North Carolina Department of Environment and Natural Resources

Pat McCrory
Governor

John E. Skvarla, III
Secretary

MEMORANDUM

TO: ENVIRONMENTAL REVIEW COMMISSION
The Honorable Brent Jackson, Chairman
The Honorable Ruth Samuelson, Co-Chairman
The Honorable Mike Hager, Co-Chairman

JOINT LEGISLATIVE COMMISSION ON ENERGY POLICY
The Honorable Bob Rucho, Co-Chairman
The Honorable Mike Hager, Co-Chairman

SENATE APPROPRIATIONS SUBCOMMITTEE ON NATURAL AND ECONOMIC RESOURCES
The Honorable Andrew C. Brock, Co-Chairman
The Honorable Brent Jackson, Co- Chairman

HOUSE APPROPRIATIONS SUBCOMMITTEE ON NATURAL AND ECONOMIC RESOURCES
The Honorable Tom Murry, Chairman
The Honorable Roger West, Chairman
The Honorable Jimmy Dixon, Vice-Chairman
The Honorable Garland E. Pierce, Vice-Chairman
The Honorable Michele D. Presnell, Vice-Chairwoman

FISCAL RESEARCH DIVISION
Mark Trogdon, Director

FROM: Jim Womack
Chairman of the North Carolina Mining and Energy Commission

SUBJECT: Funding Levels and Potential Funding Sources Study Group Report

DATE: October 1, 2013

Pursuant to Session Law 2012-143 Section 2(j), the North Carolina Mining and Energy Commission examined funding needs and potential funding sources to support a state oil and gas regulatory program and to address impacts to infrastructure and local governments resulting from oil and gas development activities. Please consider submission of the attached report as the Commission's fulfillment of requirements under respective session law.

If you have any questions or need additional information, please contact me by phone at (919) 770-4783 or via e-mail at commissioner.womack@gmail.com.

cc: Mitch Gillespie, Assistant Secretary for Environment
Neal Robbins Director of Legislative Affairs
Carr McLamb, Deputy Director of Legislative Affairs
Fred F. Steen, Office of the Governor
Jennifer Hoffman, Fiscal Research Division
Tracy Davis, Director, Division of Energy, Mineral, and Land Resources

Funding Levels and Potential Funding Sources Study Group
Final Report- September 2013
Session Law 2012-143

Mining and Energy Commission Members:

- Jane Lewis-Raymond, Director
- George Howard
- Dr. Vikram Rao
- James Womack

Additional Members:

- Jennifer Brandenburg, N.C. DOT
- Judith Corley-Lay, N.C. DOT
- Brandon Jones, N.C. DOT
- Ward Lenz, State Energy Office
- Emily McGraw, N.C. DOT
- Johanna Reese, N.C. Association of County Commissioners
- Kenneth Snead, N.C. Highway Patrol
- Erin Wynia, N.C. League of Municipalities

Table of Contents

I. Introduction

This study group report is in response to Senate Bill 820 from the North Carolina General Assembly's short session in 2012, which became Session Law 2012-143. The study is sanctioned under SECTION 2.(j) of that bill which states: "The Mining and Energy Commission, in conjunction with the Department of Environment and Natural Resources, the Department of Transportation, the North Carolina League of Municipalities, and the North Carolina Association of County Commissioners, shall identify appropriate levels of funding and potential sources for that funding, including permit fees, bonds, taxes, and impact fees, necessary to (i) support local governments impacted by the industry and associated activities; (ii) address expected infrastructure impacts, including, but not limited to, repair of roads damaged by truck traffic and heavy equipment; (iii) cover any costs to the State for administering an oil and gas regulatory program, including remediation and reclamation of drilling sites when necessary due to abandonment or insolvency of an oil or gas operator or other responsible party; and (iv) any other issues that may need to be addressed in the Commission's determination. Any recommendation concerning local impact fees shall be formulated to require that all such fees be used exclusively to address infrastructure impacts from the drilling operation for which a fee is imposed. The Commission shall report its findings and recommendations, including legislative proposals, to the Joint Legislative Commission on Energy Policy, created under Section 6(a) of this act, and the Environmental Review Commission on or before January 1, 2013" [subsequently changed to October 1, 2013].

Pursuant to the provisions of this session law, the Chairman of the Mining and Energy Commission (MEC) appointed MEC Commissioner Jane Lewis-Raymond to direct the work of this study group, to be assisted by Commissioner George Howard, Commissioner Vikram Rao, and Commissioner James Womack. The Department of Environment and Natural Resources (DENR) professional staff assigned to assist in the preparation of the report included Katherine Marciniak as the primary contact with her counterparts in the Division of Energy, Minerals, and Land Resources (DEMLR) to assist as necessary. Several other state officials, association representatives, and private sector participants were appointed to be primary participants in the research and deliberation of this report. They included Jennifer Brandenburg with the North Carolina Department of Transportation (NCDOT), Judith Corley-Lay (NCDOT), Brandon Jones (NCDOT), Emily McGraw (NCDOT), Ward Lenz (Department of Commerce- State Energy Office), Johanna Reese (N.C. Association of County

Commissioners), Kenneth Snead (N.C. Highway Patrol), and Erin Wynia (N.C. League of Municipalities).

The Study Group has completed extensive review and analysis of the oil and gas drilling cost experiences in a number of other states, with a heavy emphasis on states with comparable recent experiences (Arkansas and Pennsylvania in particular). This report addresses each of the requirements specified under section 2.(j) of Session Law 2012-143 in light of those experiences as well North Carolina's present readiness to regulate and administer this industry in the coming years. This report is crafted in such a manner as to follow the structure of the statutory language and identify each of the known and measurable costs we anticipate that state agencies and local jurisdictions may experience as the shale oil and gas industry matures in the Triassic basins across 14 counties in North Carolina. The report does not attempt to project the state and local costs associated with any expansion of the industry beyond those geographic regions.

The report fulfills the Study Group's statutory requirements to identify sources of revenues- including taxes, fees, and bonds -to accomplish full recovery for state and local costs. Recent legislative initiatives to create severance taxes that generate additional revenue streams that go beyond cost recovery were not mandated for this study, and therefore have not been included in the group's deliberations or recommendations.

II. Executive Summary

The Study Group spent considerable time over the course of eleven meetings determining the potential costs and identifying the potential sources of funding to adequately fund the costs associated with developing and implementing a modern oil and gas industry in North Carolina. The main sources for funding include permit fees, bonds, taxes, and impact fees. The Study Group's major recommendations are:

A. Impact Fees to Cover Costs to Local Governments:

For local government cost recovery, other than transportation infrastructure upgrades and repair, the Study Group recommends that a permittee be required to pay an impact fee that comports with the level of industrial activity for a given well. The impact fees would be paid into a state trust fund from which impacted entities could apply for disbursement to fund necessary improvements. Additionally, the Study Group recognizes the need to sustain local taxing methods, such as *ad valorem* taxes.

B. Bonds and Local Permit Fees to Cover Costs for Local Transportation Infrastructure:

To recover the costs associated with impact to local transportation infrastructure, the Study Group recommends a bond and permit system modeled after the one in Pennsylvania.

C. Severance Tax to Cover State Program Costs:

The Study Group recommends that a severance tax be used to fund the direct costs to the State for implementing and overseeing an active oil and gas regulatory program. These total estimated costs for the Department of Environment and Natural Resources are expected to be approximately $1.6-1.9 million annually. The costs for the Department of Transportation are estimated to be approximately $70,000 to nearly $1 million per year, depending on the estimated level of natural gas production activity in the state. See Table V.I. The projected NCDOT costs therefore illustrate a ramp up in activity over a 7-year period. The recommended severance tax rate is 1.5%. In addition, the Study Group recognizes the contribution from the existing state severance tax of 5% on the value of produced natural gas liquids and recommends no change to this severance tax. In addition, the Study Group recognizes the contribution from the existing state severance tax of 5% on the value of produced natural gas liquids and recommends no change to this severance tax.

Additionally, a statutory fee of $3,000 for well-permit applications currently exists and the Study Group recommends no change to this fee.

As the level of activity in oil and gas production in the state will increase with time, the Study Group recommends that the General Assembly initially fund the costs associated with the Oil and Gas program as noted above with general appropriated funds during the initial years.

D. Bonds:

The Study Group recommends a comprehensive bonding program to consist of the following types of required bonds: a surface owner bond, geophysical exploration bond, well plugging and abandonment bond, and a site reclamation bond.

III. Local Government Cost

To help determine potential costs to local governments, staff from the NC Association of County Commissioners and the NC League of Municipalities contacted local governments in states with a more established oil and gas industry. The majority of costs in those states were incurred through upgrades and repairs to transportation infrastructure, but the industry also necessitated expenditures in the infrastructure areas of emergency preparedness, public safety, and registers of deeds work, with minimal increases in other services.

It is anticipated that local governments will experience increased costs associated with:

- Transportation infrastructure upgrades & repair;
- Waste handling;
- Hazmat training;
- Emergency response;
- Training of local government staff – tax assessors, registers of deeds, inspectors/code compliance officers;
- Increase in local government personnel or overtime needed – tax assessors, registers of deeds, well testers, inspectors/code compliance officers;
- Drinking water well testing; and
- Increase in local government personnel or overtime needed – tax and transportation assessors, registers of deeds, well testers, inspectors/code compliance officers, public safety officers.

Some of these increased costs may be recovered by a growing property tax base, however other costs could be beyond that for which local government funds can be available; or simply may be unforeseen.

For these reasons, the Study Group recommends an impact fee be assessed and a process established whereby local governments experiencing increased infrastructure costs can apply for funds to cover said costs with appropriate justification.

A. Property Taxation:

Local governments assess and collect property taxes on real estate, personal and business property, and severed mineral rights. In accordance with the MEC's Local Government Regulation Study Group, the Funding Levels and Potential Funding Sources Study Group recommends that local authorities consider the following strategies for cost recovery:

- *Ad valorem* taxation;
- Implementing a standard approach for the taxation of severed mineral rights;
- Taxing of mineral rights only when resources are exploited;
- Taxing of oil and gas operational equipment being stored on-site;
- Use taxing of joint surface and mineral rights at the time of property sale; and
- Local governments implementing a special use permitting program should be aware of the potential for land-owner abuse of a "present value" designation to avoid taxation on the production of subsurface resources.

The Study Group also encourages local governments to exercise their authority related to the taxing of personal (business) property owned or used by oil and gas operators. DEMLR staff compiled the following details regarding this form of taxation within several Triassic Basin counties:

- Taxing of personal property by local governments is in accordance with the North Carolina Machinery Act;
- All business property, except vehicles tagged in other states, is subject to taxation. Thus, drilling rigs, storage tanks, well equipment, etc. are all taxable assets;
- Personal business property that exists within a county on January 01 of a given year is subject to taxation for that entire year;
- No time limits or time requirements exist regarding taxation eligibility;
- Any business must provide the respective county with a list of its personal property;
- Tax rates are assessed per every $100 value of personal or business property;
- Personal or business property is also subject to taxation from towns, cities, and fire districts. These taxes are supplemental to those already levied by counties;
- Tax rate amounts vary for the following Triassic Basin counties:
    i. <u>Rockingham County</u>: $0.6960 per every $100.

ii. Stokes County: $0.6400 per every $100, plus and education tax of $0.04 per every $100.
iii. Chatham County: $0.6219 per every $100.
iv. Lee County: $0.7200 per every $100.
v. Fire Districts and Towns: Range from $0.07 to $0.40 per every $100.

- Personal property tax bills are generally sent in September and are delinquent in January of the following year; and
- The likelihood of an oil or gas operator moving equipment from one county into another to take advantage of a lower tax rate is low. This is due primarily to operational and logistical costs and complexities associated with mobilization of equipment.

B. Impact Fees As Cost Recovery Mechanism:

Early discussions among the Study Group focused on how best to meet the cost needs of local governments from the timing of the initial establishment through operations of the oil and gas industry in North Carolina. The Study Group examined other states' cost recovery mechanisms, many of which rely on severance taxes and bonds, or localized fee structures. This localized model of each individual government assessing an impact fee on businesses operating within its jurisdiction was determined by the Study Group to be impractical, and potentially duplicative in its implementation; impacts to each government would vary drastically, particularly considering that municipalities, but not counties, would be responsible for repair to damage of transportation infrastructure.

