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Air Emissions

1. I ask that the State also re-consider its statement in the Overview (Sec. II) that natural gas produces lower GHG emissions than coal when burned for electricity. Any comparisons of the two energy sources should analyze the complete "life-cycle" of production. Calculation of the GHG footprint of shale gas development should include documentation of leakage rates (rates of higher than 3% effectively cancel out gas's GHG advantages over coal use) and a full accounting of potential emissions from all truck traffic needed for extraction and waste disposal. If Maryland requires a closed-loop system for waste disposal, and then transport of the waste to other states, it is likely that the truck transport needs here (and the resulting diesel emissions) will be greater than average.
2. The study should include a section dedicated to best practices for reducing methane emissions at every stage of the natural gas system.
3. The release of methane has been a great danger to people and animals, and methane is a potent greenhouse gas. The BMPs should require gas companies to meet a 1 or 2 percent leakage rate for methane throughout the drilling process. Leakage should be monitored by a certifiable method and reported annually.
4. A recent study published in the Proceedings of the National Academy of Sciences found that the methane leakage rate would have to be kept below 1 percent in order to ensure that natural gas has an immediate climate benefit over all other fossil fuels. [Alvarez, Ramon A., Stephen W. Pacala, James J. Winebrake, William L. Chameides, and Steven P. Hamburg. "Greater Focus Needed on Methane Leakage from Natural Gas Infrastructure." Proceedings of the National Academy of Sciences (2012): n. pag. Web.]
5. The stats regarding casing failure show that currently, zero leakage; which should be required but is not under the proposed BMPs, is impossible.
6. Gas companies should be required to meet a zero percent leakage rate for methane throughout the fracking process. To the extent leakage cannot be reduced to zero, the releases should be offset.
7. In order to achieve real "best practices" the state should require drilling permittees to meet the maximum emissions abatement potential based on technologies that exist today, to be achieved through a combination of offsets and EPA-certified prevention measures.
8. Permittees should be required to work with EPA STAR Program staff to estimate their annual greenhouse gas emissions after the adoption of cost-effective abatement control measures, and include that estimate in their permit application. In order to ensure that natural gas production and processing does not contribute to climate change, permittees should then include a plan for investing in carbon offsets to offset their estimated annual leakage.
9. In order to account for methane leakage that will occur after shale gas enters the transmission line, MDE should consider requiring permittees to offset leakage at a ratio greater than 1:1.
10. Venting should be absolutely prohibited.

11. The proposed BMPs allow flaring for up to 30 days for exploratory wells and place some limits on flaring during drilling. This BMP is too vague and all flaring should be prohibited. Flaring for periods longer than several days under any circumstances will result in an unacceptable level of noise and light and possibly dangerous air quality for nearby residents, especially those with small children or respiratory conditions.
12. The report says that flares should have no visible emissions. How can flared emissions NOT be visible?
13. Maryland should prohibit diesel generators, and take a stronger stance on prohibiting internal combustion engines for compressors and the like.
14. Evaporation and crystallization when combined with other chemicals which may be used/mixed on-site at gas-wells cause ground-level ozone which have serious health consequences on people, animals and plants.
15. Fugitive emissions from oil and gas operations are a source of direct and indirect greenhouse gas emissions. The Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC Guidelines) provide a three-tier approach for assessing fugitive emissions from oil and gas activities. These approaches range from the use of simple production-based emission factors and high level production statistics (i.e., Tier-1) to the use of rigorous estimation techniques involving highly disaggregated activity and data sources (i.e., Tier-3), and could include measurement and monitoring programs. There is no mention of use of Tier 3 monitoring program to ensure proper controls are in place.
16. The Draft is lacking in the required use of 'Reduced Emissions Completions' industry practice.
17. The proposed Maryland BMP provision for green completions at wellheads is an important and achievable provision that will greatly contribute to reducing GHG footprint of gas production activities in the state. Requiring green completions will provide important near-term reductions in GHG associated with gas development in Maryland.
18. Gas companies should be required to implement the model leakage detection and repair (LDAR) model program rules as described in EPA's "Leak Detection and Repair: A Best Practices Guide." In order to avoid the preventable loss of gas during the transmission and storage and distribution phases, the methane LDAR recommendations should be expanded to include transmission and distribution pipelines, pipeline compressor stations, and storage facilities.
19. The BMPs recommend that a methane leak detection and repair (LDAR) program must be established from wellhead to transmission line. This is a strong recommendation and it is vital that it is implemented strongly. Maryland's leak detection and repair BMP should be strengthened by requiring that the programs conform to EPA's Natural Gas STAR Program guidelines and EPA's best practice guidelines for leakage detection and repair programs.
    a. Written LDAR Program
    b. Training
    c. LDAR Audits

  d. Contractor Accountability
  e. Internal Leak Definition for Valves and Pumps
  f. More Frequent Monitoring
  g. Repairing Leaking Components
  h. Delay of Repair Compliance Assurance
  i. Electronic Monitoring and Storage of LDAR Data
  j. QA/QCof LDAR Data
  k. Calibration/Calibration Drift Assessment
  l. Records Maintenance

