11C,

ii) API 7C-11F,

iii) API 11K.

i) The following items should be considered in planning, installing, and using pits, firewalls, and dikes.

1) Whenever practical, tanks should be used instead of pits.

2) Existing pits should be minimized and alternate means considered, where feasible. Pits should only be used for the purpose they were intended. Personnel should be advised on the specific use of the pit and what substances are allowed in the pit.

3) During the design and construction of pits and firewalls, necessary precautions should be taken to protect ground and surface water, crops, trees, livestock, and wildlife.

4) Pits should be designed and constructed to have sufficient freeboard, or provide adequate reserve capacity, to prevent overflow under maximum anticipated operating requirements and precipitation.

5) Pits should be fenced or otherwise equipped, as necessary, for public safety and to protect livestock and wildlife.

6) Netting of pits should be considered to protect migratory birds from exposure to the pit contents if there is a potential for the pit to have an oily surface or to contain potentially harmful substances.

7) Burn pits should be located where prevailing winds will reduce fire hazards and smoke nuisance.

8) Storage vessels for liquid hydrocarbons, saltwater, chemicals, or other fluids that are not acceptable to be discharged into the local environment should have dikes constructed around their perimeters.

9) Dikes and firewalls should be constructed of material to prevent the release of fluids to the local environment during an accidental or emergency discharge from their original containment.

10) Consideration should be given to designing dikes and firewalls with a sufficient perimeter and wall height to contain the maximum volume of the largest vessel or tank contained within, and with sufficient freeboard for maximum rainfall and snow melt. Any drain lines through dikes should be equipped with valves/blinds that are normally closed and locked.

j) The following items should be considered in using utilities at production sites:

1) existing utilities should be considered in the design of production and water handling facilities;

2) if electricity is available, the use of electric motors/prime movers should be considered to minimize air emissions and noise;

3) storage facilities should not be located under or near major electrical transmission lines;

4) all electricity, potable water, sewage, and municipal gas lines should installed in accordance with any applicable codes or regulations.

k) The following items should be considered in designing and installing flares/vents at production sites.

1) Flares/vents utilized in production facilities should be located downwind (with respect to prevailing wind direction) from the installation and at a proper safe distance from the related equipment.

2) The surrounding environment should be considered when designing flares. The flare should be located far enough from trees and other vegetation to ensure they will not be ignited during times of maximum flare and strong winds. Installation of liquid scrubbers should be considered.

3) Flares and vents, assuming vent ignition, should be of sufficient height to protect workers and the public during maximum flaring/venting and strong winds.

4) Fencing around flares should be considered to protect the public, livestock, and wildlife.

5) Installation of automatic igniters, rather than standing pilots, should be considered, where feasible, to conserve natural gas and reduce emissions.

6) Flares should be of a smokeless design, if possible.

7) Consideration should be given to design features which will prevent raptors or other birds from perching on flares.

l) Safety systems for protecting the environment should be considered as follows.

1) Installation of safety equipment and systems should be considered, i.e. emergency shutdown (ESD) systems which have the ability to shut wells in, shut down compressors or other engines, or divert production during malfunctions or accidental releases. Where appropriate, alarm systems should be installed to notify the public or company officials of equipment failure or accidental releases. Equipment for fire protection should be installed and maintained, such as, fire extinguishers, spray nozzles, fire pumps, water storage, and automatic extinguishers.

2) API 2350 should be considered in the design of safety systems.

m) Corrosion abatement procedures should be considered as follows.

1) The corrosiveness of the anticipated gas or fluid should be considered during the design and selection of the equipment.

2) Where corrosion problems are anticipated, a corrosion abatement program should be established to minimize the potential for leaks.

3) Soil corrosiveness or resistivity should be evaluated for necessity of coating or wrapping of lines to be buried. In some cases, cathodic protection may be necessary.

n) Special consideration should be given to reducing air emissions associated with production and water handling facilities. The following items should be considered during design and construction of these facilities:

   1) vapor recovery units and flares;

   2) catalytic converters on fired equipment exhaust;

   3) minimization of benzene, hydrogen sulfide, and other hazardous emissions from tanks, glycol reboilers, and other equipment;

   4) minimization of operational gas vents, leaks, and discharges from pneumatic controls and other equipment;

   5) electric powered prime movers;

   6) valves installed on dead end piping should be capped, plugged, or sealed by a blind flange.

8.3.2 Equipment Location

a) Production and water handling facilities should be located where they do not present a fire hazard to nearby facilities. Fired vessels, IC engines, flares, or other equipment that produce sparks or flames should be appropriately separated from oil and gas storage facilities. Topographic and other maps should be consulted to determine if operational problems would affect the local environment. This could include, but is not limited to, the possibilities of oil or water discharges draining into surface waters. Minimization of damage to vegetation crops, forests, animal habitation, etc. should also be considered. Unnecessary removal of trees, excessive grading, or alteration of other natural features should be avoided.

b) In populated areas, the location of equipment should take advantage of prevailing winds in order to ensure public safety in the event of equipment malfunction, release, or fire. In all cases, production and water handling facilities should be located as far as practical from buildings occupied or used by the public.

c) Noise levels of production and water handling facilities should be considered when operating near populated areas.

d) Equipment should be located with consideration given to subsurface soil conditions such that there is an adequate foundation to support the facilities to be constructed and the equipment to be used in the construction processes.

e) The location of all wells should be considered to minimize rights-of-way requirements for lease roads and gathering lines.

8.3.3 Waste Management

a) Equipment and facilities should be located and designed to minimize the wastes generated by operations and maintenance activities.

b) Recyclable products should be used, where possible. Bulk storage, recyclable, and reusable containers should be considered to minimize waste.

c) Appropriate methods of collecting and recycling or disposing of waste generated during construction, operation, and maintenance of the facility should be considered.

d) Operators should develop waste management plans. Refer to *API Environmental Guidance Document: Onshore Solid Waste Management in Exploration and Production Operations* for additional information.

8.4 Construction Considerations

8.4.1 Site Preparation

The following site preparation steps must be taken before initiating construction:

a) soil characteristics should be checked to determine the appropriate foundation design for the site;

b) the size and type of equipment to be used during construction should be considered to allow sufficient room to work in a safe manner;

c) adequate culverts and drainage ditches should be provided as required by the local environment;

d) the open end of lines under construction should be temporarily capped at the end of each workday if a line could be accessible to wildlife.

8.4.2 Inspection and Testing

The following inspection and testing steps must be taken before initiating construction.

a) During construction, qualified personnel to ensure that design specifications are met should perform appropriate inspections to ensure that design specifications are met.

b) Upon completion, equipment and facilities should be inspected for possible leaks. If necessary, equipment should be pressure tested in accordance with applicable codes. If fluids are used to pressure test, collect and dispose of the fluids, refer to *API Environmental Guidance Document: Onshore Solid Waste Management in Exploration and Production Operations* for applicable information.

c) X-raying of welds should be considered in critical areas where extreme pressure or corrosiveness is anticipated or where potential risk to the local environment is of great concern.

8.4.3 Qualification of Personnel

The qualifications of personnel working on the construction site should be evaluated to aid in ensuring the work will be properly performed.

8.4.4 Selection of Contractors

Consideration should be given to requiring contractors to have performance bonds should be considered when facilities are to be constructed in environmentally sensitive areas.

8.4.5 Equipment Installation

All equipment should be installed in accordance with the original design of the equipment. Any variations from the original specifications should be evaluated thoroughly to ensure safety of the operations. Refer to API 12R1 and API 7C-11F for information regarding equipment installation.

8.4.6 As-built Drawings

Upon completion of facilities, the original drawings or schematics should be updated, as required. Changes or modifications from the original design or drawings should be noted for future reference.

8.4.7 Site Cleanup

Unused and excess construction materials should be properly stored or removed from the site upon completion. During construction, the site should be kept as clean and free of debris as possible. Where feasible, unused material should be removed from the construction site as it is determined to be surplus. Where applicable, construction waste should be recycled. Refer to *API Environmental Guidance Document: Onshore Solid Waste Management in Exploration and Production Operations* for additional information regarding management of waste.

8.4.8 Interim Reclamation

Interim reclamation consists of minimizing the footprint of disturbance by reclaiming to the extent possible all portions of the site not required for production operations. The portions of the cleared site not needed for operational and safety purposes are recontoured to a final or intermediate contour that blends with the surrounding topography as much as possible. Sufficient level area remains for the set-up of workover or production stimulation and to park necessary equipment. Where practical, the operator should spread topsoil over the entire location and revegetate as closely as possible to the production facilities, unless an all-weather, surfaced access route or turnaround is needed to inspect or operate the well or to complete workover or stimulation operations. It may be necessary to drive, park and operate on restored, interim vegetation within the previously disturbed area. This is acceptable provided damage is repaired and reclaimed following use. To reduce final reclamation costs and effort, to maintain healthy, biologically active topsoil, and to minimize habitat, visual resource, and forage loss during the life of a well, salvaged topsoil should be spread over the areas of interim reclamation rather than stockpiled.

Where the topography is flat and it is, therefore, unnecessary to recontour the well location at the time of final reclamation, the operator should set aside sufficient topsoil for reclamation of the small unreclaimed area around the wellhead. Any topsoil pile set aside should be revegetated to prevent it from eroding and to help maintain its biological viability. On sloped ground, during final reclamation the topsoil and interim vegetation must be restriped from portions of the site that are not at the original contour, the well pad recontoured, and the topsoil respread over the entire disturbed site to ensure successful revegetation.

8.5 Operation and Maintenance

8.5.1 Operational Procedures

a) Development of a standard operating procedure (SOP) manual applicable to each major facility should be considered. The SOP should contain information as to the equipment located at the facility, safe-operating practices for the equipment, start-up and shutdown procedures, and emergency procedures.

b) Consideration should be given to the analysis of failures or malfunctions so that corrective action can be taken to minimize future environmental incidents.

8.5.2 Personnel Training

Personnel should be trained in the safe and efficient use of facility equipment.

8.5.3 Equipment Inspection

Routine inspections should be considered on all equipment operating in corrosive environments. All safety equipment should be tested on a routine basis to ensure proper operation.

8.5.4 Corrosion Monitoring and Treatment

Monitoring should be considered if produced fluids are suspected of being corrosive. If produced fluids are determined to be corrosive, a corrosion abatement program should be considered. This is especially important in populated or environmentally sensitive areas. Operating procedures should provide for early identification of potential corrosion problems in failure-prone equipment. Refer to NACE MR 0175.

8.5.5 Housekeeping

a) The facilities should be kept clean, maintained, and operated in a safe and environmentally sound manner.

b) Facilities should be fenced in a manner to prevent access to the facility by the general public, livestock, or wildlife, where appropriate.

c) Signs should be posted in conspicuous locations to notify employees and the public of any dangerous situations such as, flammable conditions, high voltage, and hydrogen sulfide. State or local regulations may specify certain posting requirements.

d) Emergency phone numbers should be posted at the entrance to the facility, if located near a populated area.

e) Weeds should be controlled to a degree compatible with the local environment by cutting, mowing, or spraying to improve appearance and reduce the fire hazard. When herbicides are used to control weeds, the chemicals should be properly applied by trained personnel.

f) All equipment should be painted and/or kept clean to present an acceptable appearance and to provide protection from external corrosion.

g) Waste receptacles should be provided at appropriate locations for collecting discarded paper, rags, etc. and emptied on a regular basis.

8.6 Waste and Residual Management

8.6.1 General

Waste and residual management practices for production operations should be conducted consistent with lease and landowner obligations. This should include solid wastes and residuals, such as tank bottoms, drilling fluids and cuttings, liquid wastes and residuals, such as produced water and used oil, and gaseous wastes, such as hydrocarbons and carbon dioxide. A sound waste management plan is important to protect human health and the environment and minimize long-term liabilities to the operator.

A waste or residual management plan should utilize one or all of the options listed below, in order of preference, to protect human health and the environment.

a) Source Reduction—Minimize or eliminate the volume and/or toxicity of the waste generated.

b) Recycling—Reclaim or reuse the maximum amount of waste possible.

c) Treatment—Utilize techniques to minimize the amount and the toxicity of waste after it is generated, thereby minimizing the amount that has to be disposed.

d) Disposal—Employ environmentally sound and approved methods to properly dispose of generated wastes.

8.6.2 Source Reduction

Source reduction involves decreasing the volume or toxicity of wastes or other residuals that are generated. Product substitution is an example of source reduction. Production and workover chemicals should be evaluated to determine if less toxic substitutes are available that meet the performance and economic criteria of the operator.

Reviewing common-sense housekeeping practices can be effective in reducing waste or other residual generation. Installing drip pans, as an example, on valves and fittings allows the collection of leaked oil before it contacts the soil and becomes a waste.

8.6.3 Recycling and Reclaiming

After all reduction options are considered, recycling or reclaiming the residual material should be evaluated. Examples of recycling and reclaiming are recovering waste oil, hydraulic oil, and oily sump water by reintroduction into the oil stream or transportation to a refinery. Drums, batteries, and scrap metal can be sold or returned to the vendor, where possible. Tank bottoms and sludges can be sold to reclaimers, where feasible.

8.6.4 Treatment

Following reduction and recycling efforts, treatment of waste should be considered to minimize the waste volume and the toxicity of the waste.

Filtration, centrifugation, evaporation, and flocculation are examples of reduction techniques that can reduce the volume of the actual waste that must be disposed. The toxicity of certain wastes can be reduced by chemical treatment, thermal treatment, and biodegradation before disposal.

8.6.5 Disposal

The final option for management of a waste, after source reduction, recycling, and treatment options have been considered and incorporated, is disposal. The operator should take into consideration the long-term fate of the waste and its constituents before disposal. Considerations that should be evaluated when choosing either an on-site or an off-site commercial disposal method are as follows:

a) general site review of the topographical and geologic features,

b) groundwater review to determine the presence of groundwater and aquifers,

c) area weather patterns to estimate rainfall and flooding potential,

d) general soil conditions,

e) natural drainage areas,

f) identification of environmentally sensitive conditions,

g) air quality.

These criteria will help determine a waste disposal option that protects human health and the environment and limits future liability for the operator. Examples of waste disposal options that can be considered are:

a) landspreading,

b) roadspreading,

c) on-site burial,

d) on-site pits,

e) annular injection,

f) underground injection wells,

g) regulated and permitted discharge of fluid,

h) incineration,

i) off-site commercial facility.

The operator should maintain adequate documentation of waste management activities. Development of a long-term records retention policy should be considered.

Refer to *API Environmental Guidance Document: Onshore Solid Waste Management in Exploration and Production Operations* and API's *Guidelines for Commercial Exploration and Production Waste Management Facilities*.

8.7 Spill Prevention, Response, and Cleanup

8.7.1 General

Accidental spills (including oil and saltwater) can, besides potentially damaging the environment, create difficult operational, legal, and public relations problems. It is very important to conduct operations in a manner that minimizes the potential for unauthorized spills. Spill prevention, response, and cleanup procedures should be defined and in place before storing any oil or chemicals on site or conducting activities that have a potential for a spill. Outlined hereunder are some recommended operating practices which can be implemented by operators to minimize waste volumes and impacts on the environment.

8.7.2 Prevention

The best way to avoid adverse effects of spills is to prevent their occurrence. The key factors in spill incident prevention are adequately trained supervisors and field operating personnel. The following basic steps can be taken to prevent accidental spills.

a) The facility design should be reviewed to determine where the potential for spills exists. Information on prior spill incidents should be included in the review to assess areas where changes in equipment or practices may be needed. Using the results of the review, the following should be considered, as appropriate.

   1) Modification of existing facilities or installation of new equipment or instrumentation, as needed, to reduce the possibility of spills, commensurate with the risk involved. Consideration should be given to the use of alarms, automatic shutdown equipment, or fail-safe equipment to prevent, control, or minimize potential spills resulting from equipment failure or human error.

   2) Maintenance and/or corrosion abatement programs to provide for continued adequacy of all equipment.

   3) Routinely scheduled tests and inspections of lines, vessels, dump valves, hoses, and other pollution prevention equipment where failure(s) and/or malfunction(s) could result in a potential spill incident. These tests and inspections should be commensurate with the complexity, conditions, and circumstances of the facility.

   4) Operating procedures that minimize potential spills. These operating procedures should be clearly written and available to all operating personnel.

   5) Examination of field drainage patterns and construction of oil traps in drainage ditches at strategic points to contain spilled oil before it reaches streams or water basins.

b) Training programs should be developed on spill prevention fundamentals and presented to operating personnel as often as necessary to keep them well versed on spill prevention practices.

c) Contingency and shutdown plans should be developed for coping with hurricanes and other disasters (both natural and manmade) so as to minimize the potential for oil spills or incidents causing pollution or other environmental damage.

8.7.3 Mitigation

Some other associated steps that should be taken to reduce the potential for oil spills are:

a) “dead” piping and temporary connections should be removed when they are no longer required;

b) piping subject to vibration should be braced to reduce movement and resulting fatigue failures;

c) tanks should be checked for uneven settlement of the foundation, corrosion, and leaks;

d) installation of pressure relief valves should be considered for liquid lines, which, if left full, could potentially rupture from liquid expansion due to heat;

e) sleeve-type line couplings should not be used when there is a chance of line movement.

8.7.4 Spill Contingency Plan

In the event a spill occurs, it is extremely important for all responsible operating personnel to know how to respond quickly and effectively to control, contain, and clean up the spill. To ensure this capacity exists, a contingency plan should be prepared for inland areas as well as for areas near water. The plans should provide utilization of capabilities of oil spill cooperatives, whenever advantageous.

Spill plans should address the needs to advise the public about significant releases. The plan should include procedures to advise government officials and provide appropriate information and access to the press.

8.7.5 Control and Containment

In the event a spill occurs, the source of the spill should be stopped, or reduced as much as possible, in a safe manner. The spread of the spilled substance should be controlled or contained in the smallest possible area to minimize the adverse effects. Some methods which can be used to control and contain discharged substances, particularly oil, include:

a) retaining walls or dikes around tanks and other spill prone equipment,

b) secondary catchment basins designed to prevent the spread of oil if it escapes the primary wall or dike,

c) permanent booms in water basins adjoining the facility,

d) temporary booms deployed in the water after the spill occurs,

e) use of special chemicals to jell or biodegrade the oil to prevent the spread of oil spilled into or on water.

Operators should evaluate the potential for spills and damages and use this information to determine the type and size of primary and secondary containment necessary.

The type and footage of containment boom installed or stored for deployment will vary with the type, size, and location of the facility and spill potential. This information should be developed for each main area or facility and be stated in the facility contingency plan. In addition, the contingency plan should list where emergency equipment is located.

The contingency plan should state the type(s) of chemicals that can be used effectively and list sources and procedures for applying these chemicals. Spill response drills/simulations should be considered, with regulatory agency and contractor personnel participating.

8.7.6 Cleanup

Cleanup procedures should be developed and included in the facility contingency plan. Up-to-date lists of effective cleanup materials and equipment and a list of potential contractors who can supply needed assistance should also be included and maintained in the contingency plan.

Depending on the spill potential at each area, a stock of appropriate cleanup materials sufficient to handle small spills should be maintained on hand at all times. The amount of cleanup material will depend on the time required to obtain more material if the size of the spill should increase.

The following suggested cleanup practices should be considered.

a) Using cleanup materials and equipment on hand, immediate action should be taken to clean up any spilled oil or other substance. Depending on the substance spilled, personnel performing and supervising cleanup operations may require specific training.

b) Advance planning and arrangements should include availability and ready access to vacuum trucks and to similar pickup equipment to recover the spilled material.

c) Necessary approvals should be obtained before disposal of spill cleanup materials.

d) Advance arrangements should be made for rights of ingress and egress to public and private property that may be affected by a spill or the ensuing cleanup operation.

e) Landowners should also be notified of spills and kept informed of spill cleanup progress.

f) Plans, procedures, and programs should be improved and updated by analyzing previous spill incidents. Prevention, control and containment, and cleanup procedures should be revised accordingly to make them more effective for future responses.

8.8 Environmental Assessment Before Purchase or Sale of Existing Fields and Leases

Before the purchase or sale of an existing field or lease, consideration should be given to documenting the environmental condition of that property. By documenting the presence or absence of surface, subsurface, or groundwater contamination, an operating company may be able to reduce its exposure to significant future liabilities. Aerial photographs may be beneficial during this process.

Documentation of audits, assessments, and operating practices is important to identify potential problem areas. Care should be taken to document actions taken to correct deficiencies identified by audits.

8.9 Closure and Abandonment of Facilities

8.9.1 Purging and Flushing of Equipment Before Removal

All equipment such as tankage, separation vessels, meter runs, flow lines, and pumps should be purged and flushed, as appropriate. Whenever possible, materials recovered should be recycled, reclaimed, or disposed. Refer to *API Environmental Guidance Document: Onshore Solid Waste Management in Exploration and Production Operations* for additional information.

8.9.2 Equipment Removal

The following equipment removal issues should be considered.

a) Tanks, separation vessels, meter runs, surface lines, pumps, and any other exposed surface equipment should be removed. Removal of the associated equipment foundations should be considered.

b) Exposed piping segments from surface or subsurface equipment connecting to buried lines should be removed to a depth consistent with subsequent land use or, preferably, to the depth of buried lines. Where feasible or where desired to limit potential future liabilities, consideration should be given to removing buried lines.

c) Where appropriate, each outlet of any abandoned lines should be permanently sealed.

d) Operators should consider removing all crossing markers and other line markers.

e) Where appropriate, the location of abandoned lines should be identified on facility maps.

8.9.3 Pit Closure

All pits and surface impoundments should be properly closed after they are dry and free of waste; then they should be backfilled and graded to conform to the surrounding terrain. Closure must also be in accordance with any local and/or state regulations. The location of closed pits should be documented. Materials removed from pits should be reclaimed, recycled or disposed. Refer to *API Environmental Guidance Document: Onshore Solid Waste Management in Exploration and Production Operations* for additional information. Documentation should be kept on disposed materials.

8.9.4 Land Reclamation and Restoration

Upon completion of abandonment activities, all disturbed surface areas should be cleaned up and restored to conditions similar to the adjacent land or to landowner requirements.

Timely completion of final reclamation is as important as the initial planning. Incomplete or improperly executed final reclamation can result in the complete loss of a low-impact project opportunity. Reclamation becomes significantly more difficult, more expensive, and less effective if sufficient topsoil is not salvaged, interim reclamation is not completed, and if proper care is not taken to construct pads and roads in locations that minimize reclamation costs.

Revegetation alone does not constitute successful reclamation. Restoration of the original landform is a key element in ensuring that the effects of oil and gas development are not permanent.

To achieve final reclamation of a recently drilled dry hole, the well site should be recontoured to original contour or to a contour that blends with the surrounding landform, stockpiled topsoil redistributed, and the site revegetated. To achieve final reclamation of a formerly producing well, all topsoil and vegetation must be restriped from all portions of the old well site that were not previously reshaped to blend with the contour of the surrounding landform. All disturbed areas are then recontoured back to the original contour or a contour that blends with the surrounding landform, topsoil is redistributed, and the site revegetated, using native plant species or agency approved seed mixes using native plant species or agency approved seed mixes “that are acceptable to the landowner or trustee.

In recontouring areas that have been surfaced with gravel or similar materials, the material should be removed from the well location or buried deep in the recontoured cut to prevent possible surface exposure.

Infrastructure associated with formerly producing leases, including water impoundments, power lines, metering buildings, compression facilities and tank batteries must be removed and the footprints or lands disturbed by these facilities and associated foundations reclaimed unless the surface owner requests that items such as impoundments or water wells be kept.

Salvaged topsoil should be respread evenly over the surfaces to be revegetated. The topsoiled site should be prepared to provide a seedbed for reestablishment of desirable vegetation. Site preparation may include gouging, scarifying, dozer track-walking, mulching, fertilizing, seeding and planting. In reclamation of sites that are not cultivated for agriculture or grazing, seeding and planting should use plant species indigenous to the area.

Water breaks and terracing should only be installed when absolutely necessary to prevent erosion of fill material and should be removed when the site is successfully revegetated and stabilized.

Annex A

Good Neighbor Guidelines

(This annex provides guidance for a company to consider as it manages its relationships with surface users, communities and others in areas where it operates.)

The oil and natural gas industry is dedicated to responsible development of oil and natural gas resources. Responsible development includes good relationships with our neighbors and a commitment to environmental protection and compliance with all applicable federal, state, and local regulations.

To be a "good neighbor" in the areas where industry operates, we have three objectives:

— protection of public safety;

— protection of the environment; and

— respect for the property rights of others.

These objectives are achieved through use of sound management processes as part of the responsibility to act as a "good neighbor." As our industry pursues responsible development of energy resources to meet the nation's energy needs, we should strive for better communication and understanding with the land owners, lessees, permittees and/or residents ("land owner or surface users") impacted by our operations.

Good Neighbor Practices

Listen to the land owner or surface user concerns and respond appropriately:

— respect rights-of-way,

— take precautions to protect livestock,

— take precautions not to harm wildlife with our operations,

— drive safely,

— report damages to public or private property to the appropriate parties,

— maintain production equipment and systems, and

— train personnel on the rules and regulations applicable to our operations.

Communicate with land owners and surface users:

— be willing to discuss with the land owner or surface user of industry property use rights (including mineral rights) and surface use rights,

- designate a company contact person who is responsible for responding to community questions,
- listen to and discuss the concerns of the land owner or surface user affected by our operations, and
- attempt to notify the landowner or surface user when commencing significant activity that will impact their land.

Respect the property and the rights of others:

- minimize surface disturbances,
- take precautions to protect livestock with appropriate measures,
- practice good housekeeping,
- remediate and restore the site in a timely manner in compliance with applicable regulations, and
- drive responsibly on public and private roads.

Promote safety of the general public:

- train personnel in safe operating practices,
- conduct emergency planning where applicable, and
- post signage and warnings in accordance with regulations.

Protect the environment:

- train personnel on environmental protection in compliance with applicable regulations; and
- maintain equipment and utilize good work practices;
- seek to understand the land owner, and surface user concerns and possible questions regarding:
  - groundwater aquifers and surface water,
  - air quality,
  - wildlife and livestock protection,
  - housekeeping,
  - noise,
  - surface disturbance, and
  - noxious weeds and brush;
- follow regulations for waste management and environmental protection.

Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines

API GUIDANCE DOCUMENT HF1
FIRST EDITION, OCTOBER 2009

Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines

Upstream Segment

API GUIDANCE DOCUMENT HF1
FIRST EDITION, OCTOBER 2009

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Shall: As used in a publication, “shall” denotes a minimum requirement in order to conform to the publication.

Should: As used in a publication, “should” denotes a recommendation or that which is advised but not required in order to conform to the specification.

Suggested revisions are invited and should be submitted to the Standards Department, API, 1220 L Street, NW, Washington, DC 20005, standards@api.org.

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Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines

1 Scope

The purpose of this guidance document is to provide guidance and highlight industry recommended practices for well construction and integrity for wells that will be hydraulically fractured. The guidance provided here will help to ensure that shallow groundwater aquifers and the environment will be protected, while also enabling economically viable development of oil and natural gas resources. This document is intended to apply equally to wells in either vertical, directional, or horizontal configurations.

Many aspects of drilling, completing, and operating oil and natural gas wells are not addressed in this document but are the subject of other API documents and industry literature (see Bibliography). Companies should always consider these documents, as applicable, in planning their operations.

Maintaining well integrity is a key design principle and design feature of all oil and gas production wells. Maintaining well integrity is essential for the two following reasons.

1) To isolate the internal conduit of the well from the surface and subsurface environment. This is critical in protecting the environment, including the groundwater, and in enabling well drilling and production.

2) To isolate and contain the well's produced fluid to a production conduit within the well.

Although there is some variability in the details of well construction because of varying geologic, environmental, and operational settings, the basic practices in constructing a reliable well are similar. These practices are the result of operators gaining knowledge based on years of experience and technology development and improvement. These experiences and practices are communicated and shared via academic training, professional and trade associations, extensive literature and documents and, very importantly, industry standards and recommended practices.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API Specification 5B, *Specification for Threading, Gauging, and Thread Inspection of Casing, Tubing, and Line Pipe Threads*

API Specification 5CT/ISO 11960, *Specification for Casing and Tubing*

API Specification 10A/ISO 10426-1, *Specification for Cements and Materials for Well Cementing*

API Recommended Practice 10B-2/ISO 10426-2, *Recommended Practice for Testing Well Cements*

API Recommended Practice 10D-2/ISO 10427-2, *Recommended Practice for Centralizer Placement and Stop Collar Testing*

API Technical Report 10TR1, *Cement Sheath Evaluation*

API Technical Report 10TR4, *Technical Report on Considerations Regarding Selection of Centralizers for Primary Cementing Operations*

API Recommended Practice 65-2, *Isolating Potential Flow Zones During Well Construction*

NOTE API RP 65-2 was under development at the time of publication of API HF1. However, given its subject matter, API felt is was appropriate to include as a reference. API RP 65-2 will provide guidance on well planning, drilling and cementing practices, and formation integrity pressure testing. Upon publication, API RP 65-2 will be available at www.api.org/publications, and will serve as a valuable reference for use in conjunction with API HF1.

API Recommended Practice 90, *Annular Casing Pressure Management for Offshore Wells*

3 General Principles

3.1 Protecting Groundwater and the Environment

All oil and natural gas exploration, development, and production operations are conducted to ensure that the environment, in particular underground sources of drinking water (USDWs [a], or groundwater), is protected. Statutes and regulations have been implemented in every oil and gas producing state of the United States to ensure that oil and natural gas operations are conducted in an environmentally responsible fashion. While these regulations differ from state to state in their details, their general intent and environmental objectives are consistent (IOGCC [1], 2007).

Groundwater is protected from the contents of the well during drilling, hydraulic fracturing, and production operations by a combination of steel casing and cement sheaths, and other mechanical isolation devices installed as a part of the well construction process. It is important to understand that the impermeable rock formations that lie between the hydrocarbon producing formations and the groundwater have isolated the groundwater over millions of years. The construction of the well is done to prevent communication (the migration and/or transport of fluids between these subsurface layers).

The primary method used for protecting groundwater during drilling operations consists of drilling the wellbore through the groundwater aquifers, immediately installing a steel pipe (called casing), and cementing this steel pipe into place. All state drilling regulations specifically address groundwater protection, including requirements for the surface casing to be set below the lowest groundwater aquifer, or USDW (DOE [2], 2009 and IOGCC [1], 2007). The steel casing protects the zones from material inside the wellbore during subsequent drilling operations and, in combination with other steel casing and cement sheaths that are subsequently installed, protects the groundwater with multiple layers of protection for the life of the well.

The subsurface zone or formation containing hydrocarbons produces into the well, and that production is contained within the well all the way to the surface. This containment is what is meant by the term “well integrity.” Moreover, regular monitoring takes place during drilling and production operations to ensure that these operations proceed within established parameters and in accordance with the well design, well plan, and permit requirements. Finally, the integrity of well construction is periodically tested to ensure its integrity is maintained. The monitoring activities that should be conducted prior to and during well construction and over the life of the well will be described in more detail in Section 10.

3.2 Well Design and Construction

Drilling and completing an oil and/or gas well consists of several sequential activities. A list of these activities appears below, and those that are addressed in this guidance document are shown in bold. In sequential order, these activities are as follows:

— building the location and installing fluid handling equipment,

[a] A USDW is defined in federal statute (40 *CFR* 144.3) as any “aquifer that: (1) supplies a public water system; or (2) contains a sufficient quantity of water to supply a public water system and currently supplies drinking water for human consumption or contains fewer than 10,000 mg/L of total dissolved solids.” In addition, it cannot be an exempted aquifer. See http://www.epa.gov/region5/water/uic/glossary.htm. “Groundwater” could include other subsurface waters that do not meet these criteria.

— setting up the drilling rig and ancillary equipment and testing all equipment,

— drilling the hole,

— logging the hole (running electrical and other instruments in the well) (see note),

— running casing (steel pipe) (see note),

— cementing the casing (see note),

— logging the casing (see note),

— removing the drilling rig and ancillary equipment,

— perforating the casing (depending on completion type),

— hydraulic fracturing or stimulating the well,

— installing artificial lift equipment (if necessary),

— install surface production equipment,

— putting the well on production,

— monitoring well performance and integrity,

— reclaiming the parts of the drilling location that are no longer needed and removing equipment no longer used.

NOTE These activities may be conducted multiple times while drilling a well.

Production wells, by necessity, must penetrate the sealing formations above the target hydrocarbon reservoir. This fact alone means stringent analysis and execution of well construction and integrity is of key importance in eliminating potential leak paths. For 75 years the industry has successfully drilled and produced wells using modern drilling techniques. Continuous improvements in technology and practices have allowed these wells to maintain their integrity and provide the required isolation.

The ultimate goal of the well design is to ensure the environmentally sound, safe production of hydrocarbons by containing them inside the well, protecting groundwater resources, isolating the productive formations from other formations, and by proper execution of hydraulic fractures and other stimulation operations. The well design and construction must ensure no leaks occur through or between any casing strings. The fluids produced from the well (oil, water, and gas) must travel directly from the producing zone to the surface inside the well conduit.

The design basis for well construction emphasizes barrier performance and zonal isolation using the fundamentals of wellbore preparation, mud removal, casing running, and cement placement to provide barriers that prevent fluid migration. The selection of the materials for cementing and casing are important, but are secondary to the process of cement placement. The performance of the barrier system to protect groundwater and isolate the hydrocarbon bearing zones is of utmost importance.

All well designs and well plans include contingency planning. Although seldom needed, these contingency plans are in place to mitigate and eliminate the risk failure due to unplanned events, and most importantly, to ensure the protection of people and the environment.

3.3 The Drilling and Completion Process

Drilling a typical oil or gas well consists of several cycles of drilling, running casing (steel pipe for well construction), and cementing the casing in place to ensure isolation. In each cycle, steel casing is installed in sequentially smaller sizes inside the previous installed casing string. The last cycle of the well construction is well completion, which can include perforating and hydraulic fracturing or other stimulation techniques depending on the well type.

Drilling a well utilizes the drill string, consisting of drill bit, drill collars (heavy weight pipe to put weight on the bit), and drill pipe. The drill string is assembled and run into the hole, but suspended at the surface from the drilling derrick or mast. The drill string is then rotated by the use of a turntable (rotary table), top drive unit, or downhole motor drive.

While drilling, fluid is circulated down the drill string and up the space between the drill string and hole. This drilling fluid serves to lubricate the drilling assembly, remove the formation cuttings drilled, maintain pressure control of the well, and stabilize the hole being drilled. Drilling fluid is generally a mixture of water, clays, fluid loss control additives, density control additives, and viscosifiers. Drilling fluid is a carefully monitored and controlled mixture designed to achieve best drilling results.

Referring to Figure 1, the first hole to be drilled is for installing the conductor pipe. The conductor pipe can also be driven into place, like a structural piling, in some circumstances. This is followed by the sequentially deeper holes drilled to install the surface casing, intermediate casing (if necessary), and the production casing. Specific considerations for each of these casing strings are presented in Section 7. It is important to note that the shallow portions of the well have multiple concentric strings of steel casing installed.

In some areas, the general design shown in Figure 1 may be altered because of local environmental or geologic conditions. As such, state regulations vary to achieve the level of isolation and protection needed in different settings. For example, the number of intermediate casing strings is determined by the geologic conditions present in the well being drilled.

Horizontal wells are wells that are drilled vertically to a point and then redirected to run substantially horizontally within the targeted hydrocarbon producing formation. The vertical portion of a horizontal well is drilled the same way as vertical wells described above. However, the horizontal portion of the hole is drilled with a downhole motor in virtually all cases. While drilling the horizontal section of the well, the downhole motor, which operates using the hydraulic pressure of the drilling fluid, turns the drill bit. Downhole motors are “steerable,” meaning their direction of drilling can be controlled from the surface to stay within the target formation.

4 Casing Guidance

The design and selection of the casing is of utmost importance. The casing must be able to withstand the various compressive, tensional, and bending forces that are exerted while running in the hole, as well as the collapse and burst pressures that it might be subjected to during different phases of the well’s life. For example, during cementing operations, the casing must withstand the hydrostatic forces exerted by the cement column; after cementation, the casing must withstand the collapsing pressures of certain subsurface formations. These subsurface pressures exist regardless of the presence of hydrocarbons.

Design of the steel casing strings is a key part of the well design and a key factor in well success, including assurance of zonal isolation and wellbore integrity. It is the prime responsibility of operating companies, drilling contractors, and their drilling engineers and supervisors to design and review the design of the casing, as well as the plan to run and install the casing during well construction. Casing design and running are carefully executed technical processes.

Casing is threaded on each end, and has a coupling installed to join it to the next pipe. When several joints of casing have been screwed together they form a continuous “string” of casing that will isolate the hole. When screwing together a casing connection, applying the proper amount of torque is important. Too much torque overstresses the connection and can result in failure of the connection. Too little torque can result in a leaky connection.

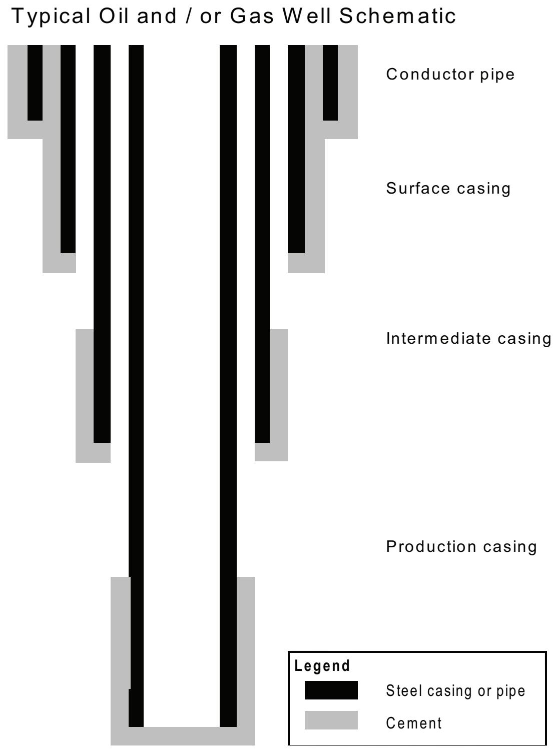

Figure 1—Typical Well Schematic

Casing used in oil and gas wells that will be hydraulically fractured should meet API standards, including API Spec 5CT. API casing specifications and recommended practices cover the design, manufacturing, testing, and transportation. Casing manufactured to API specifications must meet strict requirements for compression, tension, collapse, and burst resistance, quality, and consistency. The casing used in a well should be designed to withstand the anticipated hydraulic fracturing pressure, production pressures, corrosive conditions, and other factors. If used or reconditioned casing is installed in a well that will be hydraulically fractured, it should be tested to ensure that it meets API performance requirements for new built casing.

Casing and coupling threads should meet API standards and specifications to ensure performance, quality, and consistency, including API Spec 5B. If proprietary casing and coupling threads from a specialized supplier are used, these threads must also pass rigorous testing done by the supplier and should adhere to applicable subsets of the API qualification tests.

5 Cementing the Casing

5.1 General

After the casing has been run into the drilled hole, it must be cemented in place. This is a critical part of well construction and is a fully designed and engineered process. The purpose of cementing the casing is to provide zonal isolation between different formations, including full isolation of the groundwater and to provide structural support of the well. Cement is fundamental in maintaining integrity throughout the life of the well and part of corrosion protection for casing.

Cementing is accomplished by pumping the cement (commonly known as slurry) down the inside of the casing, and circulating it back up the outside of the casing. Top and bottom rubber wiper plugs should be used to minimize mixing of cement with drilling fluid while it is being pumped. A downhole schematic of a cement job in progress is illustrated in Figure 2.

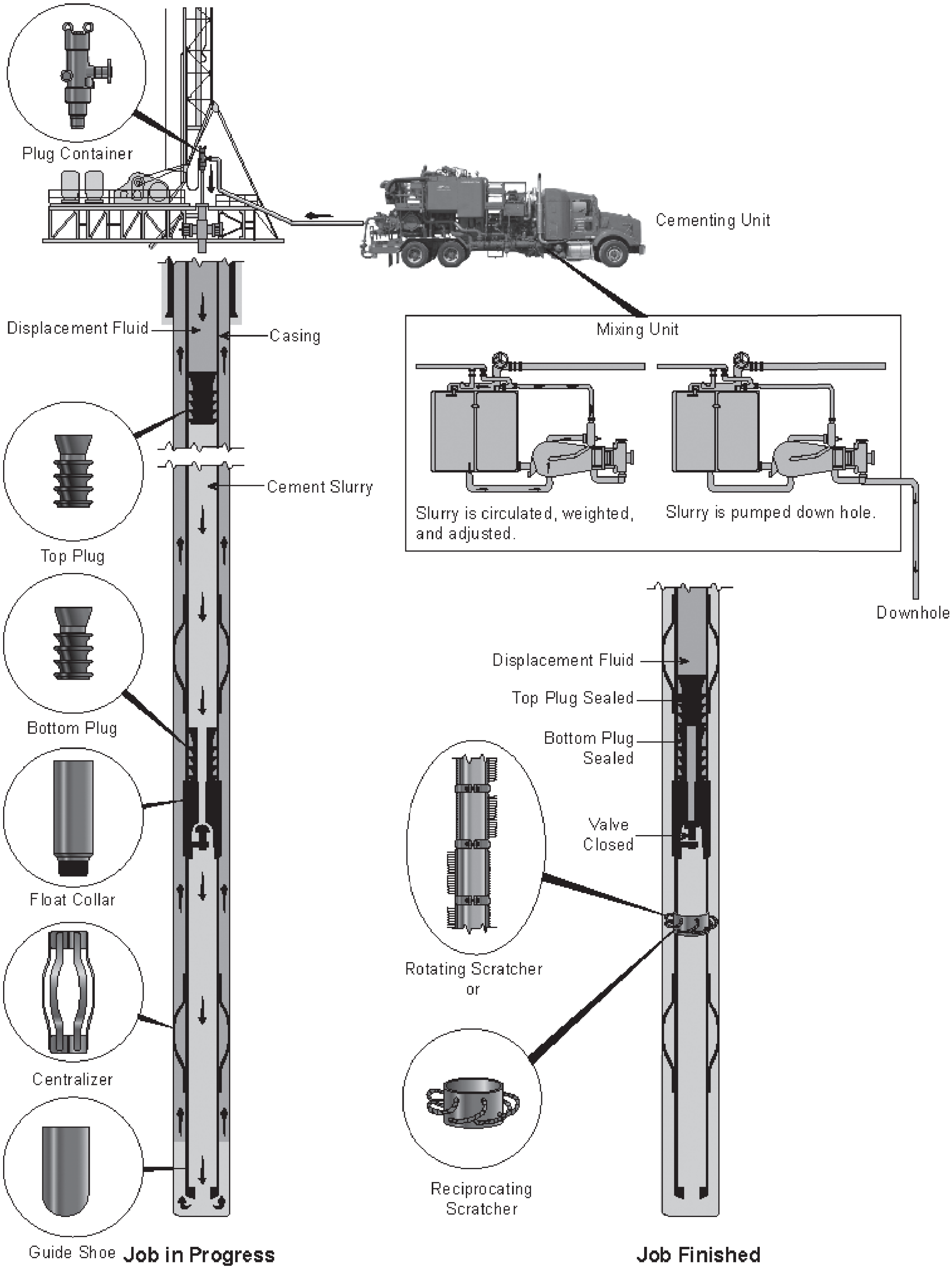

Figure 2—Cementing the Casing

5.2 Cement Selection

Oilfield cements are engineered products that are covered by API technical specifications, recommended practices, and technical reports. The cements and cement additives selected and the cementing practices utilized are an integral part of sound well design, construction, and well integrity. Various cements and cement additives are available for use. Appropriate API standards should be consulted in the selection and use of cementing products, including API Spec 10A and API RP 10B-2. Selected cements, additives, and mixing fluid should be laboratory tested in advance to ensure they meet the requirements of the well design.

Specifications and recommended practices for cementing operations, developed by API and others, are well documented and available to all companies drilling wells. These standards should be followed by operators in all wells. A general list of good cementing practices is provided in 5.4.

5.3 Zone Isolation

Placement of the cement completely around the casing and at the proper height above the bottom of the drilled hole (cement top) is one of the primary factors in achieving successful zone isolation and integrity. Good isolation requires complete annular filling and tight cement interfaces with the formation and casing. Complete displacement of drilling fluid by cement and good bonding of the cement interfaces between the drilled hole and the casing immediately above the hydrocarbon formation are key parts of well integrity and seal integrity. The absence of voids and good bonding of cement at these interfaces prevent migration paths and establish zone isolation.

5.4 Cementing Practices

The following cement practices are recommended in order to ensure that isolation is achieved.

— Prior to drilling, operators should investigate and review the history of nearby wells for cementing problems encountered, e.g. lost returns, irregular hole erosion, poor hole cleaning, poor cement displacement, etc.

— Computer simulation and other planning should be carried out in order to optimize cement placement procedures.

— Operators should use established, effective drilling practices to achieve a uniform, stable wellbore with desired hole geometry.

— Operators should ensure that the drilling fluid selection is appropriate for the designed well and the geologic conditions likely to be encountered.

— Casing hardware, including float equipment, centralizers, cement baskets, wiper plugs (top and bottom), and stage tools should be selected as necessary as part of the well design that will meet the cement design objective and challenges and ensure isolation.

— Casing centralizers should be selected to help center the casing in the hole and provide for good mud removal and cement placement, especially in critical areas, such as casing shoes, production zones, and groundwater aquifers (see 5.5).

— Appropriate cement testing procedures should be properly carried out by the service company personnel (see API RP 10B-2). Cement slurry design should include testing to measure the following parameters depending on site-specific geologic conditions.

    — Critical Parameters—Recommended for all situations:

        > slurry density;

  - > thickening time;
  - > fluid loss control;
  - > free fluid;
  - > compressive strength development;
  - > fluid compatibility (cement, mix fluid, mud, spacer).

- — Secondary Parameters—Recommended for use as appropriate to address specific well conditions:
  - > sedimentation control;
  - > expansion or shrinkage of set cement;
  - > static gel strength development;
  - > mechanical properties (Young's Modulus, Poisson's Ratio, etc.).

— Cement job design should include proper cement spacer design and volume. In many cases, cement placement is a two-stage process that uses a "lead" cement of lower density and a "tail" cement of higher density and compressive strength. Typically, the tail cement is used to isolate critical intervals in the well.

— The operator should ensure proper wellbore preparation, hole cleaning, and conditioning with wiper trips prior to the cement job.

— Rotation and reciprocation of casing should be considered where appropriate to improve mud removal and cement placement.

— Service providers should ensure proper mixing, blending, and pumping of the cement in the field.

5.5 Casing Centralizers

Centralization of the casing is important for mud removal and cement placement that help to ensure a good cement job. The casing should be centralized in the hole in order to ensure that it will be completely surrounded or encased by cement during cementing operations and achieve the required isolation.

Casing centralizers are devices that are attached to the outside of the casing to keep the casing centered in the hole, and when the casing is cemented, this will allow the cement to completely surround the casing in a continuous sheath. There are three different kinds of centralizers: the bow-spring design, the rigid blade design, and the solid design. API RP 10D-2 and API TR 10TR4 address calculations determining the number and placement of centralizers in vertical and deviated wellbores and centralizer selection guidelines, respectively.

Casing centralizers should be used in wells. Computer programs are available that can be used to optimize the number of centralizers needed and their placement within a well.

6 Well Logging and Other Testing

6.1 General

Well logs are critical data gathering tools used in formation evaluation, well design, and construction. Also, various types of mechanical integrity and hydraulic pressure tests can be used to assess well integrity during the construction of the well. This section describes various types of well logs and other testing and the type of information that can be gathered.

6.2 Open-hole Well Logging

After drilling of the hole is completed, and before casing is installed and cementing operations begin, electrical and other instruments are often run in the drilled hole on an electric cable in an operation called well logging. When well logging is carried out prior to setting casing, it is called open-hole logging. Open-hole logging is used for many purposes, including locating and evaluating the hydrocarbon producing formations. The types of logs that are run in a well are carefully selected by geologists at the time the well is designed. Common logging tools used for evaluation include the following log types.

— Gamma Ray—A device that detects naturally occurring gamma radiation.

— Resistivity—Measures the electrical resistance between probes on the logging tool in the wellbore. Usually at least three resistivity logs are run, but up to 10 may be run; the difference being the distance between the probes. The radius of investigation is increased with the distance between probes.

— Density—A device used to measure the bulk density of, and, by inference, the porosity of the formation.

— Caliper—A physical measurement of the diameter of the wellbore. A caliper log run through a wellbore is used to calculate the hole size and volume of the wellbore, and therefore provides critical data that is used in the design of the cement job.

Logging produces valuable information on all formations logged, which is useful in optimizing the well design and drilling operation. Logging determines the actual depth and thickness of the subsurface formations in the drilled hole. This allows installation of casing strings in exactly the right place to achieve the well design objectives and to properly achieve the isolation benefits of the casing and cement.

Many other types of logging tools are available and may be run on a case specific basis.

6.3 Cement Integrity (Cased-hole) Logging

After cementing the casing, “cased-hole” logs can be run inside the casing. These logs usually include the gamma ray (described above), a collar locator (a magnetic device that detects the casing collars), and a cement bond log (CBL) that measures the presence of cement and the quality of the cement bond or seal between the casing and the formation.

The CBL is an acoustic device that can detect cemented or noncemented casing. The CBL works by transmitting a sound or vibration signal, and then recording the amplitude of the arrival signal. Casing that has no cement surrounding it (i.e. free pipe) will have large amplitude acoustic signal because the energy remains in the pipe. On the other hand, casing that has a good cement sheath that fills the annular space between the casing and the formation will have a much smaller amplitude signal since the casing is “acoustically coupled” with the cement and the formation which causes the acoustic energy to be absorbed. It is precisely this coupling which is the main feature that creates the desired isolation.

The variable density log (VDL) is a display that is commonly shown with the CBL, and is a display of the wave train of an acoustic signal.

An experienced engineer can easily identify the key features of the cement operation, such as top of cement and the location of the casing collars using data derived from the various well logs that have been run. For example, when the well is perforated, a gamma-ray detector will be run in the hole with the perforating guns, and the exact location of the perforating guns with respect to the formations is known by comparison with the gamma-ray response of the open-hole log and the CBL.

The CBL-VDL is the most common type of cement evaluation tool that is used, but other types of cement evaluation tools are available and, depending on the situation, should be considered as a part of a comprehensive cement evaluation program. Information on the various types of cement evaluation tools can be found in API TR 10TR1.

A key result of the cased-hole logging program is to know the exact location of the casing, casing collars, and quality of the cement job relative to each other and relative to the subsurface formation locations. This is important in determining that the well drilling construction is adequate and achieves the desired design objectives. It is also useful information in subsequent checks of well integrity and seals over the productive life of the well.

6.4 Other Testing and Information

It is important to remember that the quality of a cement job cannot be fully evaluated without other supporting data. All of the available well information is reviewed thoroughly when assessing the integrity of a well's cement job. Such information includes drilling reports, drilling fluid reports, cement design and related laboratory reports, open-hole log information including caliper logs, cement placement information including centralizer program, placement simulations and job logs, results of mechanical integrity tests performed on the well, and other information. The effectiveness of a cement seal should also be tested with various hydraulic pressure tests to ensure well integrity.

7 Well Construction Guidelines

7.1 General

Well design and construction are generally considered to have four main components and are focused around the various casing strings used: conductor, surface, intermediate, and production. This section discusses considerations for each casing string that should be included in well design and construction. It is important to note that because of varying geologic conditions, state regulations are developed to meet the particular need of that state and are not uniform throughout the United States. However, the general principles of groundwater protection through zone isolation are maintained.

All casing setting depths are determined in advance as part of the drilling plan. The depth of each casing string is critical in assuring isolation, meeting regulatory requirements, achieving a well system with integrity to support the rest of the drilling operation, and to contain any pressures that might occur inside the well. The actual length of the casing strings is carefully adjusted as the well is drilled based on measurements and data from the drilling process. This includes the results of logs (see Section 7), drill cuttings analysis, and analysis of pressures and drilling loads while drilling.

A frequent discussion point is whether cement is required to be placed back to surface on each casing string. This is necessary only in some cases and is fully considered in the well design and addressed by state regulations. Specific recommendations for each casing string are given below.

A general recommendation applicable to all casing strings is that after the cement is set and prior to commencing further drilling or completion operations, the cement surrounding the casing shoe should have a compressive strength of at least 500 psi and should achieve 1200 psi in 48 hours at bottomhole conditions. However, for production casing the cement should be tested to ensure that it is adequate to withstand the anticipated hydraulic fracturing pressure.

In addition, each casing string, except the conductor casing, should be pressure tested prior to "drill out." The test pressure will vary depending on the casing string, depth, and other factors.

7.2 Conductor Casing

The first casing to be installed in the well is the conductor casing. The conductor casing serves as the foundation for the well. Two purposes of the conductor casing are to hold back the unconsolidated surface sediments and isolate shallow groundwater. Below the conductor casing there is harder, more consolidated rock. Thus, the conductor pipe keeps the unconsolidated surface sediment in place as the drilling operations proceed. The conductor casing also protects the subsequent casing strings from corrosion and may be used to structurally support some of the wellhead load. Requirements for the conductor hole vary by state and area.

The conductor hole is usually drilled, with steel casing inserted into the hole and cemented in place using proper cementing practices and in accordance with the well design. There are instances where it is appropriate to "hammer" the conductor casing into place, which means it is driven directly into the ground just like a structural pile for buildings and bridges. The conductor hole should be drilled using air, freshwater, or freshwater-based drilling fluid. When determining the setting depth of the conductor casing, the depth of nearby water wells should be considered. Acceptable practice for a particular area is dictated by state regulations.

When cementing conductor casing, cement should be placed back to the surface. If cement cannot be circulated back to the surface using ordinary pumping methods, in some cases it is possible to run a small diameter pipe between the hole and the conductor casing. Cement can then be pumped around the outside of the surface pipe. This type of cement procedure is often called a "top job" or "horse collar."

7.3 Surface Casing

After the conductor pipe is installed and cemented, the surface hole is drilled and the surface casing is run into the hole and cemented in place using proper cementing practices. One of the main purposes of the surface casing is the protection (through isolation) of groundwater aquifers. The surface casing is designed to achieve all regulatory requirements for isolating groundwater and also to contain pressures that might occur in the subsequent drilling process.

The surface hole is typically drilled to a predetermined depth based on consideration of the deepest groundwater resources and pressure control requirements of subsequent drilling. The surface hole should be drilled using air, freshwater, or freshwater-based drilling fluid. This setting depth can be from a few hundred feet up to 2000 ft deep or more. The surface casing is usually set at a depth sufficient to ensure groundwater protection. State regulations dictate the minimal setting depth of surface casing, and the vast majority of states require the casing to be set below the deepest groundwater aquifer. At a minimum, it is recommended that surface casing be set at least 100 ft below the deepest USDW encountered while drilling the well.

It is recommended that the surface casing be cemented from the bottom to the top, completely isolating groundwater aquifers. As is the case with conductor casing, a "top job" may be necessary in certain situations. In those cases where cementation from bottom to top is not required or possible, cementing across all USDWs is recommended. This will still provide the required isolation.

In some instances, unique geologic conditions that will not permit the surface casing to be run deep enough to cover the deepest groundwater aquifer or preclude the need for surface casing at all. In these cases, zone isolation should be achieved through additional strings or a combination of surface, intermediate, and/or production casing and cementing as appropriate.

After the surface casing cement has achieved the appropriate compressive strength and prior to drilling out, the surface casing should be pressure tested (commonly known as a casing pressure test). This test should be conducted at a pressure that will determine if the casing integrity is adequate to meet the well design and construction objectives.

In addition, immediately after drilling out of the surface casing plus a short interval of new formation below the surface casing shoe, a formation pressure integrity test (also known as a "shoe test" or "leak-off test") should be performed. If the test results of the formation pressure integrity test are inadequate, remedial measures should be undertaken as appropriate.

7.4 Intermediate Casing

After the surface hole has been drilled and the surface casing has been set and properly cemented, drilling of the intermediate hole can commence. The purpose of drilling the intermediate hole and running casing is to isolate subsurface formations that may cause borehole instability and to provide protection from abnormally pressured subsurface formations.

In some cases, the well can be drilled from the surface casing to total depth. In these cases, an intermediate casing string may not be required. This is determined by the geological setting prior to drilling, and is a part of the well design or is determined by data and measurements taken during the drilling process.

In many cases, it is not necessary to cement the intermediate casing back to the surface to provide adequate isolation. This is especially true in the cases where the surface casing string and cement are fully protecting the groundwater aquifers. Also, in many cases this is not advisable, as attempts to cement intermediate casing back to the surface can result in lost circulation. If the intermediate casing is not cemented to the surface, at a minimum the cement should extend above any exposed USDW or any hydrocarbon bearing zone.

Depending on the well design, it may be appropriate to run a CBL and/or other diagnostic tool(s) to determine that the cement integrity is adequate to meet the well design and construction objectives.

After the intermediate casing cement has achieved the appropriate compressive strength and prior to drilling out, the intermediate casing should be pressure tested (commonly known as a casing pressure test). This test should be conducted at a pressure that will determine if the casing integrity is adequate to meet the well design and construction objectives.

In addition, immediately after drilling out of the intermediate casing plus a short interval of new formation below the intermediate casing shoe, a formation pressure integrity test (also known as a “shoe test” or “leak-off test”) should be performed. If the test results of the formation pressure integrity test are inadequate or indicate a failure, remedial measures should be undertaken as appropriate. In particular, in the case of a failure, remedial cementing operations should be undertaken as appropriate. This is critical to maintaining well integrity.

7.5 Production Casing

The final hole to be drilled is the hole for the production casing. After the production hole is drilled and logged, production casing is run to the total depth of the well and cemented in place using proper cementing practices. The purpose of the production casing is to provide the zonal isolation between the producing zone and all other subsurface formations, for pumping the hydraulic fracturing fluids and other stimulation techniques from the surface into the producing formation without affecting any other geologic horizon in the well. It also contains the downhole production equipment (tubing, packer, etc.). Over the life of the well, its most important function is internally containing the hydrocarbon production from the producing zone. In most cases, it serves as a secondary barrier for the production tubing and packer that are inserted into the production casing in the final completion step.

There are many options for cementation. In most cases, the production string cement does not need to be brought completely to the surface. This depends on the geologic setting, well design, and wellbore conditions. In cases where intermediate casing is not installed, cementing the production casing to the surface should be considered. At a minimum, the tail cement should be brought at least 500 ft above the highest formation where hydraulic fracturing will be performed. In all cases, the casing is cemented to achieve the required subsurface isolation between zones.

Prior to perforating and hydraulic fracturing operations, the production casing should be pressure tested (commonly known as a casing pressure test). This test should be conducted at a pressure that will determine if the casing integrity is adequate to meet the well design and construction objectives. A CBL and/or other diagnostic tool(s) should be run to determine that the cement integrity is adequate to meet the well design and construction objectives. Remedial cementing operations should be considered if there is evidence of inadequate cement integrity.

7.6 Horizontal Wells

Drilling and completing horizontal wells is an evolving technology. Horizontal wells offer benefits that improve the production performance for certain types of producing formations. Horizontal wells also allow operators to develop resources with significantly fewer wells than may be required with vertical wells. Operators can drill multiple horizontal wells from a single surface location, thereby, reducing the cumulative surface impact of the development operation. However, horizontal wells are significantly more expensive to drill and maintain. In some areas, the typical cost of a horizontal well may be two to three times the cost of a vertical well.

As discussed earlier, horizontal wells are typically drilled vertically to a "kick-off" point where the drill bit is gradually turned from vertical to horizontal. Figure 3 illustrates a vertical and horizontal well for comparison. So the considerations and recommendations for setting conductor, surface, intermediate production casing strings are the same as those for vertical wells.

In horizontal wells, an "open-hole" completion is an alternative to setting the casing through the producing formation to the total depth of the well. In this case, the bottom of the production casing is installed at the top of the productive formation or open-hole section of the well. In this alternative, the producing portion of the well is the horizontal portion of the hole and it is entirely in the producing formation. In some instances, a short section of steel casing that runs up into the production casing, but not back to the surface, may be installed. Alternatively, a slotted or preperforated steel casing may be installed in the open-hole portion. These alternatives are generally called a "production liner," and are typically not cemented into place.

In the case of an open-hole completion, tail cement should extend above the top of the confining formation (the formation that limits the vertical growth of the fracture).

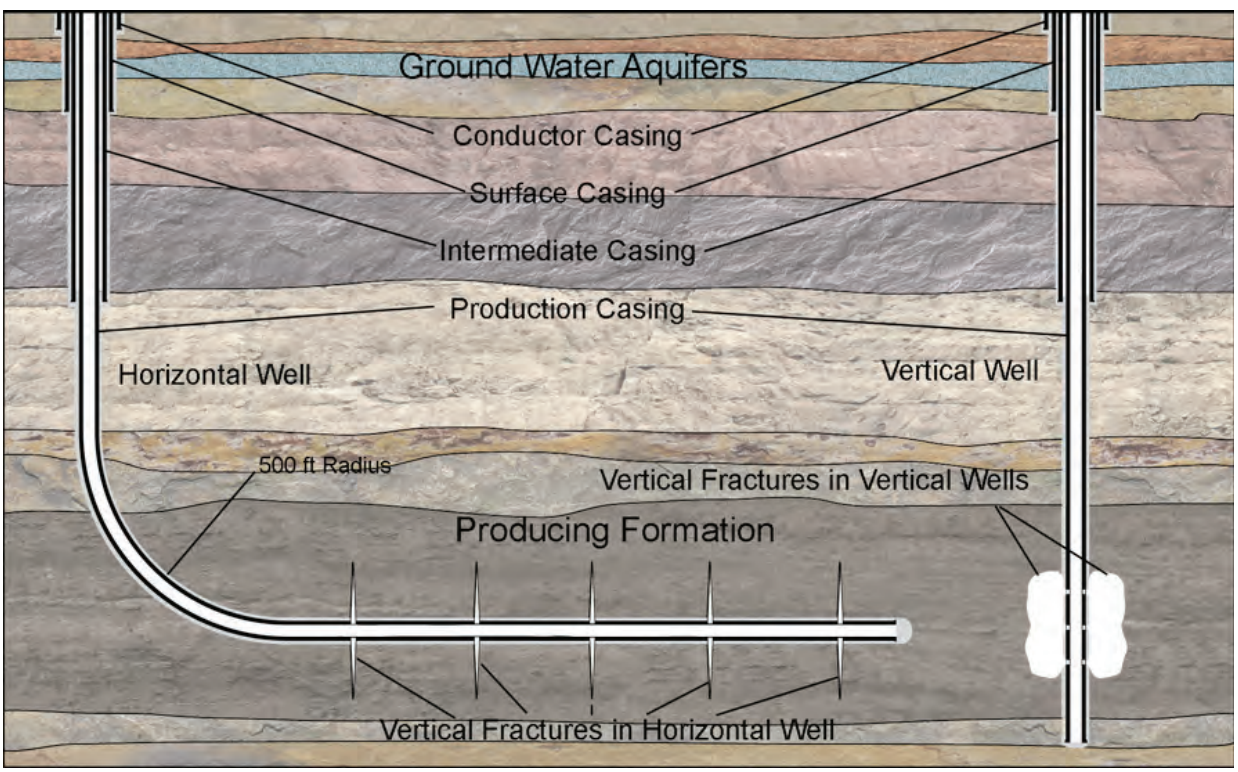

Figure 3—Example of a Horizontal and Vertical Well

8 Perforating

A perforation is the hole created between the casing or liner into the reservoir (subsurface hydrocarbon bearing formation). This hole creates communication to the inside of the production casing, and is the hole through which oil or gas is produced. By far the most common perforating method utilizes jet perforating guns that are loaded with specialized shaped explosive charges.

Figure 4 illustrates the perforation process. The shaped charge is detonated and a jet of very hot, high-pressure gas vaporizes the steel pipe, cement, and formation in its path. The result is an isolated tunnel that connects the inside of the production casing to the formation. These tunnels are isolated by the cement. Additionally, the producing zone itself is isolated outside the production casing by the cement above and below the zone.

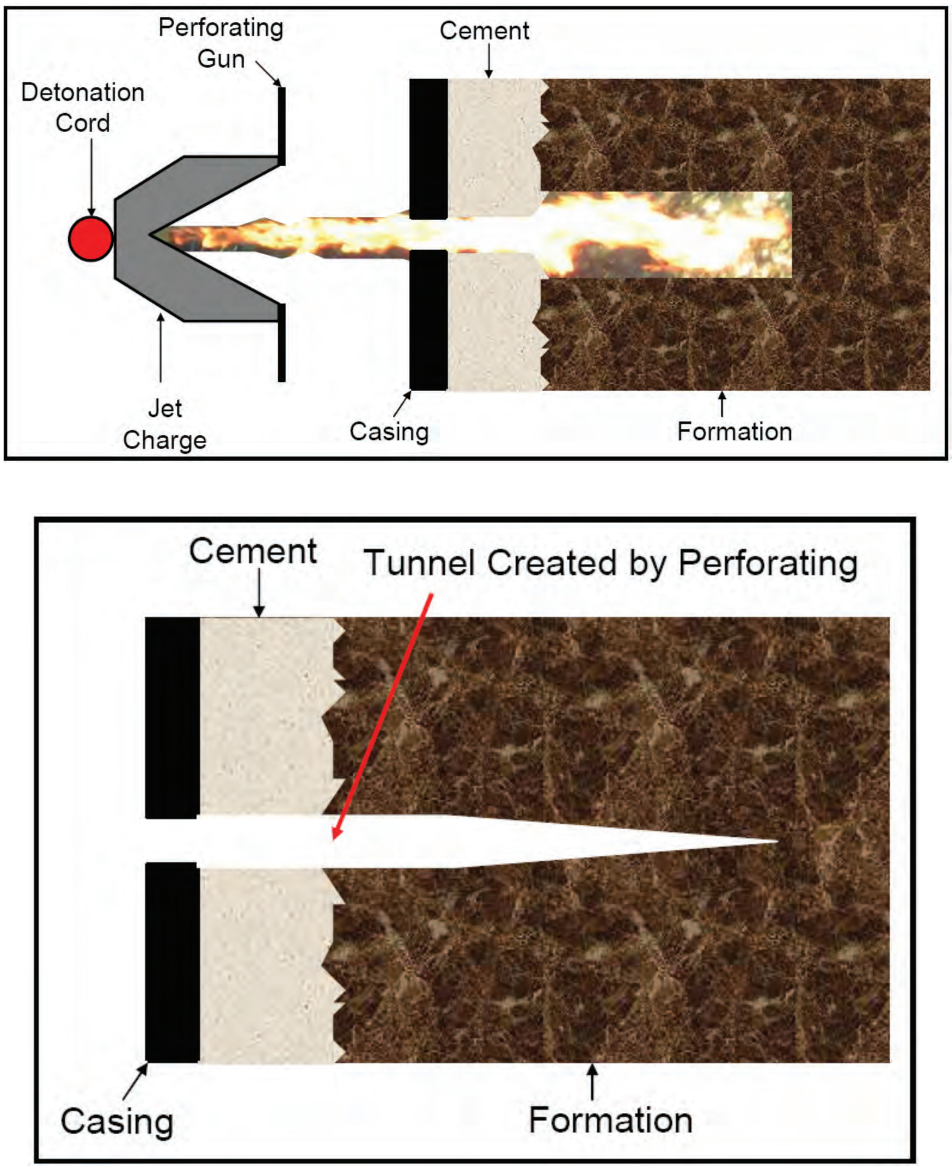

Figure 4—Perforation

9 Hydraulic Fracturing

9.1 General

Hydraulic fracturing is a well stimulation technique that has been employed in the oil and gas industry since 1947. Very low permeability formations such as fine sand and shale tend to have fine grains (limited porosity) and few interconnected pores (low permeability). Permeability represents the ability for a fluid to flow through a (somewhat) porous rock. In order for natural gas or oil to be produced from low permeability reservoirs, individual molecules of fluid must find their way through a tortuous path to the well. Without hydraulic fracturing, this process would produce too little oil and/or gas and the cost to drill and complete the well would be could not be justified by this low rate of production.

A wellbore of a "traditional" nonfractured well is schematically represented in the top part of Figure 5, where the red arrows represent the flow of fluid to the circle which represents the well. However, by creating an artificial fracture, individual molecules that are a long distance from the well can find their way to the fracture, and once there, can travel quickly through the fracture to the well. This situation is represented in the lower part of Figure 5.

The process of hydraulic fracturing increases the exposed area of the producing formation, creating a high conductivity path that extends from the wellbore through a targeted hydrocarbon bearing formation for a significant distance, so that hydrocarbons and other fluids can flow more easily from the formation rock, into the fracture, and ultimately to the wellbore. Hydraulic fracturing treatments are designed by specialists and utilize state-of-the-art software programs and are an integral part of the design and construction of the well. Pretreatment quality control and testing is carried out in order to ensure a high-quality outcome.

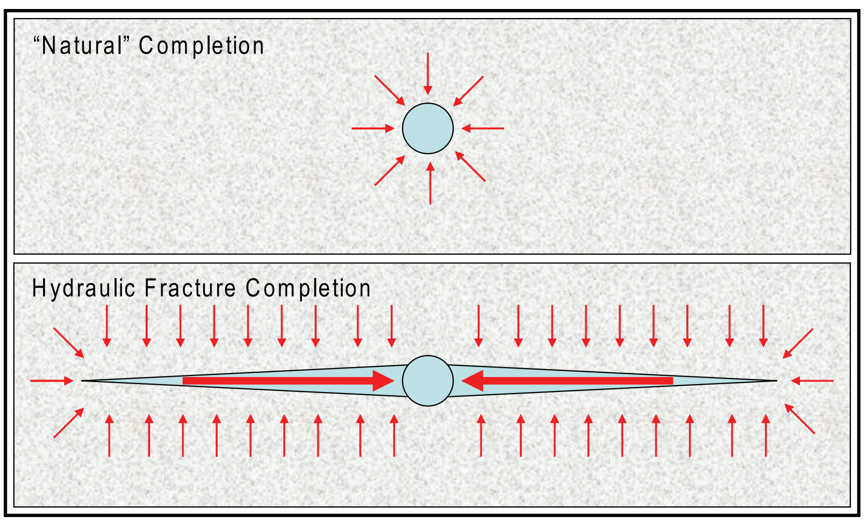

Figure 5—Illustration of a Fractured and a Nonfractured Well

During hydraulic fracturing, fluid is pumped into the production casing, through the perforations (or open hole), and into the targeted formation at pressures high enough to cause the rock within the targeted formation to fracture. In the field, this is known as "breaking down" the formation.

As high-pressure fluid injection continues, this fracture can continue to grow, or propagate. The rate at which fluid is pumped must be fast enough that the pressure necessary to propagate the fracture is maintained. This pressure is known as the propagation pressure or extension pressure. As the fracture continues to propagate, a proppant, such as sand, is added to the fluid. When pumping is stopped, and the excess pressure is removed, the fracture attempts to close. The proppant will keep the fracture open, allowing fluids to then flow more readily through this higher permeability fracture.

During the hydraulic fracturing process, some of the fracturing fluid may leave the fracture and enter the targeted formation adjacent to the created fracture (i.e. untreated formation). This phenomenon is known as fluid leak-off. The fluid flows into the micropore or pore spaces of the formation or into existing natural fractures in the formation or into small fractures opened and propagated into the formation by the pressure in the induced fracture.

As one would expect, the fracture will propagate along the path of least resistance. Certain predictable characteristics or physical properties regarding the path of least resistance have been recognized since hydraulic fracturing was first conducted in the oilfield in 1947. These properties are discussed below.

9.2 Horizontal Fractures

Hydraulic fractures are formed in the direction perpendicular to the least stress. In Figure 6, an imaginary cube of rock is shown as having confining stress exerted on it in three dimensions. Each pair of opposing stresses must be equal in order for the cube to remain stationary in space. The relative size of the arrows represents the magnitude of the confining stress. In Figure 7, the least stress is in the vertical direction. This direction is known as the direction of overburden, referring to the weight of the earth that lies above. The Earth’s overburden pressure is the least principal stress only at shallow depth. Based on experience, horizontal fractures will occur at depths less than 2000 ft.

In this example, when pressure is applied to the center of this block, the formation will crack or fracture in the horizontal plane as shown, because it will be easier to part the rock in this direction than any other direction. In general, these fractures are parallel to the bedding plane of the formation.

9.3 Vertical Fractures

As depth increases, overburden stress in the vertical direction increases by approximately 1 psi/ft. As the stress in the vertical direction becomes greater with depth, the overburden stress (stress in the vertical direction) becomes the greatest stress. This situation generally occurs at depths greater than 2000 ft. This is represented in Figure 7 by the magnitude of the arrows, where the least stress is represented by the small red horizontal arrows, and the induced fracture will be perpendicular to this stress, or in the vertical orientation.

Since hydraulically induced fractures are formed in the direction perpendicular to the least stress, as depicted in Figure 7, the resulting fracture would be oriented in the vertical direction.

The extent that the created fracture will propagate in the vertical direction toward a USDW is controlled by the upper confining zone or formation. This zone will stop the vertical growth of a fracture because it either possess sufficient strength or elasticity to contain the pressure of the injected fluids.

9.4 Hydraulic Fracturing Process

In order to carry out hydraulic fracturing operations, a fluid must be pumped into the well’s production casing at high pressure. It is necessary that production casing has been installed and cemented and that it is capable of withstanding the pressure that it will be subjected to during hydraulic fracture operations. In some cases, the production casing will never be exposed to high pressure except during hydraulic fracturing. In these cases, a high-pressure “frac string” may be used to pump the fluids into the well to isolate the production casing from the high treatment pressure. Once the hydraulic fracturing operations are complete, the frac string is removed.

The well operator or the operator’s designated representative should be on site throughout the hydraulic fracturing process. Prior to beginning the hydraulic fracture treatment, all equipment should be tested to make sure it is in good operating condition. All high-pressure lines leading from the pump trucks to the wellhead should be pressure tested to the maximum treating pressure. Any leaks must be eliminated prior to initiation of the hydraulic fracture treatment. After this, the final safety and operational meetings should be conducted.

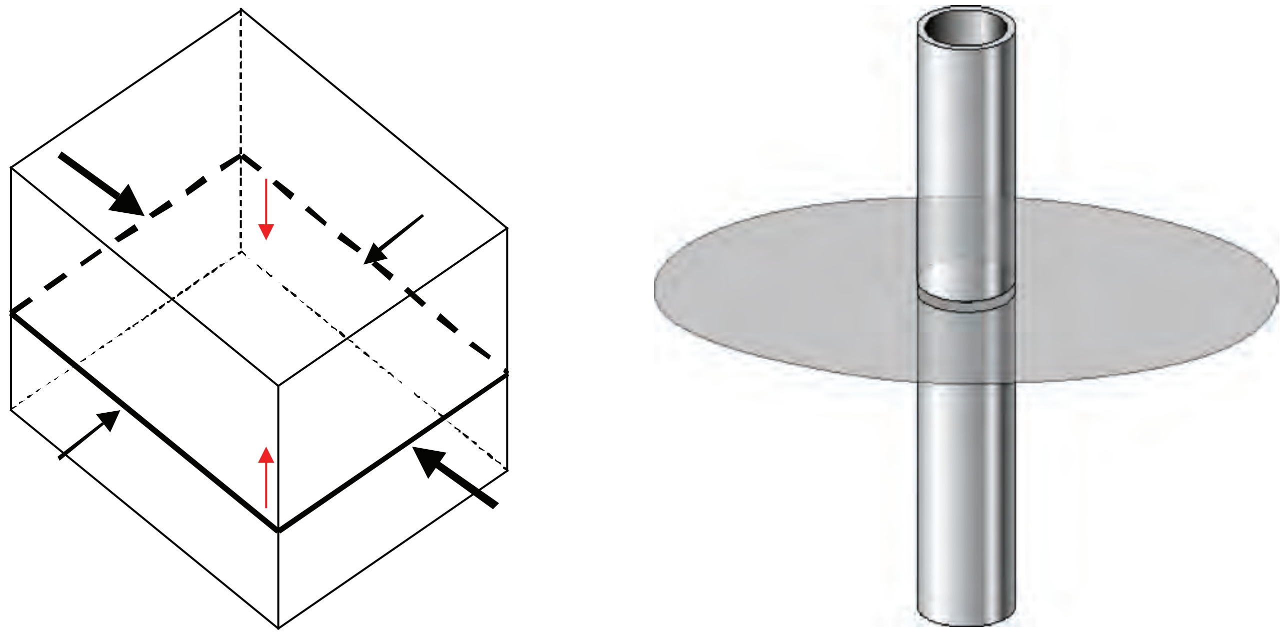

Figure 6—Least Principal Stress is in the Vertical Direction Resulting in a Horizontal Fracture

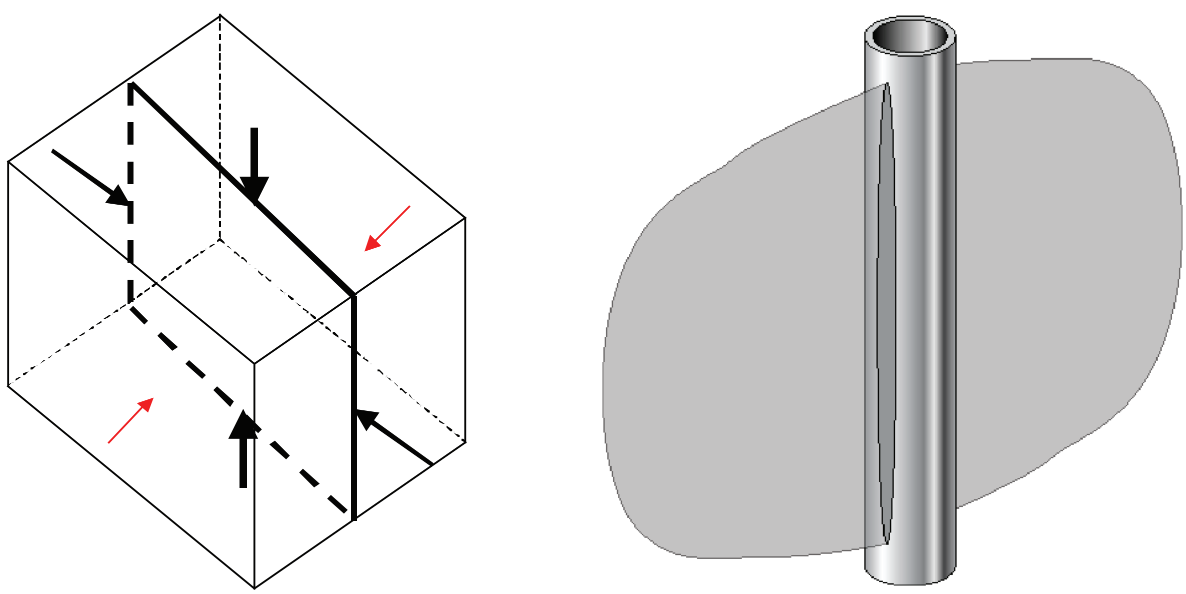

Figure 7—Least Principal Stress in the Horizontal Direction, Vertical Fracture

When these conditions are met, the well is ready for the hydraulic fracturing process. In the field, the process is called the "treatment" or the "job." The process is carried out in predetermined stages that can be altered depending on the site-specific conditions or if necessary during the treatment. In general, these stages can be described as follows.

— Pad—The pad is the first stage of the job. The fracture is initiated in the targeted formation during the initial pumping of the pad. From this point forward, the fracture is propagated into the formation. Typically, no proppant is pumped during the pad; however, in some cases, very small amounts of sand may be added in short bursts in order to abrade or fully open the perforations. Another purpose of the pad is to provide enough fluid volume within the fracture to account for fluid leak-off into the targeted formations that could occur throughout the treatment.

— Proppant Stages—After the pad is pumped, the next stages will contain varying concentrations of proppant. The most common proppant is ordinary sand that has been sieved to a particular size. Other specialized proppants include sintered bauxite, which has an extremely high crushing strength, and ceramic proppant, which is an intermediate strength proppant.

— Displacement—The purpose of the displacement is to flush the previous sand laden stage to a depth just above the perforations. This is done so that the pipe is not left full of sand, and so that most of the proppant pumped will end up in the fractures created in the targeted formation. Sometimes called the flush, the displacement stage is where the last fluid is pumped into the well. Sometimes this fluid is plain water with no additives, or it may be the same fluid that has been pumped into the well up to that point in time.

In wells with long producing intervals (e.g. horizontal wells), this process may be done in multiple stages or cycles, working from the bottom to the top of the productive interval. Staging the treatments allows for better control and monitoring of the fracture process.

9.5 Hydraulic Fracturing Equipment and Materials

The hydraulic fracturing process requires an array of specialized equipment and materials. This section will describe the materials and equipment that are necessary to carry out typical hydraulic fracture operations in vertical and horizontal wells.

The equipment required to carry out a hydraulic fracturing treatment includes fluid storage tanks, proppant transport equipment, blending equipment, pumping equipment, and all ancillary equipment such as hoses, piping, valves, and manifolds. Hydraulic fracturing service companies also provide specialized monitoring and control equipment that is necessary in order to carry out a successful treatment. Each of these components will be discussed below. Figure 8 is a diagram showing schematically how this equipment typically functions together.

During the fracture treatment, data are being collected from the various units, and sent to monitoring equipment; in some cases this is a "frac van." Data being measured include fluid rate coming from the storage tanks, slurry rate being delivered to the high-pressure pumps, wellhead treatment pressure, density of the slurry, sand concentration, chemical rate, etc.

10 Data Collection, Analysis, and Monitoring

10.1 General

The purpose of this section is to discuss what types of data collection, analysis, and monitoring activities should be carried out in order to ensure successful hydraulic fracture treatment and that groundwater aquifers are protected. Hydraulic fracturing treatments are designed using computer modeling so that the induced fractures remain below the upper confining formation. The dimensions, extent, and geometry of the induced fractures are controlled by pump rate, pressure, volume, and viscosity of the fracturing fluid. Fracture monitoring techniques provide confirmation of fracturing coverage, and allow the refinement of the computer models and enhancements to procedures for future operations.

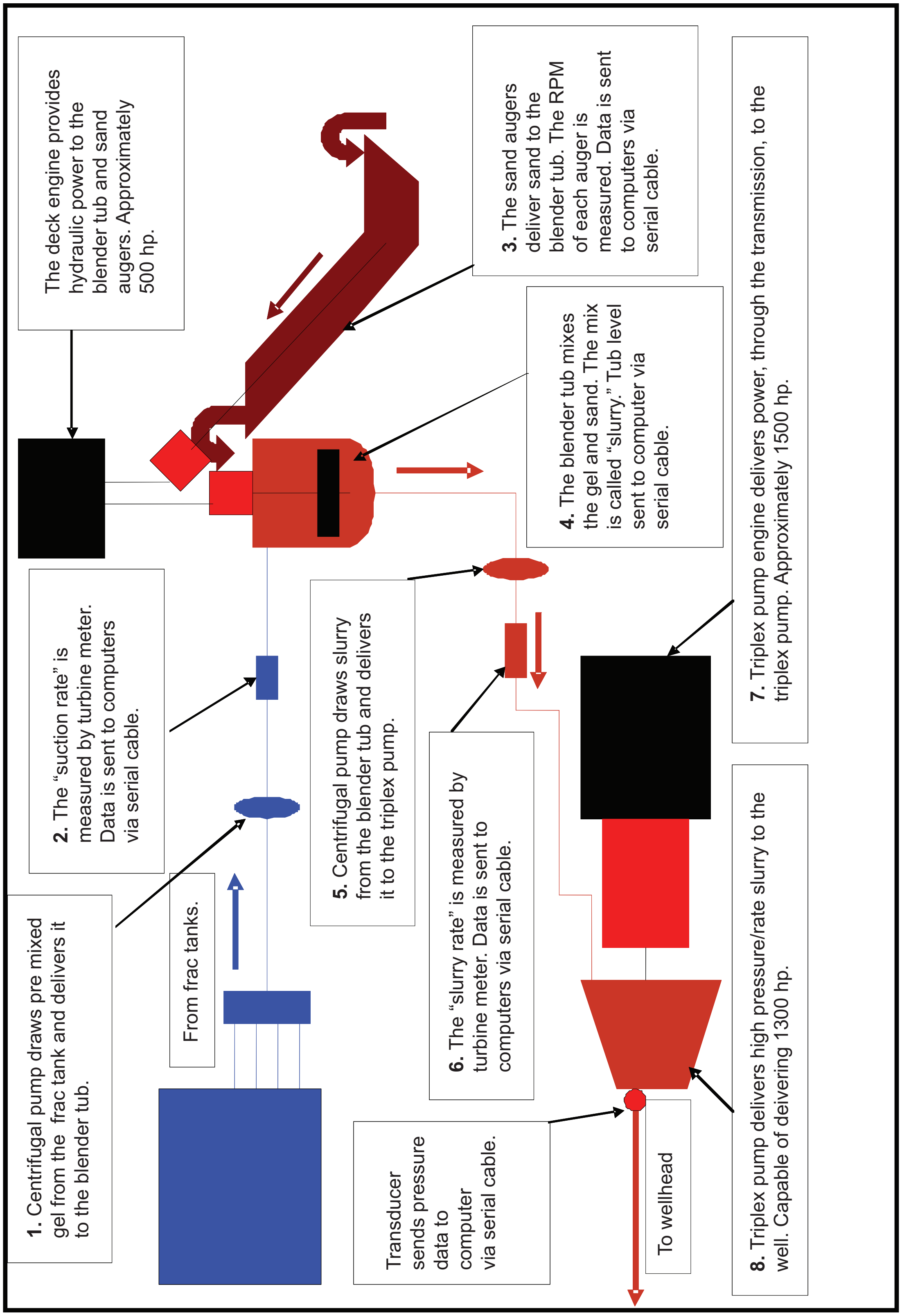

Figure 8—Schematic of Typical Fracturing Process

Data collection, analysis, and monitoring can be divided into the following activities:

— baseline assessment,

— “mini frac” treatment and analysis,

— monitoring during hydraulic fracturing operations,

— post-hydraulic fracturing monitoring techniques,

— post-completion monitoring.

10.2 Baseline Assessment

Once the location for a well has been selected and before it is drilled, water samples from any source of water located nearby should be obtained and tested in accordance with applicable regulatory requirements. This would include rivers, creeks, lakes, ponds, and water wells. If testing was not done prior to drilling, it should be done prior to hydraulically fracturing a well. The area of sampling should be based on the anticipated fracture length plus a safety factor.

This procedure will establish the baseline conditions in the surface and groundwater prior to any drilling or hydraulic fracturing operations. If subsequent testing reveals changes, this baseline data will allow the operator to determine the potential sources causing any changes. Because the constituents of the hydraulic fracturing fluid are known, a determination can be made regarding the source of the changes in the groundwater composition. However, it is important to note that changes to groundwater composition can come from other sources not related to drilling, hydraulic fracturing, or oil and natural gas development activities.

10.3 “Mini frac” Treatment and Analysis

In many cases, prior to the pad being pumped into the well to begin a fracturing job, an extended “pre-pad” stage is pumped so that certain diagnostic studies may be performed which, depending on the results, could alter how the rest of the hydraulic fracture treatment is executed. This is commonly known as a “mini frac.” The data gathered during the mini frac is analyzed, any needed adjustments to the planned job are made and the results are used to refine computer models.

10.4 Monitoring During Hydraulic Fracturing Operations

10.4.1 Treatment Parameter Monitoring

Good process monitoring and quality control during the hydraulic fracture treatment is essential for carrying out a successful treatment and for protection of the groundwater. There are certain monitoring parameters that should be observed in virtually all hydraulic fracture treatments, and others that are employed from time to time based on site-specific needs. As mentioned previously, sophisticated software should be used to design hydraulic fracture treatments prior to their execution. The same software should be used during the treatment to monitor and control treatment progression and fracture geometry in real time. During the hydraulic fracture treatment, certain parameters should be continuously monitored. These would include surface injection pressure (psi), slurry rate (bpm), proppant concentration (ppa), fluid rate (bpm), and, sand or proppant rate (lb/min).

The data that is collected is used to refine computer models used to plan future hydraulic fracture treatments. In areas with significant experience in performing hydraulic fracture treatments, the data that is collected in a particular area on previous fracture treatments is a good indicator of what should happen during the treatment.

10.4.2 Pressure Monitoring

Pressure is normally measured at the pump and in the pipe that connects the pump to the wellhead. If the annulus between the production casing and the intermediate casing has not been cemented to the surface, the pressure in the annular space should be monitored and controlled. Pressure behavior throughout the hydraulic fracture treatment should be monitored so that any unexplained deviation from the pretreatment design can be immediately detected and analyzed before operations continue. Typically, variations are within normal ranges, and slight adjustments to the original design may be made as operations proceed, based on real-time data obtained from the process monitoring. Pressure exerted on equipment should not exceed the working pressure rating of the weakest component.

Unexpected or unusual pressure behavior during the hydraulic fracturing process could indicate some type of problem. Some problems such as a leak in the casing string are immediately apparent, and if this is the case, it is possible to shut down the treatment as soon as this occurs. The intermediate casing annulus should be equipped with an appropriately sized and tested relief valve. The relief valve should be set so that the pressure exerted on the casing does not exceed the working pressure rating of the casing. The flow line from the relief valve should be secured and diverted to a lined pit or tank.

10.4.3 Tiltmeter and Microseismic Monitoring

Fracture monitoring using microseismic and tiltmeter surveys is not used on every well, but is commonly used to evaluate new techniques, refine the effectiveness of fracturing techniques in new areas, and in calibrating hydraulic fracturing computer models.

A number of technologies have been developed or adapted to improve industry's ability to monitor hydraulic fracturing operations. For example, hydraulic fracture mapping utilizing tiltmeters has been employed since the 1980s. A tiltmeter is a device that measures the change in the inclination in the earth's surface. Initially, investigations centered on determining the direct propagation of a hydraulic fracture. Advances in the sensitivity of the tiltmeter instruments, capable of measuring changes of inclination as small as a nanoradian, and in computer processing power and speed, now allow tiltmeter data to be monitored in real time.

A recent technological development, known as microseismic mapping, now allows operators to monitor microseismic events associated with hydraulic fracture growth in three dimensions in real time. Microseismic mapping requires a geophone array to be placed in an observation well, and utilizes the energy of the fracturing process to make a map of the resulting microseismic events. By processing seismic events observed in a nearby observation well, the location of the microseismic events can be calculated using standard seismic technologies. Microseismic monitoring provides a way to evaluate critical hydraulic fracturing parameters such as vertical extent, lateral extent, azimuth, and fracture complexity. This represents a tool that operators can use so that the lateral and vertical extent of fracturing can be maintained within the desired reservoir unit and the results can be used to verify and fine tune computer models used to predict hydraulic fracture performance in an area.

In some cases, the integration of tiltmeter and microseismic technologies has been utilized to achieve real time mapping of a hydraulic fracture treatment in progress. Operators can utilize these technologies in real time to decide when to end one fracturing stage and proceed with the next one. For example, if the microseismic map indicates that the fracture may soon be nearing the edge of the targeted hydrocarbon formation, that stage of the fracture treatment can be terminated and the next stage of the fracture treatment can be initiated.