Alternatively, the Study Group determined that the best means by which to allow for otherwise uncovered costs was to asses an impact fee that would be collected and maintained at the state level at the time of permitting. The Study Group further studied the basis for such a fee, and determined that tying the fee to the price of natural gas or the actual production volumes from a given well did not fairly account for the actual impact of oil and gas operations, and further could fluctuate based on that price in a manner that could be completely disassociated with activity and therefore local impacts.

Accordingly, the Study Group recommends that permittee be required to pay an impact fee that comports with the level of industrial activity for a given well, as opposed to the production from that well or the price of the commodity. In this way, the impact fee is tied more directly to costs created by what will be a new oil and gas industry in the state, as opposed to the value of the production, which can fluctuate. The fee would then go into a central fund managed at the state level, designated for local government impacts, and kept separate from the severance tax that would fund state expenses (see discussion of Severance Tax below).

Counties and municipalities could access this source of funds through an application process. Costs not eligible to be reimbursed in this process necessarily would be costs associated with transportation infrastructure damage, for which the Study Group recommends a separate bond and permit process in Section B below. The application would require justification and documentation to demonstrate the costs for which the requested funds would be used to cover or recover and that these same costs would not exist otherwise. While the standard means of distribution of funds to a successful applicant would be by reimbursement, the Study Group recommends that an option for advancement of funds should be available if a local government can demonstrate need.

In order to arrive at a recommended impact fee, the Study Group reviewed several proxies for which local activity for oil and gas industrial activities could be assessed. The Study Group arrived at the conclusion that impact is most determined by the number of fracturing stages per well because of the correlation between fracturing stages and local activity or “truck trips”; the more stages per well, the more time the well takes to be fully operational, thus the more overall activity in the local area due to projected “truck trips”. The N.C. Geological Survey provided an assessment of hydrocarbon operations in Ohio that indicated that gas wells typically have 30 or more individual hydraulic fracturing stages.

The Study Group recommends the implementation of a two-part impact fee. The first part of the fee is designed to recover the local costs that may rise simply by virtue of the fact that the well is being drilled; while the second part of the fee is designed to recover local costs that may vary based on the number of fracturing stages in a given well. The following fee structure would allow for cost recovery from both hydraulically fractured and non-hydraulically fractured wells:

1. An initial flat fee of $2,000 for the development of each well pad; and
2. A second fee of $1,800 multiplied by the number of hydraulic fracturing stages per each wellbore on a given pad; or

An operator could apply a second fee rate of $900 for the number of liquid-free fracturing stages per each wellbore on a given pad if other methods besides water were used for hydraulic fracturing. This reduced fee would encourage the use of liquid free technology for well stimulation which would result in less infrastructure damage.

The Study Group also discussed the process by which a State entity could collect and disburse impact fee monies. The Study Group looked to the DENR's Division of Waste Management (DWM) - Underground Storage Tank (UST) Trust Fund system for a model approach. The DWM-UST program manages a trust fund system, which was established under requirement of federal regulation, 40 CFR 20, to reimburse impacted entities for costs associated with spills or other unintentional releases from underground storage tanks and lines containing petroleum products, such as gasoline, diesel, kerosene, and home heating oil. The trust fund receives funding through tank registration fees ($400 per tank), along with an allotment of 19/32 of each cent of fuel tax.

In a typical UST claim, a responsible party (tank owner or operator) pays an environmental consultant to perform a site investigation and directed environmental remediation activities. The responsible party then requests reimbursement for those respective costs from the UST Trust Fund office. Trust Fund personnel review the request, ensuring that environmental site work was performed in accordance with applicable State rules and DWM guidance. Once a reimbursement request is approved, notice of approval is sent to the State Controller's office, which processes the payment to the responsible party to cover payment owed to the environmental consultant.

The DWM-UST Section- Trust Fund office currently manages cost reimbursement for around 8,000 sites throughout North Carolina. The program is composed of one supervisor, three accounting technicians, one business officer, one processing assistant, two engineers, and seven hydrogeologists. The trust fund also receives legal support from the State's Attorney's General Office.

The Study Group recommends that a similar funding office be established within DEMLR to receive and distribute impact fee monies. Local governments would submit claims for cost impact reimbursement through this office to the Mining and Energy Commission. The "Energy Fund Office" would then disburse funds to local governments based on the MEC's approval of reimbursement requests. MEC approval would be dependent upon proper findings that the impacts are measurable, are tied to oil and gas activity, and that the costs are proven to be for work that was actually conducted. In the event that it is determined that local government applicants can seek advancement of funds rather than reimbursement, proper criteria would need to be established for review and approval of those applications. The Study Group recommends that the Energy Fund Office receive appropriated funding to support the following positions: one business officer, two processing assistant, and one attorney (part time). Funding these positions through budgetary appropriations would allow for 100 percent of impact fee monies to be distributed to local governments. Cost impact specifics for this office are shown in Section IV, Table IV.6 and are included in the total cost to the State for overseeing oil and gas operations discussed in Section IV below.

C. Impacts to Local Transportation Infrastructure

To better predict the types of impacts that N.C. cities and towns may experience from development of the hydraulic fracturing industry in the state, the N.C. League of Municipalities (NCLM) surveyed towns in affected areas of drilling in Arkansas. Through conversations with those municipal officials, NCLM found that the major impacts to municipal operations occurred in the area of transportation infrastructure. Well construction and stimulation may include 1,000 to 1,200 truck trips hauling water, proppant (usually silica sand), and other materials. The NCDOT and DEMLR estimate that each truck is equivalent to a road impact of 3,000 to 6,000 cars, which is exacerbated by traffic congestion or slow speed limits on streets. In North Carolina, impacts and damages to local government transportation infrastructure from hydraulic fracturing activities will be experienced heavily by municipalities.

D. Local Permitting and Bonds to Recover Local Roads Impacts

To most adequately recover the costs of repairs to municipal transportation infrastructure, NCLM proposes, and the Study Group is recommending, a bond and permit system modeled after the one in Pennsylvania.

G.S. 160A-296 and 160A-300, provides N.C. municipalities the authority to exercise control over their municipally-controlled public streets by prohibiting, regulating, diverting, controlling, and limiting vehicular traffic. These statutes allow municipalities to establish weight restrictions and truck routes for municipal streets. With either approach, signs must be posted at the appropriate locations in order for the ordinance provisions to be effective and enforceable.

This authority can similarly be used to support the local bond and permit system. Under the proposal:

1. A municipality in an area expecting oil and gas industry-related traffic by high weight vehicles would post weight limits for its roads. In order for an oil and gas company to operate over-weight vehicles on a posted municipal road, the municipality would issue an over-weight permit for the vehicle or vehicles.

2. To receive a permit, a company would enter into an Excess Maintenance Agreement (EMA) with the municipality, under which it would agree to pay for any maintenance or restoration of a posted road that it traveled that was in excess of normal maintenance. Such maintenance and restoration would not require improvements of the road beyond the state of repair at the time the permit took effect. The agreement would cover the roadway itself, as well as shoulders, curb and gutter, sidewalks, drainage facilities, and other appurtenances.

3. The operator and the municipality would first make inspections to determine the condition of the roads covered by the EMA at the beginning and end of the EMA period. Interim inspections could also occur during the EMA period to identify damage that could be mitigated if addressed immediately, rather than at the end of the EMA period.

4. As part of the EMA, the operator would agree to either: (1) undertake all required maintenance and restoration itself, or (2) allow the municipality to undertake the maintenance and bill the company for the costs. In either, the maintenance and restoration work would be inspected by both parties upon completion.

5. The operator would provide security, such as a performance bond or irrevocable letter of credit, to ensure that funds were available to cover the cost of any required maintenance and restoration. The amount of the bond would be tied to the level of use that the oil and gas company expected to make of the covered municipal roads. An oil and gas company's liability

would not be limited to the level of security provided and the amount of security required could be increased by the municipality during the EMA period if interim inspections found that the expected cost of damage was greater than amount security.

6. If more than one operator sought a permit to operate on the same road(s), the companies would agree within a specified period of time on the percentage of maintenance and restoration cost that will be assigned to each company under its EMA. If the companies did not make the assignment within the specified time, the municipality would be authorized to make such assignment itself.

7. An operator's failure to meet the EMA's terms would result in suspension or termination of the EMA *and haul permit would be revoked*.

8. A municipality would reserve the right to close a road covered by an EMA, or portion thereof, to any vehicle in excess of a specific weight if such closing was necessary for safety, or was a temporary closing due to weather conditions.

9. A municipality may deny the right to the use of any roadway for public purpose, as long as they provide the industry an alternative, reasonable route.

IV. Energy Program Cost Impacts

The Division of Energy, Mineral, and Land Resources' (DEMLR) Energy Program is responsible for researching and drafting rules for the regulation of the oil and gas industry. Additionally, Program personnel will serve as DENR's regulatory entity to ensure that all operations are carried out in accordance with North Carolina statutes and rules.

A. Current Staffing and Support:

The Energy Program is currently staffed with a Program Supervisor, a Senior Environmental Specialist, a Senior Geologist/Hydrogeologist, and an Administrative Support Specialist. All personnel are located in the DEMLR central office in Raleigh, N.C. This Program is supported with nearly $350,000 in annual funding, along with around $18,000 of non-recurring funds. Respective monies cover employee salaries and benefits, travel, basic DEMLR-issued safety equipment (i.e. hard hats, safety glasses, and steel toe boots), and other operational needs. Refer to **Tables IV.1** and **IV.2** for specifics. As indicated below in Section VI., the Study Group recommends these costs be appropriated by the State and covered by a severance tax structure.

B. Future Staffing and Support:

Determining the future staffing needs is difficult at best, as estimating Energy Program workload is dependent on predicting the volume of future oil and gas activity in the state. Additionally, while the Energy Program is developing rules and policy to address state-wide operations, resources that are most likely to be exploited in the short term involve shale gas within the State's Triassic Basin areas. As a result, future staffing requirements addressed in this report assume a scenario where Triassic shale resources are explored, proven, and exploited, before other areas of the State (i.e. Coastal Plain) are seriously considered by industry.

The Energy Program would need to grow from its current staffing level of four to a total of 13 personnel to permit, oversee, and regulate expected oil and gas activities. These positions would include one Program Supervisor, three Senior Environmental Specialists, two Environmental Specialists, one Senior Geologist/Hydrogeologist, one Administrative Support Specialist, one Engineer, one Rules Coordinator, one Economist, one Public Information Specialist, and one

Business Application Technology Specialist. Nine of these members would remain in the Raleigh Central Office to provide technical and administrative oversight and management. However, a team each comprised of one Senior Environmental Specialist and two (junior) Environmental Specialists would likely be assigned to DEMLR's Winston-Salem Regional Office and to the Fayetteville Regional Office. Members based within Regional Offices would provide local regulation and oversight to industry field operations.

C. Equipment Needs:

Ensuring the proper permitting and regulatory compliance of oil and gas operations will necessitate special equipment and training for Energy Program members. Personal protective equipment would not be limited to the standard DEMLR issued items; staff would also require fire retardant clothing. Specialized field equipment would include water "multi-meters" for measuring field parameters within surface water bodies or water wells, cement scales for determining drilling fluid and cement density, in addition to portable gas meters to help ensure site safety.

D. Training:

Oil and gas operations involve the application of cutting-edge scientific and engineering technology. As a result, Energy Program personnel must attend annual professional training to remain up to date on the most current industry capabilities and trends. Additionally, initial and annual safety training related to oil and gas operations is essential to ensure proper regulatory oversight and staff safety.

E. Summary of Expected Future Costs:

Future annual recurring costs to support the Energy Program would be nearly $1.1 million, in addition to non-recurring equipment costs of nearly $100,000. These monies would address the specific needs which have already been noted, as well as employee salaries and benefits, travel, and other requirements. Refer to **Tables IV.3** and **IV.4** for more detailed information**.**

Table IV. 1. Energy Program: Current and Estimated Annual Costs.