20. The minimum state standards should require that permittees adopt these ten technologies and practices.
  a. Green Completions to capture oil and gas well emissions
  b. Plunger Lift Systems or other well deliquification methods to mitigate gas well emissions
  c. Tri-Ethylene Glycol (TEG) Dehydrator Emission Controls to capture emissions from dehydrators.
  d. . Desiccant Dehydrators to capture emissions from dehydrators (when the gas flow rate is less than 5 MMcfd and have temperature and pressure limitations).
  e. Dry Seal Systems to reduce emissions from centrifugal compressor seals
  f. Improved Compressor Maintenance to reduce emissions from reciprocating compressors
  g. Low-Bleed or No-Bleed Pneumatic Controllers used to reduce emissions from control devices.
  h. Pipeline Maintenance and Repair to reduce emissions from pipelines.
  i. Vapor Recovery Units used to reduce emissions from storage tanks.
  j. Leak Monitoring and Repair to control fugitive emissions from valves, flanges, seals, connections and other equipment.
21. We urge that all of the EPA New Source Performance standards be included and most importantly they be made mandatory.
22. We urge an approach that leads to a leak prevention planning requirement and a process of continuous improvement.
23. State regulations should require green completions for fracking, refracking and workovers, and also incorporate reporting requirements for green completions, gas bleed limits for pneumatic controllers, reduction requirements from storage vessels at the well site, and air toxic requirements from glycol dehydrators used at the well site.

24. The state should consider that toxic air pollutants also pose a threat in determining setbacks. One peer-reviewed study found high levels of endocrine-disrupting chemicals in the air during the drilling phase. From the study: “Selected polycyclic aromatic hydrocarbons (PAHs) were at concentrations greater than those at which prenatally exposed children in urban studies had lower developmental and IQ scores.” http://www.endocrinedisruption.com/chemicals.air.php
25. Where possible, electricity from electrical transmission lines should be used to minimize air and noise pollution; natural gas and or solar should be used for all on-site electrical generation where feasible.
26. The March 2013 CSSD standards appear to be particularly stringent in the area of air pollution. For instance, their performance standard #10 quantifies “green completion” by calling for a methane “destruction efficiency” of 98%. Their performance standard #11 specifies what percentage of drill rig engines should comply with EPA Tier 4 emission standards by what year.
27. Compression stations create toxic air that has been linked to illness.
28. A study done by The Colorado School of Health found air pollution caused by hydraulic fracturing may contribute to “acute and chronic health problems for those living near natural gas drilling sites." (http://attheforefront.ucdenver.edu/?p=2546&utm_source=feedburner&utm_medium=feed&utm_campaign=Feed%3A+theforefront+%28%40theForefront%29).
29. Unsafe levels of specific emissions and radiation should be prohibited.

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Ancillary Infrastructure

1. Standards for the location, materials, construction or testing of gathering lines must be addressed before permitting is approved in the State of Maryland.
2. The absence of specific BPs for gathering lines, gas processing units, compressor stations, or aquifer hydrological considerations are unacceptable.
3. The Maryland Public Service Commission should adopt standards for the location, materials, construction or testing of these lines before MDE approves CGDP plans or issues permits
4. The report notes that the Maryland Public Service Commission (PSC) regulates intrastate gas and liquid pipelines, and that it appears that the PSC has not established any standards for the location, materials, construction, or testing of gathering lines. API has a published recommended practice, RP 80, “Guidelines for the Definition of Onshore Gas Gathering Lines” that the PSC and others may find of value.
5. Significantly stronger and more hazardous volatile components in unconventional production, compared to standard output in past decades accelerate pipeline corrosion as well.
6. Compressor station planning is omitted and should be inserted with “pipeline planning” in the planning principles.
7. UMCES-AL recommends that applicants wishing to drill wells be required to notify property owners residing within the established setback that an application has been filed for development. This notification requirement should also apply to citing of compressor stations and other ancillary equipment. (As outlined in Title 20 of the Md. Code, Public Service Commission Article) Applicants who wish to construct ancillary infrastructure are required to notify all landowners whose property line falls within the current required setback (1,000 feet.)
8. Should include the statement, “Any further plans to modify the engineering or capacity to exceed the designed limits will not be allowed without a plan for a complete upgrade of the pipeline to newer expected maximum pressures.”
9. Comment: This statement from the draft report is incorrect: “In the past, gathering lines were generally small diameter and did not operate under high pressure. PHMSA has recognized that lines being put into service in shale plays like the Marcellus are generally of much larger diameter and operating at higher pressure than traditional rural gas gathering lines, increasing the concern for safety of the environment and people near operations.” The rural gathering lines from the Accident Dome underground storage wells are under very high pressure when gas is being injected into the wells during warm months and extracted during the winter months.
10. Why use Pennsylvania road specification? The State of Maryland has been very critical of natural gas operation in Pennsylvania. It just seems strange that we would rely on their standards, especially since Maryland has been so critical of Pennsylvania's management of Marcellus gas development. Allegany and Garrett County have standard specification and roads department personnel to review and approve plans for roads. Let the two counties determine road requirements as they do for all need development in the counties.