10.5 Post-hydraulic Fracturing Monitoring Techniques

Prior to a hydraulic fracturing treatment, the proppant, usually sand, may be "tagged" with a tracer. After the proppant has been pumped into the formation, a cased-hole log, capable of detecting the tracer, is run. The purpose of this procedure is to further confirm that the placement of the proppant was as it was intended. The radius of investigation of this type of log is relatively small, on the order of a few feet at best, but it does yield information indicating which perforations accepted proppant, and how the fracture grew immediately outside the perforations.

Another post-fracture cased-hole logging technique is a temperature log. This log can be run in conjunction with the tracer log described above. The temperature log measures the variations in temperature throughout the section of interest. The hydraulic fracturing fluid is typically at the ambient temperature of the surface, and the formation temperature at a depth of 7500 ft may be as high as 200 °F. As a result, the formation is cooled considerably during the fracture treatment. By running a temperature log, engineers can determine which perforations accepted fracturing fluid and gain some insight regarding fracture growth immediately outside the casing.

It is important to note that the use of the post-hydraulic fracturing monitoring techniques described above is declining with the advent of sophisticated computer modeling techniques.

10.6 Post-completion Monitoring

Throughout the life of a producing well, the well conditions should be monitored on an ongoing basis to ensure integrity of the well and well equipment. Mechanical integrity pressure monitoring is used to determine the mechanical integrity of tubulars and other well equipment when the well is producing and during fracturing operations.

Initially during well drilling, positive pressure tests that are part of normal well construction determine the casing and casing shoe integrity—as noted earlier in this document. During well fracturing, casing integrity is inferred by showing there is no leakage into the “A” annulus (if a frac string is used), or between the “A” annulus and “B” annulus by monitoring these pressures. After fracturing and upon final completion the tubing/packer integrity is demonstrated by showing there is no leakage of injected fluids through the tubing or packer into the “A” annulus causing pressure buildup.

It is important to monitor these annular pressures during production to determine if there are potential leaks. If an annulus is being charged with gas, an analysis of the gas content may give an indication of the source and the nature of a potential leak.

Maximum and minimum allowable annular surface pressures should be assigned to all annuli and these should consider the gradient of the fluid in each. These upper and lower limits establish the safe working range of pressures for normal operation in the well’s current service and should be considered “do not exceed” limits.

Wellhead seal tests are conducted to test the mechanical integrity of the sealing elements (including valve gates and seats) and determine if they are capable of sealing against well pressure. If non-normal pressures are noted in an annulus, a repressure test of the wellhead seal system can help determine if the source of communication is in the surface in the wellhead system.

When equipment is removed from a well or depressurized for maintenance, a breakdown or visual inspection should be conducted to document the condition of the equipment after being in service. For example, if tubing is pulled from a well, it can be inspected for corrosion/erosion damage. While the tubing is out of the well, a casing inspection log can be considered to verify the casing condition.

Regular visits by lease operators/well pumpers should identify any abnormal well conditions and should be used to monitor well pressures. This regular inspection of the casing head equipment and annulus pressures will readily indicate any leaks between any of the casing strings. In addition to wellhead pressures, gas, oil, and water production rates should be regularly monitored. This data is can be analyzed by engineers and help identify any anomalous behavior or problems.

API RP 90 covers the monitoring, diagnostic testing, and the establishment of a maximum allowable wellhead operating pressure (MAWOP) guidelines. API RP 90 is intended for use as a guide for managing annular casing pressure in offshore wells, but the dry tree recommendations are applicable for onshore wells that exhibit annular casing pressure, including thermal casing pressure, sustained casing pressure (SCP) and operator-imposed pressure.

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JANUARY 2012

EMPLOYMENT, GOVERNMENT REVENUE, AND ENERGY SECURITY IMPACTS OF CURRENT FEDERAL LANDS POLICY IN THE WESTERN U.S.

Prepared for American Petroleum Institute by

EIS SOLUTIONS

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EMPLOYMENT, GOVERNMENT REVENUE, AND ENERGY SECURITY IMPACTS OF CURRENT FEDERAL LANDS POLICY IN THE WESTERN U.S.

Prepared for American Petroleum Institute
January 2012

EXECUTIVE SUMMARY

The decline in oil and gas leasing, permitting, and new drilling on the nation's public lands since 2009 have come at a high cost to America – namely, a significant loss of domestically produced oil and natural gas, thousands of jobs in the energy-rich western United States, and the forfeit of hundreds of millions of dollars in state and federal tax revenues, royalties, and lease payments to western states and the U.S. Treasury.

These are the central findings of this Report: Employment, Government Revenue, and Energy Security Impacts of Current Federal Lands Policy in the Western U.S. The Report analyzes oil and natural gas leasing, permitting, and drilling trends on lands managed by the Bureau of Land Management (BLM) in the energy-producing western states of Colorado, Montana, New Mexico, North Dakota, Utah, and Wyoming. The balance of the evidence suggests a systematic decline of energy production activities on the nation's federal lands in the last two years.

Specifically, according to BLM data, the number of new federal oil and gas leases issued by the BLM is down 44% from an average of 1,874 leases in 2007/2008 to 1,053 in 2009/2010; the number of new permits to drill issued by the BLM is down 39%, from an average of 6,444 permits to an average of 3,962; and the number of new wells drilled on federal land have declined, 39%, from an average of 4,890 wells to 2,973 (Table E-1).

The BLM released new fiscal year 2011 oil and natural gas statistics on January 10, 2012. The trend in reduced leasing, permitting, and drilling on western lands appears to be continuing. Although the 2011 total of 1,461 federal leases issued for western states appears to be higher than the 2009/2010 average of 1,053, closer review of the BLM data shows that the majority of leases that the BLM characterizes as "issued" in 2011 were actually backlog leases that were sold in previous years but had been mired in challenges since. An estimated 860 of the 1,461 leases issued in 2011 were not new leases at all; they are leases secured in previous years that were stranded, in most cases, pending resolution of legal challenges in court. In 2011, only 601 new leases were actually sold, which is an all-time low (since 1984) when backlogged leases are accounted for. New drilling permits and wells drilled issued in 2011 were 3,851 and 2,783 respectively, both below the 2009/2010 averages and significantly below the 2007/2008 averages.

Table E-1:
Leasing and Permitting Activity on Federal Land

	Leases	Permits	Wells
2007-08 Average	1,874	6,444	4,890
2009-10 Average	1,053	3,962	2,973
Percent Change	-44%	-39%	-39%

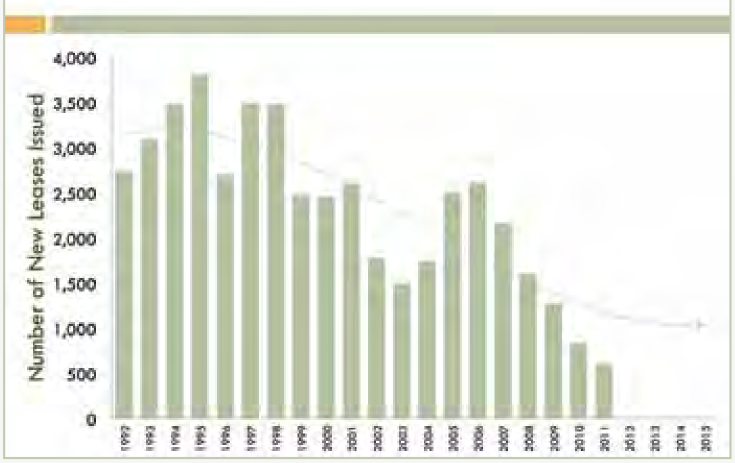
Source: BLM Oil & Gas Statistics (2010)
* Leases on federal land in FY 2011 – 601 Non-federal permits are down less than their federal counterparts over the last two years at 20%. Non-federal permits have rebounded in 2010, up 31%.

Clearly the economic downturn starting in 2007 is a factor contributing to these results. However, if market factors were the sole driver of the federal lands permitting slowdown, it would be reasonable to assume that non-federal drilling permits would generally track the trends occurring with their federal counterpart. But this is not the case.

Indeed, the number of new permits to drill on federal lands in the West is down by a significantly greater amount (-39%) than new permits to drill on non-federal lands (-20%) over the last 2 years. In 2010 alone, non-federal permits across the West actually increased by 31%, even as federal drilling permits dropped 13%. The Report shows that non-federal oil and gas production has increased in 2009/2010, even as federal oil production has plateaued and federal natural gas production has declined in the same time frame. The 2011 federal oil and natural gas production statistics recently released by the BLM had significant accounting adjustments and therefore current year production levels could not be determined. It is reported that the BLM may release 2011 production estimates in February 2012.

Even when viewed through a wider historical lens, including other recent recessionary periods, the downturn in federal energy activities is of a greater magnitude than any experienced in recent times. This is particularly the case when evaluating the number of new onshore federal oil and gas leases issued in the last two years. While federal leasing numbers have gone up and down due to a range of economic and regulatory considerations through the years, at no time in the last 25 years has the number of new onshore federal oil and gas leases been lower than the number of new leases issued in 2009 and 2010 (BLM Oil & Gas Statistics, 2010). As figure E-1 illustrates, new leases are significantly lower than at a period during the Clinton Administration, or during the George W. Bush Administration.

Figure E-1:
Number of New Leases Issued



*Western States (Includes Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming)
Source: BLM Oil & Gas Statistics (2010)

These facts strongly suggest that the downturn in oil and natural gas activity on the nation's federal lands is due to something beyond the nation's difficult economic circumstances. A host of new rules, policies and administrative actions that are not conducive to oil and natural gas production on federal land are a culprit. The slowdown in new leases, permits and wells drilled on BLM lands is, in real part attributable to the direction of current federal land energy policy. The Report characterizes these new regulatory barriers.

Finally, in addition to quantifying the magnitude of the leasing, permitting, and drilling slowdown, and describing the regulatory barriers that have contributed to this slowdown, the Report also demonstrates the substantial opportunity cost of current BLM policies on America's energy supplies and the economy.

Using economic modeling, the Report shows that a simple return to permitting, leasing and drilling levels experienced in 2007 and 2008 would benefit the nation's economic and domestic energy future. Specifically, a return to 2007/2008 federal leasing and permitting levels would result in:

- A projected increase of 7 million to 13 million barrels per year of domestic oil production from federal lands in the western U.S. over the next four years.
- An annual average projected increase of 620 billion cubic feet of natural gas from federal lands in the western U.S. over the 2012 to 2015 time period. The increases range from 103 billion cubic feet to 818 billion cubic feet per year.
- Projected direct employment increases in the oil and gas industry in energy producing western states of 4,085 jobs in 2011, 6,914 jobs in 2012, 9,937 jobs in 2013, 9,713 in 2014, and 9,032 in 2015.
- A projected total increase in jobs supported throughout the economy of between 12,656 to 30,163 in energy producing western states over the next four years.
- Projected severance and ad valorem tax revenues increases between $59 million and $362 million per year over the 2011 to 2015 time period, totaling over $1.2 billion in five years.
- Projected federal royalty increases ranging from $106 million to $670 million per year through 2015, totaling over $2.1 billion in five years.

Table E-2:
Impact of Return to 2007/2008 Levels of Leases and Permits*
(Change from Baseline Case)

Year	Annual Oil Production (mmbbls)	Annual Gas Production (bcf)	Annual NGL Production (mmbbls)	New Wells	Direct Employment	Total Employment	Annual Severance & Ad Valorem Taxes ($millions)	Annual Federal Royalties ($millions)
2011	7.1	103	1.0	610	4,085	12,656	$59	$106
2012	8.5	447	4.3	880	6,914	21,315	$183	$337
2013	12.0	517	5.0	1,140	9,937	30,163	$236	$432
2014	13.2	696	6.7	1,070	9,713	29,715	$319	$585
2015	8.9	818	7.8	940	9,032	27,642	$362	$670

* Western States (Includes: Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming)
Source: Economics International Corp., BLM Oil & Gas Statistics (2010)

In as much as a return to 2007/2008 leasing, permitting and drilling levels would boost the economic and domestic energy fortunes of America, the reverse is also unfortunately true – the loss of oil and gas production that will result from current BLM oil and gas permitting processes and practices will cost American jobs and increase our dependence on foreign sources of energy. For a nation enduring slow economic growth and increasing dependence on foreign sources of energy, the costs of this domestic drilling slowdown are profound indeed.

1 OIL AND NATURAL GAS IN THE WEST:
Understanding the Role of Federal Lands

For more than a hundred years, the West's oil and natural gas reserves have played a significant role in helping America meets its domestic energy needs. Recent advances in drilling technologies, which have made a significant amount of oil and gas resources buried deep below the earth's surface economically and technologically recoverable, will serve to greatly expand the influence of the West in America's domestic energy portfolio in the decades ahead.

According to a recent report from the Western Energy Alliance[1], the energy producing states in the western U.S. have the combined capacity to produce more energy from oil and natural gas than the total U.S. imports from Saudi Arabia, Iraq, Kuwait, Venezuela, Colombia, Algeria, Nigeria and Russia combined by 2020. Specifically, Western Energy Alliance found that the West has the capacity to generate 1.3 million barrels of domestic oil and condensate production a day by the year 2020, an amount that currently exceeds daily oil imports from Russia, Iraq and Kuwait combined. The West also has the potential to produce 6.2 trillion cubic feet of natural gas annually by 2020.

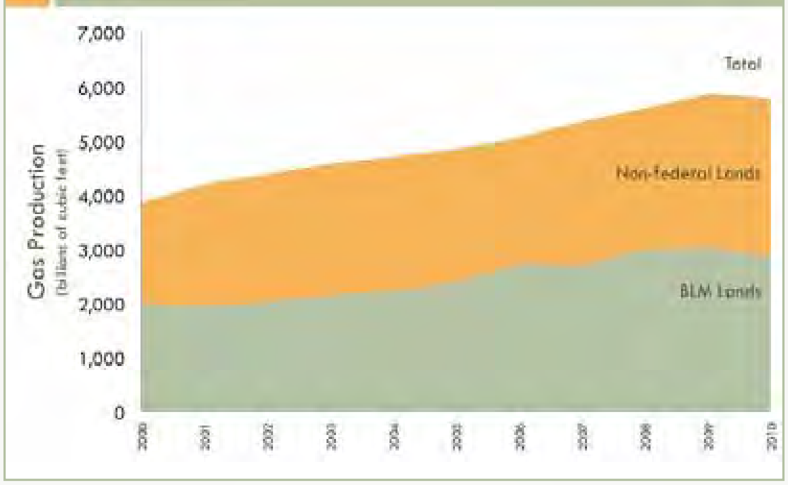
When it comes to America's energy security, the West is important.

Much of the oil and natural gas in the West is produced from public lands owned and managed by the federal government. While the vast preponderance of onshore oil and gas production in other regions takes place on private lands, many of the West's most vital energy plays are found on federal lands – usually, those managed by the Bureau of Land Management (BLM). Put simply, a robust and thriving domestic energy program in the energy-producing states of the American West is not possible without access to and production of the West's federal land resources.

Federal lands play a central role in driving overall natural gas production trends in the West. Approximately 40% of all natural gas production from western energy-producing states occurs on BLM lands.[2] This percentage has recently declined. In 2010, natural gas production on federal lands decreased while production growth from non-federal resources has experienced incremental growth. See Figure 1. In 2009, federal natural gas production decreased by 197 billion cubic feet compared to the 2008 level. See Table 1.

1. The Blueprint for Western Energy Prosperity, (2011). Western Energy Alliance.
2. As of 2009. Source: EIA Natural Gas Production Statistics (2010), BLM Oil and Gas Statistics (2011)

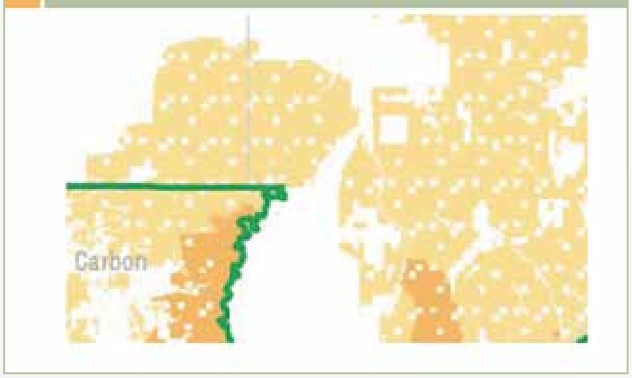
Figure 1:
Natural Gas Production, Total*



*Western States (Includes Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming)
Source: BLM Oil & Gas Statistics (2010) Energy Information Administration (2011)

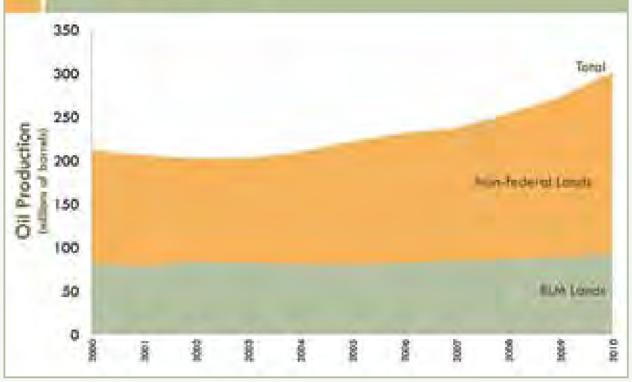
It is also important to note that a simple "federal vs. non-federal" comparison understates the impact of federal land production in the overall mix of western energy. Figure 2 demonstrates a sample ownership pattern, with federally owned lands in orange, and non-federal in white. Because federal lands are so commonly interspersed, adjacent or co-mingled with non-federal lands, many non-federal oil and gas plays in the West would be less desirable without the associated production of nearby federal lands. Therefore access to federal lands plays a more important role in energy production in the West than 40% of overall production number alone suggests. The loss of access to federal land can and will encumber access to some non-federal energy production opportunities as well.

Figure 2:
Example of Federal and Non-Federal Ownership Patterns



Source: BLM Ownership Maps, 2011.
BLM Public Lands and Administrative Jurisdictions

Figure 3:
Western States Oil Production, Total*



Western States (Includes Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming) Source: BLM Oil & Gas Statistics (2010)
Energy Information Administration (2011)

Table 1: Historical Oil and Natural Gas Production in Western States*

Natural Gas Production (billion cubic feet)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
CO Total	750.3	789.2	904.3	1,006.1	1,063.4	1,121.0	1,183.4	1,234.9	1,339.7	1,499.7	1,540.5
CO Federal	73.4	85.2	92.0	117.4	141.6	188.1	201.6	208.6	243.7	269.9	279.2
Non-federal	676.8	704.0	812.3	888.7	921.8	932.9	981.9	1,026.3	1,096.0	1,229.5	1,261.3
MT Total	67.4	78.4	84.9	85.8	93.3	105.3	112.4	116.2	114.9	102.6	89.3
MT Federal	15.8	17.8	19.1	20.6	24.1	28.7	31.8	32.2	33.5	70.9	46.3
Non-federal	52.0	60.6	65.8	65.2	69.2	76.5	80.6	84.0	8146	31.7	43.1
NM Total	1,647.2	1,689.6	1,646.9	1,611.5	1,620.9	1,647.4	1,616.8	1,547.3	1,456.5	1,409.0	1,303.6
NM Federal	1,105.7	1,030.5	1,002.0	938.0	936.7	926.3	989.4	867.0	843.4	780.1	673.7
Non-federal	541.6	659.1	644.9	673.58	684.3	721.1	627.4	680.3	613.1	628.9	629.9
ND Total	53.1	53.9	56.8	55.2	55.7	53.3	53.8	60.4	54.5	54.9	76.5
ND Federal	6.1	5.3	7.1	7.9	7.7	8.9	10.3	10.3	9.8	7.5	8.0
Non-federal	46.9	48.6	49.7	47.4	48.0	44.4	43.5	50.0	44.7	47.4	68.4
UT Total	262.7	283.3	276.3	270.9	271.6	294.4	335.3	378.9	410.7	450.8	430.9
UT Federal	80.6	86.4	107.8	123.4	134.9	170.8	193.4	223.9	250.9	285.9	271.0
Non-federal	182.1	196.9	168.5	147.5	136.7	123.6	141.9	155.0	159.8	164.9	160.0
WY Total	1,065.2	1,294.5	1,411.9	1,536.2	1,585.1	1,612.8	1,750.2	2,010.5	2,210.5	2,335.5	2,337.2
WY Federal	718.6	723.3	784.5	931.0	972.5	1,048.4	1,295.4	1,356.5	1,590.2	1,610.0	1,631.1
Non-federal	346.6	571.2	627.3	605.1	612.6	564.3	454.8	654.0	620.4	725.5	706.0
Total Federal	2,000.2	1,948.5	2,012.5	2,138.3	2,217.4	2,371.3	2,721.9	2,698.5	2,971.4	3,024.3	2,909.3
Total Non-federal	1,846.0	2,240.3	2,368.5	2,427.4	2,472.5	2,462.9	2,330.1	2,649.7	2,615.4	2,827.8	2,868.7

Oil Production (million barrels)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
CO Total	18.5	16.5	17.7	21.1	22.1	22.8	23.4	23.2	24.1	28.3	30.9
CO Federal	4.7	4.5	5.2	4.3	4.1	4.9	5.6	4.9	5.1	4.1	3.8
Non-federal	13.8	12.0	12.5	16.8	18.0	17.9	17.7	18.4	19.0	24.2	27.0
MT Total	15.4	15.9	16.9	19.3	24.7	32.9	36.3	34.8	31.5	27.7	25.3
MT Federal	2.9	2.9	3.2	3.5	3.8	3.7	3.9	3.8	3.8	3.5	3.8
Non-federal	12.5	13.1	13.6	15.8	20.9	29.1	32.4	31.0	27.7	24.2	21.5
NM Total	67.2	68.0	67.0	66.1	64.2	60.7	59.8	58.8	59.4	61.1	65.1
NM Federal	28.1	28.6	30.9	31.0	29.8	26.0	24.3	24.6	24.8	26.9	29.9
Non-federal	39.1	39.4	36.2	35.2	34.5	34.6	35.5	34.2	34.6	34.2	35.2
ND Total	32.7	31.7	31.0	29.4	31.2	35.7	39.9	45.1	62.8	79.7	113.0
ND Federal	6.0	5.9	5.8	5.8	5.6	6.2	7.0	7.6	8.4	7.6	8.2
Non-federal	26.7	25.8	25.2	23.6	25.5	29.4	32.9	37.5	54.3	72.1	104.8
UT Total	15.6	15.3	13.7	13.1	14.6	16.7	17.9	19.5	22.0	22.9	24.7
UT Federal	3.6	3.1	3.9	4.3	4.7	5.9	7.3	8.6	9.3	11.2	11.7
Non-federal	12.1	12.1	9.8	8.8	9.9	10.8	10.6	10.9	12.7	11.7	13.0
WY Total	60.7	57.4	54.7	52.4	51.6	51.6	52.9	54.1	52.9	51.3	53.1
WY Federal	35.8	32.9	33.6	32.4	32.1	32.4	33.2	34.4	34.7	33.9	34.9
Non-federal	24.9	24.5	21.1	20.0	19.2	19.2	19.7	19.7	18.3	17.4	18.2
Total Federal	81.1	77.8	82.7	81.2	80.0	79.1	81.4	83.9	86.1	87.3	92.3
Total Non-federal	129.1	127.0	118.4	120.2	128.4	141.1	148.8	151.7	166.6	183.9	219.8

BOTTOM LINE:

energy production in the West, home to more than 3 billion barrels of proved oil reserves (Western Energy Alliance, 2011), is vital to America's overall domestic energy portfolio, and federal lands are a key driver of energy production in the West. Recent oil and natural gas production on federal lands is lagging production growth on non-federal resources in the West.

*Western States (Includes Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming) Source: BLM Oil & Gas Statistics (2010) U.S. Energy Information Administration Statistics (2011)

2009 Wyoming and 2010 Montana federal natural gas production numbers contained accounting errors and adjustments. The federal production above is based on an average of the State's previous and following year's production. Wyoming –average of 2008 and 2010. Montana- average of 2009 and 2011.

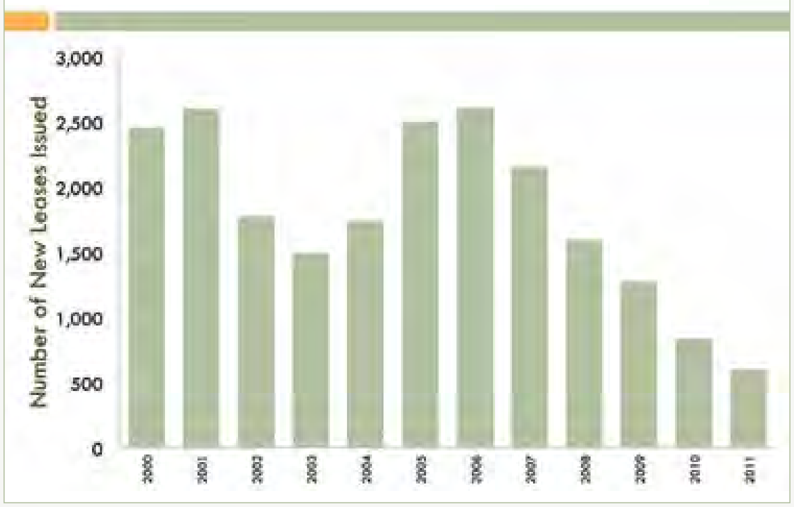
1.1 New Federal Drilling Leases Issued: Down 44%

Energy exploration and development on federally owned land is a multi-layered process, beginning first with a bid by an energy producer to obtain a lease from the relevant BLM state office. To obtain a federal lease, a company nominates a parcel it is interested in developing to the BLM state office, which then reviews the parcel for availability, lease stipulations, and conformance with a land use plan. Lease stipulations are determined and attached to the parcel prior to it being made available for bidding during the lease sale process. Once issued, these leases are "available" until they are produced, extended or expire.

A critical determinant of total available leases available for production is the number of new leases an Administration sells in a given year. New leases represent a real-time snap shot of how a given administration's policies translate into tangible action when it comes to domestic energy production on federal lands. What's more, the number of leases sold is also one of the key indicators of how private companies perceive the level of federal encouragement and commitment to oil and natural gas development.

Today new oil and natural gas leases issued for federal land are at their lowest level since 2000 (Figure 4). During 2009 and 2010, the number of new federal oil and gas leases issued has averaged 44% less compared to their 2007 and 2008 levels.[3] Indeed, while leasing numbers have gone up and down due to a range of economic and regulatory considerations through the years, at no time in the last 25 years has the number of new onshore federal oil and gas leases been lower than the number of new leases issued in 2009 and 2010 (BLM Oil & Gas Statistics, 2010).

Figure 4:
Number of Leases Sold on BLM Land*

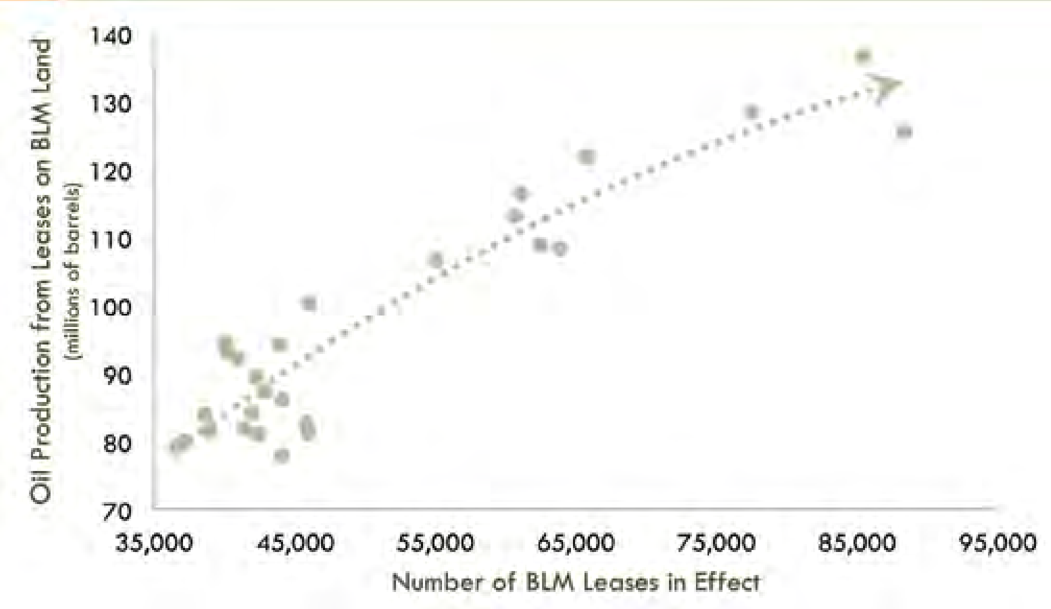


*Western States (Includes Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming)
Source: BLM Oil & Gas Statistics (2010)

3. According to BLM lease sale data compiled by Western Energy Alliance, leases sold in 2011 decreased to 601. The reported number of leases issued by the BLM in 2011 was 1,461. However, an estimated 860 of the leases issued were backlog leases sold in previous years mostly in Wyoming and Utah and released in 2011 due to resolutions of challenges to these leases in the courts. Source: BLM FY 2005 - 2011 oil and gas leasing statistics.

Historically, the relationship between the number of leases in effect and future oil production in the western states shows a strong positive correlation: the more leases that are available, the greater the domestic oil production that occurs on federal lands. As Figure 5 shows, since 1984, oil production from federal lands has consistently been at its highest levels when the number of total drilling leases available was at its highest. The reverse has also been true through the years – fewer available leases have resulted in a curtailment of oil production from the nation's federal lands.

Figure 5:
Relationship Between Leases in Effect and Oil Production



*Western States (Includes Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming)
Source: BLM Oil & Gas Statistics (2010)

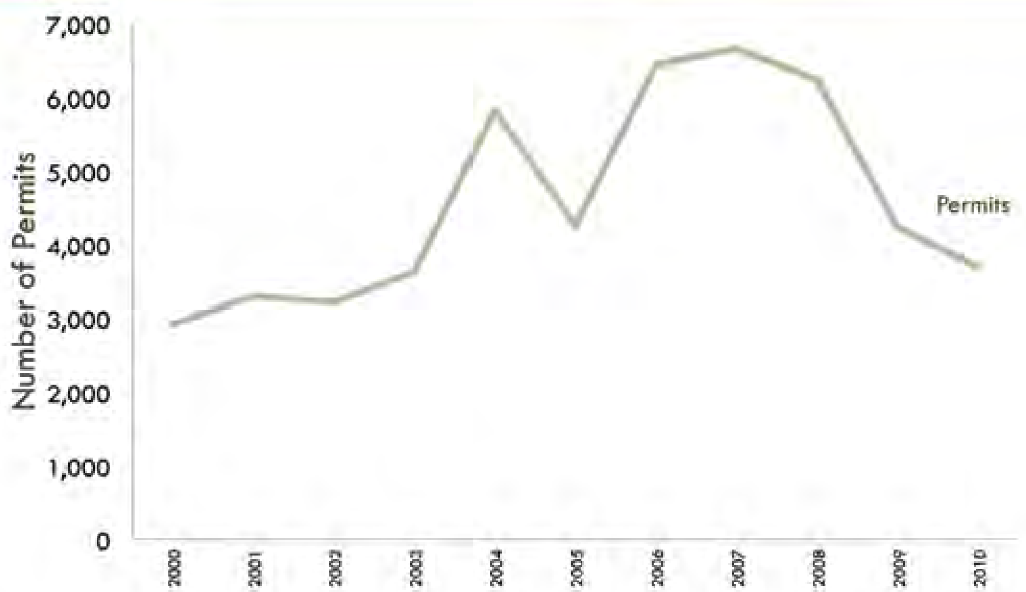
Recently released BLM figures for leases issued for 2011 were not available at the time this analysis was undertaken. However if used, they would most likely not have significantly impacted the model results of the relationship between leases and production.

1.2 Permits to Drill: Down 39%

Under federal law, once a federal lease has been issued, the next step in the administrative process for an energy producer is to obtain a permit to drill. The permit to drill is one of the administrative clearances necessary before an energy company can develop an oil and gas lease; thus, the number of permits issued in a given year is an illustrative metric of the relative priority an administration places on producing energy from public lands from one year to the next.

The most recent BLM data on drilling permits for federal leases indicates a relatively steep decline during the 2009/2010 time period. The number of permits issued from 2006 to 2008 increased significantly, but there has been a steep decline since then (Figure 6). Permits to drill are down by 39%, from an average of 6,444 in 2007/2008 to an average of 3,962 in 2009/2010. Reduced permitting trends appear to be continuing with 3,815 drilling permits recently reported for 2011.

Figure 6:
Number of Permits Issued During the Year on Federal Lands*

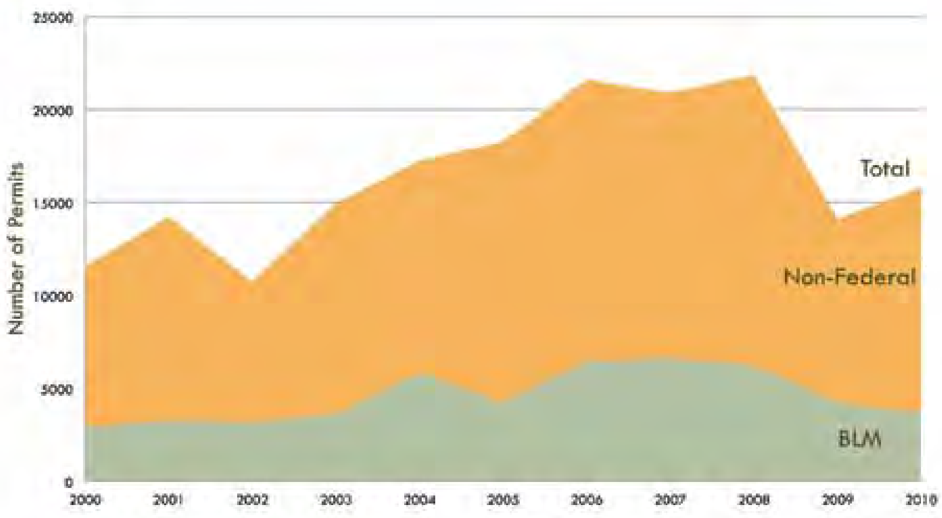


*Western States (Includes Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming)
Source: BLM Oil & Gas Statistics (2010)

*In 2005, natural gas production in many parts of the Rockies began to have difficulty reaching markets due to limited availability of pipeline capacity. However, as sections of the Rockies Express and other pipelines began to be built and put into service, pipeline constraints out of the Rockies were alleviated. There are currently no significant consistent pipeline constraints out of the Rockies.

The slowdown in federal permits issued between 2007/2008 and 2009/2010 cannot be attributed solely to the recession and the reduction in demand for energy. If market factors were the principal driver of the federal lands permitting slowdown, it would be reasonable to assume that non-federal drilling permits would generally track the trends occurring with their federal counterpart. Although all permitting declined in 2009, permitting on nonfederal land rebounded somewhat in 2010. A similar permitting rebound did not occur on federal leases (Figure 7). The number of new permits to drill on federal lands is down by a significantly greater amount (-43%) than the decline in new permits on non-federal lands (-20%). In 2010, the difference in permitting between federal and non-federal lands is especially large. Non-federal permits across the West actually increased by 31%, even as federal drilling permits dropped 13%.

Figure 7:
Total Permits on Western Lands*

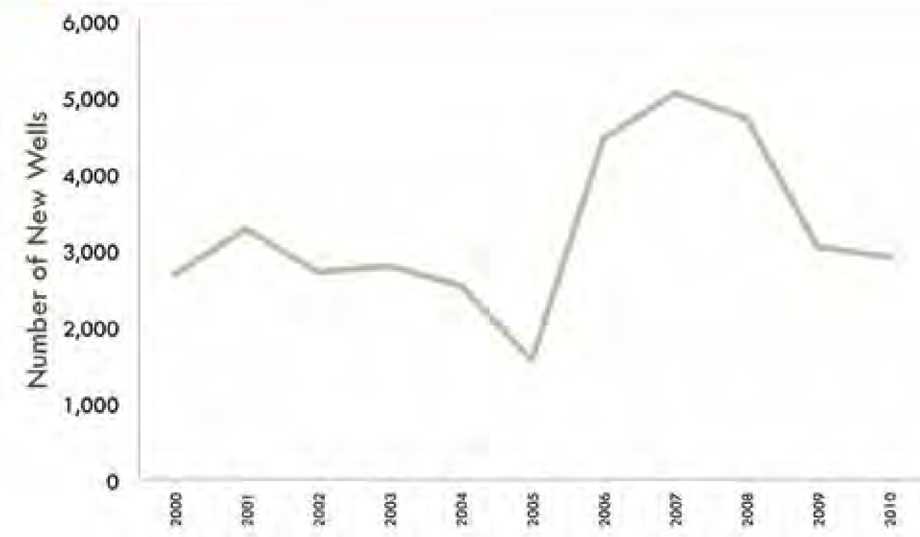


*Western States (Includes Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming)
Source: BLM Oil & Gas Statistics (2010), State Oil and Gas Commissions

1.3 New Wells Drilled on Federal Land: Down 39%

The slowdown in federal leasing and permitting has led to a decline in the number of new oil and gas wells drilled on federal land between 2008 and 2010. Following a period of general growth in the number of wells started over the previous 8 years, new wells drilled on federal lands declined in 2009 and 2010. More permits are associated with more drilling activity (Figure 8). As the number of permits has declined in 2009 and 2010, the number of new wells drilled on federal lands has declined as well; down 39% from an average of 4,890 in 2007/2008 to 2,973 in 2009/2010. The reduced level drilling appears to be continuing. The BLM recently reported 2,783 wells were drilled in the western states in 2011.

Figure 8:
Number Of New Wells Started During the Year on Federal Lands*



*Western States (Includes Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming)
Source: BLM Oil & Gas Statistics (2010)

Figure 9 summarizes, in the cumulative, current trends of oil and gas development on federal lands. Comparing the two year period of 2007/2008 to 2009/2010, the number of new oil and gas leases issued by the BLM is down 44%, the number of new permits to drill issued by the BLM is down 39%, and the number new federal wells drilled on BLM lands is also down 39%.

Figure 9:
Number of Leases, Permits Issued and Wells Started During the Year on Federal Lands*

Western States (Includes Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming)
Source: BLM Oil & Gas Statistics (2010)

2 ADVERSE FEDERAL LAND POLICY

The slowdown in new leases, permits and wells drilled on BLM lands is, in real part, attributable to the direction of current federal land energy policy. The Department of Interior (DOI) and the BLM have refused to follow the federal requirements that require timely action on important oil and gas decisions, and, what's more, DOI and BLM have established a host of new rules, policies and administrative actions that are adversarial to energy production on federal lands. Among those adversarial actions and decisions:

- From the very beginning, the current administration has failed to issue onshore oil and gas leases within the legally required 60-day timeline. Such unreasonable delays also have the effect of chasing away future investment from federal permitting, and the federal leases that are their pre-condition. Specifically, the GAO found that the administration failed to issue 91% of leases on federal land within the time frame required under federal law, without releasing or refunding more than a hundred million dollars in lease and bonus payments (U.S. GAO, 2010). In June of 2011 the BLM lost a lawsuit with independent energy producers for failure to meet this 60-day requirement, a judicial affirmation that the administration is causing unreasonable delay in federal oil and gas permitting.

- In 2009, the BLM rescinded 77 oil and gas leases issued in Utah, and in 2010, the BLM did the same, canceling 91,000 acres of oil and natural gas leases in Montana, North Dakota and South Dakota. This action, in addition to limiting energy production opportunities in these specific areas, also cast a pall of uncertainty around scores of other BLM oil and gas leases.

- In February 2009, BLM refused to issue oil-shale research and development leases in Colorado and Utah, a move that injected considerable uncertainty into the marketplace of energy producers investing significant resources into oil-shale R&D eforts. (Johnson, 2009).

- In January 2010, the DOI announced a slew of new administrative requirements to the onshore leasing process. While leasing regulations already involve land use planning and extensive reviews of parcel conformance with the land use plan and environmental and disturbance measures, new leasing regulations extend the analysis and lengthen the leasing process. The 2010 changes add entire environmental review documents for each revision or new stipulation, mandate public involvement from outside groups for comment and extend the interdisciplinary review of lease sale parcels. According to the Western Energy Alliance, "DOI created new policies in 2010 that will add three additional layers of regulation to the exploration and development of oil and natural gas on public lands. These regulations are in addition to the existing five levels of regulation and analysis that for decades have made development on federal lands more time-consuming and difficult than on private lands. All this redundant analysis has led to anemic lease sales-just a few parcels in many cases-cancelled lease sales, indeterminate deferrals, and indefinite delays from nomination to sale." (Western Energy Alliance, 2011). Here again, these new requirements cast an additional cloud of uncertainty around a leasing process that is already heavily regulated.

- In May 2010, BLM suspended 61 leases that were issued in Montana (U.S. DOI, 2010).

- In December 2010, the DOI announced a new "Wild Lands" policy, a new federal lands categorization that critics contend will force land managers to treat the lands as de facto wilderness (U.S. DOI, 2010). After Congress inserted a rider that prohibited the Wild Lands policy from proceeding in the current fiscal year, the DOI was forced to withdraw the plan, though the practical availability of these lands for energy production still remains uncertain.

- In March 2011, BLM placed new bureaucratic barriers in the way of commercial oil-shale development as part of a settlement with environmental groups (Proctor, 2011). This new rulemaking will make it difficult, if not impossible, to turn R&D oil shale leases into a commercial oil shale production program, at the point in time technological advancement allows.

- In June 2011, the head of the Environmental Protection Agency was reported saying that, at the end a 2-year study on hydraulic fracturing, EPA would promulgate new federal restrictions on hydraulic fracturing (Travers, 2011). Currently, hydraulic fracturing is regulated by the States, and many States have added new regulatory requirements to the practice in recent years. Still, new federal regulatory restrictions surrounding the practice of hydraulic fracturing, and the inevitable barrage of anti-development litigation such rules would invite, is of widespread concern, since hydraulic fracturing is the key to accessing billions of barrels of oil and trillions of cubic feet of natural gas in "unconventional" oil and gas plays across the western U.S. Various departments and agencies are considering new hydraulic rules and regulations.

- In May of 2010 the DOI issued a policy that would require redundant environmental reviews in drilling locations where a review had already recently been conducted. In years past, an expedited procedure would have minimized additional reviews for already analyzed drilling locations- ultimately allowing operators to move forward in a more timely fashion. In August of 2011, a judge ruled against the government's new policy, stating that western oil and gas companies had been harmed, and placed a nationwide injunction against the new redundant requirements promulgated by DOI earlier in 2011 (Western Energy Alliance vs. Ken Salazar et al.).

On a practical level, the current regulatory environment has not only resulted in fewer leases being issued by the BLM, but when leases are issued, these new restrictions make it more difficult, expensive and time-consuming to translate those leases into actual drilling permits, new drilling activity, and eventual production. Some have attempted to deflect blame for a decline in new federal production by attributing it to energy companies that have not developed existing federal oil and gas leases. But according to one industry survey, more than 50% of all federal lands that have been leased but not produced are hindered by post-leasing, pre-permitting, pre-drilling administrative processes (Western Energy Alliance, 2011).

Taken together, these recent policy decisions seem to have created an atmosphere which directly hinders future oil and natural gas production on federal land. Increased regulatory uncertainty – while harmful to business in general – is detrimental to an industry that depends on long-term investments for developing resources and technology necessary for energy production.

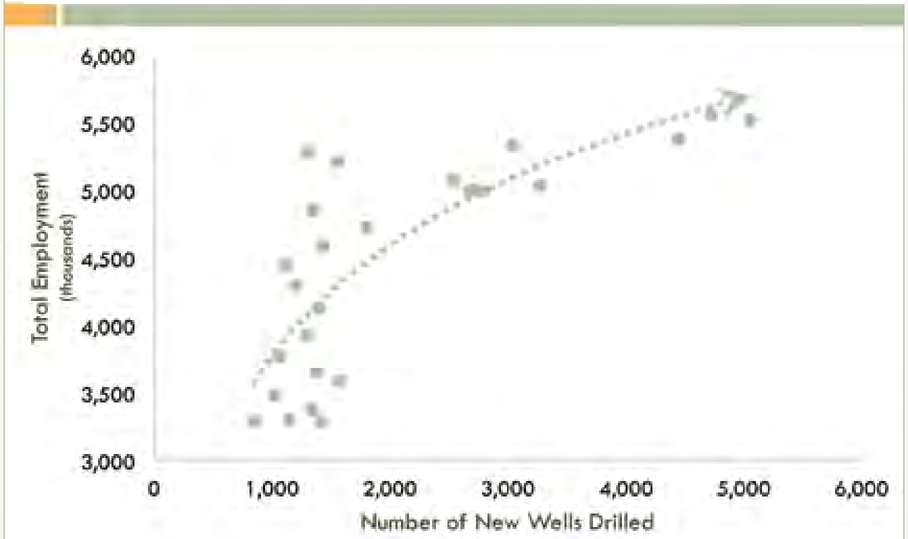
Beyond just the impact on domestic energy production, this regulatory environment has the potential to encourage energy producers to invest more of their resources in foreign nations and foreign energy reserves.

3 Economic Projections for Western U.S. Oil and Natural Gas Development

Oil and gas exploration and development is key to the economic vitality of the regional economy, and the number of new leases, permits and federal wells drilled will have economic and energy security impacts. Currently, the Western Energy Alliance estimates that oil and natural gas exploration and development supports 488,000 total jobs[4] in the western states; employment in the industry accounts for 8.1 percent of total regional employment; and oil and gas employees in the western states earn more than $27 billion in annual labor income, accounting for 10.3 percent of total regional labor income (Western Energy Alliance, 2010). For the purposes of this report, we will only narrowly focus on the direct "upstream" job implications of federal energy policy.

Figure 10 demonstrates the role that leasing and permitting plays in maintaining and expanding western states' employment. It shows that increased drilling activity is associated with increased employment in the western U.S.

Figure 10:
Relationship Between Drilling Activity and Employment, 1985–2010*



*Western States (Includes Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming)
Source: BLM Oil & Gas Statistics (2010)

4. The Western Energy Alliance estimate includes all downstream employment impacts in the industry, ranging from pipeline transportation to gas station attendants; therefore this number reflects the total impact on the industry. Our analysis deals with upstream exploration and production related job categories, mapped to the following NAICS codes, and explained further in this Report. NAICS codes: 211- Oil and gas extraction, 213111- Drilling oil and gas wells, 213112- Support activities for oil and gas operations.

Energy production on federal lands also has the capacity to contribute large sums of severance and ad valorem taxes to state and local governments, and substantial revenues to the federal government in the form of federal royalties, bonuses and leasing payments. Therefore, policy decisions that impact oil and natural gas development on federal lands will also impact jobs and government revenues. For the purposes of this Report, future projections of oil and natural gas development and the associated economic impacts are framed by the following two cases: what would happen to domestic energy production, job growth and state and federal tax revenues if federal leasing and permitting levels returned to their 2007/2008 levels as compared to a continuation of 2009/2010 levels into the future?

We use regression analysis to measure the relationship between the number of energy leases and permits issued in a given year and the subsequent production of oil and natural gas from the leases on federal land in succeeding years. The results quantify the economic consequences of more leasing/permitting/drilling and less of the same. The estimated statistical relationship can be applied to various policy cases to evaluate how prospective policies would affect future production.

Two different cases are analyzed in the modeling exercise: a Baseline Case, which demonstrates the projected effects of continuing the levels of leasing, permitting and new drilling as seen in 2009/2010; and an Alternative Case, which shows the energy production, economic, and revenue impacts of returning to the level of leasing, permitting, and new federal drilling experienced in 2007/2008. The Baseline and Alternative Cases are useful in demonstrating the difference that policy changes can have on future energy production, employment and government tax revenues. The compelling feature of the model is in highlighting the difference, or delta, between a regulatory environment that encourages more leasing, permitting and new drilling versus the current regulatory climate which is more restrictive.

The relevant data in the regression analysis includes information from the BLM regarding the number of leases, permits, and production on federal lands. Functional form and statistics results are discussed further in the appendix.

Forecasts of production were developed under a “Baseline” and an “Alternative” Case using the following assumptions.

- **Baseline** Case represents the average annual number of leases and permits issued in 2009 and 2010, (1,060 leases a year and 3,970 permits a year).
- **Alternative** Case represents the average annual total number of leases and permits issued in 2007 and 2008, (1,880 leases a year and 6,450 permits a year).

Projections of future production were pivoted off of 2010 actual production. That is, actual values for dependent variables (oil production, natural gas production, and number of new wells drilled) for 2010 were used as the basis on which the projected percent changes were applied. This provided a Baseline and an Alternative estimate of production and drilling for each of the years 2011 through 2015. The Baseline value was subtracted from the Alternative value to provide the estimated impact, or delta, associated with increased leasing and permitting activity.

3.1 Overview of Baseline and Alternative Trends

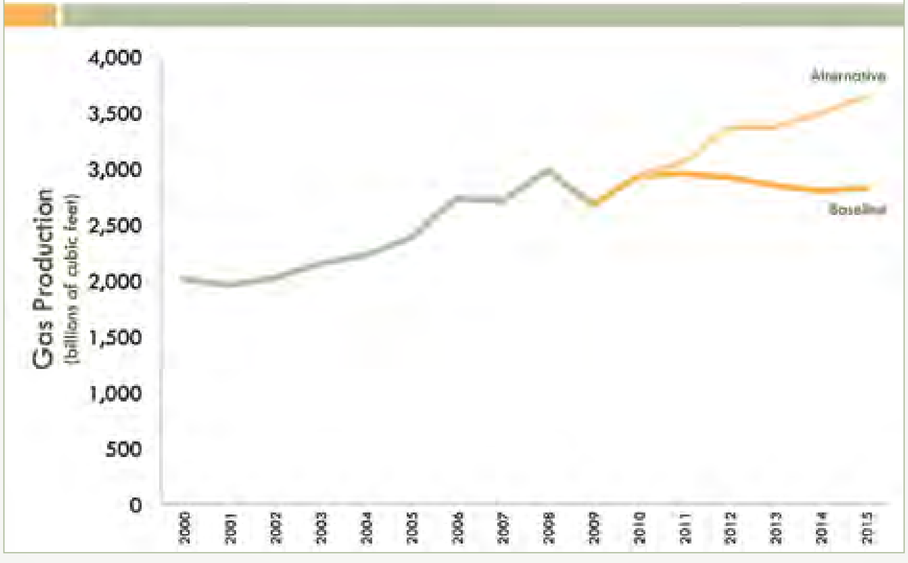
The models show that domestic oil and gas production, and the jobs and revenues that accompany such production, would experience a meaningful rebound under the Alternative Case, where a return to the 2007/2008 leasing, permitting, and drilling activities are assumed. Under the Baseline Case, where a continuation of the current slowdown is assumed going forward, natural gas production on federal lands stagnates, and oil production on federal lands would enter a period of year over year decline through the year 2015.

3.2 Increased Leasing and Permitting Would Lead to Increased Production

The models show that the effect of returning to 2007/2008 leasing and permitting levels is an increase of new domestic oil and natural gas supply for American consumers.

The impact of returning to 2007/2008 permitting and leasing levels is substantial when it comes to natural gas production, with a 516 billion cubic feet a year average increase in western states production over the next five years (Table 2). In natural gas production, the biggest winners would be Wyoming, New Mexico and Colorado, where natural gas production would increase on average by 262 billion cubic feet, 133 billion cubic feet, and 54 billion cubic feet, respectively, each year over the 2011-2015 time period.

Figure 11:
Natural Gas Production From Leases on BLM Lands*



*Western States (Includes Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming)
Source: Economics International Corp. calculations based on information from BLM Oil & Gas Statistics (2010) and ICF International Rocky Mountain Forecasts (2011)

TABLE 2 – NET (Alternative Minus Baseline)
Natural Gas Production, billion cubic feet

Increase in production relative to amount associated with baseline number of leases and permits issued

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	11	2	24	0	11	54	103
2012	45	8	110	1	50	232	447
2013	53	9	132	1	58	263	517
2014	72	12	183	2	76	351	696
2015	87	14	215	2	89	410	818
Average	**54**	**9**	**133**	**1**	**57**	**262**	**516**

Source: Economics International Corp. calculations based on information from BLM Oil & Gas Statistics (2010) and ICF International Rocky Mountain Forecasts (2011)

For natural gas liquids, returning to the 2007/2008 level of leases and permits issued would be associated with a 25 million barrel a year average increase in production between now and 2015 (Table 3). Given New Mexico and Wyoming's history of greater natural gas production on federal lands, those two states would also benefit from a return in this category as well. New Mexico would average an annual increase of 2.6 million barrels of natural gas liquids over the next five years, and Wyoming would average an annual 1.6 million barrel increase.

Figure 12:
Natural Gas Liquids Production From Leases on BLM Lands*

*Western States (Includes Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming)
Source: Economics International Corp. calculations based on information from BLM Oil & Gas Statistics (2010) and ICF International Rocky Mountain Forecasts (2011)

TABLE 3 – NET (Alternative Minus Baseline)
Natural Gas Liquids Production, million barrels

Increase in production relative to amount associated with baseline number of leases and permits issued

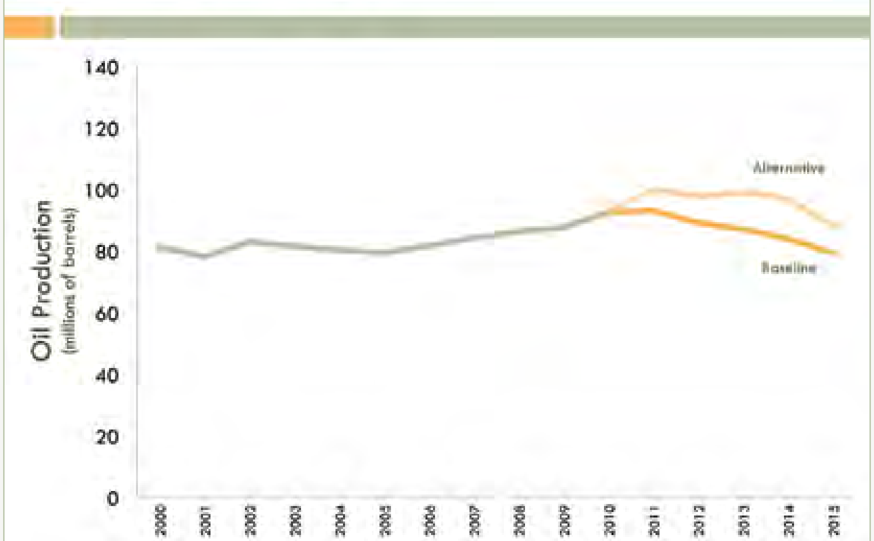
Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	0.1	0.0	0.5	0.0	0.1	0.3	1.0
2012	0.3	0.0	2.2	0.0	0.4	1.4	4.3
2013	0.3	0.0	2.6	0.0	0.5	1.6	5.0
2014	0.4	0.0	3.5	0.0	0.6	2.1	6.7
2015	0.5	0.0	4.1	0.0	0.7	2.4	7.8
Average	**0.3**	**0.0**	**2.6**	**0.0**	**0.5**	**1.6**	**5.0**

Source: Economics International Corp. calculations based on information from BLM Oil & Gas Statistics (2010) and ICF International Rocky Mountain Forecasts (2011)

When it comes to oil production, (Table 4), returning to the 2007/2008 average level of leases and permits issued would result in a 9.9 million barrel a year average increase on federal lands in western states oil production over the 2011-2015 period relative to the production that would occur under 2009/2010 average leasing and permitting levels.

A return to 2007/2008 federal leasing, permitting and new drilling levels would generate a projected average of 3.6 million additional barrels of oil each year over the next 5 years from the state of Wyoming alone. In Utah, oil production would grow by an average of 1.4 million barrels each year over the next 5 years under a return to 2007/2008 federal land productivity measures. And North Dakota would experience an average 800,000 barrel per year jump each year over the projected horizon.

Figure 13:
Oil Production From Leases on BLM Lands*



*Western States (Includes Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming)
Source: Economics International Corp. calculations based on information from BLM Oil & Gas Statistics (2010) and ICF International Rocky Mountain Forecasts (2011)

TABLE 4 – NET (Alternative Minus Baseline)

Oil Production, million barrels

Increase in production relative to amount associated with baseline number of leases and permits issued

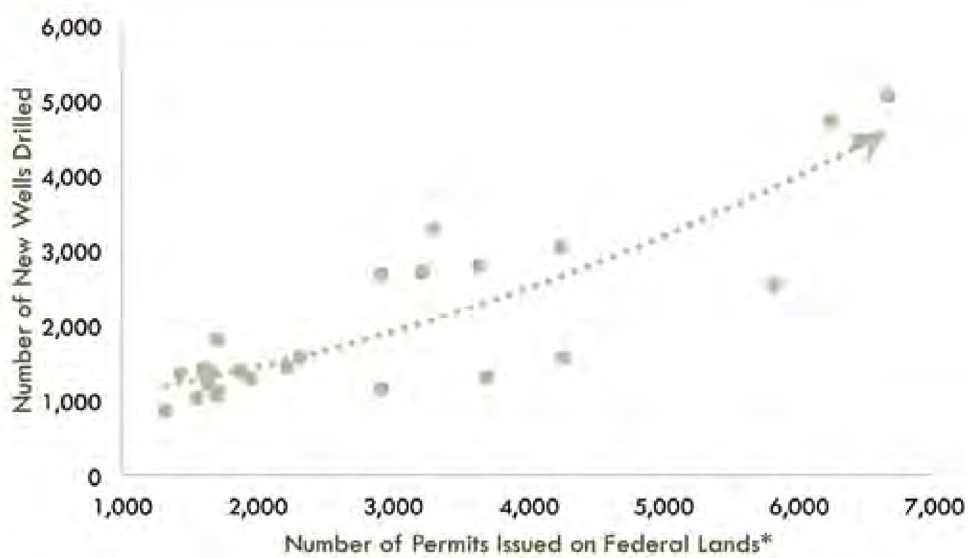
Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	0.27	0.31	2.38	0.59	0.98	2.59	7.12
2012	0.34	0.36	2.81	0.69	1.25	3.02	8.47
2013	0.51	0.52	3.91	0.95	1.72	4.42	12.03
2014	0.52	0.56	4.32	1.07	1.92	4.80	13.2
2015	0.37	0.38	2.91	0.71	1.27	3.22	8.87
Average	**0.40**	**0.43**	**3.27**	**0.80**	**1.43**	**3.61**	**9.94**

Source: Economics International Corp. calculations based on information from BLM Oil & Gas Statistics (2010) and ICF International Rocky Mountain Forecasts (2011)

3.3 Increased Production Would Lead to Increased Employment

Oil and gas exploration and development is an important part of the regional economy. Freeing up federal lands for that purpose would be a boon to the western states by paving the way for job creation. Expanding the energy productivity of federal lands would drive increased drilling activity—which in turn would mean more jobs. There is a clear relationship between increased permitting and drilling activity, as seen in Figure 14.

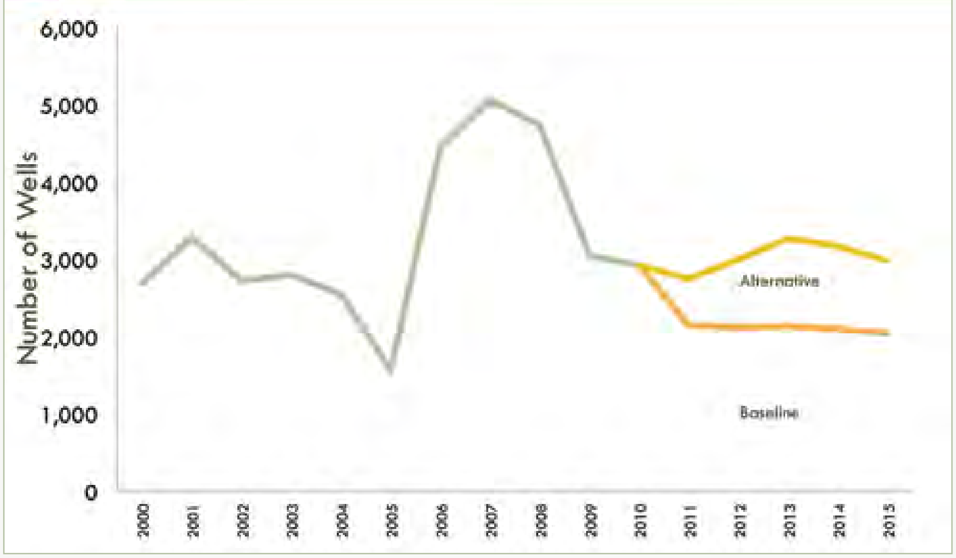
Figure 14:
Relationship Between Permitting and Drilling Activity, 1985–2010*



*Western States (Includes Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming)
Source: BLM Oil & Gas Statistics (2010) and ICF International Rocky Mountain Forecasts (2011)

Based on this type of relationship, we can quantify the effect of the number of new permits issued on the number of new wells started. For instance, returning to the 2007/2008 levels of new permitting would be associated with an increase in drilling activity (Table 5). The western states stand to gain an average of 928 new wells drilled a year over the next five years. Colorado and Utah will gain on average over 100 new wells each year, relative to their 2000-2010 average (Table 6). New Mexico and Wyoming will also more than double that gain, averaging 236 and 378 new wells each year, respectively.

Figure 15:
Number of Wells Started During the Year on Federal Lands*



*Western States (Includes Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming)
Source: Economics International Corp. calculations based on information from BLM Oil & Gas Statistics (2010) and ICF International Rocky Mountain Forecasts (2011)

2010 well numbers and the Alternative and Base scenarios were adjusted using the latest 2010 estimate from the BLM. See page 44 for more detail.

TABLE 5 – NET (Alternative Minus Baseline)
Number of Wells Started (Spud) on Federal Lands

Increase in wells relative to amount associated with baseline number of leases and permits issued

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	70	20	150	30	100	240	610
2012	120	20	220	30	130	360	880
2013	140	40	280	40	160	480	1,140
2014	120	30	280	50	160	430	1,070
2015	120	20	250	40	130	380	940
Average	**114**	**26**	**236**	**38**	**136**	**378**	**928**

Source: Economics International Corp. calculations based on information from BLM Oil & Gas Statistics (2010) and ICF International Rocky Mountain Forecasts (2011)

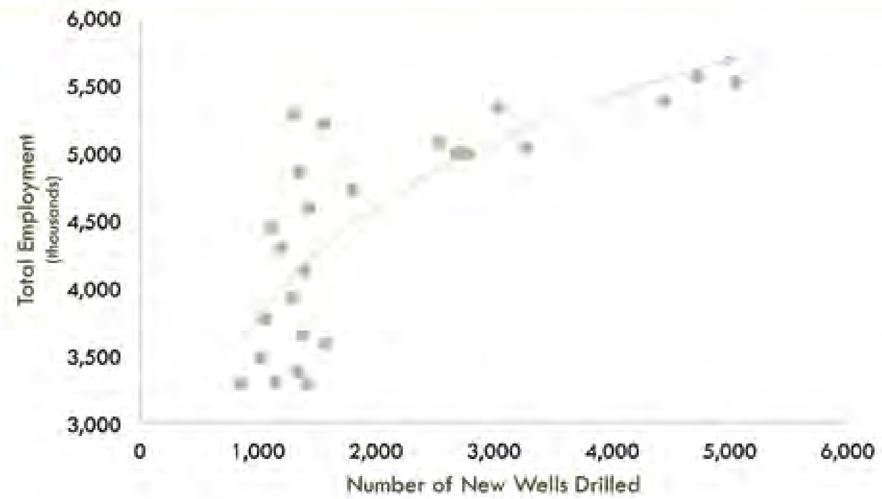
TABLE 6 – Average Actual Wells Started on Federal Lands 2000-2010

Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming
282	103	841	66	330	1,640

Source: BLM Oil & Gas Statistics (2010)

The number of new wells is also an indicator of drilling activity, which in turn is a good indicator of increased employment in the industry, as shown in Figure 16.

Figure 16:
Relationship Between Drilling Activity and Employment



*Western States (Includes Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming)
Source: Economics International Corp. calculations based on information from BLM Oil & Gas Statistics (2010) and ICF International Rocky Mountain Forecasts (2011)

Employment impacts were modeled using IMPLAN.[5] Drilling and completion expenditures were from forecasts provided by ICF.[6] Projections of the number of new wells drilled from the regression analysis (Table 5) were used in conjunction with drilling and completion expenditures to project total drilling and completion expenditures. The expenditures were mapped to IMPLAN sector 28 (drilling oil and gas wells) and sector 29 (support activities for oil and gas operations). The dollar value of production was mapped to IMPLAN sector 20 (oil and gas extraction). Dollar denominated results are not adjusted for inflation. For employment impacts, input expenditures were adjusted for inflation. Employment impacts are reported as the number of full- and part-time jobs. Impacts can be separated into: 1) direct impacts and 2) indirect and 3) induced impacts. Direct impacts are those immediately associated with a particular activity, such as employment directly associated with drilling and completion. Indirect employment includes the impact of local oil and gas companies buying goods and services from other local industries. Induced employment is created when spending increases due to additional household income from higher production in the direct and indirect industries.[7]

5. IMPLAN is an economic impact assessment modeling system that allows the construction of economic models which estimate the impacts of changes in the economies of states, counties and communities.
6. ICF International. (2011) Rocky Mountain Forecasts.
7. Indirect employment includes the impact of local industries buying goods and services from other local industries.

Table 7 outlines the number of direct oil and gas industry related jobs the western states stand to gain by returning to the 2007/2008 level of permitting. Employment in this sector would be expected to be more than five percent higher with the additional leases and permits. As spending on drilling activity works its way through the economy, the employment impacts for the state/regional economies grow too.

TABLE 7 – NET Employment – Direct Effect

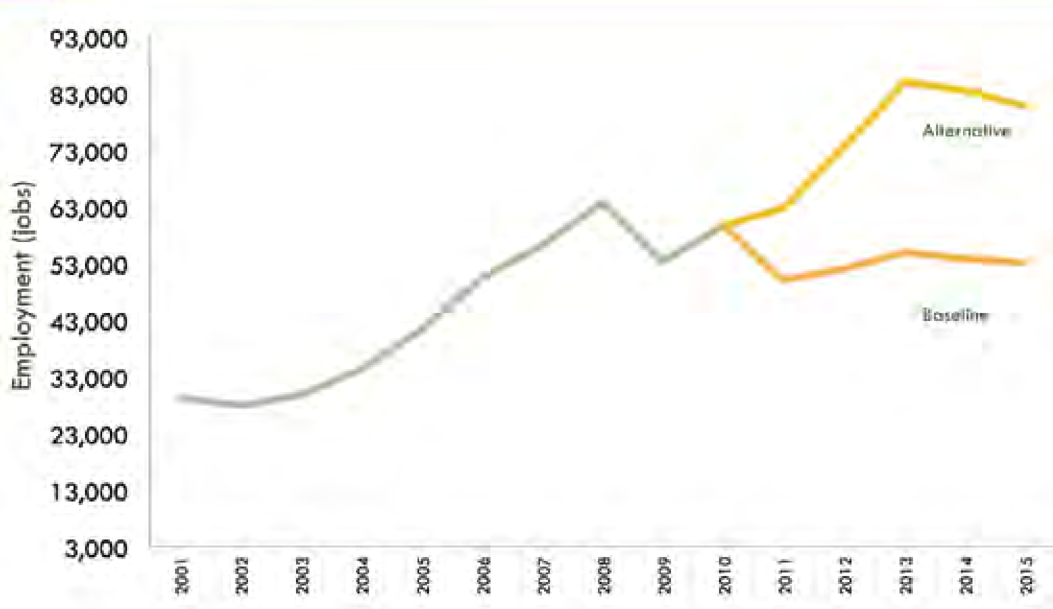
Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	463	176	738	330	588	1,790	4,085
2012	931	208	1,352	349	855	3,219	6,914
2013	1,127	453	1,793	487	1,097	4,979	9,937
2014	1,085	347	1,958	597	1,154	4,572	9,713
2015	1,156	258	1,822	508	985	4,301	9,032

TABLE 8 – NET Employment – Total Effect

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	1,840	636	2,194	966	2,515	4,505	12,656
2012	3,748	751	4,014	1,021	3,653	8,129	21,315
2013	4,536	1,635	5,325	1,427	4,689	12,550	30,163
2014	4,419	1,253	5,806	1,749	4,934	11,553	29,715
2015	4,728	931	5,400	1,488	4,211	10,887	27,642

Source: Economics International Corp. calculations based on information from BLM Oil & Gas Statistics (2010) and ICF International Rocky Mountain Forecasts (2011)

Figure 17:
Total Employment Supported by Oil and Gas Development on Federal Land in Western States*



*Western States (Includes Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming)
Source: Calculations based on information from BLM Oil & Gas Statistics (2010) and ICF International Rocky Mountain Forecasts (2011)

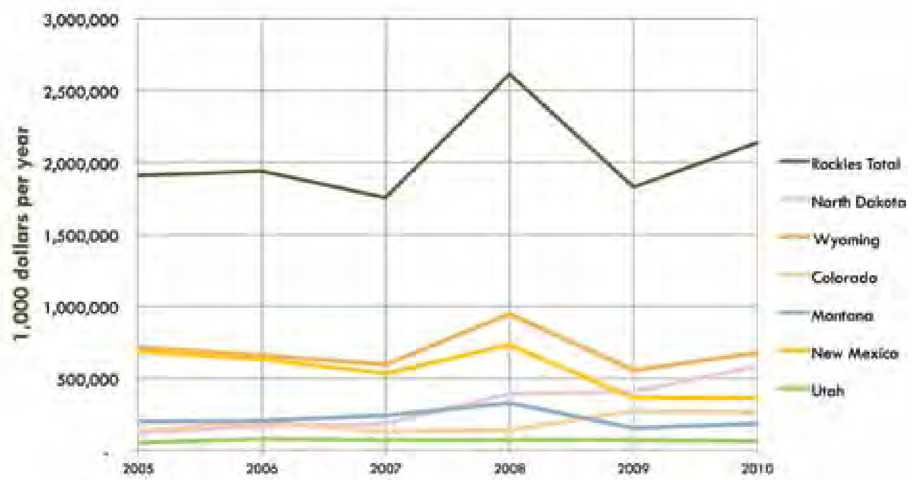
As Table 8 shows, a return to the 2007/2008 average level of leases and permits issued would be associated with an increase in employment of roughly 30,000 full- and part-time jobs by 2013, at a time when the economy is struggling to add jobs. In November 2011, the total number of unemployed residents in Utah was 85,783. The number of unemployed persons in New Mexico during that same period was 61,284. (U.S. Bureau of Labor Statistics, 2011).

Wyoming, Utah, New Mexico and Colorado – the Western States most dependent on federal lands for oil and gas production – would experience the sharpest jobs growth under a return to 2007/2008 levels. Each of these states would experience thousands of new direct jobs each and every year over the next 5 years if production levels increased to 2007/2008 levels. North Dakota would experience some jobs growth as well, although it would be less marked since the bulk of that state's new production is taking place on private lands.

3.4 Increased Production Would Lead to Increased Tax Revenues for Cash Strapped States

Increased domestic energy production brings benefits in the form of increased tax revenues. Western Energy Alliance calculates, for example, that every dollar appropriated for BLM's onshore oil and gas management program generates over $40 in royalty, rent, and bonus revenue for the federal government (Western Energy Alliance, 2010).[8] State governments too depend on revenues collected through severance and ad valorem taxes, which is assessed based on the value of the oil or natural gas produced. Figure 18 shows the degree to which the western states depend on oil and gas tax revenues—totaling billions every year.

Figure 18:
Oil and Gas Severance Taxes by State



Source: ICF International Rocky Mountain Forecasts (2011)

8. Western Energy Alliance's estimate compares the $69.3 million FY2010 Onshore BLM budget request and the $2.78 billion reported Department of Interior, Office of Natural Resources Revenue, Total Federal Onshore Federal Royalties Revenue in order to calculate the impact per dollar spent.

Table 9 shows what the western states stand to gain with increased leasing and permitting. An increase to the 2007/2008 average level of leases and permits issued would be associated with an average increase in severance and ad valorem taxes of $232 million per year for the time period 2011 to 2015. Importantly, this revenue boost to the western states would occur without the imposition of higher tax rates, and the negative implications associated with such a tax increase.

TABLE 9 – NET (Alternative Minus Baseline)
Severance and Ad Valorem Taxes, $ millions

Increase in revenues relative to amount associated with baseline number of leases and permits issued

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	$2	$3	$26	$3	$3	$22	$59
2012	$8	$7	$78	$5	$9	$75	$183
2013	$11	$9	$103	$7	$12	$95	$236
2014	$15	$11	$140	$8	$15	$130	$319
2015	$19	$11	$159	$6	$17	$151	$362
Total	**$54**	**$40**	**$506**	**$29**	**$56**	**$473**	**$1,158**

Source: Economics International Corp. calculations based on information from BLM Oil & Gas Statistics (2010) and ICF International Rocky Mountain Forecasts (2011)

Here again, the big winners under a return to 2007/2008 levels are those states that rely most heavily on federal lands for oil and natural gas production. New Mexico would, on average, see more than a $100 million increase in severance tax revenue each year over the next 5 under a return to 2007/2008 levels. Meanwhile, Wyoming would see an average increase of severance tax equaling $95 million over the next 5 years.

Figure 19:
State Severance Tax and Ad Valorem Revenues*

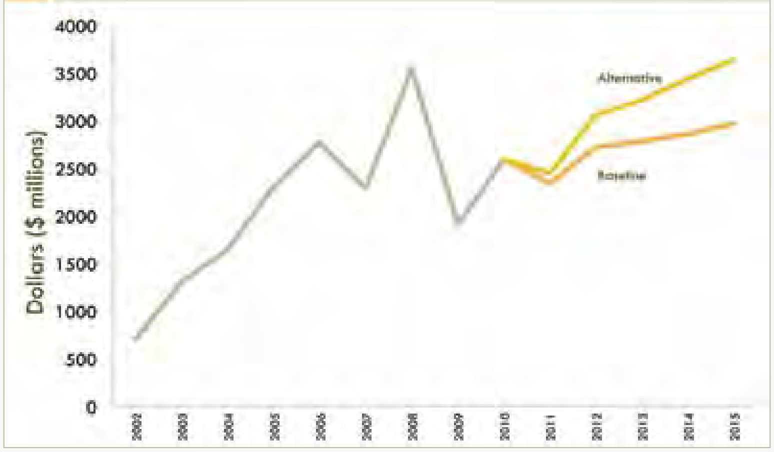
*Western States (Includes Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming)
Source: Economics International Corp. calculations based on information from BLM Oil & Gas Statistics (2010) and ICF International Rocky Mountain Forecasts (2011)

3.5 Federal Royalties

Oil and natural gas production on federal lands is taxed at the local and state level, and also by the federal government. These levies are known as Federal Mineral Lease payments and, upon receipt, they are divided between the federal government and the states from which the royalties are derived on a near 50/50 basis.

A return to 2007/2008 oil and natural gas leasing, permitting and drilling levels would result in more than $2.1 billion to the federal treasury over the next 5 years in the form of increased Federal Mineral Royalties.[9] Wyoming would generate an additional $981 million dollars combined to the federal treasury over the next 5 years under a return to 2007/2008 levels.

Figure 20:
Federal Mineral Royalties in Western States*



*Western States (Includes Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming)
Source: Economics International Corp. calculations based on information from BLM Oil & Gas Statistics (2010) and ICF International Rocky Mountain Forecasts (2011)

TABLE 10 – NET (Alternative Minus Baseline)

Federal Royalties Of Production Of Oil, Natural Gas And NGLs, $ million

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	7.3	3.2	31.9	4.6	12.8	45.6	105.5
2012	27.9	7.6	97.9	7.2	40.2	156.3	337.1
2013	36.4	9.9	127.9	9.6	51.4	197.4	432.6
2014	51.0	11.9	175.3	10.7	67.6	268.6	585.2
2015	63.4	12.3	198.6	7.7	74.5	313.0	669.6
Total	186.1	45.0	631.7	39.9	246.5	980.9	2,129.9

Source: Economics International Corp. calculations based on information from BLM Oil & Gas Statistics (2010) and ICF International Rocky Mountain Forecasts (2011)

9. Under current federal law, just less than half of all federal mineral lease royalties are directed back to the states, which means the states themselves will experience significant revenue gain as result of increasing federal mineral lease dollars.

4 CONCLUSION

The Western U.S. experienced a decline in oil and natural gas leasing, permitting, and new drilling on federal lands during 2009 and 2010 relative to previous years. Preliminary leasing data suggests that the downward trend has continued into 2011. This is expected to result in a reduction of domestically produced oil and natural gas, a loss of thousands of jobs in both energy and non-energy sectors of the economy, and the surrender of hundreds of millions of dollars in state and federal tax revenues, royalties, and lease payments to western states and the U.S. Treasury.

In sum, returning to permitting and leasing levels experienced in 2007 and 2008 would:

- Increase Western U.S. natural gas production by an average of 516 billion cubic feet per year 2012 to 2015.
- Increase Western U.S. oil production by an average of 9.9 million barrels per year 2012 to 2015.
- Direct employment increases in the oil and gas industry in energy producing western states of 4,085 jobs in 2011, 6,914 jobs in 2012, 9,937 jobs in 2013, 9,713 in 2014, and 9,032 in 2015.
- Increase total employment in energy producing western states over the next four years by an annual average increase of 24,298 total jobs.
- Severance and ad valorem taxes would increase by over $1.2 billion from 2011 to 2015.
- Federal royalty would increase ranging from $106 million to $670 million per year through 2015, totaling over $2.1 billion in five years.

For policymakers seeking to expand domestic energy production and stimulate economic growth, the public policy choice is clear. Federal lands energy policy needs to change in order to encourage development of oil and natural gas resources in a sensible, orderly and balanced way.

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5 APPENDIX: Data and Methodology

This study quantifies the relationship between the number of energy leases and drilling permits issued in a given year and the subsequent production of oil and natural gas from the leases on federal land in several western states. Projections of the impacts on production are used to forecast impacts on employment and severance and ad valorem taxes. Results from the econometric analysis were used to forecast future energy production under several scenarios.

This appendix describes the data and methodology employed in the empirical analysis. The analysis is focused on the states of Colorado, Montana, New Mexico, North Dakota, Utah, and Wyoming, which for convenience will be referred to as the "Western States." Unless stated otherwise, the analysis and findings pertain only to these Western States. The analysis is based on the information available at the time the analysis is conducted. As such, the approach and conclusions may change in future studies as new or additional information is obtained.

5.1 Data

This empirical analysis used the following data. BLM data used is from the FY2010 Oil and Gas Statistics.

- Number of new leases issued during the year, by state (BLM);
- Applications for Permit to Drill (APDs) on federal lands (BLM);
- Oil production on federal lands, barrels (BLM);
- Gas production on federal lands, mcf (BLM);
- NGL production associated with federal lands, gallons converted to barrels in this Report (BLM);
- Number of wells started (spud) during the year on federal lands (BLM);
- Well drilling and completion costs, current dollars (ICF);[10]
- Employment and output multipliers (IMPLAN);
- Oil price forecasts, current dollars per barrel, WTI (Economist Intelligence Unit);
- Natural gas price forecasts, current dollars per mcf (Economist Intelligence Unit);
- Severance and ad valorem taxes, current dollars (ICF);
- Royalties collected, current dollars (BLM).

10. Throughout this appendix, current dollars refers to dollar amounts that have not be adjusted for inflation.

5.2 Production and Drilling

Estimates of the impacts of leasing and permitting on oil, gas, and NGL production were produced using a log-log panel regression for oil and gas producing states over the period 1985 through 2010. Independent variables included a constant; cross-sectional fixed effects; a trend; dummy variables for regulatory changes (where appropriate) in 1997, 1992, 2000, and 2005; the number of new leases issued each year (including lags); and the number of permits issued each year (including lags). The analysis employs a lag structure of five lags to quantify the effects over time. Regressions were performed using the EViews econometric package for each of the following dependent variables:

- Oil production on BLM lands (14 states, 1985-2010, 149 observations),
- Gas production on BLM lands (14 states, 1985-2009, 137 observations),
- NGL production associated with BLM lands (12 states, 2000-2010, 76 observations), and
- Number of new wells begun (spud) on BLM lands (14 states, 1985-2010, 145 observations),

Dummy variables for regulatory changes include the following:

- 992: Energy Policy Act, competitive and noncompetitive leases are valid for a minimum of 10 years, and remain valid as long the lease is producing. Prior to the 1992 Act, competitive leases were valid for only five years if not producing.
- 2000: Prior to the year 2000, excess capacity meant that natural gas well production swung as wells were shut on and off to meet market conditions. Much of the excess capacity eroded by 2000 and well production did not swing with price.
- 2005: Energy Policy Act, Maguire (2010) indicates the Act has a small impact on leasing.

Forecasts of production were produced under a "Baseline" and an "Alternative" Case in EViews under the following assumptions. The Baseline represents the average annual number of leases and permits issued in 2009 and 2010 (1,060 leases a year and 3,970 permits a year). The Alternative represents the average annual total number of leases and permits issued in 2007 and 2008 (1,880 leases a year and 6,450 permits a year). The following table provides the assumed number of leases and permits issued under the Baseline and Alternative Case.

TABLE 11 – Baseline and Alternative Leasing and Permitting Scenarios

Leases Issued	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming
Baseline	120	130	200	140	120	350
Alternatives	210	230	360	250	210	620
Permits Issued						
Baseline	530	60	1,030	110	480	1,760
Alternatives	870	100	1,670	170	780	2,860

Under the assumption of ceteris paribus, all the other independent variables are assumed to remained fixed over the forecast period. Thus, the Baseline and Alternative projections should not be viewed as predictions of future production. Instead, this approach measures the difference between policy cases to evaluate the impact of policy differences.

VARIABLES USED:

OILPROD: total oil production (bbl)
GASPROD: total natural gas production (mcf)
NGLPROD: total natural gas liquids production (gallons)
LISSUED: number of new leases issued during the year
APD: number of APDs permitted during the year federal lands
SPUD: number of wells started (spud) during the year on federal lands

In the regression equations, the natural logarithms of the above variables are used.

1992: Dummy variable equal to 1 if year is 1992 or later and equal to 0 otherwise
2000: Dummy variable equal to 1 if year is 2000 or later and equal to 0 otherwise
2005: Dummy variable equal to 1 if year is 2005 or later and equal to 0 otherwise

REGRESSION EQUATIONS:

Oil production equation:

$$\begin{aligned} \text{OILPROD} = {} & b_0\,\text{C} + b_1\,\text{TREND} + b_2\,\text{LISSUED} + b_3\,\text{LISSUED(-1)} + b_4\,\text{LISSUED(-2)} \\ & + b_5\,\text{LISSUED(-3)} + b_6\,\text{LISSUED(-4)} + b_7\,\text{LISSUED(-5)} + b_8\,\text{APD} + b_9\,\text{APD(-1)} \\ & + b_{10}\,\text{APD(-2)} + b_{11}\,\text{APD(-3)} + b_{12}\,\text{APD(-4)} + b_{13}\,\text{APD(-5)} \end{aligned}$$

Gas production equation:

$$\begin{aligned} \text{GASPROD} = {} & b_0\,\text{C} + b_1\,\text{TREND} + b_2\,1992 + b_3\,2000 + b_4\,2005 + b_5\,\text{LISSUED} + b_6\,\text{LISSUED(-1)} \\ & + b_7\,\text{LISSUED(-2)} + b_8\,\text{LISSUED(-3)} + b_9\,\text{LISSUED(-4)} + b_{10}\,\text{LISSUED(-5)} + b_{11}\,\text{APD} \\ & + b_{12}\,\text{APD(-1)} + b_{13}\,\text{APD(-2)} + b_{14}\,\text{APD(-3)} + b_{15}\,\text{APD(-4)} + b_{16}\,\text{APD(-5)} \end{aligned}$$

NGL production equation:

$$\text{NGLPROD} = b_0\,\text{C} + b_1\,\text{GASPROD}$$

New wells spud equation:

$$\begin{aligned} \text{SPUD} = {} & b_0\,\text{C} + b_1\,\text{TREND} + b_2\,\text{LISSUED} + b_3\,\text{LISSUED(-1)} + b_4\,\text{LISSUED(-2)} + b_5\,\text{LISSUED(-3)} + b_6\,\text{LISSUED(-4)} \\ & + b_7\,\text{LISSUED(-5)} + b_8\,\text{APD} + b_9\,\text{APD(-1)} + b_{10}\,\text{APD(-2)} + b_{11}\,\text{APD(-3)} + b_{12}\,\text{APD(-4)} + b_{13}\,\text{APD(-5)} \\ & + b_{10}\,\text{APD(-2)} + b_{11}\,\text{APD(-3)} + b_{12}\,\text{APD(-4)} + b_{13}\,\text{APD(-5)} \end{aligned}$$

As a log-log model, estimated coefficient results are interpreted as elasticities, or percent changes. For example, in the oil production coefficient, the coefficient on one-year lagged number of permits issued is 0.20. In other words, all other things held constant, a 10 percent increase in the number permits issued the year-before-last would be associated with a two percent increase in oil production this year.[11]

TABLE 12 – Regression Results

	Oil Production	Gas Production	NDL Production	Wells Spud
R-Squared	0.99	0.99	0.97	0.95
Coefficient	14.36	14.38	14.4	-1.90
Std. Error	0.063	0.69	1.14	.87

Projections of future projection were pivoted off of 2010 actual production. That is, actual values for dependent variables for 2010 were used as the basis on which the projected percent changes were applied. This provided a Baseline and an Alternative estimate of production and drilling for each of the years 2011 through 2015. The Baseline value was subtracted from the Alternative value to provide the estimated impact, or delta, associated with increased leasing and permitting activity. The analysis evaluates the differences between a "Baseline" level of permits and leases, and an "Alternative" level of permits and leases. The regression uses a panel data set and measures cross-sectional fixed effects.

The results are presented in Table 2, 3, 4 and 5 for gas production, NGL production, oil production and new wells respectively.

11. Natural gas liquids production is modeled as a function of natural gas production; regression results indicate an elasticity of 0.5.

5.3 Employment

Employment impacts were modeled using IMPLAN. Drilling and completion expenditures were projected from forecasts provided by ICF, and presented in the following table. Total projected drilling and completion expenditures are provided in the following table were mapped to IMPLAN sector 28 (drilling oil and gas wells) and sector 29 (support activities for oil and gas operations). The dollar value of production was mapped to IMPLAN sector 20 (oil and gas extraction). Dollar denominated results are not adjusted for inflation. For employment impacts, input expenditures were adjusted for inflation. Employment impacts are reported as the number of full- and part-time jobs.

TABLE 13 – Projected Drilling and Completion Cost

Per well, current dollars (not adjusted for inflation)

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming
2011	3,319,000	4,226,000	1,832,000	5,515,000	2,669,000	3,574,000
2012	3,603,000	4,815,000	2,099,000	5,816,000	2,803,000	4,125,000
2013	3,727,000	5,445,000	2,230,000	6,101,000	2,944,000	4,900,000
2014	3,860,000	5,408,000	2,295,000	5,986,000	3,017,000	4,866,000
2015	4,017,000	5,881,000	2,285,000	6,379,000	3,071,000	5,099,000

The costs per well were applied to projections of the number of new wells drilled provided by the regression analysis (Table 5). Total projected drilling and completion expenditures are provided in the following table.

The costs per well were applied to projections of the number of new wells drilled provided by the regression analysis (Table 5). Total projected drilling and completion expenditures are provided in the following table.

TABLE 14 – Projected Drilling and Completion Cost

Total, current dollars (not adjusted for inflation)

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming
2011	497,816,000	126,790,000	622,939,000	330,871,000	560,420,000	1,930,021,000
2012	648,520,000	144,452,000	692,564,000	290,785,000	532,608,000	2,186,026,000
2013	633,592,000	163,364,000	713,503,000	366,038,000	529,910,000	2,744,174,000
2014	540,381,000	162,244,000	780,422,000	359,188,000	603,412,000	2,530,224,000
2015	602,516,000	176,436,000	754,060,000	318,960,000	552,706,000	2,498,396,000
Alternative						
2011	730,131,000	211,317,000	897,765,000	496,306,000	827,287,000	2,787,808,000
2012	1,080,867,000	240,753,000	1,154,273,000	465,255,000	897,023,000	3,670,874,000
2013	1,155,374,000	381,184,000	1,337,818,000	610,064,000	1,000,941,000	5,096,323,000
2014	1,003,564,000	324,487,000	1,423,123,000	658,511,000	1,086,142,000	4,622,525,000
2015	1,084,530,000	294,059,000	1,325,317,000	574,128,000	951,883,000	4,435,928,000
Net = Alternative = Baseline						
2011	232,315,000	84,527,000	274,826,000	165,435,000	266,867,000	857,787,000
2012	432,347,000	96,301,000	461,709,000	174,470,000	364,415,000	1,484,848,000
2013	521,782,000	217,820,000	624,315,000	244,026,000	471,031,000	2,352,149,000
2014	463,183,000	162,243,000	642,701,000	299,323,000	482,730,000	2,092,301,000
2015	482,014,000	117,623,000	571,257,000	255,168,000	399,177,000	1,937,532,000

The resulting employment impacts are provided in the Tables 5 and 6.

5.4 State Severance and Ad Valorem Taxes

Oil and gas production values were calculated by applying price projections provided by the Economist Intelligence Unit to the production forecasts in Tables 1, 2, and 3.

Severance and Ad Valorem Rate (IFC)

	2011	2012	2013	2014	2015
Oil (US $ / bbl)	98.70	95.40	90.90	85.90	83.80
Natural Gas (US $ / mcf)	4.54	5.26	5.70	6.18	6.69

NGL price projections use 2010 propane prices as a baseline and are assumed to change from year to year at the same rate as natural gas prices.

Severance and ad valorem taxes are calculated by applying these values to the severance and ad valorem tax rates reported by ICF and shown below.

Severance and Ad Valorem Rate (IFC)

Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming
2.85 %	8.61 %	7.89 %	7.07 %	2.20 %	4.70 %

The results are presented in Table 9.

5.5 Federal Royalties

Oil and gas production values were calculated in the same way as for state severance and ad valorem taxes. The following royalty rates were applied, based on the 2008/2009 royalty rate calculated from information provided by the Bureau of Land Management.