Cost Impact	Amount per year	Notes
Salary and Support	$304,000	Employees include: Program Supervisor, Geologist, Senior Specialist, and Administrative Assistant. (Four employees)
Office Supplies	$300	Assume $75 per person.
Office Space (Rent)	$0	Rent is not paid for Archdale Building offices.
Office Space (Operating)	$5,200	Includes copier use, internet access, phone use, etc. Amount based on expansion budget figures of about $1,300 per person.
Personal Protective Equipment	$1,500	Estimated based on a standard amount of $500 per operational person per year.
Professional Training	$2,000	Estimated based on a standard amount of $500 per person per year. Includes registration fees for locally-sponsored training.
Computer Software and Training	$1,000	Estimated based on a standard amount of $250 per person per year.
Cell Phone	$200	The program has one cell phone total.
Vehicle Use (Rented)	$11,000	Rental cost for one vehicle, based on minimal mileage use (1050 miles/month).
Travel	$7,200	Assumes 5,000 miles at $0.48/mi for each operational employee. Thus 15,000 miles total.
Meals	$1,636	$36.35/day for 15 days/yr. per operational employee. Thus, 45 days total.
Lodging	$3,420	$76.00/day for 15 days per operational employee. Thus, 45 days total.
Miscellaneous Travel Expenses (parking fees, tolls, etc.)	$600	Based on estimated amount of $200 per operational person per year.
Public Meeting Advertising	$8,250	15 Advertisements at $550 per advertisement.
Postage	$5,000	
Sub-Total	**$351,306**	**Current Estimated Annual Recurring Costs**

Table IV. 2. Energy Program: Current Estimated Non-Recurring Costs.

Cost Impact	Amount	Notes
Computers (hardware)	$6,000	Based on about $1,500 per computer and associated hardware. Assume a three to five year life.
Office Equipment	$11,600	Bookcases, desks, whiteboards, office chairs, etc. Estimated based on a standard rate of $2,900 per person.
Sub-Total	**$17,600**	**Current Estimated Annual Non-Recurring Costs**

Table IV. 3. Energy Program: Future Estimated Annual Costs.

Cost Impact	Amount per year	Notes
Salary and Support (13 Total Employees, which already includes the four current employees.)	$665,727	Central Office: 1 Supervisor, 1 Geologist, 1 Engineer, 1 Senior Specialist, 1 Administrative Assistant, 1 Rules Coordinator, 1 Economist, 1 Public Information Specialist, 1 Business Application Technology Specialist.
Office Supplies	$675	Assume $75 per person (nine employees)
Office Space (Rent)	$0	All personnel should be located in the Archdale Building
Office Space (Operating)	$11,700	Includes copier use, internet access, phone use, etc. Amount based on the Archdale rate of $1,300 per person.
Personal Protective Equipment	$6,500	Includes fire retardant PPE specifically designed for oil and gas operations. Estimated based on bi-annual purchases of averaging about $1,000 per year operational per employee (4). Also allot for $500 per year for other employees (5).
Professional Training	$13,000	Estimated based on an amount of $1,000 per person per year for the five administrative positions and $2,000 per year for technical positions. Includes registration fees for locally-sponsored training.
Computer Software and Training	$4,500	Estimated based on a standard amount of $500 per person per year.
Concurrent Software Licenses	$2,000	
Mobile Software Licenses	$4,000	
IT Data Storage	$25,000	
Program (IT) Support	$5,000	
Cell Phones	$800	Cost will cover four cell phones.
Vehicle Use (rented)	$5,040	Rental cost for one vehicle, based on minimal mileage use (1050 miles/month at $0.40 per mile).
Travel	$9,600	Assumes 5,000 miles at $0.48/mi for each operational employee (4 positions). Assumes that non-operational employees can travel with operational employees. Thus 20,000 miles total.
Meals	$4,907	$36.35/day for 15 days/yr. per employee (9 positions). Thus, 135 days total.
Lodging	$10,260	$76.00/day for 15 days per employee (9 positions). Thus, 135 days total.
Miscellaneous Travel Expenses (parking fees, tolls, etc.)	$1,800	Based on estimated amount of $200 per person per year (9 people).
Public Meeting Advertising	$8,250	15 Advertisements at $550 per advertisement.
Postage	$5,000	
Field Sampling	$15,000	Ability to perform random or “on-call” sampling to ensure human health and environmental protection. Cost per sample depends on the analyses performed and the laboratory conducting analyses.
State-Owned Vehicle Maintenance	$12,000	Basic maintenance and repairs over a 10 year life span. Also includes fuel costs.
Sub-Total	**$810,759**	**Estimated Annual Recurring Costs (within first three years)**

Table IV. 4. Energy Program: Future Estimated Non-Recurring Costs.

Cost Impact	Amount	Notes
Computers (hardware)	$8,000	Based on about $1,500 per computer and associated hardware. Assume a three to five year life. Five additional employees will need this equipment.
Field Equipment	$4,000	Groundwater multi-meter ($2,500 each), GPS units, gas meters, mud balance/cement scale ($300 each), buckets, shovels, etc. Total up front cost is about $4,000. Assume five-year service life.
Cost to initiate permitting database setup and access	$200,000 to $500,000	Cost depends on vendor quotes and results of contracting efforts. Actual cost will be a one-time expense and should be within this range.
Sub-Total	**$212,000 to $512,000**	**Estimated Non-Recurring Costs (within first three years)**

F. Additional Cost Impacts to DENR:

Although the Energy Program is the lead entity for rule development and regulation, other non-Program personnel will be involved in oil or gas related activities. For instance, rule development decisions, as well as regulatory hearing decisions will ultimately be determined by the Mining and Energy Commission (MEC). The MEC is generally composed of 15 members who meet two days per month in Raleigh, N.C. Eligible commissioners receive per diem, as well as travel cost reimbursements. Additionally, MEC members may sometimes travel to other locations for training to assist them with the execution of their duties. The annual recurring cost to support the Commission is estimated to be $70,350. Refer to **Table IV.5** for additional details.

Table IV. 5. Mining and Energy Commission: Future Estimated Recurring Costs.

Cost Impact	Amount per year	Notes
Per Diem	$11,250	Amount of $15 per meeting day per commissioner. Allotted for 15 commissioners and about 50 meeting days per year.
Training & Seminars	$4,500	Estimated based on a standard amount of $300 per person per year. Includes registration fees for locally-sponsored training.
Travel	$19,100	Based on current travel authorization estimates for MEC.
Meals	$14,500	Based on current meal authorization estimates for MEC.
Lodging	$14,500	Based on current lodging authorization estimates for MEC.
Miscellaneous Travel Expenses(Parking fees, tolls, etc.)	$6,500	Based on current estimates for MEC meetings, with an adjustment for fieldtrips/training.
Total	**$70,350**	

Other employees within DENR who will have involvement with oil or gas operations include non-Energy Program members, who either oversee or work within other DENR entities. Examples include the Division of Water Resources (DWR) and the Division of Waste Management (DWM), along with other DEMLR offices including Sediment and Erosion Control, Dam Safety, and the N.C. Geological Survey. The DWR and DWM are expected to provide minimal support to regulate oil and gas operations. Thus, these Divisions should only become involved whenever specific situations involving the industry are subject to their regulatory programs. Conversely, DEMLR personnel, who are not Energy Program members, will be routinely spending portions of staff time dealing with oil or gas matters. As a result, these employees will need to receive specialized training, along with travel authorizations to carry out their duties. Overall costs to DENR for non-Energy Program personnel are estimated at around $310,000. Table 6 provides specific details. Information regarding the “Energy Funding Office” is provided under the “Local Government Cost” section of this report.

Table IV. 6. Non-Energy Program DENR Entities: Future Estimated Recurring Costs.

Cost Impact	Amount per year	Notes
DEMLR (General Non-Energy Program employees): Salary & Support	$193,000	Employees include: DEMLR Division Director (35% time), Land Quality Section Chief (30 % time), Chief Engineer (25% time), Erosion Control Specialist (5% time), Dam Safety Specialist (5% time), Storm Water Engineer (5% time), State Geologist (25% time), and NC Geol. Survey Geologist (75% time).
DEMLR (General Non-Energy Program employees): Office Space (Operating)	$2,720	Includes copier use, internet access, phone use, etc. Amount based on average percentage of time spent by non-Energy Program personnel. Estimated amount is $340.00 per person.
DEMLR(General Non-Energy Program employees): Personal Protective Equipment (Standard)	$4,000	Estimated from standard amount of $500 per person.
DEMLR (General Non-Energy Program employees): Professional Training	$1,040	Estimated based on average percentage of time spent by non-Energy Program personnel. Estimated amount is $130 per person. Includes registration fees for locally-sponsored training.
DEMLR (General Non-Energy Program employees): Vehicle Use (Rented)	$3,000	Rental cost for one vehicle, based on minimal mileage use (1,050 miles/month) and the average percentage of time spent by non-Energy Program personnel.
DEMLR (General Non-Energy Program employees): Travel	$5,000	Allows for 1,300 miles at $0.48/mi for each employee. Thus, 10,400 miles.
DEMLR (General Non-Energy Program employees): Meals	$1,200	$36.35/day for 4 days/yr. per operational employee. Thus, 32 days total. Estimated at $1,200 total.
DEMLR (General Non-Energy Program employees): Lodging	$2,100	$65.90/day for 4 days per employee. Thus, 32 days total. Estimated at $2,100 total.
DEMLR (Non-Energy Program employees, “Energy Fund Office”): Salary & Support	$180,841	One business officer (100%), two processing assistants (100%), and one attorney (25%).
DEMLR (Non-Energy Program employees, “Energy Fund Office”): Office Space (Operating)	$3,900	Includes copier use, internet access, phone use, etc. Amount based on Archdale rate of $1,300 per person, excluding the attorney position.
DWM: Salary & Support	$17,000	Employees Include: Two Regional Supervisors (5% time) and Two Regional Hydrogeologists (5% time).
DWQ: Salary & Support	$17,000	Employees Include: Two Regional Supervisors (5% time) and Two Regional Hydrogeologists (5% time).
DENR (Main Office): Salary & Support	$64,000	Policy Analyst (80% time).
Total	**$492,701**	

V. NCDOT- State Costs

The costs to the state Department of Transportation are expected to be based on the level of natural gas exploration and production activity occurring in the state. That production will by necessity ramp up over time. Accordingly, the costs to the NCDOT are shown below over a multi-year period, assuming modest levels of activity in the first years and more moderate levels by the time year 7 of activity is reached. The assumptions used to determine the level of activity are based on work commissioned by the Study Group from Dr. Kenneth Taylor, Mining and Energy Commissioner. That work is discussed in Section VI. B. below and attached as an appendix hereto. As indicated below in Section VI,the Study Group recommends these costs be appropriated by the State and covered by a severance tax structure.

A. Current Staffing and Support:

The North Carolina Department of Transportation Division of Highways is made up of 14 Divisions statewide. Each Division has a similar staffing structure comprised of a Division Engineer, Division Maintenance Engineer, Division Construction Engineer, Division Operations Engineer and Bridge Engineers. Each Division is further divided into Districts. Most Districts are comprised of multiple counties. Each District has a District Engineer, Assistant District Engineer, County Maintenance Engineers, Engineering Technicians and Road Maintenance Supervisors. Multiple Clerical Support positions are located in the Division and Districts. Permitting of Access to state roads and work within NCDOT rights of way are already primary responsibilities of District Engineers. Residential, Commercial and Industrial development drives the volume of permits received and processed. The Division also has Engineering Technicians that are assigned to Resident Engineers. These Technicians inspect construction projects and are involved in contract administration. The District Engineer has the ability to utilize the construction technicians for permitting depending upon the needs.

NCDOT technical support units will also be heavily involved in the permitting and compliance aspects of the energy industry. The Structures Management Unit and Pavement Management Unit will assist Division and District personnel with condition and weight capability analysis and suggested methods of repair.

Current funding for the above positions comes from Highway Maintenance Allocations as well as the Transportation Improvement Program (TIP). Highway Maintenance Allocations also pay for equipment, materials and contract work associated with the maintenance of roads and bridges. The Transportation Improvement Program is a blend of federal and state monies that pay for our larger construction projects and bridge replacements.

B. Future Staffing and Support:

The NCDOT future staffing needs are also difficult to determine depending upon the volume of energy development and future workload of the individual offices. Future staffing requirements addressed in this report assume a scenario where Triassic shale resources are explored, proven, and exploited, before other areas of the State (i.e. Coastal Plain) are seriously considered by industry. The workload associated with the energy industry would be handled by current staff with additional consultant staff hired as needed. NCDOT is recommending a new position to serve as the Director of Energy operations. This position would serve as the coordinator for energy operations statewide and would assure uniformity and consistency in our permitting and compliance process. See **Table V.1** for Projected Annual NCDOT Permit and Compliance Costs for First Seven Years, **Table V.2** for Permitting Costs due to the energy industry, and **Table V.3** Compliance Costs.