Oil	Gas	NGLs
11.7 %	12.4 %	9.7 %

5.6 Supplemental Tables

Oil Production, million barrels

Baseline

Production associated with same total number new leases and permits – Average 2009/2010

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	3.478	3.835	30.755	8.302	12.778	33.584	92.732
2012	3.495	3.562	29.359	7.928	13.082	31.533	88.959
2013	3.584	3.563	28.042	7.507	12.383	31.642	86.721
2014	3.241	3.363	27.243	7.494	12.129	30.231	83.701
2015	3.219	3.182	25.887	7.173	11.161	28.410	79.032
Average	**3.403**	**3.501**	**28.257**	**7.681**	**12.307**	**31.080**	**86.229**

Alternative

Production associated with same total number new leases and permits – Average 2007/2008

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	3.749	4.142	33.132	8.894	13.757	36.170	99.844
2012	3.836	3.920	32.169	8.615	14.333	34.555	97.428
2013	4.092	4.085	31.954	8.456	14.106	36.059	98.752
2014	3.765	3.924	31.564	8.567	14.051	35.033	96.904
2015	3.593	3.565	28.795	7.887	12.429	31.629	87.898
Average	**3.807**	**3.927**	**31.523**	**8.484**	**13.735**	**34.689**	**96.165**

Net (Alternative Minus Baseline)

Increase in production relative to amount associated with baseline number of leases and permits issued

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	0.271	0.307	2.377	0.592	0.979	2.586	7.112
2012	0.341	0.358	2.810	0.687	1.251	3.022	8.469
2013	0.508	0.522	3.912	0.949	1.723	4.417	12.031
2014	0.524	0.561	4.321	1.073	1.922	4.802	13.203
2015	0.374	0.383	2.908	0.714	1.268	3.219	8.866
Average	**0.404**	**0.426**	**3.266**	**0.803**	**1.429**	**3.609**	**9.936**

Natural Gas Production, billion cubic feet

Baseline

Production associated with same total number new leases and permits – Average 2009/2010

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	302	51	718	8	301	1,562	2,943
2012	286	50	725	8	325	1,515	2,909
2013	286	47	731	8	317	1,448	2,839
2014	283	44	737	8	306	1,409	2,789
2015	293	46	745	9	307	1,414	2,814
Average	**290**	**48**	**731**	**8**	**312**	**1,470**	**2,859**

Alternative

Production associated with same total number new leases and permits – Average 2007/2008

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	313	53	743	8	312	1,616	3,046
2012	331	58	836	9	375	1,747	3,356
2013	340	56	863	10	375	1,712	3,356
2014	356	56	920	10	383	1,760	3,485
2015	380	60	960	12	396	1,825	3,632
Average	**344**	**57**	**864**	**10**	**368**	**1,732**	**3,375**

Net (Alternative Minus Baseline)

Increase in production relative to amount associated with baseline number of leases and permits issued

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	11	2	24	0	11	54	103
2012	45	8	110	1	50	232	447
2013	53	9	132	1	58	263	517
2014	72	12	183	2	76	351	696
2015	87	14	215	2	89	410	818
Average	**54**	**9**	**133**	**1**	**57**	**262**	**516**

Natural Gas Liquids Production, million barrels

Baseline

Production associated with same total number new leases and permits – Average 2009/2010

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	3.5	0.1	29.0	0.2	5.2	18.7	56.6
2012	3.4	0.1	29.2	0.2	5.4	18.4	56.6
2013	3.4	0.1	29.3	0.2	5.3	18.0	56.3
2014	3.4	0.1	29.4	0.2	5.2	17.8	56.0
2015	3.4	0.1	29.5	0.2	5.3	17.8	56.3
Average	**3.4**	**0.1**	**29.3**	**0.2**	**5.3**	**18.2**	**56.4**

Alternative

Production associated with same total number new leases and permits – Average 2007/2008

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	3.5	0.1	29.5	0.2	5.3	19.0	57.6
2012	3.6	0.1	31.4	0.2	5.8	19.8	60.9
2013	3.7	0.1	31.9	0.2	5.8	19.6	61.3
2014	3.8	0.1	32.9	0.2	5.9	19.9	62.8
2015	3.9	0.1	33.6	0.2	6.0	20.2	64.1
Average	**3.7**	**0.1**	**31.9**	**0.2**	**5.8**	**19.7**	**61.3**

Net (Alternative Minus Baseline)

Increase in production relative to amount associated with baseline number of leases and permits issued

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	0.1	0.0	0.5	0.0	0.1	0.3	1.0
2012	0.3	0.0	2.2	0.0	0.4	1.4	4.3
2013	0.3	0.0	2.6	0.0	0.5	1.6	5.0
2014	0.4	0.0	3.5	0.0	0.6	2.1	6.7
2015	0.5	0.0	4.1	0.0	0.7	2.4	7.8
Average	**0.3**	**0.0**	**2.6**	**0.0**	**0.5**	**1.6**	**5.0**

Number of Wells Started (Spud) on Federal Lands

Baseline*

Production associated with same total number new leases and permits – Average 2009/2010

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	270	46	548	76	282	908	2,130
2012	300	46	538	66	262	898	2,110
2013	290	46	528	76	252	928	2,120
2014	260	46	548	76	272	888	2,090
2015	270	46	538	66	252	858	2,030
Average	**278**	**46**	**540**	**72**	**264**	**896**	**2,096**

Alternative*

Production associated with same total number new leases and permits – Average 2007/2008

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	340	66	698	106	382	1,148	2,740
2012	420	66	758	96	392	1,258	2,190
2013	430	86	808	116	412	1,408	2,460
2014	380	76	828	126	432	1,318	2,360
2015	390	66	788	106	382	1,238	2,170
Average	**392**	**72**	**776**	**110**	**400**	**1,274**	**3,024**

Net (Alternative Minus Baseline)

Increase in wells relative to amount associated with baseline number of leases and permits issued

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	70	20	150	30	100	240	610
2012	120	20	220	30	130	360	880
2013	140	40	280	40	160	480	1,140
2014	120	30	280	50	160	430	1,070
2015	120	20	250	40	130	380	940
Average	**114**	**26**	**236**	**38**	**136**	**378**	**928**

*The BLM reissued the estimated number of wells started in 2010 after the completion of this analysis. The new estimate was used to adjust the 2010 number of wells as well as the Baseline and Alternative forecasts. In both scenarios, the Net (Alternative minus Baseline) remained the same.

Net (Alternative Minus Baseline)

Employment – Direct Effect

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	463	176	738	330	588	1,790	4,085
2012	931	208	1,352	349	855	3,219	6,914
2013	1,127	453	1,793	487	1,097	4,979	9,937
2014	1,085	347	1,958	597	1,154	4,572	9,713
2015	1,156	258	1,822	508	985	4,301	9,032

Employment – Indirect Effect

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	612	219	679	308	910	1,375	4,103
2012	1,238	257	1,221	326	1,305	2,467	6,814
2013	1,499	4,143	1,626	455	1,678	3,823	13,224
2014	1,452	3,849	1,753	558	1,757	3,502	12,871
2015	1,550	4,102	1,617	475	1,490	3,291	12,526

Employment – Induced Effect

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	765	241	778	328	1,017	1,340	4,469
2012	1,578	286	1441	346	1,493	2,443	7,587
2013	1,911	620	1,906	484	1,914	3,748	10,583
2014	1,883	477	2,095	594	2,023	3,479	10,551
2015	2,021	356	1,960	505	1,735	3,291	9,868

Employment – Total Effect

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	1,840	636	2,194	966	2,515	4,505	12,656
2012	3,748	751	4,014	1,021	3,653	8,129	21,315
2013	4,536	1,635	5,325	1,427	4,689	12,550	30,163
2014	4,419	1,253	5,806	1,749	4,934	11,553	29,715
2015	4,728	931	5,400	1,488	4,211	10,884	27,642

Net (Alternative Minus Baseline)

Labor Income $ millions – Direct Effect

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	52.6	16.2	62.6	29.8	51.6	165.5	378.3
2012	118.4	19.9	127.6	31.6	81.2	315.1	693.8
2013	146.8	42.4	170.3	44.1	104.7	480.6	988.9
2014	157.4	33.3	197.5	54.0	114.3	462.0	1,018.5
2015	178.7	25.5	197.1	45.9	103.3	451.6	1,002.1

Labor Income $ millions – Indirect Effect

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	49.6	11.6	38.0	18.0	52.9	80.5	250.6
2012	103.2	13.7	70.6	19.1	77.0	147.2	430.8
2013	126.7	30.1	94.8	26.7	99.4	228.1	605.8
2014	126.9	23.0	104.3	32.7	105.0	212.3	604.2
2015	140.1	17.2	99.3	27.8	90.7	203.1	578.2

Labor Income $ millions – Induced Effect

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	36.9	8.9	29.0	12.3	39.6	50.6	177.3
2012	78.7	10.7	56.3	13.1	59.3	93.9	312.0
2013	96.9	23.2	75.4	18.3	76.5	144.6	434.9
2014	175.9	32.4	154.9	38.7	143.6	270.1	815.6
2015	110.3	13.6	82.9	19.0	72.1	131.5	429.4

Labor Income $ millions – Total Effect

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	139.1	36.7	129.6	60.1	144.1	296.6	806.2
2012	300.3	44.3	254.5	63.8	217.5	556.2	1,436.6
2013	370.4	95.7	340.5	89.1	280.6	853.3	2,029.6
2014	383.4	74.3	386.9	109.1	301.2	810.6	2,065.5
2015	429.1	56.3	379.3	92.7	266.1	786.2	2,009.7

Net (Alternative Minus Baseline)

Value Added $ millions – Direct Effect

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	153.8	47.6	185.9	87.4	153.5	491.1	1,119.3
2012	344.4	58.3	376.3	92.7	240.1	931.9	2,043.7
2013	426.8	124.2	502.4	129.5	309.5	1,423.2	2,915.6
2014	455.2	97.3	580.3	158.6	337.2	1,364.4	2,993.0
2015	515.9	74.4	577.3	134.9	303.6	1,331.4	2,937.5

Value Added $ millions – Indirect Effect

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	75.5	18.2	56.4	28.2	79.4	129.2	386.9
2012	160.7	21.8	105.2	29.9	116.4	236.5	670.5
2013	197.9	47.4	141.2	41.8	150.2	366.4	944.9
2014	202.3	36.5	155.7	51.2	159.2	341.3	946.2
2015	225.3	27.4	148.4	43.5	138.1	326.7	909.4

Value Added $ millions – Induced

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	65.1	16.1	52.5	21.4	69.1	99.9	324.1
2012	139.1	19.4	102.3	22.6	103.9	185.9	573.2
2013	171.4	41.8	136.9	31.6	134.0	286.0	801.7
2014	175.9	32.4	154.9	38.7	143.6	270.1	815.6
2015	196.1	24.5	151.2	33.0	126.5	261.0	792.3

Value Added $ millions – Total Effect

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	294.4	81.9	294.8	137.0	302.0	720.2	1,830.3
2012	644.2	99.5	583.8	145.2	460.4	1,354.3	3,287.4
2013	796.1	213.4	780.5	202.9	593.7	2,075.6	4,662.2
2014	833.4	166.2	890.9	248.5	640.0	1,975.8	4,754.8
2015	937.3	126.3	876.9	211.4	568.2	1,919.1	4,639.2

Net (Alternative Minus Baseline)

Output – Direct Effect

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	307.7	117.9	601.0	213.6	398.2	1,327.2	2,965.6
2012	718.7	174.6	1,456.5	248.7	777.2	3,089.6	6,465.3
2013	895.4	320.0	1,924.4	343.1	997.8	4,380.0	8,860.7
2014	986.8	285.6	2,421.9	409.9	1,175.9	4,850.3	10,130.4
2015	1,133.0	245.2	2,582.1	334.7	1,162.1	5,149.3	10,606.4

Output – Indirect Effect

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	132.7	36.1	99.8	57.0	159.9	243.0	728.5
2012	247.0	41.1	167.7	60.1	218.3	420.7	1,154.9
2013	298.1	93.1	226.8	84.1	282.2	666.4	1,650.7
2014	264.7	69.3	233.5	103.1	289.2	592.7	1,552.5
2015	275.4	50.3	207.5	87.9	239.2	548.9	1,409.2

Output – Induced Effect

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	100.9	27.4	76.0	39.0	118.9	160.0	522.2
2012	187.8	31.2	127.6	41.1	162.4	276.9	827.0
2013	226.7	70.6	172.6	57.5	209.9	438.7	1,176.0
2014	201.2	52.6	177.7	70.6	215.1	390.2	1,107.4
2015	209.4	38.1	157.9	60.1	177.9	361.3	1,004.7

Output – Total Effect

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	541.3	181.4	776.8	309.6	677.0	1,730.2	4,216.3
2012	1,153.5	246.9	1,751.8	349.9	1,157.9	3,787.2	8,447.2
2013	1,420.2	483.7	2,323.8	484.7	1,489.9	5,485.1	11,687.4
2014	1,452.7	407.5	2,833.1	583.6	1,680.2	5,833.2	12,790.3
2015	1,617.8	333.6	2,947.5	482.7	1,579.2	6,059.5	13,020.3

Severance and Ad Valorem Taxes, $ millions

Baseline

Production associated with same total number new leases and permits – Average 2009/2010

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	$52	$47	$572	$50	$59	$505	$1,284
2012	59	53	672	59	73	574	1,490
2013	63	53	694	55	74	586	1,525
2014	65	50	723	53	74	599	1,565
2015	71	50	751	49	75	625	1,623
Average	**$62**	**$51**	**$682**	**$53**	**$71**	**$578**	**$1,497**

Alternative

Production associated with same total number new leases and permits – Average 2007/2008

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	$54	$49	$598	$53	$61	$527	$1,344
2012	67	60	750	64	82	650	1,673
2013	73	62	797	62	85	682	1,761
2014	80	61	863	61	90	729	1,883
2015	90	61	910	55	92	776	1,984
Average	**$73**	**$59**	**$784**	**$59**	**$82**	**$673**	**$1,729**

Net (Alternative Minus Baseline)

Increase in production relative to amount associated with baseline number of leases and permits issued

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	$ 2	$ 3	$ 26	$ 3	$ 3	$ 22	$ 59
2012	$ 8	$ 7	$ 78	$ 5	$ 9	$ 75	$ 183
2013	$ 11	$ 9	$ 103	$ 7	$ 12	$ 95	$ 236
2014	$ 15	$ 11	$ 140	$ 8	$ 15	$ 130	$ 319
2015	$ 19	$ 11	$ 159	$ 6	$ 17	$ 151	$ 362
Average	**$ 11**	**$ 8**	**$ 101**	**$ 6**	**$ 11**	**$ 95**	**$ 232**

Federal royalties of production of oil, natural gas, and NGLs, $ millions

Baseline

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	179.6	52.4	720.6	68.2	260.7	1,052.6	2,334.1
2012	201.6	59.7	846.2	80.9	326.8	1,195.9	2,711.1
2013	215.6	59.3	876.1	75.2	328.1	1,222.0	2,776.4
2014	224.5	56.3	913.6	72.4	331.4	1,248.9	2,847.0
2015	245.6	56.6	950.5	67.3	336.6	1,304.0	2,960.6

Alternative

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	186.9	55.6	752.5	72.9	273.5	1,098.2	2,439.6
2012	229.5	67.3	944.1	88.1	367.1	1,352.1	3,048.2
2013	252.0	69.2	1,004.1	84.8	379.5	1,419.4	3,209.0
2014	275.5	68.3	1,088.9	83.1	399.0	1,517.5	3,432.3
2015	309.1	68.9	1,149.1	75.0	411.1	1,617.0	3,630.2

Net (Alternative Minus Baseline)

Year	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming	Total
2011	7.3	3.2	31.9	4.6	12.8	45.6	105.5
2012	27.9	7.6	97.9	7.2	40.2	156.3	337.1
2013	36.4	9.9	127.9	9.6	51.4	197.4	432.6
2014	51.0	11.9	175.3	10.7	67.6	268.6	585.2
2015	63.4	12.3	198.6	7.7	74.5	313.0	669.6

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JANUARY 2012

energy API

AMERICAN PETROLEUM INSTITUTE

Energy Security

"Richard Nixon talked about freeing ourselves from dependence on foreign oil. And every president since that time has talked about freeing ourselves from dependence on foreign oil. Politicians of every stripe have promised energy independence, but that promise has so far gone unmet."

– President Barack Obama
March 2011[1]

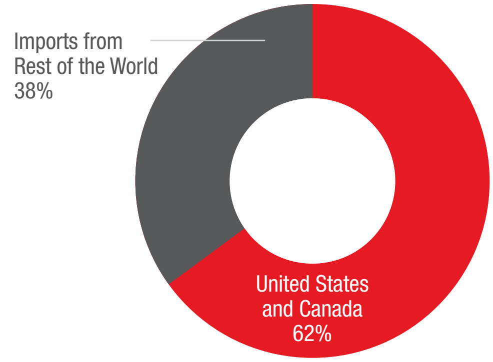
With current global uncertainty and turmoil in oil and natural gas producing regions, America needs to regain control of its energy future by increasing oil and natural gas production here at home. Greater domestic production provides U.S. families and businesses a buffer against supply disruptions, and the oil and natural gas industry's ability to reliably provide these supplies is fundamental to U.S. national and energy security.

Within 12 years, American and Canadian energy supplies could provide 100 percent of U.S. liquid fuel needs with increased biofuels development and the implementation of four straightforward policies:

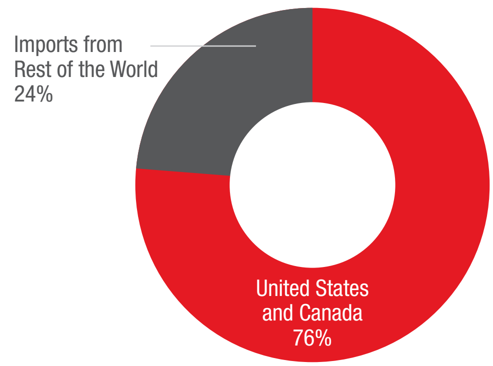
- Providing access to U.S. oil and natural gas reserves that are currently off-limits;
- Returning the Gulf of Mexico permitting rates to pre-moratorium levels, at a minimum;
- Resisting calls for imposition of unnecessary new regulatory requirements on oil and natural gas development; and
- Partnering with Canada to develop new pipeline capacity to export Canadian crude to the United States, including approval of the Keystone XL pipeline.[2]

Despite the potential benefits and numerous polls showing the majority of Americans support increased access to domestic oil and natural gas resources, many policies currently delay or outright prohibit resource development through a slow permitting pace, uncertainty caused by proposals for burdensome tax increases and costly and redundant regulations.[3] America needs public policy decisions today that bring long-term supply and stability to the marketplace.

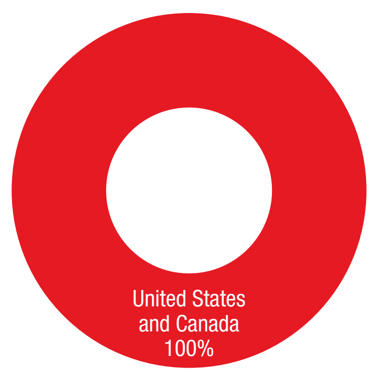
U.S. Liquid Fuel Supply – 2010



U.S. Projected Liquid Fuel Supply – 2024
Current Policy



U.S. Potential Liquid Fuel Supply – 2024
Expanded Access Policy



Source: API calculations based on EIA data and Wood Mackenzie, "U.S. Supply Forecast and Potential Jobs and Economic Impacts (2012-2030)," September 7, 2011.

[1] Press Release, "Remarks by the President on America's Energy Security," Office of the White House Press Secretary, March 30, 2011. Available at: http://www.whitehouse.gov/the-press-office/2011/03/30/remarks-president-americas-energy-security.

[2] API calculations based on EIA data and Wood Mackenzie, "U.S. Supply Forecast and Potential Jobs and Economic Impacts (2012 – 2030)," September 7, 2011.

[3] Saad, Lydia, "U.S. Oil Drilling Gains Favor with Americans; Support for offshore drilling and oil exploration in Alaska reach new highs," *Gallup*, March 14, 2011. Available at: http://www.gallup.com/poll/146615/Oil-Drilling-Gains-Favor-Americans.aspx.

EIA FORECAST	2010	2015	2020	2024	2025	2030
mb/d						
U.S. Production	8.93	9.49	10.44	10.26	10.16	9.96
Biofuels	1.00	1.24	1.61	1.87	1.97	2.55
Canada	1.97	2.24	2.49	2.63	2.64	2.88
Rest of World	7.32	6.26	4.94	4.73	4.74	4.34
U.S. Liquid Fuel Supply	19.22	19.23	19.49	19.49	19.51	19.74
Percentages	2010	2015	2020	2024	2025	2030
U.S. Production	*46%*	*49%*	*54%*	*53%*	*52%*	*50%*
Biofuels	*5%*	*6%*	*8%*	*10%*	*10%*	*13%*
Canada	*10%*	*12%*	*13%*	*13%*	*14%*	*15%*
Rest of World	*38%*	*33%*	*25%*	*24%*	*24%*	*22%*
U.S. Liquid Fuel Supply	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*

Source: EIA, AEO2012 Early Release, January 2012

POTENTIAL	2010	2015	2020	2024	2025	2030
mb/d						
U.S. Production + access	8.93	9.36	11.87	14.32	14.90	16.26
Biofuels	1.00	1.24	1.61	1.87	1.97	2.55
Canada + pipeline	1.97	2.94	3.32	3.46	3.47	3.71
Rest of World	7.32	5.69	2.69	-0.16	-0.83	-2.79
Total	19.22	19.23	19.49	19.49	19.51	19.74
Percentages	2010	2015	2020	2024	2025	2030
U.S. Production + access	*46%*	*49%*	*61%*	*73%*	*76%*	*82%*
Biofuels	*5%*	*6%*	*8%*	*10%*	*10%*	*13%*
Canada + pipeline	*10%*	*15%*	*17%*	*18%*	*18%*	*19%*
Rest of World	*38%*	*30%*	*14%*	*-1%*	*-4%*	*-14%*
Total	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*

Sources: EIA, AEO2012 Early Release, January 2012; WoodMackenzie, "U.S. Supply Forecast and Potential Jobs and Economic Impacts (2012-2030)," September 7, 2011.
State Dept XL Estimate 830,000 bpd

Two Keys to Security

1. **Access:** Allowing access to oil and natural gas resources currently off-limits as well as returning to historical levels of development on existing U.S. producing areas, would increase U.S. crude oil production by nearly 1.4 million barrels per day by 2020 and 6.3 million barrels per day by 2030.

2. **Canadian oil sands pipeline expansion:** State Department approval of the Keystone XL pipeline expansion could initially bring an extra 700,000 barrels per day to the U.S. and up to 830,000 barrels per day within the decade.

— State of —
North Dakota
Office of the Governor
Jack Dalrymple
Governor

February 8, 2012

The Honorable Ken Salazar
Secretary
U.S. Department of the Interior
1849 C Street, N.W.
Washington DC 20240

Dear Secretary Salazar;

I am writing to express my concern with the Bureau of Land Management's (BLM) decision to persist with rules and regulations for hydraulic fracturing (HF) activities on federal lands.

As you are aware, North Dakota currently regulates HF on state, federal, and private lands. According to draft regulations we have seen, your agency plans to look at three key issues pertaining to the HF process: wellbore integrity, disclosure, and flowback water. I know of no incidents on public lands in North Dakota that would precipitate federal regulation redundant with our state procedures managed by the North Dakota Industrial Commission.

Oil and natural gas operators seeking permits to drill on public lands already undergo an extensive environmental regulatory process before they can begin drilling activities – a process that has become lengthy, time consuming, and costly. In addition, North Dakota is currently permitting wells and managing the environmental risks associated with oil and natural gas production. I believe additional regulations regarding these issues are unnecessary and redundant in an area that is already effectively regulated by the states.

Similarly, disclosure of HF chemicals used on public lands is already underway. North Dakota has recently updated its HF rules, including new standards for disclosure. We have been successfully regulating wellbore integrity and other aspects of the drilling and completions process for decades.

The Environmental Protection Agency, as well as other federal agencies, are currently conducting scientific studies of HF. BLM regulation is premature in advance of the EPA study, and BLM has offered no justification for proceeding with new regulations without the benefit of these studies. Without a clear demonstration of inadequacy in the states' regulatory systems, along with an opportunity for the states to respond to any identified deficiencies, the states should not be expected to accept federal usurpation of state regulation.

According to the BLM, HF is used in more than ninety percent of oil and gas wells drilled on public lands. Oil and natural gas royalties from drilling on public lands are a significant revenue source for the federal government, the Tribes and North Dakota, and additional burdens for development on public lands could have the adverse effect of forcing operators to shift investment away from public lands, thus depriving the government of needed revenue.

A significant effect in North Dakota would fall on the 484,000 acres of trust lands managed for the Three Affiliated Tribes and individual allottees on the Fort Berthold Reservation. After many years of economic hardships, the Tribe and its members are finally seeing employment opportunities and economic development due to the oil activity on the reservation. New BLM rules on hydraulic fracturing would disproportionately impact the Tribe due to its greater reliance on oil development for economic growth.

For these reasons, I respectfully request that BLM not move forward at this time with the development of rules for HF on public lands.

Sincerely,

Jack Dalrymple

Jack Dalrymple
Governor

37:74:58

State of Utah

Gary R. Herbert
Governor

Office of the Governor
Salt Lake City, Utah
84114-2220

Greg Bell
Lieutenant Governor

February 29, 2012

The Honorable Ken Salazar
Secretary
United States Department of the Interior
1849 C Street, N.W.
Washington, D.C. 20240

Dear Secretary Salazar:

I am writing to express the concern of the State of Utah regarding the draft rule proposed by the Bureau of Land Management (BLM) to unnecessarily regulate hydraulic fracturing of oil and gas wells, commonly referred to as "fracking", on BLM-managed lands in the western United States, and to request you to direct the BLM to reconsider and reject the need for new regulatory requirements in this arena.

Hydraulic fracturing is not a new technology, but a process that has been responsibly used for over 60 years. The process has been a standard and routinely employed technique used to initiate and restimulate production from over one million wells. Over these years, state regulation assured the integrity of well operations, and state and federal revenues have benefitted greatly from the important production that followed. The proposed rule would add a redundant, burdensome and costly layer of federal approval for routine oil and gas operations on federal public lands, and threatens to usurp state authority in a field already well-managed by state regulators.

The process to receive approval to drill and produce an oil or gas well in the Western States is very complex and time consuming for federal agencies. During the approval process initiated by an Application for Permit to Drill (APD), operators must juggle BLM and state regulatory approval processes for many environmental and operational integrity requirements, including well-bore safety, blow-out prevention, production rates designed to maximize recovery of the resource, construction and work-over timing related to the needs of various species, and the like. Operators must compete for expensive and scarce field equipment, such as drill and workover rigs, and need to plan to minimize the idle time of such equipment. Operators report they often will complete six to eight workover well-stimulation processes a week.

The draft rule released by BLM would add a new regulatory requirement for BLM approval for any proposed well stimulation programs at least 30 days prior to beginning any such program, and to disclose the composition of all materials used downhole in the operation. Although the draft rule currently speaks only to well operations subsequent to initial well completion, the engineering techniques involving fluids down the wellbore are the same at initial completion.

Importantly, this new approval requirement would be separate from, and in addition to, the BLM's APD process. Operators are already experiencing an eight month delay between application and approval, compared with a 30-day state approval time for non-federal lands. The proposed regulation will simply add to the BLM's work burden, and delay the work, either at the APD or later operation, with no significant environmental benefit in return. In addition, it is very common for operators to adjust the composition of the fluids in the wellbore during a single workover operation. The new regulations would not allow for this flexibility without significant delay.

In terms of the materials used in the operation, industry, under careful state regulatory review, has already moved to voluntarily disclose these materials. As an example, FracFocus, a national online registry created by the Groundwater Protection Council and the Interstate Oil and Gas Compact Commission, is already in place, allowing companies to disclose the materials used in the hydraulic fracturing process. The Secretary of Energy Advisory Board Subcommittee on Natural Gas, in its report dated November 10, 2001, recommended the Department of Interior use FracFocus as its disclosure instrument. This is a clear example of voluntary measures eliminating the need for additional federal regulation.

I also ask you to consider whether the proposed regulation is antithetical to President Obama's remarks in the 2012 State of the Union address, promising a commitment to "take every possible action to safely develop" domestic natural gas. Because hydraulic fracturing has been safely used for decades in the responsible development of oil and gas in this nation, and the proposed regulation does nothing but add unnecessary red tape, decrease investment and jobs in rural western states, and increase the amount of energy the United States imports from foreign energy sources, we are hard-pressed to understand how the draft regulation supports the President's statement.

I hope you will reconsider this proposed regulation, reject it as an unnecessary burden on the operations of the industry with no benefit in return, and direct the BLM to cease consideration of the proposed regulation any further. Secretary, I appreciate your consideration. Please feel free to contact me to discuss this critical matter.

Sincerely,

Gary R Herbert

Gary R. Herbert
Governor

Cc: Congressman Rob Bishop
Congressman Jim Matheson
Congressman Jason Chaffetz
Senator Orrin Hatch
Senator Mike Lee
Bob Abbey, Bureau of Land Management Director
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Water Management Associated with Hydraulic Fracturing

API GUIDANCE DOCUMENT HF2
FIRST EDITION, JUNE 2010

AMERICAN PETROLEUM INSTITUTE

Water Management Associated with Hydraulic Fracturing

Upstream Segment

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Contents

Executive Summary

Hydraulic fracturing has played an important role in the development of America's oil and gas resources for nearly 60 years. In the U.S., an estimated 35,000 wells are hydraulically fractured annually and it is estimated that over one million wells have been hydraulically fractured since the first well in the late 1940s. As production from conventional oil and gas fields continues to mature and the shift to non-conventional resources increases, the importance of hydraulic fracturing will also increase.

The purpose of this guidance document is to identify and describe many of the current industry best practices used to minimize environmental impacts associated with the acquisition, use, management, treatment, and disposal of water and other fluids associated with the process of hydraulic fracturing. This document focuses primarily on issues associated with the water used for purposes of hydraulic fracturing and does not address other water management issues and considerations associated with oil and gas exploration, drilling, and production. It complements two other API Documents; one (API Guidance Document HF1, *Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines*, First Edition, October 2009) focused on groundwater protection related to drilling and hydraulic fracturing operations, [1] which specifically highlights recommended practices for well construction and integrity of hydraulically fractured wells, and the second (API Guidance Document HF3, *Surface Environmental Considerations Associated with Hydraulic Fracturing*, publication pending, but expected in 2nd Quarter of 2010) focused on surface environmental issues associated with the hydraulic fracturing process. [2]

This document provides guidance and highlights many of the key considerations to minimize environmental and societal impacts associated with the acquisition, use, management, treatment, and disposal of water and other fluids used in the hydraulic fracturing process, including the following.

1) Operators should engage in proactive communication with local water planning agencies to ensure oil and gas operations do not constrain the resource requirements of local communities and to ensure compliance with all regulatory requirements. Understanding local water needs may help in the development of water storage and management plans that will be acceptable to the communities neighboring oil and gas operations. Also, this proactive communication will help operators in understanding the preferred sources of water to be used for hydraulic fracturing by the local planning agency.

2) Basin-wide hydraulic fracturing planning can be beneficial upon an operator's entry into a new operating area or basin, depending on the scale of the planned operations. The planning effort may include a review of potential water resources and wastewater management opportunities that could be used to support hydraulic fracturing operations. This review should consider the anticipated volumes of water required for basin-wide fracturing in addition to other water requirements for exploration and production operations. Operators should continue to engage local water planning agencies when developing their hydraulic fracturing programs and consider a broad spectrum of competing water requirements and constraints, such as: location and timing of water withdrawal; water source; water transport; fluid handling and storage requirements; flow back water treatment/disposal options; and potential for water recycling.

3) Upon initial development, planning and resource extraction of a new basin, operators should review the available information describing water quality characteristics (surface and groundwater) in the area and, if necessary, proactively work with state and local regulators to assess the baseline characteristics of local groundwater and surface water bodies. Depending on the level of industry involvement in an area, this type of activity may be best handled by a regional industry association, joint industry project, or compact. On a site specific basis, pre-drilling surface and groundwater sampling/analysis should be considered as a means to provide a better understanding of on-site water quality before drilling and hydraulic fracturing operations are initiated.

4) In evaluating potential water sources for hydraulic fracturing programs, an operator's decision will depend upon volume requirements, regulatory and physical availability, competing uses, discussions with local planning agencies, and characteristics of the formation to be fractured (including water quality and compatibility

considerations). A hierarchy of potential sources should be developed based upon local conditions. Where feasible, priority should be assigned to the use of wastewater from other industrial facilities.

5) If water supplies are to be obtained from surface water sources, operators should consider potential issues associated with the timing and location of withdrawals, being cognizant of sensitive watersheds, historical droughts and low flow periods during the year. Operators should also be mindful of periods of the year in which activities such as irrigation and other community and industrial needs place additional demands on local water availability. Additional considerations may include: potential to maintain a stream's designated best use; potential impacts to downstream wetlands and end-users; potential impacts to fish and wildlife; potential aquifer depletion; and any mitigation measures necessary to prevent transfer of invasive species from one surface water body to another.

6) If water supplies are to be obtained from groundwater sources, operators should consider the use of non-potable water where feasible and possible. Using water from such sources may alleviate issues associated with competition for publicly utilized water resources. Alternatively, the use of non-potable water may increase the depth of drilling necessary to reach such resources, and/or the level of treatment necessary to meet specifications for hydraulic fracturing operations.

7) On a regional basis, Operators should typically consider the evaluation of waste management and disposal practices for fluids within their hydraulic fracturing program. This documented evaluation should include information about flow back water characterization and disposition, including consideration of the preferred transport method from the well pad (i.e. truck or piping). Operators should review and evaluate practices regarding waste management and disposal from the process of hydraulic fracturing, including: The preferred disposition (e.g. treatment facility, disposal well, potential reuse, centralized surface impoundment or centralized tank facility) for the basin; treatment capabilities and permit requirements for proposed treatment facilities or disposal wells; and the location, construction and operational information for proposed centralized flow back impoundments.

8) When considering preferred transport options, Operators should assess requirements and constraints associated with fluid transport. Transportation of water to and from a well site may significantly impact both the cost of drilling and operating a well. Alternative strategies should be considered to minimize this expense in addition to potential environmental or social impacts.

9) Operators developing a transportation plan within their hydraulic fracturing program should consider estimated truck volumes within a basin, designation of appropriate off road parking/staging areas, and approved transportation routes. Measures to reduce or mitigate the impacts of transporting large volumes of fracture fluids should be considered. Developing and implementing a detailed fluid transport strategy, as well as working collaboratively with local law enforcement, community leaders and area residents, can aid in enhancing safety and reducing potential impacts.

10) In developing plans for hydraulic fracturing, Operators should strive to minimize the use of additives. When necessary, Operators should assess the feasibility of using more environmentally benign additives. This action could help with addressing concerns associated with fracture fluid management, treatment, and disposal. While desirable, elimination or substitution of an alternative additive is not always feasible as the performance may not provide the same effectiveness as more traditional constituents.

11) Operators should make it a priority to evaluate potential opportunities for beneficial reuse of flow back and produced fluids from hydraulic fracturing, prior to treating for surface discharge or reinjection. Water reuse and/or recycling can be a key enabler to large scale future development. Pursuing this option, however, requires planning and knowledge of chemical additives likely to be used in hydraulic fracturing operations and the general composition of flow back and produced water. Reuse and/or recycling practices require the selection of compatible additives, with focused efforts on the use of environmentally benign constituents that do not impede water treatment initiatives. The wise selection of additives may enhance the quantity of fluids available and provide more options for ultimate use and/or disposal.

Water Management Associated with Hydraulic Fracturing

1 Scope

The purpose of this guidance document is to identify and describe many of the current industry best practices used to minimize environmental and societal impacts associated with the acquisition, use, management, treatment, and disposal of water and other fluids associated with the process of hydraulic fracturing. While this document focuses primarily on issues associated with hydraulic fracturing pursued in deep shale gas development, it also describes the important distinctions related to hydraulic fracturing in other applications.

Moreover, this guidance document focuses on areas associated with the water used for purposes of hydraulic fracturing, and does not address other water management issues and considerations associated with oil and gas exploration, drilling, and production. These topics will be addressed in future API documents. [3]

2 Definitions

2.1
aquifer
A subsurface formation that is sufficiently permeable to conduct groundwater and to yield economically significant quantities of water to wells and springs.

2.2
basin
A closed geologic structure in which the beds dip toward a central location; the youngest rocks are at the center of a basin and are partly or completely ringed by progressively older rocks.

2.3
casing
Steel piping positioned in a wellbore and cemented in place to prevent the soil or rock from caving in. It also serves to isolate fluids, such as water, gas, and oil, from the surrounding geologic formations.

2.4
coal bed methane/coal bed natural gas
CBM/CBNG
A clean-burning natural gas found deep inside and around coal seams. The gas has an affinity to coal and is held in place by pressure from groundwater. CBNG is produced by drilling a wellbore into the coal seam(s), pumping out large volumes of groundwater to reduce the hydrostatic pressure, allowing the gas to dissociate from the coal and flow to the surface.

2.5
completion
The activities and methods to prepare a well for production and following drilling. Includes installation of equipment for production from a gas well.

2.6
disposal well
A well which injects produced water into an underground formation for disposal.

2.7
directional drilling
The technique of drilling at an angle from a surface location to reach a target formation not located directly underneath the well pad.

2.8
flow back
The fracture fluids that return to surface after a hydraulic fracture is completed.

2.9
formation (geologic)
A rock body distinguishable from other rock bodies and useful for mapping or description. Formations may be combined into groups or subdivided into members.

2.10
fracturing fluids
A mixture of water, proppant (often sand), and additives used to hydraulically induce cracks in the target formation.

2.11
gelling agent
Chemical compounds used to enhance the viscosity and increase the amount of proppant a fracturing fluid can carry.

2.12
groundwater
Subsurface water that is in the zone of saturation; source of water for wells, seepage, and springs. The top surface of the groundwater is the "water table."

2.13
horizontal drilling
A drilling procedure in which the wellbore is drilled vertically to a kickoff depth above the target formation and then angled through a wide 90° arc such that the producing portion of the well extends horizontally through the target formation.

2.14
hydraulic fracturing
Injecting fracturing fluids into the target formation at a force exceeding the parting pressure of the rock thus inducing fractures through which oil or natural gas can flow to the wellbore.

2.15
hydrocarbons
Any of numerous organic compounds, such methane (the primarily component of natural gas), that contain only carbon and hydrogen.

2.16
hydrostatic pressure:
The pressure exerted by a fluid at rest due to its inherent physical properties and the amount of pressure being exerted on it from outside forces.

2.17
injection well
A well used to inject fluids into an underground formation either for enhanced recovery or disposal.

2.18
naturally occurring radioactive material
NORM
Low-level, radioactive material that naturally exists in native materials.

2.19
original gas in place
The entire volume of gas contained in the reservoir, regardless of the ability to produce it.

2.20
perforations
The holes created between the casing and liner into the reservoir (subsurface hydrocarbon bearing formation). These holes create the mechanism by which fluid can flow from the reservoir to the inside of the casing, through which oil or gas is produced.

2.21
permeability
A rock's capacity to transmit a fluid; dependent upon the size and shape of pores and interconnecting pore throats. A rock may have significant porosity (many microscopic pores) but have low permeability if the pores are not interconnected. Permeability may also exist or be enhanced through fractures that connect the pores.

2.22
porosity
The voids or openings in a rock, generally defined as the ratio of the volume of all the pores in a geologic formation to the volume of the entire formation.

2.23
primacy
A right that can be granted to state by the federal government that allows state agencies to implement programs with federal oversight. Usually, the states develop their own set of regulations. By statute, states may adopt their own standards, however, these must be at least as protective as the federal standards they replace, and may be even more protective in order to address local conditions. Once these state programs are approved by the relevant federal agency (usually the EPA), the state then has primacy jurisdiction.

2.24
produced water
Any of the many types of water produced from oil and gas wells.

2.25
propping agents/proppant
Silica sand or other particles pumped into a formation during a hydraulic fracturing operation to keep fractures open and maintain permeability.

2.26
reclamation
Rehabilitation of a disturbed area to make it acceptable for designated uses. This normally involves regarding, replacement of topsoil, revegetation, and other work necessary to restore it.

2.27
reservoir
Subsurface hydrocarbon bearing formation.

2.28
shale gas
Natural gas produced from low permeability shale formations.

2.29
slick water
A water based fluid mixed with friction reducing agents, commonly potassium chloride.

2.30
solid waste
Any solid, semi-solid, liquid, or contained gaseous material that is intended for disposal.

2.31
stimulation
Any of several processes used to enhance near wellbore permeability and reservoir permeability, including hydraulic fracturing

2.32
tight gas
Natural gas trapped in a hard rock, sandstone, or limestone formation that is relatively impermeable.

2.33
total dissolved solids
TDS
The dry weight of dissolved material, organic and inorganic, contained in water and usually expressed in parts per million.

2.34
underground injection control program
UIC
A program administered by the Environmental Protection Agency, primacy state, or Indian tribe under the Safe Drinking Water Act to ensure that subsurface emplacement of fluids does not endanger underground sources of drinking water.

2.35
underground source of drinking water
USDW

Defined in 40 *CFR* Section 144.3, as follows: "An aquifer or its portion:

(a) (1) Which supplies any public water system; or

(2) Which contains a sufficient quantity of groundwater to supply a public water system;

and

(i) Currently supplies drinking water for human consumption; or

(ii) Contains fewer than 10,000 mg/l total dissolved solids; and

(b) Which is not an exempted aquifer."

2.36
water quality
The chemical, physical, and biological characteristics of water with respect to its suitability for a particular use.

2.37
watershed
All lands which are enclosed by a continuous hydrologic drainage divide and lay upslope from a specified point on a stream.

2.38
well completion
See **completion**.

3 Introduction and Overview

Hydraulic fracturing is a process involving the injection of fluids into a subsurface geologic formation containing oil and/or gas at a force sufficient to induce fractures through which oil or natural gas can flow to a producing wellbore (see Section 2).

Hydraulic fracturing has played an important role in the development of America's oil and gas resources for nearly 60 years. In the U.S., an estimated 35,000 wells are hydraulically fractured annually and it is estimated that over one million wells have been hydraulically fractured since the first well in the late 1940s. [4] As production from conventional oil and gas fields continues to mature and the shift to nonconventional resources increases, the importance of hydraulic fracturing will continue to escalate as new oil and gas supplies are developed from these precious resources. The escalating importance of these resources is a testament to America's increased reliance on natural gas supplies from unconventional resources such as gas shale, tight gas sands, and coal beds—all resources that generally require hydraulic fracturing to facilitate economically viable natural gas production. [5] In addition, advances in hydraulic fracturing have played a key role in the development of domestic oil reserves, such as those found in the Bakken shale in Montana and North Dakota. [6]

In fact, very few unconventional gas formations in the U.S. and throughout the world would be economically viable without the application of hydraulic fracturing. These very low permeability formations tend to have fine grains with few interconnected pores. Permeability is the measurement of a rock or formation's ability to transmit fluids. In order for natural gas to be produced from low permeability reservoirs, individual gas molecules must find their way through a tortuous path to the well. Single hydraulic fracture stimulation can increase the pathways for gas flow in a formation by several orders of magnitude. [7]

Water requirements for hydraulically fracturing a well may vary widely, but on average required two to four million gallons for deep unconventional shale reservoirs. While these water volumes may seem large, they generally represent a very small percentage of total water use in the areas where fracturing operations occur. [8] Water used for hydraulic fracturing operations can come from a variety of sources, including surface water bodies, municipal water supplies, groundwater, wastewater sources, or be recycled from other sources including previous hydraulic fracturing operations.

Obtaining the water necessary for use in hydraulic fracturing operations can be challenging in some areas, particularly in arid regions. Water volumes required for hydraulic fracturing operations are progressively challenging operators to find new ways to secure reliable, affordable, supplies. In some areas, operators have opted to build large reservoirs to capture water during high runoff events on local rivers when withdrawal is permitted and monitored by water resource authorities, or for future use in storing fracture flow back water. Operators have also explored the option of using treated produced water from existing wells as a potential supply source for hydraulic fracturing operations. The implementation of these practices must conform to local regulatory requirements where operations occur.

The management and disposal of water after it is used for hydraulic fracturing operations may present additional challenges for operators. After a hydraulic fracture stimulation is complete, the fluids returning to the surface within the first seven to fourteen days (often called flow back) will often require treatment for beneficial reuse and/or recycling or be disposed of by injection. This water may contain dissolved constituents from the formation itself along with some of the fracturing fluid constituents initially pumped into the well.

State and local governments, along with the operating and service companies involved in hydraulic fracturing operations, seek to manage produced water in an effective manner that protects surface and groundwater resources while meeting performance specifications. Where possible, operating and service companies seek to reduce future demands on available water resources. Existing state oil and gas regulations are typically designed to protect water resources through the application of specific programmatic elements such as permitting, well construction, well plugging, and temporary abandonment requirements. In addition, state regulatory agencies are customarily charged with overseeing requirements associated with water acquisition, management, treatment, and disposal. [9]

As development of a producing area matures and additional wells are drilled, Operators acquire a better understanding of the hydrocarbon-bearing formation and surrounding geology. With this additional knowledge, drilling and completion techniques are refined and water use requirements for hydraulic fracturing operations become more predictable.

4 The Hydraulic Fracturing Process

4.1 General

Hydraulic fracturing is a well stimulation technique that has been employed in the oil and gas industry since the late 1940s. Hydraulic fracturing is intended to increase the exposed flow area of the productive formation and to connect this area to the well by creating a highly conductive path extending a carefully planned distance outward from the well bore into the targeted hydrocarbon-bearing formation, so that hydrocarbons can flow easily to the well. [10]

4.2 Hydraulic Fracture Stimulation Design

The design of a hydraulic fracture stimulation takes into consideration the type of geologic formation, anticipated well spacing, and the selection of proppant material. Other considerations include the formation temperature and pressure, length of the productive interval to be fractured, reservoir depth, formation rock properties, and the type of fracture fluid available. Long productive intervals may require the hydraulic fracture stimulation to be pumped in several cycles or stages. Each stage of the process is made up of different fluid mixtures that are pumped sequentially with the objective of creating and propagating the hydraulic fracture and placing the proppant. As a matter of course, it takes less than eight hours to pump one stage of a fracture stimulation and some wells may require many stages. Nonetheless, this is a relatively short time period when considering the 30-plus year life expectancy for most gas wells in low permeability formations.

4.3 Hydraulic Fracturing Process

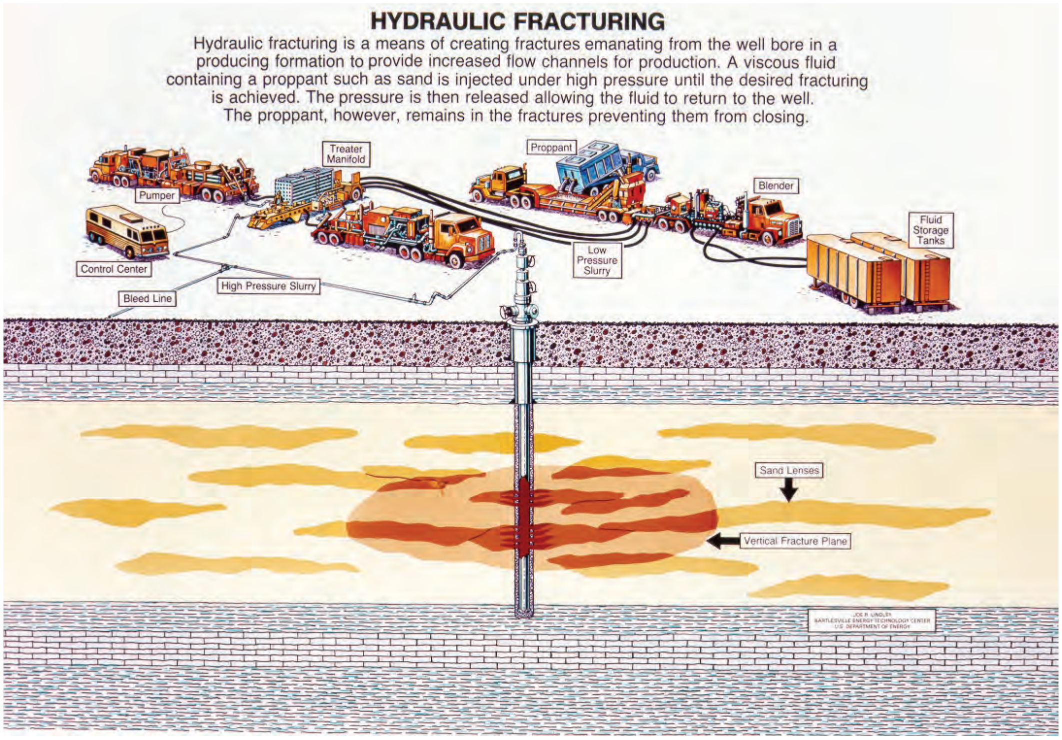
The process of hydraulic fracturing involves pumping a mixture of water, with small amounts of additives at high pressure into the targeted hydrocarbon formation (see Figure 1 and Figure 2). Sometimes gases like nitrogen or carbon dioxide are added to the mixture. Usually the proppant is sand, but other essentially inert materials are used. During the process, narrow cracks (fractures) expand outward from the perforations that serve as flowing channels for natural gas and/or other hydrocarbons trapped in the formation to move to the wellbore. The main “frac” can have small branches connected to it. The placement of proppant keeps the newly created fractures from closing.

Hydraulic fracturing begins with a transport fluid pumped into the production casing through the perforations and into the targeted formation at a sufficient rate and pressure to initiate a fracture; i.e. to crack the rock. This is known as “breaking down” the formation and is followed by a fluid “pad” that widens and extends the defined fracture within the target formation up to several hundred feet from the wellbore. The expansion of the fractures depends on the reservoir and rock properties, boundaries above and below the target zone, the rate at which the fluid is pumped, the total volume of fluid pumped, and the viscosity of the fluid.

In the late 1990s, a technology known as “slickwater fracturing” refined the hydraulic fracturing process to primarily enhance the stimulation of shale formations. Slickwater fractures may also be more economically viable, as fewer additives (which are a factor in the cost of a hydraulic fracture stimulation, [11,12]) are likely required.

4.4 Chemicals Used in Hydraulic Fracturing

Water is the primary component for most hydraulic fracture treatments, representing the vast majority of the total volume of fluid injected during fracturing operations. The proppant is the next largest constituent. Proppant is a granular material, usually sand, which is mixed with the fracture fluids to hold or prop open the fractures that allow gas and water to flow to the well. Proppant materials are selected based on the strength needed to hold the fracture open after the job is completed while maintaining the desired fracture conductivity.



Source: U.S. Department of Energy (http://www.netl.doe.gov/technologies/oil-gas/publications/eordrawings/Color/colhf.pdf)

Figure 1—Schematic Representation of a Hydraulic Fracturing Operation

In addition to water and proppant other additives are essential to successful fracture stimulation. The chemical additives used in the process of hydraulic fracturing typically represent less than 1 % of the volume of the fluid pumped (99 % sand and water) during a "hydraulic fracture treatment" and in many cases can be even less (see Figure 3). [13]

Chemical additives may consist of acids, surfactants, biocides, bactericides, pH stabilizers, gel breakers, in addition to both clay and iron inhibitors along with corrosion and scale inhibitors. Many of these additives are chemicals generally found in common household and food products, clothing, and makeup with an excellent track record of safe use. [14] While a small number of potential fracture fluid additives (such as benzene, ethylene glycol and naphthalene) have been linked to negative health affects at certain exposure levels outside of fracturing operations, these are seldom used and/or used in very small quantities. Most additives contained in fracture fluids present very low risks to human health and the environment. [15] These additives, along with the characteristics of water in the formation being fractured, can often dictate the water management and disposal options that will be technically feasible. [16]

The fracturing fluid is a carefully formulated product. Service providers vary the design of the fluid based on the characteristics of the reservoir formation and specified operator objectives. The composition of the fracturing fluid will vary by basin, contractor, and well. Situation-specific challenges that must be addressed include scale buildup, bacteria growth, proppant transport, iron content, along with fluid stability and breakdown requirements. Addressing each of these criteria may require specific additives to achieve the desired well performance; however, not all wells require each category of additives. Furthermore, while there are many different formulas for each type of additive, usually only one or a few of each category is required at any particular time. A typical fracture fluid will generally include four to six additives, but could require more or less.

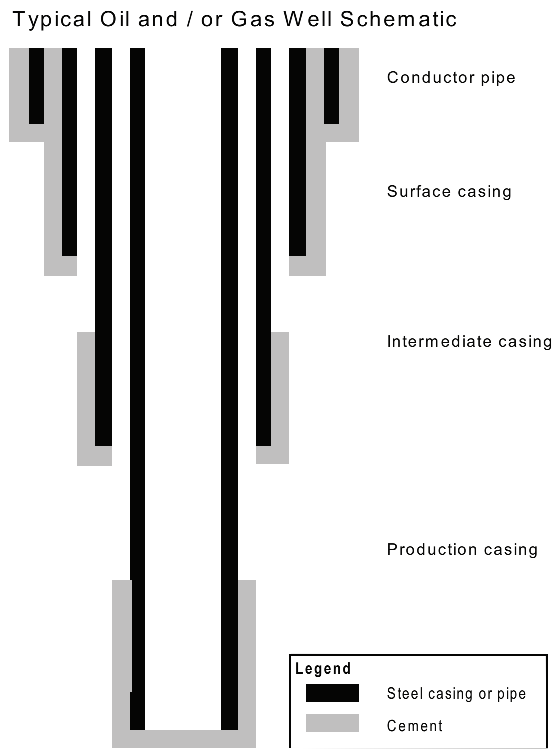
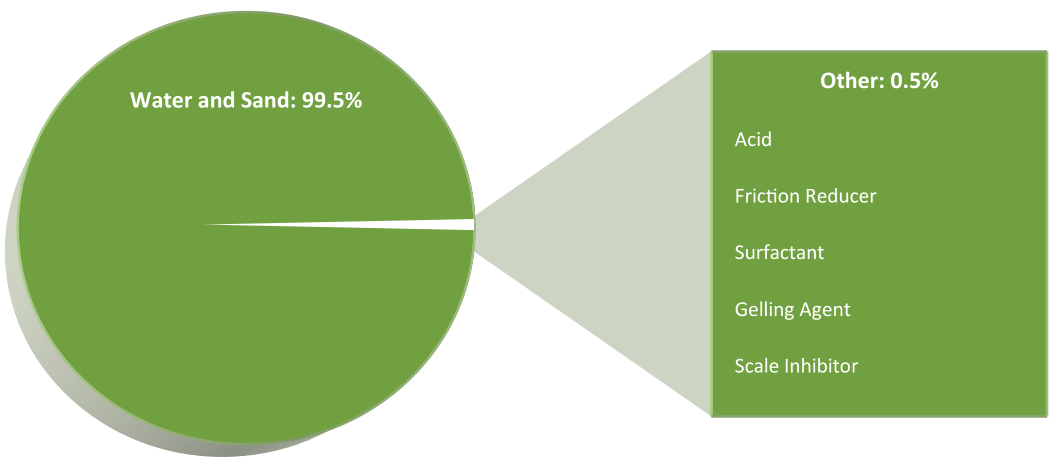


Figure 2—Schematic Representation of Hydraulically Fractured Reservoir From a Horizontal and Vertical Well



Source: Chesapeake Energy Corporation, 2009

Figure 3—Typical Fracture Fluid Composition for Hydraulic Fracturing for a Shale Gas Well

5 Water Use and Management Associated with Hydraulic Fracturing

5.1 General

Hydraulic fracturing operations require the temporary installation and use of surface water storage equipment, chemical storage, mixers, pumps, and other equipment at the well site. Additives are normally delivered in a concentrated (solid or liquid) form, in sealed sacks, tanks, or other containers (see Figure 4). Water is delivered in tanker trucks or via dedicated waterlines. The water may arrive over a period of days or weeks and may be stored on site in tanks or lined pits. Blending of the fracture fluid generally occurs as pumping of the fracture stimulation is underway, so that there is no lengthy on site storage of pre-mixed fracturing fluid. Finally, upon completion of the fracturing operation, recovered fracture fluids in the flow back water must be separated, contained, treated, disposed of, and/or reused.

5.2 Planning Considerations

Considerations associated with water acquisition, use, and management in hydraulic fracturing operations can be categorized in the following different phases.

— Source Water Acquisition—Where will the water supplies needed for hydraulic fracturing operations be acquired?

— Transport—How does the water get from the source to the well site and from the well site to the point of treatment and/or disposal?

Source: Chesapeake Energy Corporation, 2008

Figure 4—Hydraulic Fracturing Well Site for a Marcellus Shale Well

— Storage—What requirements and constraints exist for water storage on site, and how do source water considerations and fracture fluid requirements affect storage requirements?

— Use—How will the water be used, what volume is required, and what must be done (e.g. the addition of proppant and additives) to achieve the fracturing objectives?

— Treatment and Reuse/Recycle—Can the water produced from the fracturing operation be treated and recycled for reuse?

— Treatment and Disposal—If the water is not to be recycled and or reused, what must be done either prior to disposal or with any treatment byproducts?

Regulatory requirements often dictate water management options. These include federal, state and local regulatory authorities. Along with these regulatory authorities, multi-state and regional water permitting agencies may also be responsible for maintaining water quality and supply, such as the Susquehanna River Basin Commission (SRBC) [17] and/or the Delaware River Basin Commission (DRBC), [18] all authorities may dictate water withdrawal and/or disposal options that are available for consideration and use.

Injection wells that may be used for disposal of flow back water and other produced waters are classified as Class IID in EPA's Underground Injection Control (UIC) program [19] and require state or federal permits. The primary objective of the UIC program, whether administered at the state or federal level, is protection of underground sources of drinking water (USDWs) (see 2.35).

In many cases, the responsible authority is a function of the acquisition or disposal option chosen. For example, surface water discharge may be regulated by a different agency than subsurface injection. Therefore, regardless of the regulatory agency with UIC program authority over subsurface injection, new injection wells will require a permit that meets the appropriate state or federal regulatory requirements.

A report prepared for the U.S. Department of Energy provides a comprehensive, practical guide of state oil and gas regulations designed to protect water resources. [20]

5.3 Water Management Drivers

5.3.1 Fluid Requirements for Successful Fracturing

The primary factor influencing water management and disposal associated with hydraulic fracturing relates to the fluid requirements for a successful fracturing operation. All phases of water management ultimately depend on the requirements the frac fluid properties need for fracturing success. These requirements are the result of the geology, the operating environment, the frac design, the scale of the development process, and the results required for total project success.

The first step in understanding the management of water for hydraulic fracturing involves asking the question: "What does the reservoir rock need, and what will the rock give back after fracturing?" The choice of the fracturing fluid dictates the frac design and what types of fracturing fluids and additives are required. The choice of the frac fluid dictates the fate and transport of fracturing fluids used in fracturing operations, and how the recovered fluids will need to be managed and disposed. [21]

Modern hydraulic fracturing practices are sophisticated, engineered, processes designed to create single fractures or multiple fractures in specific rock strata. These hydraulic fracture treatments are controlled and monitored processes designed for site specific conditions of the reservoir (see Figure 5). These conditions are based on the target product (natural gas or crude oil), the target formation properties and rock fracturing characteristics, the formation water characteristics (e.g. some coalbed methane formations are classified as USDWs), the anticipated water production (formation water vs fracturing flow back water), and the type of well drilled (horizontal or vertical).

Source: Advanced Resources International, Inc. (2009)

Figure 5—Control Room Monitoring a Hydraulic Fracture Stimulation

Understanding the in-situ reservoir conditions is critical to successful stimulations, and in the design of the fracture treatment and fluid used. Hydraulic fracturing designs are continually refined, both during the fracture stimulation itself, as well as over time as more about fracturing the target formation is learned from experience. Thus, while the concepts and general practices are similar, the details of a specific fracture operation can vary substantially from resource to resource, from area to area, from operator to operator, and even from well to well.

The ideal properties of a fracturing fluid relate to its compatibility with the formation rock; its compatibility with the formation fluids; its ability to transfer enough pressure throughout the entire fracture to create a wide fracture, and be able to transport the proppant into the fracture, while breaking back down to a low viscosity fluid for cleanup after the treatment. Finally, and most importantly, the fracture treatment must meet necessary performance specifications.

5.3.2 Factors Influencing Fracturing Fluid Composition

As described in 4.4, there are a wide variety of additives that could be included in the fracturing fluid mix to achieve successful fracturing. These could include proppants, gel and foaming agents, salts, acids, and other fluid additives. Today, operators and service companies are working to maximize the utilization of environmentally benign additives and minimize the amount of additives required.

The characteristics of the resource target determine the required fracture fluid composition. For example, gas shale's may contain various naturally occurring trace metals and compounds that are leached from rocks by acidic water, oxidation, and the action of ions found in brines. Numerous compounds have been formed naturally in the shale, and a stimulation fluid pumped into a well may require various chemicals to counteract any negative effects these compounds may have in the well or the reservoir. Iron compounds found within the Fayetteville shale require an iron sequestering agent so that the compounds of iron will not precipitate out of the fracturing fluid and be deposited within the pore spaces of the reservoir, reducing the reservoir's permeability.

In the Marcellus shale, iron control agents are generally not necessary, but strontium and barium compounds can be present in the flow back water. Strontium and barium scales have very little solubility to the acids that would be used in an attempt to clean up any scale that occurred in the wellbore or the reservoir. Specialized scale inhibitors are thus necessary within the fracturing fluids to eliminate any chance of these scale compounds precipitating out of solution before, during, or after a stimulation job.

Recently developed shale-specific surfactants, combined with friction reducers, have improved the recovery and flow back of stimulation water in shale by improving the inhibition of swelling tendencies of clays that are present in the rock, lowering the resistance to flow in these typically low-pressure reservoirs. The Fayetteville shale is successfully fractured using a cross-linked gel system in very low concentrations with a surfactant, corrosion and scale inhibitors, iron and pH control, biocide, acid and sand. The Huron shale of Kentucky is stimulated using nitrogen and sand or light weight proppant as the major element of the fracturing fluid formulation.

For dry shales or those shale reservoirs that contain clays, making them particularly sensitive to contact with fresh water, foam fracturing—the use of foam as the carrier for the propping agent applied under high pressure—has been the predominant method used for stimulation. Such techniques have been employed for over 30 years and the foam application continues to be the method of choice. Nitrogen or carbon dioxide gas has also been used when fracturing dry shale reservoirs in many basins in the U.S., but success has been limited to relatively shallow shale formations that are very brittle.

5.3.3 Fluid Requirements to Minimize Environmental Concerns

When developing hydraulic fracturing plans, in addition to considerations associated with successfully fracturing the target formations, operators should carefully consider the fluid management and disposal implications of their fracture fluid formulations. The best practice is to use additives that pose minimal risk of possible adverse human health effects to the extent possible in delivering needed fracture effectiveness. While desirable, this type of product substitution is not currently possible in all situations, since effective alternatives are not available for all additives.

6 Obtaining Water Supply For Hydraulic Fracturing

6.1 General

A significant part of a hydraulic fracturing operation involves securing access to reliable sources of water, the timing associated with this accessibility, and the requirements for obtaining permission to secure these supplies. When investigating potential options for securing water supplies to support hydraulic fracturing operations, awareness of competing water needs, water management issues, and the full range of permitting and regulatory requirements in a region is critical. Consultation with appropriate water management agencies is a must, if not required, since they have top level responsibility for the management (including permitting) and protection of water resources.

Proactive communication with local water planning agencies, and the public where appropriate, should be pursued to ensure that oil and gas operations do not disrupt local community water needs. Understanding local water needs can help in the development of water acquisition and management plans that will be acceptable to the communities neighboring oil and gas developments. Although the water needed for drilling and fracturing operations may represent a small volume relative to other requirements, withdrawals associated with large-scale developments, conducted over multiple years, may have a cumulative impact to watersheds and/or groundwater. This potential cumulative impact can be minimized or avoided by working with local water resource managers to develop a plan of when and where withdrawals will occur.

Operators should conduct a detailed, documented review of the identified water sources available in an area that could be used to support hydraulic fracturing operations. Considerations factoring in this review should include:

— evaluating source water requirements,

— fluid handling and storage,

— transportation considerations.

Each of these factors is considered in more detail in 6.2, 6.3 and 6.4.

6.2 Evaluating Source Water Requirements

In evaluating water requirements for hydraulic fracturing, the operator should conduct a comprehensive evaluation of cumulative water demand on a programmatic basis, as well as the timing of these needs at an individual well site. This should include consideration of the water requirements for drilling operations, dust suppression, and emergency response, along with the water requirements for hydraulic fracturing operations. The operator must determine whether or not the sources of water are adequate to support the total operation, with water of the desired quality, and can be accessed when needed for the planned development program.

Specifically, water supply options for hydraulic fracturing will depend on the amount of water that will be required, in aggregate, for the broader, long-term, area-wide development program anticipated. Water sources will need to be appropriate for the forecasted pace and level of development anticipated.

Water for hydraulic fracturing may be obtained from:

1) surface water,

2) groundwater,

3) municipal water suppliers,

4) treated wastewater from municipal and industrial treatment facilities,

5) power plant cooling water, and/or

6) recycled produced water and/or flow back water.

The choice will depend upon volume and water quality requirements, regulatory and physical availability, competing uses, and characteristics of the formation to be fractured (including water quality and compatibility considerations). If possible, wastewater from other industrial facilities should be considered, followed by ground and surface water sources (with the preference over non-potable sources over potable sources), with the least desirable (at least for long-term, large scale development) being municipal water supplies. However, this will depend on local conditions and the availability of ground and surface water resources in proximity to planned operations.

Importantly, not all options may be available for all situations, and the order of preferences can vary from area to area. Moreover, for water sources such as industrial wastewater, power plant cooling water, or recycled flow back water and/or produced water, additional treatment may be required prior to use for fracturing, which may not be possible or feasible and may not deliver the results necessary to assure project success.

Particular issues of concern associated with each of the categories of potential water sources are discussed in more detail in 6.2.1 through 6.2.6.

6.2.1 Surface Water

Many areas draw their principal water supplies from surface water sources, so the large-scale use of this source for hydraulic fracturing operations can possibly impact other competing uses and will be of concern to local water management authorities and other public officials. In some circumstances there will be a need to identify water supply sources capable of meeting the needs for drilling and fracturing water that do not compete or interfere with community needs and other existing uses.

Important considerations in evaluating water supply requirements from surface water sources include the volume of water supplies required, as well as the sequence and scheduling of acquiring these supplies. Withdrawal from surface water bodies, such as rivers, streams, lakes, natural ponds, private stock ponds, etc., may require permits from state or multi-state regulatory agencies, as well as landowner permission. In some regions, water rights are also a key consideration.[22] In addition, water quality standards and regulations established by these regulatory authorities may prohibit any alteration in flow that would impair a fresh surface water body's highest priority use, which is often defined by local water management authorities. Also consideration should be given to ensure Moreover, water withdrawals during periods of low stream flow do not affect fish and other aquatic life, fishing and other recreational activities, municipal water supplies, and other industrial facilities, such as power plants.

Water withdrawal permits can require compliance with specific metering, monitoring, reporting, record keeping, and other consumptive use requirements, which could include specifications for the minimum quantity of water that must pass a specific point downstream of the water intake in order for a withdrawal to occur. In the case where stream flow is less than the prescribed minimum quantity, withdrawals may be required to be reduced or cease.

The operator should consider the issues associated with the timing and location of withdrawals since impacted watersheds may be sensitive, especially in drought years, during low flow periods during the years, or during periods of the year when activities such as irrigation place additional demands on the surface supply of water. In making requests for surface water withdrawal, operators should consider the following potential impacts that could control the timing and volume available:

— ownership, allocation, or appropriation of existing water resources;

— water volume available for other needs, including public water supply;

— degradation of a stream's designated best use;

— impacts to downstream habitats and users;

— impacts to fish and wildlife;

— aquifer volume diminishment;

— mitigation measures to prevent transfer of invasive species from one surface water body to another (as a result of water withdrawal and subsequent discharge into another surface water body).

State, regional, or local water management authorities may request that the operator identify the source of water to be used for supplying hydraulic fracturing operations, and provide information about any newly proposed surface water source that has not been previously approved for use. Information that must be supplied could include the withdrawal location and the size of the upstream drainage area and available stream gauge data, along with demonstration of compliance relative to stream flow standards. For obtaining approval and/or maintaining a good relationship with regulatory bodies, local communities, and other stake-holders it is obvious that requests for water withdrawals from sensitive watersheds should be carefully considered for their wider impact.

Finally, in some jurisdictions, a variety of permits may be required for the transport of water via pipes, canals or streams; as well as by tanker truck. Moreover, equipment or structures used for surface water withdrawal, such as standpipes, may also require permits.

One alternative that could be considered and that may be acceptable to local water management authorities is water withdrawal programs that make use of seasonal changes in river flow, in order to capture water when surface water flows are greatest. This would likely involve the use of large-scale water diversion and storage impoundments (see Figure 6).

As described in more detail below, additional regulatory requirements are likely to be associated with such facilities. Diverting water to storage impoundments during periods of high flow allows withdrawals at a time of peak water availability which avoids impacts to municipal drinking water supplies or to aquatic or riparian communities. However, operators need to keep in mind that this approach will normally require the development of sufficient water storage capabilities to meet the overall requirements of drilling and hydraulic fracturing plans over the course of a season, year, or perhaps even over a multi-year period (to plan for possible periods of drought).

Another alternative to ensuring water supply is to use abandoned surface coal mining pits for the storage of water. Having more permanent facilities such as this may provide for the installation of a comprehensive water distribution system that can be matched to development plans. Of course, the water quality in such impoundments must meet with operational requirements and will likely vary depending on the nature of the exposed overburden present in such areas. Moreover, these pits must meet all regulatory requirements for such surface impoundments.

Another simple method that can be used is to excavate low lying areas and allow for rain water harvesting. The potential use of such a method requires planning as it may take a long time for the excavation to fill up, depending on precipitation conditions. This option should be discussed with state, regional, or local water management authorities to ensure compliance with stormwater runoff program elements.

Source: Little Red River Reservoir—Chesapeake Energy Corporation, 2008

Figure 6—Example of Diversion Pond Construction

6.2.2 Groundwater

Most regulatory programs with jurisdiction over oil and gas operations, have a strong focus on groundwater. Withdrawals from groundwater, especially USDWs, will almost always require permits from state or multi-state regulatory agencies.

Whenever practicable, operators should consider using non-potable water for drilling and hydraulic fracturing. Many of the concerns about water supply can be avoided if lower-quality groundwater sources, such as water with > 10,000 ppm total dissolved solids (TDS) are used. For example, in some cases, operators are using saline waters with up to 30,000 ppm, content as a water source for hydraulic fracturing where fresh water availability may be uncertain or limited. [23] However, this may require the drilling of source water wells that are deeper than publicly used potable water aquifers. Deeper water may contain additional constituents that could require treating, but it can alleviate issues of competition with publicly utilized water resources.

For example, domestic and municipal water wells in the Fort Worth Basin access the Upper Trinity aquifer to supply fresh water to the public. Operators working in the Barnett shale are drilling to the Lower Trinity aquifer to supply water for drilling and hydraulic fracturing. The Lower Trinity water has a higher TDS content that would not be suitable for domestic use without extensive water treatment. Again, in order to ensure that drilling deep into useable aquifers will not negatively impact the available freshwater zones, operators should consult with state, regional, or local water management authorities and consider undertaking a study to determine the feasibility of success in such areas.

Operators may need to address many of the same types of considerations for groundwater as for surface water. The primary concern regarding groundwater withdrawal is temporary aquifer volume diminishment. In some areas, the availability of fresh groundwater is limited, so withdrawal limitations could be imposed. Operators may be directed to other shallow alluvial aquifers from which they can withdraw groundwater. Louisiana, for example, has such requirements. [24]

Another groundwater protection consideration is locating water source wells for oil and gas operations at an appropriate distance from municipal, public, or private water supply wells. Again in consideration of hydrologic conditions, public or private water supply wells and fresh water springs within a defined distance of any proposed drilling location for a water supply well, including locations of other water supply wells, should be identified and their characteristics evaluated, both in terms of production capacity and water quality. Depending on the available data, this may include testing of the water currently available from these sources. This will require locating the public and private water wells and obtaining information about their depth, completed interval and use (including whether the well is public or private, community or non-community, and the type of facility or establishment if it is not a private residence). This information is normally available from state and local regulatory authorities, however direct contact with property owners and/or tenants may be appropriate if undocumented water wells are suspected. [25]

Guidance for groundwater protection related to well drilling and hydraulic fracturing operations are the subject of a separate API guidance document, [26] the purpose of which is to provide industry guidance for well construction and integrity for wells that will be hydraulically fractured. The objective is to ensure that USDWs and the environment will be protected, while delivering successful and effective fractures and overall successful projects. Specifically, maintaining well integrity is featured as the key design principle of all oil and gas production wells, which is essential for two primary reasons:

— to isolate the internal conduit of the well from the surface and subsurface environment,

— to isolate and contain the well’s produced fluid to a production conduit within the well.

6.2.3 Municipal Water Supplies

Obtaining water supplies from municipal water suppliers can be considered, but again, the water needs for fracturing would need to be balanced with other uses and community needs. This option might be limited, since some areas may be suffering from current water supply constraints, especially during periods of drought, so the long term reliability of supplies from municipal water suppliers needs to be carefully evaluated.

6.2.4 Wastewater and Power Plant Cooling Water

Other possible options for source water to support hydraulic fracturing operations that could be considered are municipal wastewater, industrial wastewater, and/or power plant cooling water. Clearly, the specifications of this water source need to be compatible with the target formation and the plan for fracturing as well as whether treating is technically possible and whether treatment can deliver an overall successful project. In some cases, required water specification could be achieved with the proper mixing of supplies from these sources with supplies from surface water or groundwater sources.

6.2.5 Reservoir Water and Recycled Flow Back Water

Produced reservoir water and recycled flow back water can be treated and reused for fracturing, depending on the quality of the water. Natural formation water has been in contact with the reservoir formation for millions of years and thus contains minerals native to the reservoir rock. Some of this formation water is recovered with the flow back water after hydraulic fracturing, so that both contribute to the characteristics of the flow back water. The salinity, TDS, and overall quality of this formation/flow back water mixture can vary by geologic basin and specific rock strata. For example, water salinity can range from brackish (5,000 parts per million (ppm) to 35,000 ppm TDS), to saline (35,000 ppm to 50,000 ppm TDS), to supersaturated brine (50,000 ppm to >200,000 ppm TDS). Other water quality characteristics that may influence water management options for fracturing operations include concentrations of hydrocarbons (analyzed as oil and grease), suspended solids, soluble organics, iron, calcium, magnesium, and trace constituents such as benzene, boron, silicates, and possibly other constituents.

Several efforts are underway to examine the conditions where the use of reservoir water and recycled flow back water for fracturing operations may be economically viable. [27] Typically, the water must be treated. This option is discussed in more detail elsewhere in this guidance document.

Some coalbed methane operations may also have discharge water that is appropriate for hydraulic fracturing use.

Finally, operators should be aware that black shales, as well as other formations that are often the target formations for hydraulic fracturing operations, sometimes contain trace levels of naturally occurring radioactive materials (NORM). Gamma ray logs indicate, for example, that this is true of the Marcellus shale. Gas wells can bring NORM to the surface in the cuttings, flow back fluid and production brine, and NORM can accumulate in pipes and tanks (pipe scale). NORM contained in the discharge of fracturing fluids or production brine may be subject to discharge limitations. The Environmental Sciences Division of Argonne National Laboratory has addressed exploration and production (E&P) NORM disposal options in detail and maintains a Drilling Waste Management Information System website [28] that links to regulatory agencies in all oil and gas producing states. API also has published several documents providing guidance on the management of NORM in oil and gas operations. [29]

6.2.6 Make-up Water Requirements, Availability and Quality

In situations where water is recycled and/or reused, or additional sources of industrial wastewater make some contribution to supply water for fracturing operations, additional make up water may be required. In these cases, water management alternatives to be considered will depend on the volume and quality of both the recycled water and the make up water, to ensure compatibility with each other and with the formation being fractured.

6.3 Fluid Handling And Storage Considerations

6.3.1 General

Fluids handled at the well site both before and after hydraulic fracturing often must be stored on site, and must be transported from the source of supply to the point of ultimate treatment and/or disposal. Fluids used for hydraulic fracturing will generally be stored onsite in tanks or lined surface impoundments. Returned fluids, or flow back, may also be directed to tanks or lined pits.

The volume of initial flow back water recovered during the first 30 days following the completion of hydraulic fracturing operations may account for less than 10 % to more than 70 % of the original fracture fluid volume. The vast majority of fracturing fluid injected is recovered in a very short period of time, of several hours up to a maximum of several months.

All components of fracture fluids, including water, additives and proppants, should be managed properly on site before, during, and after the fracturing process. Ideally, fracture fluid components should all be blended into the fluids used for fracturing only when needed. Any unused products should be removed from the location by the contractor or operator as appropriate. The job planning process should consider unexpected delays of the fracture operations and ensure that materials are properly managed.

While flow back fluids are a federally E&P exempt waste [i.e. exempt from hazardous waste requirements under the Resource Conservation and Recovery Act (RCRA)], they still need to be addressed under any applicable state regulations. In the unlikely event that small amounts of products used to fracture a well are accidentally leaked they may become RCRA managed waste. Any leak to the ground creates a waste that should be managed and disposed of properly in accordance with all rules, regulations, and permits.

The Material Safety Data Sheet (MSDS) for each additive should be obtained from the supplier or manufacturer, be reviewed prior to using the additive, and be readily available at the job site. The MSDS will contain information about proper storage, hazards to the environment, spill clean-up procedures and other information to minimize environmental impacts. Addressing these issues is the subject of other API documents. [30]

Operators may be required to provide information about their water management and storage operations at the site. Such information may include the following:

— information about the design and capacity of storage impoundments and/or tanks;

— information about the number, individual and total capacity of receiving tanks on the well pad for flow back water;

— description of planned public access restrictions, including physical barriers and distance to edge of well pad;

— how liners are to be placed to prevent possible leakage from such impoundments.

6.3.2 Storage in Surface Impoundments

If lined impoundments or pits are used for storage of fracture fluids or flow back water, the pits must comply with applicable rules, regulations, good industry practice, and liner specifications. However, it is important to recognize that storage impoundments containing fluids associated with fracturing operations will likely contain significantly larger volumes of fluids than from conventional operations. To enhance efficiency and limit the number of impounds, some operators are considering the use of centralized impoundments to manage flow backwater. Thus, these impoundments will be designed and constructed in such a manner as to provide structural integrity for the life of their operation. Proper design and installation is imperative to the objective of preventing a failure or unintended discharge.

All surface impoundments, including those used for storing fracture fluids, will be constructed in accordance with existing state and federal regulations. In some states, use of such an impoundment requires a prior authorization from the regulatory agency; and in some, a separate permit is required specifically for the pit’s explicit functional use. [31]

Depending upon the fluids being placed in the impoundment, the duration of the storage and the soil conditions, an impound lining may be necessary to prevent infiltration of fluids into the subsurface. In most states, pits must have a natural or artificial liner designed to prevent the downward movement of pit fluids into the subsurface. Pits used for long term storage of fluids should be placed an appropriate distance from surface water to prevent unlikely overflows from reaching the surface water.

In addition, to ensure the safe operation and maintenance of any impoundment, an inspection and maintenance plan should be followed.

Additional information may be required by regulatory authorities for centralized surface impoundments for fracture fluids. For such facilities, requirements may include an initial review of site topography, geology and hydrogeology, especially if such impoundments are within defined distances of a water reservoir; perennial or intermittent stream, wetland, storm drain, lake or pond, or a public or private water well or domestic supply spring.

6.3.3 Storage in Tanks

Many operators store fluids used in and produced from fracturing operations in steel tanks, in addition to or rather than earthen pits. These tanks must meet appropriate state and federal standards, which may be specific to the use of the tank (e.g. use for temporary tank flow back water or more permanent production tank batteries).

6.4 Transportation Considerations

Before fracturing, water, sand and any other additives are generally delivered separately to the well site, in accordance with Department of Transportation and state regulations. Water is generally delivered in tanker trucks that may arrive over a period of days or weeks, or via pipelines from a supply source or treatment/recycling facility.

Water supply and management approaches should take into consideration the requirements and constraints associated with fluid transport. Transportation of water to and from a well site can be a major expense and major activity. To manage the expense, improve efficiency, and limit other impacts, several strategies are used by operators.

Trucking costs can be the biggest part of the water management expense. One option to consider as an alternative to trucking is the use of temporary or permanent surface pipelines. Producers are increasingly turning to temporary surface pipelines to transport fresh water to impoundments and to well sites. However, in many situations, the transport of fluids associated with hydraulic fracturing by surface pipeline may not be practical, cost effective, or even feasible. [32]

The use of multi-well pads make the use of central water storage easier, reduces truck traffic, and allows for easier and centralized management of flow back water. In some cases it can enhance the option of pipeline transport of water.

In order to make truck transportation more efficient, cost effective and less impactful operators may want to consider constructing storage ponds and drilling source wells in cooperation with private property owners. The opportunity to help a private landowner by constructing or improving an existing pond, drilling a water well, and/or improving the roads on their property can be a win-win situation for the operator and the landowner. It provides close access for the operator to a water source, and adds improvements to the property that benefit the landowner.

Operators should also consider utilizing agricultural techniques to transport the water used near the water sources. Large diameter, aluminum agricultural pipe is sometimes used to move the fresh water from the source to locations within a few miles where drilling and hydraulic fracturing activities are occurring. Water use by the shale gas industry has spurred agricultural and field service companies to supply the temporary pipe, pumps, installation, and removal as a business pursuit in some areas.

When fracture fluids are transported by truck, operators should develop a basin-wide trucking plan that includes the estimated amount of trucking required, hours of operations, appropriate off road parking/staging areas, and routes. Considerations for the trucking plan for large volumes of fracture fluid include the following:

— seek public input on route selection to maximize efficient driving and public safety;

— avoidance of peak traffic hours, school bus hours, community events, and overnight quiet periods;

— coordination with local emergency management agencies and highway departments;

— upgrades and improvements to roads that will be traveled frequently to and from many different well sites;

— advance public notice of any necessary detours or road/lane closures;

— adequate off-road parking and delivery areas at the site.

7 Water Management And Disposal Associated With Hydraulic Fracturing

7.1 General

In general, well permits will specify that all fluids, including fracture fluids and flow back water, must be removed from the well site. In addition, any temporary storage pits used for fracturing fluids must be removed as part of reclamation.

Water used in the hydraulic fracturing process is usually managed and disposed of in one of three ways:

1) injected in permitted disposal wells under a UIC regulatory program;

2) delivered to water treatment facilities depending on permitting (in certain regions of the country, the water is actually treated to remove pollutants and achieve all regulated specifications and then surface discharged);

3) reused/recycled.

Disposal options are dependent on a variety of factors, including the availability of suitable injection zones and the possibility of obtaining permits for injection into these zones; the capacity of commercial and/or municipal water treatment facilities; and the ability of either operators or such plants to successfully obtain surface water discharge permits.

While treatment of produced fluids from some fracturing operations remains an option in some jurisdictions, requirements associated with the use of this option are likely to continue to become more stringent. [33] Operators should prepare for proper management and disposal of fluids associated with hydraulic fracturing operations. Considerations for fluid management should include ñ flow back water disposition, including the planned transport off of the well pad (truck or piping), and information about any proposed piping; planned disposition (e.g. treatment facility, disposal well, reuse, centralized surface impoundment or centralized tank facility); identification and permit numbers for any proposed treatment facility or disposal well, and the location and construction and operational information for any proposed centralized flow back water surface impoundment.

Operators should work proactively with state, regional and local regulators to ensure surface and groundwater quality is adequately described. This may include supporting regional sampling/analytical programs to provide general information. This information will provide a better understanding of regional and local water quality before extensive drilling and hydraulic fracturing are initiated, and will help inform the local community about existing groundwater quality. Operators should consider collecting additional site specific baseline water samples collected from public and private wells near planned operations, as well as from nearby surface water bodies prior to drilling specific wells if existing information is not adequate. The actual parameters to be tested will depend somewhat on site specific geology and hydrology. Testing parameters should include, but are not limited to TDS, total suspended solids (TSS), chlorides, carbonates, bicarbonates, sulfate, barium, strontium, arsenic, surfactants, methane, hydrogen sulfide, NORM, and benzene.

Primary potential destinations for flow back/production fluids generally include the following:

— injection wells, which are regulated under either a state or federal UIC program;

— municipal waste water treatment facilities;

— industrial waste treatment facilities;

— other industrial uses;

— fracture flow back water recycling/reuse.

Each of these is discussed in more detail in 7.2 through 7.6.

7.2 Injection Wells

Disposal of flow back fluids through injection, where an injection zone is available, is widely recognized as being environmentally sound, is well regulated, and has been proven effective. API has published several documents related to injection wells and subsurface disposal. [34] In order to handle the expected amount of water associated with large scale developments, additional injection wells in an area may need to be drilled and permitted.

Injection wells for disposal of brine associated with oil and gas operations are classified as Class IID in EPA's UIC program [35] and require state or federal permits. The primary objective of the UIC program, whether administered at the state or federal level, is protection of USDWs. Therefore, whether the EPA or the state regulatory agency has UIC program authority over subsurface injection, new injection wells will require an injection well permit that meets the appropriate state and/or federal regulatory requirements.

7.3 Municipal Waste Water Treatment Facilities

Municipal wastewater treatment plants or commercial treatment facilities could be available as a treatment and disposal option for fracture fluid flow back and/or other produced waters. However, the availability of municipal or commercial treatment plants may be limited to larger urban areas where treatment facilities with sufficient available capacity already exist. Moreover, as with underground injection, transportation to treatment facilities may or may not be practical.

Municipal sewage treatment facilities, often know as Publicly Owned Treatment Works (POTWs) must have a state-approved pretreatment program for accepting any industrial waste. POTWs generally must also notify appropriate regulatory authorities of any new industrial waste they plan to receive at their facility and certify that their facility is capable of treating the pollutants that are expected to be in that industrial waste. POTWs are generally required to perform certain analyses to ensure they can handle the waste without upsetting their system or causing a problem in the receiving water. Ultimately, approval is required of such analysis and modifications to the POTW's permits to ensure water quality standards in receiving waters are maintained at all times. Thus, the POTW may require that operators provide information pertaining to the chemical composition of the hydraulic fracturing additives in an effort to assist in this review.

7.4 Industrial Waste Treatment Facilities

Many operators believe that future disposal needs will unlikely be met by POTW's due to regulatory and other restrictions in the future. Thus, an alternative solution may be the construction of private or industry-owned treating facilities, perhaps built and operated by an industry cooperative or an environmental services company. In several regions, the evolving practice is to set up temporary treatment facilities located in active drilling development areas or to treat the waste stream onsite with mobile facilities. The temporary facilities can alleviate/reduce the trucking of waste streams by the use of transitory pipeline systems that serve local wells.

These facilities may need to be permitted by the appropriate local, state, and/or federal regulatory authorities. Permits for a dedicated treatment facility would include specific discharge limitations and monitoring requirements.

7.5 Other Industrial Uses

Other industrial uses for flow back water could also be considered, but will be highly dependent on site specific considerations, and some treatment would likely be required. One such example could be the use of the flow back water to support drilling operations. Another is the use of this water as source water for water flooding operations, where water is injected into a partially depleted oil reservoir to displace additional oil and increase recovery. Waterflood operations are regulated under state regulations and/or EPA's UIC Program. These authorities would review the proposed use of flow back fluids from hydraulic fracturing operations as a waterflood injectate. Often, water injection operations that are authorized by rule are required to submit an analysis of the injectate any time it changes; such operations are usually required to modify their permits to inject water from a new source.

7.6 Fracture Flow Back Water Recycling/Reuse

In some cases, it might be more practical to treat the water to a quality that could be reused for a subsequent hydraulic fracturing job, or other use, rather than treating to meet requirements for surface discharge. Consequently, operators should consider options for the recycling of fracture treatment flow back fluid. Water reuse/recycling can be a key enabler to large scale future developments that use fracturing. This is already being considered in some areas. This ability to reuse fracturing fluid will depend on the degree of treatment required and the volume of make up water necessary for reuse.

Options considered will depend on the rates and total water volumes to be treated, water constituents that need to be treated, their concentrations, their treatability, and water reuse or discharge requirements. The reuse of flow back water can provide a practical solution that overcomes many of the constraints imposed by limited source water supplies and difficult disposal situations.

For example, technological advancements from other water treating industries are being adapted to work with the high saline water that results from hydraulic fracturing and include reverse osmosis and membrane innovations. Distillation technology is in the process of refinement to improve the 75 % to 80 % treating effectiveness of the current return water. [36] However, distillation is also a very energy intensive process. It may only become an option for all operations with technological improvements to increase the treatment effectiveness and the overall efficiency of the process.

Pursuing this option requires careful planning and knowledge of the composition of the flow back water and/or the produced reservoir water. It requires proper chemical selection and design and additives that do not create major water treatment issues. Technology advances are making it more economical to treat these fluids with better results in water quality. The treatment of these fluids may greatly enhance the quantity of acceptable, reusable fluids and provide more options for ultimate disposal.

Such treatment facilities either could be run by operators, or could function as stand alone, independent commercial enterprises, as described previously.

A number of treatment approaches exist, and many others are being developed and modified to address the specific treatment needs of flow back water in different operating regions. [37,38,39,40] Processes that can be utilized for water treatment include but are not limited to filtration, aeration and sedimentation, biological treatment, demineralization, thermal distillation, condensation, reverse osmosis, [41] ionization, natural evaporation, freeze/thaw, crystallization, and ozonation.

This is by no means an exhaustive list, and new alternatives are continuously being considered and evaluated. Operators are encouraged to keep abreast of new developments in this field.

Given the complexity of hydraulic fracturing and flow back fluids, it is likely that multiple processes will be required in many, if not most cases. Obviously, key considerations are the performance and cost-effectiveness of the water treatment process along with the volume and environmental considerations associated with the resulting concentrate.

Additional information on the comparative performance of potential water treatment technologies could be obtained from the following websites:

— http://www.pe.tamu.edu/crisman/,

— http://foodprotein.tamu.edu/separations/index.php, and

— http://www.membrane.unsw.edu.au/.

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Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing

API GUIDANCE DOCUMENT HF3
FIRST EDITION, JANUARY 2011

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Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing

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Contents

Executive Summary

Hydraulic fracturing has played an important role in the development of America's oil and gas resources for nearly 60 years. In the U.S., an estimated 35,000 wells are hydraulically fractured annually and it is estimated that well over one million wells have been hydraulically fractured since the first well in the late 1940s. As production from conventional oil and gas fields continues to mature, the need for hydraulic fracturing becomes even more important to the economic recovery of non-conventional resources.

This guidance document identifies and describes best practices currently used in the oil and natural gas industry to minimize potential surface environmental impacts associated with hydraulic fracturing operations. It complements two other API documents: API Guidance Document HF1, *Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines*, First Edition, October 2009, which focuses on groundwater protection related to drilling and hydraulic fracturing operations [1] while specifically highlighting recommended practices for well construction and the integrity of hydraulically fractured wells, and API Guidance Document HF2, *Water Management Associated with Hydraulic Fracturing,* First Edition, June 2010 [2].

A fourth related guidance document, API 51R*, Environmental Protection for Onshore Oil and Gas Production Operations and Leases,* First Edition, July 2009 [3], addresses the design and construction of access roads and well locations prior to drilling, as well as site abandonment, reclamation and restoration operations, including produced water handling.

While hydraulic fracturing does not introduce new or unique environmental risks to exploration and production (E&P) operations, concerns have been raised due to the potential scale of operations where this technology is applied, especially with regard to emerging developments in shale gas in the United States. Many of the best practices for E&P operations are the same as those applicable to hydraulic fracturing operations.

Moreover, where shale gas development intersects with urban settings, regulators and the industry have developed special practices to alleviate potential nuisances and sensitive environmental resources impacts, along with interference with existing commercial activity. Operators need to be vigilant and proactive in mitigating potential environmental impacts from E&P operations, including hydraulic fracturing operations. The following provides highlights from this guidance document:

1) Operators must comply with all federal, state and local requirements. Approvals may be necessary for many activities including:

   — surface water use;

   — wastewater management;

   — injection activities;

   — site construction;

   — stormwater discharges;

   — air emissions; and

   — protection of sensitive areas.

2) Two principal reasons for recent concerns regarding hydraulic fracturing, especially as applied in the development of shale gas, are: the increase in well permitting in a number of regions in the U.S. and the new development activity in areas that have not experienced concentrated oil and gas development in the past. Consequently, operators should be cognizant of the increase in public scrutiny of fracturing operations, be

proactive in communicating to, and working with, communities and local regulatory authorities, and minimize, whenever possible, the impacts of their operations. For example, the use of multi-well pads when feasible, which can consolidate water storage, minimize overall footprint, reduce truck traffic and allow for centralized management of fluids.

3) Like all oil and gas E&P operations, before hydraulic fracturing operations are initiated, approvals from one or more government agencies are required. Operators must obtain all necessary permits before commencing operations, and ensure that operations comply with the requirements of local, state and federal regulatory authorities. Proactive engagement with surface owners and/or surface users to inform the owners about the operations prior to project initiation is also recommended. Upon initial development, planning and resource extraction of a new basin, operators should review the available information and, if necessary, assess the baseline characteristics.

4) To alleviate concerns associated with fracture fluid management, hydraulic fracturing operations should be planned and designed in a manner that manages materials and protects the environment. All components of fracture fluids, including water, additives and proppants, should be managed properly on site before, during and after the fracturing process. Both the operator and on-site contractors should require that all responsible personnel involved in the fracturing job and in pre- and post-fracture activities be trained in the transportation and handling of fluids, chemicals and other materials associated with the process. Personnel should be trained on the equipment to be used and the procedures to be implemented to prevent leaks and spills during fracturing operations.

5) State authorities must retain the ability to assess potential incident response needs and plan accordingly, with appropriate confidentiality protections. To balance the protection of trade secrets with the public's need to know, proprietary formulations should be disclosed upon request by designated state agency representatives and health professionals in the event of an emergency, or when designated state agency representatives and health professionals demonstrate a need to know such information.

6) Using hydraulic fracturing fluids in an environmentally safe way means that the base fluid and any additives are sourced, transported, prepared, pumped into the formation, returned from the formation, reused/recycled, and/or finally disposed of in a way that is fully compliant with all federal, state, and local regulations.

7) Surface impoundments, including those used for storing fracture fluids, must be constructed in accordance with existing regulations. Depending on the fluids being placed in the impoundment, the duration of the storage and the soil conditions, impoundment design and construction should be impervious to prevent infiltration of fluids into the subsurface. All surface impoundments must be properly closed in accordance with all local, state and/or federal regulations. Materials removed from impoundments should be reclaimed, recycled or disposed.

8) Fracture fluids should be managed according to federal and state regulations. Fracturing operations should be conducted in a manner that minimizes the potential for any unplanned release and movement beyond the site boundaries. Spill prevention, response and cleanup procedures should be in place prior to initiating activities that have a potential for a spill. The best way to avoid adverse effects of spills is to prevent their occurrence.

9) Hydraulic fracturing is a highly technical process performed by trained personnel. Equipment should be maintained, inspected and tested to assure proper operating integrity and reliability. Facilities and equipment should be kept clean, maintained and operated in a safe and environmentally sound manner. All leaks should be immediately contained and repairs initiated upon discovery—as safety permits. Any spill or leak should be addressed promptly and reported to the site manager for proper identification, management, cleanup and appropriate regulatory actions. It may be necessary to fence operations to prevent access to the facility by the general public, livestock or wildlife.

10) Public concerns relating to fracturing operations may be heightened by the location chosen for the well and the techniques used in constructing the access road and the overall site. To the extent practicable,

consideration for siting a well location might include visual impact of the operational layout; preservation of salient natural features such as natural terrain, trees, groves, waterways and other similar resources; and minimizing cut and fill operations.

11) Truck traffic creates additional concern in populated areas of development. Opportunities to reduce truck traffic might include use of flowlines to transport fluids. Where feasible, producers are increasingly turning to temporary surface flowlines to transport fresh water to impoundments and to wellsites. However, in many situations, the transport of fluids associated with hydraulic fracturing by surface pipeline may not be practical, cost effective or even feasible. Multi-well pads allow centralized water storage and management of flowback water, reducing truck transport. In some cases, it can also enhance the option of pipeline transport of water. Often, operators are able to construct storage ponds and drill source wells in cooperation with private property owners to provide close access to a water source and add improvements to the property that benefit the landowner.

Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing

1 Scope

The purpose of this guidance document is to identify and describe practices currently used in the oil and natural gas industry to minimize surface environmental impacts—potential impacts on surface water, soils, wildlife, other surface ecosystems and nearby communities—associated with hydraulic fracturing operations. While this document focuses primarily on issues associated with operations in deep shale gas developments, it also describes the important distinctions related to hydraulic fracturing in other applications.

2 Terms and Definitions

For the purposes of this document, the following definitions apply.

2.1
aquifer
A subsurface formation that is sufficiently permeable to conduct groundwater and to yield economically significant quantities of water to wells and springs.

2.2
basin
A closed geologic structure in which the beds dip toward a central location; the youngest rocks are at the center of a basin and are partly or completely ringed by progressively older rocks.

2.3
casing
Steel piping positioned in a wellbore and cemented in place to prevent the soil or rock from caving in. It also serves to isolate formations and water zones from production fluids, such as water, gas and oil, from the surrounding geologic formations.

2.4
completion
Following drilling, the activities and methods to prepare a well for production, including the installation of equipment to produce a well.

2.5
downhole
Located in a wellbore.

2.6
flowback
The fracture and produced fluids that return to surface after a hydraulic fracture is completed.

2.7
formation (geologic)
A rock body distinguishable from other rock bodies and useful for mapping or description. Formations may be combined into groups or subdivided into members.

2.8
fracturing fluids
A mixture of water, proppant (often sand) and additives used to hydraulically induce cracks in the target formation.

2.9
gelling agent
Chemical compounds used to enhance the viscosity and increase the amount of proppant a fracturing fluid can carry.

2.10
groundwater
Subsurface water (fresh or saline) that is in the zone of saturation; source of water for wells, seepage and springs. The top surface of the groundwater is the water table.

2.11
horizontal drilling
A drilling procedure in which the wellbore is drilled vertically to a kickoff depth above the target formation and then angled through a wide 90° arc such that the producing portion of the well extends horizontally through the target formation.

2.12
hydraulic fracturing
Injecting fracturing fluids into the target formation at a force exceeding the parting pressure of the rock, thus inducing fractures through which oil or natural gas can flow to the wellbore.

2.13
hydrocarbons
Any of numerous organic compounds, such as methane (the primarily component of natural gas), that contain only carbon and hydrogen.

2.14
original gas in place
The entire volume of gas contained in the reservoir, regardless of the ability to produce it.

2.15
perforations
The holes created from the wellbore into the reservoir (subsurface hydrocarbon-bearing formation). These holes create the mechanism by which fluid can flow from the reservoir to the inside of the casing, through which oil or gas is produced.

2.16
permeability
A rock's capacity to transmit a fluid; dependent upon the size and shape of pores and interconnecting pore throats. A rock may have significant porosity (many microscopic pores) but have low permeability if the pores are not interconnected. Permeability may also exist or be enhanced through fractures that connect the pores.

2.17
porosity
The voids or openings in a rock, generally defined as the ratio of the volume of all the pores in a geologic formation to the volume of the entire formation.

2.18
produced water
Any of the many types of water produced from oil and gas wells.

2.19
propping agents/proppant
Specifically sized silica sand or other manmade or naturally occurring particles pumped into a formation during a hydraulic fracturing operation to keep fractures open and maintain permeability.

2.20
reclamation
Restoration of a disturbed area to make it acceptable for designated uses. This normally involves regrading, replacement of topsoil and vegetation, and other work necessary to restore it.

2.21
reservoir
Subsurface hydrocarbon-bearing formation.

2.22
shale gas
Natural gas produced from low-permeability shale formations.

2.23
slickwater
A water-based fluid mixed with friction reducing agents, to reduce friction pressure during hydraulic fracturing operations.

2.24
solid waste
Any solid, semi-solid, liquid or contained gaseous material that is intended for disposal.

2.25
stimulation
Any of several processes used to enhance near-wellbore permeability and reservoir permeability, including hydraulic fracturing.

2.26
tight gas
Natural gas trapped in a hard rock, sandstone or limestone formation that is relatively impermeable.

2.27
total dissolved solids
TDS
The dry weight of dissolved elements, organic and inorganic, contained in water and usually expressed in parts per million.

2.28
underground source of drinking water
USDW
Defined in 40 *CFR* Section 144.3, as follows:

"An aquifer or its portion:

(a) (1) Which supplies any public water system; or

(2) Which contains a sufficient quantity of groundwater to supply a public water system;

and

(i) Currently supplies drinking water for human consumption; or

(ii) Contains fewer than 10,000 mg/l total dissolved solids; and

(iii) Which is not an exempted aquifer."

2.29
water quality
The chemical, physical and biological characteristics of water with respect to its suitability for a particular use.

2.30
watershed
All lands which are enclosed by a continuous hydrologic drainage divide and lay upslope from a specified point on a stream.

2.31
well completion
See **completion**.

3 Introduction and Overview

Hydraulic fracturing is the injection of fluids into a subsurface geologic formation containing oil and/or gas at a pressure sufficient to induce fractures through which oil or natural gas can flow to a producing wellbore.

Hydraulic fracturing has played an important role in the development of America's oil and gas resources for nearly 60 years. In the U.S., an estimated 35,000 wells are hydraulically fractured annually and it is estimated that more than one million wells have been hydraulically fractured since the first well in the late 1940s [4]. As production from conventional oil and gas fields continues to mature and the shift to non-conventional resources increases, the importance of hydraulic fracturing will continue to escalate as new oil and gas supplies are developed from these precious resources. The escalating importance of these resources is a testament to America's increased reliance on natural gas supplies from unconventional resources such as gas shale, tight gas sands and coal beds—all resources that generally require hydraulic fracturing to facilitate economically viable natural gas production [5]. In addition, advances in hydraulic fracturing have played a key role in the development of domestic oil reserves, such as those found in the Bakken formation in Montana and North Dakota [6].

In fact, very few unconventional gas formations in the U.S. and throughout the world would be economically viable without the application of horizontal drilling and hydraulic fracturing. These extremely low permeability formations tend to have fine grains with few interconnected pores. Permeability is the measurement of a rock or formation's ability to transmit fluids. In order for natural gas to be produced from low permeability reservoirs, individual gas molecules must find their way through a tortuous path to the well. Hydraulic fracture stimulation can increase the pathways for gas flow in a formation by several orders of magnitude [7].

Recently, natural gas production from gas-bearing shales in the U.S. has increased significantly, with hydraulic fracturing playing a key role. Some of this expansion has occurred in geographic regions with little to no history of oil and gas development. While the use of hydraulic fracturing itself has not introduced any new or unique environmental concerns associated with oil and gas development, as shale gas development has occurred in new areas, new challenges have been encountered, and increased focus has been given to address community concerns.

For example, communities may be especially sensitive to the surface footprint left by expanded oil and natural gas development. In response, operators should consider the advantages of multi-well pad development and horizontal well fracturing. Compared to drilling vertical wells with single hydraulic fractures, multi-well pad drilling and fracturing horizontal wells from one location can significantly reduce surface disturbance and the potential for surface-related impacts. Horizontal drilling has the advantages of requiring substantially fewer well pads and reducing surface disturbances, while providing for a comparable volume of production.

Where shale gas development has intersected with urban settings, regulators and industry have developed special practices to alleviate nuisance impacts, impacts to sensitive environmental resources and interference with existing commercial activity. Examples of such practices in the Dallas/Fort Worth area include establishing set-backs of buildings and construction at specific distances from the natural gas wellbore; establishment of buffer zones around drill sites next to protected use areas; limiting gas well drilling to only certain identified property; and requiring approval of both a local Specific Use Permit and a Gas Well Permit.

Nonetheless, this increase in attention and focus on hydraulic fracturing requires operators to pursue such practices with renewed focus and diligence, as set forth in this guidance document.

4 Stakeholder Engagement

One way to address many of the concerns associated with hydraulic fracturing operations is through proactive engagement by operators with regulators and surface owners. Collaboration between the industry, regulators, and the public have resulted in positive solutions for the environment.

Similar to all oil and gas E&P operations, before hydraulic fracturing operations are initiated, approvals from one or more (primarily state) government agencies may be required for a series of activities, including surface water use, wastewater management, injection activities, site construction, stormwater discharges, air emissions and protection of sensitive areas. Operators must obtain all necessary permits before commencing operations, and verify that operations are conducted in accordance with the requirements of all local, state and federal regulatory authorities. Proactive consultation with the appropriate regulatory authorities can help greatly in ensuring local considerations are addressed and the appropriate permits are provided as expeditiously as possible.

Proactive engagement with surface owners and/or surface users before fracturing operations are initiated may foster understanding and alleviate concerns. It is recommended that the operator communicate with land owners or surface users concerning activities planned for the site and measures to be taken for safety, protection of the environment and minimizing impacts to surface uses. Additional recommendations may be found in API 51R [3], Annex A—*Good Neighbor Guidelines*. Operators of federal oil and gas leases under private surface ownership are encouraged to consult the BLM publication, *Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development* ("Gold Book"), for BLM guidance with respect to communication and recommended practices to address concerns of surface owners [8].

The footprint of hydraulic fracturing operations can vary depending on the operator's equipment and operational needs, and the mutual objectives established by the operator, appropriate regulatory agencies and the owner of the surface rights.

Upon initial development, planning and resource extraction of a new basin, operators should review the available information describing water quality characteristics (surface and groundwater) in the area and, if necessary, proactively work with state and local regulators to assess the baseline characteristics of local groundwater and surface water bodies, Depending on the level of industry involvement in an area, this type of activity may be best handled by a regional industry association, joint industry project, or compact. On a site specific basis, pre-drilling surface and groundwater sampling/analysis should be considered as a means to provide a better understanding of on-site water quality before drilling and hydraulic fracturing operations are initiated.

5 Wide-scale Development

One of the principal reasons for the rise in concerns regarding hydraulic fracturing operations, especially as applied to gas shale development, is the increase in the number of wells being permitted throughout several regions in the U.S. In addition, many communities are experiencing new development activity where there has been no concentrated oil and natural gas development in the past. This has caused regulatory authorities in several states to re-evaluate their regulatory schemes to verify that their rules are appropriate for the heightened level and broader geographic extent of development activity. Furthermore, as the level and extent of drilling activity has increased, so has the public concern for the health, safety and welfare of neighboring communities.

Consequently, operators should be cognizant of the increase in public scrutiny and be proactive in communicating to, and working with, communities and regulatory authorities to minimize impacts from hydraulic fracturing operations.

Several examples of the ways the oil and natural gas industry is currently working collaboratively to inform its members on best practices, working cooperatively with regulatory agencies and other stakeholders to promote best practices, and reaching out to local communities about these practices include:

— Barnett Shale Energy Education Council (BSEEC). The BSEEC is a community resource that provides information to the public about natural gas drilling and production in the Barnett shale region. The goal of BSEEC is to provide information and answers to questions regarding the opportunities and issues related to urban drilling in the Barnett shale. The BSEEC also works on promoting best practices in operations, community relations and other issues important to the communities they serve [9].

— Barnett Shale Water Conservation and Management Committee. Similarly, a consortium of energy companies formed the Barnett Shale Water Conservation and Management Committee to study the industry's water use in the Barnett shale and to discuss conservation and water management techniques to help conserve freshwater resources.

— Marcellus Shale Coalition (MSC). The MSC was founded in 2008 as an organization committed to the responsible development of natural gas from the Marcellus shale in Pennsylvania and the enhancement of the Commonwealth's economy that can be realized by this clean-burning energy source. The members of the coalition work together to address concerns with regulators, government officials and the people of the Commonwealth about all aspects of drilling and extracting natural gas from the Marcellus shale formation.

— State Review of Oil and Natural Gas Environmental Regulations (STRONGER). This organization was formed in 1999 to reinvigorate and carry forward the state review process begun cooperatively in 1988 by the U.S. Environmental Protection Agency (EPA) and the Interstate Oil and Gas Compact Commission (IOGCC). STRONGER is a non-profit, multi-stakeholder organization whose purpose is to assist states in documenting the environmental regulations associated with the exploration, development and production of crude oil and natural gas. STONGER shares innovative techniques and environmental protection strategies and identifies opportunities for program improvement. The state review process is a non-regulatory program and relies on states to volunteer for reviews.

— Environmentally Friendly Drilling (EFD). Industry has made great strides in protecting the environment while increasing oil and natural gas production in the U.S. The objective of EFD is to identify, develop and test innovative technologies that reduce the environmental impact of oil and gas activities in environmentally sensitive areas, should these areas be opened up for development. The program continues to add participants from environmental organizations, academia, state and federal agencies, government laboratories and industry. Currently, more than 100 organizations support this effort in a variety of ways, including providing grants and other financial assistance. The partnership identifies new technologies and transfers them to areas that must incorporate new practices to address environmental concerns. Regional partners optimize technologies to fit the needs of their locale. Partners routinely come together to discuss progress with the sponsors/advisors.

— The National Petroleum Council (NPC). The sole purpose of the NPC is to represent the views of the oil and natural gas industry in advising, informing and making recommendations to the Secretary of Energy with respect to any matter relating to oil and natural gas. The NPC is chartered by the Secretary of Energy under the provisions of the Federal Advisory Committee Act of 1972. In selecting the membership, special attention is given by the Secretary to assure a well-balanced representation from all segments of the oil and gas industry, from all sections of the country, and from large and small companies. The Council also has members with interests outside of oil or gas operations, including representatives from academic, financial, research, Native American and public interest organizations and institutions.

Operators are encouraged to participate in regional and national organizations and partnerships to keep abreast of best practices, to learn about local environmental issues and concerns, and to communicate with stakeholders. In areas of the country where such organizations are not readily accessible, operators are encouraged to establish such groups.

6 Selection of Hydraulic Fracturing Fluids

The design of a hydraulic fracture job and fracture fluid composition takes into consideration the type of geologic formation, anticipated well spacing and proppant requirements. Other considerations include the formation temperature and pressure, compatibility with the formation lithology and fluid (oil, gas, water, etc.), the productive interval to be fractured, reservoir depth, formation and underlying/overlying rock properties, fluids within the formation and other site-specific considerations.

Water is the primary component of hydraulic fracture treatments, representing the vast majority of the total volume of fluid injected during fracturing operations. The proppant (normally sand) is the next largest constituent in the injected fracturing slurry. In addition to water and proppant, other additives may be essential to a successful fracture stimulation operation.

The fracturing fluid is a carefully formulated product. Service providers vary the design of this fluid based on the characteristics of the reservoir formation, make-up water quality and operator objectives. The appropriate composition of the fluid for successful fracturing will vary by basin, contractor and well. Situation-specific challenges that must be addressed include scale formation, bacterial contamination, proppant transport, iron content, fluid stability and viscosity breakdown requirements. Addressing each of these criteria may require specific additives to achieve the desired performance; however, not all fracture jobs will require all categories of additives.

When developing hydraulic fracturing plans, in addition to considerations associated with successfully fracturing the target formations, operators should carefully consider the fluid management and disposal implications of their choices for fracture fluid formulations. Operators should regularly evaluate new products that provide environmental protection opportunities while meeting operational goals.

7 Management of Chemicals and Materials

Like other exploration and production activities, both service companies and operators have key roles in managing the chemicals and materials stored and utilized on site for fracturing operations. It is the responsibility of the service companies to educate operators about the various fluids and additives that may be used as a part of a fracture fluid. An essential first step is providing operators with the Material Safety and Data Sheets (MSDS) for products used in their wells.

Operating companies have the responsibility to understand the base fluids and additives that may be used as a part of a fracture fluid and to utilize proper handling procedures of the fluid during fracture treatment and flowback. Service companies work with operators for optimal fracturing designs, which should include a full complement of suggested fluid alternatives, along with the potential environmental impacts and costs associated with each alternative. Training and procedures for operating and handling for each chemical utilized in the fracturing process improve responsiveness to potential surface incidents. As part of the overall operation plan, service companies should provide operating and handling procedures for each chemical utilized, including those for emergencies and disposal.

API recommends that operators be prepared to disclose information on chemical additives and their ingredients. Our own policy position on chemical disclosure follows below.

POLICY POSITION OF API ON CHEMICAL DISCLOSURE FOR

HYDRAULIC FRACTURING OPERATIONS

Hydraulic fracturing is, and has been, a routine industry practice since 1947. Hydraulic fracturing operations have safely enabled increased production of domestic oil and natural gas in more than 1 million wells over the last 60-plus years [1]. While America has abundant natural gas resources, most cannot be produced without this technology. Experts estimate that 90 percent of gas wells drilled in the United States utilize hydraulic fracturing in operations [2] and studies have shown this to be an environmentally safe practice [3].

States have played, and continue to play, the critical role in the oversight and management of hydraulic fracturing operations and are best positioned to tailor requirements to local conditions and to closely monitor environmental performance. API supports transparency regarding the disclosure of the chemical ingredients used in hydraulic fracturing operations to ensure that state regulators have the ability to assess potential incident response needs and plan accordingly, with appropriate confidentiality protections.

Additionally, we endorse state programs that balance the need to protect oilfield service company confidential business information with the public's need to know. Subject to an agreement of confidentiality, we support disclosure of proprietary formulations upon request by designated state agency representatives and health professionals in the event of an emergency, when the designated state agency representatives and health professionals have demonstrated a need to know such information in order to treat or diagnose patients. States must require the designated individuals to keep the supplied information confidential.

Hydraulic fracturing should not be regulated under the Safe Drinking Water Act (SDWA) or any other federal statue. Since hydraulic fracturing has been successfully managed at the state level, it would be problematic, unnecessary and duplicative to have any additional requirements at the federal level.

1 "States Experience with Hydraulic Fracturing, A Survey of the Interstate Oil and Gas Commission," July 2002.

2 Testimony Submitted To The House Committee On Energy and Commerce By Victor Carrillo, Chairman, Texas Railroad Commission, Representing The Interstate Oil and Gas Compact Commission. February 10, 2005. http://www.rrc.state.tx.us/commissioners/carrillo/press/energytestimony.html

3 Environmental Protection Agency, "Study of Potential Impacts of Hydraulic Fracturing of Coalbed Methane Wells on Underground Sources of Drinking Water," Office of Ground Water and Drinking Water report, June 2004, accessed December 6, 2006; Ground Water Protection Council, "State Oil and Gas Regulations Designed to Protect Water Resources," May 2009; Ground Water Protection Council, "Inventory and Extent of Hydraulic Fracturing in Coalbed Methane Wells in the Producing States," 1998.

8 Transport of Chemicals and Other Materials

Materials should be transported to and from the site of hydraulic fracturing operations in accordance with federal, state and local regulations, and in a manner designed to prevent spillage and minimize air and noise impacts. All transport vehicles should display proper markings as required.

Trucks and temporary piping are the more common method for transporting the equipment, proppant, additives and fluids to the site. Trucking costs can be the biggest part of the water management expense. One option to consider as an alternative to trucking is the use of temporary or permanent surface pipelines. Producers are increasingly turning to temporary surface pipelines to transport fresh water to impoundments and to well sites. However, in many situations, the transport of fluids associated with hydraulic fracturing by surface pipeline may not be practical, cost effective, or even feasible. The use of multi-well pads make the use of central water storage easier, reduces truck traffic, and allows for easier and centralized management of flow back water. In some cases it can enhance the option of pipeline transport of water. In order to make truck transportation more efficient, cost effective and less impactful operators may want to consider constructing storage ponds and drilling source wells in cooperation with private property owners. The opportunity to help a private landowner by constructing or improving an existing pond, drilling a water well, and/or improving the roads on their property can be a win-win situation for the operator and the landowner. It provides close access for the operator to a water source, and adds improvements to the property that benefit the landowner.

Operators should also consider utilizing agricultural techniques to transport the water used near the water sources. Large diameter, aluminum agricultural pipe is sometimes used to move the fresh water from the source to locations within a few miles where drilling and hydraulic fracturing activities are occurring. Water use by the shale gas industry has spurred agricultural and field service companies to supply the temporary pipe, pumps, installation, and removal as a business pursuit in some areas.

Fracturing equipment transported over the highway and equipment used to transport fracturing fluids should be checked for leaks and any open-ended lines should be properly capped prior to leaving the storage yard or warehouse. Proppant containers should be checked to ensure materials cannot leak out or be impacted by the wind while on public or private thoroughfares. Chemical additive containers should be checked to make sure there are no leaks. Tankers carrying fracturing fluids should be checked to ensure all discharge valves are closed and leak free.

9 Pre-job Planning

Prior to fracturing operations, operators and/or service companies should consider conducting a job site safety meeting with all site personnel to ensure that personnel performing and supporting the fracture job understand their responsibilities and recognize potential environmental and safety impacts associated with fracturing operations. Suggestions for this meeting include the following.

— Spill prevention measures for any equipment or material they bring on site or manage for the fracture treatment.

— Awareness that spilled materials constitute a waste that should be cleaned up, managed, and disposed of or reused in an approved manner.

— Communication about and location of the Material Safety Data Sheet (MSDS) information for each hazardous chemical used. Awareness that the MSDS must be readily accessible for each chemical on site. Hazard communication to personnel should include emergency and first aid procedures.

— Procedures to report all leaks or spills caused by the service companies to the service companies' on-site manager, appropriate operator manager and personnel, and regulatory agencies (the information should include the material spilled, the MSDS for the material, the location of the spill, the estimated amount of the material that was spilled, and the response action taken and planned).

— And, operator and/or contractor procedures and response plans to properly manage, reuse or dispose of all waste generated.

10 Water Management

10.1 General

Using hydraulic fracturing fluids in an environmentally safe way means that the water and chemicals are sourced, transported, prepared, pumped into the formation, returned from the formation and disposed of in a way in that is in full compliance with all federal, state, and local regulations, and that minimizes impacts. Briefly:

— water must be obtained according to local regulations and use agreements;

— water should be transported to the wellsite in enclosed tanks aboard tanker trucks in Department of Transportation (DOT) compliant vehicles, or via authorized flowline;

— water is stored in tanks or impoundments on the wellsite while waiting to be pumped;

— hydraulic fracturing equipment (blenders and pumpers) must be monitored for leaks and loss of integrity;

— prior to pumping the fracture job, piping must be pressure tested and job monitored so as not to exceed the pressure rating of the piping or equipment;

— after the fracture treatment is finished, fracture fluid must be flowed back into storage tanks, lined impoundments, production equipment or other suitable containers; and

— water must be transported to the approved disposal facility, treatment facility, approved discharge location, or to a subsequent hydraulic fracturing operation in enclosed tanks aboard DOT compliant tanker trucks or a dedicated pipeline system.

Water use and management is discussed in more detail in the companion API Guidance Document HF2, *Water Management Associated with Hydraulic Fracturing*, First Edition, April 2010 [2], focused on issues associated with the acquisition, use, management, treatment, and disposal of water and other fluids associated with hydraulic fracturing.

10.2 On-site Fluid Handling

All components of fracture fluids, including water, additives and proppants, should be managed properly on site before, during and after the fracturing process. Typically, fracture fluid components should be blended into the fluids used for fracturing only when needed. Any unused products should be removed from the location by the contractor or operator as appropriate. The job planning process should consider the possibility of unforeseen circumstances that may delay the fracture operations and provide a plan for proper material management. This includes management of fluids that remain in lines, tanks and other containment devices after the fracturing has been completed.

Operators should maintain information about their fluid management and storage at the site. Such information may include:

— site design and capacity of storage impoundments and/or storage tanks;

— information about the number, as well as the individual and total capacity of, receiving impoundments and/or tanks on the well pad;

— description of planned public access restrictions, including physical barriers and distance to edge of the well pad; and

— description of how liners are to be installed to prevent possible leakage from impoundments, in locations where liners are required by state or local regulations.

Both the operator and any on-site contractors should verify that all personnel involved in the fracturing job and pre- and post-fracture activities are fully trained in the proper precautions for transporting and handling fluids, chemicals and materials, and have operational knowledge of the equipment to be used and of the procedures implemented to prevent leaks and spills during a fracturing operation. The training should include:

— preventative measures for transporting and handling fluids, chemicals and materials; and operational knowledge of the equipment to be used and the procedures implemented to prevent leaks and spills during a fracturing operation;

— proper management, cleanup and disposal practices that should be utilized if any products are accidentally spilled or leaked;

— the management and disposal practices that should be followed for flowback operations including both the liquid and solid components, and managing well gas during the operation;

— procedures for testing and inspecting equipment, hoses and connections prior to, and during, pressure operations;

— procedures for collecting fluids remaining in lines including the use of collection buckets, catch basins or vacuum trucks; and

— remedial actions in the event of an incident to avoid and minimize impacts to soil, groundwater and surface waters.

The MSDS for each covered additive should be obtained from the supplier or manufacturer, be reviewed prior to using the chemical, and be readily available at the job site. The MSDS should contain information about physical hazards of the chemical, spill cleanup procedures and other information to minimize environmental and health impacts.

10.3 Surface Impoundments and Storage Tanks

Fluids used for hydraulic fracturing operations will generally be stored on-site in tanks or lined surface impoundments. Returned fluids, or flowback fluids, may also be directed to tanks or impoundments.

All surface impoundments, including those used for temporarily storing fracture fluids, must be constructed in accordance with existing state and federal regulations. In some states, an impoundment requires prior authorization from one or more regulatory agencies; and in some, a separate permit is required specifically for the impoundment's functional use [10]. In addition, documentation should be kept on all materials placed in surface impoundments.

Larger centralized impoundments must be designed and constructed to provide structural integrity for the life of their operation, taking into consideration their size and extended use. Proper design, installation and operation are imperative to preventing a failure or unintended discharge off the site.

Depending on the fluids being placed in the completion impoundment, the duration of the storage and the soil conditions, liners may be necessary to prevent infiltration of fluids into the subsurface. In most states, impoundments must have a natural or artificial liner designed to prevent the downward movement of fluids into the subsurface. Typically, liners are constructed of compacted clay or synthetic materials like polyethylene or treated fabric that can be joined using special equipment. Impoundments used for long-term storage of fluids should be sited in accordance with state stream setback distances from surface water to prevent unauthorized discharge to surface waters.

Additional information may be required by regulatory authorities for centralized surface impoundments for fracture fluids. For such facilities, requirements may include an initial review of site topography, geology and hydrogeology, in addition to inspection and maintenance procedures—especially if such impoundments are within defined distances of a water reservoir, perennial or intermittent stream, wetland, storm drain, lake or pond, or a public or private water well or domestic supply spring.

In some cases, impoundments used to hold freshwater for supply purposes may be retained by the landowner for their future use. Otherwise, all surface impoundments should be properly closed in accordance with local, state and/ or federal regulations. Materials removed from surface impoundments should be reclaimed, recycled or properly disposed. Refer to API Environmental Guidance Document E5, *Waste Management in Exploration and Production Operations*, Second Edition, February 1997 [11] for additional guidance on fluid impoundments and practices on minimizing waste generation in the upstream sector.

In addition to surface impoundments, some operators store fluids used in, and produced from, fracturing operations in tanks. These tanks must meet applicable state and federal standards.

10.4 Spill Prevention and Control

Fracture fluids should be managed according to state and federal regulations. Some fluids found at E&P sites are actively or passively managed to eliminate spills using various containment methods, including those found in the federal Spill Prevention Control and Countermeasures (SPCC) requirements. Flowback fluids are a federally E&P exempt waste (i.e. exempt from hazardous waste requirements under the Resource Conservation and Recovery Act or RCRA); however, they still need to be addressed under any applicable state regulations. Products used to fracture a well, which have the potential to be released or spilled, may not meet the E&P exemption. Any spill to the ground creates a waste and should be managed properly.

Spills can create difficult operational, legal and public relations problems. Operations should be conducted to minimize the potential for any releases. Spill prevention, response and cleanup procedures, as part of the overall standard operating procedures (SOP) manual for the operation, are a recommended best practice for storing oil, chemicals or other fluids.

The best way to avoid adverse effects of spills is to prevent their occurrence. Key factors in spill incident prevention are planning and training. The facility design should be reviewed to determine where the potential for spills exists. Information on prior spill incidents should be included in the review to assess areas where changes in equipment or practices may be needed. Contingency elements might include the following.

— Modification of site layout or installation of new equipment or instrumentation, as needed, to reduce the possibility of spills, commensurate with the risk involved. Consideration should be given to the use of alarms, automatic shutdown equipment, or fail-safe equipment to prevent, control or minimize potential spills resulting from equipment failure or human error.

— Maintenance and/or corrosion abatement programs to provide for continued sound operation of all equipment.

— Tests and inspections of lines, vessels, dump valves, hoses and other pollution prevention equipment where failure(s) and/or malfunction(s) could result in a potential spill incident. These tests and inspections should be commensurate with the complexity, conditions and circumstances of the facility.

— Operating procedures that minimize potential spills. These operating procedures should be clearly written and available to all operating personnel.

— Examination of field drainage patterns and installation of containment, BMPs, barriers or response equipment as deemed appropriate.

When bringing fracturing materials on site, they should be stored in such a way to prevent any accidental release to the environment. These fluids may include both solid and liquid components. Primary containment methods commonly used include tanks, hoppers, blenders, sand separators, lines and impoundments. It is recommended these primary containers be visually inspected before and during the fracturing operation to ensure integrity.

The use of techniques such as sloping the well location away from surface water locations, positioning absorbent pads between sites and surface waters, and perimeter trenching systems and catchments may be used to contain and collect any spilled fluids.

Operators should evaluate the potential for spills and damages and use this information to determine the type and size of primary and secondary containment necessary. The contingency elements of the manual might include the location of emergency equipment, the type(s) of materials and products that can be used effectively for clean-up, and list sources and procedures for using these chemicals. Spill response drills/simulations should include participation of relevant contractor personnel.

In the event a spill occurs, the source of the spill should be controlled, or reduced to the extent possible, in a safe manner. The release should be confined or contained to minimize potentially adverse effects. Some methods to control and contain spilled substances, particularly oil, include:

— retaining walls or dikes around tanks;

— sluice gates;

— secondary catchment basins designed to prevent the spread of fluids that escape the primary wall or dike;

— absorbent pads;

— booms in water basins adjoining the facility;

— temporary booms deployed in the water after the spill occurs; and

— use of special chemicals to jell or bio-degrade the spilled fluids. Note that special chemicals may require approval prior to use.

10.5 Storm Water Management and Control

Construction designs may include installation of erosion and sedimentation control systems to control stormwater runoff (escaping off location) as well as run-on (storm water coming onto the location). Minimizing the storm water or precipitation that flows across the site will minimize the potential to transport contaminants into jurisdictional water.

Natural drainage patterns of the area should be considered in the location of equipment, pads and impoundments so stormwater runoff does not erode base material, which could lead to equipment instability, or adversely impact impoundments, potentially causing a discharge of fluids into local surface waters.

Site construction should be inspected on a routine basis and following each significant storm event. Repairs to the control systems should be completed promptly. During the drilling and completion phases, the site should be stabilized and all raw materials should be stored in a manner to prevent the contamination of natural runoff. Temporary containment and liners should be used to minimize the impact of spills and to prevent impacted precipitation from affecting surface or groundwater.

Operators are encouraged to consult the Guidance Document, *Reasonable and Prudent Practices for Stabilization (RAPPS) at Oil and Natural Gas Exploration and Production Sites* [12], that describes various operating practices and control measures used by oil and natural gas operators to effectively control erosion and sedimentation in stormwater runoff from clearing, grading and excavation operations at exploration and production sites under various conditions of location, climate and slope.

A wide variety of documents describing best management practices for stormwater management exist, and operators are encouraged to consult such documents. [13]

11 Maintaining Equipment and Facilities

11.1 General

Hydraulic fracturing is a complex operation performed by trained personnel who understand the operation of the fracture treatment, as well as their role and the role of the equipment they operate or the material they manage. Key personnel operating all equipment involved in the hydraulic fracturing operation, and others on site during the fracture stimulation operation should work together following a procedure that can be modified quickly in response to changing conditions.

Communication and training are critical to a successful operation. A SOP for fracturing operations might contain information about the equipment used, safe-operating practices for the equipment, start-up and shutdown procedures and emergency procedures.

11.2 Equipment Maintenance

All equipment, including wellhead valves and assemblies, should be evaluated to determine if they are designed for well fluid conditions, as well as pressures and abrasion created by the fracturing fluids and proppants during the fracture stimulation (see API 6A, *Specification for Wellhead and Christmas Tree Equipment* [14]). Fracturing valves or other devices may be used during fracturing to protect the original wellhead. The presence of contaminants such as H_2S or CO_2 may require additional design and safety considerations. Specially designed valves and equipment may be required to protect the wellhead to prevent failures and accidental releases to the environment during the hydraulic fracturing operation.

Proppant handlers are used to move large quantities of solid proppant to the blenders and mixers. Augers or conveyer belts are used to transport the proppant from a large storage container. Care should be taken to minimize any spillage of solids off the auger or conveyor belt systems.

Blenders and mixers are used to mix the fracturing fluids, proppant and chemicals. Equipment should be configured to minimize the potential for spillage of proppant or leaks of fracture fluids or chemicals. Pumping equipment may experience leaks from the drive train (engine and transmission), pumps, tanks or piping connections. The pumping unit should be tested for leaks after it is connected. All hoses and connections should be checked prior to pressuring up.

Hammer unions, in addition to threaded and flanged connections, are used to connect the fracture lines to the wellhead. The piping system should be inspected and tested before the fracturing operation is initiated. Piping used to transport fracturing fluids from the pumping units to the wellhead, and associated unions and connections, should be pressure tested to verify integrity and confirm they have been properly inspected and free of defects prior to use. Blowdown lines should be tied down securely and inspected prior to use to prevent unintended movement.

Upon discovery, a spill or leak should be promptly reported to the site manager for proper identification, management and clean-up, and, when required, reported to proper officials.

11.3 Inspections

Appropriate equipment should be used for all operations, and inspections/maintenance performed according to design and manufacturer's requirements. Monitoring, corrosion abatement or resistant equipment should be considered if produced fluids are suspected of being corrosive.

Operating procedures should provide for early identification of potential corrosion problems in failure-prone equipment. Consideration should be given to the analysis of failures or malfunctions so that corrective action can be taken to minimize future environmental incidents.

Equipment, including pump packing and hydraulic lines, should be inspected prior to, and during, operation for leaks that could result in pumped fluids being spilled on the ground. Engines should be checked for leaking lube oil, coolant and other fluids.

11.4 Facility Maintenance

Facilities and equipment should be kept clean, maintained and operated in a safe and environmentally sound manner. Signs should be posted in conspicuous locations to notify employees and the public of any dangerous situations such as flammable conditions, high voltage, etc. State or local regulations may specify certain posting requirements.

If the site is located near a populated area, emergency phone numbers should be posted at the entrance to the facility. Weeds should be controlled to a degree compatible with the local environment by cutting, mowing or spraying to improve appearance and reduce fire hazards. When herbicides are used to control weeds, they should be properly applied by trained personnel being cognizant of nearby landowners.

All equipment should be painted and/or kept clean to present an acceptable appearance and to provide protection from external corrosion. Waste receptacles should be provided at appropriate locations for segregating and collecting discarded paper, rags, etc. and emptied on a regular basis.

11.5 Pipeline Maintenance

Pipelines may be used to transport water from wells, ponds or municipal water connections. Pipelines may also be used for the transmittal of flowback and produced water associated with hydraulic fracturing operations. Pipelines should be tested for integrity after installation and inspected as appropriate to ensure they are not leaking. Any identified leaks in the pipelines should be repaired before continuing operation. Temporary lines should be flushed with fresh water before being dismantled, with the flush water disposed of according to appropriate state and federal requirements. Operators should not allow any unauthorized fluid to be discharged during the removal of the pipelines.

Additional steps that should be considered to reduce the potential of a release from a pipeline include the following.

— “Dead” piping and temporary connections should be removed when they are no longer required.

— Piping subject to vibration should be braced to reduce movement and avoid fatigue failures.

— Tanks should be checked for uneven settlement of the foundation, corrosion and leaks.

— Installation of pressure relief valves should be considered for liquid lines, which could potentially rupture from liquid expansion.

— Sleeve-type line couplings should not be used when there is a chance of line movement.

12 Minimizing Surface Disturbance

12.1 General

The well location should accommodate all the equipment used to perform the fracturing job. Any off-location equipment staged during the job should be parked so it does not restrict or block local or emergency traffic. If it is necessary to block portions of the road, affected residents and emergency agencies should receive advance notification.

Wellsites should always be planned with safety—both worker safety and community safety—as a first priority. In addition, site determinations are also based on operational issues and regulatory requirements. Public nuisance issues associated with certain locations, including: vehicle traffic, emissions, noise, lighting, erosion control, material use and management of produced hydrocarbons and fracturing wastes, including flowback fluids, are also important factors in a final site determination.

Larger drilling locations (pads) required for multiple wells and horizontal fracture stimulation, ultimately reduce the overall surface disturbance when compared to single well pads. Pads should be sized to accommodate the drilling and fracturing equipment, multiple well pads, and larger production facilities necessary for higher volumes of produced fluids. These larger locations may result in additional localized impacts during construction, drilling, fracturing, well completion and production operations that must be considered and mitigated as appropriate. As soon as practicable, temporary equipment can be removed and excess areas may be reclaimed, restored or returned to other uses, reducing the location size and overall footprint. See API 51R for further information on appropriate reclamation practices [3].

12.2 Mitigating Impacts Associated with Site Selection

Site selection for all E&P activities warrants careful evaluation and planning. To minimize surface impact, additional attention is prudent for hydraulic fracturing operations. For example, the layout of the site for hydraulic fracturing operations should consider the potential for soil and surface water impacts in the event of a spill. As possible, equipment and materials should be positioned and stored to minimize disturbance to the environment. An environmental site assessment can be valuable in site selection. This assessment might include evaluating topographic, population, environmental hazard, zoning and other maps to locate sensitive or high-exposure areas [such as churches, schools, hospitals, residential areas, surface waters, freshwater wells, flood zones, active fault areas, threatened and endangered plants and animals (including habitat), protected bird habitat, wetlands, archeological, recreational, biological or scenic areas]. Where feasible, the site should be located away from these sensitive areas. Potential impact from upset conditions, such as oil or produced water spills and leaks, should also be considered.

Existing roads and rights-of-way should be utilized to the maximum extent possible. The land owner and/or surface tenant should be consulted to consider present and future uses of affected and adjacent land. A site should be selected that minimizes the amount of surface terrain alteration to reduce environmental and aesthetic damages. Locations requiring construction practices such as cut and fill, which pose possible landslide or slump problems, should be avoided when possible. Consideration should be given to stock piling topsoil, if feasible. Subsurface soil conditions should be considered for adequate foundation support of buildings, pumps, engines, tanks and equipment used during hydraulic fracturing operations.

Detailed guidance for site selection considerations is provided in API 51R [3].

13 Protecting Air Quality

The sources of potential air emissions associated with hydraulic fracturing are temporary in nature. Hydraulic fracturing operations utilize large amounts of horsepower (hp), normally provided almost exclusively by diesel engines. There are federal, state, local and tribal requirements regarding air emissions that apply to oil and gas E&P operations.

Federal regulations that have a direct impact on controlling emissions from fracturing operations include the Standards of Performance for Stationary Compression Ignition and Spark Ignition Internal Combustion Engines (NSPS) and Reciprocating Internal Combustion Engine (RICE) NESHAP rules, which regulate new, reconstructed and existing stationary engines. In general, these rules apply to most internal combustion engines regardless of horsepower rating, location or fuel.

The EPA typically delegates implementation of air regulations to state and tribal agencies. This delegation of authority can include rule implementation, permitting, reporting and compliance. Any state with delegation of authority can pass more restrictive rules, but they are prohibited from passing a rule that is less stringent than the federal rule.

14 Preserving Visual Resources

The visual impacts from hydraulic fracturing operations at any particular site are generally minor and short-term, and vary with topography, vegetation and distance to the viewer. Site-specific impacts will be more pronounced with multi-well pads, but the overall impact of a large-scale operation is reduced. Horizontal drilling can provide flexibility to locate well pads in optimal locations and use of multi-well pads will reduce the number of visual impacts in an area. Operators should work with municipalities to identify and/or map potential areas of high visual sensitivity.

15 Mitigating Noise Impacts

Noise is best mitigated by distance—the further from receptors, the lower the impact. The second level of noise mitigation is direction. Directing noise-generating equipment away from receptors greatly reduces associated impacts. Timing also plays a key role in mitigating noise impacts. Scheduling the more significant noise-generating operations during daylight hours provides for tolerance that may not be achievable during the evening hours.

Hydraulic fracturing operations should be planned with these noise-related considerations in the forefront. When possible, attention to the location of the access road may mitigate noise impact associated with trucking and the hydraulic fracturing operations. When feasible, the wellsite and access road should be located as far as practical from occupied structures and places of assembly. The goal is to protect non-lease holders from noise impacts that conflict with their property use.

Other examples of noise mitigation techniques that can be considered with regard to hydraulic fracturing operations include:

— the placement of tanks, trailers, topsoil stockpiles or hay bales between the noise sources and receptors;

— the use of noise reduction equipment such as hospital mufflers, exhaust manifolds or other high-grade baffling; and

— the orientation of high-pressure discharge pipes away from noise receptors and the addition of noise wall or noise barriers.

16 Mitigating Road Use Impacts

One of the largest local concerns with large-scale deployment of hydraulic fracturing operations is often associated with lease roads. Lease roads are constructed and used to support various exploration and production activities, including fracturing operations. The environmental impact of the construction of a road can have longer lasting effects, beyond the limits of the right-of-way. Existing roads that meet transportation needs should be utilized, where feasible, to limit additional disturbance and new road construction. When it is necessary to build new roadways, they should be developed with potential impacts and purpose in mind. Mitigation options should be considered prior to construction and landowner recommendations should be part of the planning process. In addition, proper road maintenance is critical for the performance of roads, to manage erosion and to protect environmentally sensitive areas.

One of the potential impacts of the proposed activity on community character is the issue of trucking to support high-volume hydraulic fracturing. Local authorities retain control over local roads and, where appropriate, operators should obtain road use agreements.

Whether agreements are in place or not, in areas with traffic concerns, operators should develop a trucking plan that includes an estimated amount of trucking, hours of operations, appropriate off-road parking/staging areas and routes for informational purposes.

Examples of possible measures in a road use agreement or trucking plan include:

— route selection to maximize efficient driving and public safety;

— avoidance of peak traffic hours, school bus hours, community events and overnight quiet periods;

— coordination with local emergency management agencies and highway departments;

— upgrades and improvements to roads that will be traveled frequently;

— advance public notice of any necessary detours or road/lane closures; and

— adequate off-road parking and delivery areas at the site to avoid lane/road blockage.

Detailed guidance for lease road planning, design and construction, maintenance and reclamation, and abandonment are also provided in API 51R [3].

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Energy Policy at a Crossroads: An Assessment of the Impacts of Increased Access versus Higher Taxes on U.S. Oil and Natural Gas Production, Government Revenue, and Employment

Released – January 4, 2011
Revised – June 24, 2011

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Project Background

API has requested Wood Mackenzie to undertake a study which examines the implications of increasing exploration and development access in 5 key US regions currently closed to development. The 5 key regions are the Eastern Gulf of Mexico, portions of the Rocky Mountains, ANWR, and the Atlantic and Pacific Outer Continental Shelf (OCS).

Additionally, Wood Mackenzie has contrasted this 'Access' study with an analysis of the potential threat to production and jobs associated with increasing taxation on the oil and gas industry at a rate of $5 billion per year, which was less than the amount that was considered by the US Congress and Administration in 2010. The taxes were applied on both an income and production basis so as to capture the impacts of the slate of proposed taxes put forward by the Administration in 2010.

Key Results

Wood Mackenzie's analysis found that increasing access leads to a direct increase in domestic production, jobs, and government revenue. Whereas increasing taxes reduces production and jobs. It is also detrimental to government revenues five years into the future.

ACCESS – Compared to Base Case

Total Potential Production Impact:
Gain of 1.4 mmboed* by 2020, and 4 mmboed by 2025**

Total Potential Government Revenue:
$20 billion by 2020 and $150 billion by 2025 assuming current regional fiscal regimes. In addition, we estimate leasing activity will raise a further $44 billion by 2020

- *mmboed = million barrels of oil equivalent per day*

*** 2010 total US production is18.8 mmboed (8 mmb/d liquids and 61 billion cubic feet per day (bcfd) natural gas)*

TAXES – Compared to Base Case

Total Potential Production Impact:
Estimated loss of 0.7 mmboed by 2020 with an additional 1.7 mmboed put at increased risk***; and an estimated loss of 0.4 mmboed by 2025 with an additional 1.2 mmboed put at increased risk

Total Potential Government Revenue:
Averages a positive $3 billion per year the first five years, 2011-2015. An estimated $6 billion less in 2020 with an additional $8 billion put at increased risk; and an estimated $10 billion less in 2025 with an additional $8 billion put at increased risk

**** Risk of not being developed due to unprofitable project economics*

Key Results

ACCESS – Compared to Base Case

Direct Employment Potential:

130,000 direct jobs are estimated to be created by 2020 and 150,000 by 2025

Indirect* Employment Potential:

330,000 indirect jobs are estimated to be created by 2020, growing to 380,000 by 2025

TAXES – Compared to Base Case

Direct Employment Potential:

An estimated 50,000 jobs lost in 2014, dropping to 15,000 in 2020 and 8,000 in 2025

Indirect Employment Potential:

An estimated decrease in employment of 120,000 in 2014, 35,000 in 2020 and 20,000 in 2025

** Indirect Employment includes both jobs that provide goods and services to the oil and natural gas industry as well as jobs resulting from spending of income earned either directly or indirectly from the oil and natural gas industry's spending*

Contents

Scope of Study – Access Scenario

- The study considered the following federal areas currently off-limits:
  - Eastern Gulf of Mexico
  - Rocky Mountains*
  - Atlantic OCS
  - Pacific OCS
  - Alaska National Wildlife Refuge (ANWR) – 1002 Area
- To estimate the potential economic benefits of opening up new access, a development scenario was created for each region including field size distributions and schedules for leasing, exploration, and development. Leasing in all areas was assumed to start in 2012. See appendix for additional details
- Production and economic forecasts were created using Wood Mackenzie's proprietary economic modeling software (GEM)
- Production models were based on analog fields in the Gulf of Mexico and Alaska. Rocky Mountain models were based on existing Wood Mackenzie play models

** The Rocky Mountains resource considered here was deemed effectively "no access" by the Department of Interior's updated "EPCA" assessment. For explanation of this assessment and treatment here, see the first two citations in References*

Resource Estimates of Areas Currently Off-limits

Estimated resource potential in bnboe = billions of barrels of oil equivalent

Methodology
Access Scenario - OCS/ANWR – Modeling Process

- Using existing field models as analogues, generic models were created in GEM for each field size: 75 mmboe, 400 mmboe, 700 mmboe, 1,500 mmboe
- Production streams were adjusted to account for varying gas-oil ratios across regions
- Capital and operating costs were adjusted to account for differences in operating environments. (e.g. drilling CAPEX was lowered in Pacific OCS fields to account for shallower water depth). See Appendix for details on cost assumptions
- Using these region-specific field files and development forecasts, aggregate drilling and production schedules were compiled for each region

Methodology
Access Scenario - Assumed Field Size Distributions (Commercial reserves*)

ANWR	mmboe** per field	# of fields	Total Resource (mmboe)
Small	75	20	1,500
Medium	400	12	4,800
Large	1500	3	4,500
TOTAL (mmboe)			10,800

Atlantic OCS	mmboe per field	# of fields	Total Resource (mmboe)
Small	75	40	3,000
Medium	400	15	6,000
Large	1500	3	4,500
TOTAL (mmboe)			13,500

East GoM	mmboe per field	# of fields	Total Resource (mmboe)
Small	75	40	3,000
Medium	400	20	8,000
Large	700	5	3,500
TOTAL (mmboe)			14,500

Pacific OCS	mmboe per field	# of fields	Total Resource (mmboe)
Small	75	30	2,250
Medium	400	15	6,000
Large	1500	2	3,000
TOTAL (mmboe)			11,250

* Commercial reserves are the resources which we have estimated will be developed successfully given today's technology and price forecasts. Given the nature of the areas we are modeling, we have assumed that a significant proportion of the discovered resources will remain undeveloped

** mmboe – millions of barrels of oil equivalent

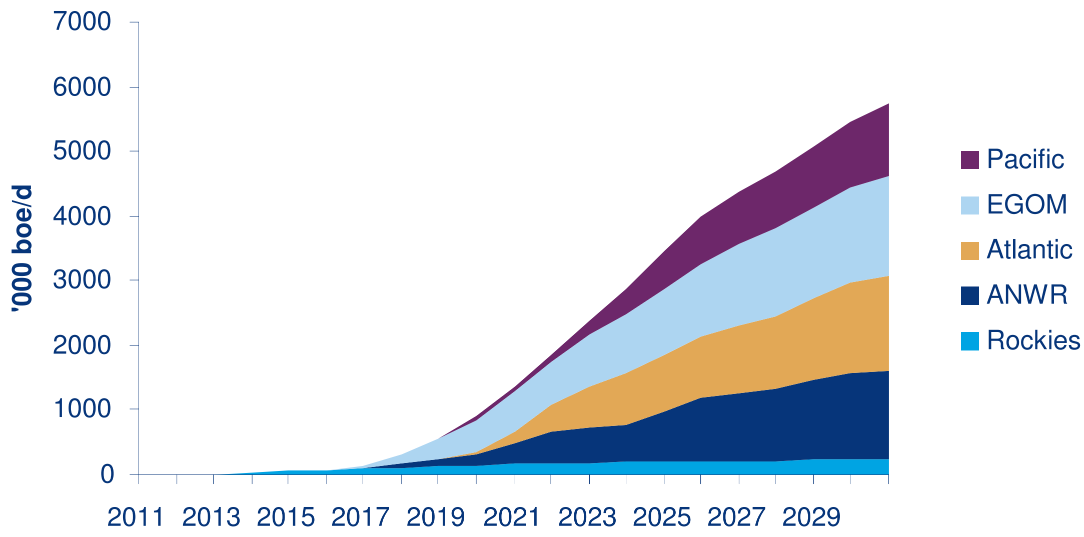
Methodology
Access Scenario - Rockies – Modeling Process

- The Rockies region was modelled at the play level
- Based on the USGS 2008 Resource Assessment, total Rockies reserves were split as follows:
  - 10% Uinta-Piceance Basin
  - 15% San Juan Basin
  - 13% Montana Thrust Belt
  - 12% Williston Basin
  - 50% Southwestern Wyoming (Greater Green River Basin)
- Representative play models were constructed for each of these basins including average per well costs, type curves, and appropriate tax regime
- Using Wood Mackenzie's estimates for average reserves per well, the number of wells necessary to develop the entire estimated resource was determined, and 20 year drilling forecasts were created for each basin
- Commercial reserves for the Rockies are estimated to be 2.0 bnboe based upon Wood Mackenzie internal assessments

Results
Access Scenario - Production Impacts

- Through increased access 1.4 mmboe/d could be brought on stream* by 2020 (850 mb/d liquids and 3 bcf/d natural gas)
- Potential production gains are estimated at 4.0 mmboe/d by 2025 (2.8 mmbl/d liquids and 6.6 bcf/d natural gas)
- For context, 2010 total US production is 8 mmb/d of liquids and 61 bcfd of natural gas. This equates to a total of 18.8 mmboed

Total Potential U.S. Production Impacts of Increased Access

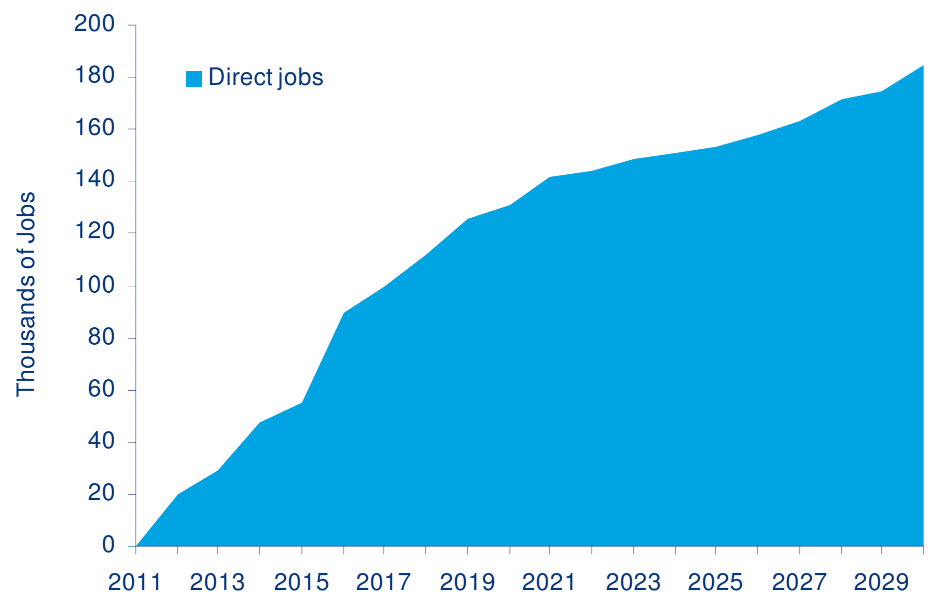


*See appendix for fields development plan

Access Scenario – Employment Impacts

- Job creation is projected to be approximately 50K direct jobs and 120K indirect jobs by 2014
- Approximately130K direct jobs and 330K indirect jobs by 2020.
- Approximately150K direct jobs and 380K indirect jobs* by 2025.
- Estimated Upstream jobs by sector:
    - Leasing & Seismic – 9,000 by 2020
    - Exploration Drilling – 42,000 by 2020
    - Appraisal Drilling – 5,000 by 2020
    - Construction – 64,000 by 2020
    - Operations – 12,000 by 2020
- **Indirect Jobs estimated at 2.5 per direct job based upon PWC and ICF Analysis (see references)**

Potential Employment Impacts of Increased Access

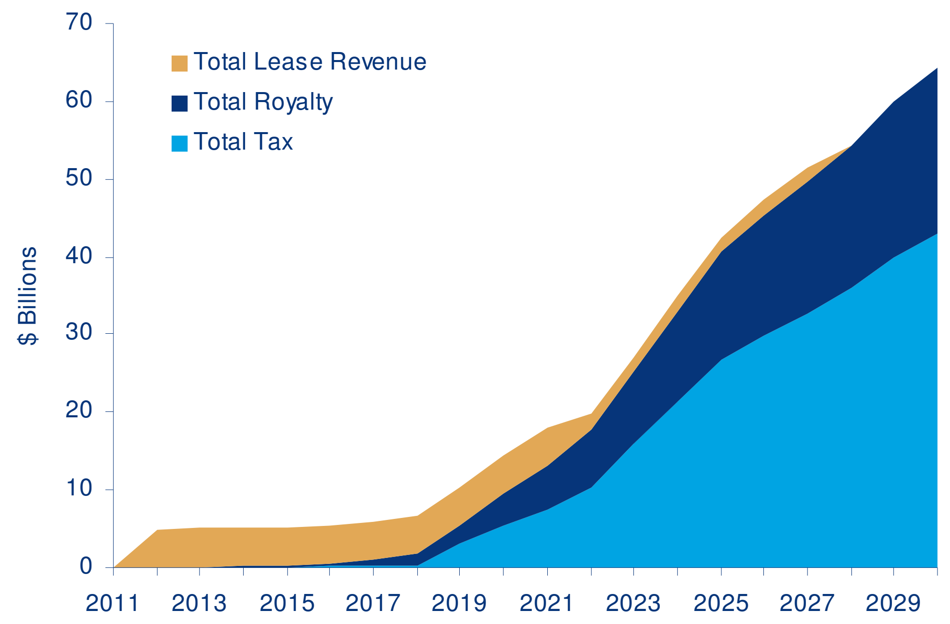


**Indirect jobs are those which are created in other industries to support the oil and gas sector as well as jobs resulting from spending of income earned either directly or indirectly from oil and natural gas industry spending*

Access Scenario– Government Revenues

- Total incremental government revenue (inclusive of state and local taxes) due to increased access is estimated to rise by a cumulative of $20 billion by 2020 and $150 billion by 2025.
- Further federal income will be generated as a result of by leasing activity. This will total $44 billion by 2020 and $61 billion by 2027

Estimated Government Revenue Impact of Increased Access



2

Increased Tax Scenarios:
Scope, Methodology and Results

Scope of Study – Taxes Scenarios

- The study considered tax impacts on future production and jobs from the following areas:
  - Central and Western Gulf of Mexico
  - Onshore US excluding areas currently inaccessible (i.e. Rocky Mountains considered in the Access Scenario)
  - Alaska, areas which are currently open
  - Pacific OCS areas which are currently open
- To estimate the potential government revenue impacts of increasing taxes, we developed two scenarios:
  - The first considered the impact of increased income taxes
  - The second considered the impact of increased production taxes
- Production and economic forecasts were created using Wood Mackenzie's proprietary economic modeling software (GEM)
- Wood Mackenzie's analysis of tax impact does not include any potential impact which could result from future discoveries – a key difference to note when comparing the Access and Taxes scenarios

Methodology – Tax Scenarios

- The objective of this part of the study was to assess the impacts on U.S. oil and gas upstream operations of increased taxes by $5 billion per annum starting in 2011. U.S. production of oil and natural gas, employment, and government revenue impacts were ascertained
- The increased taxation scenario was based upon proposals considered by the Administration and Congress in 2010 ($7.3 billion per annum of tax proposals are catalogued on next slide) representing a combination of income and production taxes. Two tax scenarios were developed, one income based, the other production based, as proxies for taxes considered by policy makers in 2010
- Using these proposed fiscal regimes, Wood Mackenzie proprietary models and data were run to determine which "probable developments" would no longer be economic (i.e., Internal Rate of Return (IRR) falls below 15%)
- Marginal fields which are included in the base case development plan were considered to be "at risk" in the increased taxation scenario and no longer economic (these fields already had an IRR close to or below 15%)
- Production from these fields was then removed from the regional and national roll up, and the impacts on production, employment and government revenue were calculated

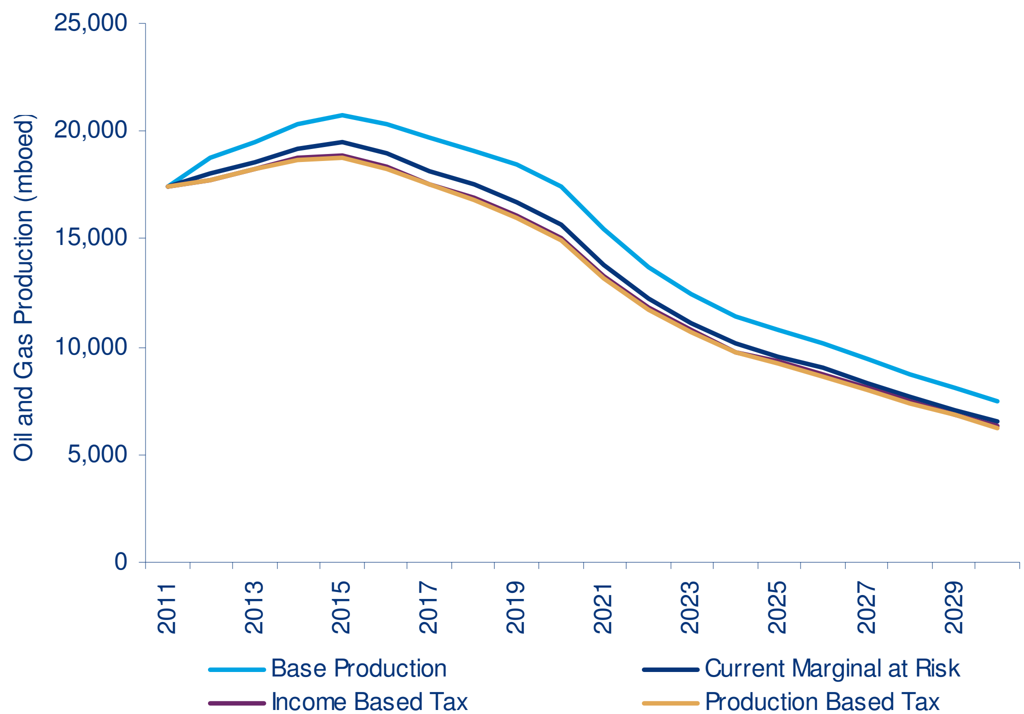
Proposed Tax Amendments Considered by Congress and the Administration in 2010

Amendment	FY 2011 Budget JCT Score – Industry Portion, 2011 – 2020 ($ millions)	Citation
Repeal EOR Credit	$0	Joint Committee on Taxation Report JCX-7-10R
Repeal Marginal Well Credit	$0	Joint Committee on Taxation Report JCX-7-10R
Repeal Expensing Intangible Drilling Costs	$10,924	Joint Committee on Taxation Report JCX-7-10R: VII.H.1.c
Repeal Deduction for Tertiary Injectants	$57	Joint Committee on Taxation Report JCX-7-10R: VII.H.1.d
Repeal Passive Loss Exemption	$217	Joint Committee on Taxation Report JCX-7-10R: VII.H.1.e
Repeal Percentage Depletion	$9,653	Joint Committee on Taxation Report JCX-7-10R: VII.H.1.f
Repeal Section 199 for Oil and Gas Activities	$14,789	Joint Committee on Taxation Report JCX-7-10R: VII.H.1.g
Increase G&G Amortization Period	$1,003	Joint Committee on Taxation Report JCX-7-10R: VII.H.1.h
GoM Excise Tax	$5,300	S. 3405 – 111th Congress (score from FY2010 budget)
Increase in Oil Spill Tax	$31,000	Senate Finance Committee estimate to S. 3793 – page 11
Potential Total Facing Industry	**$72,943**	

Results
Taxes Scenarios – Potential Production Impacts

- By increasing taxation on the industry, the modeling shows that several development opportunities are put at risk (IRR<15%)
- The production lost* from these sub-economic fields could reach 2.4 mmboed (1.7 mmboed due to increased risk**, while 0.7 mmboed could be lost under the Production Based Tax) in 2020 and drops to 1.6 mmboed in 2025
- The largest production impact is expected to be in the Lower 48, due to the larger proportion of marginal fields and the relative size of total Lower 48 production compared to the Gulf of Mexico and Alaska

Total Potential U.S. Production Impacts – Increased Taxes

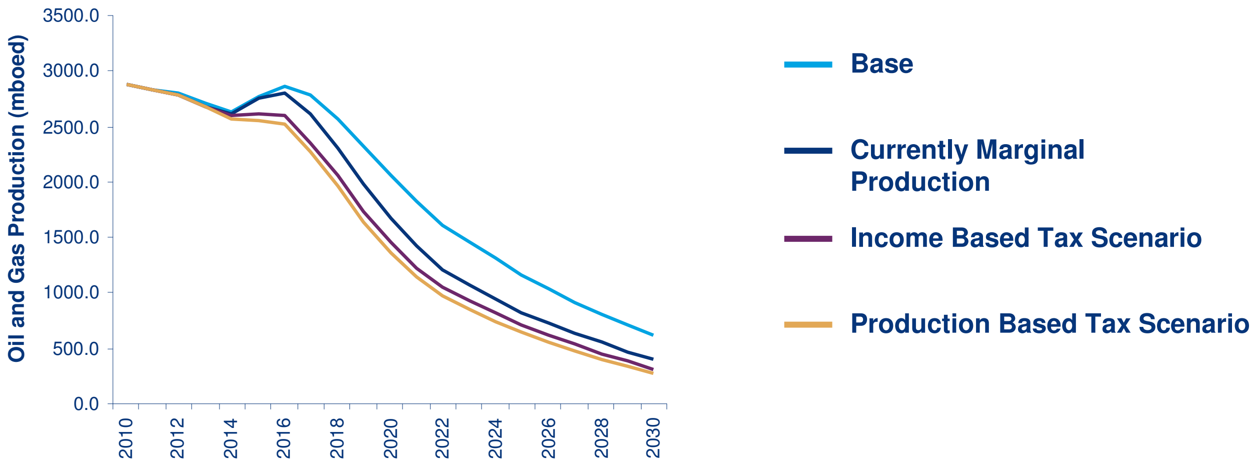


**Production loss estimates include: fields currently marginal and fields which become marginal under the high tax scenarios*

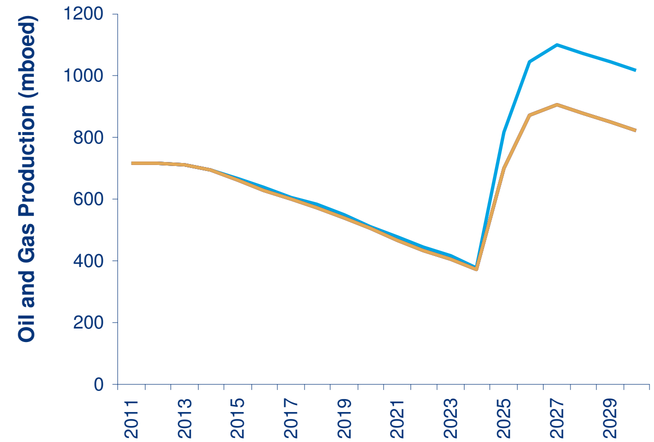
***Risk of not being developed due to unprofitable project economics.*

Tax Scenarios – Estimated Production Impacts by Region

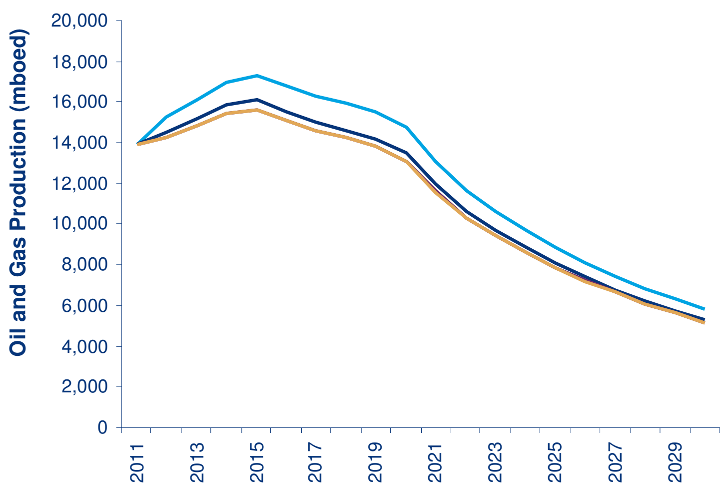
Gulf of Mexico Deepwater & Shelf



Alaska*



Lower 48



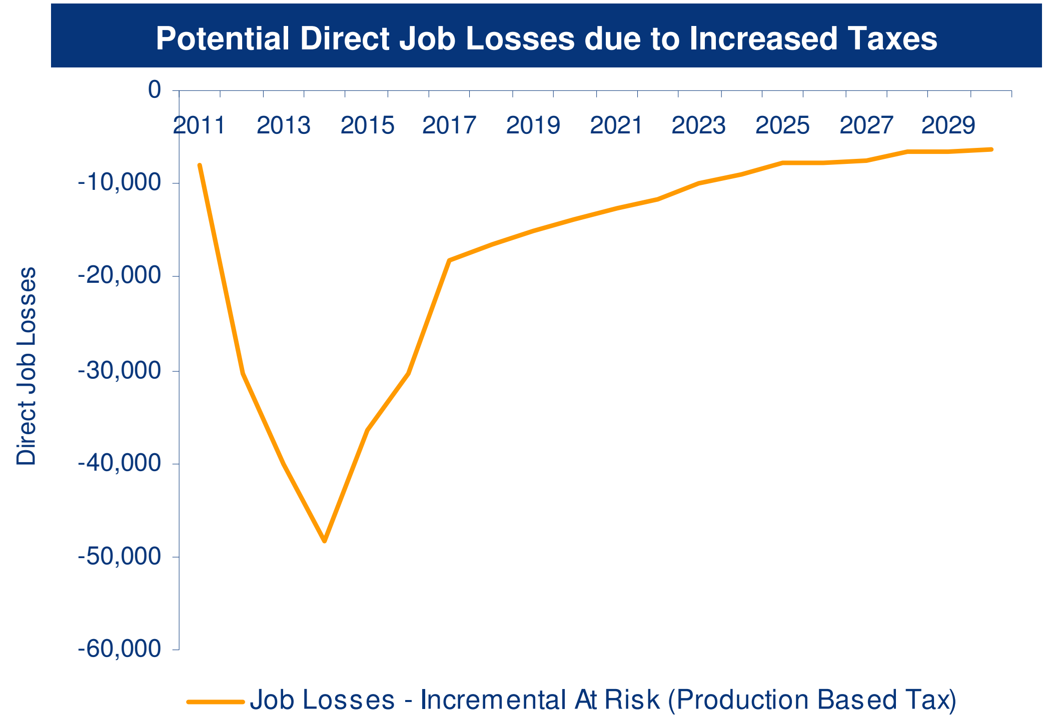
**Alaska's currently marginal, income based tax scenario, and production based tax scenario are all equal*

Tax Scenarios – Estimated Production Impacts by Region

Region	Year of Maximum Production Loss	Incremental Production Loss (mboed)	Total At Risk Production Loss (mboed)
Lower 48	2019	370	1,746
GoM	2020	313	701
Alaska	2027	191	191

Tax Scenarios – Projected Employment Impacts

- Increased taxes will make a number of currently economic fields un-economic, resulting in additional direct job losses of nearly 50,000 in 2014
- Due to the labor intensity of onshore drilling, the L48 would see the largest adverse employment impact
- Based upon the potential forecast of direct job losses, the resultant indirect losses is 120,000 in 2014, 35,000 in 2020 and 20,000 in 2025



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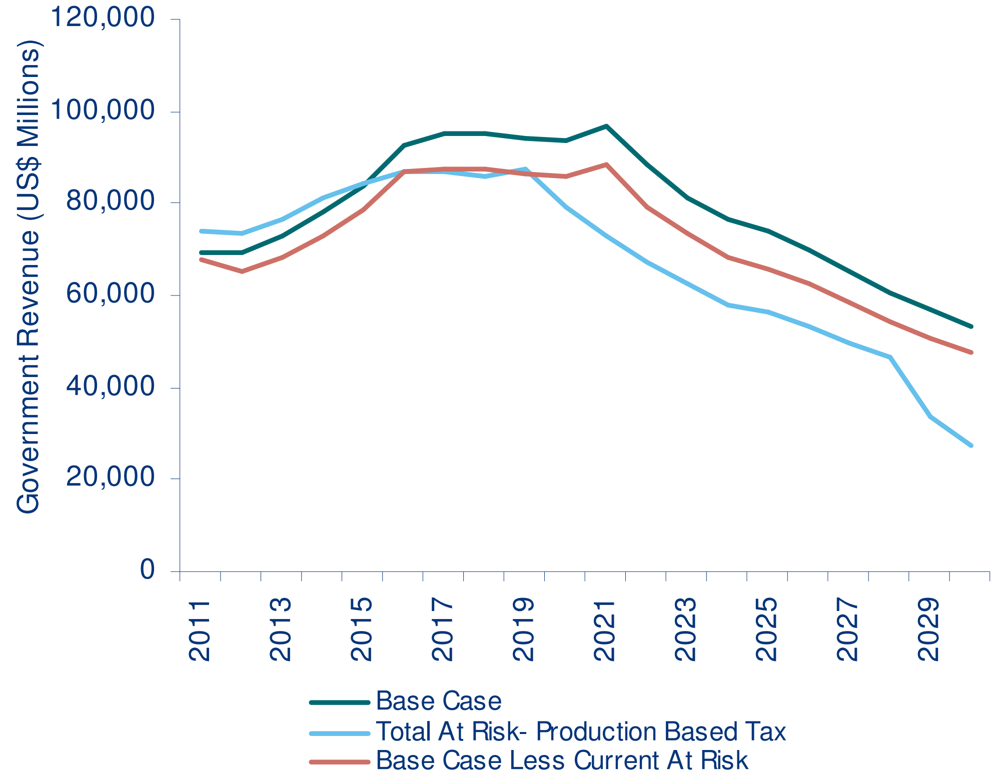
Tax Scenarios – Government Revenues

- Government tax increases* will result in a $16 billion increase in government revenue in the period 2011 to 2015.
- However, starting in 2016 government revenue will be reduced (compared to the base case) due to the lost tax income from potential opportunities not being developed
- We estimate a cumulative shortfall in government revenue* in the period 2016 to 2025 to potentially reach $144 billion if sub-economic fields do not get developed
- Considering only incremental sub-economic fields, results in a potential $65 billion cumulative shortfall in government revenue between 2016 and 2025

Estimated Government Revenue Impact due to Increased Taxes



** Government revenue estimates include fields currently marginal and fields which become marginal under the high tax scenarios*

3 Appendix

Access Scenario - Resource Assumptions

- Total resource estimates for all regions were based on the "alternative case" estimates generated by ICF International for their report "Strengthening our Economy: The Untapped U.S. Oil and Gas Resources", December, 2008
- These alternative resource estimates were based on the history of USGS resource assessments that have continually increased over time. In particular, for the Eastern Gulf of Mexico and Atlantic OCS, the most recent (2006) USGS resource estimates were uplifted by a factor of 4.8 for oil and 2.4 for natural gas. In the Pacific case, both oil and gas were increased by a factor of 2.4
- The ANWR resource estimate was taken from the "high case" scenario in the 2005 USGS assessment
- ICF's Rocky Mountain "alternative case" resource estimate was based on the Department of the Interior's 2008 assessment of Federal land in the Rockies
- In Wood Mackenzie's development scenario, only a portion of the overall resource base was assumed to be commercial. Across the five regions analyzed, 43% of the total resource was expected to be developed and produced

Access Scenario - Total Resource by Region

- Total undiscovered resource potential is 118 bnboe (ICF “Alternative case”)
- Total commercial reserve base is estimated at 52 bnboe

Resource Base	Rocky Mtns	Atlantic OCS	Pacific OCS	Eastern GoM	ANWR
Gas (tcf)	8.4	89	44	53	18
Oil (bnbbl)	0.5	18	26	19	17

Commercial Reserves	Rocky Mtns	Atlantic OCS	Pacific OCS	Eastern GoM	ANWR
Oil Equivalent (bnboe)	2.0	13.5	11.3	14.5	10.8

Access Scenario - Leasing Assumptions

- Leasing was assumed to begin for each region in 2012
- Combined income from lease sales in all regions is projected to total $61 billion

	Rocky Mtns	Atlantic OCS	Pacific OCS	Eastern GoM	ANWR
Total Region Acreage	10,137,000	269,130,000	248,450,000	64,556,650	1,500,000
Acreage to be leased	10,000,000	40,000,000	20,000,000	16,000,000	1,500,000
$/acre	$1,500	$200	$350	$1,000	$10,000
Lease revenue	$15,000 M	$8,000 M	$7,000 M	$16,000 M	$15,000 M

Access Scenario - Exploration Assumptions

- Discovery of large fields was distributed evenly over the first 20 years of each region's development
- Exploration expenses in the Rockies were considered negligible and were not modeled

	Atlantic OCS	Pacific OCS	Eastern GoM	ANWR
Exploration Start	2016	2016	2014	2014
Expl./Appraisal Well Cost	$80 million	$65 million	$90 million	$75 million
Expl. Success Rate	20%	30%	33%	50%
Seismic Cost per acre	$4,000	$4,000	$4,000	$4,000
Total Exploration Cost	$32 billion	$17 billion	$27 billion	$9 billion

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Tax Scenario - Base Case Tax Rates

The 'Base Case' scenario was used to calculate the current tax revenues collected by the government, using the following assumptions:

Region	Federal Corporate Tax*	Royalty Rate
Alaska	35%	16.5% Oil / 12.5% Gas
Deepwater GoM	35%	12.5-18.75%
Shelf GoM	35%	16.67-18.75%
Gulf Coast	35%	12.5%
Mid-Continent	35%	12.5%
Northeast	35%	12.5%
Permian	35%	12.5%
Rockies	35%	12.5%
West Coast	35%	12.5%

** State taxes were applied where applicable . To account for state taxes paid by corporations operating in the Gulf of Mexico, Wood Mackenzie used an effective state tax rate of 4%*

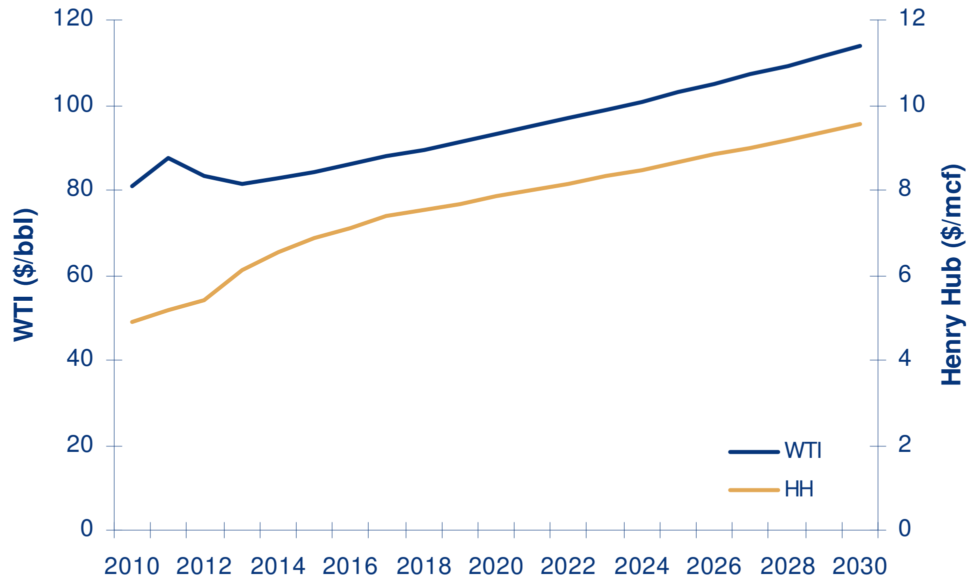
Access & Tax Scenarios - Model Assumptions

- All models included the following assumptions:
    - Federal royalty rates modelled at 12.5%
    - Federal Income Tax modelled at 35%

  i.e. current fiscal conditions

- Wood Mackenzie's commodity price forecast was used. All oil priced at WTI, gas priced at Henry Hub (HH)

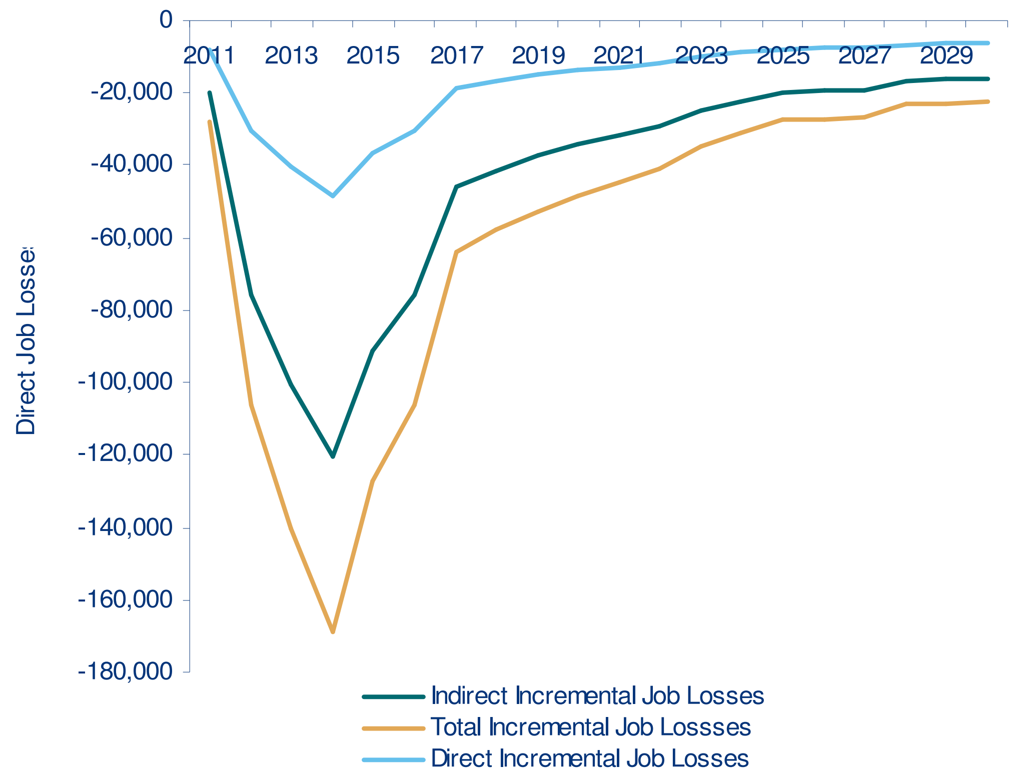
Wood Mackenzie Oil & Gas Nominal Prices



Tax Scenarios – Projected Employment Impacts

- Increased taxes will make a number of currently economic fields un-economic, putting them at risk. At its peak in 2014, this could result in 50,000 direct job losses
- Using a multiplier of 2.5 indirect jobs per direct job based upon ICF and PWC studies implies that nearly 170 K total jobs put at risk in 2014

Potential Job Losses due to Increased Taxes



Access Scenario – Estimated Production Impacts (mboed)

Year	Rockies	ANWR	Atlantic	East GoM	Pacific	Total
2012	12	0	0	-	-	12.4
2013	38	0	0	-	-	38.4
2014	63	0	0	-	-	63.2
2015	84	0	0	-	-	84.1
2016	103	0	0	32.2	-	134.8
2017	119	57	0	156.4	-	332.3
2018	134	104	0	320.1	-	558.6
2019	148	160	57	492.4	56.6	914.1
2020	161	341	177	599.0	104.0	1,382.4
2021	173	503	403	683.9	103.4	1,866.3
2022	184	539	636	825.0	196.1	2,379.9
2023	194	579	790	928.6	364.1	2,856.2
2024	203	776	876	1,019.8	589.4	3,463.5
2025	211	976	936	1,131.1	724.5	3,978.7
2026	219	1,052	1,032	1,250.4	806.5	4,360.9
2027	226	1,120	1,121	1,351.9	875.2	4,694.3
2028	232	1,233	1,262	1,419.6	916.6	5,063.8
2029	238	1,325	1,404	1,469.5	1,006.9	5,443.1
2030	243	1,360	1,491	1,533.7	1,103.1	5,730.0

Access Scenario – Estimated Employment Impacts

Year	Total direct jobs	Total Indirect jobs	Total jobs
2012	19,669	49,173	68,842
2013	28,706	71,765	100,471
2014	47,418	118,544	165,962
2015	55,753	139,382	195,135
2016	90,717	226,792	317,509
2017	100,535	251,338	351,873
2018	113,311	283,279	396,590
2019	127,086	317,715	444,801
2020	132,603	331,507	464,110
2021	143,407	358,519	501,926
2022	145,794	364,486	510,280
2023	150,256	375,639	525,895
2024	151,513	378,783	530,296
2025	153,933	384,833	538,766
2026	158,085	395,211	553,296
2027	162,771	406,927	569,698
2028	171,222	428,055	599,277
2029	174,020	435,049	609,069
2030	184,228	460,569	644,797

Access Scenario – Estimated Impact on Government Revenue ($ billions)

Year	Total Tax	Total Royalty	Total Leases	Total Revenue
2012	0.0	0.0	4.9	5.0
2013	0.1	0.1	4.9	5.1
2014	0.1	0.1	4.9	5.2
2015	0.1	0.2	4.9	5.2
2016	0.2	0.3	4.9	5.4
2017	0.2	0.8	4.9	6.0
2018	0.3	1.5	4.9	6.8
2019	3.0	2.4	4.9	10.4
2020	5.5	4.1	4.9	14.5
2021	7.6	5.6	4.9	18.1
2022	10.4	7.4	1.9	19.8
2023	15.9	9.2	1.9	27.1
2024	21.5	11.5	1.9	34.9
2025	26.7	13.9	1.9	42.5
2026	30.0	15.4	1.9	47.3
2027	32.7	16.9	1.9	51.5
2028	36.2	18.2	0.0	54.3
2029	40.0	19.9	0.0	59.9
2030	42.9	21.4	0.0	64.3

Access Scenario – Value of Production and Government Revenue

Life of Field Production (including 2030 and beyond)

	Rockies	ANWR	Atlantic	Eastern GoM	Pacific	Total
Production						
Natural Gas (Tcf)	8.2	9.4	37.1	26.9	13.5	**95.1**
Natural Gas (Bnboe)	1.5	1.7	6.6	4.8	2.4	**16.8**
Oil (Bnbbls)	0.5	8.7	6.8	9.7	8.1	**33.8**
Total Oil & Gas (Bnboe)	**1.9**	**10.4**	**13.4**	**14.5**	**10.4**	**50.7**
Total Value of Production ($BN)	**$126**	**$1,149**	**$1,163**	**$1,346**	**$1,061**	**$4,846**
Governemnt Revenue ($BN)						
Lease Bonus Bids	15	15	8	16	7	**61**
Taxes (State, Local, Federal)	29	285	283	332	282	**1,211**
Royalties	15	141	137	162	127	**581**
Total Government Revenue ($BN)	**$59**	**$440**	**$428**	**$510**	**$416**	**$1,853**

Tax Scenario – Estimated Total U.S. Production Impacts (mboed)

Year	Base Production	Less Current Marginal at Risk	Income Based Tax	Production Based Tax
2011	17,455	17,455	17,455	17,455
2012	18,753	18,046	17,786	17,768
2013	19,545	18,603	18,257	18,236
2014	20,332	19,211	18,753	18,704
2015	20,754	19,505	18,905	18,817
2016	20,304	18,939	18,334	18,238
2017	19,708	18,199	17,581	17,480
2018	19,119	17,480	16,875	16,773
2019	18,426	16,689	16,090	15,990
2020	17,386	15,687	15,067	14,966
2021	15,422	13,838	13,303	13,206
2022	13,707	12,251	11,811	11,722
2023	12,483	11,144	10,762	10,669
2024	11,366	10,140	9,797	9,711
2025	10,816	9,595	9,290	9,217
2026	10,169	8,992	8,711	8,646
2027	9,439	8,325	8,078	8,019
2028	8,714	7,672	7,434	7,383
2029	8,042	7,058	6,850	6,804
2030	7,431	6,549	6,310	6,269

Tax Scenario – Estimated Total L48 Production Impacts (mboed)

Year	Base Production	Less Current Marginal at Risk	Income Based Tax	Production Based Tax
2011	13,905	13,905	13,905	13,905
2012	15,232	14,534	14,274	14,257
2013	16,129	15,215	14,870	14,848
2014	16,998	15,905	15,461	15,437
2015	17,310	16,094	15,631	15,607
2016	16,795	15,510	15,109	15,087
2017	16,316	14,980	14,622	14,602
2018	15,967	14,591	14,248	14,229
2019	15,549	14,173	13,821	13,803
2020	14,808	13,506	13,114	13,098
2021	13,116	11,942	11,604	11,590
2022	11,651	10,601	10,320	10,307
2023	10,615	9,673	9,421	9,410
2024	9,673	8,826	8,602	8,592
2025	8,846	8,076	7,878	7,869
2026	8,094	7,392	7,216	7,209
2027	7,433	6,789	6,634	6,628
2028	6,832	6,239	6,101	6,096
2029	6,290	5,742	5,619	5,615
2030	5,788	5,329	5,171	5,168

Tax Scenario – Estimated Total Employment Impacts

Year	Direct Incremental Job Losses	Indirect Incremental Job Losses	Total Incremental Job Lossses
2011	8,000	20,000	28,000
2012	30,371	75,927	106,297
2013	40,157	100,393	140,550
2014	48,240	120,600	168,840
2015	36,378	90,945	127,323
2016	30,367	75,919	106,286
2017	18,335	45,838	64,174
2018	16,566	41,415	57,980
2019	15,012	37,531	52,543
2020	13,749	34,372	48,121
2021	12,725	31,813	44,539
2022	11,711	29,278	40,989
2023	9,865	24,664	34,529
2024	8,868	22,171	31,039
2025	7,879	19,697	27,576
2026	7,737	19,342	27,079
2027	7,602	19,005	26,607
2028	6,634	16,585	23,219
2029	6,512	16,281	22,793
2030	6,397	15,992	22,388

Tax Scenario – Estimated Impacts on Government Revenue ($ millions)

Year	Base Case Government Revenue $Million	Production Based Tax Scenario Government Revenue $Million	Differential $Million
2011	69,107	73,763	4,656
2012	69,559	73,275	3,716
2013	72,890	76,322	3,432
2014	78,049	81,464	3,415
2015	83,997	84,563	566
2016	92,709	86,990	(5,719)
2017	95,209	87,041	(8,168)
2018	95,194	85,750	(9,444)
2019	94,323	87,544	(6,779)
2020	93,738	79,282	(14,457)
2021	96,906	73,107	(23,799)
2022	88,197	67,324	(20,873)
2023	81,435	62,428	(19,008)
2024	76,557	58,172	(18,385)
2025	73,876	56,278	(17,598)
2026	69,573	53,360	(16,213)
2027	65,308	49,860	(15,448)
2028	60,726	46,394	(14,333)
2029	56,692	33,686	(23,006)
2030	53,181	27,286	(25,895)

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Isolating Potential Flow Zones During Well Construction

API STANDARD 65—PART 2
SECOND EDITION, DECEMBER 2010

AMERICAN PETROLEUM INSTITUTE

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Upstream Segment

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Foreword

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A future planned standard, API RP 96, Deepwater Well Design Considerations, will identify considerations for use in deepwater well design. API Std 65-2 has been written to complement the objectives of API RP 90 and API RP 96 and their recommended practices.