C. Equipment Needs:

The NCDOT Equipment needs include vehicles used for traveling to and from meetings, site investigations and other local travel needs. Other needs include Personal Protective Equipment (PPE) such as steel toe boots, hardhats, safety vests and safety glasses. Electronic equipment including GPS receivers, digital cameras and laptops will be essential to effectively manage the workload associated with the energy industry.

Table V.1. Projected Annual NCDOT Permit and Compliance Costs for First Seven Years

Staff Costs					
Year	**Projected Wells**	**Projected Permits*/Yr***	**Permit Costs****	**Compliance Costs*****	**Total Annual Costs**
0	3	3	$18,309.03	$50,565.60	$68,874.63
1	7	7	$42,721.07	$117,986.40	$160,707.47
2	22	22	$134,266.22	$370,814.40	$505,080.62
3	75	30	$183,090.30	$505,656.00	$688,746.30
4	75	30	$183,090.30	$505,656.00	$688,746.30
5	75	30	$183,090.30	$505,656.00	$688,746.30
6	109	36	$219,708.36	$606,787.20	$826,495.56
7	160	40	$244,120.40	$674,208.00	$918,328.40
Totals	**526**	**198**	**$1,208,395.98**	**$3,337,329.60**	**$4,545,725.58**

Projected Permits based on single well sites for first several years then more sites with multiple wells through year 7. If practice of majority single well sites continues then projected permits would increase therefore increasing total costs.

Table V.2. Permitting Costs (annual costs)

Staff Costs				
Positions	**Hrs/ Permit**	**Total Hrs (40 Permits /Year)**	**Rate /Hr *****	**Total Costs**
Energy Coordinator (New)	4	160	$97.36	$15,577.60
District Engineers	10	400	$91.95	$36,780.00
County Maintenance Engineers	6	240	$76.89	$18,453.60
Road Maintenance Supervisors	6	240	$61.66	$14,798.40
Assistant District Engineers	16	640	$54.09	$34,617.60
Engineering Technicians	30	1,200	$45.43	$54,516.00
Bridge Engineering	12	480	$81.13	$38,942.40
Pavement Engineering	4	160	$81.13	$12,980.80
Clerical Support	3	120	$32.45	$3,894.00
	$230,560.40			
Equipment Support Item	**/Permit**	**Total**		
Vehicles (Mileage @.565/mile)	600 mi.	24,000 mi.	$13,560	
	$244,120.40			

**The hours associated with the positions above will be using primarily existing staff and supplemented with consultants as needed.*

****Rates determined using a 2.25 salary multiplier, which is a typical overhead and profit multiplier used when hiring consultants.*

Table V.3. Compliance Costs (annual costs, based on a rate of 40 permits approved per year).

Positions	Total Hrs	Rate /Hr ***	Total Costs
Energy Coordinator (New)	1,920	$97.36	$186,931.20
District Engineers	208	$91.95	$19,125.60
County Maintenance Engineers	312	$76.89	$23,989.68
Road Maintenance Supervisors	624	$61.66	$38,475.84
Assistant District Engineers	2,080	$54.09	$112,507.20
Engineering Technicians	3,120	$45.43	$141,741.60
Bridge Engineering	624	$81.13	$50,625.12
Pavement Engineering	312	$81.13	$25,312.56
Clerical Support	416	$32.45	$13,499.20
	$612, 208.00		
Equipment Support			
Item			
Vehicles (Mileage @.565/mile)	100,000 mi.		$56,500
Personal Protective Equipment			$2,000
GPS/Cameras (7each)			$1,400
Laptops (7each)			$2,100
TOTAL:			**$674, 208**

**The hours associated with the positions above will be using primarily existing staff and supplemented with consultants as needed.*

****Rates determined using a 2.25 salary multiplier which is a typical overhead and profit multiplier used when hiring consultants.*

V. Potential Revenue Sources

A number of possible revenues sources to cover the costs of operating a modern oil and natural gas program were studied by the Study Group. These sources include severance taxes, impact fees, assessment of property taxes, and well permitting and abandonment fees. Initially the Group had listed a possible fee for site inspections, but this was later removed due to no other Division within the Department charging a fee for site inspections. Within the DEMLR sections, routine inspections are performed by staff as either a component of their job responsibilities or the main component of their job responsibilities.

A. Permitting and Application Review Fees:

The majority of oil and gas producing states have some amount of fee that is required for the permitting of wells. Under existing statute, GS113-395 Part A, there is a fee per permit application of $3,000. It is expected that this fee will cover some of the costs of administering the program at DENR, but not be sufficient to recover all of the increased costs to the state set out in the above tables. We recommend keeping this fee at $3,000 for cost recovery of the permitting function only. This fee structure has been built into our analysis of the needs of the state to recover the costs of administering and oil and natural production program.

B. Severance Tax:

The Study Group understands that the North Carolina General Assembly is planning to draft legislation to establish severance tax rates. The Study Group asks the legislature to consider these fundamental tenets regarding severance taxing:

1. Any severance tax should be based on computed market values, not merely the volume of product being produced;
2. The severance tax should be sufficient to fund NCDOT and NCDENR work related to the oil and gas industry;
3. North Carolina should have a simple severance tax structure; and

4. North Carolina should structure its severance tax to be competitive with other states so that industry is not discouraged from developing North Carolina's oil and gas resources.

Various states impose a severance tax on oil and gas wells that are in production. Tax structure is generally based on the volume of product produced, the market value of product produced, or a combination of both. Examples of severance taxing strategies from selected states are presented in **Table VI.1**.

Table VI. 1. Summary of Severance Tax Examples. Data within this table were excerpted from the article, "State Revenues and the Natural Gas Boom" (Cassarah Brown, 2013), which is available at http://www.ncsl.org/issues-research/energyhome/state-revenues-and-the-natural-gas-boom.aspx.

State	Type of Tax	Tax Strategy	Revenue Distribution
Arkansas	Natural Gas Severance tax	Tax on market value of gas produced: 1.5% for new discovery gas 1.5% for high-cost gas 1.25% for marginal gas 5% on natural gas not defined as new discovery or marginal gas 5% on high-cost gas	5% of revenues deposited into state general fund 95% of revenues deposited as special revenues distributed via Highway Distribution Law
	Oil Excise Tax	Tax on market value at time of severance: 4% of the market value when production averages 10 barrels or less per well per day 5% of the market value when production averages more than 10 barrels per well per day	3% of revenues deposited into General Revenue Fund Account Of remaining 97%: 75% to State Treasury 25% to County Aid Fund
Colorado	Gas and oil tax	Levied on the gross income from crude oil, natural gas, and oil and gas.	Deposited in the state general fund and distributed among various state and local government funds.
Nevada	Oil and Gas Fee	Up to $0.20 per 50,000 cubic feet of natural gas or barrel of oil	Revenues credited to the Oil and Gas Conservation Fund
	Oil and Gas Gross	$0.1143 per MCF of gas	30% of revenues deposited in the

State	Type of Tax	Tax Strategy	Revenue Distribution
N. Dakota	Production Tax	5% of gross value of gas or oil	state Legacy Fund Remainder distributed, via formula, to Oil and Gas Impact Fund and political subdivisions within state, including state general fund
Ohio	Severance Tax	\$0.025 per MCF of natural gas \$0.10 per barrel of oil	10% of revenue deposited in the Geological Mapping Fund 90% of revenue deposited in the Gas Well Fund
Pennsylvania	Gas Well Fee	Fee on oil or gas well. Fee changes annually with price of natural gas.	Monies distributed among the Unconventional Gas Well Fund, the Marcellus Legacy Fund, counties, and municipalities.
Texas	Gas and Oil Production Tax	7.5% tax of gas market value 4.6% tax of oil market value 4.6% tax of gas condensate market value for gas condensate	0.5% of revenues used for enforcement of production tax and tax provisions Remaining revenues: 25% deposited in the Foundation School Fund 75% deposited in the General Revenue Fund

Because the Study Group recommends that the state eventually use monies collected from severance taxes to fund the costs to the state of an oil and gas permitting program, including the increased Energy Program costs and the increased Department of Transportation costs, it became important for the Study Group to estimate the potential dollars that could be collected by a severance tax based on some level of oil and natural gas production. Yet, the current paucity of exploratory data and the difficulty of obtaining additional data regarding the potential for actual production in the state makes projecting future production nearly impossible. Rather, the Study Group developed a few plausible scenarios that could act as a guide for gross estimation of potential future revenues. Low, medium and high case scenarios were developed based on the production experience of the Fayetteville Shale basins in Arkansas. The experience of Arkansas was used as proxy because of similarities in reservoir characteristics to those in the Triassic Basins of North Carolina, among other considerations. The scenarios could be used with regard to natural gas production in the state would be the best way to arrive at a severance tax rate that would collect enough monies to cover the costs of the program. Accordingly, the Study Group reviewed scenarios for possible production put forth by Mining and Energy Commissioner Dr. Kenneth Taylor. Dr. Taylor's report is attached as an Appendix A, hereto. Based on that report, the Study Group concluded that an initial severance tax rate of 1.5% on the market value of natural gas produced would be a reasonable tax that would be expected to achieve state program cost recovery and also be in accord with the four tenets set out above. This severance tax would be in addition to the existing statutory severance tax rate of 5% on the market value of liquid petroleum and other Natural Gas Liquids expected to be found in association with the produced natural gas. The study group did not study the potential for assigning severance taxes for volumes of inert gases that may also be extracted with the hydrocarbons. In the event commercially viable percentages of helium or other inert gases are present in North Carolina's gas reserves, those gases should be taxed in the same manner as the natural gas.

C. Well Abandonment Fee:

North Carolina General Statute 113-395 has already established the abandonment fee for an oil or gas well as being $450. The Study Group agrees with this current legislation and understands that setting this fee too high will discourage industry from properly abandoning wells.

VI. Recommended Bonding

Within the general statutes of the Oil and Gas Conservation Act, amended and rewritten by Session Law 2012-143, there are a number of areas where an oil or gas permittee is required to furnish a bond or provide compensation for damages incurred to surface land owners. The operator is required under § 113-378 to furnish a bond for well plugging and abandonment. Under § 113-421 an operator is to provide compensation for damages to a water supply, personal property, and to market resources like timber, livestock, and crops if the land owner is not also the permittee. Based on research conducted by staff and others, the Study Group compiled a number of recommendations on purposed amounts to be required for each bond, **Table VII.1**. On direction from the Study Group, DEMLR staff compiled **Table VII.2** to show the different bonding types and practices seen in other oil and gas producing states.

A. Surface Owner Bonding:

Under § 113-421 (a1)(1-3) the permittee is to provide compensation for damages to a water supply, personal property, and to market resources such as timber, livestock, and crops. The study group researched surface owner bonding practices of other states and Federal agencies; see **Table VII.3**.

The Study Group determined that there should be some level of protection for affected land owners and shall be addressed in lease negotiations.

B. Geophysical Exploration Bonding:

DEMLR staff researched and provided information to the Study Group related to bonding for geophysical activities in North Carolina and in other states. Overall, geophysical bonding addresses two primary classifications, designated as explosive and non-explosive exploration. Bonding ranges from $25,000 to $250,000 in states that regulate exploration activity, **Table VII.4**. Currently in North Carolina, under 15NCAC 05C.0100, the state does regulate all geophysical exploration that will use dynamite or other explosives to produce and collect subsurface geophysical data. These types of investigations require that a permit be filed with the Geological Survey. There is currently no permit fee or bond required to conduct this type of explosion investigations in North Carolina.

The recommendation of the Study Group is that a blanket bond of $50,000 be provided by any person or company seeking to perform geophysical exploration involving explosive charges or other similar techniques in the state of North Carolina. If the person or company hires out or subcontracts any work, the subcontractor shall be covered under the $50,000 bond provided.

C. Well Plugging and Abandonment Bonding:

Currently under § 113-378 an operator is required to submit a bond in the amount of $5,000, plus $1.00 for each linear foot proposed to be drilled for the well. Proper plugging, cementing, and abandonment of an oil or gas well is a complex procedure that should only be performed by competent oil and gas professionals.

Based on a cost estimate provided by Halliburton Corporation (**Figure VII.1**), the Study Group recommends a bonding amount of$27.00 per foot of wellbore that will be filled with cement in accordance with North Carolina well abandonment rules.