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Isolating Potential Flow Zones During Well Construction

1 Scope

1.1 Overview

This standard contains practices for isolating potential flow zones, an integral element in maintaining well integrity. The focus of this standard is the prevention of flow through or past barriers that are installed during well construction. Barriers that seal wellbore and formation pressures or flows may include mechanical barriers such as seals, cement, or hydrostatic head, or operational barriers such as flow detection practices. Operational barriers are practices that result in activation of a physical barrier. Though physical barriers may dominate, the total system reliability of a particular design is dependent on the existence of both types of barriers.

1.2 Objectives

The objectives of this guideline are two-fold. The first is to help prevent and/or control flows just prior to, during, and after primary cementing operations to install or “set” casing and liner pipe strings in wells. Some of these flows have caused loss of well control. They threaten the safety of personnel, the environment, and the drilling rigs themselves. The second objective is to help prevent sustained casing pressure (SCP), also a serious industry problem.

API RP 90, provides guidelines on managing annular casing pressure (ACP) including SCP, thermal casing pressure, and operator-imposed pressure. These guidelines include monitoring, diagnostic testing, establishing the maximum allowable wellhead operating pressure (MAWOP), documenting annular casing pressure, and risk assessment methodologies.

1.3 Background and Technology Review

A detailed background and technology review are in Annex A. Historical data, perspectives, studies, statistics, lessons learned, etc. are included. All this information has been written to help explain how some practices work, have become proven or invalidated, or had performance limitations placed upon their application.

1.4 Conditions of Applicability

The process of barrier element selection and installation (including cement) is governed by the anticipated presence or absence of potential flow zones that require isolation for well integrity or regulatory purposes. This document applies only when it is deemed necessary that a potential flow zone be isolated. The guidance from this document covers recommendations for pressure-containment barrier (cement, packers, etc.) design and well construction practices that affect the zonal isolation process to prevent or mitigate annular fluid flow or pressure. These practices may also help prevent loss of well control (LWC) incidents and minimize the occurrence of SCP during well construction and production.

As presented earlier herein, the content of this document is not all inclusive and not intended to alleviate the need for detailed information found in textbooks, manuals, technical papers, or other documents. Included are those practices (well design, drilling, completion, etc.) that may positively or negatively affect pressure-containment barrier sealing performance along with methods to enhance the positive effects and to minimize any negative ones.

This document does not address shallow water flow zones in deepwater wells which are covered in API RP 65.

1.5 Well Planning and Drilling Plan Considerations

Annex B includes consideration in well planning and drilling plan determinations, such as evaluation for flow potential, site selection, shallow hazards, deeper hazard contingency planning, well control planning for fluid influxes, planning for lost circulation control, regulatory issues and communications plans, planning the well, pore pressure, fracture gradient, drilling fluid weight, casing plan, cementing plan, drilling plan, wellbore hydraulics, wellbore cleaning, barrier design, and contingency planning. These elements factor into the planning of the well to enhance the barrier sealing performance.

In some cases, pre-spud information gathered from offset well(s) and/or from high resolution seismic surveys can be used to indicate flow potential for a particular drilling prospect. Any relevant information should be communicated to the appropriate service provider for incorporation into the design for a particular fluid (drilling fluid or cement) and for preparing engineering and operations procedures.

1.6 Drilling the Well

Annex C gives a general overview of drilling the well and some of the factors that might be considered by the drilling group. Some of those factors may include general practices while drilling, monitoring and maintaining wellbore stability, mitigating lost circulation, and planning and operational considerations. There may be other factors to consider such as type and location of the well being drilled. These factors should be considered during the drilling of the well to enhance the barrier sealing performance. Detailed discussion of these factors is included in Annex C and may be mentioned in other sections.

1.7 Summary of Considerations

Isolating a potential flow zone with cement is an interdependent process. Individual process elements such as slurry design and testing, applied engineering and job execution all impact the ability to successfully install a cement barrier. Superimposed upon these elements are the conditions found in the well at the time of cementing.

Certain cementing process elements contained in Annex D may be individually critical to isolating a potential flow zone or may be of minor consequence until made critical by a separate (sometimes unrelated) event or past well engineering decisions. Conversely, certain elements may not be dominant factors in the success in one cementing operation, yet vitally important in another.

Collectively, the elements described in Annex D produce the design, engineering and operational framework for successfully isolating a potential flow zone.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API Recommended Practice 10B-2/ISO 10426-2, *Recommended Practice for Testing Well Cements*

API Recommended Practice 10B-3/ISO 10426-3, *Recommended Practice on Testing of Deepwater Well Cement Formulations*

API Recommended Practice 10B-4/ISO 10426-4, *Recommended Practice on Preparation and Testing of Foamed Cement Slurries at Atmospheric Pressure*

API Recommended Practice 10B-5/ISO 10426-5, *Recommended Practice on Determination of Shrinkage and Expansion of Well Cement Formulations at Atmospheric Pressure*

API Recommended Practice 10B-6/ISO 10426-6, *Recommended Practice on Determining the Static Gel Strength of Cement Formulations*

API Specification 10D/ISO 10427-1, *Specification for Bow-Spring Casing Centralizers*

API Specification 10D-2/ISO 10427-2, *Recommended Practice for Centralizer Placement and Stop Collar Testing*

API Recommended Practice 10F/ISO 10427-3, *Recommended Practice for Performance Testing of Cementing Float Equipment*

API Technical Report 10TR1, *Cement Sheath Evaluation*

API Technical Report 10TR3, *Temperatures for API Cement Operating Thickening Time Tests*

API Technical Report 10TR4, *Technical Report on Considerations Regarding Selection of Centralizers for Primary Cementing Operations*

API Technical Report 10TR5, *Technical Report on Methods for Testing of Solid and Rigid Centralizers*

API Recommended Practice 13B-1/ISO 10414-1, *Recommended Practice for Field Testing Water-Based Drilling Fluids*

API Recommended Practice 13B-2/ISO 10414-2, *Recommended Practice for Field Testing Oil-based Drilling Fluids*

API Recommended Practice 53, *Blowout Prevention Equipment Systems for Drilling Operations*

API Recommended Practice 65, *Cementing Shallow Water Flow Zones in Deep Water Wells*

API Recommended Practice 90, *Annular Casing Pressure Management for Offshore Wells*

3 Definitions, and Abbreviated Terms

3.1 Definitions

For the purposes of this document the following terms and definitions apply. In addition to those listed below other definitions and abbreviations may be found in oilfield glossaries at websites listed in the Bibliography. [47,48,49,50,51]

3.1.1
ambient pressure
Pressure external to the wellhead. In the case of a surface wellhead it would be 0 psig. In the case of a subsea well head, it would be equal to the hydrostatic pressure of seawater at the depth of the subsea wellhead in psig.

3.1.2
annular flow
The flow of formation fluids (liquids and/or gases) from the formation into a space or pathway in an annulus within a well. The annular flow may follow various flow paths inside the annulus to other points including those at shallower or deeper depths.

3.1.3
annular packers and seal rings
Mechanical barrier devices with flexible, elastomeric sealing elements that can be run into a well on casing or liners for application as:

a) annular element installed between an inner and outer pipe or between a casing and openhole formation to seal the annulus,

b) annular seal rings installed on the inner pipe string to seal the micro-annulus and voids formed between the cement sheath and the inner pipe string.

3.1.4
annular pressure buildup
APB
Pressure generated within a sealed annulus by thermal expansion of trapped wellbore fluids typically during production. May also occur during drilling operations when trapped annular fluids at cool shallow depths are exposed to high temperatures from fluids circulating in deep, hot hole sections. This thermally induced pressure is defined and listed in API RP 90 as thermal casing pressure. APB is also referred to as annular fluid expansion (AFE).

3.1.5
annuli
Plural of annulus. A well may contain several annuli formed by multiple casing and liner pipe strings.

3.1.6
annulus
The space between the borehole and tubulars or between tubulars, where fluid can flow. The annulus designation between the production tubing and production casing is the "A" annulus. Outer annuli between other strings are designated B, C, D, etc. as the pipe sizes increase in diameter.

3.1.7
barrier (barrier element)
A component or practice that contributes to the total system reliability by preventing liquid or gas flow if properly installed.

3.1.8
blowout preventer
BOP
A device attached to the casing head that allows the well to be sealed to confine the well fluids in the wellbore. Refer to API RP 53 or other relevant standards for further information.

3.1.9
borehole
Wellbore sections which are not cased with pipe, commonly called open hole.

3.1.10
bottom hole assembly
BHA
Bottom hole assembly is the collection of the bit, drill collars, stabilizers, reamers, hole openers, MWD/LWD/PWD, mud motor, directional steering system and other tools at the base of the drill string that serve special purposes associated with drilling.

3.1.11
cased hole
The wellbore intervals in a well that are cased with casing and/or liner pipe. The diameter of these hole sections is the inside diameter of the pipe contained therein.

3.1.12
completion string
The completion string consists primarily of production tubing, but also includes additional components such as the surface controlled subsurface safety valve (SCSSV), gas lift mandrels, chemical injection and instrument ports, landing nipples, and packer or packer seal assemblies. The completion string is run inside the production casing and used to produce fluids to the surface.

3.1.13
conductor casing
Provides structural support for the well, wellhead and completion equipment, and often provides hole stability for initial drilling operations. This casing string is typically not designed for pressure containment. However, in some cases, the conductor casing may serve to isolate shallow formations, similar to a surface casing.

3.1.14
critical gel strength period
CGSP
The time between the development of the critical static gel strength (CSGS) and a static gel strength of 500 lbf/100 ft^2.

3.1.15
critical static gel strength
CSGS
The static gel strength of the cement that results in the decay of hydrostatic pressure to the point at which pressure is balanced (hydrostatic equals pore pressure) at a point adjacent to the potential flowing formation(s).

3.1.16
diverter
A device connected to the top of the wellhead or marine riser, directing flow away from the rig.

3.1.17
riser
The extension of the wellbore from the subsea BOP stack to the drilling vessel. The riser provides for fluid returns to the drilling vessel, supports the choke, kill, and control lines, guides tools into the well, and serves as a running string for the BOP stack.

3.1.18
drive/jet pipe
Casing which supports unconsolidated sediments providing hole stability for initial drilling operations. This is normally the first string set and provides no pressure containment. This string can also provide structural support to the well system. See also definition for structural pipe (or casing).

3.1.19
equivalent circulating density
ECD
Equivalent circulating density is the effective density of the circulating fluid in the wellbore resulting from the sum of the hydrostatic pressure imposed by the static fluid column and the friction pressure.

3.1.20
external casing packer
ECP
An external casing packer is a mechanical annular barrier that has elastomeric elements that seal the annulus when inflated. Also see the definition in this section for annular packers and the description of an ECP in 4.4.

3.1.21
fixed platform wells
Wells completed with a surface wellhead and a surface tree on a fixed platform. All of the casing strings are tied back to the surface wellhead.

3.1.22
formation fluids
Fluids present within the pores, fractures, faults, vugs, caverns, or any other spaces of formations are called formation fluids whether or not they were naturally formed or injected therein. The physical state of formation fluids

may be liquids or gases and include various types such as hydrocarbons, fresh or saline water, carbon dioxide, hydrogen sulfide, etc.

3.1.23
formation integrity test
FIT
Formation integrity test is similar to a leak-off test (LOT) except that fracture initiation pressure is not exceeded. See definition of leak-off tests.

3.1.24
fracture gradient
FG
A factor, that when multiplied by the true vertical depth, calculates the fracturing initiation pressure.

3.1.25
hybrid wells
Wells drilled with a subsea wellhead and completed with a surface casing head, a surface tubing head, a surface tubing hanger and a surface tree.

3.1.26
intermediate casing
Casing that is set when geological characteristics or wellbore conditions require isolation. These conditions include, but are not limited to, prevention of lost circulation, formation fluid influx or hole instability. Multiple intermediate casing strings can be run in a single well.

3.1.27
leak-off test
LOT
A leak-off test is a procedure used to determine the wellbore pressure required to initiate a fracture in the open or exposed formations.

3.1.28
liner
A liner is a casing string that does not extend to the top of the well or to the wellhead. Liners are anchored or suspended from inside the previous casing string using a liner hanger. The liner can be fitted with special components so that it can be connected or tied back to the surface at a later time.

3.1.29
liner hanger
A device used to attach or hang a liner from the internal wall of a previously set casing string. Conventional liner hangers are “hung” (connected to the last casing) by setting slips that grip against the inner wall of the previously set casing string. Expandable liner hangers are hung by external expansion of the hanger against the inner wall of the previously set casing string.

3.1.30
liner top packer
LTP
A mechanical barrier device typically with flexible, elastomeric sealing elements that can be run into a wellbore with a smaller initial outside diameter that then expands externally to seal the annulus between the liner and the previously installed casing string. Liner top packers are also called liner packers.

3.1.31
loss of well control
LWC
A loss of well control incident is an uncontrolled flow of subterranean formation fluids such as gas, oil, water, etc. and/or well fluids into the environment or into a separate underground formation, in which case it is called an underground blowout.

3.1.32
logging while drilling
LWD
The measurement of formation properties during the drilling of the borehole by logging tools installed in the BHA.

3.1.33
maximum allowable wellhead operating pressure
MAWOP
The maximum allowable operating pressure for a particular annulus, measured at the wellhead relative to ambient pressure. It applies to SCP, thermal casing pressure, pressure from a well control event and operator imposed casing pressure.

3.1.34
mechanical barrier
A subset of physical barriers that features mechanical equipment; not set cement or a hydrostatic fluid column.

3.1.35
mudline
Mudline as referenced in subsea operations refers to the seafloor.

3.1.36
mudline packoff or packer
An upper packer run on the production tubing and set in the production casing below the mudline wellhead to isolate the production riser section from the production casing. These mechanical barrier devices are commonly installed in hybrid wells.

3.1.37
mudline suspension system
A casing suspension system that allows a well to be drilled using a surface BOP and wellhead. The mudline suspension equipment provides for individual casing hangers to be installed with each casing string that interconnect with each other at a preset point below the mudline. The mudline suspension casing hangers do not provide a pressure barrier.

3.1.38
mudline suspension wells
A well drilled using a mudline suspension system and a surface BOP. The mudline suspension well may be completed as either a surface well or as a subsea well.

3.1.39
measurement while drilling
MWD
The measurement of physical properties while drilling, such as pressure, temperature and borehole trajectory, by tools installed in the BHA.

3.1.40
non-aqueous fluid
NAF
Non-aqueous fluid is a non-aqueous drilling fluid or well circulating fluid. Common NAF systems are diesel, mineral oil, or synthetic fluid based invert emulsions, or other non-water based fluids.

3.1.41
nippling down
The process of removing well-control or pressure-control equipment such as a BOP system.

3.1.42
nippling up
The process of installing well-control or pressure-control equipment such as a BOP system.

3.1.43
operator imposed casing pressure
Pressure in a casing that is operator imposed for purposes such as casing pressure integrity tests (prior to drilling out the shoe), gas lift, fluid injection, stimulation treatments, thermal insulation, etc.

3.1.44
overbalance pressure
OBP
Overbalance pressure is the amount by which the hydrostatic pressure exceeds the pore pressure of a formation.

3.1.45
physical barrier element
Physical barrier elements can be classified as hydrostatic, mechanical or solidified chemical materials (usually cement).

3.1.46
polished bore receptacle
PBR
A device with a honed internal diameter (ID) sealing surface for landing a production tubing seal assembly or tie back casing.

3.1.47
pore pressure
PP
Pore pressure is the pressure of the fluid inside the pore spaces of a formation.

3.1.48
potential flow zone
Any zone in a well where flow is possible under when wellbore pressure is less than pore pressure.

3.1.49
production casing
Casing that is set through a productive interval.

3.1.50
production liner
A liner that is set through a productive interval.

3.1.51
production riser
The casing string(s) rising from the seafloor to the wellhead on fixed platforms or the casing string(s) attached to the subsea wellhead rising from the seafloor to the surface wellhead on hybrid wells.

3.1.52
production tubing
Tubing that is run inside the production casing and used to convey produced fluids from the hydrocarbon bearing formation to the surface. Tubing may also be used for injection.

3.1.53
pressure while drilling
PWD
The measurement of downhole pressure while drilling by a tool installed in the BHA.

3.1.54
rate of penetration
ROP
Common term for drilling rate; usually expressed in units of ft/hour or m/hour.

3.1.55
static gel strength
SGS
The yield stress of fluids at rest.

3.1.56
structural pipe (or casing)
Pipe utilized to facilitate the drilling of a well, but not intended for pressure containment after the well has been drilled. Supports unconsolidated sediments and provides hole stability for initial drilling operations, axial support for casing loads and bending loads from the wellhead. See also definition for drive/jet pipe.

3.1.57
subsea wells
Wells drilled and completed with a subsea wellhead located near the seafloor.

3.1.58
subsea wellhead
A wellhead that is located near the seafloor.

3.1.59
surface casing
Casing run to isolate shallow formations.

3.1.60
surface well
A land or offshore well completed on the surface with individual casing heads, tubing head, a surface tubing hanger, and a surface christmas tree, all residing at a designated level above the water line on a fixed platform.

3.1.61
sustained casing pressure
SCP
Pressure in an annulus of casing strings that is measurable at the wellhead that rebuilds to at least the same pressure level after pressure has been bled down. SCP is not due solely to temperature induced fluid expansion or a pressure that has been imposed by the operator. See API RP 90 for further information.

3.1.62
tieback casing
Casing that is run from a liner hanger back to the wellhead after the initial liner and hanger system have been installed.

3.1.63
well barrier system
Well barrier system is one or more barriers that act in series to prevent flow. Well barriers that do not act in series are not considered part of a single well barrier system, as they do not act together to increase total system reliability.

3.1.64
wellbore
The borehole or cased hole sections in a well.

3.1.65
wellhead
A device upon which the BOP and casing hangers are installed during the well construction phase. Also the system of spools, valves and assorted adapters that provide pressure control of a producing well. The wellhead also incorporates a means of hanging the production tubing and installing the christmas tree and surface flow-control facilities in preparation for the production phase of the well.

3.1.66
well integrity
A quality or condition of a well in being structurally sound with competent pressure seals by application of technical, operational and organizational solutions that reduce the risk of uncontrolled release of formation fluids throughout the well life cycle.

3.1.67
waiting on cement
WOC
Waiting on cement, normally expressed in hours, is the period of time after the cement has been placed until the time subsequent drilling or completions operations can resume.

3.2 Abbreviations

ACP	annular casing pressure
API	American Petroleum Institute
APB	annular pressure buildup
BHA	bottom hole assembly
BHCT	bottom hole circulating temperature
BHP	bottom hole pressure
BHST	bottom hole static temperature
BHT	bottom hole temperature
BOEMRE	Bureau of Ocean Energy Management Regulation and Enforcement
BOP	blowout preventer
CGSP	critical gel strength period
CSGS	critical static gel strength
ECD	equivalent circulating density
ECP	external casing packer

EMW	equivalent mud weight
FG	frac gradient
FIT	formation integrity test
HPHT	high pressure, high temperature
LOT	leak-off test
LCM	lost circulation material
LWC	loss of well control
LWD	logging while drilling
LTP	liner top packer
mD	millidarcy
MD	measured depth
MLSH	mud line suspension hanger
MMS	Minerals Management Service
MWD	measurement while drilling
NAF	non-aqueous fluid
ND	nippling down
NU	nippling up
OBP	over balanced pressure
PBR	polished bore receptacle
PIT	pump-in tests
PP	pore pressure
ppge	pounds per gallon equivalent density
psi	pounds per square inch
PWD	pressure while drilling
ROP	rate of penetration
RP	Recommended Practice
SCP	sustained casing pressure
SGS	static gel strength
SPE	Society of Petroleum Engineers
TOC	top of cement
TVD	true vertical depth
WOB	weight on bit
WOC	waiting on cement

4 Barriers

4.1 General

Barrier elements can be classified as either physical or operational. With the exception of operational procedures related to the use of cement as a physical barrier element, operational barriers are not covered in this standard.

Barriers contribute to total system reliability; total system reliability is the probability of barrier success, or one minus the probability that all barriers to uncontrolled flow along a particular path will fail simultaneously. The principles, processes and procedures for planning and implementing barriers are necessary to ensure operations integrity during all life cycle phases of the well. This barrier philosophy should be applied to each potential flow path, considering the consequences of a loss of control.

4.2 Physical Barrier Elements

Physical barrier elements can be classified as hydrostatic, mechanical or solidified chemical materials (usually cement).

4.3 Hydrostatic Barrier Elements

Hydrostatic barrier elements are those in which a column of fluid(s) imposes a hydrostatic pressure which exceeds the pore pressure of the potential flow zone. These fluids may include drilling fluids, cement spacers, cement slurries, water and completion fluids. It is important to understand the hydrostatic contribution of any of these fluids can change with time. Solids settling in drilling fluids or spacers could reduce the hydrostatic pressure at the flow zone. Static gel strength development of cement during hydration will also reduce the transmission of pressure (see 5.7.8). Drilling fluids and spacers also develop static gel strength, although to a lesser extent than cement, and their contribution to loss of hydrostatic pressure should be considered. Some fluids such as NAF may exhibit compressible behavior so downhole temperature and pressure should be considered when calculating the hydrostatic contribution of those fluids. A decrease in the height of the fluid column due to downhole losses may compromise the hydrostatic barrier element and should be taken into account in the planning stages of the operation.

4.4 Annular Mechanical Barrier Elements

4.4.1 General

A mechanical barrier is a seal achieved by mechanical means between casing strings, a casing string and a liner, a casing string and the borehole, a casing string and a wellhead housing, or a liner and the borehole that isolates a potential flowing zone(s). When both cement and mechanical barriers are used in series, it is not possible to physically test them independently to know which is holding pressure. Consequently, both should be designed to be effective and contain the maximum anticipated load. As with all engineering processes, the application of mechanical barriers should be chosen with care. Such barriers may not be necessary or advisable. It is up to the user to exercise due diligence in understanding the variables involved and make the correct decisions.

NOTE When cement cannot be used as a barrier during well construction, mechanical barriers become the primary barriers for isolating annular flow.

Mechanical barriers can be divided into two basic classifications.

1) Mechanical barrier elements designed for preventing loss of well control (LWC).

2) Mechanical barrier elements designed for preventing sustained casing pressure (SCP).

4.4.2 Mechanical Barrier Elements for Preventing LWC

4.4.2.1 General

Mechanical barriers can significantly reduce the risk of annular flow past them. Annular flows may occur while temporary mechanical barriers such as BOPs or diverters are nippled down or a hydrostatic barrier is removed following cementing operations. These flows may result from:

— loss of hydrostatic pressure as the unset cement column develops static gel strength and supports its own weight;

— cement fluid loss;

— internal cement shrinkage;

— reduced fluid density in the annulus during cement washout operations;

— lost circulation during cementing causing:

  — reduced hydrostatic pressure due to shorter fluid columns,

  — lower than planned top of cement columns leaving potential flow zones un-cemented;

— or combination of the above.

While mechanical barriers are designed to prevent the flow of annular fluids past the barrier element or seal, setting of the barrier may actually increase the chance of fluids entering the cement slurry if the cement slurry is not properly designed. Setting the barrier isolates all potential flow zones below the barrier from all of the hydrostatic pressure above the barrier. This reduction in overbalance pressure (OBP) on any potential flow zones effectively decreases the CSGS as defined in 5.7.8. The pressure in the annulus therefore drops to the pore pressure of the flow zones at an earlier time after the cement is in place, increasing the window of opportunity for fluid to enter the cement slurry. Because of this increased chance of fluid entering the cement, it is very important that the slurry placed across potential flow zones is designed with fluid migration control properties (see 5.7.14). Properly designed cement slurries should be considered to help prevent the fluid from migrating through the annulus once it has entered the cement. If migration is not controlled there is potential for either a cross-flow into a lower pressure zone or a collection of fluid directly below the mechanical barrier.

4.4.2.2 Liner Top Packers

Liner top packers (LTP) are typically run in the well with the liner and set immediately after cementing; however, they may be run and set on a separate trip after the liner has been cemented. LTPs seal the annulus between the liner and the host casing string. Once set, they prevent upward or downward flow. If they are tested after they are set, they may allow select operations to safely proceed without having to wait on cement (WOC). Local regulations may supersede this provision.

The industry has successfully used liner top packers for many years to eliminate/reduce flow after cementing as well as to reduce squeeze work on liner tops. The liner top packer is a proven product when properly designed, installed, and verified for the specific application. Expandable liner hangers with elastomer pack-off elements function both as liner hangers and liner top packers.

4.4.2.3 Expandable Tubulars

Expandable tubular liners or expandable liner hangers provide a mechanical barrier while preserving the maximum interior diameter of the liner. A cone or other device expands the pipe to a larger diameter forming either a metal-to-metal or elastomeric seal with the host pipe. When an expandable liner is installed below a host pipe, the liner is placed on the bottom of the hole and cement is (optionally) circulated around the pipe. Expandable tubulars have reduced burst and collapse ratings, which **shall** be taken into account in the well design.

4.4.2.4 Multiple Seals in a Single High Pressure Wellhead Housing

Some wellhead systems provide several casing suspension and sealing positions in one high pressure wellhead housing. The casing hanger is landed, the pipe is cemented in place and then the seal assembly is energized. In some situations the weight of the casing string may hold the seal in place, while in others it is necessary to engage a locking mechanism.

4.4.2.5 Sub Wellhead Liner Hanger Profiles

Landing profiles can be pre-installed in a host casing to allow installation of liners without using the wellhead hanger profiles. The liners are run with a mating profile and the mechanical seals are subsequently engaged to provide a mechanical barrier in the annulus between the liner and host casing, usually following cementing operations. The liner is an extension or deepening of the host casing. This allows for more casing size flexibility in the well design.

4.4.2.6 Inflatable External Casing Packers

Inflatable external casing packers have inflatable elements mounted on mandrels that are equivalent in strength to the liner or casing string. The advantages of these packers include the ability to run through reduced IDs and seal in larger ID sections of casing or open hole. Some open holes may not be suitable for sealing by an inflatable packer. These include holes with irregularities such as fractures, faults, and unconsolidated formations or with drilling induced hole enlargements or key seats. The mechanical barrier is installed by inflating the packer with cement, drilling fluid, or completion fluid. Sealing elements or elastomers can be designed for specific applications.

4.4.2.7 Hydraulic Set External Casing Packers

Hydraulic set external packers differ from inflatable packers in that the external elastomer element is expanded by compressing it, rather than inflating it. Hydraulic-set external casing packers can be used in situations in which pressure can be applied to the casing string to set the packer. The mechanical barrier is energized by applied pressure that activates hydraulic cylinders within the tool to generate pack-off forces. This generally requires bumping the plug that follows the cement slurry; however, pressure can be applied through alternate means. This mechanical barrier can be installed on the inner casing string anywhere within the casing/casing annulus and does not require that casing be set off bottom. This type packer does not require a load shoulder or other setting device. Packers are available with or without slips and are selected for the diameters of the tubulars involved and anticipated differential pressure across the sealing area.

4.4.3 Mechanical Barrier Elements for Preventing SCP

4.4.3.1 General

Some of the barrier elements designed for preventing loss of well control (see 4.4.2) may also act to minimize the potential for SCP. The barrier elements discussed in this section may prevent SCP but they are not effective for preventing LWC events, either because they do not isolate the entire annular area or because a full seal from the set cement will not have developed while the slurry is in the critical gel strength period (CGSP).

4.4.3.2 Annular Seal Rings

Annular seal rings are mechanical barrier devices with flexible, elastomeric sealing elements that can be run in a well on casing or liners for applications to seal the micro-annulus and voids formed between the cement sheath and the inner pipe string. The sealing element has an outside diameter designed to seal the size of a micro-annulus and should not excessively restrict flow during the hole conditioning and cementing process. The sealing element may or may not be designed to chemically swell and may only deform to seal a micro-annulus or void at the interface between the cement sheath and inner pipe string.

4.4.3.3 Swellable Packers

Swellable packers are mechanical barrier devices with flexible, swellable elastomers that are run in a well on casing or liners. The sealing element is designed to chemically swell when it comes into contact with an appropriate activating fluid such as hydrocarbons or produced water. Due to the limited expansion ratios, swellable packers may not be appropriate for some applications. Swellable packers may be used alone or in conjunction with cement.

4.5 Mechanical Wellbore Barrier Elements

4.5.1 General

A mechanical wellbore barrier is a seal achieved by mechanical means inside casing or the borehole that isolates a potential flowing zone. When cement is used in conjunction with a mechanical barrier, there are two potential barriers and it is not possible to know if one or both is preventing flow. When cement is used as a barrier during well construction, mechanical barriers are complementary to a properly executed cementing operation and both may contribute to the total system reliability.

4.5.2 Downhole Tools

4.5.2.1 General

During well construction operations, downhole tools such as packers, retainers and bridge plugs are typically utilized as temporary mechanical barriers to facilitate rig operations. These tools can be classified as retrievable, permanent or drillable and can be used separately, or sometimes in combination.

Downhole tools have various pressure and temperature ratings and tool selection should consider the pressure and temperature of the application for which the tool will be utilized. Care should be exercised when removing the barriers as there could be a differential pressure across the tools.

4.5.2.2 Cased Hole Retrievable Tools

Packers and retrievable bridge plugs are tools that consist of a sealing device, a holding or setting device and an inside passage for fluids. These tools commonly contain mechanical slips to hold the packer in place and elastomeric sealing elements either mechanically or hydraulically set to provide a seal against the casing. Retrievable tools can be set and released many times in a single trip into the wellbore and can perform multiple functions including providing temporary barriers, testing casing, remedial cementing, etc.

Storm packers can provide a temporary barrier and are typically utilized when a rig is required to evacuate. These packers support the total of the drill pipe and drilling assembly to be hung off below the packer. Storm packers utilize a valve and back-off assembly above the packer, allowing the drill pipe above the packer to be pulled from the wellbore, leaving the packer and drill pipe isolation valve in place with the drill string hanging below.

4.5.2.3 Drillable Bridge Plugs

Drillable bridge plugs can be run in the wellbore, set and then drilled after other operations. The slip system on the tools outer body anchors the plug to the wellbore while a packing element provides a pressure seal. Drillable bridge plugs are constructed of drillable metals such as cast iron or composite materials.

One aspect in which composite and conventional cast iron drillable bridge plugs differ is their life expectancies. Cast iron plugs have a long life and can be left in the wellbore for an extended period of time, depending on the downhole environment. Composite plugs, on the other hand, have a short life expectancy and the tool must be selected with the longevity required for the given application. When utilizing composite bridge plugs, the working life of the plug in the planned downhole setting environment should be considered.

4.5.2.4 Retainers

Drillable squeeze packers are commonly referred to as cement retainers. A retainer is a mechanical barrier that can be set on drill pipe or wireline. The retainer provides isolation both above and below where set, but communication through the retainer can be achieved though a sliding sleeve check valve. The check valve is typically operated by a stinger seal assembly. When the stinger is removed from the retainer, the valve closes and isolates the wellbore below the retainer.

4.5.2.5 Cementing Head

Cementing plug containers and head assemblies provide the means by which conventional casing wiper plugs, or darts to launch subsea plugs, can be launched from the surface without significant interruption of pumping operations. If other wellbore barriers are not in place and the float equipment fails, surface cementing plug containers may function as a temporary wellbore mechanical barrier. Prior to removing the cementing head, ensure adequate wellbore barriers are in place.

Cementing heads **shall** be pressure tested by the supplier to the maximum working pressure rating of the head as part of a regular maintenance program. The cementing head selected **shall** have a working pressure in excess of the maximum anticipated surface pressure for the job. Cementing heads are discussed further in 5.4.5.

4.6 Set Cement as a Barrier Element

4.6.1 General

Regulators require that if the operator plans to remove a barrier element, such as a diverter or BOP stack, the operator **shall** determine when it will be safe to do so.

Determination of the safe WOC time should take into account several factors including whether or not a potential flow zone is exposed in the wellbore or if there is the possibility that one is exposed (if it is unknown). There may be other downhole conditions that could impact the guideline. It is extremely important that any plan for removing a barrier element be modified toward a conservative approach to avoid loss of well control or risk to personnel or equipment. Observations prior, during and after the cementing operation that could impact the plan for removing a barrier element include but are not limited to:

— substantial loss of returns while pumping cement;

— significant deviation from the cementing plan such as inability to maintain the desired density of the slurry, use of less than designed volume of slurry, etc.;

— premature returns of cement slurry to surface;

— measured lift pressure of the cement just prior to bumping the plug indicates the top of cement (TOC) is not high enough in the annulus to isolate the uppermost potential flow zone;

— indications of fluid influx prior to, during or after cementing.

In these cases, confidence in the cement job would decrease and further assessment is needed before removing a barrier element.

4.6.2 Special Operational Requirements

The following are special operational requirements.

— Operators and all involved contractors **shall** perform a risk assessment prior to utilizing foamed cement (see 5.6.5.9 and 5.7.13 for more information on foamed cement), and make sure that the results of this assessment are incorporated in the cementing plan. The risk assessment should address safety, health and environmental risks as well as design and operational risks;

— Operators and contractors **shall** not run tubing in the annulus between the casing and the diverter, or BOP, after completion of the cementing operation and prior to determining the well has no potential for flow.

— Hydrostatic pressure calculations **shall** be performed and results considered prior to commencing any operation that will result in a change in hydrostatic pressure in the wellbore.

4.6.3 WOC Guidelines Prior to Removing a Temporary Barrier Element

If no potential flow zone(s) exist or if alternate physical barrier elements are in place, subsequent operations may commence without WOC, if regulations allow.

If design and operational parameters indicate isolation of potential flow zones, cement **shall** be considered a physical barrier element only when it has attained a minimum of 50 psi compressive or sonic strength. The 50 psi compressive or sonic strength threshold exceeds the minimum static gel strength value needed to prevent fluid influx. Local regulations **shall** be adhered to with regards to WOC. However, caution should be exercised when the specified WOC time is less than the time required for the cement to reach a strength of 50 psi.

Laboratory tests, conducted under simulated downhole temperature and pressure conditions (within the limits of the laboratory equipment) with representative cement, additives and mix water **shall** indicate the sustained development of 50 psi compressive or sonic strength. Care should be taken that sonic strength continues to develop following the cement slurry's initial set and that the first "Time to 50 psi" reading is not an artifact of the initial temperature and pressure ramp used in the testing. See the example below (Figure 1) in which an initial "Time to 50 psi" is recorded in 29 minutes 30 seconds while the sustained development of 50 psi occurs in approximately 3 hrs 30 minutes.

Contingency plans to address a flow should be in place prior to initiating the removal of a temporary barrier element after completing a cement job. This planning should include key parties involved in performing the associated operations and specifically should include the operator, drilling contractor, and cementing contractor. The time from the start of removing a barrier element to securing the exposed annulus **shall** be minimized. Waiting time can be reduced if the operator has the required number of tested or verified barrier elements remaining in place prior to removing the barrier element (such as a BOP), subject to local regulatory requirements.

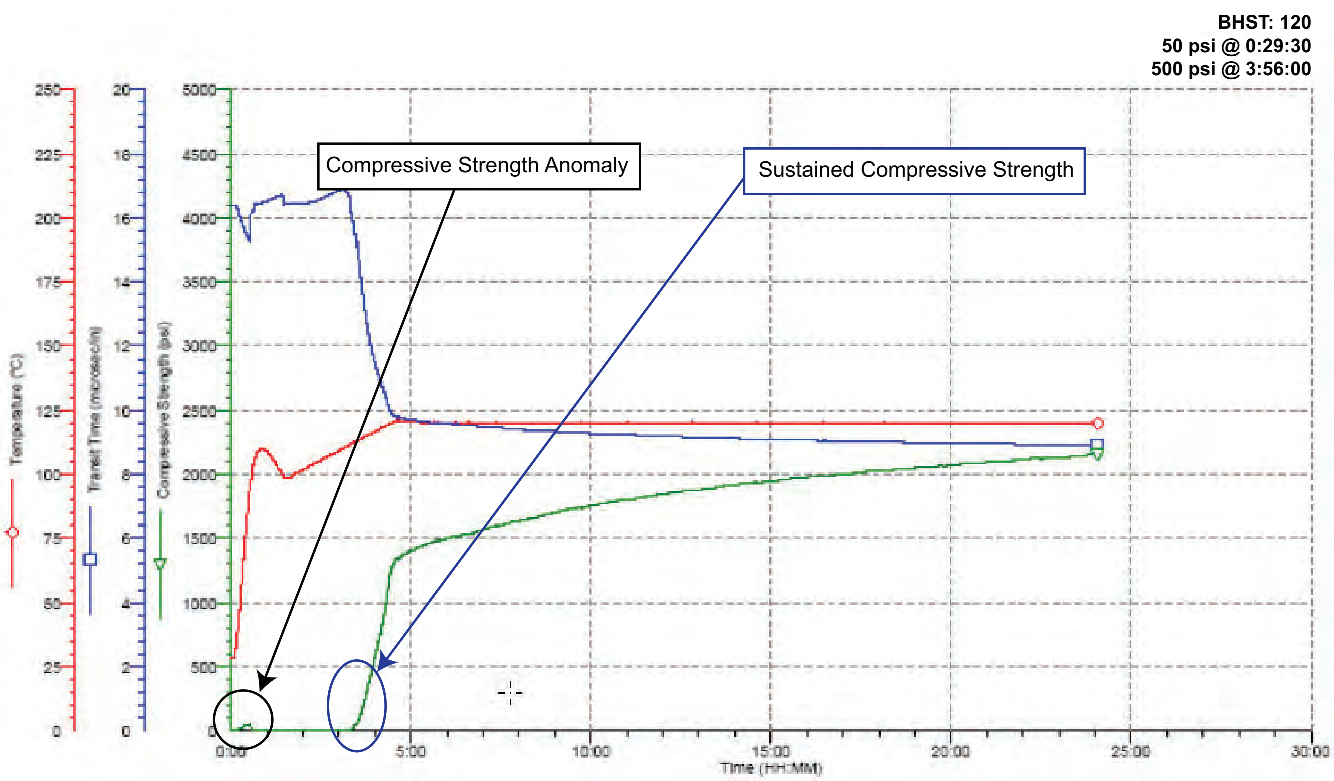

Figure 1—Sonic Strength Anomaly

4.6.4 Cement Wellbore Barriers

4.6.4.1 Shoe Track Barrier Element

A shoe track barrier element is a combination of the two independent float valves and a shoe track of set cement. Under special circumstances (inner-string, reverse cementing, etc.), the use of float valves may not be possible.

Float valves should be rated for the anticipated flow rates and volumes of the fluids pumped during circulation and cementing of the casing string. Float valves **shall** be rated for the differential pressure between the minimum anticipated hydrostatic column above the shoe track and the hydrostatic column in the casing annulus with cement in place. Ensure the float collar is rated for the load imposed when a top cementing plug is landed on it and pressure is applied to verify landing and test the casing. Float valves are typically designed for liquid service (e.g. drilling fluid, cement, etc.). Refer to API RP 10F/ISO 10427-3 for determining service class corresponding to anticipated service requirements.

Float valves may be configured to allow the casing to fill automatically while run into the hole, thereby reducing the surge pressure exerted on the wellbore. These auto-fill devices should be deactivated prior to beginning cementing operations. The impact of auto-fill tools on well control while running casing and procedures for auto-fill conversion should be considered and operational response plans should be in place if flow occurs through the auto-fill float system and up the inside of the casing.

4.6.4.2 Cement Plugs

Cement plugs are set cement located in open hole or inside casing / liner to prevent formation fluid flow between zones or flow up the wellbore. The placement and design of the cement plug should consider specific well conditions such as; pore and fracture pressure gradients, estimated hole volumes, drilling fluid density, presence of hydrocarbons, etc. Slurry properties **shall** be consistent with any regulatory requirements. Cement plugs **shall** be installed and verified as required by regulations.

5 Cementing Practices and Factors Affecting Cementing Success

5.1 Introduction

A well-designed cement job optimizes cement placement through considerations such as laboratory-tested slurry design, honoring pore pressure/ fracture gradient window, use of spacers/pre-flushes, proper density and rheological hierarchy, fluid compatibility and adequate centralization. This section summarizes many of the key drilling issues that affect the quality of a primary cementing operation. This section is not exhaustive, nor does it provide the reader with a comprehensive set of detailed recommendations for well construction. The intent is to highlight the salient aspects that should be considered and summarize the interrelationship between drilling operations and cementing success. All topics discussed are covered in detail in various API, ISO, and other industry publications.

5.2 Hole Quality

Hole quality affects many aspects of the cementing operation. In situations where hole quality could compromise cementing quality, practices exist that may minimize the impact of hole quality. Avoidance of severe doglegs, hole enlargement and spiral patterns in the wellbore will improve the efficiency of drilling fluid displacement during cementing. Use of directional survey data, including azimuth, when modeling centralization and drilling fluid displacement will improve the quality of the results of the simulation.

A caliper log can be a useful tool to confirm the volume of cement slurry required to fill the annulus to the designed TOC. Knowledge of actual hole sizes provides better friction pressure estimations, both for the cementing operation and for running casing. Caliper data of sufficient quality can be used to calculate the centralizer requirements and from centralizer calculations, to calculate flow regimes and rates recommended for effective drilling fluid removal. Sonic and fluid calipers may also be used.

5.3 Drilling Fluid

5.3.1 Drilling Fluid Selection

Drilling fluid (mud) selection and maintenance play a key role in cementing success. Drilling fluid performance affects hole condition (enlargements, etc.), drilling fluid filter cake thickness and gel strength (measured as described in API RP 13B-1/ISO 10414-1 or API RP 13B-2/ISO 10414-2), drilling fluid mobility, fluid and formation compatibility, and bonding of cement to formation.

Drilling fluid performance is controlled by many factors. Drilling with fluids that provide a thin, low permeability filter cake and low non-progressive gel strengths sufficient for transport of drill cuttings and barite support can be more effectively displaced when cementing. Achieving good cementing success through effective drilling fluid displacement requires proper planning. Computer modeling of cement placement or drilling fluid displacement requires careful evaluation of fluid properties and placement processes.

5.3.2 Drilling Fluid Rheology

Drilling fluid rheology has a significant impact on cement placement. Samples representative of the drilling fluid at the time of cementing should be tested for rheological properties prior to cementing operations. This data should be used in displacement simulations.

5.4 Casing Hardware

5.4.1 General

Casing hardware and auxiliary downhole equipment may be used to enhance the cementing operation. Examples include: centralizers, float equipment, stage collars, external casing packers, liner hangers and liner top packers and expandable casing (mechanical barriers are discussed in Section 4).

5.4.2 Centralizers

Appropriate casing centralization is important to successful cement placement and zonal isolation. Casing centralizers exist in many models and designs and are generally categorized as either rigid, solid or bow-spring models. Auxiliary functionalities such as flow diversion and mechanical friction-reduction are also available. Custom-built centralizers are available for either slimhole or extremely large annular clearances. In order for centralization calculations to be done for bowspring centralizers, performance data as measured according to API Spec 10D/ISO 10427-1 should be used. See discussion of installation under 5.6.5.7. Also, see, API RP 10D-2/ISO 10427-2, API 10TR4 and API 10TR5.

5.4.3 Float Equipment

Float equipment is used to prevent the cement from flowing back into the casing when pumping is stopped and/or pressure released. Test procedures for various classes of float equipment and associated mechanical components are provided in API RP 10F/ISO 10427-3.

Float equipment choice should be matched to anticipated bottom hole temperatures and the pressure differentials expected at the end of the cement job. Specialized float equipment including auto-fill, side-ported, and custom-profiled is also available to address the functionalities of surge-reduction and collapse protection, improved hole cleaning, and ease of running casing, respectively. When utilizing auto-fill float equipment, recognize there will be well control implications while the casing is run in the hole.

A float collar and a float shoe can be used together to provide redundant flow-back control as well as a receptacle for contaminated cement slurry. Some lost-circulation materials (LCM) in the drilling fluid and/or cementing fluids may preclude or hamper the use of certain float equipment valve designs. Standard float equipment is not designed to provide a gas-tight seal.

5.4.4 Wiper Plugs

Casing and liner wiper plugs, whether conventional surface release or subsea release, provide the function of mechanically separating cementing fluids from the drilling fluid, wiping the internal diameter of the tubulars, and providing a positive indication of the end of displacement. Wiper plugs should be matched to the anticipated bottom hole temperatures, pressures, depths and drilling fluid type. Not all wiper plugs and associated operating systems (releasing darts) are compatible with all types and manufacturers of float equipment and/or stage tools, liner hanger tools, and liner top packers. Tapered diameter casing strings may require customized wiper plug systems. Wiper plugs and associated operating systems should be designed for the specific size and weight of the casing and all other casing hardware components.

5.4.5 Cementing Plug Containers and Heads

Cementing plug containers and head assemblies provide the means by which wiping devices (casing wiper plugs, drill pipe darts, balls, etc) can be launched from the surface without significant interruption of pumping operations. Cementing heads (plug containers) also allow control of cement U-tubing should the float equipment fail. Each type of cementing head has its own specific capabilities in terms of pressure ratings, mechanical operation, load-carrying capacity, and auxiliary capabilities such as allowing rotation or remote operation. These characteristics are published by the manufacturer. Not all casing wiper plugs are compatible with every model of cementing head and float equipment. Cementing heads and plug sets should be checked for compatibility. Plug containers equipped with remotely-operated plug releasing mechanisms reduce risk to personnel and may minimize shut-down time.

Cementing heads should be in good working order and be pressure-tested as per the service provider's requirements. Various components such as the plug releasing mechanism, plug release indicators, valves, threads and o-rings should be examined prior to each use. Thickness testing should be performed as per the service provider's requirements or if a component is suspect. Type-certification is available from the service provider in many instances. A type-certified plug container is one that has fully traceable components with material mechanical properties verified by laboratory tests.

5.5 Close-tolerance and Other Flow Restriction Considerations

Close tolerances may restrict the flow of drilling and cementing fluids during well circulation and cause lost circulation. Close tolerances are often encountered in pipe-to-pipe annuli, liner tops, expandable casings, and between the inner diameter of outer tubulars and some tools such as liner hangers, liner top packers, polished bore receptacles (PBR), stage tools, external casing packers (ECPs), and expandable tubulars. Conventional types of liner hangers also have reduced flow cross-sectional area called “bypass area” from the flow restrictions formed by the unset slips protruding from the hanger body. The bypass area is further reduced after these slips are set against the inner casing wall to “hang” or connect to and suspend the liner from the casing. Equivalent circulating density (ECD) pressure calculations **shall** include any flow restrictions, particularly those of significant length and small cross-sectional area, such as liner overlaps, liner top packers, liner hangers, tieback sleeves, casing connections and drill pipe tool joints.

5.6 Engineering Design

5.6.1 General

Well construction objectives and local regulations determine the extent of cement coverage and cement performance requirements for each well section. Performance requirements include (but are not limited to) gas control, static gel strength development, fluid loss, free fluid, slurry stability, thickening time, and compressive or sonic strength. Mechanical parameters such as, tensile strength, Young’s Modulus and Poisson’s ratio may also be taken into account in the cement design.

5.6.2 Zonal Coverage Determination

It is important to evaluate which zone(s) have potential for flow in order to plan the cement job to achieve suitable zonal isolation. Such zones should be covered with cement slurries designed to prevent flow after cementing, and the cement placement mechanics should be designed to maximize drilling fluid removal. Zones left uncemented may not flow in the short term if pore pressure is balanced by drilling fluid hydrostatic pressure. However, phenomena such as barite sag and drilling fluid dehydration may lead to SCP.

Cement top selection is influenced by the location of the potential flow zones, regulatory requirements and pore pressure/fracture gradient consideration. Higher density tail slurries may be more easily designed to be “gas tight” (gas controlling) than some lower density lead cements. However, some types of gas controlling cement slurries may be more easily designed based on solids to liquid content rather than density.

5.6.3 Pore Pressure/Frac Gradient

Accurate knowledge of pore pressure and fracture gradient profiles is necessary for successful primary cementing and helps design jobs that prevent lost circulation and annular flows. Pore pressure is a crucial piece of information needed to assess flow potential. The pore pressure and fracture gradient profiles are two of many input values used in computer simulation programs used to evaluate static and dynamic well security.

5.6.4 Temperature

Temperature has the single greatest influence on cement slurry performance. Accurate estimates of cementing temperatures (both static and circulating) are essential to the success of the cement job. These may be available through thermal modeling and or measurement in offset wells. For many wells, API temperature schedules provide adequate estimates of circulating temperatures. However, these schedules are based on data collected in wells in shallow water with little deviation (see API TR 10TR3 on Cementing Temperature Schedules). The API schedules should not be used for wells that vary greatly from these conditions (e.g. deepwater offshore wells or wells with significant deviation). The heat up rate used for a thickening time test can significantly impact the testing result. The heat up rate used for thickening time testing should be based on the anticipated time to bottom for the cement as described in API RP10B-2/ISO 10426-2.

Computer-based thermal modeling programs may be used to develop cementing testing temperatures. Such programs require input information such as static temperature, formation and well fluid thermal characteristics, rheologies, estimated job volumes, planned pump rates and well geometry. The predictions generated by thermal modeling programs may vary significantly; operators may consider employing more than one thermal model to arrive at a cement test temperature schedule. In most circumstances the highest annular temperature found during a cementing operation occurs some distance above the casing/liner shoe.

Temperature information may be obtained from measurement while drilling (MWD) or logging while drilling (LWD) tools as the hole is drilled. Temperatures from MWD or LWD devices tend to be somewhat higher than those derived from models or sensors used on cleanup trips, therefore caution should be applied in using these temperature measurements as the basis for cement testing. Several factors account for this including an elevated drilling fluid suction temperature while drilling compared to initial slurry temperature while cementing. Some bottomhole assemblies and formation types have been demonstrated to give highly elevated MWD readings.

In summary, there are many sources of temperature information. All temperature information should be considered. Sound engineering judgment should be applied to select the best temperature or range of temperatures and the cement should be designed to perform acceptably at that temperature or range of temperatures.

5.6.5 Drilling Fluid Removal

5.6.5.1 Design

Proper slurry design is only part of a successful cementing operation. The other part involves effectively removing the drilling fluid from the well and replacing it with cement slurry. Computer based placement simulators allow the engineer to tailor the cement job to a particular well's conditions rather than relying on arbitrary "rules of thumb." Factors to be considered in planning for efficient drilling fluid removal are discussed in 5.6.5.2 through 5.6.5.9.

5.6.5.2 Annular Fluid Velocity

Higher fluid velocities introduce more energy into the system allowing more efficient removal of gelled drilling fluid. However, tight annular clearances in some wellbore configurations limit how fast the job can be pumped without causing lost returns. Depending on the differentials between fluid rheology and density of the displacing and displaced fluids, and the degree of centralization and hole angle, specific pump rates may promote uneven flow between the narrow and wide sides of the annulus. Fluid simulation modeling is used to determine the best annular velocity, given the parameters and hydraulic limits of the wellbore and surface equipment.

5.6.5.3 Rheology and Density

As a general statement, barring chemical interactions and turbulent dilution effects, drilling fluid removal is more efficient when the displacing fluid displays a higher frictional pressure drop and is of higher density than the fluid being displaced. Various guidelines have been used to decide how to design the density and rheological hierarchy in the displacement design. Narrow pore pressure/fracture gradient windows in some wells may limit application of density/rheology hierarchies.

5.6.5.4 Drilling Fluid Compressibility

Depending on the temperature and pressure, the density and rheology of compressible fluids can vary. Downhole pressure measurements provide static density and ECD information which can be used for modeling drilling fluid removal.

5.6.5.5 Cement Preflush (Wash) and Spacer Design

The purpose of preflushes and spacers is to aid in bulk drilling fluid removal by avoiding incompatible mixtures of the cement slurry and drilling fluid. When non-aqueous drilling fluids are used, preflushes and spacers are used to remove the oily drilling fluid film and water-wet the downhole surfaces. Procedures for testing spacer compatibility are found in API RP 10B-2/ISO 10426-2. Compatibility testing between the cement and spacer or mixtures of cement, spacer and drilling fluid may be required if well conditions warrant. Some computer programs may be used to determine the type and volume of spacers to be pumped for drilling fluid removal and predict the degree of fluid (cement, spacer, drilling fluid) intermixing that may occur during placement. The use of unweighted preflushes or base oil may worsen channeling in some cases and computer simulators may be used to predict this.

5.6.5.6 Pipe Movement

One of the best aids to achieving effective bulk drilling fluid removal is pipe movement. Pipe movement improves the probability of flow on all sides of the annulus. While reciprocating pipe aids in drilling fluid removal it also imparts swab and surge pressures in the well which could lead to fluid influx or losses respectively. Computer simulators can be used to predict surge and swab pressures. The results of these simulations can provide guidance on maximum reciprocation rates that will prevent losses or influx.

Studies have shown that pipe rotation provides better fluid displacement than reciprocation. Depending on well conditions, rotational rates of 10 rpm to 40 rpm have proven effective. Both reciprocation and rotation present operational challenges. When reciprocating pipe it is important that the pipe does not become stuck in a position that prevents it from properly landing out in the wellhead at the end of the cement job. Pipe reciprocation is not possible on subsea wells. The ability to rotate pipe may be limited by the amount of torque that can be applied. Torque limitations may be casing connections, running tools or rig equipment. For full casing strings a rotating cement head is required. Liners are often suitable candidates for rotation if a rotating liner hanger is used.

5.6.5.7 Centralization

If casing is not centralized, it may lay near or against the borehole wall. Drilling fluid, washes, spacers and cement slurry flow most easily on the wide, less restricted side of the annulus. It is difficult, if not impossible, to displace drilling fluid efficiently from the narrow side of the annulus if the casing is poorly centralized. This results in bypassed mud channels, contaminated fluids and the inability to achieve zonal isolation. Centralization is necessary to improve flow all around the pipe and aid in drilling fluid removal. Other devices in the flow path of the cement, such as liner hanger assemblies, PBR, etc. will also impact fluid flow due to eccentricity.

Computer software is available to design centralizer placement to achieve optimum standoff for drilling fluid removal. The effectiveness of centralization is dependent on a number of factors, including the hole size and deviation, casing size and weight, internal diameter of previously set casing/liner, fluid densities, and centralizer placement and properties. Centralizer properties to be considered in calculating the standoff include centralizer type (e.g. rigid, solid or bow spring), minimum and maximum OD, restoring force, starting force and running force. The actual standoff performance properties provided by the manufacturer should be used in these calculations. Caliper logs (preferably giving two or more diameters) and directional surveys are necessary to correctly calculate standoff.

5.6.5.8 Engineering Software

Engineering programs allow the user to tailor the cementing process to account for an individual well's unique conditions. Engineering programs eliminate the need for users to follow arbitrary "rules of thumb." Numerous programs are available but significant variation in the computational complexity and functional capability exists in current well engineering software. These programs are engineering tools; users are encouraged to recognize the capabilities and limitations of the programs and apply sound engineering judgment in their application. Typical program capabilities include the following:

— swab and surge pressures;

— ECD simulations to predict whether the cement job can be performed within the pore pressure/fracture gradient window;

— centralization/standoff calculations;

— displacement effectiveness;

— circulating and post cementing temperature profiles;

— surface pressure predictions;

— foamed cementing calculations (see 5.6.5.9).

As with any engineering program, the quality of a cementing simulator's output depends on the degree to which the input variables are known. It is not likely an engineering program can provide a single correct answer. However, by bracketing variables, the engineer can gain insight that will assist in achieving zonal isolation.

In order to best facilitate the installation of a cement barrier element, centralizer placement, ECD and fluid displacement simulations **shall** be performed. Within the constraints imposed by hydraulic, operational, logistical or well architecture limitations, these results **shall** be considered during the cementing design and execution.

The information entered into the computer simulation should be as accurate as possible. This information should include drilling fluid, spacer, and slurry rheologies, anticipated pump rates, temperature, caliper log information (if available), survey data (if available), well architecture, fracture and pore pressures and hardware configuration.

5.6.5.9 Foamed Cement Modeling

Engineering software should be used in the design and placement of foamed cement. Foamed cement design software is normally incorporated into the cementing service providers' ECD engineering programs. There are two foamed cement placement methods that are commonly used: (1) constant nitrogen injection rate and (2) constant foam density. Regardless of which method is selected, variances in hole size across the foamed cement column may change the density and the downhole nitrogen volume (foam quality) from that which was designed. This density variance is more pronounced when using the constant density method.

The constant nitrogen injection rate method calls for a single nitrogen injection rate (in volume of nitrogen per volume of base cement) to be added to the base cement at surface. This produces a variable foamed cement density downhole owing to the effects of temperature and pressure. The target foamed cement density used for the design will normally be found at the midpoint of the foamed cement column in the annulus.

When using the constant nitrogen injection rate technique there are two points to be considered.

1) When the foamed cement is placed, the leading edge of the foamed cement, will have a density lower than the target density used for the design. This is due to the lower hydrostatic pressure and lower temperature found at the top of the foamed cement column compared to the pressure and temperature found at the mid-point of the foamed cement column (which was used to calculate the average nitrogen injection rate at surface). When using the constant nitrogen injection rate method the foamed cement density at the top of the foamed cement column should not cause a loss of overbalance pressure.

2) When the leading edge of the foamed cement exits the casing/liner shoe and enters the annulus it will contain a volume of nitrogen designed for a location higher in the annulus (which has a lower hydrostatic pressure and a lower temperature). As such, the density of the leading edge volume of foamed cement, will be greater than the density reduction of that same volume of foamed cement once in place. This produces a higher effective foamed cement density as it exits the casing/liner shoe.

A second placement technique, constant foam density, calls for the nitrogen injection rate at surface to be varied as a function of the temperature and pressure conditions found at expected placement point of the foamed cement in the annulus. This produces a pseudo-constant foamed cement density once the cement is in place. This technique is performed either by constantly ramping or incrementally stepping up the nitrogen injection rate at surface.

When using the constant density technique there are two points to be considered.

1) The density of the foamed cement column should be examined to ensure that it does not cause a loss of overbalance pressure.

2) The density of the leading edge of the foamed cement when exiting the casing/liner shoe should be examined to ensure that ECD does not exceed the fracture gradient.

An accurate cementing temperature profile for the column of foamed cement is necessary to calculate the volume of nitrogen gas injected at surface to produce a foamed cement of desired in-situ density. Temperature simulators should be used to characterize the circulating temperature profile of the well for use in the nitrogen injection rate calculation.

A foamed cement will generally exhibit a higher viscosity than the base fluid from which it was generated. The higher the nitrogen content of the foamed cement (foam quality), the greater the viscosity increase of the foamed cement compared to the base cement from which it was generated. ECD models should account for this increase in foamed fluid viscosity. The process of foaming cement also produces a higher effective fluid rate in the wellbore compared to the base cement fluid rate that will affect ECD.

5.7 Slurry Design and Testing

5.7.1 General

The primary goal of cementing is to maintain the required hydraulic isolation for the life of the well. This may include placing competent cement between pipe and openhole or between pipe and pipe. Cement also serves to protect the casing from corrosive fluids and provides mechanical support of the casing. Cement slurries are designed to function under the expected downhole conditions while meeting the well construction objectives. Various performance parameters are considered in the design process, these include the following:

— rheological properties,

— hydrostatic pressure control,

— fluid loss control,

— free fluid and sedimentation control,

— static gel strength development,

— resistance to invasion of gas or fluid,

— compressive or sonic strength development,

— shrinkage/expansion,

— long-term cement sheath integrity.

The relative importance of each of these factors to cement performance over the life of the well will vary with the application. In some cases they are even competing priorities. There may also be specific well conditions that require other attributes to be prioritized in the cement design. While computer modeling may aid the designer in conducting sensitivity analysis across a range of possible designs, it will still be necessary to use judgment and compromise between competing priorities.

The specific slurry performance properties required to isolate flow zones will vary depending upon the severity of the flow potential and the formation fluids contained in the potential flow zone.

Test methods for determining the performance of cement are described in API RP 10B-2/ISO 10426-2, API RP 10B-3/ISO 10426-3, API RP 10B-4/ISO 10426-4, API RP 10B-5/ISO 10426-5 and API RP 10B-6/ISO 10426-6. These test methods should be adapted, as closely as possible, to simulate the conditions to which the cement will be exposed during placement across any potential flowing zones requiring isolation. The conditioning schedule and test conditions of the slurry will typically reflect the temperature and pressure found at the potential flow zone.

5.7.2 Lead and Tail Cement

Lead and tail cements are routinely placed in the annulus during primary casing cementing. Lead cements can be formulated to meet various requirements ranging from economical filler systems to high performance designs. Low density lead cements are used to lower the hydrostatic pressures to avoid or minimize losses of the cement to the formations. Tail cements are typically mixed without extending components and thus have a higher density.

Carefully consider the design of the cement which will cover the potential flowing formations. Lead cements, although not normally designed to cover formations which might flow, can be designed to control flows. Doing so may require special formulations. Design criteria for lead slurries which are placed across non-productive formations having the potential to flow are the same as for slurries placed across the hydrocarbon bearing zones.

It is important to note that if the potential flow zone is to be covered by tail cement with a lead cement above the zone, the static gel strength development of the lead slurry may reduce the hydrostatic pressure exerted on the potential flow zone before the tail slurry reaches 500 lbf/100 ft^2. These situations may require additional assessment and adjustments of the design parameters and/or operational procedures.

5.7.3 Density

Density plays a key role in the design of cement slurries. In cases with potential for flow, there are two primary considerations for selecting the density: (1) preventing losses to the formation and (2) preventing flow from permeable formations. This implies the density falls between that necessary to provide enough hydrostatic pressure to control flow from the permeable formations (well security) and that which will fracture the weak formations causing lost or partial lost circulation (see previous discussion of pore pressure/frac gradient under engineering design). Other considerations related to the density of the slurry are the performance related to strength development, mechanical properties and slurry stability.

The density under placement conditions (temperature and pressure) should be considered in the design. Some slurries are compressed by pressure while others have components which are deformed by pressure. Either of these can lead to higher densities after placement downhole than the density at which the slurry was mixed at surface.

5.7.4 Thickening Time

The thickening time is the time the cement slurry is judged to be pumpable under conditions simulating those found downhole during placement. Slurries are designed for the specific set of conditions found in the well and for the designed pumping schedule (rates) to be employed during the cementing operation. Wellbore temperature simulators are commonly used to develop schedules for conducting tests while API schedules are not appropriate (see 5.6.4).

Avoid using excessive safety factors in thickening time design. Excessive safety factors can cause delayed strength development, long periods of gelation and increased likelihood of solids segregation. These factors may present a higher potential for flow from the formation before the cement has adequate strength to prevent it.

5.7.5 Fluid Loss

Control of fluid loss plays a key role in preventing flow. Loss of fluid from the slurry is a contributing factor in the loss of the overbalance pressure controlling flow. The rate of fluid loss is dependent on the overbalance pressure, the permeability of the formation, the condition of the drilling fluid cake (including its permeability), and the fluid loss characteristics of the cement. There are numerous fluid loss additives available, such as synthetic and natural polymers, copolymers, latex, and blends thereof.

Fluid loss testing should be conducted according to API RP 10B-2/ISO 10426-2. It is not possible to make a specific recommendation on the fluid loss rate as it depends on many factors, however a low fluid loss rate is generally preferred where there is potential for flow.

5.7.6 Slurry Stability, Sedimentation, and Free Fluid

Stability of the slurry is an important property in preventing annular flow. Free fluid and sedimentation may occur simultaneously or one may occur without the other.

Free fluid can result in a channel or a void in the cement into and through which formation fluid or gas can easily flow. It may also result in a severely underbalanced condition (through the water channel) initiating the flow. Control of free fluid is imperative in situations where there is the potential for flow.

Not only is the presence of a free fluid channel and the resulting underbalanced condition critical, but the condition of the remaining slurry is key as well. When water is lost from the slurry (by free fluid separation), the solids concentration is increased. This can result in uncontrolled gelation, changing other properties of the cement (such as ability to transmit hydrostatic pressure).

Additionally, sedimentation (which results in concentration of solid particles in lower sections and reduced concentrations in upper sections of the well) should be controlled to the extent that the slurry properties both at the top and the bottom of the column are sufficient for controlling flow zones in the well. The properties of the slurry will be changed by sedimentation, leading to greater gelation where the solids are concentrated and low strength and high permeability where they are reduced.

5.7.7 Rheology

Rheology affects fluid displacement and friction pressure generated during placement. The temperatures to which a fluid is exposed, and to a lesser extent the pressure, will alter its rheological properties. In some cases, slurry stability may be dependent on rheology. Gel strength development may also be affected by components of the cement which are used to control rheology. The design of the fluids used in cementing should take these parameters into account.

5.7.8 Static Gel Strength

Static Gel Strength (SGS) development is one of many factors that contribute to decay of hydrostatic pressure. As gelled fluid interacts with the casing and the borehole wall it loses its ability to transmit hydrostatic pressure. It also contributes to the ability of slurries to suspend solids under static conditions. One method to evaluate the impact of gel strength development on wellbore fluid influx is to calculate the CSGS and then to measure the CGSP.

CSGS is defined as the static gel strength of the cement that results in the decay of hydrostatic pressure to the point that pressure is balanced (hydrostatic equals pore pressure) across the potential flowing formation(s).

The CSGS is calculated by:

$$CSGS = (OBP)(300) \div (L/D_{\mathrm{eff}})$$

where

OBP is the initial calculated overbalance pressure, i.e. hydrostatic pressure minus the pore pressure, (psi);

300 is a conversion factor;

L is the length of the cement column above the flow zone (ft);

D_{eff} is the effective diameter (in.) = $D_{\mathrm{OH}} - D_{\mathrm{c}}$;

D_{c} is the outside diameter of the casing (in.);

D_{OH} is the diameter of the open hole (in.).

Wellbores have variable hole diameters and contain multiple fluids (drilling fluid, spacer, lead cement, tail cement) in the annulus. Many wellbore sections have more than one potential flow zone to be evaluated. For these reasons, it is recommended that a computer program be used to accurately calculate CSGS for all potential flow zones.

Experimental data has shown that gas cannot freely percolate through cement that has a static gel strength ranging from 250 to 500 lbf/100 ft^2 or more [21]. The industry has conservatively adopted the upper end of the range as the accepted limit. A CSGS that is considerably lower than the 500 lbf/100 ft^2 limit indicates a situation with a relatively high potential for formation fluid to enter the wellbore during cement hydration. A CSGS value that approaches 500 lbf/100 ft^2 indicates a situation where there is a relatively low probability of fluid influx during cement hydration. It is important to note that, with the exception of density, slurry properties do not affect the CSGS. The CSGS can only be increased by increasing the hydrostatic overbalance on the potential flow zone (e.g. increase the density of the drilling fluid, spacer or cement), decreasing the length of the cement column above the top of the flow zone, increasing the open hole size or decreasing the casing size.

The CGSP is the time period starting when laboratory measurements indicate the slurry has developed CSGS and ending when they show it has developed 500 lbf/100 ft^2. If insufficient information is available to confidently calculate the CSGS, a value of 100 lbf/ft^2 can be substituted as the starting point for determining the CGSP.

When flow potential is deemed severe, the cement slurry should be designed with the CGSP minimized to the extent possible. A CGSP of 45 minutes or less (measured at the temperature of the potential flow zone) has proven effective but for less severe flow potentials a longer period is acceptable.

Static gel strength development is a function of the hydration kinetics of the cement. Gel strength development is highly dependent on temperature, the chemical and physical nature of the cement being used and any additives in the slurry. Static gel strength can be controlled by the use of special additives designed to shorten the CSGP.

Additives for controlling other properties of the cement may also impact gel strength.

5.7.9 Compressive and Sonic Strength

Compressive strength is the force per unit area required to mechanically fail the cement. While not identical, for the purposes of this standard, the sonic strength; (the extent of strength development based on specific mathematical correlations and calculated by measuring the velocity of sound through the sample) and the compressive strength are considered synonymous. As discussed in 4.6, development of a minimum of 50 psi compressive or sonic strength is required to consider cement a barrier element. The compressive or sonic strength also impacts the WOC requirements for drill out and can also be important when considering long term well integrity. The use of highly retarding surfactant spacers may require the compressive or sonic strength testing take into account contamination of the cement which may have occurred during placement.

5.7.10 Compatibility

All fluids expected to come into direct contact with each other during the cementing operation should be compatible. Compatible fluids are capable of forming a mixture that does not undergo undesirable chemical and/or physical reactions. When intermixing occurs at a fluid interface the rheologies of the mixture will be altered. If the fluids are incompatible the mixture may become viscous resulting in poor displacement efficiency and/or lost circulation due to excessive friction pressure. Combining incompatible fluids may also thin the mixture which could lead to fluid bypass and/or instability. If non-aqueous fluids (NAFs) are used, a spacer containing surfactants that water-wet downhole surfaces will be necessary. Compatibility and wettability test procedures for NAF and spacers are found in API RP 10B-2/ISO 10426-2.

Cement slurries are usually compatible, but certain types of cement additives may be incompatible with one another. If additives that are suspected to be incompatible are in slurries that will be in contact with each other then the compatibility should be tested to ensure that rheological behavior, thickening time, fluid loss, slurry stability and compressive strength are not compromised. Procedures described in API RP 10B-2/ISO 10426-2 can be adapted to test cement slurries for which there is concern about compatibility between the slurries.

5.7.11 Mechanical Parameters

The mechanical parameters of set cement such as compressive or sonic strength, tensile strength, Young's modulus, Poisson's ratio, cohesive strength, internal angle of friction, etc. play a key role in the integrity of the cement during the life of the well. The in-situ behavior of the casing and cement system is complex, as is the range of potential loading conditions the cement may be exposed to over the life of the well. Stresses placed on the cement such as changing wellbore temperatures, applying casing pressure or declining reservoir pressure can cause de-bonding between the cement and the casing or formation, tensile failure of the cement sheath, compressive failure of the cement sheath or a combination of the above. These failures can lead to annular fluid leakage resulting in SCP and/or communication between two formations and/or environmental release.

Cements designed to have a low Young's Modulus, high tensile strength and high Poisson's Ratio are considered to be less susceptible to failure. Computer models are available to qualitatively predict the impact of cement design, however, due to assumptions made by the models and the difficulty attaining quality input data, the models alone should not be used to determine the necessity for special slurry designs.

Testing methods adapted from other disciplines may be used for testing mechanical parameters of well cement formulations until fit-for-purpose test protocols are developed. The results derived from these different test protocols can vary widely for a given cement formulation.

5.7.12 Expansion/Shrinkage

When Portland cement reacts with water, the volume of products produced by the reaction is less than the initial volume of reactants. Without access to external water, cement may shrink under certain conditions encountered in the wellbore, such as tieback casing or liner over-laps. Cement shrinkage can be considered in terms of dimensional (external boundary) shrinkage and internal shrinkage. Internal shrinkage causes no dimensional change, but does result in an increase in porosity of the cement matrix. Internal cement shrinkage can reduce the pore pressure within the cement matrix which may contribute to gas influx during cement hydration. Dimensional cement shrinkage may lead to loss of seal resulting in leakage through or around the cement sheath and/or SCP. Expansive agents may be employed to counteract the effects of this shrinkage; however, excessive expansion can also be detrimental to cement integrity. Expansion against an incompetent or "soft" formation can lead to a microannulus at the cement/casing interface or the formation of radial cracks in the cement sheath.

Test methods for determination of shrinkage or expansion of well cement are found in API RP 10B-5/ISO 10426-5.

5.7.13 Foamed Cement Slurry Design

A properly designed foamed cement is a stable dispersion of an inert gas, usually nitrogen, in a base cement slurry. A combination of special surfactants and stabilizing additives are used to create discrete gas bubbles in the slurry and inhibit their coalescence. The ratio of the volume of gas to the volume of base cement slurry (also referred to as foam quality) controls the density and porosity of the foamed cement. As the gas ratio increases, the compressive strength decreases and the permeability increases. Studies have shown that when the gas volume exceeds approximately 35 % of the slurry volume the strength reduction and permeability increase may exceed acceptable levels and the stability of the foam can become compromised. Unless testing of the foamed slurry and the set cement indicate that the foamed cement properties are acceptable, a 35 % in-situ gas volume should not be exceeded.

The compressible nature of foamed cement improves its ability to prevent influx and migration of gas from a potential flow zone. Immediately after placement the pressure in the gas bubbles in the foam are at the hydrostatic pressure of the fluid column. This trapped pressure delays the loss of overbalance pressure to the flow zone while the cement is developing static gel strength.

Procedures for the preparation and testing of foamed cement under atmospheric pressure can be found in API RP 10B-4/ISO 10426-4. It is important to note that when foamed cement is prepared with field mixing equipment, the gas is introduced into the base slurry under pressure and the bubble size and uniformity therefore will not be the same as it will be with foamed cement prepared under atmospheric pressure in the laboratory. Foamed cement prepared under atmospheric pressure cannot be tested in pressurized laboratory equipment. This is because the volume of slurry prepared at atmospheric pressure will significantly decrease when pressurized in lab equipment. For example, a foamed cement with 20 % by volume nitrogen prepared at atmospheric pressure will undergo an approximately 75 fold decrease in nitrogen volume when placed under 1000 psi of pressure.

Since the gas used in foamed cement is inert the rate of cement hydration does not change. This means that the thickening time is not affected and thickening time tests should be performed in a standard HTHP consistometer on the base slurry. The surfactants and stabilizers as well as any other additives should be added to the base slurry because they will affect the thickening time.

The time required for foamed cement to begin to develop strength is also unaffected by the addition of an inert gas but the magnitude of the strength will be lower. Compressive strength of foamed cement is normally performed by crushing specimens of the cement after they have been cured in a sealed curing vessel submerged in a water bath at atmospheric pressure. Studies with specialized equipment have shown that the compressive strength of foamed cement generated and cured under pressure is generally higher than the compressive strength of samples generated and cured under atmospheric pressure.

Even though the chemistry of the base slurry remains unchanged, many slurry properties such as fluid loss and rheology will be altered due to the compressible nature of a multi-phase fluid. Compressible fluids like foamed cement have a lower inherent rate of fluid loss than the base slurry from which they were prepared because as differential pressure is applied across a porous media the gas bubbles will compress more readily than the water can be forced from the base cement slurry. Specialized test equipment can be built to measure the fluid loss of foamed cement slurries but generally the fluid loss of the base slurry is used as the design criteria.

The rheology of foamed cement is difficult to characterize but in general it can be considered to be higher than the rheology of the base slurry. Measuring the rheology of foamed cement on a rotational viscometer will give erroneous results. The rheology of the base slurry can be measured and correlations can be applied to estimate the rheology of the foam.

The stability of foamed cement is one of the most important parameters to evaluate. If the foam is not stable, the bubbles will begin to coalesce and migrate through the slurry. This will result in a decrease in the density of the column as the bubbles rise. It will also cause the set cement to have an unacceptably high permeability and a very low compressive strength. If the gas completely breaks out of the foamed slurry and migrates upwards it will likely result in a loss of overbalance pressure. The loss of the gas from the foamed cement will also result in a loss of volume and thus a lower TOC. The methods for evaluating the stability of both the foamed cement slurry and the set foamed cement described in API RP 10B-4/ISO 10426-4 should be followed to evaluate stability. If there is a possibility that the foamed cement could come into contact with other fluids in the well that could potentially destabilize it, such as NAF, additional stability tests simulating the contact should be performed.

5.7.14 Cement Slurry Techniques for Controlling Annular Flow

A number of slurry design methods have been developed to control annular gas flow. These methods differ fundamentally in their mechanisms of control and it is up to the designer to determine that the selected method is likely to perform well in the specific application. These methods include compressible slurries, such as foamed cement and cement with in-situ gas generating materials, latex of certain types, systems containing microsilica, slurries with surfactants or polymer dispersions and static gel strength controlled slurries. Certain of these require special laboratory testing techniques.

Some of these slurries and techniques are proprietary and service company design criteria should be considered for their use. Simple mathematical expressions are sometimes used to gauge the potential for gas flow within a cemented annulus. Care should be exercised when evaluating the potential for gas flow using this type of generalized expression. Variations in wellbore diameter, the undefined hydrostatic contribution of by-passed drilling fluid, uncertainty in the location of the top of cement and unknown degree of annular hydrostatic pressure reduction owing to the setting of liner top packer or annular wellhead seals can lead to predictions which overestimate or underestimate the actual potential for gas flow.

5.8 Wellbore preparation and conditioning

5.8.1 General

Well preparation, particularly circulating and conditioning fluids in the wellbore, enhances cementing success. Many primary cementing failures are the result of fluids that are difficult to displace and/or of inadequate wellbore conditioning. Drilling fluid with low fluid loss (thin, tough filter cake) and rheological properties that provide low, flat gel strengths are generally more conducive to proper displacement.

Even when good well preparation is planned, contingencies in the cementing operation should be provided in case well conditions prevent the planned well conditioning program from being performed.

Well preparation may include the following:

— adjusting drilling fluid rheological properties to aid in its removal during cementing;

— ensuring the well is static;

— curing losses;

— conditioning of fluids prior to cementing to ensure that static gel strength is broken, that cuttings and gas are removed and that the well is cooled for cementing.

The pre-cementing considerations that are included in this summary are based on sound cementing best practices that are known to enhance the probability of success. Primary cement job failures are predominately due to a breakdown in the “displacement process” which leads to channeling of the cement through the drilling fluid. These guidelines, when applied in conjunction with a simulation software program will enhance the displacement process and improve the probability of successful primary cementing. It is not possible to predict the exact behavior of a fluid in a complex wellbore, but simulation software can be used to gain a qualitative understanding of the impact of design and displacement options.

5.8.2 Lost Circulation Control

If losses have occurred or are expected, impact of the loss on the well objectives should be assessed. In some cases, it may not be necessary to treat the loss, such as when the loss zone is shallower than the potential flow zone which will be covered regardless of losses. When treatment is necessary there are a plethora of options. These include: maintaining the downhole circulating pressures below the pressure at which losses occur by reducing the density of the cement slurry, minimizing the height of the cement column and/or limiting friction pressure during the cementing operation, using lost circulation materials, running a liner rather than a long string, using stage tools, using diverter tools, etc.

5.8.3 Conditioning the Drilling Fluid

The condition of the drilling fluid is one of the most important variables in achieving good displacement during a cement job. Regaining and maintaining good mobility of the drilling fluid is a key parameter. The drilling fluid should be conditioned in preparation for cementing.

Drilling fluids with low gel strength, low rheology and low fluid loss are more easily displaced. Pockets of gelled fluid, which commonly exist following drilling, make displacement difficult. Drilling fluid is conditioned by adjusting properties to those which will be favorable for drilling fluid removal during cementing.

To condition the drilling fluid in preparation for a cement job, the following should be considered.

a) Drilling fluid displacement is generally more effective if yield point and gel strength are minimized. However, other competing priorities may prevent this, such as hole cleaning requirements. The manner in which cuttings are transported, and the ideal rheological properties, vary between low, intermediate and high angles. Hydraulic and hole cleaning software may be used to conduct sensitivity analysis to aid the rheological design of the drilling fluid in balancing hole cleaning and cement placement.

b) The gel strength profile of the drilling fluid should be determined as per methods defined in the following publications:

   1) API RP 13B-1/ISO 10414-1, for water-based drilling fluids,

   2) API RP 13B-2/ISO 10414-2, for oil-based drilling fluids.

   Gel strength should be as low as possible within the constraints of cuttings transport. The gel strength profile should be non-progressive. The API standard time periods for measuring gel strength are at 10 seconds and 10 minutes. Longer time periods are allowed by the API procedures such as measurements at 30 minutes or longer. For the purpose of conditioning the drilling fluid prior to cementing, a minimum of three measurements (10 seconds, 10 and 30 minutes) are recommended to plot a gel strength profile showing whether or not a flat profile exists.

c) Maintain filtrate loss control. Filtrate loss into a permeable zone enhances the creation of a filter cake. A high fluid loss creates a thick or high viscosity, drilling fluid layer immediately adjacent to the formation wall that is difficult to displace prior to or during cementing. The fluid loss recommended is dependent on the hole section being drilled. Fluid loss control should be maintained while conditioning the hole and running casing and cementing. Note that a thick, gelled filter cake deposited while drilling using high fluid loss drilling fluid cannot easily be removed by later lowering the fluid loss of the drilling fluid.

5.8.4 Rathole

Rathole beneath the casing shoe can lead to contamination of cement during placement, or drilling fluid can swap with the cement after placement. These can result in poor strength development, pockets of drilling fluid, or a wet shoe. Rathole length should be minimized or filled with densified drilling fluid.

5.8.5 Surge Pressures while Running Casing

Surge pressures while running casing may cause lost returns if the pressure exceeds formation integrity, or in some situations, loss of well control. When casing is run into the hole, the drilling fluid flow rate (and the friction pressure) is proportional to the casing running speed. Running casing with conventional float equipment causes the drilling fluid to flow at a higher rate up the annulus. Since the well has been static for a prolonged period, the drilling fluid will be gelled, also increasing the surge pressure. Surge pressures can be reduced by decreasing running speed, using auto-fill float equipment, lowering the rheology and gel strength of the drilling fluid and/or staging in hole and breaking circulation while running casing.

Surge prediction software may be used for job planning to predict running speeds that maintain wellbore pressure below formation integrity. However, the lowest integrity in the open hole is often unknown and the surge calculation itself is affected by many other factors that are not precisely known. If losses occur at the planned running speeds, it may be possible to regain circulation by lowering the running speed.

5.8.6 Centralizer Program

Centralizing the casing across the intervals to be isolated helps optimize drilling fluid displacement. In poorly centralized casing, cement will follow the path of least resistance; as a result, the cement flows on the wide side of the annulus, leaving drilling fluid in the narrow side. In a deviated wellbore, standoff is even more critical to prevent a solids bed from accumulating on the low side of the annulus. Computer models may be used to assess the impact of centralizer placement and other conditions on drilling fluid removal (see discussion in 5.6.5.8).

Centralizers can be installed such that they are allowed to slide between casing collars or be held in place with either stop collars or set screws on the centralizer itself. Such holding devices may be exposed to significant forces while running casing and while moving pipe during cementing and may not hold the centralizers in place. Stop collars are necessary to hold centralizers in place when installed on flush joint casing. The practice of holding centralizers in place with set screws may prevent casing rotation.

The preferred method of installation of bow string centralizers is so that the centralizer is pulled into the hole, rather than pushed. An example of pulling a centralizer is when it is placed around a casing or stop collar; an example of pushing a centralizer is when it is allowed to travel freely between stop or casing collars.

5.8.7 Circulating and Conditioning after Casing is Landed

When the casing is on bottom and before cementing, circulating the drilling fluid will break its gel strength, decrease its viscosity and increase its mobility. The volume of the circulatable hole can be estimated by using a fluid caliper. Good fluid returns at the surface do not reliably indicate the mobility of fluid in the annular space.

A fluid caliper is a small volume of fluid which is easily identifiable when it appears on the shale shaker or returns to the pits after circulation. Knowing the time between injection and recovery, and the pump rate, the volume of fluid which is flowing in the well can be calculated. A fluid caliper pumped through the well in a full hole or “trip” volume circulation helps perform several functions:

— measure the openhole circulating volume by subtracting casing capacity and pipe-in-pipe annular volume from the trip volume,

— measure hole cleaning performance (gelled drilling fluid/cake/cuttings removal) of various methods/materials mentioned below,

— validate cement volumes predicted by wireline caliper logs.

Hole cleaning methods include higher circulating rates, pipe movement, and the use of high/low viscosity “sweep” pills to remove any partially dehydrated “gelled” drilling fluid, wall cake, and cuttings that can impair drilling fluid displacement during cementing. More information can be found in the literature (see the Bibliography for papers SPE 18617 [4] and 29470 [5]).

Once the drilling fluid has been conditioned (i.e. drilling fluid properties going in equal to properties at the flowline outlet), stopping circulation may allow the gel strength to rebuild. Shutdown time between circulation and cementing should be minimized by installing the cementing head and pressure testing lines before pre-cementing circulation. The time to drop the plug should be minimized by proper planning. It is best to land casing close to the floor to allow easy access to pins and valves on the cementing head necessary to drop the plug (and to minimize hazards).

5.9 Cement Job Execution

5.9.1 Bulk Plant QA/QC

Accurate cement blends are extremely important to the success of any cement job. Cement blends should be blended in accordance with the written procedures established by the service company providing the cement blend. In addition, the personnel blending and/or loading the cement should be properly trained and competent. The cement blenders and all associated equipment should be regularly maintained and inspected to ensure there are no leaking valves or other equipment malfunction that could cause improper additive introduction, erroneous cement concentrations, or contamination.

Bulk plant scales should be accurate and in proper working order. These scales should be part of a regularly scheduled calibration program. Copies of the calibration certification should be retained at the bulk plant. A certified calibration technician should perform all calibrations.

Bulk plants should be equipped with proper sampling devices to ensure that multiple representative samples are taken throughout each blend. The sampling device should be located in an area on the discharge line that ensures that excess moisture cannot enter the sample containers.

Certain cement blends require specific loading best practices. Service company-specific best practices should be used as appropriate.

5.9.2 Cement and Additive Lot Numbers

The service company providing the cement and/or cement blend should follow all established, documented company procedures to ensure that all received neat cement is within acceptable specifications upon arrival at the bulk plant. In addition, the lot numbers of all additives used should be documented for each cement blend. This information should be contained in the paperwork associated with the particular job for which the blend is loaded. A minimum of two samples of at least one gallon each of neat cement or blend should be documented, labeled, and retained. One of these samples should be retained at the bulk plant and the other sent to the lab for verification testing (if recommended). If verification testing is recommended, testing should be conducted with representative samples of location water.

5.9.3 Transportation and Storage of Cementing Materials

All cement blends should be stored and transported in properly maintained bulk storage tanks. This includes physical inspection of the pads and interior surfaces of the tanks prior to loading/bulk transfer and tank clean-out if weather conditions allow. Allowing moisture into tanks during inspection will lead to possible degradation of cement properties and difficulty unloading the bulk storage tank. Inspection and cleaning will ensure that no contamination is present in the storage tank(s). In addition, discharge, fill, inspection port, and vent valves should be checked to determine that no valves are malfunctioning. Rock catchers should be installed at key points throughout the bulk transport and storage process. Rock catchers should be inspected and cleaned as needed prior to transfer.

Cement volumes to be loaded should take into account any bulk transfer losses that may occur. This is particularly important in an offshore environment where losses in the bulk tanks of a boat and in transfer to the rig may be significant.

5.9.4 Mixing and Pumping

Slurry density fluctuations can have adverse effects on slurry properties including: reduced or extended thickening times, free fluid, retarded compressive strength development, extended slurry transition time, and reduced fluid loss control. Additionally, density fluctuations can result in increased ECD, fracturing of weak formations, and the potential loss of well control.

The cement spacer(s) and slurries should be mixed as closely as possible to the planned densities. Some variance in density will occur with field mixing equipment but acceptable performance properties of the fluids should not be compromised. Computer-aided density control mixing systems normally improve density control. Batch mixing may be necessary if mixing on-the-fly methods are not acceptable.

Low density slurries, such as those containing hollow spheres, have a dry blend density very close to the density of the mix water. A very small change in slurry density with these systems could result in a large variation in the solids content and possibly unacceptable slurry performance. A system that controls the solid/liquid ratio of the slurry (and not the density) should be used when mixing low density systems that will not perform acceptably if density is not controlled within an achievable tolerance.

5.9.5 Executing as Designed

Deviations from the planned job design can result in failure to meet the objectives of the cement job. It is recommended that the job design is communicated with all key personnel prior to job execution. Contingency plans that address surface and downhole equipment malfunctions, bulk delivery problems, losses etc. should also be prepared and disseminated.

Pumping the cement job with the designed pump rates is important but density control should not be sacrificed to obtain a planned rate. From a drilling fluid removal standpoint, flow rate only becomes critical once the spacer/pre-flush has entered the annulus which often occurs during displacement, after mixing of cement has been completed. A computer simulation can be used to determine a range of pump rates to optimize placement efficiency (see 5.6.5.8).

5.9.6 Pipe Movement

Pipe reciprocation and rotation can assist in effective drilling fluid removal. Pipe movement assists in drilling fluid removal by altering the flow path of the drilling fluid, spacer(s), and cement slurry. Pipe movement can also help to break the gel strengths of drilling fluid that may otherwise be bypassed by the spacer and slurry. Reciprocation should be done slowly to ensure that surge pressures are minimized and losses are not induced due to fracturing of formations. Computer surge programs can supply the maximum reciprocation rate during a cement job.

Proper equipment should be utilized anytime pipe movement is planned. When reciprocating, ensure that enough treating iron has been installed from the rig floor to the cementing plug container. Pipe rotation necessitates the use of equipment designed to rotate without creating stress on the plug container and treating iron.

5.9.7 Data Acquisition

All pertinent job data should be monitored and recorded by computerized data acquisition equipment. The data to be recorded should include density of all fluids pumped, rate at which they were pumped, and surface treating pressure. Pressure and rate should be recorded during the entire displacement, regardless of whether cement pumps or rig drilling fluid pumps are used to displace the plug. If possible, return rates should also be recorded.

The recorded job data discussed in this section is necessary as a quality control record and for post job analysis and reporting. It can also supply valuable information in the event that the job cannot be pumped as planned.

5.9.8 Lost Circulation Contingency Plans

Lost circulation contingency plans should be discussed prior to job execution (see A.10). These plans can include increasing or decreasing cement volumes, altering cement thickening times, altering fluid loss control of the slurry, and increasing or decreasing slurry pumping and displacement rates. Computer aids such as surge analysis programs and ECD programs can minimize the risk of lost circulation. In addition, there are several float equipment designs that can be used to help reduce the risk of fracturing formations while running the casing into the wellbore.

5.9.9 Spacers and Pre-flushes

Spacers and pre-flushes play a key role in proper cement placement so it is very important that they are mixed and pumped as designed.

Pre-flushes are not densified and usually contain only a low concentration of a few additives so they can be easily mixed on-the-fly. This means that the volumes pumped are not limited by mix tank capacities and the risk of contamination is low.

The major components of most spacers are a viscosifying agent and a weighting agent (e.g. barite, calcium carbonate, etc.). Small concentrations of other materials such as drilling fluid thinners and fluid loss additives may also be included. The viscosifier and other additives are generally provided by the cementing company as a single mixture which may be either liquid or solid.

Spacers can either be mixed on-the-fly or pre-mixed in a tank. Both the viscosity and the density of the spacer need to be very close to the original design for effective cement placement and fluid stability to prevent sedimentation of the weighting agent. Some amount of time is required for the viscosifying agents to fully hydrate and attain the required viscosity. The density and viscosity of the spacer should be verified to be within acceptable variance of the design parameters. If this cannot be achieved when mixing on-the-fly the spacer should be pre-mixed in a clean tank. Some volume of spacer may be left in the mixing tank so extra spacer should be prepared so that the designed volume will be pumped downhole.

If surfactants are included in the pre-flush or spacer recipe there is a possibility of foaming when mixing which could cause the cement pump to lose prime. If this is an issue, the surfactants may need to be metered into the spacer in the suction manifold of the high pressure pump. An anti-foam agent can also be added before the surfactant.

5.9.10 Displacement

Cement slurries should be displaced at rates required for drilling fluid removal as determined from computer modeling unless lost circulation is encountered and contingency plans are initiated. Cement jobs with small displacement volumes or those that are pumped through drill pipe such as squeezes, plugs, liners, stab-ins and inner-strings may benefit from displacement by the cementing unit for improved volume accuracy. The rig drilling fluid pumps can be used to displace large casing jobs, although the cement unit should monitor and record the displacement pressures. Displacement rates should also be recorded if possible, and methodically documented if recording is not possible.

Over-displacing if the plug does not bump should be discussed prior to job execution. In most instances, volumes in excess of 50 % of the capacity of the shoe track should not be exceeded when pumping additional fluid over calculated displacement volume. When compressible fluids such as NAF are used for displacement, the volume required for bumping the plug will be greater than the volume measured in the displacement tanks on the cementing unit. If there is a technical or operational need to bump the plug (e.g. pressure test casing, operate hydraulic hardware, etc.) then either a measured or calculated compressibility factor can be taken into consideration when determining the surface volume to be pumped.

5.9.11 Multiple Plugs

Top and bottom wiper plugs are recommended for all casing jobs, with the exception of stab-in casing jobs. On stab-in casing jobs, a drill pipe wiper dart or ball should be dropped behind the cement slurry.

A bottom plug may be placed either at the interface between the spacer and the cement or the interface between the spacer and the drilling fluid. Choice of plug location depends upon fluid properties and casing size. Normally, it is preferred to place the plug between the spacer and cement to prevent contamination of the cement by the spacer. The use of two bottom plugs is preferable but not always operationally feasible. This ensures that the cement is uncontaminated in the casing. In addition, double plug containers are recommended where possible. The wiper plug container should have a system to indicate the launch of the wiper plug. The wiper plug departure should be carefully noted, due to the potential for fluid bypass in some plug containers prior to plug launch.

The length of shoe track required may be affected by the amount of mud film removed from the inside of the casing and the number/type of cementing plugs used (cement contamination).

5.9.12 Holding Pressure Inside Casing

The casing floats should be tested after the displacement is complete. Once it has been determined that the floats are holding properly, pressure should be bled off the casing completely. Care should be taken to ensure that no pressure is trapped inside the casing due to closed valves on the cement head. Valves on the cement head should remain open as the fluid inside the casing will undergo heating and thermal expansion. If the valves on the cement head are closed, the casing will expand as pressure increases. Then, when the pressure is released, a micro-annulus may be created as the casing contracts, which could result in poor zonal isolation and SCP.

It is typically not advisable to trap pressure inside the cemented casing unless the float valves have malfunctioned and are not holding pressure.

5.10 Post Cementing Operations

5.10.1 Maintaining a Full Hole and Cases for Applying Surface Pressure

In order to maintain maximum overbalance pressure, the fluid level should be maintained in the annulus. In addition to maintaining the overbalance pressure, keeping the hole full will give an early warning if the well begins to flow. It also provides a means for tracking fluid losses in the annulus.

If wellbore ballooning is occurring, the annulus should be closed and monitored until the cement has gained 50 psi of compressive strength at the loss zone in order to prevent fluids lost to the formation from flowing back and contaminating the unset cement.

Under some circumstances (see A.13), the controlled application, via pumping, of a constant pressure to the annulus can be used to mitigate well control events such as kicks and reduce the risk of a LWC incident. This surface pressure application increases pressure down the annulus to the source of the flow and helps create an overbalance across the flowing zone to mitigate or stop the flow.

Some specialized applications such as foamed cementing or under-balanced operations may require that pressure be held on the annulus during WOC time. Job-specific procedures should be consulted to determine a pressure and time schedule for the annulus.

The characteristics of the well, including depth, fracture gradient and geometry can play a role in the success of the above techniques. They are intended only to supplement other techniques used for control of flow. To be effective, the well should be rigged up and the technique started within a few minutes after bumping the top wiper plug which ends pumping for the primary cementing job.

Care should be taken in washing out a riser, as this can reduce the hydrostatic pressure, leading to flow.

5.10.2 WOC

Operations on the well following cementing should be done in such a way that they will not disturb the cement and damage the seal or cause the cement to set improperly.

Normally pipe movement to complete hanging the casing and activating seals should be finished before significant gel strength has developed. If done after the cement has developed significant gel strength, such pipe movement could cause a micro-annulus. There is also danger of initiating flow if the pipe movement swabs the well in. In some instances the pipe may be moved at a low-rate as a means to break gels until hydration starts.

If the casing is to be hung after cement strength is developed, as when intentionally increasing or decreasing the landed tension in the casing, consideration should be given to the imposed forces on the cement and the cement strength.

Regulations may require casing to be pressure tested. Preferably, pressure testing casing should be done before significant gel strength has developed. However, such pressure testing will be limited by the pressure ratings of plugs, floats, cementing heads and other equipment. Pressure testing can be done after the cement has set but this can result in micro-annulus formation or damage to the cement sheath. The pressure should be held on the casing for the shortest length of time required to accomplish the test. The effect of pressure testing will depend on the properties of the cement, the pressure at which the casing is tested (and consequently the amount of enlargement of the casing) and the properties of the formation around the cement. Mechanical stress modeling can assist in determining the best time to conduct the pressure tests.

In the absence of regulatory guidelines on compressive strength requirements before drilling out, usually a minimum compressive strength of 500 psi is recommended before drilling out the shoe of the cemented casing.

When cement is considered a barrier, refer to the WOC Guidelines Prior to Removing a Temporary Barrier Element (see 4.6.3).

5.10.3 Top Job

A top cement job (that is, one conducted to fill in the annulus when cement did not reach the desired depth for the top of cement) can be conducted immediately after bumping the top wiper plug or it can be done after the cement has set. Consideration should be given to the probable poor displacement when a top job is performed. Every effort should be made to ensure that the primary job circulates cement to surface, when recommended, and a top job be done only as a last resort.

If done immediately after bumping the wiper plug, formations deeper in the well may be broken down. The formations which might be broken down and the impact on the integrity of the well and the annular seal should be considered when using this method.

If the top job is done after the cement has set, consideration should be given to the method of placement, whether it is to be bullheaded or grouted. Bullheading requires breaking down a weak formation somewhere in the wellbore. If the cement has set and there is not a channel in the cemented annulus, the formation will break down between the top of the set cement and the shoe of the previous casing. If the top of set cement is above the shoe of the previous casing, this method cannot be used. In such a case, the cement will have to be placed by grouting with a small diameter pipe run inside the annulus. If the top job is done by grouting comply with requirements in 4.6.3.

6 Casing Shoe Testing

Casing shoe tests including formation integrity tests (FIT), Leak-Off Tests (LOT), and pressure-integrity tests or pump-in tests (PIT) are carried out during the drilling phase after a string of casing has been cemented and a short section of new hole, typically10 ft to 20 ft, has been drilled.

Casing shoe tests serve the following purposes.

— To confirm the pressure containment integrity to ensure that no flow path exists to formations above the casing shoe or to the previous annulus. If such a flow path exists, and it extends to a formation without adequate integrity, the seal around the casing shoe may have to be repaired (e.g. by cement squeeze).

— To investigate the capability of the wellbore to withstand additional pressure below the shoe such that the well is competent to handle an influx of formation fluid or gas without the formation breaking down.

— To collect in-situ stress data that can be used for geo-mechanical analyses and modeling (e.g. wellbore stability and lost circulation prediction).

Most governmental regulatory organizations maintain criteria regarding verification of casing shoe integrity. Formation integrity tests are normally carried out in accordance with the operator’s policy and procedure.

7 Post-cement Job Analysis and Evaluation

7.1 Material Inventory

One important aspect of the post job analysis is material inventory after cementing operations are complete. A final inventory of material should be completed and compared to the pre-job inventory as described in the cementing execution section. A material mass balance, comparing the job plan to the actual final inventory, will determine if the correct amount of cement and additives were used during job execution.

7.2 Job Data

To further evaluate the cementing operations, the real time data can confirm fluid volumes, densities and rates in accordance with the initial design. Using computer software, the acquired versus predicted data can be compared to obtain pressure matching, equivalent circulating densities and confirm well security. When problems occur during the cementing operations, this information can be useful when investigating job failures.

Comparison of the predicted and actual job data may provide verification of placement, or insight into other issues. Prior to the cementing operation, a checklist can be prepared from the job design to ensure all requirements have been achieved after execution is complete. The checklist should include all critical job information such as rates, volumes, densities, pressures, fluid rheologies etc.

Job data collected for a complete analysis can serve as a reference for future wells drilled in the same or similar areas. The knowledge may also be shared with other operators to better understand the reasons why wells flow after cement.

7.3 Cement Evaluation

Formation integrity and cement placement and strength are important parameters to be evaluated before drilling the next hole section. Failure to achieve a positive test may be due to inadequate seal by the cement in the annulus or failure of weak formations near the shoe. When the LOT or the FIT results are inadequate, the operator can perform a cement squeeze or other treatment to enhance the formation's pressure containment integrity or to seal a leaking cement sheath in the annulus. A repeat LOT or FIT may then confirm the squeeze or treatment results in increasing the interval's wellbore pressure containment.

In order to effectively evaluate a cement job, one should determine whether the objectives of the operation have been achieved. The objectives will vary depending on the cement job. Field evidence of a properly executed job may include records of spacer density and rheology, slurry density control, pump rates, pump pressures and observed returns which conform to the cementing plan. Based on the job objectives, multiple techniques are available which include temperature, noise, acoustic and ultrasonic cement logs.

Caution should be exercised when using cement evaluation logs as the primary means of establishing the hydraulic competency of a cement barrier. The interpretations of cement evaluation logs are opinions based on inferences from downhole measurements. As such, the interpretation of cement evaluation logs can be highly subjective. Refer to API TR 10TR1 for an overview of the attenuation physics, features and limitations of the various types of cement evaluation logs.

Annex A
(informative)

Background and Technology

A.1 Background

A.1.1 General

In 2010, the Minerals Management Service was reorganized into the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE). The BOEMRE in 2010 referenced API RP 90 and API RP 65-2 (first edition), in addition to API RP 65, in the *Code of Federal Regulations* (*CFR*).

A.1.2 Historical Background

On August 16, 2000, the MMS of the U.S. Department of the Interior presented safety concerns on uncontrolled annular flows to a new API Work Group. This group included government and industry representatives from several organizations including API Washington staff, API Executive Committee on Drilling and Production Operations, API Subcommittee 10 on Well Cements, International Standards Organization, International Association of Drilling Contractors, Drilling Engineering Association, the MMS, and other interested parties. Issues related to annular casing pressure (ACP) were also discussed. This new group called "API Work Group on Annular Flow Prevention and Remediation" agreed to document industry "best practices" to improve zonal isolation, reduce the occurrence of SCP, and help prevent annular flow incidents prior to, during, and after cementing operations. Studies of available information on flow event causes and prevention helped the Work Group write "best practice" documents for publication as API Recommended Practices. The API Work Group is responsible for the following API Recommended Practice publications:

1) API RP 65 entitled *Cementing Shallow Water Flow Zones in Deep Water Wells*,

2) API Std 65-2 entitled *Isolating Potential Flow Zones During Well Construction* (this document).

Another group has prepared API RP 90 providing guidance on managing ACP, if encountered. API RP 90 covers procedures such as ACP monitoring, diagnostic testing, establishing maximum allowable wellhead operating pressures (MAWOP), documenting ACP, and assessing risk to help determine the need for mitigation measures. API RP 90 refers to API RP 65 for more information on ACP prevention and remediation methods and materials.

A comprehensive overview of API RP 65 and its API Task Group is available in SPE paper 97168 [3]. The following section summarizes some of the key issues studied by this API Group and addressed herein.

A.2 Historical Data and Perspectives

Historical data and verbal communications obtained from many countries strongly suggests that annular flows, gas migration, vent flows, ACP (both sustained and thermal annular casing pressure), pressure zone kicks, and LWC incidents, particularly prior to, during or after cementing pipe strings, can have grave consequences. Some of them have caused loss of human life and/or severe injuries, environmental pollution, loss of expensive facilities, and negative effects on the operator's future ability to obtain leases. Historical data also suggests that this is a common problem and presents an opportunity for governments, industry, and other contributing parties to work together on solutions. The API is committed to this task and continually works on relevant standard practices that help industry work safely and protect the environment.

API's publication of a series of API RP 65 documents is a key part of the solution by documenting proven technology that can mitigate and prevent annular flows linked to the well's casing installation and cementing process. Unforeseen events can happen on any cement job, even when it has been properly designed, so relevant well design parameters, drilling practices, redundant equipment systems, gas control cements, and/or other means of preventing these LWC incidents should be employed when the risk of hydrocarbon flow exists. The current trend to drill deeper HPHT wells heightens the concern for the risk of severe kicks and LWC incidents. Published annular flow study data from some countries is available from government and industry sources with examples from four countries listed below.

A.3 Studies of Annular Flows Primarily in the USA

In 1964, Bearden et al [17] reported on an investigation of inter-zonal flows of formation fluids through the cemented annulus and methods to prevent them. This study concluded that the hydraulic seal of cements can fail when exposed to certain conditions. This type of failure is often due to low "bond" strengths or, in the worst case, a "micro-annulus" formed between the pipe and cement creating pathways for annular flows between high-/low-pore-pressure, high-/low-permeability formations.

For example, cement is placed in the annulus across a potential flow zone and initially it has an internal pressure of 8000 psi caused by the hydrostatic head pressure of the column of cement or cement and drilling fluid above it. At the same depth and time, the hydrostatic head pressure inside the casing or liner pipe has a lower pressure of 6000 psi (called "casing pressure") from the lower density displacement drilling fluid or "mud." This gives a 2000 psi force pushing against the outside wall of the pipe which allows a hydraulic seal or "bond" to form between the cement and the pipe once the cement is set. Figure A.1 (Figure 3 from SPE 903) shows that this example cement seal can withstand over 1400 psi differential pressure between a nearby low pore pressure, permeable zone and the high pore pressure, permeable formation (potential flow zone) in the same annulus.

NOTE The data curve in Figure A.1 should not be used to predict bond or hydraulic seal integrity as it only represents the data for one particular operator's cement slurry tested in one unique device that it not standardized. It serves here only to show how it helped one operator identify his specific zone isolation issues and solutions at a given time in history. For example, today the cements and additives together with the relevant slurry designs may now have different properties that would provide different "bond failure" data curves.

On the other hand, if the initial 8000 psi hydrostatic head (HH) pressure within the cement is prematurely reduced before the cement has set hard and gained enough structural integrity, the hydraulic seal ("bond") can be substantially reduced or totally lost. For example, if the initial 8000 psi annular hydrostatic pressure is reduced to 4000 psi, the force against the outer pipe wall will be totally lost and a 2000 psi force (6000 psi HH csg. pressure to 4000 psi HH annular pressure) will then push against the inter pipe wall causing it to expand slightly in diameter. Figure A.1 shows that this change in direction of force (+2000 to –2000 psi) may reduce the potential hydraulic seal ("bond") strength from 1400 psi to less than 600 psi with the example cement. If this 600 psi is less than the inter-zonal differential pressure, an annular flow may initiate between the zones and also migrate further up the annulus via a micro-annulus. Also, if the 6000 psi internal casing pressure is sufficiently reduced after the cement is set hard, the pipe diameter may shrink enough to break the cement/pipe "bond" leaving an unsealed annular flow path or "micro-annulus" between the set cement and the casing's outer pipe wall.

The more the hole/casing annular HH pressure is reduced during the cement curing phase, the greater chance for an annular flow. The risk of an annular flow also increases as the casing's internal HH pressure decreases after the cement's initial set. However, highly-gelled, unset cement may not deform and fail to maintain contact with the outer pipe wall when the casing diameter shrinks as internal HH pressure is reduced. Thermal effects may also create and/or increase the size of a micro-annulus formed by the loss of annular or internal HH pressure. For example, casing and liners may have a micro-annulus formed or a larger one when:

1) holding pressure inside casing as cement cures (see 5.9.12);

2) the hole fluid level is not kept full (see 5.10.1);

3) moving the casing during WOC (see 5.10.2);

4) the cement displacement fluid is replaced by a lighter density fluid;

5) the replacement fluid inside the casing is much cooler than the displacement fluid;

6) casing pressure tests or other imposed pressure applications are performed:

a) after the cement starts to gain SGS during WOC,

b) after the cement sets at a test pressure above the cement's tensile strength,

c) repeatedly during the life of the well that exceed the cement's fatigue limits;

7) mechanical seals are activated before the cement has gained enough structural integrity to resist pipe expansion from the loss of hydrostatic head pressure in the annulus.

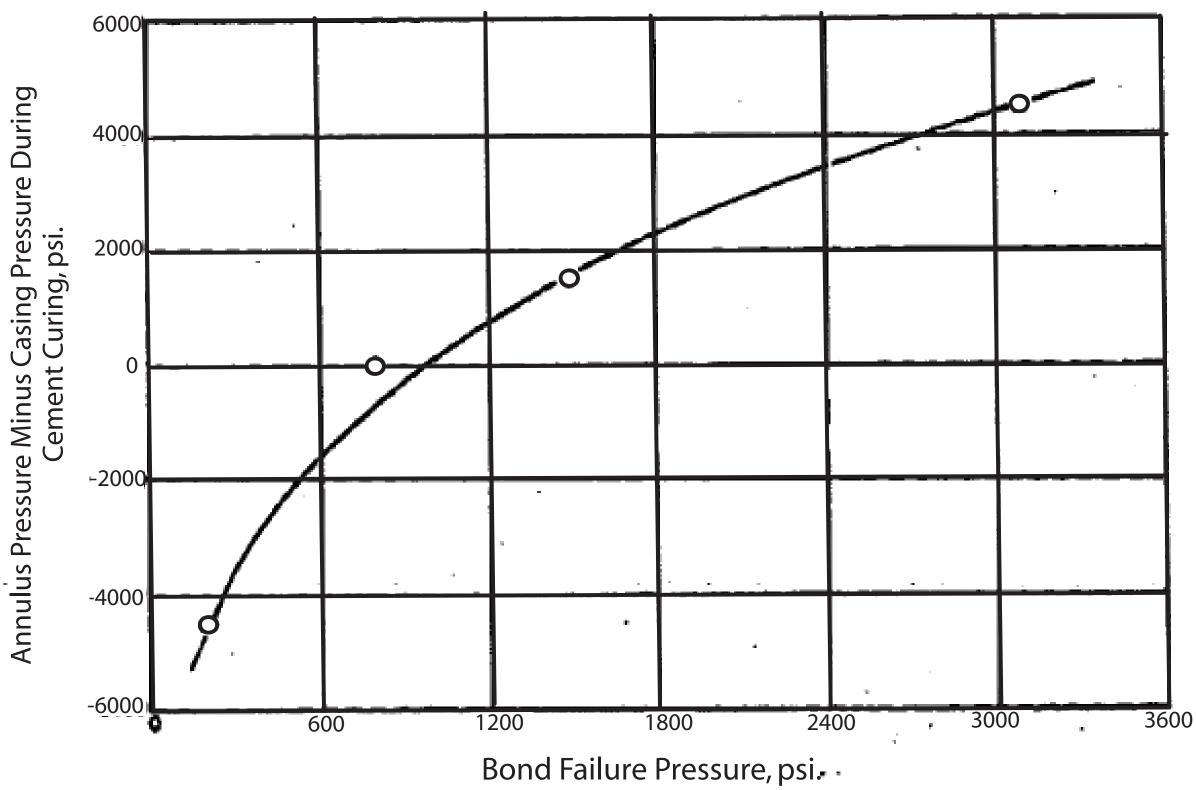

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Figure A.1—Effect of Curing Pressure on Bond Failure

Some of the preventive measures mentioned by Bearden [6] included the use of float equipment, displacing with lighter density fluids, and, in some cases, attaching annular seal rings (type of mechanical barrier) to the casing. The latter method was proven successful in 25 out of 27 well applications. More preventive measures such as new types of annular mechanical barriers have been developed since then and are described in Section 4.

Garcia and Clark [18] disclosed the results of a seven year (1968 to 1975) lab and field study of annular gas flows in numerous wells to better define the issues, challenges, and recommend preventive practices. The significance of this study is the identification of annular flows in the 1960's by various investigators and postulating of the hypothesis or theory that of the loss of hydrostatic head pressure on top of and within the annular column of unset cement slurry was the root cause. A new cause for this loss of hydrostatic pressure was discovered and reported to be premature setting or dehydrated “bridges” of a portion of the cement in the upper parts of the cement column. Another way to visualize this phenomenon is to think of these early set or bridging points as “artificial annular packers” made from cement or “annular cement packers.” Included in the field study were cases where logs were used to identify and measure annular flows between zones after casing and liners were cemented.

Also during the 1960 to 1980 time period other investigators, Carter and Slagle [19] and Christian et al [20] presented substantial evidence of the cement packer effect also called “hydrostatic-pressure bridging” above potential flow zones that resulted in costly annular flows. In 1979, Tinsley et al [21] identified continuing annular gas flow problems and associated costs from several tens to many hundreds of thousands of U.S. dollars per wells. Several years of research efforts to find solutions with associated field applications were summarized by Tinsley. One major finding was that compressible cement systems had positive results in reducing the occurrence of annular gas flow. Included in the field study were several offshore wells in the High Island area of the Gulf of Mexico where annular gas flow events after cementing surface and intermediate casing strings had caused uncontrolled releases of gas to the surface and to the atmosphere (called blowouts in the paper). Also land wells in South Texas were studied that had a history of annular gas flows after cementing production casing and liners causing communications between zones. Other areas with annular gas flows were identified that in low to moderate flow rate cases cause loss of production to thief zones above and/or below the production interval and in severe cases (also called underground blowouts) result in high risk conditions for safe well operations. Tinsley cited the researcher’s consensus of opinion on the “annular cement packer” phenomenon mentioned above that “once pressure in the annulus has decreased by as little as 0.5 psi less than the formation pressure, gas flow can occur” and “this gas entry tends to form a gas channel in the cement column.” Lab studies were presented that better defined how cement slurries can develop SGS which prevents transmission of hydrostatic pressure in cement columns. In addition to having “fluid-loss-controlled” cement slurry properties, Tinsley said that “free water” control in cement slurries, as identified by Webster [22], was needed for compressible cement systems to provide more comprehensive solutions to annular gas flow problems. This combination of cement performance properties was 90 % successful in preventing annular gas flows in over 200 well applications.

Martinez et al [23] studied the causes of annular gas flow and LWC incidents in Outer Continental Shelf (OCS) wells for the U.S. Department of Energy (DOE) and published a report on their work in 1980. This report is available at http://www.mms.gov/tarprojects/027.htm This DOE study report includes case history reports on annular flows after cementing including “USGS” federal agency (pre-MMS) reports on LWC incidents that had similar causes to those disclosed herein API Std 65—Part 2. Also contained within API Std 65—Part 2 is more information on annular flow causes and up to date solutions to this challenge. The benefits of developing and/or implementing solutions to these issues were outlined on pp.6-7 in the DOE report and are still applicable today as follows:

1) safety improved by reduced risk from:
   a) underground blowouts,
   b) pressurized shallow sands,
   c) blowout adjacent conductor and potential loss of platform;
2) environmental protection enhanced by reduced potential for leaks to the seafloor or shallow formations;
3) economics:
   a) expensive blowout risk is reduced (as well as public loss of confidence in industry and agencies),
   b) reduced well control problems save drilling time and cost,
   c) remedial squeeze jobs are reduced.

Martinez et al [23] also called for more research on why cement failed to control annular flows. As mentioned above, significant progress has been made since then to understand the relevant issues and to formulate solutions. Although most of the information in this DOE report is still relevant today, some parts may be updated as follows.

1) Page 4, no.4—Many laboratory and field studies have been published since 1980 that adequately describe cement hydration mechanics. Information from these studies helped developers make significant improvements in cementing technology which are incorporated in the practices recommended in API RP 65 and API Std 65 Part 2. However, methods to measure set cement's mechanical properties are currently being studied by the API and others in order to standardize laboratory test procedures.

2) Page 10, C. on Unreliable Cement Slurry Mixtures—Same update as above no.1 and much more predictable and reliable cement slurries are available today including those designed to prevent annular flows.

3) Page 11, no.2 a.—Research on gas control cement properties in long columns of cement has been performed and reported in several studies cited herein. Laboratory tests to predict these properties and design gas control cements have been developed from these studies. Field cementing practices and materials have also been substantially improved by these studies.

4) Pages 19 to 20—SPE paper 8255 was cited as having good practices to design cementing compositions and field cementing practices. The above mentioned studies, many of which are described herein API Std 65—Part 2, have proven that the following cementing compositions and field cementing practices advised in SPE 8255 are not always technically valid. This uncertainty should be considered accordingly:

   a) Limiting the reduction in loss of unset-cement column hydrostatic pressure to no more than the cement mixwater density gradient and enhancing this gradient by additions of salt to the cement and/or cement mixwater is not valid (see A.13) based on downhole pressure sensor measurements by Cooke et al [24,25] and others that show gradients can decrease below the cement mixwater density gradient.

   b) Applying pump pressure to the annulus during WOC to replace some or all of the loss of unset cement column hydrostatic pressure is not reliable in some cases (see A.13) based on downhole sensor measurements by Cooke et al [24,25] showing surface applied pressures that fail to reach the downhole pressure sensors.

Cement permeability was also evaluated as a potential factor in gas migration incidents by various investigators in the period from 1960 to the early 1980's. Cement permeability is a concern, but risks due to permeability can be mitigated by the use of additives. These slurries formed hard set, very low permeability cements which resisted adverse downhole conditions. Example cement slurries, lab tested under downhole conditions, have properties such as low fluid loss, no free fluid, no-settling, and short transition times for SGS development. Other design methods and associated additives are well known to those skilled in the art. Sutton, Sabins and Faul [26] in 1984 reported that maximum cement permeability of 12 mD found in several test measurements that could be substantially reduced by adding polymer type fluid loss control additives. Even without these additives, the reported 12 mD cement permeability calculates, with Darcy's equation, a migration time period that is too long vs those encountered in field operations. This case can be explained by calculating migration travel times.

The total travel time period (at 0.038 in./hr) for gas to migrate thru cement with high (12 mD) permeability in a 2000 ft long, annular cement column (p.3 of Sutton, Sabins and Faul [26] article) is calculated as follows:

(2000 linear ft $\times$ 12 in./ft) $\div$ 0.038 in./hr = 24,000 in. $\div$ 0.038in./hr = 631,579 hours for gas to displace the cement's uncombined or free water in the pore throats of the cement's matrix permeability (12 mD).

631,579 hours $\div$ (24 hr/day $\times$ 365 days/yr) = 631,579 hr $\div$ 8760 hr/yr = 72.1 years total time period for gas migration through 2000 linear ft of 12 mD cement.

The above 72 year gas migration time period removes cement permeability as a factor or cause for many gas migration occurrences. MMS statistics on well ages for SCP initiation (see graph in A.15) show that the vast majority of cases occur in less than 10 years instead of several decades like the 72 year example calculation above.

When cements contain materials that resist unfavorable downhole conditions and allow very low permeabilities to be achieved, gas migration travel time periods calculated with fractions of a millidarcy (mD) may be several hundreds or thousands of years depending on cement column lengths and differential pressures. Calculation of time to flow through permeability does not eliminate permeability as a concern, especially as permeability may act in concert with other wellbore or cement performance factors, such as communication with channels, high permeability pathways, etc. Additionally, filtrate water does not have to flow all the way to the surface; it can flow into shallow or shallower formations. Other factors may restrict annular gas flow and increase gas migration travel times such as a sealed and fluid filled annulus above the TOC that does not provide a vent for the cement filtrate water pushed out of the cement top by gas migration.

A.4 Barrier Failure Study

A study of LWC incidents in U.S. areas of the Gulf of Mexico OCS and some of the coastal states from 1960 to 1996 is reported in SPE/IADC 39354 by Skalle and Podio [27]. The many types of barrier element failures listed below in Table A.1 (from Table 6 of SPE/IADC 39354) may be prevented with the updated and proven practices described within this API publication. Note the higher total of failures for mechanical vs cement types of barrier elements.

Table A.1—Most frequent Primary and Secondary Barriers that Failed in all Phases (Louisiana + Tx + OCS; 1960 to 1996)

Primary Barrier	BO	Secondary Barrier	BO
Swabbing	158	Failed to close BOP	78
Too low drilling fluid weight	50	Rams not seated	14
Drilling break/unexpectedly high pressure	45	Unloaded too quickly	13
Formation breakdown/lost circulation	43	DC/Kelly/TJ/WL in BOP	5
Wellhead failure	40	BOP failed after closure	66
Trapped/expanding gas	40	BOP not in place	43
Gas cut drilling fluid	33	Fracture at casing shoe	38
Christmas tree failure	23	Failed at stab valve/Kelly/TIW	34
While cement setting	20	Casing leakage	23
Unknown why	19	Diverter—no problem	21
Poor cement	16	String safety valve failed	19
Tubing leak	15	Diverter failed after closures	17
Improper fill up	13	Formation breakdown/ lost circulation	15
Tubing burst	10	String failure	13
Tubing plug failure	9	Casing valve failed	11
Packer leakage	6	Wellhead seal failed	10
Annular losses	6	Failed to operate diverter	7
Uncertain reservoir depth/ pressure	6	Christmas tree failed	7

The high number of BOP failures, such as the “BOP not in place” and other types of BOP failures, was a key focus area for the API Work Group and is addressed accordingly within 3.7. For example, MMS regulation 30 *CFR* 250.422 (b) requires that if the operator plans to nipple down the diverter or BOP stack during the 8-hour or 12-hour WOC time period, the operator should determine when it will be “safe” to do so. The decision should be based on the operator’s knowledge of the formation, cement composition, effects of nippling down, potential drilling hazards, well conditions, and past experience. Even though this regulation is currently in force, the API Work Group determined that more specific guidance (see 3.7) is needed since well control incidents, with this category (BOP failures) involved, are still occurring.

A.5 Studies of Annular Flows in the United Kingdom

Hinton [28] with the Offshore Safety Division of United Kingdom’s Heath and Safety Executive reported in SPE 56921 that 11 % of all wells drilled in the U.K. continental shelf from 1988 to 1998 have experienced reportable kicks during well construction operations. Of these 22 % were in HPHT wells (>10,000 psi and 300 °F). Other U.K. sources cited by Gao et al [29] in SPE 50581 claim that HPHT wells have much higher reportable kick incident rates (1 to 2 kicks per 1 well) compared to non-HPHT wells (1 kick per 20 to 25 wells). Some of the most frequent causes of kicks in drilling U.K. wells were also found in the U.S. wells such as lost circulation in the same hole section with potential flow zones, drilling fluid weight too low, and uncertainty in flow zone existence, flow potential, location, or other important characteristics.

The following quote (SPE 56921, p.3, 1st paragraph) on other types of barrier failures during casing installation operations is significant. “Exactly half the kicks associated with casing operations occurred when liner overlaps or casing shoes leaked when drilling fluid weight was reduced.” The liner overlap failures mentioned in SPE 56921 included one case history of a well with a 7,500 psi shut in drill pipe pressure caused by a leaking liner top packer. These two types of barrier failures (liner overlaps and casing shoes) present opportunities to help prevent future incidents by implementing the updated guidance on proven practices contained herein.

A.6 Studies of Annular Flows in Canada

Gas migration is reported by the Canadian government authorities to exist in many wells in Canada. A recent article by Lang [30] reported on annular flows in Canada’s shallow to moderate depth wells in the areas of Alberta and Saskatchewan “historically have had problems with gas migration developed leaks after primary cementing in 57 % of the cases, on average.” In 2003, Getzlaf and Watson [31] stated that a database that registers gas migration in Alberta “currently has over 5000 recorded vent flows, some serious, but most recorded as non-serious.” A vent flow is the local name for an annular gas flow.

In the time period from April 1998 to March 1999, the Alberta Energy and Utilities Board [32] cites the following LWC statistics for 7094 new wells drilled and included in the new total of over 129,000 active wells.

Table A.2—Drilling and Service Well Control Occurrences, 1998/1999

	Drilling	Servicing
Blowouts	9	1
Blows	1	
Kicks	101	N/A

The latest AEUB [33] report posted on their website is for 17,108 new wells drilled in 2003.

Table A.3—Drilling and Service Well Control Occurrences, 2003

	Drilling	Servicing
Blowouts	1	4
Blows	3	7
Kicks	106	N/A

The 2003 statistics compared to those in 1998 and earlier periods continues the favorable trend in recent years showing substantial decreases in the occurrence of blowouts (also called LWC) and kick incidents (a type of annular flow) during the drilling of new wells.

The AEUB [32] reported gas migration and surface casing vent flows (also called casing pressure) of gas as follows in Table A.4 and Table A.5.

Table A.4—Surface Casing Vent Flows

Year	Serious	Non-serious	Total
1995	393	3121	3514
1996	75	3103	3178
1997/1998	76	3537	3613
1998/1999	139	3671	3810

Table A.5—Gas Migration Problems

Year	Serious	Non-serious	Total
1995	4	596	600
1996	6	809	815
1997/1998	6	801	807
1998/1999	1	813	814

Of the 7667 wells that applied packers to maintain well integrity, relatively low numbers of leaking packers were identified in the mandatory packer isolation testing and reporting program [32] as follows in Table A.6.

Table A.6—Packer Isolation Testing and Reporting Program Results

Year	Notice of suspension letters issued		Closure orders issued		Repeat companies for closures	Abandonment orders issued	
	Companies (no.)	Wells (no.)	Companies (no.)	Wells (no.)	Companies (no.)	Companies (no.)	Wells (no.)
1995	N/A	N/A	51	172	N/A	20	34
1996	N/A	N/A	137	446	24	11	
1997/1998	90	180	15	23	3	1	1
1998/1999	128	443	22	34	6	2	2

A.7 Studies of Annular Flows in Russia

A study by Krylov [34] reports an analysis of data on monitoring annulus pressures (AP) of wells at the Karachaganak gas condensate field. Development drilling began in 1985. The analysis showed that AP is found in wells regardless of their category—operating or shut-in. The percentage ratio of wells with AP to the total stock was calculated for both well categories for the purpose of studying the dynamics of wells with AP. The data show an increase of the percentage of operating and shut-in wells with AP from 45 % and 1 % in 1993 to 56 % and 33 % in 2000, respectively. Assumptions about the causes for the increase of wells with AP are given in the study report.

A.8 LWC Insurance Database Studies

Studies by Adams [35], Adams and Young [36], and Jackson [37] (Willis Ltd.) provide information that helps explain some of the causes, cause effects, and costs of LWC incidents. Adams states that "about 65 % of all blowouts are UGBOs (underground blowouts)." and "Flows originating behind casing after cementing are perhaps the second most common UGBO cause." Adams and Young report the following.

— "UGBOs occur about 1.5 to 2 times more frequently than surface blowouts. Cumulative costs are believed to far exceed that for surface blowouts."

— "A common flowpath is a poorly cemented casing-openhole annulus."

— "The danger associated with this flowpath (poorly cemented annulus) is the circumvention of the primary well-control hydraulic system of the hole, casing and BOPs."

Adams and Young cited Willis Energy Loss Database [37] analytical reports for the costs of 1,224 LWC incidents all with financial loss claims greater than one million U.S. dollars. The well loss incidents include blowouts (~90 % of total), mechanical failure, stuck drill pipe, fire/lighting/explosion, heavy weather, design/workmanship, collisions and others.

Table A.7 from Adams and Young's *World Oil* article [36] shows LWC incident costs by the status of the wells. OEE in the table means operator's extra expense. The intent of the table is to identify where more focus should be placed relative to blowout prevention measures in the future. Drilling operations (includes cementing) has the highest number of incidents at 668 out of the total of 1,224.

Table A.7—Well Status at Time of the Incident

Status of well	Incidents	OEE actual US$	Average OEE actual US$
Abandoned	3	45,383,105	15,127,702
Completion	17	106,722,607	6,277,800
Drilling	668	4,396,562,496	6,581,680
Plugging	3	11,165,400	3,721,800
Producing	82	1,045,737,073	12,752,891
Shut In	14	134,887,062	9,634,790
Workover	42	319,808,465	7,614,487
(Unknown)	393	2,029,815,203	5,164,924
Other	2	8,100,000	4,050,000
Total	**1224**	**8,098,181,411**	**6,616,161**

More LWC incidents are caused by natural gas formations based on the data shown in Adams and Young's [36] Table A.8. The type of blowout fluid was not known for the 500 incidents listed under unclassified well types. This is often the case for underground blowouts.

Table A.8—Blowouts by Well Type

Well type	Incidents	OEE actual US$	Average OEE actual US$
Gas	536	3,732,864,691	6,964,300
Oil	86	560,968,996	6,522,895
Oil & gas	86	1,069,809,755	12,439,648
Sulphur	3	14,443,297	4,814,432
Sulphur	1	3,330,000	3,330,000
Water	9	39,643,956	4,404,884
Other	3	23,100,000	7,700,000
Unclassified	500	2,654,020,716	5,308,041
Total	**1,224**	**8,098,181,411**	**6,616,161**

The highest frequency of LWC incidents occurred in wells between 7500 ft. and 14,999 ft. deep according to the data that Adams and Young [36] present in Table A.9.

Table A.9—Blowouts by Depth Category

Depth (ft)	Incidents	Total actual OEE US$
0 to 4,999	95	795,786,456
5,000 to 7,499	69	558,347,594
7,500 to 9,999	126	567,598,068
10,000 to 14,999	345	1,555,519,961
15,000 to 19,999	183	1,838,981,875
20,000+	28	397,994,687
Unclassified	378	2,382,952,770
Total	**1224**	**8,098,181,411**

Discussions in April 2006 with Andrew Jackson at Willis Limited provided an updated well population in the Willis Energy Loss Database, i.e. includes 1381 well loss incident claims of which 1237 wells are LWC incidents or blowouts (501 underground blowouts, 308 surface blowouts, and 428 unknown). Jackson said that certain types of data needed to pin-point the root cause of incidents are not captured in the database and may only be available from the well owner/operator and/or the insurance claims adjuster for the specific case.

A.9 Summary of API 65 Work Group's Study of 14 LWC Incidents

In API 65 Work Group [3] meetings, annular flow statistics on offshore wells in U.S. federal waters were presented including MMS records on the occurrence of SCP and on 34 LWC incidents that occurred during drilling operations and reported in the years 1992 through 2002. Of the 34 LWC incidents, 19 (56 %) were caused by annular flows associated with the cementing process.

The API Work Group [3] studied 14 of the 19 LWC incidents linked to cementing that occurred from 1996 to 2001 on the U.S. outer continental shelf (OCS), i.e. annular flow events during or after cementing operations. Conclusions of the study of the 14 incidents are listed below.

1) Most of the LWC incidents studied took place during or just after cementing surface casing.

2) In more recent years (2003 to 2004), these events involved deep casing strings with no occurrence of LWC incidents in surface casing cementing operations.

3) Most wells used a mudline hanger/suspension system.

4) Frequently the annulus between surface and conductor casings at the surface was washed out to a point 30 ft to 50 ft below the mudline after cementing. Washing out this annulus resulted in a small but possibly very significant reduction in hydrostatic pressure while also impairing the operation of the BOP and diverter (wash pipes in the annulus prevents sealing).

5) Often, cement slurries were not designed to prevent flows.

6) Effective drilling fluid removal and zonal isolation practices were not followed.

The study included reviews of detailed information on the incidents including “lessons learned” presentations by many of the operators involved. Public documents were available for some of the incidents that reported causes and proposed preventive measures. The studied incident information and the membership’s knowledge of annular flow events in other areas allowed the Work Group to prepare proven practices contained herein to help prevent future annular flow incidents and also help reduce the occurrence of SCP.

A.10 Lost Circulation Increases Risk for LWC Incidents

Lost circulation before, during, or just after primary cementing.

a) Can cause a failure to maintain an overbalance across potential flow zones exposed in the wellbore whereby:

   1) an inadequately designed cement slurry (density too heavy, etc.) fails to reach the designed depth for the TOC column;

   2) or the drilling fluid column is reduced or “falls back” or “goes on vacuum;”

   3) and either one of these shortened columns results in an insufficient hydrostatic head pressure to overbalance formation(s) pore pressures.

b) Has often been found by investigators as the root cause for many of the LWC incidents experienced in offshore drilling operations.

c) Can induce LWC incidents at any depth in the well construction process from soon after “spudding” (starting to drill) the well to drilling the well at total depth when conditions occur such as:

   1) structurally weak zones are exposed in the wellbore;

   2) naturally occurring leak off flow paths are encountered such as fractures, faults, vugs, caverns, etc.

As mentioned above, lost circulation during primary cementing operations may cause reduced hydrostatic pressure and underbalanced conditions when losses cause the drilling fluid column to fall to create an underbalance. For example when heavier density (than the drilling fluid) cement slurries are removed from the annulus by total or partial lost circulation (cement flows into weak zones), the TOC can be much lower than the designed top of cement depth.

This substantially decreases the annular column hydrostatic pressure across potential flow zones within the cemented annulus. This decreased hydrostatic pressure allows formation fluids to influx into the wellbore which starts annular flows that can lead to LWC incidents.

Another way for lost circulation during cementing operations to lead to LWC incidents is when the actual TOC does not reach the planned depth to cover potential flow zones and, instead, places drilling fluid across these formations. If the drilling fluid hydrostatic pressure is below the formation's pore pressure, annular flows may start immediately. If the drilling fluid hydrostatic pressure is above the formation's pore pressure, an annular flow may not start until drilling fluid gellation (also called SGS development), solids settling, etc. decreases the hydrostatic pressure enough to create an underbalanced pressure condition. See A.14, 4) for more information on this phenomenon.

Cement channeling may cause total or partial lost circulation during primary cementing by initially raising the cement column to longer than planned heights (shallower depths) which results in pressures greater than fracture initiation/ propagation pressures. Relevant formations exposed to these pressures then "breakdown" or fracture and start taking volumes of the cement slurry out of the annulus. When this occurs, the annular fluid level drops (called "fallback" or the annular fluid flow rate out of the well decreases to less than the rate pumped into the well. In either case, the risk of an LWC incident increases when these losses result in underbalanced pressure conditions across potential flow zones. Applying adequate measures to prevent cement channeling and associated losses are described herein including methods to optimize drilling fluid and cuttings removal/displacement by operational procedures and cementing job designs such as measuring drilling fluid conditioning and hole cleaning performance with fluid calipers (see 5.2), pipe movement, installing centralizers, and pumping relevant cement flushes and spacers at engineered rates.

An API cementing book [38] published in 1991 includes data (see Table A.10) indicating that up to 45 % of all wells require an intermediate casing to prevent severe lost circulation while drilling to total depth (TD). With these extra pipe strings in well designs, lost circulation events still occurred in 18 % to 26 % of all hole sections. Some areas reported many more occurrences of lost circulation events ranging from 40 % to 80 % of wells. In recent years, these percentages have likely increased as the number of shallow, easy-to-find reservoirs has steadily declined and well operators have intensified their search for deeper reservoirs and drilled through depleted or partially depleted formations. Conventional LCM including pills, squeezes, and pre-treatments, and drilling procedures such as ECD management often reach their limit in effectiveness and become unsuccessful in the deeper hole conditions where some formations are depleted, structurally weak, or naturally fractured and faulted.

In some cases, operators perform FIT or LOT measurements after the initial casing shoe test while drilling critical hole intervals or after drilling the entire hole section. This practice helps confirm that lost circulation can be prevented by the integrity of the open hole to contain pressures generated from deeper drilling and/or from operations to set casing/ liner pipes (higher ECD in running pipe and primary cementing). Successful cases over the last 50 years have proven that this practice can successfully predict cementing placement without losses. In other cases when cement losses are predicted by the hole section FIT or LOT, the operator may decide to apply alternative measures such as LCM pills, tack and squeeze, etc. Some technical papers describe these practices including the lessons learned procedure reported by Rederon et al [39] in SPE 149 (p. 5, rt. Column, step no.1) published in the late 1950's.

Table A.10—1991 API Survey Data on Lost Circulation

	United States	North America	Global
Producing fields in survey	204	218	339
Wells needing intermediate casing and/or drilling liner	31 %	33 %	45 %
	Lost Circulation Encountered		
Surface casing	24 %	24 %	21 %
Intermediate casing	24 %	25 %	23 %
Production casing	24 %	24 %	24 %
Liners	18 %	26 %	19 %

A.11 Example LWC Incident Case After Primary Cementing Operations

A drilling rig had completed cementing surface casing. Shortly after the surface/conductor casing annulus was washed out, the annulus began flowing. Rather than release the flow into the diverter system, the crew attempted use the diverter to hold pressure to allow time for the cement to heal. To hold pressure, the diverter was placed in the "test" mode, which allowed both the diverter packer element and vent-line valves to be closed simultaneously and immediately.

The diverter in use featured a telescopic riser with seals bracketing the vent-line housing. When the diverter was closed, the pressure rapidly increased until the seals began leaking, forcing abandonment of the rig floor. It was then discovered that the "test" mode disabled the ability to control the diverter system from the remote location. Seal pressure could not be increased to contain the surface leak; the diverter valves could not be opened to relieve the pressure. With gas on the rig and pressure rising on the untested conductor casing shoe, the rig and adjacent platform were evacuated.

Several factors contributed to the potential severity of the event, including an erroneous chain of decisions, inadequate training of personnel, minimal knowledge of diverter system, and poor planning.

There were 20 diverter incidents in the Gulf of Mexico from 1973 to 1995 related to well kicks after cementing surface casing. Another 13 similar incidents have occurred since 1995, with the most serious consequences being gas broaching to the surface, cratering, well loss, and rig and platform destruction by fire. Annular flow related to cementing surface casing has been identified as one of the most frequent causes of loss of control incidents in the Gulf of Mexico. Additional examples of such well control incidents can be found at http://www.mms.gov/incidents/blowouts.htm.

A.12 General Review of Key Technologies

Achieving zonal isolation in the presence of a potential annular flow requires not only the modification of the cement properties to facilitate control of migrating formation fluids but also several other features including:

— a stable wellbore—no losses or gains,

— adequate annular circulating flow clearances,

— proper drilling fluid conditioning and hole cleaning prior to cementing,

— spacer design,

— casing centralization,

— proper fluid dynamics during circulation and placement of cement to achieve drilling fluid removal,

— tripping requirements,

— drilling techniques,

— well monitoring,

— proper WOC time and associated rig operations,

— sustained hydrostatic pressure during cement curing,

— no wash pipes in the annulus that negates BOP function,

— use of mechanical barriers when appropriate.

This document is a compilation of best practices, engineering considerations and cement property requirements to assist in the prevention of annular flows and to establish zonal isolation within the wellbore. This task entails, at its most fundamental level, the removal of drilling fluid from the wellbore and replacement of drilling fluid with cement capable of achieving and maintaining annular isolation.

During the API Work Group's study and draft RP preparation process, the relevant technology and practices contained herein generated prolonged discussions and comprehensive work in writing the relevant text in this and other parts of API Std 65—Part 2. Numerous literature searches were conducted to find, discuss, and cite the information that helps document whether or not a practice is field proven, technically valid, and reliable in preventing annular flows.

A.13 Loss of Hydrostatic Pressure After Cement Placement

The failure of an annular cement column to control and isolate zones exposed in the wellbore is the root cause for many of the LWC incidents experienced in offshore drilling operations. LWC incidents can occur at any point in the well construction process from soon after spudding the well to drilling the well at total depth.

A number of factors are common to LWC incidents experienced while drilling the top-hole sections. From a pressure maintenance standpoint, many wells are drilled in a near-balanced condition. Often only a minimal pressure margin exists between formation pore pressure and circulating hydrostatic pressure of the drilling fluid. Typically, the well is drilled with simple spud muds with minimal fluid loss control. The cement designs employ lightweight, extended lead cement systems with a tail cement of higher density placed in the lower section of the cemented interval. In common practice, both lead and tail cement slurries are designed without any gas control capabilities. Further, certain lightweight and other cement systems are prone to gel before setting, thereby causing and accelerating the loss of hydrostatic pressure exerted on the column of tail cement below. A detailed discussion of this phenomenon is included in A.13 and A.14 where the "loss of hydrostatic pressure" effect can be caused by pre-mature gellation, also called early static gel strength development of the "critical gel strength period" (see 5.7.8) [18].

Annular flows have been caused by hydrostatic pressure losses that occur before the cement cures into a hard, impermeable barrier. This has happened in both top-hole sections and bottom-hole sections of the well. Several factors or combinations may cause annular flows in the deeper sections of the well including the cementing process, cement design, and the immediate setting of mechanical barriers that can reduce hydrostatic pressures.

While mechanical barriers are designed to prevent the flow of annular fluids past the barrier element or seal, setting of the barrier may actually increase the chance of gas entering the cement slurry. This is because setting the barrier isolates all potential flow zones below the barrier from all of the hydrostatic pressure above the barrier. This reduction in OBP on any potential flow zones effectively decreases the CSGS as defined in 5.7.8. The pressure in the annulus therefore drops to the pore pressure of the flow zones at an earlier time after the cement is in place, increasing the window of opportunity for gas to enter the cement slurry. Because of this increased chance of gas entering the cement, it is very important that the slurry placed across potential flow zones is designed with gas migration control properties (see 5.7.13). Properly designed cement slurries should be used to help prevent the gas from migrating through the annulus once it has entered the cement. If migration is not controlled there is potential for either a cross-flow into a lower pressure zone or the collection of a gas pocket directly below the mechanical barrier.

In other cases (no mechanical barrier), annular hydrostatic pressure losses may fall below permeable formation pore pressures resulting in underbalanced conditions that cause higher pressure formation liquids and gases to flow into the cemented annulus. This can lead to annular flows of formation liquids and gases which may induce cross-flows into permeable formations with lower pore pressures, paths that flow up to the wellhead, or a combination of both.

Cooke et al [24,25] investigated the loss of hydrostatic pressure in columns of drilling fluid and cement slurries and reported the results in SPE papers 11206 and 11416 and in JPT articles dated August 1983 and December 1984. Cooke studied hydrostatic pressure losses by measuring annular pressures vs time at various depths with sensors installed on the casing and hard wired to surface recorders. Measurements were recorded prior to, during, and after primary cementing operations in several wells. Measurements were recorded for several months in some wells that showed long term reductions in drilling fluid column hydrostatic pressures.

Cooke's study [24,25] discovered fundamental mechanisms and explanations supporting some theories on loss of hydrostatic pressure and invalidating others. These discoveries were verified by others such as a similar separate downhole sensor study (SPE 19552) by Morgan [40] while running and cementing casing in the North Sea. Morgan also reported how these downhole measurements indicated the failure to set an ECP.

An analysis of downhole annular pressure measurements can explain other difficult to find or complex root causes for other cause effects such as high ECD pressures when cementing liners. Brehme et al [41] et al found that downhole pressure sensor measurements are a reliable method to help diagnose and evaluate liner running and liner cementing operations. Cementing simulation computer model results were favorably compared to the actual downhole pressures. Brehme et al [41] proposed this process to help predict and evaluate results in future cementing operations by downhole gauge diagnosis of conditions not included in software models such as annular restrictions by cuttings, hole cleaning performance, and liner hanger equipment functions. For example, this data can help operators find answers for some annular flows linked to lost circulation events such as those caused by complete or partial flow restrictions in liner overlaps or liner hanger bypass or cross-sectional areas plugged by cuttings not removed during hole cleaning operations.

A.14 Some Key Results from Cooke's Study [24,25]

Some of the key results from Cooke's study [24,25] are as follows.

1) Downhole sensor measurements proved that the loss of hydrostatic pressure in columns of unset cement may be reduced to values below those found in cement mixwater (fresh, sea or saltwater) density gradients [see A.3, no.4.a)]. See Figure A.2 (Figure 9 in SPE 11206) showing that the cement hydrostatic head from the sensor at 1900 ft. in well G decreased from 13.4 lb/gal to 2.5 lb/gal equivalent density in ca. 420 minutes. This measurement is 6.0 lb/gal equivalent density below the average seawater gradient of 8.5 ppge. Cooke concluded that SGS development caused the cement hydrostatic head to regress to 2.5 ppge based on hole conditions such as formations with little or no permeability across and above the sensor at 1900 ft. This invalidates the idea claimed in SPE 8255 [42] that the loss of hydrostatic head in the cement column never falls below the cement's mixwater density gradient. It also invalidates the associated practice [38] of adding salt in cement slurries to increase the gradient and reduce the loss of hydrostatic head.

2) Surface pressure applied to the annulus may not reach the desired depth depending on drilling fluid and cement properties such as gel strength development (A.3, no.4.b. and 5.7.8). See Figure A.3 (Figure 4 in SPE 11206) that illustrates the lack of pressure response in 3 sensors at 4430 ft, 5454 ft, and 7412 ft in well B when surface pressure is applied. Also notice the large amount of pressure applied after 2100 minutes was high enough to break the cement SGS and allow hydrostatic pressure to be measured at 2 of the 3 sensors. Figure A.3 (Figure 2 in SPE 11206) also shows no pressure response from all sensors in well A by the applications of surface pressure designed to test the validity of said practice described in SPE 8255 [42]. The surface pressure was applied 24 minutes after the cement job ended. This uncertainty in transmitting hydrostatic pressure through unset cement slurry at various times during a cement's curing phase makes it unreliable to carry out the practice of applying and maintaining an annular surface pressure to compensate for hydrostatic head pressure losses as claimed in SPE 8255[42]. Therefore, applying surface pressure by pumping into the top of the annulus should be considered only for well control purposes such as controlling a kick in the annulus. However, in some recent cases applying small amounts of surface pressure in the form of controlled pressure pulses has worked in some wells to help prevent annular flows when the entire process, including the cement system, is properly engineered, understood by all involved, and validated by relevant means such as the lab testing described in 5.7.8.

3) Prior to Cooke's study [24,25] our industry did not have relevant field data to fully understand and confirm the theoretical mechanisms accounting for the rapid losses of designed overbalances after cementing jobs. Cooke's measurement of this rapid decrease in cement column hydrostatic pressures to underbalanced conditions across potential flow zones helped explain the cause of many LWC incidents. It also helped explain how other annular flows such as cross-flows and underground blowouts were initiated. The understanding of how SCP may initiate via different types of annular pathways was also improved. Figure A.4 (Figure 2 in SPE11206) presents annular pressure and temperature measurements in well A that illustrate how the hydrostatic head

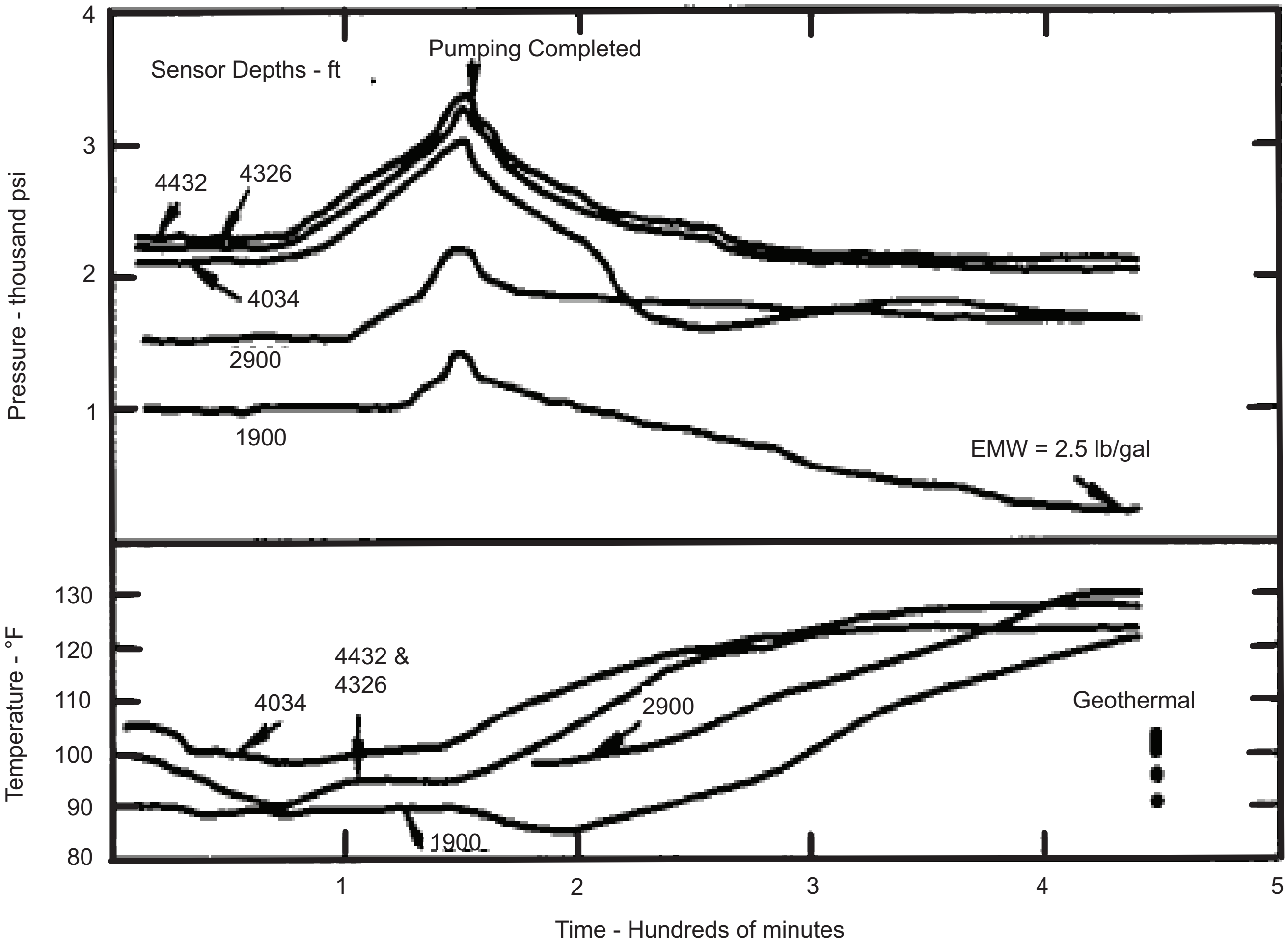

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Figure A.2—Annular Pressure and Temperature—Well G

decreased vs time. Note that the hydrostatic head loss in all sensors started immediately after pumping of the cement slurry ended and the temperature at each sensor indicated that the cement was not set until inflection points in each temperature curve was recorded. These inflection points represent the principal exotherm of the cement that occurs when the cement achieves initial set. In 1983 all the information from Cooke's study was an industry revelation that helped accelerate the implementation of cement practices and materials that were already developed to help control annular flows. It also helped R&D funding by various companies for even better solutions.

4) Many other interesting facts and data analysis results are presented in SPE 11206 and the follow-up paper SPE 11416. The latter one focused on temperature effects, lost circulation during cementing diagnostics, and the hydrostatic pressure decline in columns of "mud" or drilling fluids. Figure A.5 (Figure 7 in SPE 11416) indicates the drilling fluid hydrostatic pressure loss recorded by sensors above the TOC during many days after the cementing jobs in wells B and D.

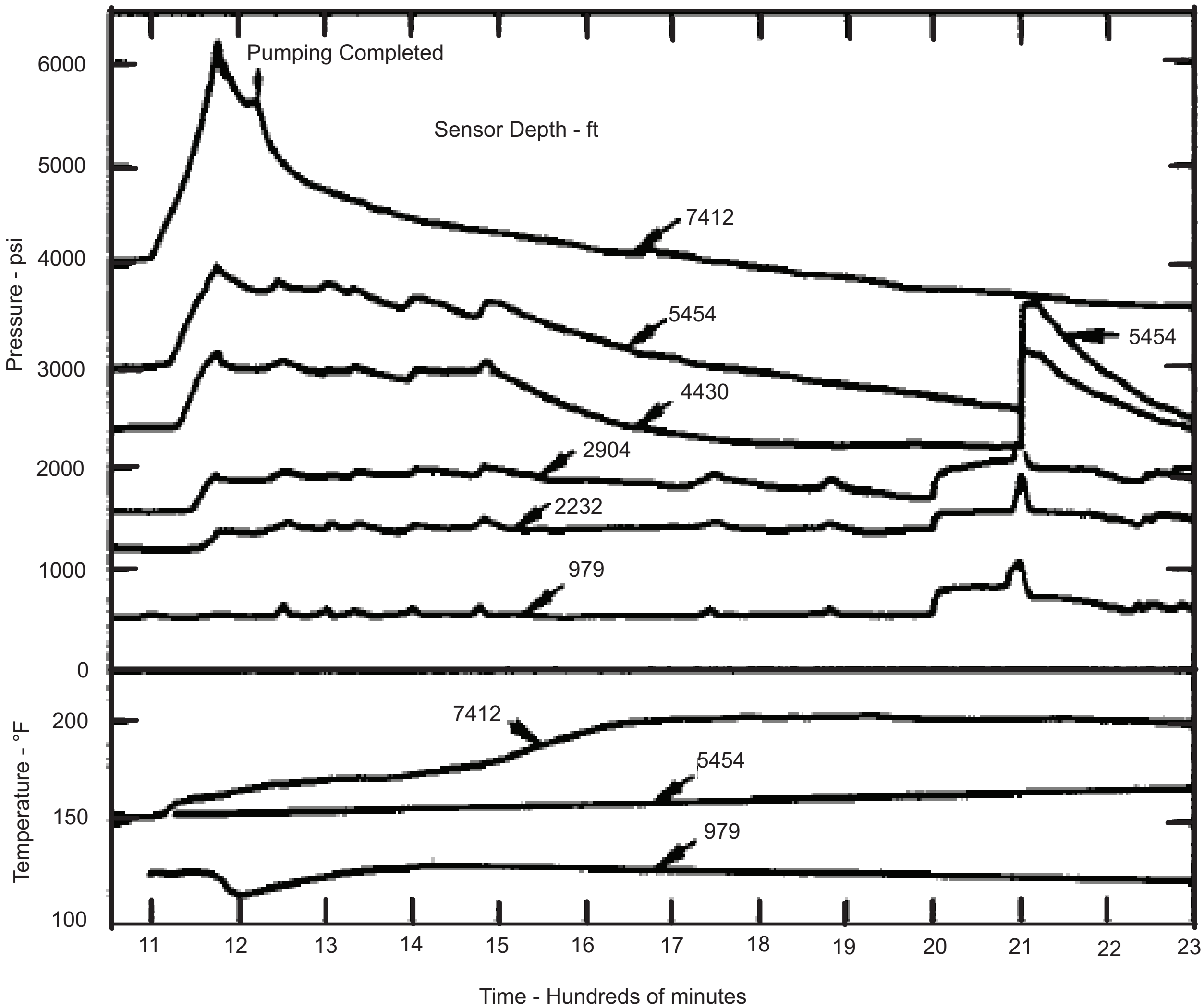

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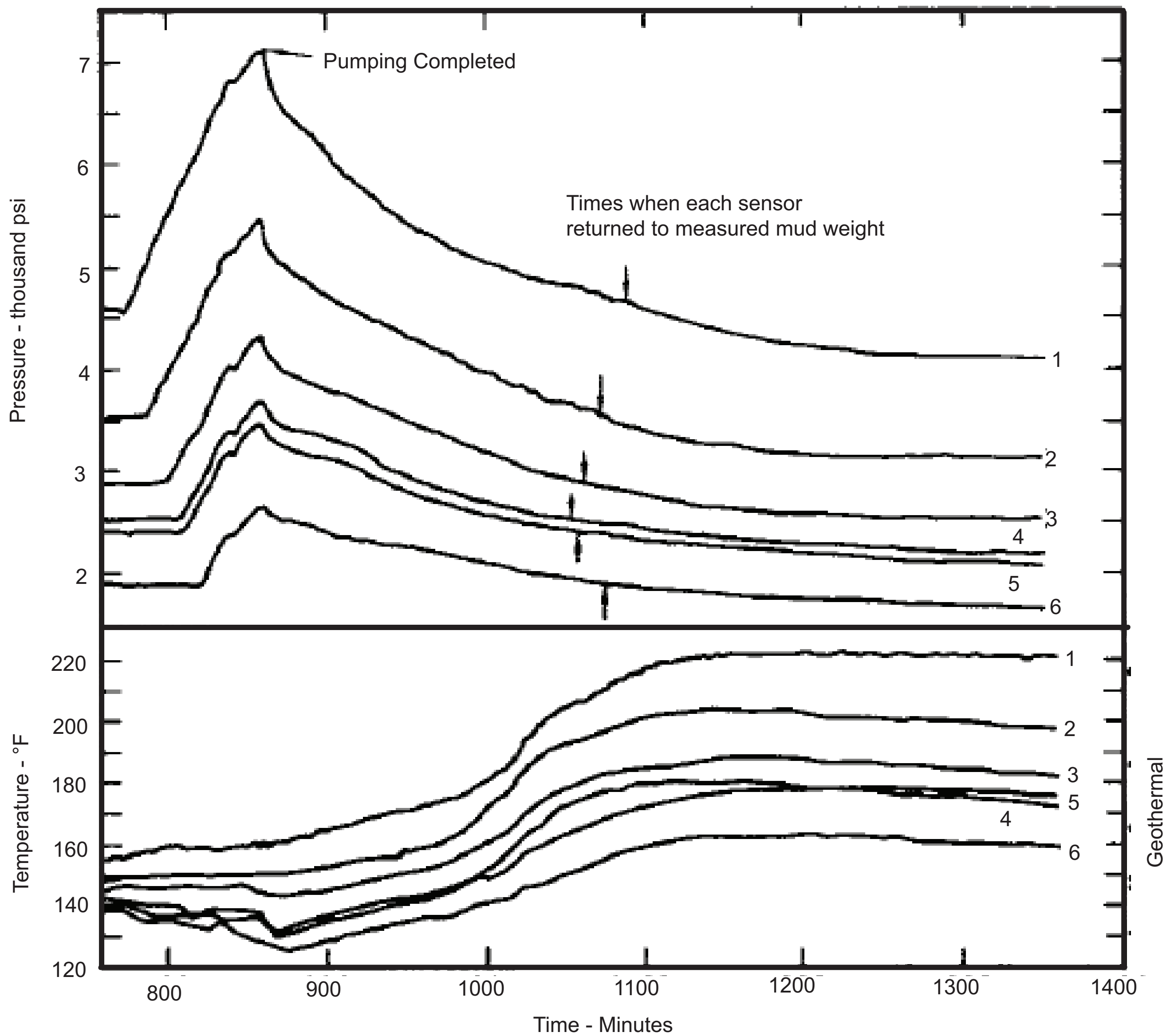
Figure A.3—Annular Pressure and Temperature—Well B

This unexpected loss of drilling fluid hydrostatic head has two major impacts on well design practices:

a) the "initial density of the drilling fluid in the annulus should not be used as the backup pressure in casing burst design,"

b) the drilling fluid hydrostatic pressure based on the original drilling fluid density should not be counted on to overbalance potential flow zones during the life of the well.

During the late 1980's, Cooke's study [24,25] was favorably peer reviewed by API's Subcommittee 10 on Cementing and recognized as one of industry's most important publications for the advancement of cementing technology. Accordingly, its significant findings and data measurements were published in API's book [38] on cementing practices in 1991.



Sensor No.	1	2	3	4	5	6
Depth (ft) (RKB)	8754	6909	5488	4787	4632	3636

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Figure A.4—Annular Pressure and Temperature—Well A

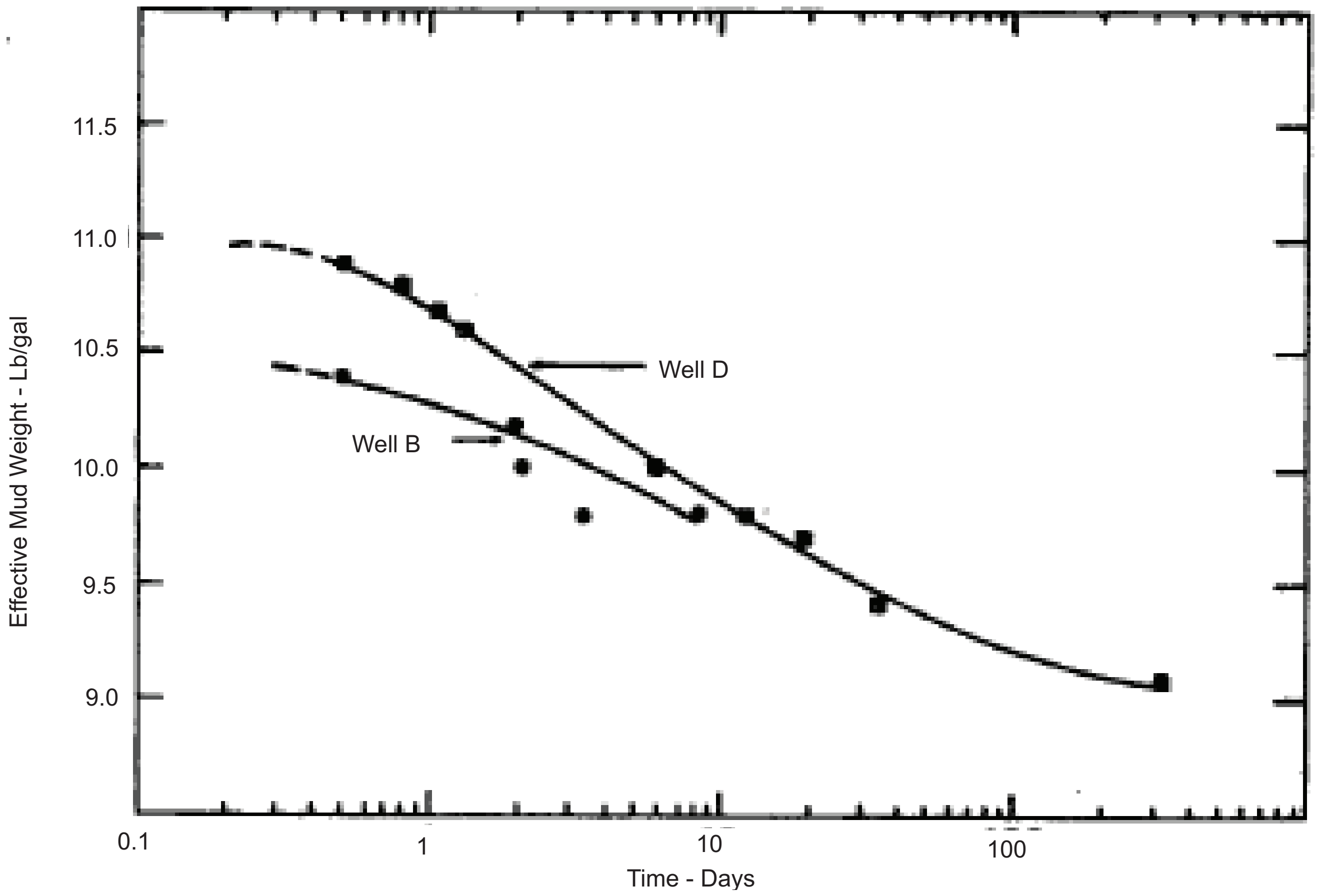

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Figure A.5—Mud Densities Measured By Pressure Sensors in Annulus

Annex B
(informative)

Well Planning and Drilling Plan Considerations

B.1 Evaluation of Well for Flow Potential

B.1.1 General

Before drilling a well, the operator should attempt to identify and analyze potential flow zones. A variety of techniques are available to do this, three of which are discussed below. The success of these techniques in identifying and successfully dealing with flow zones is related to the quality of the available data, a company's experience in a specific geographical area, and the capabilities of the personnel involved in the analysis.

B.1.2 Site Selection

Prior to drilling, the operator can minimize encounters with potential flow zones by carefully selecting a site that achieves target depth while minimizing the risk of encountering a flow. This is accomplished primarily through accurate review and analysis of available shallow and deep hazards data, proper interpretation of this information, and assimilation of this information into the drilling program.

Offset well information (when available) can be evaluated to determine if flow zones were encountered, the magnitude of any flow events, and the methods used to mitigate the effects of these flows. This information should be incorporated into the current drilling program.

API RP 65, Section 4, addresses site selection for minimizing shallow flows in deepwater wells. Many of the same principles apply to operations for all water depths and well depths and are discussed below in this Annex.

B.1.3 Shallow Hazards

Identification and evaluation of hazards through the use of shallow seismic surveys obtained over potential wellsites can aid the operator in proper site selection. If available, shallow seismic data from offset wells or adjacent fields where shallow flows occurred should be used to verify the analysis. If hazards are identified, the risk should be evaluated and mitigation measures taken as appropriate. The operator is cautioned that a shallow hazards analysis is not a conclusive method of prediction, so precautions to minimize the probability of a flow should still be implemented when drilling the shallow portions of the well. If the decision is made to drill a well in an area that is likely to encounter shallow hazards, drilling the shallow portions of the well with a small diameter pilot hole will make killing the well easier to achieve.

B.1.4 Deeper Hazards

Potential sources of deeper drilling hazards include abnormal pressure, pressure depleted zones, faults, tectonic stresses, salt flows, and lost circulation. Such hazards can often be identified through seismic interpretation and/or analysis of offset wells or fields. Identification of hazards that could be encountered during drilling operations will aid in proper well planning and in minimizing risk. If available, deep seismic data from offset wells or adjacent fields should also be analyzed to aid in the prediction of flow zones.

B.2 Planning the Well

B.2.1 Well Conditions

After evaluating the well for flow potential and determining the location that minimizes this potential, detailed well planning can begin. An optimum well plan for these conditions incorporates the following features, which are not all inclusive:

— an understanding of pore pressures, fracture gradients, and required drilling fluid densities;

— a casing plan that addresses limitations imposed by pore pressure, fracture gradient, wellbore stability, and other operational concerns;

— a cementing plan that provides for short- and long-term isolation of potential flow zones;

— evaluation of the impact of potential thermal pressure (APB) in subsea wells;

— selection of drilling fluid(s) that will best control wellbore pressures and enhance cementing success;

— a hydraulics plan that provides for adequate wellbore cleaning and control of static and dynamic wellbore pressures;

— a barrier design that provides for control of all pressures that may be encountered during the life of the well;

— a contingency plan that addresses wellbore instability and unintended gains and losses of fluids;

— adherence to regulations;

— a means to thoroughly and effectively communicate the plan to the personnel that will execute it.

B.2.2 Pore Pressure/Fracture Gradient/Drilling Fluid Weight

The well planner should understand and/or model the anticipated pore pressures, fracture gradients, and drilling fluid densities that will be encountered while drilling the well. Exploration wells will not provide the same level of certainty of pore and fracture gradients as will development wells. This information is generally presented in a graph, as shown in Figure B.1.

General guidelines for the construction of this graph are as follows.

— Plot the predicted pore pressure vs depth, expressed as an equivalent mud weight (EMW). It may also be helpful to note lithological information, if it is available.

— Similarly, plot the predicted fracture gradient (as an EMW) vs depth. Draw a design fracture gradient profile that is offset to the left of the predicted curve by a prescribed amount to roughly account for kick tolerance and the increased ECD during drilling and cementing operations. Typical offset values range from 0.2 ppg to 0.5 ppg.

— Draw the planned drilling fluid weight profile based on the pore pressure and fracture gradient data. In general, the drilling fluid weight profile is offset to the right of the pore pressure curve to provide sufficient overbalance for trips (i.e. a trip margin). Typical trip margin values range from 0.3 ppg to 0.5 ppg.

— Include planned casing diameters and setting depths to clarify wellbore construction features. If drilling fluid weight and LOT information is available from offset wells, include it on the graph for reference.

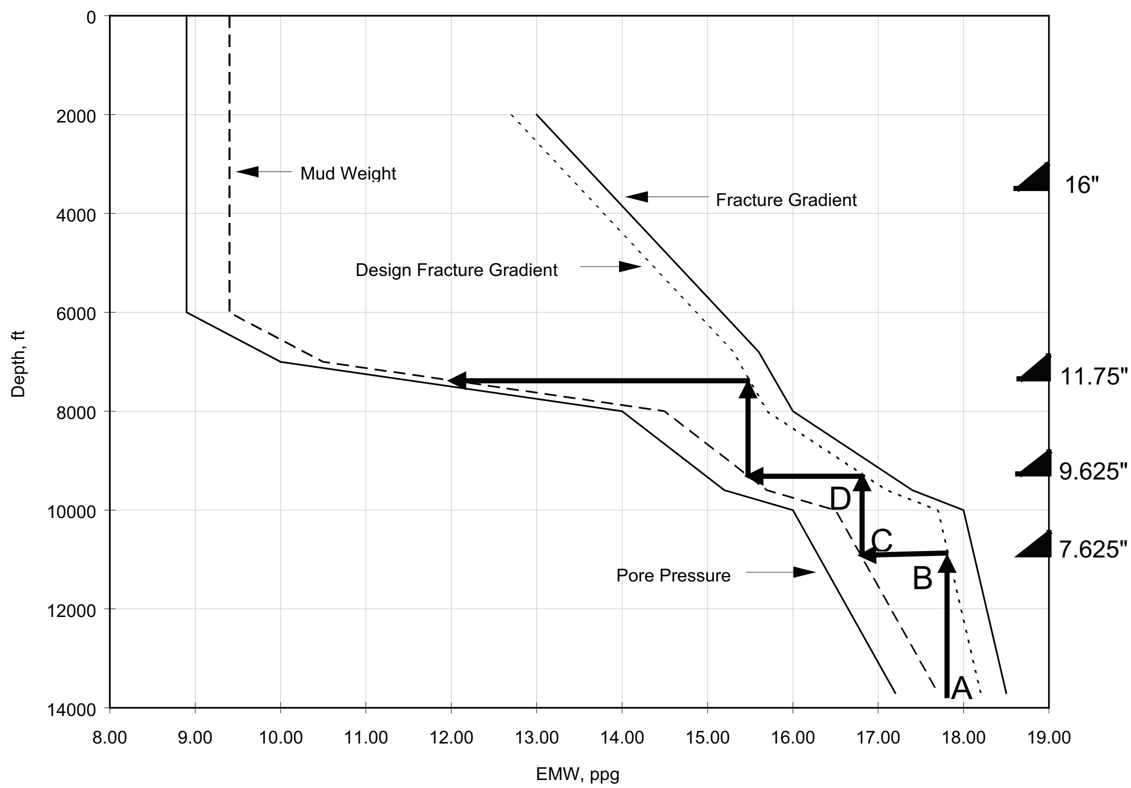

Figure B.1—Casing Shoe Depths with Pore Pressure/Fracture Gradient Graph

If large disparities exist between the offset well information and the predicted values, further investigation may be warranted. This graph will become the design basis for the well.

B.2.3 Casing Plan

The appropriate selection of shoe depths and consequently, the required number of strings is critical to the well design. General guidelines are given here for the selection of shoe depths. Local practices, regulatory requirements and experience should also be used to fine-tune this process.

Initial shoe depth determinations are made as follows (see Figure B.1).

— Starting at the drilling fluid weight at the well’s TD (point A), draw a vertical line upwards until it intersects the design fracture gradient curve (point B). This is the approximate shoe depth of an intermediate casing.

— Draw a horizontal line from point B leftwards until it intersects the drilling fluid weight curve (point C) and then upward until it intersects the design fracture gradient curve (point D). This represents the approximate shoe depth of the next casing string.

— Repeat this process until all shoe depths dictated by drilling fluid weight and fracture gradient constraints have been established.

After the preliminary shoe depths have been established, an additional check should be made based on kick tolerance. The kick tolerance is the maximum size kick of a specified intensity that can be circulated out of the hole without causing the formation to fracture in the open hole section (often near the shoe). It may be necessary to adjust casing shoe depths to conform to kick tolerance limits.

In some higher pressure wells with a small margin between the drilling fluid weight and the fracture pressure, the recommended kick tolerance is nearly impossible to achieve. This is particularly true for many wells drilled in the Gulf of Mexico.

There are numerous other factors that affect the design of shoe depths. These factors include the following.

— Regulatory Requirements—Applicable local regulations should be obtained before beginning the design.

— Hole Stability—This can be a function of drilling fluid weight, deviation and stress at the wellbore wall, or it can be chemical. Hole stability problems often exhibit time-dependent behavior, making shoe selection a function of penetration rate. The plastic flowing behavior of salt zones should also be considered.

— Differential Sticking—The probability of becoming differentially stuck increases with increasing differential pressure between the wellbore and formation, increasing permeability of the formation, and increasing fluid loss of the drilling fluid (i.e. thicker drilling fluid cake).

— Shallow Zones with Potential for Flow—Any potential flow zone should be isolated.

— Zonal Isolation—Shallow fresh water sands need to be isolated to prevent contamination. Lost circulation zones should be isolated before a higher-pressure formation is penetrated to avoid downhole cross flow.

— Directional Drilling Concerns—A casing string is often run after an angle-building section has been drilled. This avoids drillstring key seating problems in the curved portion of the wellbore due to the increased normal force between the wall and the drill pipe while drilling deeper sections of the well.

— Uncertainty in Predicted Formation Properties—Exploration wells often require additional strings to compensate for the uncertainty in the pore pressure and fracture gradient predictions.

— Hole and Pipe Diameters—The selection of pipe diameters has the largest impact on well costs in both design base and detailed casing design. In general, hole and pipe diameters should be designed to be the smallest possible, which meet all design requirements, well objectives, safety, and environmental requirements. In exploratory wells, hole diameters may be larger to allow for contingency casing string(s). The final hole or casing diameter is generally determined by evaluation, completion, and production requirements. Because of this, casing sizes should be determined from the inside outward.

Hole and casing diameters are based on the following requirements.

— Drilling—Bit diameter (hole size) should be minimized to aid in maintaining the required “reflection point” when directionally drilling, available downhole equipment, rig specifications, and available BOP equipment.

— Cementing—See B.2.4 for more information.

— Production—Production equipment requirements including tubing, subsurface safety valve, submersible pump and gas lift mandrel size, completion requirements (e.g. gravel packing), and weighing the benefits of increased performance of larger tubing against the higher cost of larger casing over the life of the well.

— Evaluation-logging requirements and tool diameters.

B.2.4 Cementing Plan

Short- and long-term isolation of potential flow zones requires proper cementing planning and execution. Listed below are several aspects of well planning that may affect the success of primary cementing operations. These items are covered in more detail in Section 5:

— hole size and shape (enlargement and annular dimension),

— selection of drilling fluid for filter cake and rheological properties,

— drilling fluid conditioning,

— spacers,

— cement slurry design,

— pump rates,

— centralization,

— testing/evaluation plan.

B.2.5 Drilling Fluids Plan

The drilling fluid is a key factor in the isolation of potential flow zones because of its pressure-control function and because it can affect the success of any cementing operation. Key drilling fluid considerations that relate to cementing success include:

— drilling fluid density or mud weight (MW),

— drilling fluid type,

— filter cake properties,

— rheology and gel strength properties,

— fluid stability,

— effects of drilling fluid on wellbore stability.

These items are covered in more detail in Section 7.

B.2.6 Wellbore Hydraulics

B.2.6.1 (ECD) Management

A plan should be developed to monitor and control static and dynamic fluid pressures of the drilling fluid column such that ECD is maintained within appropriate limits. Static fluid pressure should be sufficient to contain maximum open hole formation pressure and minimize wellbore stability problems, while dynamic fluid pressure should be controlled to minimize fracturing of any exposed formation unless required for wellbore strengthening. Hole size, casing size, BHA and drill pipe size selection should be balanced with the fluid properties and surface equipment ratings to ensure ECD can be maintained within the desired range. Offset well files should be reviewed for indications of lost circulation, stuck pipe, significant borehole enlargement, etc., and the ECD management plan should be modified to mitigate these problems. ECD increase in high-angle and horizontal wellbore sections should be addressed in the plan, as the formation fracture gradient will remain constant in the horizontal section of the well while fluid friction pressure will increase.

Numerous well design parameters can impact ECD including the use of casing strings with increased annular clearances, use of liners rather than full casing strings, selecting fluids that reduce frictional losses, expandable tubulars to preserve hole size, and controlling ROP to avoid overloading the annulus with cuttings. Critical circulating and swab pressures should be documented in the plan. A wellbore hydraulics simulator should be used on each well.

B.2.6.2 Wellbore Cleaning

Cuttings transport to the surface is primarily controlled by annular velocity and fluid rheology, so care should be taken when selecting components that impact these parameters. Surface drilling equipment (drilling fluid pumps, flow lines, and shakers) should be sized to accommodate the maximum rate of cuttings generated. Hole deviation should be considered when designing higher annular velocities for proper hole cleaning. Ensure chemical compatibility of the formation and the drilling fluid system to avoid swelling problems. The bit nozzle selection should be based on optimizing ROP, bit cleaning, and annular velocity for transport of solids to the surface. It is recommended that a wellbore hydraulics/hole cleaning simulation model be run on each well to determine minimum and maximum flow rates. Maximum pipe-tripping speed should be controlled to avoid creation of excess swab/surge pressure during hole cleaning operations. Wells drilled from floating vessels should consider the use of a booster line when high solids loading is expected in the riser.

Conventional hole cleaning tactics may have to be supplemented with hole cleaning pills under certain conditions. Viscous pills and high weight pills can be effective at removing cuttings. However, the use of some pills can contaminate the drilling fluid system.

B.2.7 Barrier Design

The operational goal of any well design is to provide sufficient barriers between formations and between those formations and the surface. A well's barrier plan should include maintaining well control via hydrostatic pressure from fluids, selection and use of well control equipment, and the placement of cement or other mechanical barriers in the well. The well design (i.e. wellhead, BOP equipment, riser, etc.) should consider including a minimum of two barriers available during any operation to prevent uncontrolled flow from the well to the environment. If an operation is performed with fewer than two physical barriers in place, then operational barriers become critical. See industry well design documents for more information. The barrier design should consider incorporating the following elements:

— ability to withstand the maximum anticipated wellbore pressure,

— ability to be tested for function or leaks,

— failure of a single barrier will not result in uncontrolled flow from the well,

— the operating environment is within the design specifications of the barrier element.

In addition, at least one of the barriers should have the capability to do the following.

— Shear any device that passes through the barrier and seal the wellbore after shearing. If this is not possible, an alternative pressure control plan should be considered.

— Seal the wellbore with any size device penetrating the barrier element. If this is not possible, an alternative pressure control plan should be considered.

Evaluation of the viability of each barrier should be considered in the planning process. Plans should address well control issues each time a barrier is removed or replaced. For example, after a cement job, the BOP system is typically removed to install wellhead components. At these times, the barriers in the well have changed from fluids and the BOP stack to fluids and cement. The plan should address when the cement properties are adequate to make that change.

Plans for testing of barrier elements should be part of each well design. Barrier plans should address pressure integrity through pressure testing, but may also require negative testing of a liner top prior to changing out the wellbore fluid. If drilling is planned for an extended period of time (> 30 days), potential casing wear issues should be reviewed, and casing size/tool joint facing material should be selected such that wear will not impair the casing's ability to withstand all potential loads.

B.2.8 Deepwater Barrier Planning

The column of fluid in the riser does not act as a barrier element when the marine riser has been disconnected. Planned or accidental disconnect of the marine riser should be addressed in the well plan. Operators may be able to maintain a drilling fluid density that will provide an overbalance condition with the marine riser disconnected. If this is not possible, a weighted fluid may be displaced into a portion of the wellbore, so that zones with flow potential remain under control in the absence of the hydrostatic pressure from fluid in the marine riser.

Deepwater operating plans should also address the following issues:

— detailed riser analysis should be performed to verify that the riser can withstand all anticipated environmental (weather, current, and sea state) and operating loads;

— the riser disconnect system should be analyzed to verify the ability to safely disconnect under all anticipated loads;

— riser stress should be measured or calculated to determine an optimum rig position to minimize the effects of static and dynamic loads.

B.2.9 Contingency Planning

B.2.9.1 General

The potential for instability caused by unintended transfers of fluids or solids between the wellbore and the formation should be identified in pre-drill analyses. Contingency plans should be developed to specify the procedures, equipment, and personnel needed to avoid adverse situations or to suppress incipient dangers before they become unmanageable. Contingency plans should consider events that fall into three categories: fluid influxes, lost circulation, and formation failures such as breakouts and packoffs.

B.2.9.2 Well Control Planning for Fluid Influxes

Kicks—The following equipment and supplies for contending with kicks should be available at the rig site:

— adequate supplies of heavy drilling fluid—these should be kept ready for mixing in the reserve pit;

— a diverter when shallow formation flow hazards exist such as high pressure shallow gas or water zones; or

— properly selected and well-maintained well control equipment such as blowout preventers (BOPs), chokes, and degassers.

Well control procedures vary depending upon whether surface or subsea BOPs are employed and whether a kick occurs while tripping, drilling, or the bit is out of the hole; however, in general, such procedures include:

— the use of kill drilling fluid and circulating out the kick,

— bullheading the kick back into the formation,

— diverting shallow gas,

— temporarily shutting in the well,

— plugging the borehole with barite or cement plugs leading to partial or complete abandonment of the well.

B.2.9.3 Shallow Water Flows

Shallow water flows are best managed by drilling the interval with weighted fluid. For cementing of shallow flow zones, specialized cements are recommended as detailed in 5.7 and in API RP 65. More information on controlling and cementing shallow water flow zones can be found in API RP 65.