D. Site Reclamation Bonding:

Currently the Mining Section of DEMLR uses a table where the acreage of different land uses associated with a mine and costs are used to determine the appropriate bond amount that a mining operator would need to secure prior to receiving an approved mining permit. The land uses range from haul roads, pits, to stockpiles.

The recommendation of the Study Group is that the Mining and Energy Commission adopt a similar table for calculating the site reclamation bond. Staff prepared an example using acreage from an oil and gas permit from another state to determine what potential costs of reclamation would be; see **Table VII.5**. The costs in the table for the different land use categories represent an estimate from various sources, including NCDOT.

VII. Types of Allowed Bonds

The recommendation of the Study Group is to accept the same types of bonds, or assurances, that the Mining Program within the DENR- Land Quality Section (LQS) currently accepts. This is due to the Department and the industries familiarity with the program.

The current procedure under the Mining Programs is that the applicant must use the Department's standard forms when completing the bond forms for surface owner, site reclamation, and well plugging and abandonment. The name on the bond, assignment of savings account, or irrevocable letter of credit form must be the same as the name of the company or individual that the application for oil and gas permit was filed under.

For example: An application is filed by Mr. John Q. Permittee, under the company name of Oil and Gas Company; therefore, the security must be in the name of Oil and Gas Company. An exception to this would be for Mr. Permittee to have the security form filled out to read John Q. Permittee d/b/a (doing business as) Oil and Gas Company. This way the oil and gas permit could be issued in the name of Oil and Gas Company and Mr. Permittee could have his name listed on any other financial documents. See **Table VII.5** for a breakdown of advantages and disadvantages of each bond type allowed.

A. Assignment of Savings Account:

These are issued by an acceptable banking institution licensed to do business in North Carolina. The applicant and an authorized agent for the bank must sign the form and both signatures must be notarized. “Savings Account" refers to any savings instrument not just a passbook account. A money market account or certificate of deposit can also be utilized. Whatever savings instrument is chosen, the original or photocopy of the document issued by the bank (passbook, deposit receipt, actual certificate of deposit) must be attached to the original assignment form and both forwarded to the DENR-LQS

Central Office. The account numbers and dollar amounts listed on the assignment form must match those on the savings instrument.

B. Surety Bonds:

These are issued by an issuance company licensed to do business in North Carolina. A Power of Attorney must accompany the completed original standard bond form provided by the Department to substantiate that the issuing agent has authorization to act on behalf of the insurance company.

C. Bank Guaranty:

These guaranties of payment must be issued from an acceptable bank licensed to do business in North Carolina.

D. Cash Deposits:

Cashiers or certified checks must be made payable to the Department. A cover letter specifying the intended function of the money being submitted to the Department must accompany the check.

HALLIBURTON

Cost Estimate ***Cement PTA***

Mtrl Nbr	Description	Qty	U/M	Unit Price	Gross Amt	Net Amt
1	ZI-MILEAGE FROM NEAREST HES BASE,/UNIT	1500	MI	9.79	14,685.00	8,811.00
	Number of Units	1				
2	MILEAGE FOR CEMENTING CREW,ZI	1500	MI	5.76	8,640.00	5,184.00
	Number of Units	1				
16094	PLUG BACK/SPOT CEMENT OR MUD,ZI	1	EA	6,626.00	6,626.00	3,975.60
	DEPTH	2550				
	FEET/METERS (FT/M)	FT				
114	R/A DENSOMETER W/CHART RECORDER,/JOB,ZI	1	JOB	1,285.00	1,285.00	771.00
	NUMBER OF UNITS	1				
119534	SUCTION HOSE, 4"/FT W/HES,PER JOB ZI	200	FT	4.40	880.00	528.00
	NUMBER OF JOBS	1				
14089	PUP TRAILER,NON-ACID MATLS,0-8 HRS,ZI	1	EA	822.00	822.00	493.20
	HOURS (MIN8)	8				
100003687	PREMIUM CEMENT	400	SK	53.28	21,312.00	12,787.20
3965	HANDLE&DUMP SVC CHRG, CMT&ADDITIVES,ZI	400	CF	5.49	2,196.00	1,317.60
	NUMBER OF EACH	1				
	Unit of Measurement					
76400	ZI MILEAGE,CMT MTLS DEL/RET MIN	750	MI	3.35	47,235.00	28,341.00
	NUMBER OF TONS	18.8				
7	ENVIRONMENTAL SURCHARGE,/JOB,ZI	1	JOB	134.00	134.00	134.00
372867	Cmt PSL - DOT Vehicle Charge, CMT	1	EA	241.00	241.00	241.00
11881	ZI OVERWEIGHT PERMIT FEE-CEMENTING	1	EA	60.00	60.00	60.00
86955	ZI FUEL SURCHG-HEAVY TRKS >1 1/2 TON	1500	MI	0.72	1,080.00	1,080.00
	Number of Units	1				
86954	ZI FUEL SURCHG-CARS/PICKUPS<1 1/2TON	1500	MI	0.24	360.00	360.00
	Number of Units	1				
87605	ZI FUEL SURCHG-CMT & CMT ADDITIVES	750	MI	0.24	3,384.00	3,384.00
	NUMBER OF TONS	18.8				
	Total	**USD**				**108,940.00**
	Discount	**USD**				**41,472.40**
	Discounted Total	**USD**				**67,467.60**

Primary Plant: Sandersville, MS, USA
Secondary Plant: Sandersville, MS, USA
Price Book Ref: 29 Southeast - NEW
Price Date: 3/20/2013

Mtrl Nbr	Description	Qty	U/M	Unit Price	Gross Amt	Net Amt
16092	ADDITIONAL HOURS (PUMPING EQUIPMENT), ZI	1	EA	1,139.00	1,139.00	797.30
	HOURS	1				
	UNIT OF MEASURE - HRS	H				
464256	CMT, Bulk Truck on loc, additional hours	1	EA	196.00	196.00	137.20
	HOURS	1				
	UNIT OF MEASURE - HRS	H				
10	FOOD AND LODGING, ZI	3	DAY	653.00	5,877.00	4,113.90
	NUMBER OF PERSONNEL ON JOB	3				

Primary Plant: Sandersville, MS, USA
Secondary Plant: Sandersville, MS, USA
Price Book Ref: 29 Southeast - NEW
Price Date: 3/20/2013

Figure VII.1. Cost estimate breakdown from cement contractor for plugging of a 2,550 foot well in Lee County, NC.

Table VII.1. Bonding practice and amounts recommended by the Study Group.

Bond Type	Authority Source	Amount	Notes
Surface Owner	113-421 (a1)	Undetermined	Addressed in lease negotiations
Geophysical	15 NCAC 05C.0100	$50,000	Blanket bond for projects using explosive charges
Well Plugging/Abandonment	113-378	$ 27.00 per foot of well bore to be cemented	
Site Reclamation		See Table VII.4	Based on land use

Table VII. 2. State by state comparison of bonding practice and types.

	Cost of Bond	What is Being Bonded?	Type of Surety Allowed
Alaska	*Amount per well*: Not less than $100,000 (Based on the cost of abandonment and location clearance; may be less if the operator can prove that the cost for abandonment would < $100K) *Blanket bond*: Not less than $200,000.	Ensures proper construction, operation, maintenance, and abandonment; and that each location is cleared according to State rules.	Surety or a personal bond
Arizona	*Amount per well*: $10,000 for well depth to 10,000 ft.; $20,000 for well depth > 10,000 ft. *Blanket bond*: $25,000 for 10 or fewer wells; $50,000 for between 10 - 50 wells; or $250,000 for 50+ wells.	Ensures proper construction, abandonment, plugging, repairing, and restoration of well site.	Surety bond executed by the operator (principal) and a corporate surety, authorized to work in AZ; Certified checks or CDs are acceptable.
Arkansas	*Blanket bond*: $25,000 for 1 to 25 wells; $50,000 for 60 to 100 wells; $100,000 for more than 100 wells.	Plugging, well repair, and well site restoration.	Surety bond, irrevocable letter or credit, CD, cash.
California	*Amount per well*: $15,000 for each well <5,000 ft. deep; $20,000 for each well 5,000 to <10,000 ft.; $30,000 for each well 10,000 ft. or greater. *Blanket bond*: (a) $250,000 (not including the idle well fee); (b) $100,000 for any operator with 50 or fewer wells in CA (not including the idle well fee); (c) $1,000,000 which does include the idle well fee. *Idle well fee or bond*: $100 for each well that has been idle for <10 yrs.; $250 for each well idle for 10 to <15 yrs.; $500 for each well idle for 15 yrs. or more. May also be drawn off an established escrow account established by depositing $5,000 for each idle well.	Well construction, repair, re-drilling, plugging, and site restoration Also, a "life of production" or "life of well" facility bond may be required of operators with a history of violations. A facility bond will cover plugging and abandonment; decommissioning of facilities; financing of spill/incident response and remediation.	Cash or indemnity bond.
Florida	*Amount per well*: $50,000 for 0 to 9,000 ft.; $100, 000 if 9,000 ft. or greater. Amounts are doubled if well is successful. *Blanket bond*: $1,000,000 (10 well limit).	Plugging and/or site clean-up if the operator goes bankrupt	Bond, letter of credit, cash or asset deposit, and participation in Minerals Trust Fund.

	Cost of Bond	What is Being Bonded?	Type of Surety Allowed
Georgia	*Amount per well*: Flexible, up to $50,000 *Blanket bond*: $50,000 and adequate documentation of financial resources to plug wells.	Well plugging according to specifications.	Not specified
Idaho	*Amount per well*: $10,000 plus $1.00 per ft. *Blanket bond*: $50,000 (up to 10 wells); $100,000 (11 to 30 wells); $150,000 (more than 30 wells).	Well plugging, surface reclamation, protection of surface estate if separate from mineral estate.	Cash or surety bond.
Illinois	Amount per well: $1,500 (less than 2,000 ft.); $3,000 (over 2,000 ft.). *Blanket bond*: $25,000 (0 to 25 wells); $50,000 (26 to 50 wells); $100,000 (51 or more wells)	Penalty, plugging and restoration.	Surety letter, letter of credit, and certificate of deposit.
Indiana	*Amount per well*: $2,500 *Blanket bond*: $45,000	Plugging and abandonment of wells, restoration.	Surety bond, certificate of deposit, cash.
Kansas	*Amount per well*: $0.75 times the aggregate depth for all wells drilled or operated. *Blanket bond*: Ranges from $7,500 to $45,000 depending on the number of wells and depth.	Plugging, restoration, and requirement by statute for an operator to receive a license.	Performance bond, letter of credit, fee, state lien on tangible personal property, other.
Kentucky	*Amount per well*: $500 (0 to 500 ft.); $1,000 (501 to 1,000 ft.); $1,500 (1,001 to 1,500 ft.); $2,000 (1,501 to 2,000 ft.); $2,500 (2,001 to 2,500 ft.); $3000 (2,501 to 3,000 ft.); $3,500 (3,001 to 3,500 ft.); $4,000 (3,501 to 4,000 ft.); $5,000 or other amount set by the Oil and Gas Commission (over 4,000 ft.). *Blanket bond* (for "qualified" operators): $10,000 (1 to 25 wells); $25,000 (25-100 wells); $50,000 (100 to 500 wells); $100,000 (over 500 wells). *Blanket bond* (for "unqualified" operators): $50,000 (1 to 100 wells); $100,000 (over 100 wells).	Compliance purposes – plugging.	Cash, letter of credit, surety, and certificates of deposit

	Cost of Bond	What is Being Bonded?	Type of Surety Allowed
Louisiana	*Amount per well* (land-based): $1.00 per ft. (less than 3,000 ft. depth); $2.00 per ft. (3,001 to 10,000 ft.); $3.00 per ft. (over 10,001 ft.). *Amount per well* (inland water): $8.00 per ft. *Amount per well* (water): $12.00 per ft. *Blanket bond* (land): $25,000 (0 to 10 wells); $125,000 (11 to 99 wells); $250,000 (over 100 wells). *Blanket bond* (inland water): $125,000 (0 to 10 wells); $625,000 (11 to 99 wells); $1,250,000 (over 100 wells). *Blanket bond* (water): $250,000 (0 to 10 wells); $1,250,000 (11 to 99 wells); $2,500,000 (over 100 wells).	Plugging and restoration.	Certificate of deposit, performance bond, letter of credit.
Maryland	*Amount per well*: no minimum, $100,000 maximum. *Blanket bond*: no minimum, $500,000 maximum.	Plugging and site restoration.	Surety bonds, cash, letters of credit, certificates of deposit.
Michigan	*Amount per well:* dependent on well depth, ranges from $10,000 to $30,000. *Blanket bond*: dependent on well depth, ranges from $100,000 to $250,000.	Well plugging and site restoration.	Conformance bond, letter of credit, cash, certificate of deposit.
Missouri	*Amount per well:* $1,000 (0 to 500 ft.); $2,000 (501 to 1,000 ft.); $3,000 (1,001 to 2,000 ft.); $4,000 (2,001 to 5,000 ft.); $4,000 + $1.00 per ft. (5,001 ft. and deeper). *Blanket bond*: $20,000 (0 to 800 ft.) for 50 wells; $30,000 (801 to 1,200 ft.) for 15 wells.	Plugging, abandonment, and site restoration.	Surety bond, personal bond, letter of credit.
Nebraska	*Amount per well:* Currently $5,000 but will increase to $10,000 *Blanket bond*: Currently $25,000 but will increase to $100,000.	Plugging, abandonment, and site restoration.	Insurance or certificate of deposit.

	Cost of Bond	What is Being Bonded?	Type of Surety Allowed
Nevada	*Amount per well:* $10,000. *Blanket bond*: $50,000.	Plugging and abandonment	Corporate surety licensed to do business in Nevada.
New Mexico	*Amount per well:* $5,000 + $1.00 per ft. in major producing counties; $10,000 + $1.00 per ft. for wells located elsewhere. *Blanket bond*: $50,000, but single well bond may be required in addition to the blanket bond for wells inactive for more than 2 years.	Plugging, abandonment, restoration, and remediation.	Surety shall be a reputable corporate surety authorized to do business in New Mexico.
North Dakota	*Amount per well:* $50,000 except that wells drilled to 2,000 ft. or less may be bonded in a lesser amount. Commercial disposal wells are bonded at $50,000 each. *Blanket bond*: $100,000 (more than 1 well). Limited to cover no more than 6 unplugged dry holes, plugged wells with site not reclaimed, and/or abandoned wells. This bond does not cover commercial disposal wells.	Drilling, plugging, and restoration.	Collateral bond, self-bond, cash, or any alternative form of security approved by the commission.
Oklahoma	*Amount per well:* Based on cost of plugging and abandonment of each well. If statewide plugging liability is less than $25,000, surety can be in the form of Category B. Blanket bond: $25,000 (Category B); $50,000 (Category A).	Drilling, operation, plugging, and restoration.	*Category A*: Financial statement showing net worth of $50,000 or greater. *Category B*: Corporate surety bond, irrevocable commercial letter of credit, bank joint custody receipt, certificate of deposit, cashier's check, cash, or other negotiable instrument.
Oregon	*Amount per well:* $10,000 (less than 2,000 ft.); $15,000 (2,000 ft. to 5,000 ft.); $25,000 (deeper than 5,000 ft.). *Blanket bond*: $100,000 minimum and must equal the individual well bond amounts. *Seismic bond*: $50,000, but may be waived if a blanket bond is in place.	Compliance with rules and regulations of the State of Oregon.	Not specified

	Cost of Bond	What is Being Bonded?	Type of Surety Allowed
Pennsylvania	*Amount per well (conventional wells):* $2,500 per well. *Blanket bond (conventional wells)*: $25,000 for all wells. *Unconventional wells bond (wells with total bore length less than 6,000 ft.)*: Operating up to 50 wells, $4,000 per well, but no bond may exceed $35,000; Operating 51 to 150 wells, $35,000 plus $4,000 per well for each well in excess of 50 wells, but no bond may exceed $60,000; Operating 151 to 250 wells, $60,000 plus $4,000 per well for each well in excess of 150 wells, but no bond may exceed $100,000; Operating more than 250 wells, $100,000 plus $4,000 per well for each well in excess of 250 wells, but no bond may exceed $250,000; *Unconventional wells bond (wells with total well bore length of 6,000 ft. or greater)*: Operating up to 25 wells, $10,000 per well, but no bond may exceed $140,000; Operating 26 to 50 wells, $140,000 plus $10,000 per well for each well in excess of 25 wells, but no bond may exceed $290,000; Operating 51 to 150 wells, $290,000 plus $10,000 per well for each well in excess of 50 wells, but no bond may exceed $430,000; Operating more than 150 wells, $430,000 plus $10,000 per well for each well in excess of 150 wells, but no bond may exceed $600,000.	Plugging, abandonment, and restoration.	Any method is allowed, as long as the surety complies with the respective bonding statute (58 P.A.C.S. 3225).
South Dakota	*Amount per well:* $5,000 for plugging and performance; $2,000 for surface restoration. *Blanket bond*: $20,000 for plugging and performance; $10,000 for surface restoration.	Proper plugging and surface restoration.	Corporate surety bond, certificate of deposit, letter of credit.
Tennessee	*Amount per well*: $2,000 for 0 to 2,500 ft.; $3,000 for 2,501 ft. to 5,000 ft.; $1.00 per foot for any well drilled deeper than 5,000 ft. *Blanket bond*: $20,000 for 10 wells drilled form 0 to 5,000 ft.; $30,000 for 10 wells from 5,001 ft. to 10,000 ft.; No blanket bonds for wells deeper than 10,000 ft.	Proper plugging of wells, closure of pits, and cleanup of leases and other facilities.	Individual performance bond; blanket performance bond; letter of credit; cash deposit; or individual well plugging insurance policy.

	Cost of Bond	What is Being Bonded?	Type of Surety Allowed
Texas	*Amount per well*: $2.00 per foot for each well, excluding wells covered by plugging insurance. *Blanket bond*: At least the base amount or $25,000, whichever is greater. Base amounts determined as: 10 or fewer wells is $25,000; 10 to 99 wells is $50,000; 100 or more wells is $250,000. *Additional bond* (Operators of bay/near shore wells): $60,000, in addition to the other required bonds (above). *Additional bond* (offshore wells or combination of bay and offshore wells): $100,000, in addition to the other required bonds (above). *Note*: Reductions of "additional bonds" may be allowed by the State, if the operator can prove other means of financial assurance.	Proper plugging of wells, closure of pits, and cleanup of leases and other facilities.	Individual performance bond; blanket performance bond; letter of credit; cash deposit; or individual well plugging insurance policy.
Virginia	*Amount per well*: An amount sufficient for plugging and site restoration not less than $10,000 per well plus $2,000 per acre of disturbed land. *Blanket bond*: $25,000 (1 to 15 wells); $50,000 (16 to 30 wells); $75,000 (31 to 50 wells); $100,000 (51 or more wells).	Plugging and restoration	Certificate of deposit, cash, other surety bonds acceptable by the State.
Washington	*Amount per well*: Not less than $50,000 *Blanket bond*: Not less than $250,000	Proper well abandonment and site reclamation.	Not specified
West Virginia	*Amount per well*: $5,000 per vertical well; $50,000 per horizontal well. *Blanket bond*: $50,000 for multiple vertical wells; $250,000 for multiple horizontal wells.	Plugging and site reclamation	Not specified

	Cost of Bond	What is Being Bonded?	Type of Surety Allowed
Wyoming	*Amount per well*: \$10,000 for each well less than to equal to 2,000 ft.; \$20,000 for each well deeper than 2,000 ft. *Blanket bond*: \$75,000 *Idle well bond*: \$10.00 per ft.	Plugging and restoration, also includes seismic operations, well operation, well abandonment, idle wells, and pits.	Not specified

Table VII.3. Comparison of surface owner bonding.

Comparison of Surface Owner Bonding	
State	**Bonding Specifics**
Colorado	$2,000 per well for non-irrigated land, $5,000 per well for irrigated land Optional $25, 000 statewide blanket bond The operator can still be held liable for damages exceeding the financial assurance.
New Mexico (proposed legislation)	Requires financial assurance agreement between a surface owner and the operator -OR- Binding Arbitration Agreement -OR- Requires compensation for a land tenant in accordance with incurred damages.
North Dakota	Oil and gas developers must pay for incurred damages.
Oklahoma	Requires agreement between the operator and the surface owner -OR- State will appoint appraisers, through the court system, to determine damages.
Wyoming	$2,000 per well site -OR- The Commission may establish an alternate blanket bond for the owner's land.
Bureau of Land Management	Based on an agreement between the lessee (operator) and surface owner -Or- Mandatory Bonding, depending on laws related to the respective land; minimum bond is $1,000.

Table VII.4. Comparison of bonding practices for geophysical exploration.

State	Rule	Requirement	Forms	Fees & Bonding
Colorado	Rule 333 (seismic operations)	**Form 3** and prove financial assurance in accordance with rule 705. Bond remains in effect until request is made by the company. Statewide blanket financial assurance of $25,000 required prior to commencing operations. 1. Shot holes have been properly plugged and abandoned and source/receiver lines have been reclaimed. 2. No outstanding complaints received from surface owners.	**Form 3**: Performance Bond	$25,000 statewide blanket bond
Arkansas	Rule B-42 (seismic)	The amount of the financial assurance shall be determined by the Director based on, but not limited to, the proximity of the seismic shoot to populated areas, cultural features, sensitive environmental areas, and past Commission enforcement history against the applicant.	**Form 19B**: Seismic Bond	Application fee for seismic operations is $500. Bond will be a minimum of $50,000 but not more than $250,000. Financial assurance shall remain in effect for one year following the conclusion of all field seismic operations.
Ohio	N/A	The Division does not regulate seismic activity. Since the testing is an agreement between the company and the landowner, no permit is required.	N/A	N/A
Oklahoma	165:10-11-6 (bonding)	**Form 1006SB**: Surety Bond for Seismic Shot Hole Plugging within the State of Oklahoma. Before drilling shot holes a $50,000 bond must be posted.	**Form 1006SB**: Surety Bond for Seismic Shot Hole Plugging within the State of Oklahoma	$50,000 bond
North Dakota	43-02-12-03	Any person desiring to engage in geophysical exploration within the state must obtain from the		Bonding: $50,000 if contractor intends to conduct shot hole

State	Rule	Requirement	Forms	Fees & Bonding
	(bonding)	secretary of state a certificate of authority to transact business.		operations, $25,000 for any other method of geophysical exploration. Each subcontractor shall carry a $10,000 bond. Permit fee = $100
Pennsylvania	25 PA Code Chapters 210 and 211	Pennsylvania Department of Environmental Protection (DEP) regulates the storage, handling, and use of explosives.	5600-PM-MR0021	No amount provided
U.S. Department of the Interior – Bureau of Land Management (BLM) & U.S. Department of Agriculture – Forest Service (FS)	Code of Federal Regulations 43 CFR 3000 & 36 CFR 228 Subpart E; Onshore Oil & Gas Orders & Notices to Lessees (NTLs) – The Gold Book. BLM/WO/ST-06/021+3071/REV 07.	BLM managed lands – party filing NOI will need a bond and geophysical operator will need a bond. FS managed lands – authorized officer decides whether bond is required.	**BLM Form 3150-4/FS Form 2800-16** - Notice of Intent (NOI) and Authorization to Conduct Oil and Gas Geophysical Exploration Operations **BLM Form 3150-5/FS Form 2800-16a** - Notice of Completion (NOC) of Oil and Gas Exploration Operations	No amount provided

Table VII.5. Proposed reclamation costs table constructed by staff.

DETERMINATION OF RECLAMATION COST AND BOND

Category	Affected Area	Unit	Reclamation Cost/Unit		Reclamation Cost
Topsoil Stockpiles	7,000	Cubic Yard	$3.50		$24,500.00
Stone Removal for Access Road & Well Pad (Does not include transportation and disposal cost)	6,220	Cubic Yard	$20.00		$124,400.00
Spreading Stockpiles and Berms to Prepare for Fine Grading (filling a 2 acre 15 foot deep pit)	50,000	Cubic Yard	$3.50		$175,000.00
Fine Grading (5 acres)	24,250	Square Yard	$1.15		$27,887.50
Seed & Mulch, Repair Seeding, & Fertilizing	9.2	Acre	$2,700.00		$24,840.00
Matting for Soil Cover (Straw/Wood)	1,345	Square Yard	$2.00		$2,690.00
Matting Permanent Soil Reinforcement (Poly)		Square Yard	$8.50		$0.00
Drainage Ditch Excavation		Cubic Yard	$9.00		$0.00
Borrow Excavation		Cubic Yard	$7.00		$0.00
		Subtotal removing road & pad			$379,317.50
Inflation based on life of permit at 2% annually		Inflation cost			$7,586.35
		Total			**$386,903.85**
		Subtotal leaving road & pad			$254,917.50
Access Road Construction	Cubic Yards	Inflation cost			$5,098.35
Aggregate Base	630	Total			**$260,015.85**
Course Aggregate	945				
Subtotal Access Road	1575	Reclamation cost per acre			$41,230.16
Well Pad Construction		Reclamation cost per acre leaving			$27,708.42
Aggregate Base	1860				
Course Aggregate	2785	Total Land Distrubance		9.2	Acres
Subtotal Well Pad	4645	Access Road		1.14	Acres
Total Aggregate	6220	Well Pad		3.45	Acres

Table VII.6. Comparison of bond types currently in use by other DEMLR sections.