B.2.9.4 Planning for Lost Circulation Control

Methods for avoiding or curing lost circulation during drilling can be found in C.2 and C.3, while those for handling lost circulation during casing and cementing operations are described in 5.8.1. Procedures for managing wellbore breathing or ballooning should also be considered. Wellbore breathing can be an indication of imminent lost circulation. If breathing is observed, the following responses should be considered.

— Review system hydraulics to determine if it is possible to reduce ECD. Consider reducing the drilling fluid weight, if possible.

— Monitor flowback while making connections. Record the volume and duration of flow.

— Do not weight up and risk loss of returns.

— Apply LCM pill.

— When a kick and breathing both occur, consider setting casing.

B.2.9.5 Formation Failure

Procedures for avoiding or managing formation failure vary depending upon the type of formation, the nature of the instability, and the availability of resources. In general, the following practices should be considered:

— maintain the ECD within planned boundaries (see B.2.6);

— use an appropriate drilling fluid type that provides adequate filter cake and cuttings transport, and inhibits chemical reactions with the formation;

— avoid surging or swabbing the formation and reduce tripping speeds when the BHA is opposite problem formations;

— minimize the exposure time in areas where rock deformation or failure is time-dependent (e.g. in salt);

— ensure good hole cleaning (see B.2.6).

In the event of a packoff, the following measures should be considered in the order listed:

— turn off the pumps and bleed down the standpipe pressure;

— apply maximum make-up torque;

— work the drillstring up and down;

— increase the standpipe pressure and continue to apply torque and work the pipe;

— as a last resort, commence jarring in the direction opposite to the last pipe movement.

B.2.10 Regulatory Issues

One component of proper well planning includes appropriate regulatory review. Typically, the regulatory agency with jurisdiction for the well will need to review the well plan before operations begin.

Well plan submittal documents tend to have the following features in common:

— a description of drilling objectives,

— planned casing and cementing programs,

— drilling fluid program,

— equipment testing policies and procedures,

— borehole evaluation and directional survey programs,

— estimates of pore pressures and fracture gradient.

Depending on the type of regulatory system in effect, the agency may or may not approve the well plan in its entirety, or it may require certain changes to the plan to meet regulatory requirements.

B.2.11 Communications Plan

A key feature of good well design is effective communication of the plan to the personnel that will execute that plan. The well design should be communicated through a written plan and through personnel meetings.

For complicated wells, holding a meeting to “drill the well on paper” can often highlight areas of risk and concern, and gives an opportunity for all parties to understand their role in executing the well program. A discussion of human factors, required training and experience of personnel should be highlighted.

Pre-spud meetings are often used to review the relevant topics contained in the well plans, highlight and review safety issues with the personnel, and address topics related to annular flow prevention. The prevention of annular flow does not rest solely with the cementing operation and well control equipment. It is a process that involves wellhead equipment, directional control, wellbore quality, drilling fluid management and cementing operations.

Annex C
(informative)

Drilling the Well

C.1 General Practices While Drilling

The following practices help maintain efficient drilling results and provide hole quality conditions suitable for primary cementing:

— using a drilling fluid of sufficient density to contain formation fluids;

— use of high viscosity sweeps to reduce potential for annular pack off or excessive gumbo deposition;

— controlling drilling fluid losses using LCM as needed;

— minimizing static gelled drilling fluid with flat gel strength drilling fluid rheology;

— preventing excessive drilling fluid filter cake buildup with low fluid loss drilling fluids;

— preventing balling on the BHA due to gumbo;

— rotating pipe while breaking circulation to reduce lost circulation potential on connections;

— while on diverter, the rig should pump out of the open hole and assess trip fill by monitoring each stand while circulating through the trip tank;

— controlling rate of penetration (ROP) to prevent overloading the wellbore with cuttings and minimizing the opportunity for gumbo accumulation;

— monitoring drilling fluid gas content and volume to verify flow potential.

C.2 Monitoring and Maintaining Wellbore Stability

Having a stable wellbore prior to, during, and after the cement job is crucial to cement job success. If losses or gains occur during a cementing operation the possibility of obtaining a successful cement job is greatly diminished. Corrective action should be considered to stabilize the wellbore prior to the cementing operation. Certain corrective measures are best applied prior to running the casing or liner string into the well. The following indicators are used to identify potential flows and losses, contributing to wellbore instability:

— changes in pit volume—monitor trend;

— changes in flow rate—monitor trend;

— changes in pump pressure;

— ROP—monitor trend;

— torque and drag;

— changes in weight on bit (WOB)—monitor trend;

— pressure while drilling (PWD) data;

— ECD variations;

— fracture gradient via shoe and open hole LOT data;

— cuttings size and shape;

— variation in “d” and dxc” exponent;

— abrupt lithology changes;

— returned drilling fluid gas (background, connection, and trip);

— flowline temperature;

— drilling fluid properties-look for drilling fluid cut density, change in salinity, oil in retort, etc.;

— shale density;

— formation changes from LWD/MWD data;

— presence of geologic hazards:

  — fractures,

  — faults,

  — unconformities.

Many of these indicators are precursors to wellbore losses or kicks which can result in an unstable wellbore.

C.3 Lost Circulation

C.3.1 General

Detailed well planning and accurate hydraulic modeling is extremely important in minimizing lost circulation. Lost circulation is one of the most common and expensive problems that are encountered while drilling or while running casing. Loss of circulation can lead to loss of well control and a multitude of associated problems. The financial consideration is of concern with any type of drilling fluid but the importance is the greatest when using NAF. Loss of circulation can lead to well bore instability and well control problems that can drastically affect the outcome of drilling and cementing of the well. See A.10 for more information.

Loss of circulation occurs when either one of the following conditions is met:

— the static or dynamic pressure exerted by the drilling fluid column exceeds the fracture pressure of one or more of the formations exposed in the borehole;

— the porosity and permeability of the formation or space within the fissure or pre-existing “natural” fracture is large enough to permit the passage of whole drilling fluid thus preventing the sealing effect of the filter cake.

Drilling fluid losses can be categorized as two types: natural and induced.

C.3.2 Natural Losses

Examples of natural losses include the following.

— Loss Through Rock Permeability—For whole drilling fluid to be lost, the formation openings are larger than the largest particles contained in the drilling fluid. These types of formations are usually characterized by seepage losses occurring in highly porous intervals usually encountered at shallow depths. Typically these formations are sands and gravels.

— Formations containing natural fractures and leaking faults.

— Cavernous and Vugular Porosity—Formations such as limestone or dolomites in which voids have been dissolved by ground water.

C.3.3 Induced Losses

Losses due to a mechanical disturbance of the wellbore can create fractures in the formation. The hydrostatic pressure thus created in the wellbore exceeds the formation break-down pressure and mechanically fractures the rock. These types of losses are different than what is seen in natural fractures since the fracture network is not interconnected. Some of the causes of induced fractures are affected by the following:

— fluid density and/or ECD,

— additional hydrostatic pressure due to length of riser,

— insufficient hole cleaning,

— excessive ROP with solids loading of drilling fluid column increasing MW,

— high pump rates,

— drilling fluid rheological properties,

— tripping speed,

— wellbore geometry,

— restricted annulus from packoffs or BHA balling.

C.3.4 Loss Rate Categories

Losses of drilling fluid to the formation have been arbitrarily defined in the following categories:

— seepage losses from 1 to 20 bbl/hr;

— partial losses from 20 to 50 bbl/hr;

— severe losses greater than 50 bbl/hr but the hole will remain full with the pumps off;

— complete losses, no returns while pumping or the hole will not remain full with the pumps off.

C.3.5 Preventing Losses

C.3.5.1 Drilling Fluid Properties

Drilling fluid properties can be optimized to prevent losses using the following:

— proper solids control management,

— keeping the fluid density as low as possible,

— maintaining gel strengths and yield point at the lowest levels that will effectively clean the hole and effectively suspend barite and cuttings,

— preventing excessive filter cake build-up by controlling fluid loss,

— using hydraulic prediction software to predict ECD and determine optimum fluid properties.

C.3.5.2 Minimize Surge Pressures

Surge pressures can be minimized by:

— staging in the hole to prevent excessive circulating pressures;

— rotating the pipe to mechanically shear the drilling fluid reducing gel strength before turning on the pumps, and bringing the pumps up slowly;

— monitoring and controlling pipe running speeds;

— using available hydraulics modeling software for predicting surge pressures;

— calculating annular flow and running casing slowly enough to avoid high pressure (speed of lowering each joint, not the average speed).

C.3.5.3 Downhole Equipment

The following downhole equipment practices will help reduce ECD to limit losses:

— using downhole pressure measurements to monitor and manage ECDs in real time;

— using BHA components with maximum annular flow paths across the tools;

— installing auto-fill and various enhanced flow by-pass equipment to minimize surges while running casing, note well control implications while running casing;

— using downhole tools that allow for high concentrations of LCM.

C.3.6 Identifying the Loss Zone

Quickly identifying where the loss zone is located will greatly enhance the performance of the treatment used to counter the lost circulation. Temperature logs, spinner surveys, noise logs, LWD data analysis and stress modeling, connection flow monitoring analysis, lost circulation computer model simulations, and offset well drilling fluid loss data are a few of the techniques used to identify where the suspected loss zone may be located. If a NAF is used, the suspected loss zone could be identified during a short trip by very high resistivity readings in an otherwise non-productive zone.

C.3.7 Lost Circulation Materials and Systems

C.3.7.1 General

There are a wide variety of lost circulation materials available to deal with the most severe types of lost circulation. There is no universal treatment available to cure all types of lost circulation. LCM can range from fine to coarse particulate materials, fibers, cements, reactant pills and acid soluble particulates. The type of material should be matched with the severity of the lost circulation encountered.

C.3.7.2 Seepage Losses

The most common type of lost circulation materials for seepage losses are the fine cellulosic fibers and fine granular types of additives. The most commonly used granular material is calcium carbonate. Another widely used technique is to pump the fine seepage loss additives as a sweep while drilling the seepage loss zone.

C.3.7.3 Partial Losses

The most commonly used materials for this type of loss circulation are granular- and flake-type products that have particles sizes larger than those used to deal with seepage losses. These can include mica, nut shells, and medium to coarse calcium carbonate, graphitic materials and coarse cellulosic fibers. These additives can be added to the drilling fluid system as a continuous treatment or can be spotted as a sweep across the suspected loss zone.

C.3.7.4 Severe Losses

Materials commonly used for severe losses are granular and flake type products that have larger particle sizes than those used to deal with partial losses. As the severity of the loss becomes greater than the preceding two types of losses, coarser sizes of the same additives should be used for bridging, but some of the finer particles can be included. These additives can be added to the drilling fluid system as a continuous treatment or they can be spotted as a sweep across the suspected loss zone.

C.3.7.5 Complete Losses

The types of additives and procedures used to deal with complete losses are generally different than those required for the preceding types of lost circulation. These types of losses generally occur in formations with leakoff flow paths larger than the diameter of most bridging particles. Large fracture openings and vugs usually account for these massive losses. These openings are not effectively sealed with the cellulosic and granular type of products described above. Reactive pills and agglomerating-type LCM materials are used under these circumstances. Some of these include:

— high filtration squeezes allowing for rapid loss of the carrier fluid resulting in a solid plug forming in the formation opening;

— hydration type systems where a very active material such as powdered clay or mixtures of clays and polymers in an inert carrier reacts with the drilling fluid to form a rubbery type of plug;

— chemical systems where special resins or polymers and catalysts react to form a semi-solid plug;

— mixtures of the above systems with cement to create highly viscous and hard setting plugs;

— special, highly thixotropic cement slurries squeezed into the zone or left in the wellbore as a plug;

— large volumes of these materials for cavernous loss zones or special squeeze cements such as foamed cement;

— silicate-base gels with and without cement;

— fibrous cement systems that form a bridge across the thief zone.

C.3.8 Planning and Operations Considerations

The following outline summarizes, in general terms, the data requirements and steps involved to plan a well in which lost circulation is a possibility.

a) Pre-well planning for all phases.

1) Drilling:

i) pore pressures and fracture gradients;

ii) fluid selection—NAF vs water based mud (WBM);

iii) optimizing flow properties;

iv) ECD control, annular pressure measurements;

v) controlled ROP and hole cleaning;

vi) caliper logs;

vii) lost circulation, near-wellbore stress, and ECD computer modeling;

viii) treatment plan to prevent or mitigate losses.

2) Running casing and liners:

i) swab and surge pressure modeling;

ii) insure the hole is clean and free of cuttings;

iii) reduced drilling fluid weight and rheology;

iv) casing hardware selection;

v) pre-treat the drilling fluids to reduce pressures;

vi) breaking circulation.

3) Cementing:

i) ECD modeling;

ii) ensure losses are cured before cementing;

iii) utilize good cementing practices

iv) cement slurry design;

v) LCM in the cement slurries;

vi) spacer considerations—flushes, spacer design (hydraulics);

vii) use proper cement densities and cement volumes.

b) Operational considerations.

1) Drilling:

i) pre-treat drilling fluid with various particle size distribution materials;

ii) modify pre-treatment as required depending on wellbore reaction;

iii) apply planned treatments as needed to control losses.

2) Running casing:

i) if possible cure the lost circulation prior to running casing;

ii) spot LCM in the open hole prior to running casing.

3) Lost circulation and near-wellbore stress computer modeling:

i) optimize planned treatments based on actual conditions.

Annex D[1]
(normative)

Process Summary: Isolating Potential Flow Zones During Well Construction

Isolating a potential flow zone with cement is an interdependent process. Individual process elements such as slurry design and testing, applied engineering and job execution all impact the ability to successfully install a cement barrier. Superimposed upon these elements are the conditions found in the well at the time of cementing.

Certain cementing process elements contained in this annex may be individually critical to isolating a potential flow zone or may be of minor consequence until made critical by a separate (sometimes unrelated) event or past well engineering decisions. Conversely, certain elements may not be dominant factors in the success in one cementing operation, yet vitally important in another.

Collectively, the elements described below produce the design, engineering and operational framework for successfully isolating a potential flow zone.

Flow Potential Risk Assessment	
The results from any pre-spud hazard assessment of the proposed drill site should be provided to the cementing service provider to be used as a basis of design for the cementing program or used in the slurry design guidelines provided by the operator. Typically the information provided will include location of possible hydrocarbon bearing, water bearing and lost circulation intervals as well as over-pressured or under-pressured zones.	
Site Evaluation	Was a pre-spud hazard assessment conducted for the proposed well site?
Assess Flow Potential	Are there any potential flow zones within the well section to be cemented?
Communication	Has the information concerning the type, location, and likelihood of potential flow zones been communicated to key parties (cementing service provider, rig contractor, or 3rd parties)?

Critical Drilling Fluid Parameters	
The drilling fluid design should be appropriate for parameters such as formation type, wellbore stability, formation damage potential, cuttings removal and proper management of ECD, etc. The drilling fluid used to drill a hole section containing a potential flow zone may not be ideal for cementing operations. Within the limitations imposed by the drilling fluid used, computer modeling **shall** be conducted to assess the impact of the drilling fluid circulation and cement placement on the pore and fracturing pressure limits and on drilling fluid removal across any hole section with a potential flow zone. This analysis will allow the cementing service provider and operator to consider alternate means of meeting the objective of isolating potential flow zones should drilling fluid circulation or cementing placement be ECD constrained limits.	
Rheology	Are rheological properties and static gel strength value conducive to cuttings removal, solids suspension and proper management of ECD?
Density	Are fluid densities sufficient to maintain well control without inducing lost circulation?
Fluid Loss	Is filtration control appropriate for formation type and well conditions?

[1] Users of these forms should not rely exclusively on the information contained in this document. Sound business, scientific, engineering, and safety judgment should be used in employing the information contained herein.

Critical Well Design Parameters	
The condition of the wellbore affects the ability to successfully isolate a potential flow zone. These well conditions, whether induced or naturally occurring, should be considered in the cement design and placement.	
Pore/Fracture Pressure	Wellbore fluid hydraulics (ECD) modeling **shall** be performed in well sections containing a potential flow zone in order to assess pore pressure and fracture gradient limits.
Simulations	In order to best facilitate the installation of a cement barrier element, centralizer placement, ECD and fluid displacement simulations **shall** be performed. Within the constraints imposed by hydraulic, operational, logistical or well architecture limitations, the results of these simulations **shall** be considered during the cementing design and execution.
Close-tolerance and Other Flow Restriction Considerations	ECD pressure calculations **shall** include any flow restrictions, particularly those of significant length and small cross-sectional area, such as liner overlaps, liner top packers, liner hangers, tieback sleeves, casing connections and drill pipe tool joints.
TOC	The planned TOC **shall** cover the shallowest potential flow zone.
Hole Diameter	Is hole enlargement minimized sufficiently to allow for adequate centralization?
Deviation, Dogleg Severity	Is the wellbore trajectory sufficiently smooth to allow for running casing and adequate centralization?
Trapped Annular Pressure	Has the risk of trapped annular pressure in designing the TOC been assessed and mitigated for subsea wellheads?
Lost Circulation	Is there a plan for mitigating lost circulation?
Mechanical Barrier	Has the use of mechanical barriers (e.g. liner top packers, ECPs) been evaluated and included in the well design if warranted?
Rathole	Has the rathole length been minimized or filled with drilling fluid with a density greater than the cement density?

Critical Operational Parameters	
There are a number of operational parameters, prior to and during the cementing operation, which can affect the ability to successfully isolate a potential flow zone.	
Float Equipment	Are the float valves rated for the anticipated flow rates and volumes of the fluids pumped during circulation and cementing of the casing string? Float valves **shall** be rated for the anticipated differential pressure between the minimum anticipated hydrostatic column above the shoe track and the hydrostatic column in the casing annulus with cement in place. Have two independent float valves been installed in the shoe track?
Cementing Heads	Cementing heads **shall** be pressure tested by the supplier to the maximum working pressure rating of the head as part of a regular maintenance program. The cementing head selected **shall** have a working pressure in excess of the maximum anticipated surface pressure for the job.
Contingency Plans	As a minimum, are contingency plans in place for the following? — Lost circulation. — Unplanned shut-down. — Unplanned rate change. — Float equipment does not hold differential pressure. — Surface equipment issues.
Running Casing	Has the maximum casing running speed been determined to minimize swab and surge effects?
Well Control	Is the well stable (no volume gain or losses, drilling fluid density equal in vs out) before commencing cementing operations?
Surface Systems	As a minimum, were the following surface systems checked for operability? — Cement mixing and pumping equipment. — Additive proportioning equipment. — Bulk delivery system. — Plug launching systems. — Treating iron. — Mix water/drilling fluid deliverability. — Monitoring and recording systems.
Annular Returns Monitoring	Is there a plan to monitor the annulus during cementing and WOC time?
Static Time	Has the time between drilling fluid circulation/conditioning and commencing cementing operations been minimized?
WOC	Has the appropriate WOC time been determined?
Barrier Removal	The time from the start of removing the barrier element to securing the exposed annulus **shall** be minimized.
Risk Assessment	If foamed cement is used, operators and all involved contractors **shall** perform a risk assessment prior to utilizing foamed cement, and make sure that the results of this assessment are incorporated in the cementing plan

Critical Drilling fluid Removal Parameters	
Displacing the drilling fluid during the cementing operation is one of the most important factors in isolating a potential flow zone. Poor drilling fluid displacement will jeopardize the ability to isolate potential flow zones.	
Centralization	Centralizer placement simulations **shall** be performed in order to best facilitate the installation of a cement barrier element. Have the centralizer simulator results been considered during the cementing design and execution within the constraints imposed by hydraulic, operational, logistical or well architecture limitations?
Mixing and Placement Rate	Have placement rates during cementing been modeled and designed to achieve the best possible drilling fluid removal?
Spacer	Has the spacer been modeled and designed to achieve the best possible drilling fluid removal?
Fluid Compatibility	Has the spacer been tested for compatibility with drilling fluid and cement according to API RP 10B-2/ISO 10426-2? When using NAF, has the spacer composition been optimized for wettability according to API RP 10B-2/ ISO 10426-2?
Circulation Volume	As a minimum, does the pre-cementing circulating plan account for actual well conditions? — Drilling fluid conditioning and mobility. — Gas in excess of background levels. — Wellbore cooling. — Lost circulation/ballooning. — Confirm float equipment is free of obstruction. — Hole stability.
Rheology	Has altering the drilling fluid's static and dynamic properties after drilling the section containing the potential flow zone been considered to improve drilling fluid displacement efficiency and/or ECD management? Do the fluids' rheological profiles provide a friction pressure hierarchy appropriate for effective drilling fluid removal?
Wiper Plugs	If possible, are top and bottom wiper plugs used?
Pipe Movement	Has pipe movement been considered?
Annular Volume Determination	Has consideration been given for how the open hole volume will be determined?

Critical Cement Slurry Parameters	
Cement serves as an isolation medium during well construction. The design of the cement slurry, taking into account the anticipated well conditions, is central to successfully isolating potential flow zones. Lead and tail cement slurries designed to isolate potential flow zones should be fit for their intended purpose.	
Cement Compressive or Sonic Strength	Cement **shall** be considered a physical barrier element only when it has attained a minimum of 50 psi compressive or sonic strength as measured at simulated pressure and temperature conditions (within the limits of the laboratory equipment) at the uppermost flow zone. Once the time to reach a minimum of 50 psi compressive or sonic strength has been determined by lab tests for the specific cement slurry, the operator **shall** wait on the cement to set for that amount of time prior to removing or disabling a barrier element.
Wellbore Barriers: Cement Plugs	Slurry properties **shall** be consistent with any regulatory requirements. Testing **shall** comply with accepted industry standard practices.
Temperature for Cement Testing	Have temperature schedules been established based on methods contained in API RP 10B-2/ISO 10426-2, direct measurements, computer modeling and/or offset well data?
Slurry Design (lead vs tail slurry)	Has the lead slurry been designed so that the static gel strength development and thickening time are longer than for the tail slurry, including applicable (batch) mixing and placement times?
Slurry Design (static gel strength)	Have the cement slurries, placed across potential flow zones, been designed to have as short a CGSP as possible, preferably less than 45 minutes, at the temperature and pressure conditions found at the potential flow zone?
Slurry Design (rheology)	Are the rheological properties of the slurries conducive to surface mixability, drilling fluid removal and ECD management with respect to fracture pressure?
Slurry Design (fluid loss)	Does the fluid loss of the slurry placed across potential flow zones have appropriate control for the flow potential?
Slurry Design (density)	Does the slurry density meet requirements for maintaining well control?
Slurry Design (stability)	Are free fluid control, sedimentation and foam stability (when cement is foamed) appropriate for the conditions found at the potential flow zone?
Slurry Design (compatibility)	Are lead and tail slurries compatible?
Slurry Design (mechanical properties)	Is the cement designed with mechanical properties suitable for long-term sheath integrity for anticipated well operations?
Slurry Design (field blend verification)	Have representative field blended samples been tested?
Slurry Design (mechanical barriers)	Has the presence of mechanical barriers been taken into account in the slurry design and testing?
Slurry Design (formation type and fluids)	Is the cement designed for specific formation (such as salt) and for expected formation fluids (such as gas)?
Slurry Design (regulatory)	Slurry properties **shall** be consistent with any regulatory requirements.

Job Execution	
A well executed cement job is critical to isolating potential flow zones.	
Circulation and Conditioning	Was the well circulated and the drilling fluid conditioned prior to cementing
Density Control	Was the cement placed across potential flow zones mixed within a density range or solid to liquid ratio range that did not compromise the slurry performance (static gel strength, thickening time, etc.) required for flow prevention?
Pre-flushes and Spacers	Were spacers mixed and pumped as designed including rheology, density and volume?
Placement Rates	Were the placement rates adequate for effective drilling fluid removal?
Centralizers	Were centralizers properly installed as designed?
Special Blending Mixing	If used, were specialty blended cements prepared, transported and stored in accordance with the suppliers established guidelines?
Liquid Additive System	If used, was the liquid additive system calibrated before the cement job and was an inventory check performed after the job to verify actual usage?
Post Job Monitoring	During WOC was the annulus monitored and kept full?

Special Operational Considerations	
Barrier Acceptance	If the criteria for verification of a mechanical barrier or cement cannot be met the operator **shall** establish an appropriate course of action with the regulator or permitting authority.
Diverter or BOP Obstruction	Operators or rig contractors **shall** not run tubing in the annulus between the casing and the diverter, or BOP, after completion of the cementing operation and prior to determining the well has no potential for flow.
Hydrostatic Overbalance	The operator **shall** perform hydrostatic pressure calculations to verify sufficient hydrostatic overbalance pressure throughout the well prior to washing out to the mudline suspension hanger.
Foamed Cement	Operators and cementing service providers **shall** perform a risk assessment prior to utilizing foamed cement to isolate a potential flow zone. The results of this assessment **shall** be incorporated into the cementing plan.
Foamer, Stabilizer and Nitrogen Injection (foamed cement)	Will the foamer, stabilizer and nitrogen injection be controlled by an automated process system? Were the foamer, stabilizer and nitrogen ratios within design tolerances?
Cement Plugs	Cement plugs **shall** be installed and verified as required by regulations.

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Economic Impacts of Oil and Gas Development on BLM Lands in Wyoming

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INTRODUCTION

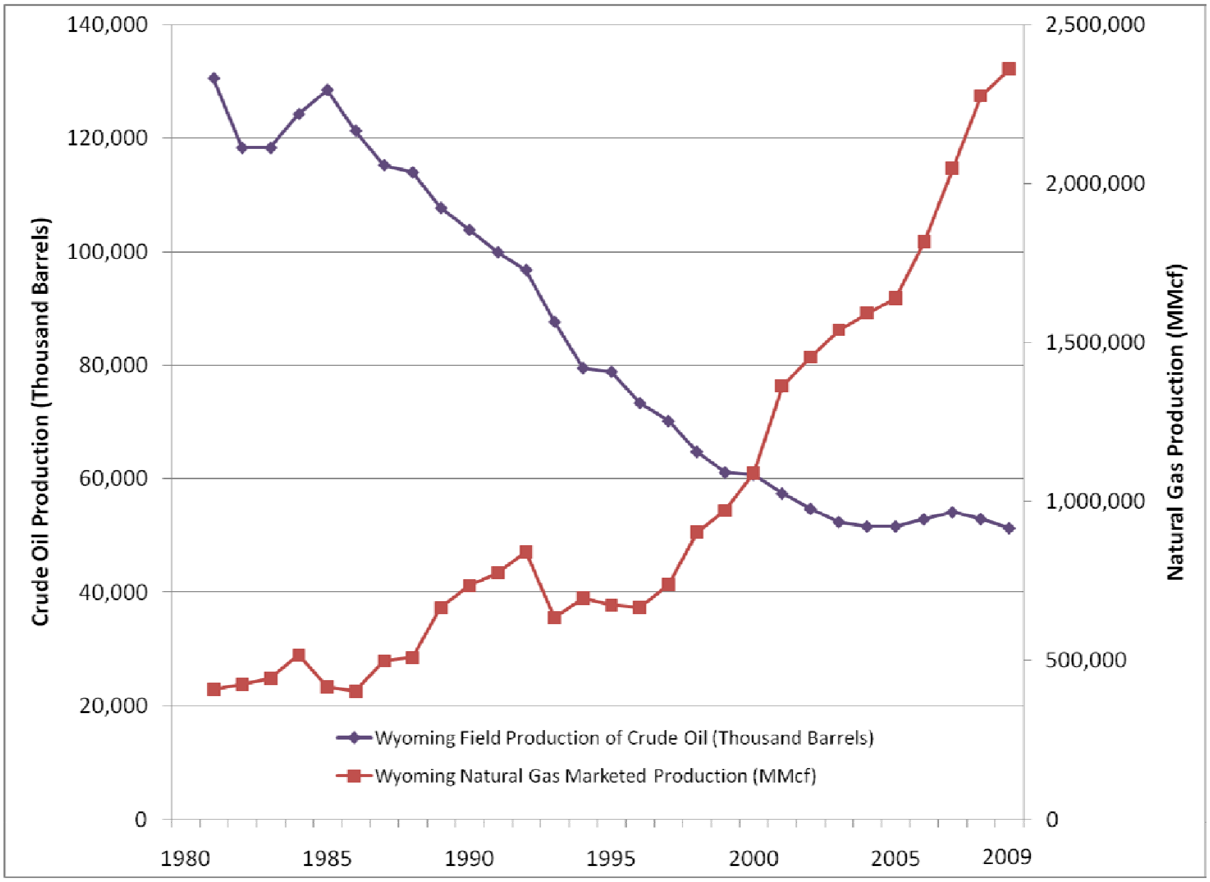
The oil and gas industry has a significant impact on Wyoming's economy, and has the potential to be a continued economic driver for the state. This document has been prepared to provide an overview of the economic contribution of the oil and gas industry to the state of Wyoming in terms of employment, income, gross revenues, and taxes. An evaluation of the economic contributions of currently proposed oil and gas development projects on Bureau of Land Management (BLM)-administered land in Wyoming has also been included for better understanding of the impact project delays could have on the state's economy. Existing data pertaining to oil and gas production in Wyoming were used to provide information on current oil and gas-related trends and the proposed oil and gas projects on BLM-administered land. Recently completed economic impact analyses were used to provide baseline data required to estimate the employment and revenues postponed as a result of the project delays. Potential impacts due to project delays include deferred or lost jobs, deferred or lost earnings, and deferred or lost tax revenue for the state.

TRENDS OF OIL AND GAS DEVELOPMENT IN WYOMING

The geologic basins in Wyoming contain vast amounts of fossil fuel deposits. Wyoming currently has more than one dozen of the largest oil and gas fields in the United States. In 2010, Wyoming ranked second in the nation in terms of total energy production. The state also ranked second in the nation in terms of natural gas production in 2010 (2,274,850 million cubic feet [MMcf]) and eighth in the nation for crude oil production (4.5 million barrels) in August 2010 (U.S. Energy Information Administration [EIA] 2010a).

Natural gas development in Wyoming has increased rapidly in the past decade. In 2000, the state produced 1,088,328 MMcf of natural gas (EIA 2010b). By 2009, production increased 53 percent to 2,359,248 MMcf. Wyoming's oil production peaked in the mid 1980s with 128.5 million barrels and has decreased consistently through 2009 to 51.3 million barrels (EIA 2010c). Figure 1 reflects Wyoming's oil and gas production trends in recent decades.

Over half of all oil and gas production in Wyoming is from lands administered by the BLM. The BLM administers over 18,097 federal oil and gas leases that cover approximately 12.94 million acres of public land (BLM 2009). In 2009, production of crude oil on BLM land totaled 28.2 million barrels and accounted for 55 percent of the total 51.3 million barrels produced in the state. Natural gas production on BLM land totaled 1,261,552 MMcf, approximately 53 percent of the total 2,359,248 MMcf (EIA 2010a; BLM 2009).



Source: EIA 2010b, 2010c

Figure 1. Trends in Oil and Gas Production in Wyoming 1980–2009.

WELLS

According to the Wyoming Oil and Gas Conservation Commission (WYOCC), there were approximately 39,570 producing wells in Wyoming in 2009 (WYOCC 2010). These wells produced 51.3 million barrels of crude oil and 2,359,248 MMcf of natural gas (EIA 2010a). Wyoming oil and gas development occurs primarily in seven geologic basins: Big Horn Basin, Denver-Cheyenne, Greater Green River, Laramie, Overthrust Belt, Powder River Basin, and Wind River Basin (Wyoming Heritage Foundation 2008). The largest percentage of oil and gas development occurs in the Powder River Basin (primarily in Campbell County) and the Greater Green River Basin (primarily in Sublette and Sweetwater counties) where the Pinedale and Jonah natural gas fields are located. The distribution of producing oil and gas wells in Wyoming is illustrated in Figure 2.

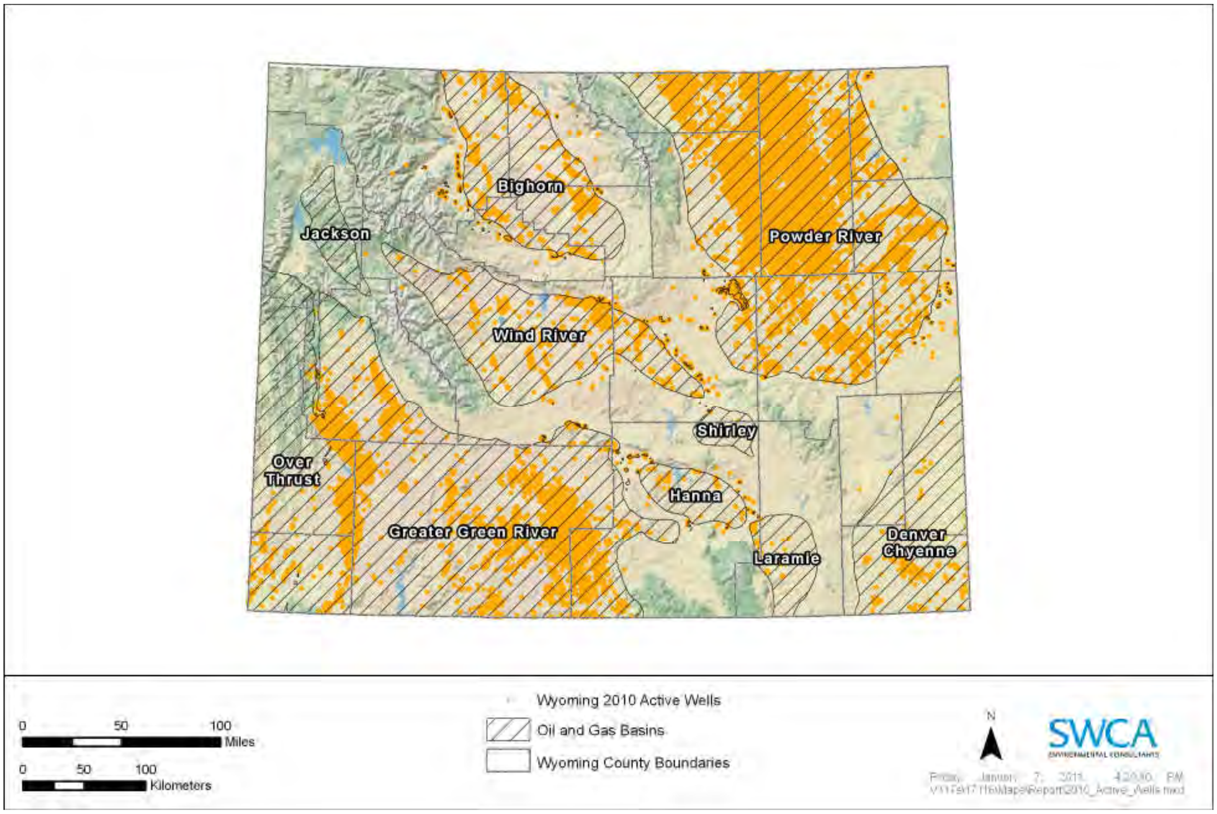


Figure 2. Producing Wells in Wyoming in 2010.

Twenty of the state's 23 counties produce crude oil and natural gas. In 2009, Campbell County was the largest producing county with 13,470 producing wells and 7.5 million barrels of oil (14.6 percent of the state total) and 142,183 MMcf of natural gas (5.6 percent of the state total). Sublette County was the second largest producing county with 4,209 producing wells and 7.9 million barrels of oil (15.5 percent of the state total) and 1,194,249 MMcf of natural gas (47.0 percent of the state total) (WYOCC 2010).

ECONOMIC CONTRIBUTIONS AND JOBS

Two primary activities are associated with the oil and gas industry: development and production. Development activities consist of drilling, completing, and recompleting wells. The drilling and completion processes generally take a few months. Recompletion activities involve stimulating or reactivating wells after they have been producing for a period of time. The act of removing the oil and/or gas from geologic formations is called extraction or production (Wyoming Heritage Foundation 2008).

The development of a single well in Wyoming requires an initial expenditure by the operator and employees to drill and complete the well. It was estimated that operators in the Pinedale Anticline natural gas field spend approximately $5.5 million (inflated to 2010 $s) for each well developed (BLM 2008). In the Pinedale Anticline Environmental Impact Statement (EIS), the IMPLAN economic model was used to estimate the economic impact of the operators' spending. It was estimated that direct expenditures on well development generate approximately $975,100 in secondary spending, thus the total economic impact per well in southwest Wyoming was estimated to be $6.5 million (BLM 2008).

The direct expenditures and secondary spending generate employment within an oil and/or natural gas field to develop wells (direct effects). Outside of the project area, employment results from expenditures by operators on goods and services used to drill wells (indirect effects) and expenditures by operator employees on items such as food, clothing, and fuel (induced effects).

A study completed on behalf of the Wyoming Heritage Foundation in 2008 reported that the total oil and gas industry-related employment (direct, indirect, and induced impacts) resulted in 73,229 jobs in 2007 (20 percent of the total employment in Wyoming). Drilling, completion, and recompletion of wells accounted for 26,701 jobs (36 percent of the total jobs). Extraction operations resulted in 11,765 jobs (17 percent) and indirect and induced employment resulted in 34,763 jobs (47 percent) (Wyoming Heritage Foundation 2008). It is assumed that current oil and gas-related employment numbers are quite similar to 2007 employment numbers, if not slightly increased, as the amount of wells producing in the state has increased 6 percent from 37,350 in 2007 to 39,570 in 2009. Total oil and gas production volumes were also similar in 2009 when compared to 2007 (a 4 percent increase in natural gas production from 2007 and a 5 percent decrease in oil production).

The oil and gas-related jobs generate labor earnings for the state and local economies. In 2007, the total labor earnings that resulted from the 73,229 jobs totaled $3.9 billion (25 percent of the total Wyoming labor earnings). Jobs directly related to the oil and gas industry generate higher wages than jobs in other employment sectors. In 2007, the average wage for oil and gas-related employment was $53,457 per year and the average wage in Wyoming was $41,907 (Wyoming Heritage Foundation 2008).

TAXES AND ROYALTIES

The taxes and royalties that are received by federal, state, and local governments as a result of oil and gas extraction are based on the total annual production volumes. As indicated above, the 2009 production volumes according to the EIA (2010a) were determined to be:

- Oil – 51,333,707 barrels
- Natural Gas – 2,359,248 MMcf

In order to estimate the dollar value of the oil and gas extracted in 2009, the quantities were converted to dollar amounts using the 2009 Wyoming production prices from the EIA. In December 2009, the Wyoming domestic crude oil first purchase price was $64.17 per barrel (bbl) and the natural gas price at the wellhead was $3.40 per thousand cubic feet (Mcf) (EIA 2010a). To determine the value of the oil and gas produced, the 2009 prices were multiplied by the production volumes to estimate the total industry output for oil and gas extraction in Wyoming. In 2009, the total industry output was estimated to be:

- Oil – $3,294,083,978
- Natural Gas – $8,021,443,200
- Total – $11,315,527,178

In order to estimate the economic benefits of oil and gas development in Wyoming to federal, state, and local governments, we have compiled the government revenues generated from the oil and gas extraction in 2009 (Table 1). The government revenues come in the form of royalties, severance taxes, and ad valorem taxes. Royalties are paid on net revenues (gross revenues minus operating expenses). The royalty rate on federally leased Wyoming land is 12.5 percent of production revenues (after operating costs). The 2009 estimate from the Office of Natural Resource Revenue (ONRR) (formerly Minerals Management Service) indicates that the royalty revenues generated from oil and gas development on public land in 2009 totaled approximately $1.1 billion[1] (ONRR 2010a). Of the total royalties generated in Wyoming in 2009, $849 million (75 percent) were generated on BLM lands (BLM 2009).

Table 1. Summary of Total Estimated Contribution of Oil and Gas Activities in Wyoming 2009.

Impact	2009
Total producing wells	39,570
Total economic output	$11,315,527,178
Total employment*	73,229
Labor earnings	$3,914,633,314
Federal mineral royalties	$1,139,840,538
Severance tax	$460,013,007
Ad valorem tax	$479,306,925

* Employment and labor estimates are from 2007.
Source: WOCC 2010; ONRR 2010a; Wyoming Heritage Foundation 2008

The federal government returns 48 percent of the total royalties to the state of Wyoming. In 2009, the ONRR disbursed $957 million back to the state of Wyoming[2] (ONRR 2010b). It should be noted that the total amount of royalties disbursed to the state include royalties derived from coal, sodium, and other minerals and approximately half of the $957 million in royalties is related to oil and gas production. The royalties are distributed by the state of Wyoming to cities and towns, the University of Wyoming, and highway and construction fund projects. Over half of the federal royalties (51.2 percent) received by the state of Wyoming are allocated to the Budget Reserve Account. The Foundation Fund received 35.5 percent of the royalties (BLM 2008).

[1] The 2009 estimate from the Office of Natural Resource Revenue includes federal royalties from carbon dioxide, coalbed methane, condensate, gas plant products, oil, processed and unprocessed gas, and royalties associated with rents, bonuses, and other revenues.

[2] The total amount disbursed to Wyoming includes royalties from coal, salt, and other minerals.

State severance taxes and ad valorem taxes are paid after royalties are deducted. A severance tax is a tax that is imposed on the present and continuing privilege to remove, extract, or produce any mineral in Wyoming. In 2009 the severance tax rate for oil and gas extraction was 6 percent. Severance taxes totaled $460 million ($351 million for natural gas and $108 million for oil) in 2009 (WYOCC 2010). The largest percentage (40.7) of severance tax in Wyoming is allocated to the Permanent Mineral Trust Fund. The state General Fund and the Budget Reserve Account each receive approximately 25 percent of the levied tax.

Ad valorem taxes (i.e., property taxes associated with oil and gas operations) generate revenues for the state of Wyoming and the county where the extraction occurred. A 6.2 percent ad valorem tax is levied on the total value assessed by the county for mineral production. The majority of ad valorem tax revenue goes to fund public schools (75 percent). Approximately 20 percent goes to the county of origin's General Fund, and the remainder goes to Special Districts within the county of origin (BLM 2008). The estimated ad valorem tax levied for oil and natural gas development in 2009 was $479 million ($364 million for natural gas and $115 million for oil) (WYOCC 2010). Ad valorem tax assessed in the counties with the largest number of producing wells in 2009, Campbell and Sublette, totaled $243 million and $186 million, respectively.

To consider the annual royalties and tax revenue from a typical natural gas well in Wyoming, the estimated dollar amount from a well in the Pinedale Anticline Project Area (PAPA) was inflated to 2010 $ (BLM 2008). While it should be noted that a producing well can produce more or less than the typical well in a given year, Table 2 highlights the royalty and revenues for a single natural gas well.

Table 2. Annual Royalties and Tax Revenue for a Typical Wyoming Natural Gas Well.

Tax and Royalty Revenues	$/MMcf Gas	$/bbl Oil	$/Well/Year
Federal mineral royalties – Wyoming Share *	$338.00	$2.91.00	$44,967.00
Severance tax – State of Wyoming	$329.00	$2.80	$43,783.00
Ad valorem tax – Sublette County	$347.00	$2.97	$46,015.00
Total	**$1,015.00**	**$8.68**	**$134,669.00**

* Note: The Wyoming federal mineral royalties share is half of the total federal mineral royalty rate (minus 1 percent administrative fee). A typical well in the PAPA generated $677 per MMcf in federal mineral royalties in 2006.
Source: BLM 2008

NEPA IN WYOMING

Over half of all oil and gas development that occurs in Wyoming takes place on lands administered by the BLM. Proposed actions with a federal nexus (i.e., a federal action, proposed on federal lands, using federal funds, or needing federal approval/permitting) are required to undergo analysis under the National Environmental Policy Act (NEPA). There are three levels of analysis that a federal agency may undertake to comply with the law depending on the level of anticipated impacts. These three levels include 1) preparation of a Categorical Exclusion (CE); 2) preparation of an Environmental Assessment (EA) and Finding of No Significant Impact (FONSI); or 3) preparation of an EIS. If the lead federal agency expects the impacts of the proposed action to be significant, then an EIS is prepared. An EIS discloses all potential impacts to the human environment using the best available science and guides the agency in choosing among alternatives to the proposed action. The EIS process differs from the EA process in that it requires additional public involvement, alternatives development, and often contains a more rigorous impacts analysis. The EIS process also allows for considerable involvement by stakeholders and cooperating agencies in impact analysis and the alternatives development process.

Two recently completed EISs have allowed for further natural resource extraction on public lands in Wyoming. These projects are the Pinedale Anticline Oil and Gas Exploration and Development Project (Record of Decision [ROD] issued September 2008) and the Jonah Infill Drilling Project (ROD issued March 2006). The Pinedale Anticline and Jonah Infill oil and natural gas fields are two of the top 10 largest in the nation (EIA 2010a). There are currently six oil and gas development projects in Wyoming undergoing NEPA analysis in the form of an EIS. These are the Moxa Arch Area (MAA) Infill Gas Development Project, the Hiawatha Regional Energy Development Project, the Gun Barrel, Madden Deep, Iron Horse (GMI) Natural Gas Project, the LaBarge Platform Exploration and Development Project, the Continental Divide-Creston (CDC) Natural Gas Project, and the Beaver Creek Coal Bed Natural Gas (CBNG) Project. The status of these projects and their estimated economic contribution are discussed in the following sections.

PAST NEPA PROJECTS

Expansions to the Pinedale Anticline and Jonah Infill projects have resulted in increased economic revenues to the state of Wyoming. The Final Supplemental Environmental Impact Statement (FSEIS) of the Pinedale Anticline Oil and Gas Exploration and Development Project in Sublette County, Wyoming, was completed in 2008. The FSEIS ROD authorizes exploration and development of 4,399 wells on 198,037 acres of federal, state, and private land. Of the total land in the PAPA, 158,415 surface acres (80 percent) are administered by the BLM Pinedale Field Office. In 2008 there were 642 producing wells in the PAPA. The new wells authorized by the FSEIS within the PAPA are estimated to have a 40-year production life and the project would conclude in 2065.

The total jobs, earnings, and revenues anticipated for the life of the project were analyzed in the FSEIS. The development phase of the project is anticipated to occur from 2008 to 2025. Development-related jobs and earnings were anticipated to have peaked in 2009. Production jobs and associated earnings are anticipated from 2007 through 2065. Production jobs and earnings would peak in 2017 (BLM 2008). According to the FSFEIS, the federal mineral royalties, severance, and ad valorem taxes would peak around 2018 and continue through 2065. See Table 3 for estimated employment and earnings during the life of the project. The total estimated government revenue for the Pinedale Anticline project is estimated to be $27.5 billion through 2065. With 48 percent of the federal mineral royalties disbursed to the state of Wyoming and all severance and ad valorem tax revenues remaining within the state, $20.6 billion (75 percent of the total revenues) would be received throughout the life of the project. See Table 4 for estimated total tax and royalty revenues (in 2006 $s) resulting from the PAPA.

Table 3. Employment and Earnings Associated with Development and Production in the PAPA (2006 $s).

Year	Development		Production	
	Total AJE	Total Earnings	Total AJE	Total Earnings
2007	12,698	$651,287,865	939	$49,072,344
2014	13,598	$607,461,258	3,041	$158,868,849
2021	8,386	$430,141,612	2,411	$125,968,128
2028	N/A	N/A	379	$19,819,464
2039–2065	N/A	N/A	<10/year	<$500,000/year

Note: Annual Job Equivalents (AJE) represents 12 months of employment and makes no distinction between full- and part-time jobs. One AJE could represent one job for 12 months or two jobs for 6 months or three jobs for 4 months.

Source: BLM 2008

Table 4. Total Royalty and Tax Revenue Associated with the Pinedale Anticline Project 2007–2065 (2006 $s).

Source of Revenue	Estimated $ Amount
Total federal mineral royalties ($640 per MMcf)	$13,738,403,517
Federal mineral royalties-Wyoming ($312 per MMcf)	$6,869,201,758
Severance tax ($305 per MMcf)	$6,708,480,051
Ad valorem production ($320 per MMcf)	$7,045,335,138
Total	$27,492,218,706

MMcf = million cubic feet
Source: BLM 2008

The Jonah Infill Drilling Project (JIDP) Final Environmental Impact Statement (FEIS) was completed in 2006 and authorized the drilling of approximately 3,100 oil and gas wells in Sublette County, Wyoming. The project is located within the BLM's Pinedale Field Office and includes 30,500 acres of federal (94 percent), private (2 percent), and state (4 percent) managed land (BLM 2006). Prior to the authorization of the JIDP, there were more than 500 producing shut-in natural gas wells and production-related infrastructure. The economic impacts from the JIDP, although factored differently in each of the EIS socioeconomic analyses, would be similar to the impacts from the PAPA. Table 5 highlights the total economic impacts of the JIDP.

Table 5. Total Estimated Economic Activity Associated with the JIDP.

Type of Impact	Estimated $ Amount[a]
Average wage range	$31,881–$47,173
Value of development	$6,631,800,000
Value of production	$17,963,800,000
Taxes and royalties	$3,474,700,000
Total	$28,066,900,000

[a] Based on 85,715.7 average job equivalents
Source: BLM 2006

CURRENTLY PROPOSED NEPA PROJECTS

Currently, there are six oil and gas projects proposed on lands managed by five Wyoming BLM field offices. EISs are being prepared for each of the six projects. The NEPA planning processes (and ROD that follows the completion of the EIS) for each of the projects are currently experiencing delays. On average the planning process for each EIS was originally estimated to take two to three years. However, due to a range of issues that have arisen with each project, the RODs have been delayed one to five years. Table 6 highlights the six EISs currently under development with the Wyoming BLM. Figure 3 shows the location of the proposed projects.

Table 6. The Six Oil and Gas EISs Underway in Wyoming BLM Field Offices.

Pending EIS	BLM Field Office	ROD Delay*	Total Wells	Wells Developed Annually
Beaver Creek	Lander	11 months	228	23–46
Continental Divide – Crestone	Rawlins	49 months	8,950	600
Gun Barrel, Madden Deep, Iron Horse	Lander	27 months	1,400	130
Hiawatha	Rock Springs	49 months	4,208	140–210
LaBarge Platform	Pinedale	Unknown	838	60
Moxa Arch	Kemmerer	53 months	1,861	186
			Total 17,485	Average 1,166/year

*ROD delay was determined through interviews with project proponents and based on the estimated completion date compared to the original EIS schedule.

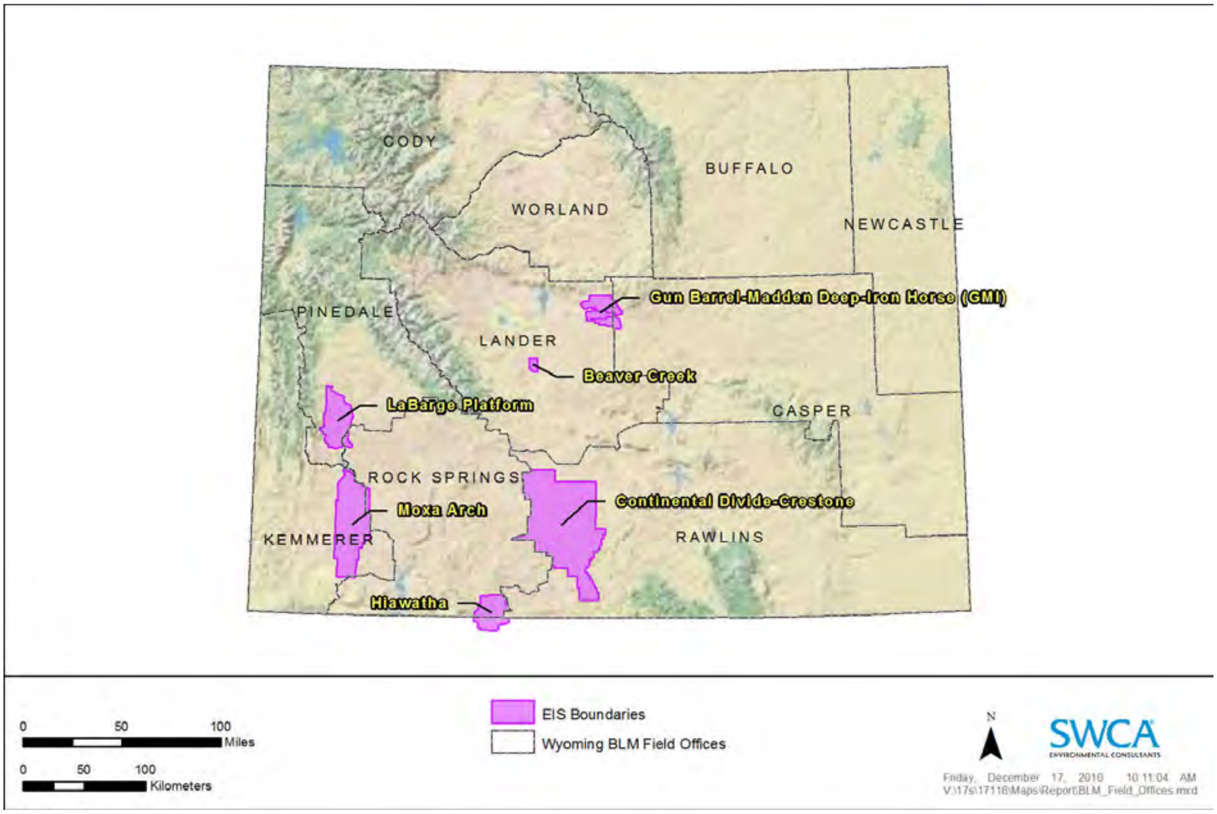


Figure 3. Oil and Gas EISs Currently Underway within Wyoming BLM Field Offices.

Figure 4 shows the average oil and gas EIS cycle time for EISs that have been completed in the Rocky Mountain Region (Colorado, Utah, and Wyoming) since 1993 compared to the current estimated EIS cycle for projects currently undergoing NEPA analysis. The average EIS completion time for EISs between 1994 and 2005 was 38 months. For projects with pending RODs, the average duration of the EIS cycle is 43 months as of March 2011. Note that the majority of these projects (listed in Table 6) have not released a DEIS and therefore, the EIS cycle time will increase as the NEPA process continues.

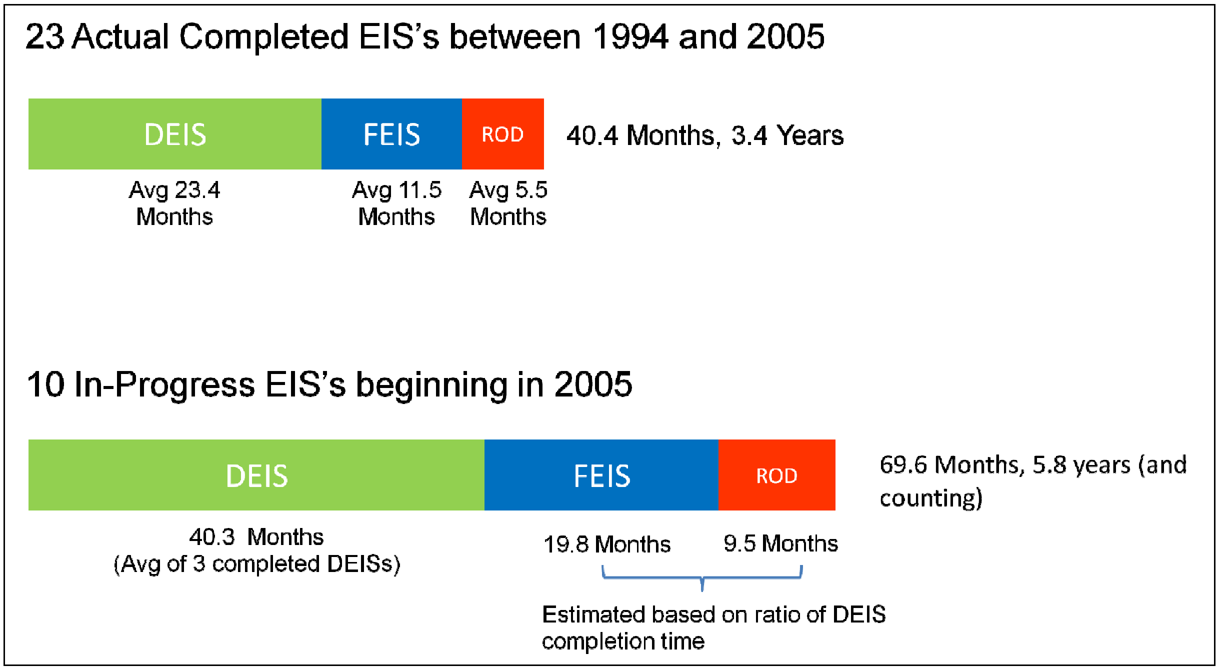


Figure 4. Actual & Estimated EIS Cycle Times in the Rocky Mountain Region.

It should be noted that there are smaller-scale oil and gas projects going through the NEPA planning process within Wyoming BLM field offices that may or may not be experiencing delays similar to the six large-scale EISs. In addition, there are other large oil and gas projects that are just beginning the NEPA planning process. The Normally-Pressured Lance (NPL) Natural Gas Development Project and EIS is within the Pinedale and Rock Springs Field Offices and proposes up to 3,500 wells drilled over a 10-year period. This project is in the initial public comment gathering phase and economic and environmental impacts assessments have yet to be completed.

POTENTIAL IMPACTS FROM DELAYS

Delaying a federal decision on the six proposed projects consequently delays oil and gas companies from beginning the approved development and production phases of these large-scale projects. As indicated in the sections above, the development and production of oil and gas wells bring substantial economic contributions to the state of Wyoming. Therefore, delays in a BLM decision result in deferral of project development, employment, and government revenues.

The economic activity potentially affected by the delays of the six projects is estimated in the following analysis. Full approval of the six projects proposed would result in the development and production of approximately 17,485 wells. Based on the assumptions that all projects start in the same year, and all wells will be drilled within each projects' first 15 years, approximately 1,166 wells will be drilled annually. It is also assumed that the average well in Wyoming has a 40-year productive life and during that time it would produce 5.0 billion cubic feet of natural gas and 35,000 barrels of oil condensate; a typical well can be expected to produce 125 Mcf of natural gas and 875 barrels of oil annually. The annual averages do not imply that a single well would produce at this level each year. Rather, production rates are typically highest when a well is first drilled then decline rapidly and finally level off after about 10 years of production (BLM 2008). Using the dollar amounts (inflated to 2010 $s) and workforce estimates applied to the economic impacts analysis in the Pinedale Anticline EIS (completed in 2008), a rough annual estimate of the economic impacts of delaying the six projects is presented below.

Development

Assuming an average total economic impact of $3.7 million per well[3], $4.3 billion dollars would be spent annually in Wyoming as a result of drilling 1,166 wells. This spending would generate direct, indirect, and induced employment. Based on the assumptions that 26.3 jobs[4] and $2.3 million[5] in labor earnings are created with the development of each well, approximately 30,666 average job equivalents (AJEs) and $2.6 billion in earnings would not be realized annually within the state of Wyoming. That is to say that, each year that the six oil and gas projects are postponed, the state of Wyoming does not receive the benefit of over 30,666 AJEs and over $2.6 billion in employment earnings resulting from drilling 1,166 wells annually. As the delays continue, the jobs and employment earnings are not realized until project initiation. The postponement of jobs and earnings related to development are estimated over a 5- and 10-year timeframe and presented in Table 7.

Table 7. Economic Impacts of Oil and Gas Project Delays on Well Development.

Impact	Project Delay		
	1-year	5-year	10-year
Deferred development AJE	30,666	153,330	306,660
Deferred development earnings	$2,682,612,702	$13,413,063,510	$26,826,127,020

AJE = average job equivalent

Production

The long-term production of a single well requires many fewer AJEs than the development of a single well. Based on the assumption that 0.251 AJE (0.1255 direct, 0.06275 indirect, and 0.06275 induced) would be required per well (BLM 2008), approximately 4,389 AJEs would not be required until the projects get underway (assumes all 17,485 wells would be producing simultaneously). With a 5-year delay approximately 21,945 AJEs would not be realized, and with a 10-year delay approximately 43,890 AJEs would not be realized.

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[3] The average economic impact of a single well includes the direct, indirect and induces costs of drilling and completing a single well in the Pinedale ($5.5 million), Jonah ($2.9 million), GMI ($3.5 million), Hiawatha ($4.6 million) and Moxa ($1.8 million) project areas. All total costs in 2010 dollars.

[4] The average AJE per well includes the direct, indirect and induced jobs per well in the Pinedale (47.4 AJE), Jonah (16.7 AJE does not include direct project-related jobs), Hiawatha (28.7 AJE) and Moxa (12.4 AJE) project areas.

[5] The average labor earnings include the direct, indirect and induced earnings per well for Pinedale ($2,628,535) and Hiawatha ($1,972,859) project areas, in 2010 dollars.

Continuing delays of the six oil and gas projects would result in the delay of federal, state, and local government revenue. Using the annual royalties and tax revenue rates from the Pinedale Anticline EIS (inflated to 2010 $s) shown in Table 4, the total government revenues generated from one well in the PAPA totaled $134,669. Applying this total annual amount to the 1,166 wells projected to be producing annually as a result of the six proposed projects, approximately $157 million in annual revenues are not being obtained by the state of Wyoming each year. Estimates are provided in Table 8 that highlight the amount of federal revenue not realized by the state of Wyoming should the six projects fail to progress in the next 5 to 10 years.

Table 8. Total Annual Estimated Tax and Royalty Revenue for Wells from the Six EISs (17,485 wells).

Revenue	Project Delay		
	1-year	5-year	10-year
Royalty and Tax Revenues	$157,024,054	$785,120,270	$1,570,240,540

In 2009 there were 39,570 producing wells in Wyoming. The six large-scale proposed oil and gas projects would result in approximately 17,485 additional wells (or 1,166 wells developed annually over a 10-year period). The implementation of the six proposed projects would result in a 44 percent increase in the total amount of producing wells in Wyoming. The annual development (and subsequent production) of 1,166 wells would result in an annual 3 percent increase in the amount of wells producing in the state over a 10-year period. The estimated economic activities resulting from development and production of the wells currently proposed in the six large-scale projects would be delayed until federal approval is given and the projects commence. In addition, other NEPA projects just getting underway (such as the NPL EIS) could be subject to similar delays which would result in further postponement of oil and gas-related revenue and employment to the state of Wyoming.

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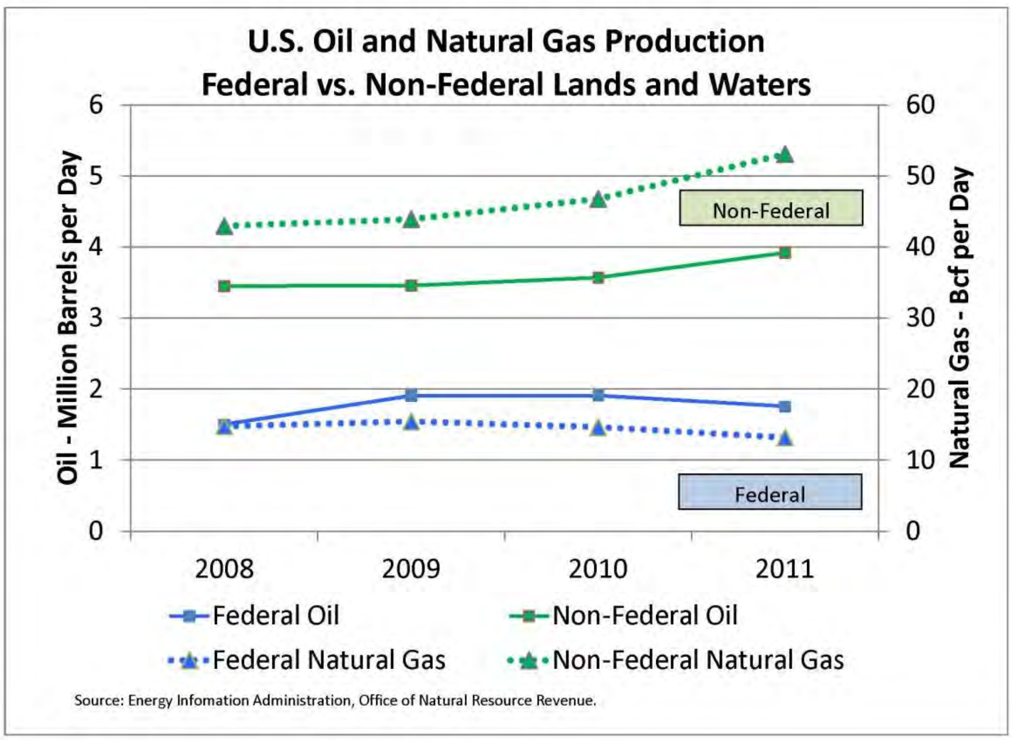
Administration energy strategy is not "all of the above"

An "all-of-the-above" energy strategy, including oil and natural gas, is essential to America's economic and energy future. Administration projections show oil and gas will supply most of the nation's energy for at least 25 years. While the administration claims to support an "all-of-the-above" strategy, it is, in fact, delaying or obstructing oil and gas development in the United States.

The administration says that U.S. oil and natural gas production is up, but most of the increase relates to leasing and permitting decisions made before it took office. Moreover, combined oil and gas production from all federal areas (land and water) – where the administration actually has control – was down in 2011 compared with 2009, according to Energy Information Administration data. Over this period, production in federal areas fell for both oil (7.9 percent) and for natural gas (6.8 percent).

U.S. oil and natural gas production increased in 2011 over 2009 only as a result of growing production on state and private lands – up almost 29 percent for oil and 22 percent for natural gas.



Leasing and permitting have continued to occur, although, comparing 2011 with 2009, at diminished rates. But a better barometer of the administration's commitment to more U.S. oil and natural gas development – which could generate huge numbers of new jobs, increase revenue to the government, enhance our energy security, and increase supplies that could put downward pressure on prices – is administration policy decisions.

The picture here is mostly discouraging:

2009

- Administration cancels leases on 77 parcels of land in Utah (February).
- Administration delays new offshore leasing plan by adding another half year to comment period (February).
- Administration proposes billions in new taxes on oil and gas industry in FY 2010 budget proposal (February).
- Following protests by environmentalists, BLM suspends sale of 31 drilling tracts in Utah that had already been purchased (June).
- Administration revisits Utah leases, continuing suspension or permanently withdrawing most (October).
- Administration announces new round of oil shale research and development leases in Colorado, Wyoming, and Utah with significantly reduced lease acreage and unattainable lease terms (October).
- Administration shortens lease terms for upcoming Central Gulf of Mexico lease sale (November).

2010

- Administration proposes additional regulatory hurdles for development on federal lands (January).
- Administration proposes billions in new taxes on oil and gas industry in FY 2011 budget proposal (February).
- Administration cancels the remaining Alaska lease sales in the Beaufort and Chukchi Seas offshore and withdraws Bristol Bay from the program (March).
- Administration cancels the Virginia offshore lease sale, despite bipartisan support from Virginia's governor and congressional delegation (May).

2011

- Administration proposes billions in new taxes on oil and gas industry in FY 2012 budget proposal (February).
- Administration orders additional environmental review of Keystone XL pipeline despite 32 months of prior multi-agency scrutiny (March).
- Administration releases a draft forest management plan that proposes a ban on horizontal drilling in the George Washington National Forest (April).
- Administration issues an ANPR regarding new regulations for gas gathering lines that would substantially impact development of the Marcellus Shale (August).
- Administration proposes one-size-fits-all new source performance standards that, lacking a phase-in period to manufacture the control equipment, may significantly hamper oil and gas operations (August).
- Administration again proposes billions in new taxes on the oil and gas industry (September).
- Administration issues new 2012-2017 five-year plan that fails to open any new offshore areas to oil and gas development (November).
- Administration releases final study plan on potential impacts on groundwater from hydraulic fracturing that fails to address concerns regarding the transparency and scientific validity of the study approach (November).

- Administration raises the minimum bid amount for offshore lease blocks in water depths of 400 meters and greater from $37.50 per acre to $100 per acre (December).
- Administration produces a draft report outlining the findings of its groundwater investigation in Pavillion, Wyoming and receives extensive criticism for questionable scientific methodology (December).
- Administration cancels a planned auction of public lands in the Wayne National Forest to review scientific information regarding horizontal drilling and hydraulic fracturing (December).

2012

- Administration rejects permit for Keystone XL pipeline (January).
- Administration begins testing water wells in Dimock, Pennsylvania despite having no new information to justify reversing previous statements that laboratory data did not indicate that water quality presented an immediate health threat (February).
- Administration recommends removing from leasing availability over 1.8 million acres of oil shale and tar sands energy resources in Colorado, Utah and Wyoming (February).
- Administration proposes billions in new taxes on oil and gas industry in FY 2013 budget proposal (March).

U.S. Supply Forecast and Potential Jobs and Economic Impacts (2012-2030)

Released – September 7, 2011

Wood Mackenzie
energy consulting

consulting
strategy • transactions • business environment • government • monetisation •

Wood Mackenzie

Study Background

API has requested Wood Mackenzie undertake a study which examines the energy supply, job and government revenue implications at the state and federal levels of enacting policies in the U.S. that encourage the development of North American hydrocarbon resources. Given the high level of unemployment and budgetary stress facing the nation, the findings of this study should be of interest to policy makers as they move forward to craft solutions to these problems.

This study examines the impacts of opening access to key U.S. regions which are currently closed to development, as well as assessing a return to historical levels of development on existing U.S. producing areas (including onshore U.S., the Gulf of Mexico and Alaska). The economic impacts of the Keystone XL pipeline and other potential Canada to U.S. oil pipelines are also considered.

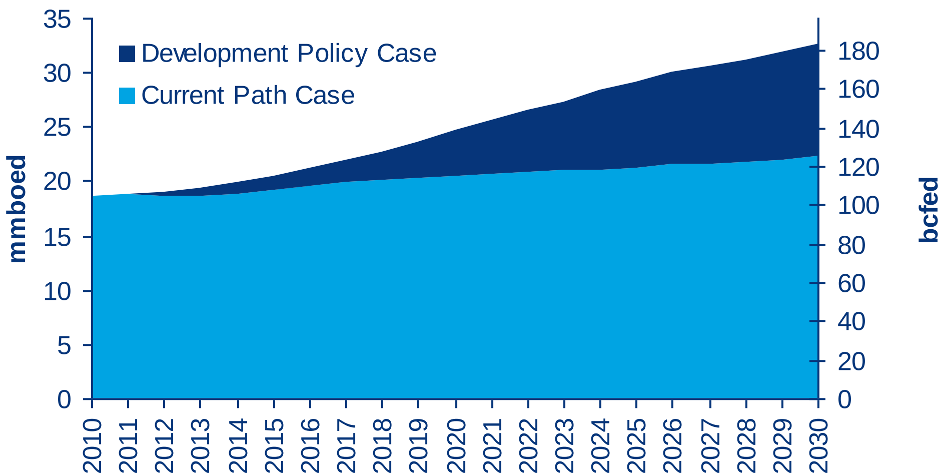
Additionally this report looks at the potential threats to production, jobs and government revenues associated with a continuation on the current path of an increased regulatory burden and slower permitting relative to historical levels.

Key National Results

Wood Mackenzie's analysis found that U.S. policies which encourage the development of new and existing resources could, by 2030, increase domestic oil and natural gas production by over 10 million boed, support an additional 1.4 million jobs, and raise over $800 billion of cumulative additional government revenue. Whereas increasing regulatory burdens on the oil and gas upstream sector will result in higher development costs, which can potentially hinder the growth of production, tax revenues, and job creation.

Continuing the current path of policies which slow down the issuance of leases and drilling permits, increase the cost of hydraulic fracturing through duplicative water or air quality regulations, or delay the construction of oil sands export pipelines such as Keystone XL, will likely have a detrimental effect on production, jobs, and government revenues.

Total U.S. Oil and Natural Gas Production (Projected)



Development Policy Case Incremental Impacts:

(Change from the Current Path Case)

U.S. IMPACTS	2015	2020	2025	2030
Production (000's boed)	1,267	4,189	7,937	10,371
Jobs	668,462	1,138,567	1,262,035	1,403,877
Annual Revenues ($Millions)	10,165	27,796	67,613	99,769

Total Potential Jobs Impact:
Approximately 1.0 million jobs by 2018 and over 1.4 million by 2030

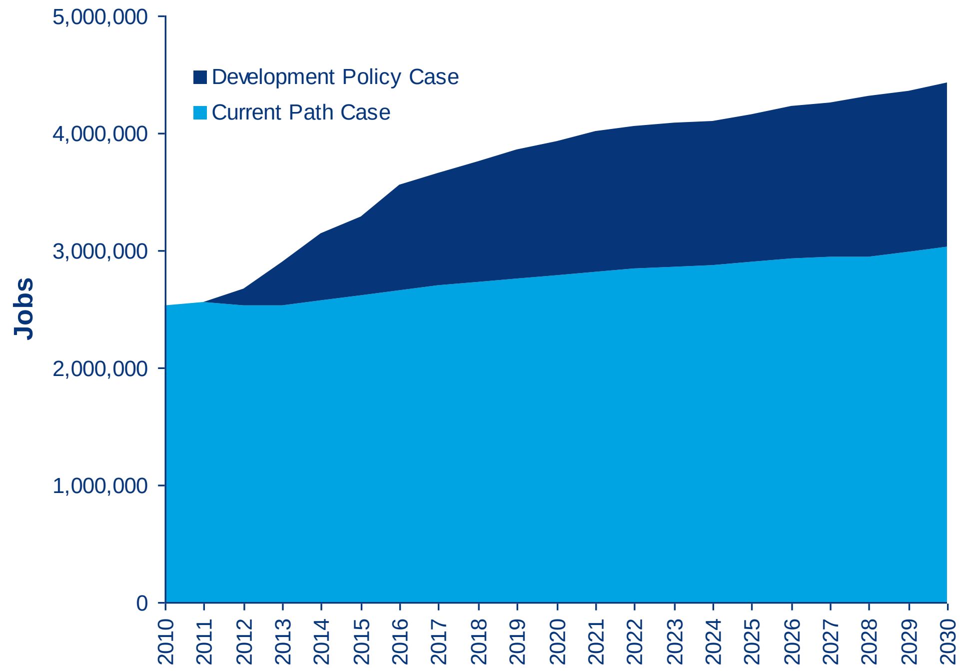
Total cumulative potential government revenue:
Additional $36 billion by 2015 and nearly $803 billion by 2030

Total Potential Production impact:
By 2015, an additional 1.27 million boed could be produced, rising to 10.4 million boed by 2030. Over the period 2012 to 2030, it is estimated an additional cumulative 35.4 billion boe of reserves could be produced through development policies

U.S. Employment Impacts of Oil and Natural Gas Development (Projected)

- Wood Mackenzie estimates 1.4 million new jobs could be added through policies which encourage the development of U.S. and Canadian resources by 2030
- Jobs added could exceed 1.0 million by 2018
- Policies that increase access to currently undeveloped regions have the largest potential to create jobs in the U.S.. An estimated 690,000 new jobs by 2030

U.S. Employment Impacts of Oil and Natural Gas Development (Projected)



Total U.S. employment supported by the upstream oil and natural gas sector

Key State Results (Projected)

	Annual Production (mboed)				Total Jobs Supported				Annual Gov't Revenue ($M)			
	2010	2015	2020	2030	2010	2015	2020	2030	2010	2015	2020	2030
TEXAS - Current Path Case	5,110	5,365	5,521	5,880	939,167	1,008,652	1,059,378	1,122,682	9,728	11,884	16,018	22,030
Development Policy Case	5,110	5,713	6,438	7,655	939,167	1,118,785	1,211,604	1,297,352	9,728	13,980	20,698	38,213
Difference	-	348	917	1,775	-	110,133	152,225	174,670	-	2,096	4,679	16,183
ALASKA - Current Path Case	711	641	601	844	35,568	32,809	31,375	43,857	8,602	8,593	9,002	10,381
Development Policy Case	711	655	1,174	2,467	35,568	85,783	135,164	167,074	8,602	8,641	13,096	32,237
Difference	-	14	573	1,623	-	52,974	103,789	123,217	-	1,703	5,968	21,856
FLORIDA - Current Path Case	-	-	-	-	27,719	27,719	27,719	27,719	-	-	-	-
Development Policy Case	-	-	621	1,620	27,719	112,328	159,465	197,795	-	-	4,798	16,629
Difference	-	-	621	1,620	-	84,609	131,746	170,076	-	1,134	6,407	17,465
CALIFORNIA - Current Path Case	887	647	516	410	104,217	97,167	93,231	90,206	5,631	5,361	3,908	3,801
Development Policy Case	887	650	620	1,459	104,217	123,501	179,429	241,022	5,631	5,837	4,759	16,261
Difference	-	3	105	1,050	-	26,333	86,197	150,816	-	476	851	12,460
LOUISIANA - Current Path Case	882	951	1,097	1,040	281,625	310,905	365,819	345,022	1,066	1,771	2,764	3,128
Development Policy Case	882	1,133	1,605	1,985	281,625	376,540	453,482	433,836	1,066	2,991	5,480	12,805
Difference	-	182	508	946	-	65,635	87,663	88,814	-	1,221	2,716	9,678
NEW YORK - Current Path Case	31	9	7	2	14,811	14,811	14,811	14,811	12	14	16	6
Development Policy Case	31	328	529	791	14,811	47,052	62,628	64,883	12	203	1,177	2,899
Difference	-	319	522	789	-	32,241	47,817	50,072	-	189	1,161	2,893
NORTH CAROLINA - Current Path Case	-	-	-	-	4,834	4,834	4,834	4,834	-	-	-	-
Development Policy Case	-	-	45	382	4,834	12,479	45,407	45,231	-	-	101	3,554
Difference	-	-	45	382	-	7,646	40,573	40,398	-	-	101	3,554
UTAH - Current Path Case	341	320	419	465	27,043	25,960	34,687	38,280	927	1,170	1,888	2,679
Development Policy Case	341	379	586	707	27,043	52,514	83,991	80,528	927	1,431	2,698	4,088
Difference	-	59	167	242	-	26,554	49,304	42,248	-	261	810	1,409
COLORADO - Current Path Case	1,111	1,065	1,192	1,359	118,879	116,539	133,132	151,055	3,020	3,891	5,369	7,834
Development Policy Case	1,111	1,133	1,333	1,567	118,879	177,669	221,416	236,087	3,020	4,420	6,359	9,119
Difference	-	68	141	208	-	61,131	88,283	85,032	-	528	990	1,285
MAINE - Current Path Case	-	-	-	-	638	638	638	638	-	-	-	-
Development Policy Case	-	-	24	201	638	4,211	21,018	20,074	-	74	137	1,864
Difference	-	-	24	201	-	3,573	20,380	19,436	-	74	137	1,864
WYOMING - Current Path Case	1,455	1,452	1,627	1,731	68,944	70,383	80,493	85,228	3,954	5,306	7,329	9,980
Development Policy Case	1,455	1,521	1,753	1,912	68,944	131,672	147,603	152,090	3,954	6,362	8,905	11,263
Difference	-	69	125	180	-	61,289	67,110	66,862	-	1,056	1,576	1,283
MASSACHUSETTS - Current Path Case	-	-	-	-	2,111	2,111	2,111	2,111	-	-	-	-
Development Policy Case	-	-	20	169	2,111	5,917	20,936	21,825	-	63	116	1,570
Difference	-	-	20	169	-	3,806	18,826	19,715	-	63	116	1,570

Key State Results (continued)

	Annual Production (mboed)				Total Jobs Supported				Annual Gov't Revenue ($M)			
	2010	2015	2020	2030	2010	2015	2020	2030	2010	2015	2020	2030
VIRGINIA - Current Path Case	112	58	53	91	15,456	15,456	15,456	15,456	42	80	118	252
Development Policy Case	112	58	71	237	15,456	19,062	31,857	33,641	42	133	218	1,584
Difference	-	1	18	146	-	3,606	16,401	18,185	-	53	100	1,332
NEW JERSEY - Current Path Case	-	-	-	-	5,359	5,359	5,359	5,359	-	-	-	-
Development Policy Case	-	-	14	114	5,359	8,407	19,212	21,322	-	42	78	1,063
Difference	-	-	14	114	-	3,049	13,853	15,964	-	42	78	1,063
PENNSYLVANIA - Current Path Case	441	1,771	2,271	2,848	121,783	184,719	236,870	296,217	167	2,438	5,051	7,862
Development Policy Case	441	1,824	2,351	2,961	121,783	200,630	257,499	322,042	167	2,510	5,229	8,172
Difference	-	52	80	112	-	15,912	20,629	25,824	-	72	178	310
OKLAHOMA - Current Path Case	1,211	1,122	1,065	1,264	239,883	227,378	220,403	260,264	1,692	2,204	2,720	4,051
Development Policy Case	1,211	1,157	1,125	1,373	239,883	234,959	231,975	277,100	1,692	2,273	2,872	4,398
Difference	-	35	59	108	-	7,581	11,572	16,836	-	69	152	347
MONTANA - Current Path Case	112	95	88	93	10,832	9,335	8,877	9,316	305	345	397	535
Development Policy Case	112	128	149	188	10,832	35,080	38,851	46,554	305	750	1,024	1,169
Difference	-	34	61	95	-	25,745	29,975	37,239	-	405	628	634
CONNECTICUT - Current Path Case	-	-	-	-	3,005	3,005	3,005	3,005	-	-	-	-
Development Policy Case	-	-	10	84	3,005	4,958	12,545	13,220	-	31	58	785
Difference	-	-	10	84	-	1,953	9,540	10,215	-	31	58	785
WEST VIRGINIA - Current Path Case	198	195	232	300	45,378	45,697	55,462	71,284	75	269	516	827
Development Policy Case	198	220	280	379	45,378	51,185	62,499	79,269	75	303	622	1,047
Difference	-	25	48	80	-	5,487	7,037	7,986	-	34	106	220
ARKANSAS - Current Path Case	692	856	1,072	1,234	46,611	58,974	75,361	86,275	967	1,683	2,738	3,952
Development Policy Case	692	873	1,106	1,281	46,611	63,197	83,281	94,145	967	1,715	2,823	4,105
Difference	-	17	33	48	-	4,223	7,920	7,870	-	32	85	152
NEW MEXICO - Current Path Case	885	668	565	603	58,535	45,182	38,970	41,421	3,132	2,810	2,886	3,901
Development Policy Case	885	682	589	654	58,535	59,785	54,955	57,013	3,132	3,049	3,232	4,265
Difference	-	14	25	51	-	14,603	15,986	15,592	-	239	346	365
SOUTH CAROLINA - Current Path Case	-	-	-	-	2,811	2,811	2,811	2,811	-	-	-	-
Development Policy Case	-	-	6	52	2,811	4,200	9,030	9,610	-	19	27	481
Difference	-	-	6	52	-	1,390	6,220	6,799	-	19	27	481
Other States and Offshore - Current Path Case	4,344	3,958	4,123	4,064	347,979	301,026	277,517	309,558	1,776	2,317	4,549	6,940
Development Policy Case	4,344	3,986	4,190	4,361	347,979	350,016	383,036	519,570	1,776	3,775	6,637	10,355
Difference	-	28	67	297	-	48,990	105,519	210,011	-	366	527	2,579
Total - Current Path Case	18,526	19,174	20,450	22,228	2,523,186	2,611,468	2,788,316	3,027,406	41,095	50,135	65,270	88,159
Development Policy Case	18,526	20,441	24,639	32,599	2,523,186	3,279,930	3,926,882	4,431,282	41,095	58,602	91,146	187,929
Difference	-	1,267	4,189	10,371	-	668,462	1,138,567	1,403,877	-	10,165	27,796	99,769

Contents

Case Development

- The objective of the study was to evaluate the impact on production, jobs and government revenues of implementing U.S. oil and natural gas regulatory policies which support the development of North America's oil and natural gas resources
- To achieve this, Wood Mackenzie has developed two scenarios reflecting different regulatory policy with respect to North American hydrocarbon resources
- The base case will be referred to throughout this report as the **"Current Path Case"**
  - The case assumes that current policy and regulatory environment continue into the future
  - In essence, the policies in this case hinder the development of North America's oil and gas resources. Resource development increases in this case but at a relatively modest pace
- The alternative to the Current Path Case is referred to throughout this report as the **"Development Policy Case"**
  - This case evaluates the impact of policies that encourage development of the U.S. upstream oil and natural gas sector

Current Path Case - Assumptions

- The **“Current Path Case”** assumes the following policy and regulatory initiatives:

- Continued “slow walk” of Federal permitting for offshore Gulf of Mexico
    - The case assumes an increase from current offshore exploration and development activity levels, but not back to pre-Moratorium rates
- Tighter Federal hydraulic fracturing and water disposal regulations which are beyond the current state regulations
    - Slow down of onshore drilling due to increased cost of well completions. Results in a negative impact on development economics
- No opening of new areas for exploration and development
    - No new exploration and development in frontier areas of Alaska, Eastern Gulf of Mexico, Atlantic and Pacific offshore, and Federal Rockies
- Restrictions on new pipeline development from Canada
    - Curtailment of oil sands pipeline infrastructure into the U.S.. No development of the Keystone XL pipeline or other future Canada to U.S. pipelines

Current Path Case – Assumptions (continued)

- In developing the **"Current Path Case"** Wood Mackenzie has made the following assumptions:
  - Onshore U.S.
    - Slowdown of the development of onshore plays to a rate below current company plans. This is due to increased cost resulting from slower permitting and a heavier regulatory burden. Key assumptions are that leasing and permitting continues at a slower pace relative to historical trends as borne out by a time series of BLM leasing and permitting data, and a heavier regulatory burden adds to drilling and completion costs
    - The impact of increasing costs is to increase the breakeven economics of all U.S. wells by 30 cents per mcfe relative to the Development Policy Case. This has two effects:
      - A number of marginal plays become sub-economic (primarily gas plays), i.e. their economics fall below a 15% hurdle rate. It is therefore assumed that no further drilling will occur in these plays
      - A U.S.-wide slowdown in drilling activity. This results in a 4% decline in drilling across all remaining oil and natural gas plays which have not become sub-economic as a result of increased cost
    - No lifting of moratorium on shale gas development in New York
  - Gulf of Mexico
    - In the future the leasing of deep water acreage will continue, but at 50% of the pre-Moratorium rates
    - Exploration activity picks-up from current level, but only recovers to 50% of the pre-Moratorium drilling rates, approximately 20 wells per year
  - Alaska
    - No drilling activity offshore Alaska, ANWR or the NPRA
  - No future development activity in the currently closed areas

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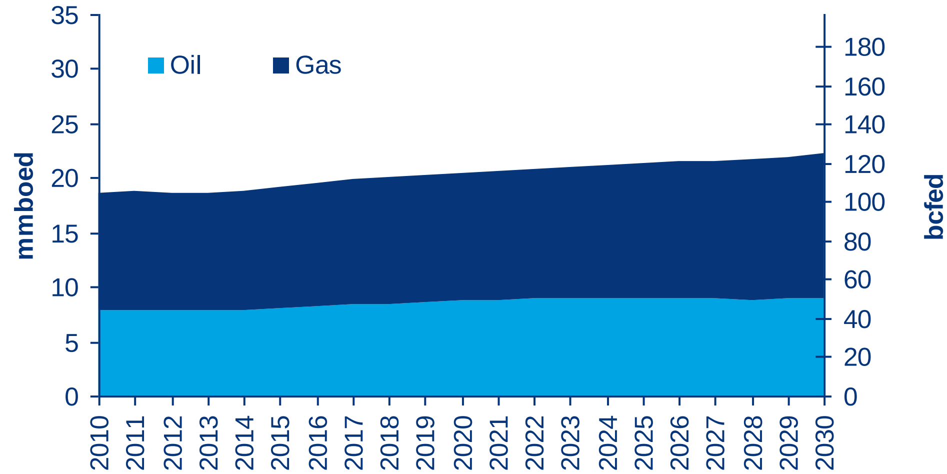
Current Path Case Production Projection

- If the current U.S. policy and regulatory environment continues (the Current Path Case), Wood Mackenzie predicts U.S. production will grow from 18.5 mmboed in 2010 to 22.2 mmboed in 2030, a 20% increase
- We expect to see significant production growth from the Rockies, Northeast and Gulf Coast regions
- Primarily driven by unconventional plays, development activity will more than offset declines from the conventional regions

Total U.S. Production - Current Path Case



Production	2010	2030	Difference
Liquids (mmbd)	7.8	9.0	1.2
Gas (Bcfd)	60.1	74.5	14.4

Development Policy Case – Assumptions

- The **"Development Policy Case"** assumes the following policy and regulatory initiatives:
- Opening of Federal areas that are currently "off limits" to exploration and development
  - Commencement of leasing, drilling and development activity in currently closed regions. Regions to be opened include: Eastern Gulf of Mexico, portions of the Rocky Mountains, Atlantic OCS, Pacific OCS, Alaska National Wildlife Refuge (ANWR) – 1002 Area, National Petroleum Reserve, Alaska (NPRA) and Alaska offshore
- Lifting of drilling moratorium in New York State
  - Commencement of drilling and development of Marcellus shale in New York State
- Increased rate of permitting in the offshore Gulf of Mexico
  - Allows for a return to pre-Moratorium exploration and development activity
- Approval of the Keystone XL and other future Canada to U.S. oil pipelines
  - Facilitates additional Canadian oil sands development, thereby increasing the demand for U.S. supplied equipment and infrastructure
- Regulation of shale resources remains predominately at the State level
  - Environmental regulation of shale gas and tight oil plays are not duplicative or unduly burdensome. Permitting levels are at sufficient rates to develop resources in a timely manner

Development Policy Case – Assumptions (continued)

- In developing the **"Development Policy Case"** Wood Mackenzie has made the following assumptions:
  - Onshore U.S.
    - Development of onshore plays as per company plans. Includes tight oil, shale gas and tight gas plays
    - Leasing and permitting rates do not significantly hinder current company plans
    - No restrictions of shale development in New York state
  - Gulf of Mexico
    - Leasing of deep water acreage returns to pre-Moratorium rates
    - Exploration activity recovers to pre-Moratorium drilling rates, approximately 40 wildcat wells per year
  - Alaska
    - Resources offshore Alaska and NPRA are developed
  - Access is allowed in current and previously restricted areas
    - Atlantic Coast – Production begins 2019
    - Pacific Coast – Production begins 2019
    - Eastern Gulf of Mexico – Production begins 2016
    - ANWR – Production begins 2017
    - Portions of the Rocky Mountains – Production begins 2012

New Resource Areas – Development Policy Case

Source: Wood Mackenzie

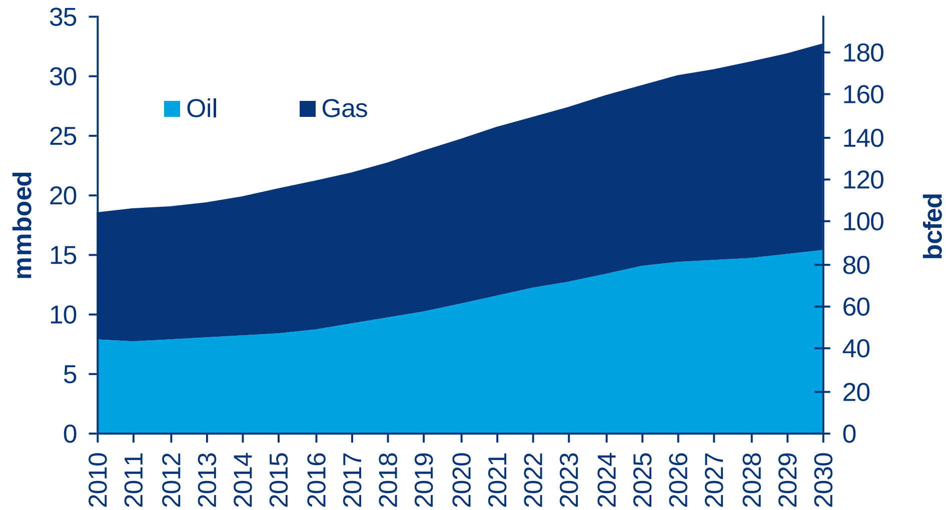
- Under the Development Policy Case, it is assumed that a number of new Federal areas become open for exploration drilling and field development. These are:
  - Pacific, Atlantic, Eastern GoM, portions of the Rockies, ANWR, NPRA and the Chukchi Sea
  - Also Wood Mackenzie has assumed that New York lifts its drilling moratorium
- Under this case, the permit and regulatory policies encourage the development of currently permitted onshore areas
- Permit and regulatory policies allow for relatively faster development of the Gulf of Mexico
- Canadian oil sands pipelines into the U.S. are fully developed (e.g., Keystone XL)

Region	Resources added (bnboe)
Atlantic OCS	13.5
Pacific OCS	11.3
Eastern GoM	14.5
Rockies Federal	2.0
Alaska ANWR	10.8
Alaska NPRA/Chukchi	2.1
New York	5.3
Total	59.5

Development Policy Case Production Projection

- If the U.S. enacts policies that encourage domestic oil and natural gas development (the Development Policy Case), Wood Mackenzie expects production to grow from 18.5 mmboed in 2010 to 32.6 mmboed by 2030, a 76% increase from 2010 levels
- The opening of restricted Federal areas would add over 6.7 mmboed
- The remaining production growth comes from New York, and accelerated drilling across the onshore U.S. and the Gulf of Mexico

Development Policy Case – Production Projection



Production	Development Policy Case 2010	Development Policy Case 2030	Difference 2010-2030	Current Path Case 2030	Difference 2030
Liquids (mmbd)	7.8	15.4	7.6	9	6.4
Gas (Bcfd)	60.1	96.9	36.8	74.5	22.4

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Scenario Modeling

- For the two scenarios described, Wood Mackenzie has developed an activity outlook based upon the expected impact of the respective policies on oil and natural gas development activity levels
- Policy impacts on production and tax revenue are estimated by contrasting the results of Wood Mackenzie's proprietary economic model (GEM) for the two stated scenarios
- The GEM (Global Economic Model) is an Excel based tool which Wood Mackenzie has developed to forecast capex, opex, production and taxation at the asset level across the whole of North America. Wood Mackenzie defines an asset as a stand-alone field or distinct play which has a distinct development scenario. GEM is capable of generating full economic analysis for each asset modeled in North America. Outputs include Internal Rates of Return, Net Present Values and $/boe estimates
- Data inputs and tax assumptions are based upon publicly available state and federal information, public and private disclosures by oil and gas operating companies, and information referenced in the appendix of this report and other public sources (industry journals, independent agencies, etc.)
- Where no such information is available, Wood Mackenzie has made assumptions based on its in-depth technical knowledge of the U.S. industry, supplemented by its many years of experience studying the activity in the North American oil and gas sector

Methodology – Production and Revenues

- The basic methodology that was developed to assess the impacts of two cases and associated production, and revenues was as follows:
  - Build individual asset models as described in the previous slide to represent each scenario
  - Generate cash flow and production information from the asset models
  - Assign assets to regions and states, then consolidate the assets to generate cash flow and production information at the state level
  - Tag each asset to a particular policy to generate the impact of each individual policy either at the national or state level, i.e. consolidation of all new Access areas
  - Consolidation of assets to generate regional impacts
  - Tax assumptions
    - Royalties from new OCS areas were split with the states (see appendix)
    - Potential state income taxes which could be generated from new OCS areas were not included

Methodology – Employment Estimation Base (2010) Level

- Wood Mackenzie has derived the base count for the Current Path Case jobs numbers from the 2008 Implan database
- Wood Mackenzie took these direct employment numbers for the upstream sector, then added a multiplier of 2.5 for indirect and induced (income related) jobs per direct job. This multiplier is likely conservative given that total employment multipliers for the oil and natural gas sector estimated by BEA are in the rage of 5 to 7 total jobs per 1 direct jobs
- The combined direct, indirect and induced job counts gives the total economic impact for the upstream sector across the U.S.
- Since these numbers were calculated for 2008, Wood Mackenzie used a production ratio to derive the 2010 base job count per state
- The production ratio is defined as a ratio of 2010 production in boed divided by 2008 production
- Future base job counts for the Current Path Case are derived by using future production ratios generated from dividing future production by 2010 production levels

Methodology – Employment Estimation – New Activity

- For each new project being developed in the future Wood Mackenzie has developed associated employment levels
- The number of jobs generated is dependent on a number of factors, including:
  - Type of project - onshore drilling, offshore field development
  - Location of project – onshore, offshore, shallow or deep water, Alaska
- Potential employment associated with OCS production was allocated to each state based upon the percentage of the state's coastline in the region's total
- Jobs were also attributed to exploration activity
  - Relevant to new access areas and the Gulf of Mexico
- For each activity a direct job count was estimated
- Multiplying the number of each discrete activity per annum by the number of direct jobs per activity gave an overall job count
- Indirect and induced jobs which were calculated using an indirect jobs multiplier
  - A multiplier of 2.5 indirect and induced jobs per every 1.0 direct jobs was used (Note: this is conservative relative to other estimates, e.g. BEA estimated multipliers are typically in the 5 to 7 range)

Methodology – Employment Estimation – New Activity (continued)

- For estimating the jobs impact for the opening of the Marcellus play in New York State, Wood Mackenzie utilized supporting material from the Timothy J. Considine study entitled “The Economic Impacts of the Marcellus Shale: Implications for New York, Pennsylvania, and West Virginia”
- For estimating the U.S. jobs impact from Canadian Oil Sands pipeline development, Wood Mackenzie has utilized outputs from the Canadian Energy Research Institute study entitled “Economic Impacts of New Oil Sands Projects in Alberta (2010-2035)”
- These two studies provided job impact data for development scenarios in the Marcellus Play and Keystone XL and other related Canada to U.S. oil pipelines

Access Areas Resource Assumptions – Development Policy Case

- The following table details the assumptions Wood Mackenzie used for developing the resource base for each of the new Access areas in the Development Policy Case
    - These assumptions form the basis of the economic models which generate the production and revenue forecasts
    - Each discovery for each of the new Access areas has its own cash flow and production profile
    - Consolidation of each model generates the forecasts for each region

Access Areas*	Atlantic	Pacific	ANWR	NPRA/Chukchi	Eastern GoM	New York	Rockies
Acreage	40,000,000	20,000,000	1,500,000	1,500,000	16,000,000	2,560,000	10,000,000
Lease Revenue ($Billion)	8	7	15	N/A	16	N/A	15
Exploration Wells	290	157	70	10	198	N/A	N/A
Discovery Rate	20%	30%	50%	60%	33%	N/A	N/A
Commercial Discoveries	58	47	35	24	65	N/A	N/A
Average Discovery Size (mmboe)	386	239	309	90	222	N/A	N/A
Resource (bnboe)	14	11	11	2	15	3	2

*** Source:**
- Wood Mackenzie report January 2011 " Energy Policy at a Crossroads: An Assessment of the Impacts of Increased Access versus Higher Taxes on U.S. Oil and Natural Gas Production, Government Revenue, and Employment"
- ICF International, 2008, "Strengthening Our Economy: The Untapped U.S. Oil and Gas Resources"

Gulf of Mexico and Onshore Areas Resource Assumptions – Development Policy Case

- In the Development Policy Case, Wood Mackenzie made specific assumptions surrounding development activity in the onshore regions and the Gulf of Mexico
- These assumptions have a direct impact on production, jobs, and government revenues
- Onshore regions assumptions
  - Addition of production from any play which becomes economic after removing the well cost of 30 cents/mcf (environmental policy costs)
  - Increase in activity across all onshore plays of 4% as marginal wells in all regions become economic
- Gulf of Mexico
  - Increasing leasing and permit rates back to pre-Macondo levels raises production relative to the Current Path Case

Production Impact (000's boed)	2015	2020	2025	2030
Onshore Lower 48*	851	1,447	1,678	1,887
Gulf of Mexico	0	1,183	2,401	3,150

*excluding New York State - Marcellus Shale

Production – Development Policy Case less Current Path Case

Jobs Assumptions – Development Policy Case

- For each discovery and field development in the Development Policy Case, Wood Mackenzie has assigned a direct job count
- The following table details the assumptions Wood Mackenzie used for developing the job impacts for onshore and offshore new access and existing production areas
  - The indirect multiplier stated in the table is taken from a recent PriceWaterhouse Coopers study and used to assess the impact of the upstream oil and gas sector activity on employment in other sectors

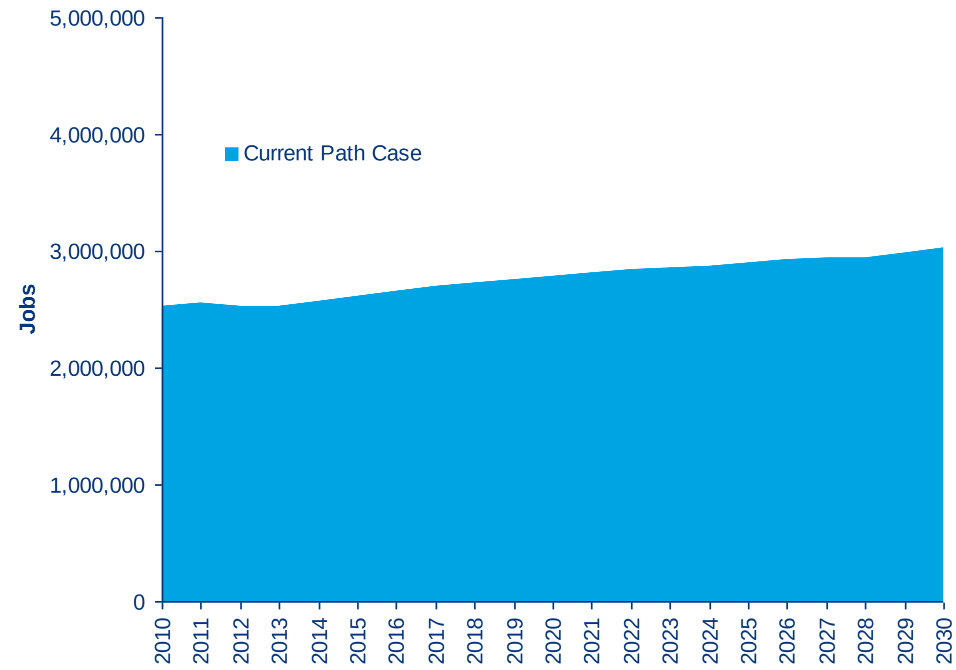
Job Category	Offshore	Onshore
Landmen (jobs)	400 per million acres	200 per million acres
E&A Drilling (jobs)	280 per rig	60 per rig
Associated Drilling (jobs)	5 per rig	3 per rig
Wells per rig per year	2	9
Construction (jobs)	2,000 per field	2 per rig worker
Operations (jobs)	200 per field	100 per 10,000 boed
Indirect Multiplier	2.5	2.5

Contents

Current Path Case – Employment Forecast

- Wood Mackenzie estimates that 2010 U.S. employment supported by the upstream sector was 2,523,000
- This consists of 631,000 direct jobs and 1,892,000 indirect and induced jobs
- By 2030 Wood Mackenzie projects the total U.S. employment in the Current Path Case will be 3,027,000
- The assumption used to generate this jobs forecast, is that jobs will grow in direct proportion to the production growth over the period analyzed

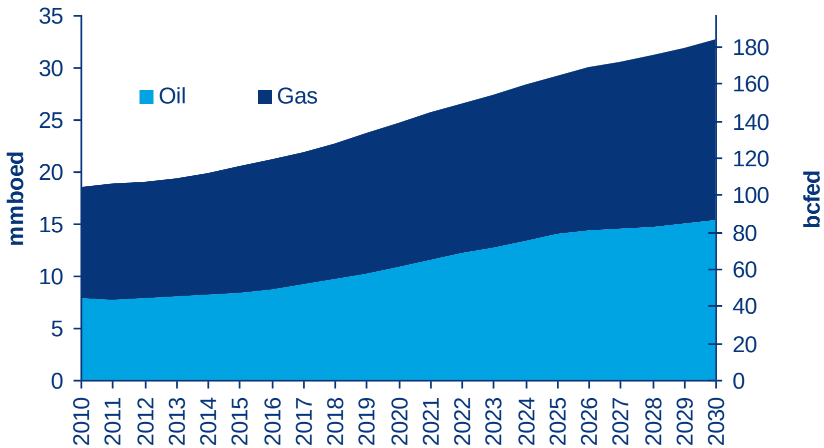
U.S. Jobs Forecast – Current Path Case



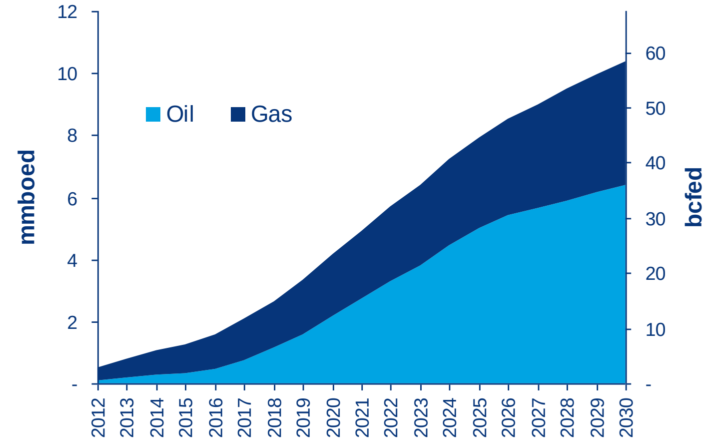
Added U.S. Production from Development Policy Case

- Wood Mackenzie projects that by 2030, an estimated 10.4 mmboed of incremental domestic production could be added through policies which encourage the development of U.S. resources
- This is a 47% increase over the estimated 2030 production levels in the Current Path Case

Total U.S. Production – Development Policy Case



Potential U.S. Production Impact

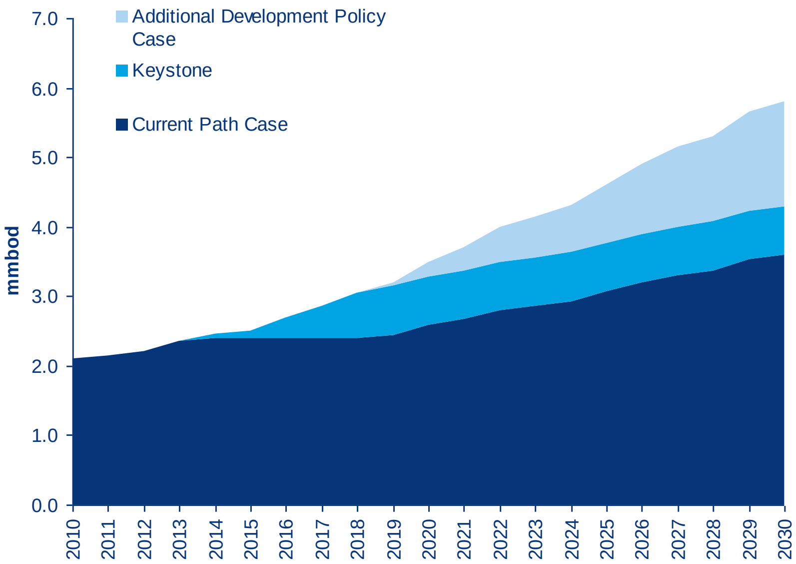


Total U.S. Production : Development Policy Case less Current Path Case

Oil Sands Production Impacts – Current Path Case vs. Development Policy Case

- Total Alberta oil production, both conventional and oil sands, is limited by the 3.5 mmbod of oil pipeline capacity out of the region. Oil sands production is expected to increase from 2.10 mmbod in 2010 to 2.40 mmbod in 2014. Further production growth will not happen without the Keystone XL or other pipelines that can export oil out of Alberta
- Most of the incremental oil production is expected to be exported to the U.S. although the oil could also be exported to other countries with additional pipelines being built to the Canadian West coast
- The Keystone XL pipeline has a potential to import 700,000 bod into the U.S. and can be expanded to 900,000 bod
- Building sufficient oil pipeline capacity into the U.S. should allow Canadian oil sands production to increase from 2.10 mmbod in 2010 to 5.80 mmbod by 2030, an increase of 3.70 mmbod or 280%. This is 2.20 mmbod greater than the level in the Current Path Case, which assumes no additional oil pipeline capacity into the U.S.

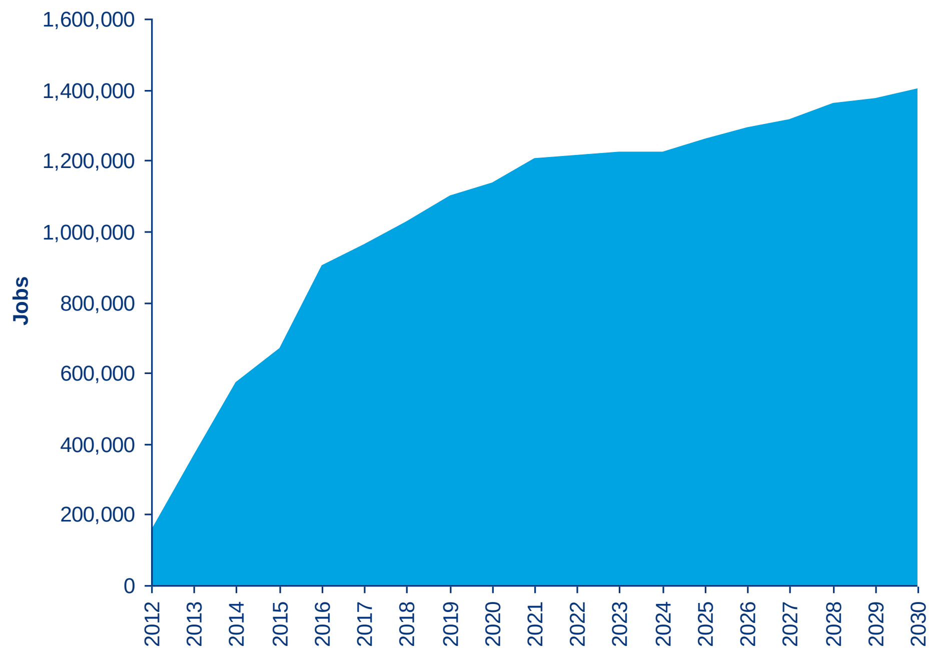
Potential Canadian Production Impact



Added U.S. Jobs from Development Policy Case

- Wood Mackenzie estimates that by 2030, 1.4 million new jobs could be added through policies which encourage the development of U.S. oil and natural gas resources and facilitate Canadian oil sands production through the development of the Keystone XL and other related U.S. pipelines
- Jobs added have the potential to exceed 1.0 million by 2018

Potential U.S. Job Impact

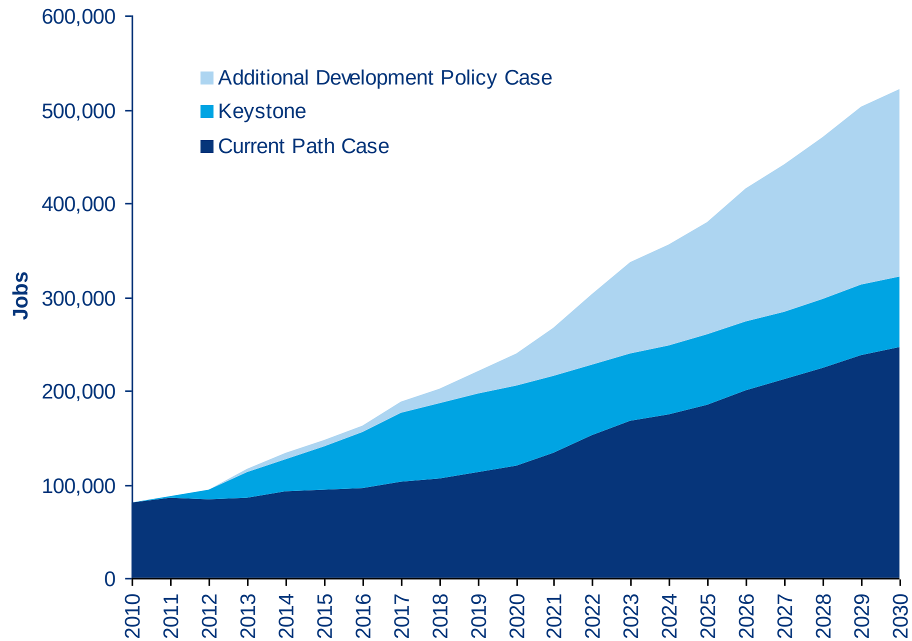


Total U.S. Employment: Development Policy Case less Current Path Case

Added U.S. Jobs Canadian Oil Sands Pipelines

- Canadian oil sands production stimulates demand for U.S. produced services and equipment (e.g., large trucks and related infrastructure) and hence an increase in U.S. jobs
- U.S. employment associated with Canadian oil sands production that is expected to fill the initial phase of the Keystone XL pipeline should reach nearly 85,000 new jobs by 2020
- By 2030, U.S. employment associated with Canadian oil sands production that could fill new Canada to U.S. pipeline capacity could reach 270,000
- If 3.50 mmbod of additional oil pipeline export capacity is built out of Alberta (either to the U.S. or Canadian West Coast), the U.S. employment associated with Canadian oil sands production has the potential to reach 520,000 by 2030 (inclusive of jobs in the Current Path Case)

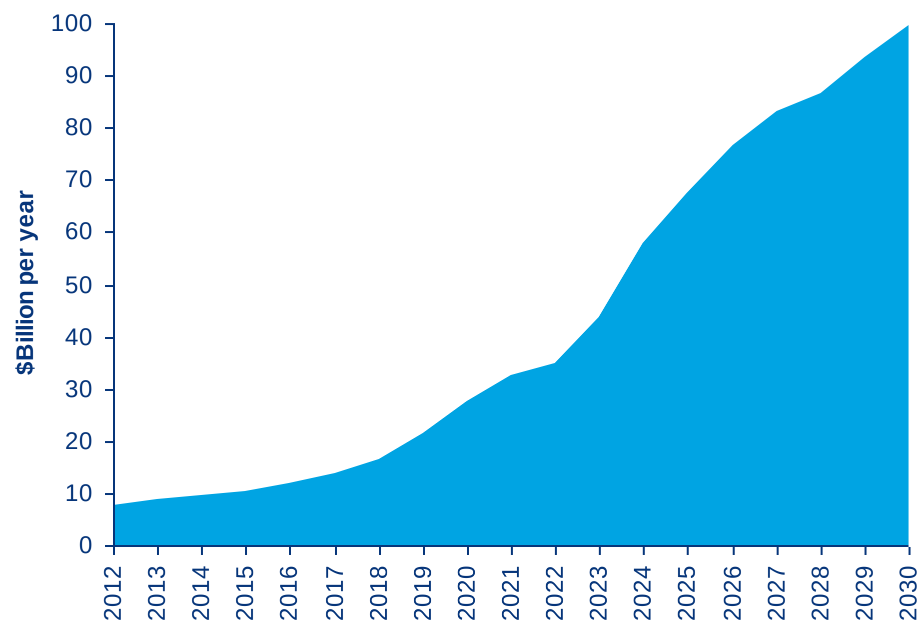
Potential Total Job Impact



Added U.S. Government Revenue from Development Policy Case

- Wood Mackenzie estimates over $99 billion per year of new U.S. government revenue could be added by 2030 under the current taxation regime through policies which encourage the development of U.S. oil and natural gas resources
- Furthermore, Wood Mackenzie estimates total additional cumulative government revenues of $803 billion could be generated by 2030 under policies assumed in the Development Policy Case.

Potential Annual Government Revenue Impact

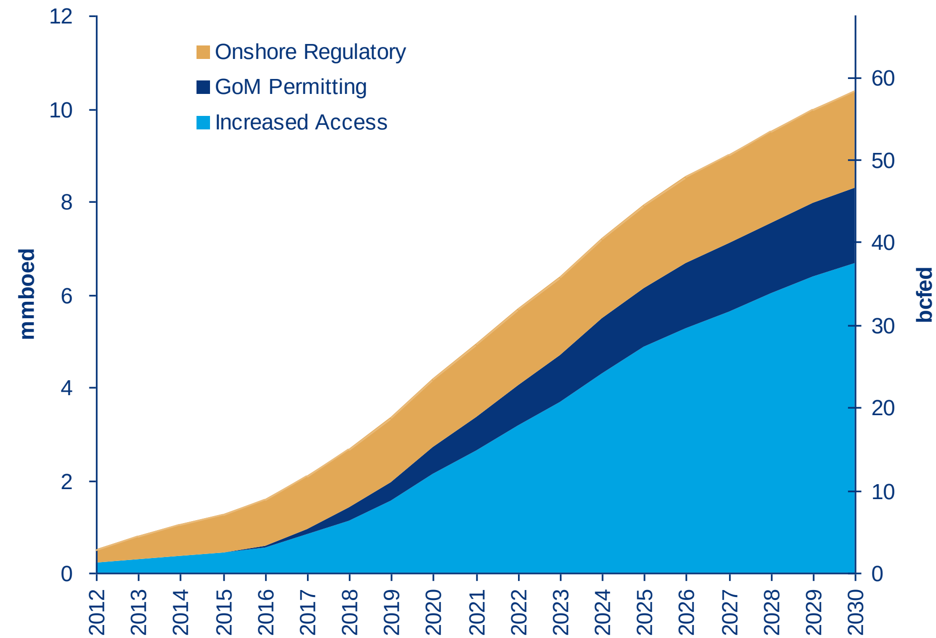


Total Government Revenue: Development Policy Case less Current Path Case

Oil and Natural Gas Production Impacts by Policy

- Opening access to areas which are currently closed to development has the largest incremental impact on production between 2012 and 2030
- Wood Mackenzie estimates these new access areas could add up to 6.7 mmboed by 2030
- Regulations which permit timely development of GoM and the U.S. onshore would add a further 3.7 mmboed by 2030
- Total incremental production could increase by 10.4 mmboed by 2030

Potential U.S. Production Impact

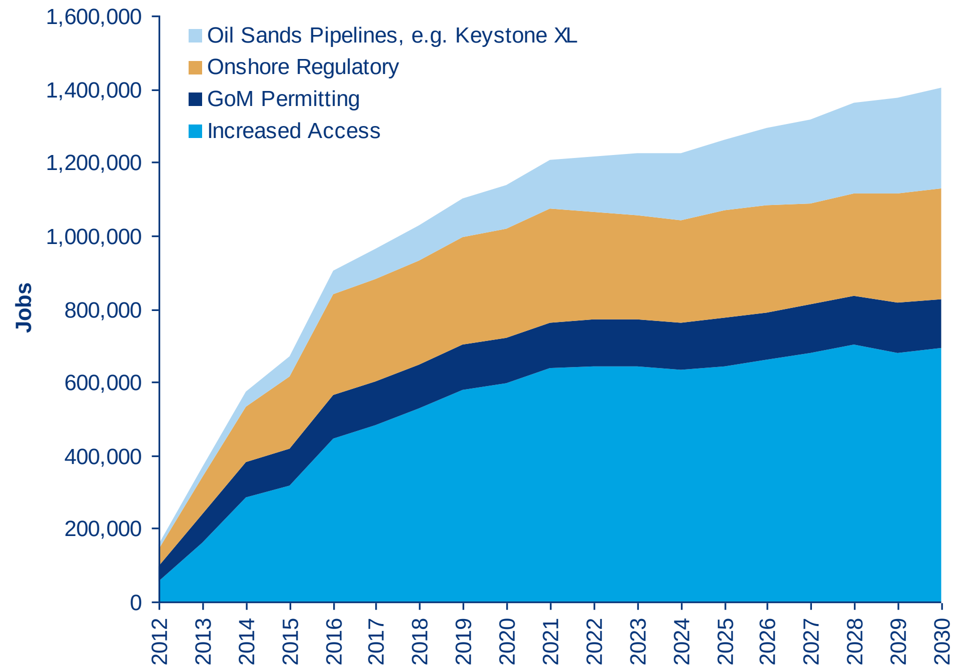


Total Production: Development Policy Case less Current Path Case

Employment Impacts by Policy

- Opening access to new areas for oil and natural gas development could add 690,000 jobs by 2030, approximately half of the total potential jobs added
- Wood Mackenzie estimates that a more favourable policy to develop pipelines from the Canadian oil sands to the U.S. would add over 270,000 U.S. jobs by 2030
- These jobs are primarily a result of U.S. services and the production of capital and intermediate goods exported to Canada for the development of the oil sands
- The impact on jobs from the GoM and onshore regions is more immediate as companies are already active in these regions with portfolios of opportunities to develop

Potential Total Job Impact

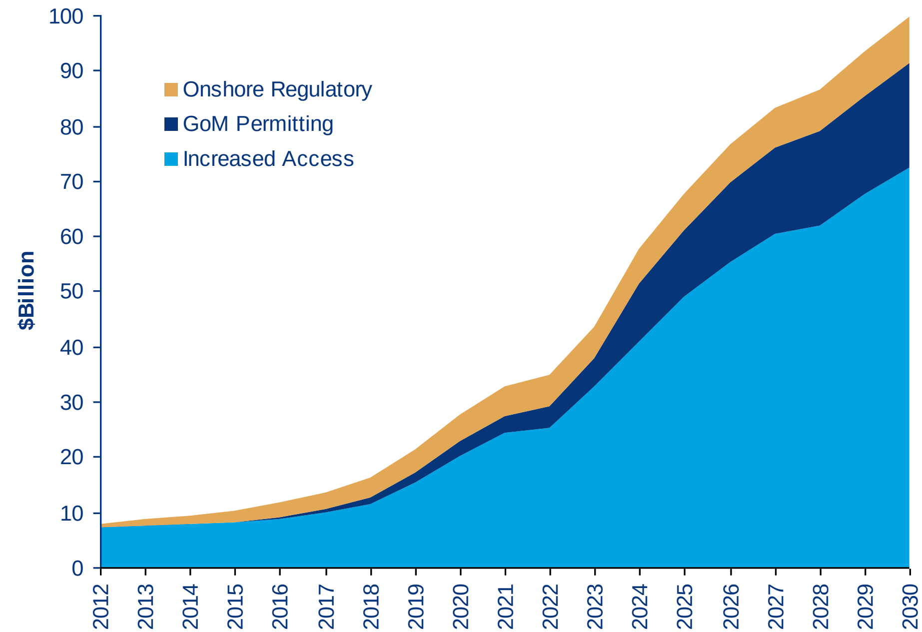


Total Employment: Development Policy Case less Current Path Case

Added Revenue by Policy

- Increasing access to areas currently off-limits to oil and natural gas development has the greatest potential to increase government revenues
- Cumulative government revenue (inclusive of leases, state and local taxes) due to increased access, has the potential to reach a cumulative $127 billion by 2020 and $803 billion by 2030
- New lease sales drive the majority of revenues derived from the access policies in the short term
- From 2020 onwards, the impact of new production from these access areas drives the majority of revenue growth
- More timely development of existing oil and natural gas regions, both on and offshore, will also create additional government revenue

Potential U.S. Government Revenue Impact



Total Revenue: Development Policy Case less Current Path Case

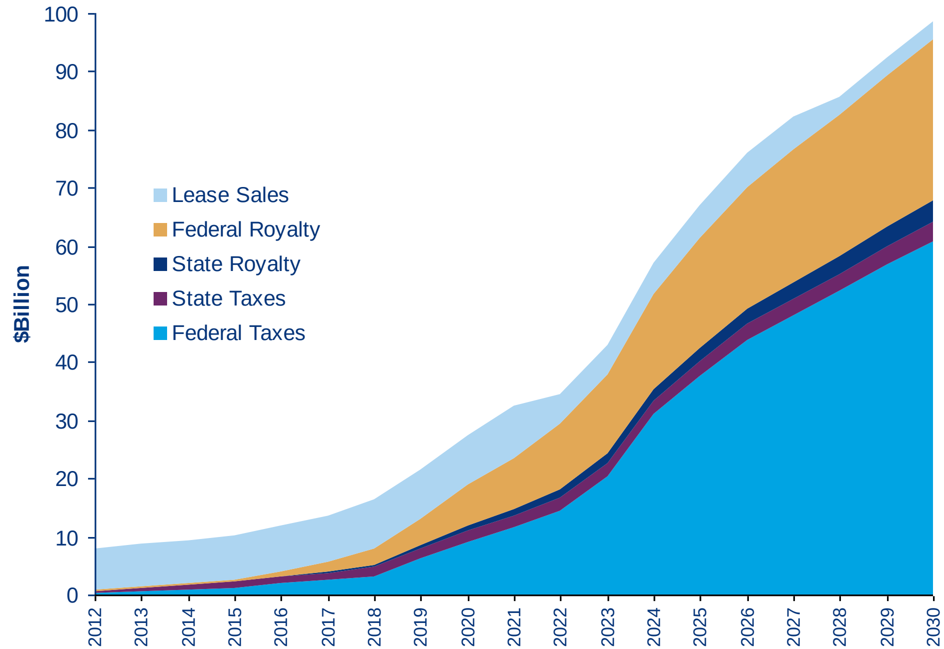
Added Revenue by Type

- Of the cumulative $803 billion of government revenues which could be generated through the Development Policy Case by 2030, $618 billion will be paid as Federal royalties and taxes. The states will generate a further $63 billion in royalties and taxes, with the remainder being new lease sales
- Revenue from both lease sales in new areas and from incremental lease sales in existing areas could reach $29 billion by 2015 and $122 billion by 2030
- Policies that encourage U.S. oil and gas development have the greatest potential to increase Federal income tax and royalty revenue

Cumulative Revenue Impact ($ Billion)

	2015	2020	2025	2030
State Royalty	0.0	1.8	10.8	26.7
Federal Royalty	0.9	18.0	87.7	211.5
State Taxes	2.6	10.0	21.4	36.3
Federal Taxes	3.1	26.1	142.2	406.1
Lease Sales	29.5	70.8	101.1	122.0

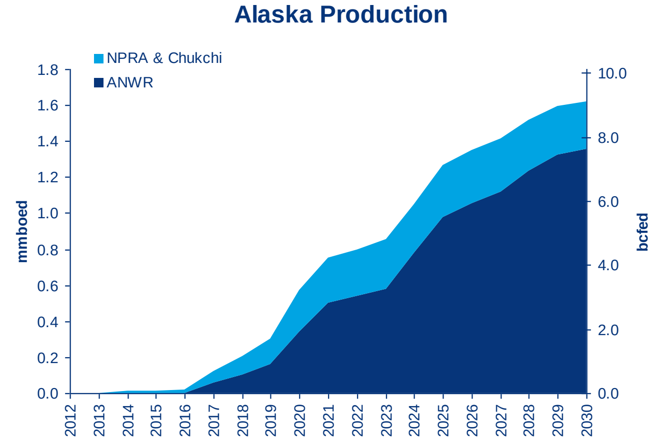
Potential U.S. Government Revenue Impact



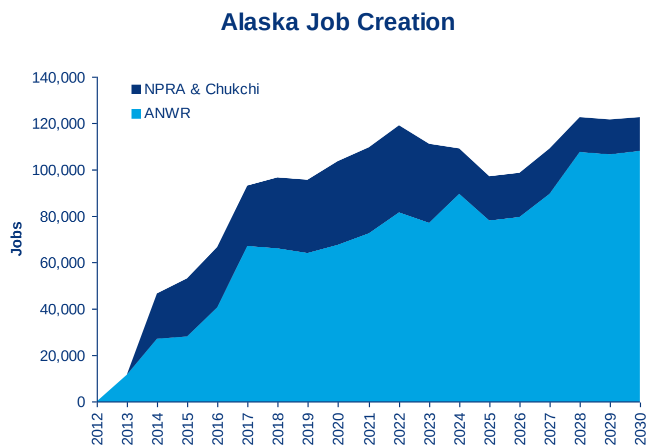
Total Revenue: Development Policy Case less Current Path Case

Development Policy Case Projected Regional Impacts* - Alaska

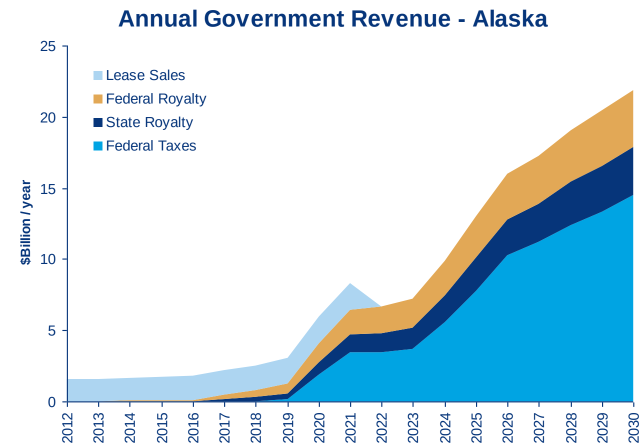
- Alaska new development production could reach over 1.6 mmboed by 2030, with up to $22 billion of government revenue, and over 120,000 jobs being created
- Creating access to new federal areas and more efficient regulatory policies have the biggest impact on the future development of Alaska's oil and gas industry
- ANWR provides the main growth opportunity in Alaska, supplemented by development of the Chukchi and NPRA
- Wood Mackenzie has assumed that the State of Alaska and the Federal Government will share royalties from these areas



All production from Federal lands



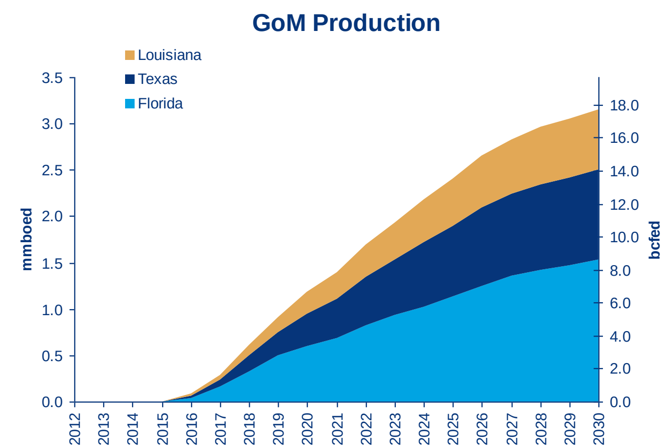
* Relative to the Current Path Case



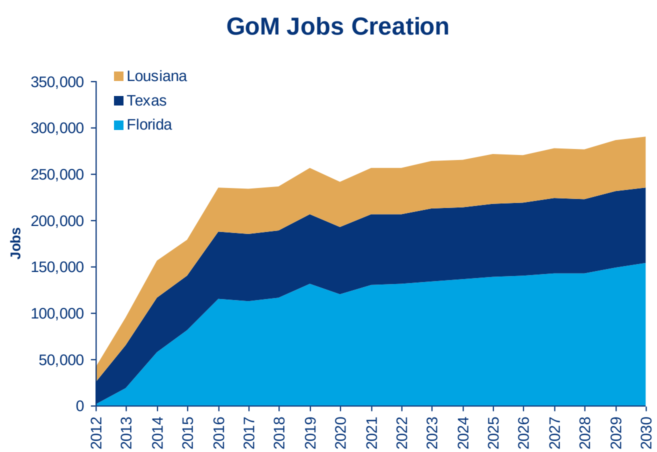
OCS and Federal BLM Royalties split with state

Development Policy Case Projected Regional Impacts* – Gulf of Mexico

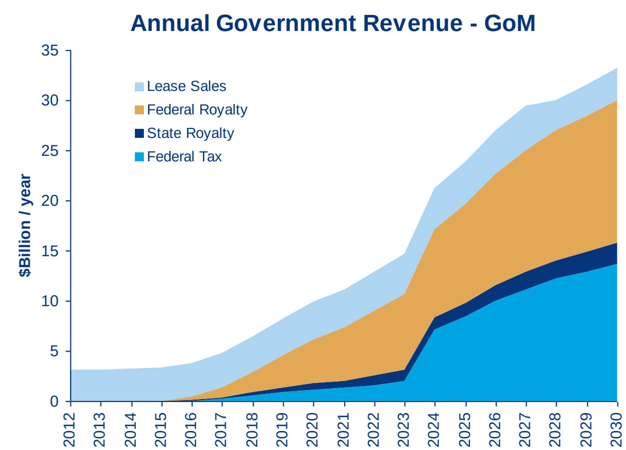
- Gulf of Mexico production could reach 3.1 mmboed by 2030, with up to $33 billion of government revenue, and 290,000 jobs being created as a result
- The opening of currently off-limits areas off the coast of Florida to exploration and development has the largest potential impact on the Gulf of Mexico's oil and gas industry
- Up to 100,000 new Florida jobs could be created by 2016
- More timely and efficient permitting for the offshore can increase production, government revenue, and jobs from Gulf of Mexico oil and natural gas development



All production from Federal lands



* Relative to the Current Path Case

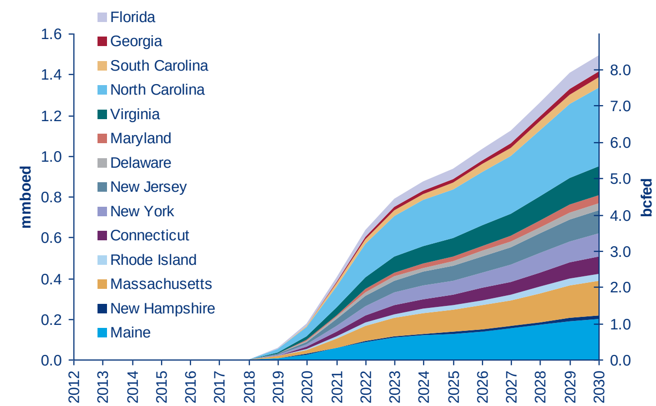


GoM royalties 100% Federal allocation

Development Policy Case Projected Regional Impacts* – Atlantic OCS

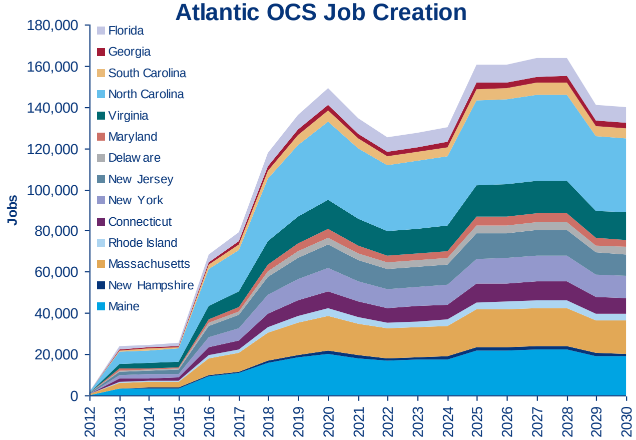
- Atlantic OCS production could reach nearly 1.6 mmboed by 2030, with up to $14 billion of government revenue per year, and 140,000 jobs being created as a result
- Cumulative government revenue for the region has the potential to reach $95 billion by 2030 (inclusive of lease bonuses)
- Wood Mackenzie assumes that states will be impacted on a proportionate basis of their coastline length

Atlantic OCS Production



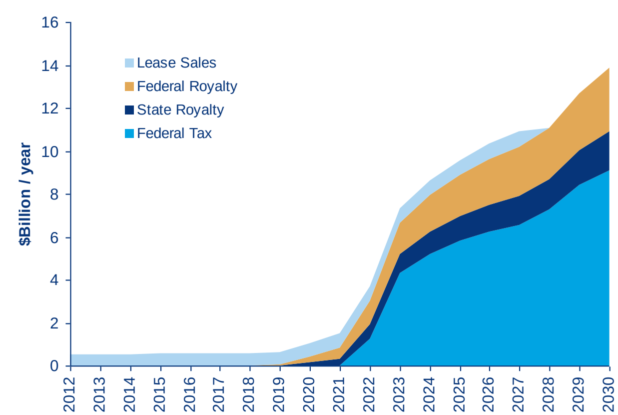
All production from Federal lands

Atlantic OCS Job Creation



* Relative to the Current Path Case

Annual Government Revenue - Atlantic OCS



OCS royalties split with states

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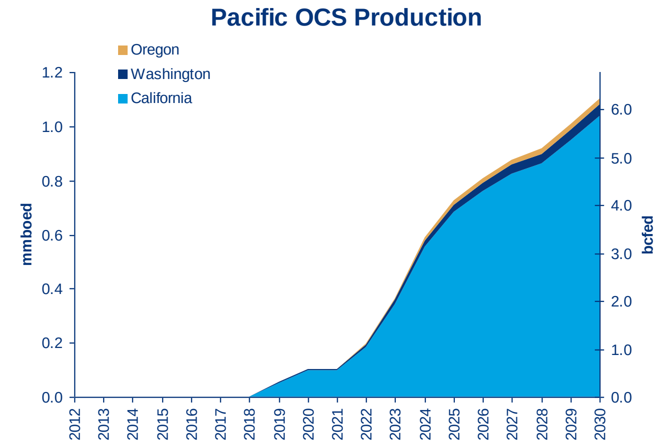
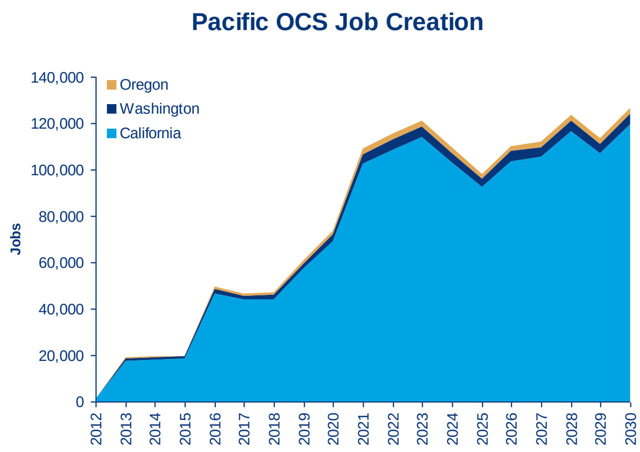
Development Policy Case Projected Regional Impacts* – Pacific OCS

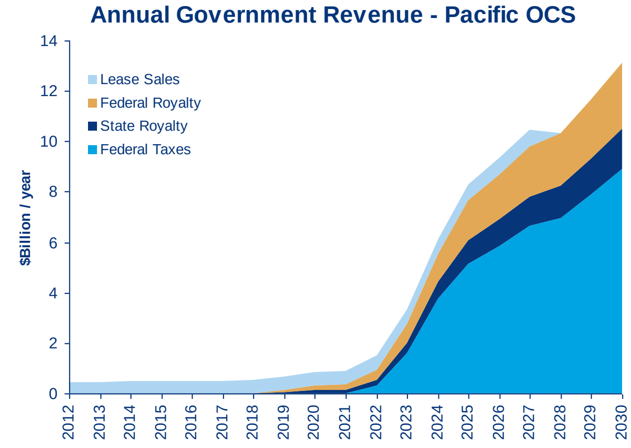
- Pacific OCS production could reach 1.1 mmboed by 2030, with up to $13 billion of government revenue, and over 120,000 jobs being created as a result
- Creating access to new federal areas and more efficient regulatory policies have the biggest impact on the future development of the Pacific OCS' oil and gas industry
- Wood Mackenzie projects that California would account for over 94% of production and job creation if the Pacific OCS were open for oil and gas development



All production from Federal lands



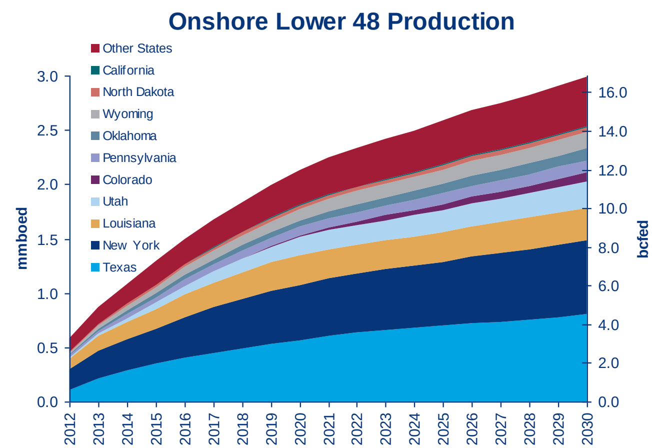
* Relative to the Current Path Case



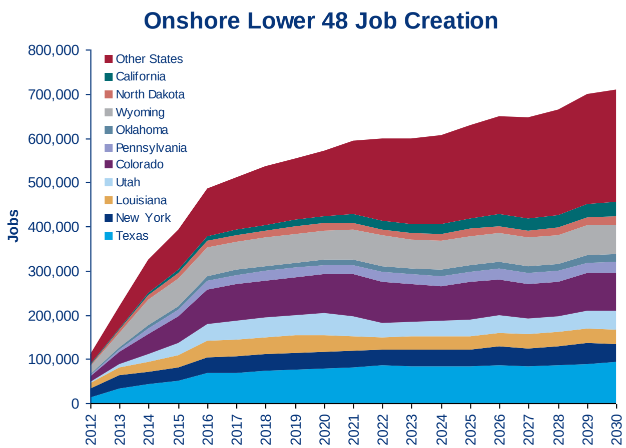
OCS royalties split with states

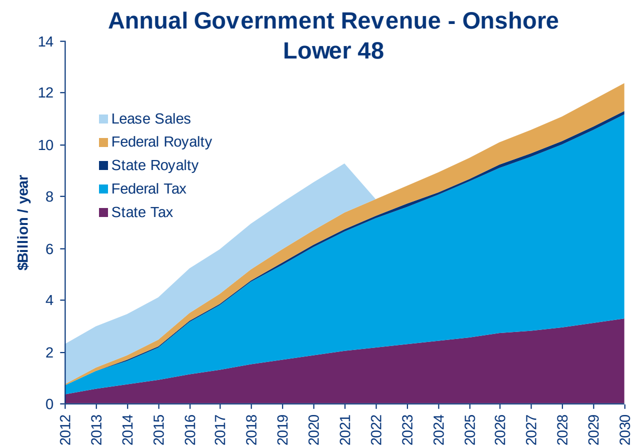
Development Policy Case Projected Regional Impacts* – Onshore U.S.

- Onshore new development production could reach 3.0 mmboed by 2030, with over $12 billion of government revenue, and over 700,000 jobs being created
- Creating greater access to portions of the Rocky Mountains, removing the moratorium on shale development in New York State, and supporting efficient onshore regulatory policies will all have a positive impact on the future development of U.S. domestic onshore oil and natural gas resources. The development of Canadian oil sands associated with Canada to U.S. pipelines will also create jobs in the U.S.



Production from Federal, State and Private lands





* Relative to the Current Path Case

Royalties allocated 100% to Federal, Sate or Private depending on ownership rights

Contents

Development Policy Case - Production Impact Forecasts by State ('000 boed)

	2015	2020	2025	2030
TEXAS	348	917	1,458	1,775
LOUISIANA	182	508	783	946
MISSISSIPPI	2	2	2	1
ALABAMA	1	1	2	2
ARKANSAS	17	33	41	48
KANSAS	2	5	17	23
OKLAHOMA	35	59	87	108
NEW MEXICO	14	25	41	51
COLORADO	68	141	184	208
N. DAKOTA	22	32	38	47
S. DAKOTA	0	0	0	0
WYOMING	69	125	160	180
UTAH	59	167	204	242
MONTANA	34	61	81	95
ILLINOIS	0	0	0	0
INDIANA	0	0	0	0
PENNSYLVANIA	52	80	97	112
VIRGINIA	1	18	92	146
KENTUCKY	0	1	2	2
OHIO	0	0	0	0

	2015	2020	2025	2,030
MICHIGAN	0	1	2	1
NEW YORK	319	522	661	789
WEST VIRGINIA	25	48	69	80
TENNESSEE	1	1	1	1
CALIFORNIA	3	105	691	1,050
ALASKA	14	573	1,270	1,623
WASHINGTON	0	2	15	22
OREGON	0	4	28	42
NEW HAMPSHIRE	0	2	10	16
MASSACHUSETTS	0	20	106	169
S. CAROLINA	0	6	32	52
RHODE ISLAND	0	4	22	35
GEORGIA	0	3	17	28
N. CAROLINA	0	45	240	382
NEW JERSEY	0	14	72	114
MARYLAND	0	5	25	39
DELAWARE	0	4	22	36
CONNECTICUT	0	10	53	84
MAINE	0	24	126	201
FLORIDA	0	621	1,187	1,620
TOTAL:	1,267	4,189	7,937	10,371

Development Policy Case - Annual Job Creation Forecasts by State

	2015	2020	2025	2030
TEXAS	110,133	152,225	161,539	174,670
LOUISIANA	65,635	87,663	83,884	88,814
MISSISSIPPI	815	1,278	1,438	1,564
ALABAMA	922	1,438	2,460	2,249
ARKANSAS	4,223	7,920	7,464	7,870
KANSAS	3,224	6,832	20,411	19,820
OKLAHOMA	7,581	11,572	14,826	16,836
NEW MEXICO	14,603	15,986	15,561	15,592
COLORADO	61,131	88,283	83,817	85,032
N. DAKOTA	13,144	15,840	16,093	19,119
S. DAKOTA	125	240	363	466
WYOMING	61,289	67,110	66,054	66,862
UTAH	26,554	49,304	38,132	42,248
MONTANA	25,745	29,975	33,017	37,239
ILLINOIS	6,914	17,670	32,899	49,237
INDIANA	1,179	2,037	3,177	4,059
PENNSYLVANIA	15,912	20,629	23,512	25,824
VIRGINIA	3,606	16,401	19,163	18,185
KENTUCKY	876	2,071	2,823	3,043
OHIO	2,751	6,437	10,986	15,585

	2015	2020	2025	2030
MICHIGAN	2,428	4,426	7,766	9,797
NEW YORK	32,241	47,817	50,823	50,072
WEST VIRGINIA	5,487	7,037	8,683	7,986
TENNESSEE	1,534	1,848	3,245	3,808
CALIFORNIA	26,333	86,197	116,582	150,816
ALASKA	52,974	103,789	97,592	123,217
WASHINGTON	2,110	5,708	9,496	13,601
OREGON	1,400	4,034	5,390	6,866
NEW HAMPSHIRE	453	1,956	2,242	2,181
MASSACHUSETTS	3,806	18,826	21,097	19,715
S. CAROLINA	1,390	6,220	7,075	6,799
RHODE ISLAND	723	3,782	4,192	3,841
GEORGIA	1,540	5,066	6,451	7,247
N. CAROLINA	7,646	40,573	44,628	40,398
NEW JERSEY	3,049	13,853	16,126	15,964
MARYLAND	1,320	5,344	6,417	6,652
DELAWARE	732	3,841	4,296	3,989
CONNECTICUT	1,953	9,540	10,786	10,215
MAINE	3,573	20,380	22,079	19,436
FLORIDA	84,609	131,746	153,428	170,076
OTHER STATES	6,800	15,671	26,022	36,886
TOTAL:	**668,462**	**1,138,567**	**1,262,035**	**1,403,877**

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Development Policy Case – Annual Gov't Revenue Impact by State (US$M)

	2015	2020	2025	2030
TEXAS	2,096	4,679	11,325	16,183
LOUISIANA	1,221	2,716	6,782	9,678
MISSISSIPPI	8	7	6	4
ALABAMA	1	3	6	6
ARKANSAS	32	85	116	152
KANSAS	4	12	49	75
OKLAHOMA	69	152	249	347
NEW MEXICO	239	346	260	365
COLORADO	528	990	995	1,285
N. DAKOTA	125	201	203	285
S. DAKOTA	0	0	0	1
WYOMING	1,056	1,576	992	1,283
UTAH	261	810	1,043	1,409
MONTANA	405	610	472	634
ILLINOIS	0	0	0	1
INDIANA	0	0	0	1
PENNSYLVANIA	72	178	242	310
VIRGINIA	53	100	919	1,332
KENTUCKY	0	2	4	5
OHIO	0.0	0.1	0.3	0

	2015	2020	2025	2,030
MICHIGAN	1	1	4	4
NEW YORK	189	1,161	2,182	2,893
WEST VIRGINIA	34	106	172	220
TENNESSEE	1	1	3	4
CALIFORNIA	476	851	7,868	12,460
ALASKA	1,703	5,968	13,045	21,856
WASHINGTON	10	17	168	266
OREGON	18	33	316	501
NEW HAMPSHIRE	6	11	102	147
MASSACHUSETTS	63	116	1,084	1,570
S. CAROLINA	19	27	332	481
RHODE ISLAND	13	24	226	327
GEORGIA	10	19	178	257
N. CAROLINA	142	262	2,454	3,554
NEW JERSEY	42	78	734	1,063
MARYLAND	15	27	253	366
DELAWARE	13	24	228	331
CONNECTICUT	31	58	542	785
MAINE	74	137	1,287	1,864
FLORIDA	1,134	6,407	12,772	17,465
TOTAL:	**10,165**	**27,796**	**67,613**	**99,769**

Lease Sales by Region ($M)	2015	2020	2025	2030
Rockies	1,656	1,873	0	0
ANWR	1,656	1,873	0	0
Atlantic OCS	552	624	706	0
East Gulf of Mexico	1,104	1,249	1,413	0
Pacific OCS	483	546	618	0
Central and West Gulf of Mexico	2,208	2,498	2,826	3,197

Projected Results by State and Policy

		Annual Production (mboed)					Total Jobs Supported (Upstream)					Total Government Revenue ($M)					State Government Revenue ($M)				
		2010	2015	2020	2025	2030	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030
AL	Current Path	36	26	22	24	17	10,283	7,469	6,478	6,998	5,031	40	46	55	66	51	25	20	19	23	18
	On-shore Regulatory		1	1	2	2		373	300	810	93		1	3	6	6		1	1	2	2
	Oil Sands Support							548	1,138	1,651	2,155										
	Incremental		1	1	2	2		922	1,438	2,460	2,249		1	3	6	6	0	1	1	2	2
	Development Policy	36	26	23	26	19	10,283	8,390	7,915	9,459	7,280	40	47	58	72	57	25	21	20	25	19
AK	Current Path	711	641	601	574	844	35,568	32,809	31,375	29,961	43,857	8,602	8,593	9,002	7,579	10,381	6,083	6,375	6,748	4,950	7,703
	Federal Access		14	573	1,270	1,623		52,885	103,583	97,248	122,728		1,703	5,968	13,045	21,856		645	1,808	2,647	3,694
	Oil Sands Support							89	206	345	490										
	Incremental		14	573	1,270	1,623		52,974	103,789	97,592	123,217		1,703	5,968	13,045	21,856	0	645	1,808	2,647	3,694
	Development Policy	711	655	1,174	1,844	2,467	35,568	85,783	135,164	127,553	167,074	8,602	10,297	14,970	20,624	32,237	6,083	7,020	8,556	7,597	11,397
AZ	Current Path	0	0	0	0	0	12,781	12,781	12,781	12,781	12,781	0	0	0	0	0	0	0	0	0	0
	Oil Sands Support							682	1,443	2,169	2,897										
	Incremental		0	0	0	0		682	1,443	2,169	2,897		0	0	0	0		0	0	0	0
	Development Policy	0	0	0	0	0	12,781	13,463	14,224	14,950	15,678	0	0	0	0	0	0	0	0	0	0
AR	Current Path	692	856	1,072	1,134	1,234	46,611	58,974	75,361	79,714	86,275	967	1,683	2,738	3,239	3,952	436	575	818	967	1,180
	On-shore Regulatory		17	33	41	48		3,912	7,269	6,516	6,629		32	85	116	152		11	25	35	46
	Oil Sands Support							311	652	948	1,241										
	Incremental		17	33	41	48		4,223	7,920	7,464	7,870		32	85	116	152	0	11	25	35	46
	Development Policy	692	873	1,106	1,175	1,281	46,611	63,197	83,281	87,178	94,145	967	1,715	2,823	3,355	4,105	436	586	843	1,002	1,226
CA	Current Path	887	647	516	438	410	104,217	97,167	93,231	92,778	90,206	5,631	3,950	3,798	3,832	3,882	1,278	890	846	848	863
	On-shore Regulatory		3	7	9	11		2,758	6,180	7,620	8,957		15	36	57	78		5	10	16	22
	Federal Access		0	98	682	1,039		18,545	69,249	92,344	119,286		460	815	7,811	12,383		171	299	1,106	1,491
	Oil Sands Support							5,030	10,769	16,618	22,573										
	Incremental		3	105	691	1,050		26,333	86,197	116,582	150,816		476	851	7,868	12,460		175	309	1,122	1,513
	Development Policy	887	650	620	1,129	1,459	104,217	123,501	179,429	209,360	241,022	5,631	4,426	4,648	11,700	16,343	1,278	1,065	1,156	1,971	2,376
CO	Current Path	1,111	1,065	1,192	1,306	1,359	118,879	116,539	133,132	145,834	151,055	3,020	3,891	5,369	6,600	7,834	1,289	1,534	1,884	2,311	2,743
	On-shore Regulatory		53	114	148	167		40,895	64,611	58,281	56,872		245	670	995	1,285		98	224	324	415
	Federal Access		14	28	36	42		18,993	20,652	20,234	20,422		283	320							
	Oil Sands Support							1,242	3,020	5,302	7,738										
	Incremental		68	141	184	208		61,131	88,283	83,817	85,032		528	990	995	1,285	0	98	224	324	415
	Development Policy	1,111	1,133	1,333	1,490	1,567	118,879	177,669	221,416	229,652	236,087	3,020	4,420	6,359	7,595	9,119	1,289	1,631	2,108	2,635	3,158

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Projected Results by State and Policy (continued)

		Annual Production (mboed)					Total Jobs Supported (Upstream)					Total Government Revenue ($M)					State Government Revenue ($M)				
		2010	2015	2020	2025	2030	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030
CT	Current Path	0	0	0	0	0	3,005	3,005	3,005	3,005	3,005	0	0	0	0	0	0	0	0	0	0
	Federal Access		0	10	53	84		1,438	8,441	9,091	7,914		31	58	542	785		12	22	80	101
	Oil Sands Support							515	1,099	1,695	2,301										
	Incremental		0	10	53	84		1,953	9,540	10,786	10,215		31	58	542	785	0	12	22	80	101
	Development Policy	0	0	10	53	84	3,005	4,958	12,545	13,791	13,220	0	31	58	542	785	0	12	22	80	101
DC	Current Path	0	0	0	0	0	581	581	581	581	581	0	0	0	0	0	0	0	0	0	0
	Oil Sands Support							155	359	606	867										
	Incremental		0	0	0	0		155	359	606	867		0	0	0	0		0	0	0	0
	Development Policy	0	0	0	0	0	581	736	940	1,187	1,448	0	0	0	0	0	0	0	0	0	0
DE	Current Path	0	0	0	0	0	522	522	522	522	522	0	0	0	0	0	0	0	0	0	0
	Federal Access		0	4	22	36		606	3,555	3,829	3,333		13	24	228	331		5	9	34	43
	Oil Sands Support							126	285	467	656										
	Incremental		0	4	22	36		732	3,841	4,296	3,989		13	24	228	331	0	5	9	34	43
	Development Policy	0	0	4	22	36	522	1,254	4,363	4,818	4,511	0	13	24	228	331	0	5	9	34	43
FL	Current Path	0	0	0	0	0	27,719	27,719	27,719	27,719	27,719	0	0	0	0	0	0	0	0	0	0
	Federal Access		0	621	1,187	1,620		82,642	127,486	146,940	161,332		1,134	6,407	12,772	17,465		425	1,169	2,209	2,215
	Oil Sands Support							1,967	4,260	6,488	8,745										
	Incremental		0	621	1,187	1,620		84,609	131,746	153,428	170,076		1,134	6,407	12,772	17,465	0	425	1,169	2,209	2,215
	Development Policy	0	0	621	1,187	1,620	27,719	112,328	159,465	181,147	197,795	0	1,134	6,407	12,772	17,465	0	425	1,169	2,209	2,215
GA	Current Path	0	0	0	0	0	2,469	2,469	2,469	2,469	2,469	0	0	0	0	0	0	0	0	0	0
	Federal Access		0	3	17	28		471	2,765	2,979	2,593		10	19	178	257		4	7	26	33
	Oil Sands Support							1,069	2,301	3,473	4,654										
	Incremental		0	3	17	28		1,540	5,066	6,451	7,247		10	19	178	257	0	4	7	26	33
	Development Policy	0	0	3	17	28	2,469	4,009	7,535	8,920	9,716	0	10	19	178	257	0	4	7	26	33
HI	Current Path	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Oil Sands Support							152	341	538	740										
	Incremental		0	0	0	0		152	341	538	740		0	0	0	0		0	0	0	0
	Development Policy	0	0	0	0	0	0	152	341	538	740	0	0	0	0	0	0	0	0	0	0

Projected Results by State and Policy (continued)

		Annual Production (mboed)					Total Jobs Supported (Upstream)					Total Government Revenue ($M)					State Government Revenue ($M)				
		2010	2015	2020	2025	2030	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030
ID	Current Path	0	0	0	0	0	1,948	1,948	1,948	1,948	1,948	0	0	0	0	0	0	0	0	0	0
	Oil Sands Support							189	380	531	674										
	Incremental		0	0	0	0		189	380	531	674		0	0	0	0		0	0	0	0
	Development Policy	0	0	0	0	0	1,948	2,137	2,328	2,479	2,622	0	0	0	0	0	0	0	0	0	0
IL	Current Path	4	3	3	4	5	30,320	24,507	22,238	37,582	46,575	1	4	6	11	15	1	1	1	1	2
	On-shore Regulatory		0	0	0	0		52	28	138	118		0	0	0	1		0	0	0	0
	Oil Sands Support							6,862	17,642	32,761	49,120										
	Incremental		0	0	0	0		6,914	17,670	32,899	49,237		0	0	0	1	0	0	0	0	0
	Development Policy	4	3	3	5	6	30,320	31,421	39,908	70,481	95,813	1	4	6	11	16	1	1	1	2	2
IN	Current Path	2	5	3	4	4	9,168	19,284	12,393	17,107	17,853	1	6	6	10	12	1	1	1	1	2
	On-shore Regulatory		0	0	0	0		185	5	209	168		0	0	1	1		0	0	0	0
	Oil Sands Support							994	2,032	2,968	3,890										
	Incremental		0	0	0	0		1,179	2,037	3,177	4,059		0	0	1	1	0	0	0	0	0
	Development Policy	2	5	3	4	4	9,168	20,463	14,430	20,284	21,912	1	7	7	11	13	1	1	1	1	2
IA	Current Path	0	0	0	0	0	1,512	1,512	1,512	1,512	1,512	0	0	0	0	0	0	0	0	0	0
	Oil Sands Support							437	884	1,251	1,604										
	Incremental		0	0	0	0		437	884	1,251	1,604		0	0	0	0		0	0	0	0
	Development Policy	0	0	0	0	0	1,512	1,949	2,396	2,763	3,116	0	0	0	0	0	0	0	0	0	0
KS	Current Path	222	116	81	88	88	67,469	36,157	25,610	27,875	27,729	310	229	206	251	282	140	78	62	75	84
	On-shore Regulatory		2	5	17	23		2,409	4,832	16,877	14,647		4	12	49	75		1	4	15	22
	Oil Sands Support							815	2,000	3,534	5,173										
	Incremental		2	5	17	23		3,224	6,832	20,411	19,820		4	12	49	75	0	1	4	15	22
	Development Policy	222	118	86	105	111	67,469	39,381	32,443	48,286	47,549	310	232	219	301	356	140	79	65	90	106
KY	Current Path	59	32	39	50	52	20,024	11,012	13,924	17,500	18,156	22	44	88	124	143	22	7	12	16	19
	On-shore Regulatory		0	1	2	2		352	989	1,258	1,005		0	2	4	5		0	0	1	1
	Oil Sands Support							524	1,081	1,564	2,038										
	Incremental		0	1	2	2		876	2,071	2,823	3,043		0	2	4	5	0	0	0	1	1
	Development Policy	59	32	41	51	54	20,024	11,888	15,994	20,323	21,199	22	44	90	128	148	22	7	12	17	20

Projected Results by State and Policy (continued)

		Annual Production (mboed)					Total Jobs Supported (Upstream)					Total Government Revenue ($M)					State Government Revenue ($M)				
		2010	2015	2020	2025	2030	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030
LA	Current Path	882	951	1,097	1,014	1,040	281,625	310,905	365,819	338,048	345,022	1,066	1,771	2,764	2,826	3,128	669	782	954	969	1,071
	On-shore Regulatory		182	275	275	299		25,547	36,439	26,759	28,476		338	693	767	901		471	609	686	788
	GoM Permitting		0	234	508	646		39,144	48,944	53,144	54,544		883	2,023	6,015	8,777					
	Oil Sands Support							944	2,281	3,982	5,794										
	Incremental		182	508	783	946		65,635	87,663	83,884	88,814		1,221	2,716	6,782	9,678	0	471	609	686	788
	Development Policy	882	1,133	1,605	1,797	1,985	281,625	376,540	453,482	421,933	433,836	1,066	2,991	5,480	9,608	12,805	669	1,253	1,563	1,655	1,859
ME	Current Path	0	0	0	0	0	638	638	638	638	638	0	0	0	0	0	0	0	0	0	0
	Federal Access		0	24	126	201		3,416	20,047	21,592	18,796		74	137	1,287	1,864		28	51	189	239
	Oil Sands Support							157	333	487	639										
	Incremental		0	24	126	201		3,573	20,380	22,079	19,436		74	137	1,287	1,864	0	28	51	189	239
	Development Policy	0	0	24	126	201	638	4,211	21,018	22,717	20,074	0	74	137	1,287	1,864	0	28	51	189	239
MD	Current Path	0	0	0	0	0	4,313	4,313	4,313	4,313	4,313	0	0	0	0	0	0	0	0	0	0
	Federal Access		0	5	25	39		671	3,936	4,239	3,691		15	27	253	366		5	10	37	47
	Oil Sands Support							649	1,408	2,177	2,962										
	Incremental		0	5	25	39		1,320	5,344	6,417	6,652		15	27	253	366	0	5	10	37	47
	Development Policy	0	0	5	25	39	4,313	5,633	9,657	10,730	10,965	0	15	27	253	366	0	5	10	37	47
MA	Current Path	0	0	0	0	0	2,111	2,111	2,111	2,111	2,111	0	0	0	0	0	0	0	0	0	0
	Federal Access		0	20	106	169		2,877	16,882	18,183	15,829		63	116	1,084	1,570		23	43	159	202
	Oil Sands Support							930	1,944	2,914	3,886										
	Incremental		0	20	106	169		3,806	18,826	21,097	19,715		63	116	1,084	1,570	0	23	43	159	202
	Development Policy	0	0	20	106	169	2,111	5,917	20,937	23,208	21,826	0	63	116	1,084	1,570	0	23	43	159	202
MI	Current Path	104	49	41	57	43	30,136	14,675	12,361	17,275	12,973	39	68	91	142	119	39	10	12	19	16
	On-shore Regulatory		0	1	2	1		515	207	991	373		1	1	4	4		0	0	1	0
	Oil Sands Support							1,913	4,218	6,775	9,424										
	Incremental		0	1	2	1		2,428	4,426	7,766	9,797		1	1	4	4	0	0	0	1	0
	Development Policy	104	49	42	59	44	30,136	17,103	16,787	25,041	22,770	39	69	92	146	122	39	10	12	19	16
MN	Current Path	0	0	0	0	0	4,551	4,551	4,551	4,551	4,551	0	0	0	0	0	0	0	0	0	0
	Oil Sands Support							796	1,675	2,499	3,322										
	Incremental		0	0	0	0		796	1,675	2,499	3,322		0	0	0	0		0	0	0	0
	Development Policy	0	0	0	0	0	4,551	5,347	6,226	7,050	7,873	0	0	0	0	0	0	0	0	0	0

Projected Results by State and Policy (continued)

		Annual Production (mboed)					Total Jobs Supported (Upstream)					Total Government Revenue ($M)					State Government Revenue ($M)				
		2010	2015	2020	2025	2030	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030
MS	Current Path	125	106	80	58	39	28,980	25,126	19,294	13,985	9,252	326	345	242	166	116	187	170	101	61	40
	On-shore Regulatory		2	2	2	1		485	570	378	151		8	7	6	4		1	2	2	1
	Oil Sands Support							330	708	1,060	1,413										
	Incremental		2	2	2	1		815	1,278	1,438	1,564		8	7	6	4	0	1	2	2	1
	Development Policy	125	109	82	60	40	28,980	25,941	20,573	15,423	10,817	326	352	249	171	120	187	171	103	63	42
MO	Current Path	0	0	0	0	0	11,553	11,553	11,553	11,553	11,553	0	0	0	0	0	0	0	0	0	0
	Oil Sands Support							714	1,499	2,195	2,883										
	Incremental		0	0	0	0		714	1,499	2,195	2,883		0	0	0	0		0	0	0	0
	Development Policy	0	0	0	0	0	11,553	12,267	13,052	13,748	14,436	0	0	0	0	0	0	0	0	0	0
MT	Current Path	112	95	88	89	93	10,832	9,335	8,877	8,938	9,316	305	345	397	448	535	165	165	168	191	228
	On-shore Regulatory		20	33	44	54		5,441	5,794	6,000	6,486		121	290	472	634		55	91	158	210
	Federal Access		14	28	36	42		18,993	20,652	20,234	20,422		283	320							
	Oil Sands Support							1,311	3,529	6,784	10,331										
	Incremental		34	61	81	95		25,745	29,975	33,017	37,239		405	610	472	634	0	55	91	158	210
	Development Policy	112	128	149	169	188	10,832	35,080	38,851	41,955	46,554	305	750	1,007	920	1,169	165	219	259	349	439
NE	Current Path	0	0	0	0	0	3,095	3,095	3,095	3,095	3,095	0	0	0	0	0	0	0	0	0	0
	Oil Sands Support							240	503	735	964										
	Incremental		0	0	0	0		240	503	735	964		0	0	0	0		0	0	0	0
	Development Policy	0	0	0	0	0	3,095	3,335	3,598	3,830	4,059	0	0	0	0	0	0	0	0	0	0
NV	Current Path	0	0	0	0	0	4,248	4,248	4,248	4,248	4,248	0	0	0	0	0	0	0	0	0	0
	Oil Sands Support							310	692	1,077	1,471										
	Incremental		0	0	0	0		310	692	1,077	1,471		0	0	0	0		0	0	0	0
	Development Policy	0	0	0	0	0	4,248	4,558	4,940	5,325	5,719	0	0	0	0	0	0	0	0	0	0
NH	Current Path	0	0	0	0	0	879	879	879	879	879	0	0	0	0	0	0	0	0	0	0
	Federal Access		0	2	10	16		270	1,583	1,705	1,484		6	11	102	147		2	4	15	19
	Oil Sands Support							184	373	537	697										
	Incremental		0	2	10	16		453	1,956	2,242	2,181		6	11	102	147	0	2	4	15	19
	Development Policy	0	0	2	10	16	879	1,332	2,835	3,121	3,060	0	6	11	102	147	0	2	4	15	19

Projected Results by State and Policy (continued)

		Annual Production (mboed)					Total Jobs Supported (Upstream)					Total Government Revenue ($M)					State Government Revenue ($M)				
		2010	2015	2020	2025	2030	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030
NJ	Current Path	0	0	0	0	0	5,359	5,359	5,359	5,359	5,359	0	0	0	0	0	0	0	0	0	0
	Federal Access		0	14	72	114		1,948	11,430	12,311	10,717		42	78	734	1,063		16	29	108	137
	Oil Sands Support							1,101	2,423	3,815	5,246										
	Incremental		0	14	72	114		3,049	13,853	16,126	15,964		42	78	734	1,063	0	16	29	108	137
	Development Policy	0	0	14	72	114	5,359	8,408	19,212	21,485	21,323	0	42	78	734	1,063	0	16	29	108	137
NM	Current Path	885	668	565	596	603	58,535	45,182	38,970	41,128	41,421	3,132	2,810	2,886	3,424	3,901	1,004	934	867	1,038	1,189
	On-shore Regulatory		5	7	17	24		1,956	2,023	1,658	1,352		54	136	260	365		21	39	71	98
	Federal Access		9	18	24	27		12,440	13,526	13,252	13,376		185	210							
	Oil Sands Support							207	436	650	865										
	Incremental		14	25	41	51		14,603	15,986	15,561	15,592		239	346	260	365	0	21	39	71	98
	Development Policy	885	682	589	637	654	58,535	59,785	54,955	56,689	57,013	3,132	3,049	3,232	3,684	4,265	1,004	955	906	1,108	1,287
NY	Current Path	31	10	7	8	2	14,811	14,811	14,811	14,811	14,811	12	14	16	20	6	12	2	2	3	1
	On-shore Regulatory & Fed Access (incl Moratorium)		319	522	661	789		29,905	42,699	42,737	38,932		189	1,161	2,182	2,893		81	173	301	381
	Oil Sands Support							2,336	5,118	8,086	11,141										
	Incremental		319	522	661	789		32,241	47,817	50,823	50,072		189	1,161	2,182	2,893		81	173	301	381
	Development Policy	31	329	529	669	791	14,811	47,052	62,628	65,634	64,883	12	203	1,177	2,202	2,899	12	83	175	304	382
NC	Current Path	0	0	0	0	0	4,834	4,834	4,834	4,834	4,834	0	0	0	0	0	0	0	0	0	0
	Federal Access		0	45	240	382		6,513	38,218	41,164	35,834		142	262	2,454	3,554		53	98	361	456
	Oil Sands Support							1,133	2,355	3,464	4,564										
	Incremental		0	45	240	382		7,646	40,573	44,628	40,398		142	262	2,454	3,554	0	53	98	361	456
	Development Policy	0	0	45	240	382	4,834	12,480	45,407	49,462	45,232	0	142	262	2,454	3,554	0	53	98	361	456
ND	Current Path	376	812	876	913	1,056	33,098	73,127	80,489	83,857	96,553	1,022	2,968	3,946	4,614	6,088	450	1,197	1,417	1,654	2,183
	On-shore Regulatory		19	27	32	40		9,939	12,264	12,501	15,414		78	148	203	285		32	51	68	96
	Federal Access		2	5	6	7		3,110	3,382	3,313	3,344		46	52							
	Oil Sands Support							95	195	279	361										
	Incremental		22	32	38	47		13,144	15,840	16,093	19,119		125	201	203	285	0	32	51	68	96
	Development Policy	376	834	908	951	1,103	33,098	86,272	96,329	99,950	115,672	1,022	3,093	4,147	4,817	6,373	450	1,229	1,468	1,723	2,279
OH	Current Path	5	2	1	2	0	48,111	16,608	14,428	21,134	0	2	2	3	5	0	2	0	0	1	0
	On-shore Regulatory		0	0	0	0		13	53	172	93		0	0	1	0		0	0	0	0
	Oil Sands Support							2,738	6,384	10,814	15,491										
	Incremental		0	0	0	0		2,751	6,437	10,986	15,585		0	0	1	0		0	0	0	0
	Development Policy	5	2	1	2	0	48,111	19,360	20,865	32,119	15,585	2	2	3	6	0	2	0	0	1	0

Projected Results by State and Policy (continued)

		Annual Production (mboed)					Total Jobs Supported (Upstream)					Total Government Revenue ($M)					State Government Revenue ($M)				
		2010	2015	2020	2025	2030	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030
OK	Current Path	1,211	1,122	1,065	1,159	1,264	239,883	227,378	220,403	239,820	260,264	1,692	2,204	2,720	3,311	4,051	762	753	812	989	1,210
	On-shore Regulatory		35	59	87	108		7,094	10,547	13,303	14,818		69	152	249	347		24	45	74	104
	Oil Sands Support							487	1,026	1,522	2,018										
	Incremental		35	59	87	108		7,581	11,572	14,826	16,836		69	152	249	347		24	45	74	104
	Development Policy	1,211	1,157	1,125	1,246	1,373	239,883	234,959	231,975	254,646	277,100	1,692	2,273	2,872	3,559	4,398	762	776	858	1,063	1,313
OR	Current Path	0	0	0	0	0	3,143	3,143	3,143	3,143	3,143	0	0	0	0	0	0	0	0	0	0
	Federal Access		0	4	28	42		752	2,809	3,745	4,838		18	33	316	501		7	12	45	60
	Oil Sands Support							648	1,225	1,645	2,028										
	Incremental		0	4	28	42		1,400	4,034	5,390	6,866		18	33	316	501		7	12	45	60
	Development Policy	0	0	4	28	42	3,143	4,543	7,177	8,533	10,009	0	18	33	316	501	0	7	12	45	60
PA	Current Path	441	1,771	2,271	2,566	2,848	121,783	184,719	236,870	267,677	296,217	167	2,438	5,051	6,386	7,862	167	365	674	852	1,049
	On-shore Regulatory		52	80	97	112		14,403	17,423	18,696	19,390		72	178	242	310		11	24	32	41
	Oil Sands Support							1,509	3,206	4,816	6,434										
	Incremental		52	80	97	112		15,912	20,629	23,512	25,824		72	178	242	310		11	24	32	41
	Development Policy	441	1,824	2,351	2,663	2,961	121,783	200,630	257,499	291,189	322,042	167	2,510	5,229	6,629	8,172	167	376	697	884	1,090
RI	Current Path	0	0	0	0	0	548	548	548	548	548	0	0	0	0	0	0	0	0	0	0
	Federal Access		0	4	22	35		599	3,517	3,788	3,298		13	24	226	327		5	9	33	42
	Oil Sands Support							123	265	404	544										
	Incremental		0	4	22	35		723	3,782	4,192	3,841		13	24	226	327		5	9	33	42
	Development Policy	0	0	4	22	35	548	1,271	4,330	4,740	4,389	0	13	24	226	327	0	5	9	33	42
SC	Current Path	0	0	0	0	0	2,811	2,811	2,811	2,811	2,811	0	0	0	0	0	0	0	0	0	0
	Federal Access		0	6	32	52		881	5,171	5,570	4,849		19	35	332	481		7	13	49	62
	Oil Sands Support							508	1,049	1,505	1,950										
	Incremental		0	6	32	52		1,390	6,220	7,075	6,799		19	35	332	481		7	13	49	62
	Development Policy	0	0	6	32	52	2,811	4,201	9,031	9,886	9,610	0	19	35	332	481	0	7	13	49	62
SD	Current Path	4	3	2	3	3	1,881	1,214	1,000	1,310	1,585	11	9	9	14	19	5	4	3	5	7
	On-shore Regulatory		0	0	0	0		15	12	36	43		0	0	0	1		0	0	0	0
	Oil Sands Support							110	227	327	423										
	Incremental		0	0	0	0		125	240	363	466		0	0	0	1		0	0	0	0
	Development Policy	4	3	2	3	3	1,881	1,339	1,240	1,673	2,050	11	9	9	14	19	5	4	3	5	7

Projected Results by State and Policy (continued)

		Annual Production (mboed)					Total Jobs Supported (Upstream)					Total Government Revenue ($M)					State Government Revenue ($M)				
		2010	2015	2020	2025	2030	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030
TN	Current Path	3	5	3	5	5	6,762	10,100	7,557	10,990	12,107	1	6	7	12	15	1	1	1	2	2
	On-shore Regulatory		1	1	1	1		725	191	867	725		1	1	3	4		0	0	0	0
	Oil Sands Support							808	1,656	2,378	3,082										
	Incremental		1	1	1	1		1,534	1,848	3,245	3,808		1	1	3	4		0	0	0	0
	Development Policy	3	5	4	6	7	6,762	11,634	9,405	14,235	15,915	1	7	9	15	18	1	1	1	2	2
TX	Current Path	5,110	5,365	5,521	5,621	5,880	939,167	1,008,652	1,059,378	1,078,627	1,122,682	9,728	11,884	16,018	18,601	22,030	4,135	4,678	5,221	6,045	7,109
	On-shore Regulatory		348	567	696	806		47,400	69,880	67,479	72,899		772	1,645	2,302	3,018		304	536	748	974
	GoM Permitting		0	350	762	970		58,716	73,416	79,716	81,816		1,325	3,035	9,023	13,165		496	562	636	719
	Oil Sands Support							4,017	8,929	14,344	19,955										
	Incremental		348	917	1,458	1,775		110,133	152,225	161,539	174,670		2,096	4,679	11,325	16,183	0	800	1,098	1,384	1,693
	Development Policy	5,110	5,713	6,438	7,079	7,655	939,167	1,118,785	1,211,604	1,240,166	1,297,352	9,728	13,980	20,698	29,926	38,213	4,135	5,478	6,319	7,429	8,802
UT	Current Path	341	320	419	434	465	27,043	25,960	34,687	35,945	38,280	927	1,170	1,888	2,195	2,679	389	455	653	758	925
	On-shore Regulatory		56	162	198	235		23,124	45,238	33,791	37,531		215	757	1,043	1,409		84	260	356	481
	Federal Access		2	5	6	7		3,110	3,382	3,313	3,344		46	52							
	Oil Sands Support							320	685	1,028	1,373										
	Incremental		59	167	204	242		26,554	49,304	38,132	42,248		261	810	1,043	1,409	0	84	260	356	481
	Development Policy	341	379	586	639	707	27,043	52,514	83,991	74,078	80,528	927	1,431	2,698	3,239	4,088	389	538	913	1,114	1,405
VT	Current Path	0	0	0	0	0	539	539	539	539	539	0	0	0	0	0	0	0	0	0	0
	Oil Sands Support							78	163	235	306										
	Incremental		0	0	0	0		78	163	235	306		0	0	0	0		0	0	0	0
	Development Policy	0	0	0	0	0	539	617	702	774	845	0	0	0	0	0	0	0	0	0	0
VA	Current Path	112	58	53	80	91	15,456	15,456	15,456	15,456	15,456	42	80	118	199	252	42	12	16	27	34
	On-shore Regulatory		1	1	3	3		249	149	702	575		0	0	1	1		0	0	1	1
	Federal Access		0	17	89	142		2,423	14,221	15,317	13,334		54	99	919	1,331		20	46	208	284
	Oil Sands Support							934	2,032	3,143	4,277										
	Incremental		1	18	92	146		3,606	16,401	19,163	18,185		54	100	920	1,332	0	20	46	209	285
	Development Policy	112	58	71	172	237	15,456	19,062	31,857	34,619	33,641	42	133	218	1,119	1,584	42	32	62	235	319
WA	Current Path	0	0	0	0	0	6,204	6,204	6,204	6,204	6,204	0	0	0	0	0	0	0	0	0	0
	Federal Access		0	2	15	22		399	1,490	1,987	2,566		10	17	168	266		4	6	24	32
	Oil Sands Support							1,711	4,218	7,510	11,035										
	Incremental		0	2	15	22		2,110	5,708	9,496	13,601		10	17	168	266		4	6	24	32
	Development Policy	0	0	2	15	22	6,204	8,314	11,912	15,700	19,805	0	10	17	168	266	0	4	6	24	32

Projected Results by State and Policy (continued)

		Annual Production (mboed)					Total Jobs Supported (Upstream)					Total Government Revenue ($M)					State Government Revenue ($M)				
		2010	2015	2020	2025	2030	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030
WV	Current Path	198	195	232	280	300	45,378	45,697	55,462	66,965	71,284	75	269	516	697	827	75	40	69	93	110
	On-shore Regulatory		25	48	69	80		5,320	6,677	8,143	7,265		34	106	172	220		5	14	23	29
	Oil Sands Support							168	360	540	720										
	Incremental		25	48	69	80		5,487	7,037	8,683	7,986		34	106	172	220		5	14	23	29
	Development Policy	198	220	280	349	379	45,378	51,185	62,499	75,648	79,269	75	303	622	869	1,047	75	45	83	116	140
WI	Current Path	0	0	0	0	0	2,860	2,860	2,860	2,860	2,860	0	0	0	0	0	0	0	0	0	0
	Oil Sands Support							3,046	7,732	14,189	21,157										
	Incremental		0	0	0	0		3,046	7,732	14,189	21,157		0	0	0	0		0	0	0	0
	Development Policy	0	0	0	0	0	2,860	5,906	10,592	17,049	24,017	0	0	0	0	0	0	0	0	0	0
WY	Current Path	1,455	1,452	1,627	1,706	1,731	68,944	70,383	80,493	84,382	85,228	3,954	5,306	7,329	8,622	9,980	1,576	1,984	2,440	2,859	3,309
	On-shore Regulatory		28	46	56	61		6,780	7,738	7,755	7,891		245	658	992	1,283		97	196	273	342
	Federal Access		41	79	104	119		54,425	59,177	57,980	58,519		811	918							
	Oil Sands Support							84	195	320	451										
	Incremental		69	125	160	180		61,289	67,110	66,054	66,862		1,056	1,576	992	1,283	0	97	196	273	342
	Development Policy	1,455	1,521	1,753	1,866	1,912	68,944	131,672	147,603	150,436	152,090	3,954	6,362	8,905	9,614	11,263	1,576	2,081	2,636	3,132	3,652

GEM Tool Description

The Global Economic Model (GEM) is Wood Mackenzie's proprietary economic modeling software

- GEM combines Wood Mackenzie's unique and proprietary data, both historic and forecast, with company interests, price decks and fiscal models to produce cash flow and valuation reports. It contains more than 190 fiscal regimes covering the globe
- GEM generates cash flow and production forecasts based on user input development plans. These include drilling forecasts and assumed type well profiles and well costs for onshore U.S. plays. For offshore developments, Alaska and the Canadian oil sands, production facilities and export pipelines are also included
- GEM includes a sensitivity tool to show the economics impact of changes in costs, taxes, production and prices. Outputs include cash flow summaries, IRR, NPV and $/boe calculations
- Wood Mackenzie has developed cost, tax and production data in the following productive regions:
    - Alaska – 57 fields
    - Gulf of Mexico – 212 fields
    - Canadian oil sands – 25 projects
    - Onshore U.S. – 245 plays

Tax Assumptions

- Models included the following assumptions:
  - Federal royalty rates modelled at 12.5%
  - Federal income tax modelled at 35%
- Wood Mackenzie's commodity price forecast was used. For all new Access region models, oil was priced at WTI, gas was priced at Henry Hub (HH). Oil price forecast was $80/bbl in 2012 inflating at 2.50%. Gas price forecast was $6.00/mcf in 2012 inflating at 2.50%
- In the Atlantic and Pacific OCS regions royalties were split with 37.5/62.5 between the states and the federal government respectively. In Alaska federal areas the royalty split with the state was 50/50.
- Production and revenue from new access regions were split by state according to the following:
  - Atlantic OCS – Maine 13%, New Hampshire 1%, Massachusetts 11%, Rhode Island 2%, Connecticut 6%, New York 7%, New Jersey 8%, Delaware 2%, Maryland 3%, Virginia 10%, North Carolina 26%, South Carolina 3%, Georgia 2%, Florida 5%
  - Pacific OCS – California 94%, Oregon 4%, Washington 2%
  - East Gulf of Mexico – Florida 100%
  - Rockies – Colorado 27.0%, North Dakota 19.4%, South Dakota 0.1%, Wyoming 31.7%, Utah 12.4%, New Mexico 6.8%, Montana 2.6%
- For the existing producing areas; Gulf of Mexico, Alaska and onshore U.S., Wood Mackenzie has modeled each producing field or play by its applicable state and federal royalty
- Other state taxes, such as Ad Valorem, Severance Taxes, and fee royalties have been applied which applicable

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