Bond Type	How it Works	Advantages and Disadvantages
Assignment of Savings Account	The operator puts money into a bank account, CD, or other bank-based financial instrument. This money is "frozen" in the account until the bond is either released or used by DENR.	Advantages: **(1)** If the bank releases the bond money prematurely, the bank is still responsible for paying the bond. **(2)** The money is already set aside for bonding purposes before a project begins. **(3)** If the operator goes bankrupt, DENR can still access the bonding money using the Attorney's General Office. **(4)** The operator can collect and keep all interest on the money in the account. Disadvantages: **(1)** DENR must move quickly to obtain these funds if the operator goes bankrupt. Otherwise, other creditors might obtain the money first. **(2)** If the bank goes bankrupt, DENR must trace the money to whatever financial institution has taken over the account.
Surety Bonds	The operator pays a financial surety company a monthly bond premium to cover the respective bond. If the operator fails to make the payment, the bonding company must notify DENR at least 60 days before canceling coverage.	Advantages: **(1)** If the operation is limited in time duration, the operator does not have to pay for the entire bond up front, and may save money in the long term. **(2)** The bonding company provides a guarantee of payment. Disadvantages: **(1)** The operator cannot recover the premium costs. **(2)** Late payments to the bonding company prompt threats of canceling coverage, which costs DENR a lot of staff labor to either prompt the operator to maintain payments, or to process paperwork to recover the bond.
Bank Guaranty	The bank issues a guaranty of payment. In other words, a financial institution provides a letter to DENR stating that a given operator is "good" for the bond money. Obviously, this instrument is almost never used.	Advantages: **(1)** Bank guaranty that the bond will be covered. **(2)** Paperwork is easier to process, compared to other instruments. Disadvantage: DENR must move quickly to obtain funds if the operator goes bankrupt. Otherwise, other creditors might obtain money first.
Cash Deposits	A cashier's check or a certified check for the bonding amount is sent to DENR by the operator. (DEMLR's mining program discourages this instrument.)	Advantage: The money is "in-hand" and easily accessed by DENR. Disadvantages: **(1)** The operator gains no interest from the bonding money. **(2)** DENR staff labor is extensive, as checks must be processed and deposited in a State-maintained account. **(3)** Releasing the bond back to the operator takes considerable time (roughly two months).

Appendix A: Report on Production and Severance Tax Scenarios

Scenario analyses in support of a structure for severance tax for natural gas and natural gas liquids

Introduction

In a July 13, 2013 e-mail, Mining and Energy Commission (MEC) Chairman James Womack tasked Dr. Ray Covington and Dr. Kenneth Taylor to prepare a reasonable baseline estimation of the production volumes of natural gas along with pricing for the shale gas basins in the State. This estimation was needed so that the Funding Levels and Potential Funding Sources Study Group could ensure the funding requirements could be met through the Study Group's recommended funding formulae.

At the September 5, 2013 MEC meeting, Dr. Vikram Rao suggested that rather than preparing an estimate of production volumes, a number of scenarios should be prepared indicating a Low, Medium and High estimate of production using early development in similar shale gas fields in other parts of the country.

A preliminary analysis of the scenarios was presented at the September 12, 2013 meeting of the Funding Levels and Potential Funding Sources Study Group. Following that presentation and with feedback from the MEC Chairman and other members of the study group, a final set of scenarios were prepared. Chairman Womack's assumptions for the estimation were:

(A) Successful completion of pre-production exploration of the Sanford sub-basin to include 3-D seismic and 2-5 exploratory wells by mid- 2014;
(B) MEC completion of its rule-set by 1 October 2014, NCGA adoption of the MEC's rule-set, and permit issuance beginning 1 March 2015;
(C) Confirmation of the presence of wet gas in the Sanford Sub-basin with marketable condensates as reflected in pre-production gas sampling over the past 40 years;
(D) Reasonable (in-stride) development of gathering lines, field separators and compressor stations to meet mid-stream infrastructure requirements throughout 2015-16; and
(E) Sufficient market demand to sustain the price points used in the EIA price projections.

Methodology

The (B-43 Field) of the Fayetteville Shale in north Arkansas was selected as the field for these scenarios. Production of natural gas in the nine Fayetteville Shale counties has increased from 100.6 million cubic feet in 2004 to 944 billion cubic feet in 2011. [Revisiting the Economic Impact of the Natural Gas Activity in the Fayetteville Shale: 2008-2012 – Center for Business and Economic Research, Sam M. Walton College of Business, May 2012] A diagram of the Fayetteville Shale Natural Gas Production is shown in Figure 1.

- **Production of natural gas** in Fayetteville Shale counties increased significantly from 100.6 million cubic feet in 2004 to **almost 943.6 billion cubic feet in 2011**. The highest level of natural gas production in 2011 occurred in Van Buren County, followed by White, Conway, and Cleburne counties.

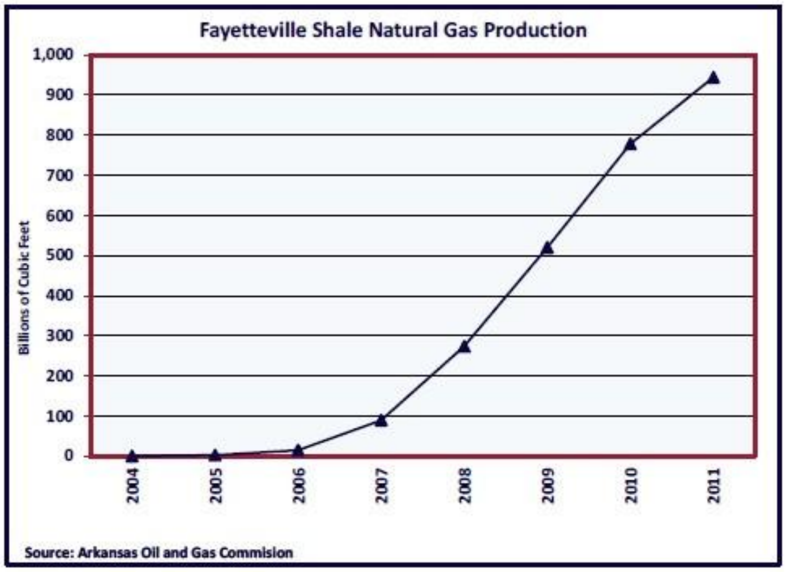


Figure 1

Starting from 2004 with 30 wells completed, the cumulative number of wells increased to 1,080 completed before 2008, and ending in 2011 with 823 completions and 4,878 total wells. A plot of the number of drilling permits issued per year is shown as Figure 70 in the Economic Report and is shown below as Figure 2.

Figure 70: Fayetteville Shale Counties Drilling Permits

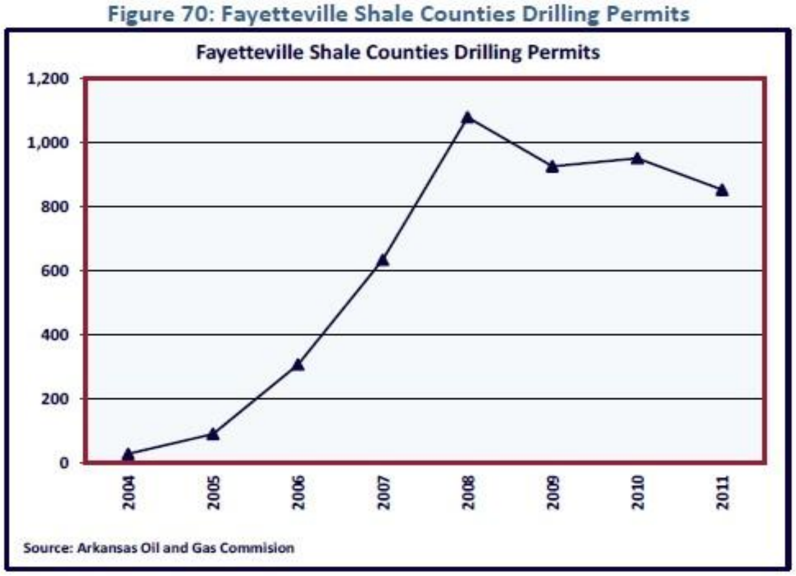


Figure 2

The natural gas production from that field is shown in Table 1. All figures in bold in the table were obtained directly from the Economic Report cited earlier. The other values were calculated from the graphs in Figures 1 & 2.

Year	number of wells completed	total number of wells	Production MCF (thousands of cubic feet gas)	average production per well (MCF)			Severance Tax (1.5%) in MCF
2004	30	30	101,000	3,367	101,000	3,367	1,515
2005	95	125	2,400,000	19,200	2,501,000	20,008	36,000
2006	315	440	14,800,000	33,636	17,301,000	39,320	222,000
2007	640	1080	89,200,000	82,593	106,501,000	98,612	1,338,000
2008	1090	2170	280,000,000	129,032	386,501,000	178,111	4,200,000
2009	930	3100	510,000,000	164,516	896,501,000	289,194	7,650,000
2010	955	4055	790,000,000	194,821	1,686,501,000	415,907	11,850,000
2011	823	4878	944,000,000	193,522	2,630,501,000	539,258	14,160,000

2,630,501,000 Cumulative Production (MCF)

Table 1

There are nine counties which contribute to the Fayetteville Shale production. For 2011, they are in rank order: Van Buren (30.5%), White (24.3%, Conway (21.0%), Cleburne (14.8%), Faulkner (7.5%), Independence (1.3%), Pope (0.3%), Jackson (0.3%) and Franklin (0.01%).

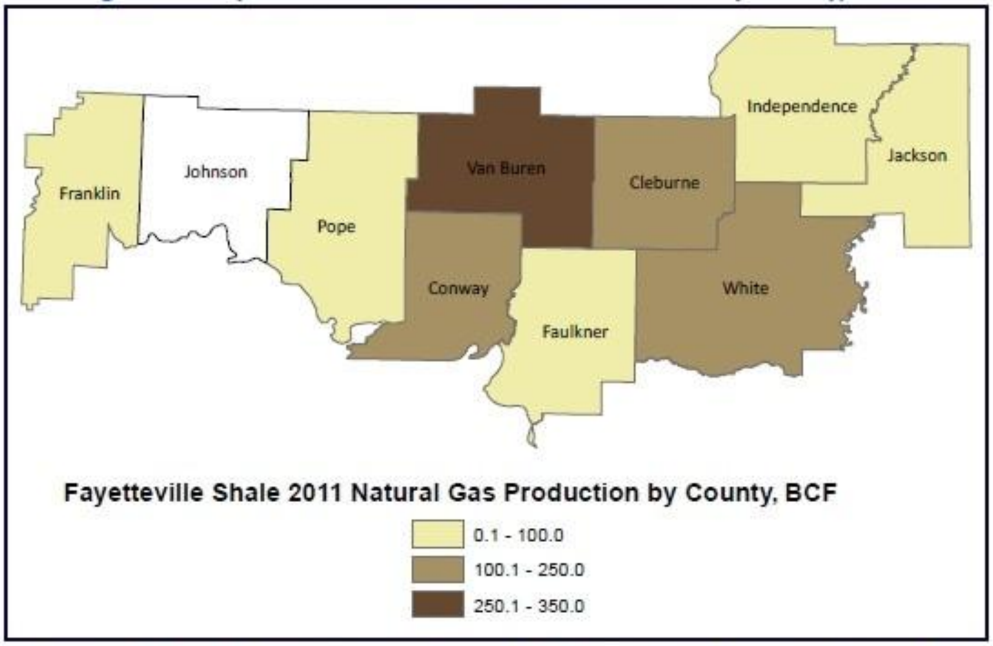
A map of these counties is shown in Figure 3, with the counties classified into three groups by production. The three level of production provides the basis for the direct comparison of the production in these counties compared to an equal area and number of wells to use in the scenarios.

Total production is 944,000,000 MCF and the total number of wells of 4,878. Using the percentages in for each county, the number of well for Group 1-- (Van Buren) is 1,488; Group 2 -- (White) is 1,185, (Conway) is 1024, and (Cleburne) is 722; Group 3 -- (Faulkner) is 366.

The areas of the counties in square miles are Van Buren, 712; White, 1234; Conway, 556; Cleburne, 553; and Faulkner, 647. For the three scenarios, the production is calculated in terms of the number of wells at an average annual production of 130,000 MCF is compared to the equivalent area of the Deep River Basin.

For Scenario 1 – the area of Deep River Basin = 1,184 square miles. The area of Van Buren County = 712 square miles. The ratio of the areas is 1,184/712 = 1.66. The number of wells in Van Buren County = 1488. Because the area of Deep River Basin is larger than Van Buren County, the number of wells must be increased to make a direct comparison of the production two areas with the same density of wells; 1,488 * 1.66 = **2,470 wells**.

Figure 77: Fayetteville Shale Natural Gas Production by County, 2011



Source: Arkansas Oil and Gas Commission, Center for Business and Economic Research estimates

Figure 3

For Scenario 2 – Again the area of Deep River Basin = 1,184 square miles. The area of Cleburne County and Conway County and White County = 2,143 square miles. The ratio of the areas is 1,184/2,143 = 0.55. Note that in this scenario, the number of wells in Cleburne, Conway and White is 2,931 which must be reduced since the area of the Deep River Basin is smaller than the area of those three counties. 2931 * 0.55 = **1,612 wells**.

For Scenario 3 -- Again the area of Deep River Basin = 1,184 square miles. The area of Faulkner County = 647 square miles. The ratio of areas is 1,184/647 = 1.83; Number of wells in Faulkner County = 366. The number of wells in the scenario must be increased to account for the larger area of the Deep River Basin; 366 * 1.83 = **615 wells**.

Scenario 1, Scenario 2, and Scenario 3 are shown in the attached PDF document "Scenarios_for_estimating_severance_taxes.pdf".

Each scenario starts with the number of well (Scenario 1 – 2,470; Scenario 2 – 1,612; and Scenario 3 – 615) and back calculates the cumulative number of wells by year using the Fayetteville Shale cumulative production curve (Figure 1 and Table 1). The number of wells completed per year is then calculated by subtracting the previous year's cumulative number from the current year number.

The number of wells is multiplied by the average production per well (130,000 MCF) to produce the production MCF. The annual production is summed into the cumulative production. The cumulative production is used to calculate the number of barrels of natural gas liquids which could be expected from such production based on the USGS Resource Assessment [“Assessment of Undiscovered Oil and Gas Resources of the East Coast Mesozoic Basins of the Piedmont, Blue Ridge Thrust Belt, Atlantic Coastal Plain, and New England Provinces, 2011”, U.S. Geological Survey Fact Sheet 2012-3075, June 2012].

In the USGS assessment, the mean total undiscovered resource of gas is 1,660 billion cubic feet of gas (BCFG) and the mean volume of natural gas liquids is 83 million barrels of natural gas liquids (MMBNGL). In order to calculate the number of gallons of natural gas liquids per thousand cubic feet of gas (MCF), one multiplies the number of barrels of natural gas liquids by 42 gallons/barrel and divide that number by the number of MCF gas.

83 MMBNGL = 83 x 10^6 BNGL, which is multiplied by 42 gallons/barrel which equals 3.486 x 10^9 gallons. 1,660 BCFG equals 1.66 billion MCF (1.66 x 10^9 MCF). Divide the two numbers and one obtains the value of 2.1 gallons/MCF. This is the same number Dr. Rao gave at the September 12th meeting.

Discussion

An examination of the three spreadsheets shows that for Scenario 3 – 615 wells, the severance tax of 1.5 percent does not generate the required $3.0 million annual funding need. However, when the severance tax of 5% (which is already set by statute) on liquid petroleum, sufficient revenue is generated to sustain the proposed funding needs.

For Scenario 2 – 1,612 wells, the severance tax of 1.5% on natural gas provides two-thirds of the need and when combined with a portion of the severance tax of 5% on liquid petroleum, there is more than sufficient funds.

For Scenario 1 – 2,470 wells, the severance tax of 1.5% could provide the necessary funding with only a small portion of the natural gas liquids severance tax.

Report by:

Dr. Kenneth B. Taylor, PG
State Geologist of North Carolina

September 19, 2013

Scenario 1 -- Area of Deep River Basin = 1,184 square miles. Area Of Van Buren County = 712 square miles. Ratio of area 1,184/712 = 1.66; Number of wells in Van Buren County = 1488; 1,488 * 1.66 = 2,470 wells

Year	number of wells completed	total number of wells	Production MCF (thousands of cubic feet gas)	average production per well (MCF)	Cumulative Production (MCF)	Severance Tax (1.5%) in MCF	$3.50/MCF	$4.50/MCF	Severance Tax (3.0%) in MCF	$3.50/MCF	$4.50/MCF	Natural Gas Liquids Severance Tax (5%) in bngl	$90/barrel	$110/barrel
0	15	15	1,950,000	130,000	1,950,000	29,250	$102,375	$131,625	58500	$204,750	$263,250	4,875	$438,750	$536,250
1	49	65	6,370,000	130,000	8,320,000	95,550	$334,425	$429,975	191100	$668,850	$859,950	15,925	$1,433,250	$1,751,750
2	162	226	21,060,000	130,000	29,380,000	315,900	$1,105,650	$1,421,550	631800	$2,211,300	$2,843,100	52,650	$4,738,500	$5,791,500
3	339	565	44,070,000	130,000	73,450,000	661,050	$2,313,675	$2,974,725	1322100	$4,627,350	$5,949,450	110,175	$9,915,750	$12,119,250
4	566	1131	73,580,000	130,000	147,030,000	1,103,700	$3,862,950	$4,966,650	2207400	$7,725,900	$9,933,300	183,950	$16,555,500	$20,234,500
5	452	1583	58,760,000	130,000	205,790,000	881,400	$3,084,900	$3,966,300	1762800	$6,169,800	$7,932,600	146,900	$13,221,000	$16,159,000
6	475	2058	61,750,000	130,000	267,540,000	926,250	$3,241,875	$4,168,125	1852500	$6,483,750	$8,336,250	154,375	$13,893,750	$16,981,250
7	412	2470	53,560,000	130,000	321,100,000	803,400	$2,811,900	$3,615,300	1606800	$5,623,800	$7,230,600	133,900	$12,051,000	$14,729,000
	2470						$16,857,750	$21,674,250		$33,715,500	$43,348,500	802,750	$72,247,500	$88,302,500

321,100,000 Cumulative Production (MCF)

Natural Gas Liquids -- 2.1 gal/mcfg

Cumulative Production (MCF)	2.1 gal/MCF	number of gallons	number of barrels (42 gal/barrel)	value per barrel $90/barrel	
321,100,000	2.1	674,310,000	16,055,000	90	$1,444,950,000

802,750 Check Sum of 5% of total number of barrels

Scenario 2 -- Area of Deep River Basin = 1,184 square miles. Area of Cleburne County and Conway County and White County = 2,143 square miles. Ratio of area 1,184/2,143 = 0.55; Number of wells in Cleburne, Conway and White = 2,931; 2931 * 0.55 = 1,612 wells

Year	number of wells completed	total number of wells	Production MCF (thousands of cubic feet gas)	average production per well (MCF)	Cumulative Production (MCF)	Severance Tax (1.5%) in MCF	$3.50/MCF	$4.50/MCF	Severance Tax (3.0%) in MCF	$3.50/MCF	$4.50/MCF	Natural Gas Liquids Severance Tax (5%) in bngl	$90/barrel	$110/barrel
0	10	10	1,300,000	130,000	1,300,000	19,500	$68,250	$87,750	39000	$136,500	$175,500	3,250	$292,500	$357,500
1	32	42	4,160,000	130,000	5,460,000	62,400	$218,400	$280,800	124800	$436,800	$561,600	10,400	$936,000	$1,144,000
2	106	148	13,780,000	130,000	19,240,000	206,700	$723,450	$930,150	413400	$1,446,900	$1,860,300	34,450	$3,100,500	$3,789,500
3	221	369	28,730,000	130,000	47,970,000	430,950	$1,508,325	$1,939,275	861900	$3,016,650	$3,878,550	71,825	$6,464,250	$7,900,750
4	369	738	47,970,000	130,000	95,940,000	719,550	$2,518,425	$3,237,975	1439100	$5,036,850	$6,475,950	119,925	$10,793,250	$13,191,750
5	295	1033	38,350,000	130,000	134,290,000	575,250	$2,013,375	$2,588,625	1150500	$4,026,750	$5,177,250	95,875	$8,628,750	$10,546,250
6	310	1343	40,300,000	130,000	174,590,000	604,500	$2,115,750	$2,720,250	1209000	$4,231,500	$5,440,500	100,750	$9,067,500	$11,082,500
7	269	1612	34,970,000	130,000	209,560,000	524,550	$1,835,925	$2,360,475	1049100	$3,671,850	$4,720,950	87,425	$7,868,250	$9,616,750
	1612						$11,001,900	$14,145,300		$22,003,800	$28,290,600	523,900	$47,151,000	$57,629,000

209,560,000 Cumulative Production (MCF)

Natural Gas Liquids -- 2.1 gal/mcfg

Cumulative Production (MCF)	2.1 gal/MCF	number of gallons	number of barrels (42 gal/barrel)	value per barrel $90/barrel	
209,560,000	2.1	440,076,000	10,478,000	90	$943,020,000

523,900 Check sum of 5% of total number of barrels

Scenario 3 -- Area of Deep River Basin = 1,184 square miles. Area of Faulkner County = 647 square miles. Ratio of area 1,184/647 = 1.83; Number of wells in Faukner County = 366; 366 * 1.83 = 615 wells

Year	number of wells completed	total number of wells	Production MCF (thousands of cubic feet gas)	average production per well (MCF)	Cumulative Production (MCF)	Severance Tax (1.5%) in MCF	$3.50/MCF	$4.50/MCF	Severance Tax (3.0%) in MCF	$3.50/MCF	$4.50/MCF	Natural Gas Liquids Severance Tax (5%) in bngl	$90/barrel	$110/barrel
0	4	4	520,000	130,000	520,000	7,800	$27,300	$35,100	15600	$54,600	$70,200	1,300	$117,000	$143,000
1	12	16	1,560,000	130,000	2,080,000	23,400	$81,900	$105,300	46800	$163,800	$210,600	3,900	$351,000	$429,000
2	40	56	5,200,000	130,000	7,280,000	78,000	$273,000	$351,000	156000	$546,000	$702,000	13,000	$1,170,000	$1,430,000
3	85	141	11,050,000	130,000	18,330,000	165,750	$580,125	$745,875	331500	$1,160,250	$1,491,750	27,625	$2,486,250	$3,038,750
4	141	282	18,330,000	130,000	36,660,000	274,950	$962,325	$1,237,275	549900	$1,924,650	$2,474,550	45,825	$4,124,250	$5,040,750
5	112	394	14,560,000	130,000	51,220,000	218,400	$764,400	$982,800	436800	$1,528,800	$1,965,600	36,400	$3,276,000	$4,004,000
6	118	512	15,340,000	130,000	66,560,000	230,100	$805,350	$1,035,450	460200	$1,610,700	$2,070,900	38,350	$3,451,500	$4,218,500
7	103	615	13,390,000	130,000	79,950,000	200,850	$702,975	$903,825	401700	$1,405,950	$1,807,650	33,475	$3,012,750	$3,682,250
	615						$4,197,375	$5,396,625		$8,394,750	$10,793,250	199,875	$17,988,750	$21,986,250

79,950,000 Cumulative Production (MCF)

Natural Gas Liquids -- 2.1 gal/mcfg

Cumulative Production (MCF)	2.1 gal/MCF	number of gallons	number of barrels (42 gal/barrel)	value per barrel $90/barrel	
79,950,000	2.1	167,895,000	3,997,500	90	$359,775,000

199,875 Check sum of 5% of total number of barrels