11. There is a need to ensure proper regulation of rural compressor stations that may not be regulated by the federal government.

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The Comprehensive Gas Development Plan.

1. The study is unclear about how the cumulative impact of shale gas development by multiple companies will be considered in the review of CGDPs.
2. We support the recommendation for a Comprehensive Gas Development Plan (CGDP) to be prepared by the gas industry that plans for a development area prior to considering each individual well). Such an approach makes sense for maximizing efficiency and minimizing potential impacts to water quality of source and receiving waters.
3. We concur with MDE's view that the CGDP should be mandatory in Maryland and its preparation is a prerequisite to an application for a well permit.
4. It is not clear whether the State can actually require a CGDP, or if the requirements will be undermined by judicial decisions. Without the CGDP, many protections will be lost.
5. The CGDP should require geological mapping to cover the potential existence of fault lines.
6. Using a Comprehensive Gas Development Plan will concentrate the adverse impacts of shale gas development in a few places, creating intolerable levels of negative impact on those who live there.
7. The CGDP will not be effective unless the data that goes into it is reliable. Data collected by the industry should be compared to data independently collected or confirmed by MDE and DNR, especially if two or more companies participate jointly in the development of a CGDP. Industry data should not be accepted without verification.
8. According the draft report, "If the State determines that the CGDP conforms to regulatory requirements and, to the maximum extent practicable, avoids impacts to natural, social, cultural, recreational and other resources, minimizes unavoidable impacts, and mitigates remaining impacts, the State shall approve the CGDP." How will "the maximum extent practicable" be determined? The State should describe a threshold at which it would reject a CGDP if it determines that impacts are not sufficiently minimized or mitigated. How does the state plan to balance the various interests and determine if a plan "conforms to regulatory requirements and, to the maximum extent practicable?" Will the economic burden on an applicant be part of the determination?
9. Approval of a CGDP should not amount to a pre-approval of a gas drilling permit.
10. Integrated CGDPs (involving more than one company) are merely encouraged, not required. This does not protect the public's interest.
11. We need a set of temporary regulations that will allow for exploratory wells to quantify the quality and quantity of the gas underlying the shale play in Western Maryland.
12. The CGDP should be voluntary and should not apply to exploratory wells. It is not reasonable to require the development of an extensive plan for long term development in areas where there is no information on the viability of the project, or indeed if the Marcellus formation in the area would support such a development. The time frame for a CGDP should be shortened to two or three years to allow for more accurate forecasting. It would also make sense to require some basic information before doing any initial drilling

and then requiring a very detailed document before production can occur. If an exploratory well is allowed and it produces gas, it should be permitted for production.

13. We have serious concerns about a mandatory Comprehensive Gas Development Plan (CGDP) for at least five years. This requirement is premature, requiring it after a company has drilled initial exploratory wells would make much more sense. Shortening the time frame to two or three years would also allow for more accurate forecasting. Bifurcating it to provide some basic information before doing any initial drilling and then requiring a very detailed document before production can occur would be practical. It would also allow for a significantly more substantive and accurate long term CGDP being submitted.
14. Without validating the need for a mandatory CGDP, a more practical approach would be the permitting of one or more exploratory wells in accordance with current state regulations to allow operators the opportunity to determine the feasibility of further development. It should be noted that to begin the process of drilling an exploration well, the operator must dedicate approximately four years of resources and expense before obtaining any information on the viability of production from the Marcellus formations in Maryland. This timing assumes the noted policies, maps, and toolbox are in place.
15. The CGDP adds a time consuming and expensive planning for a driller who may not even have obtained the leases, options, rights-of-way and other property rights. It may have minimal environmental benefit. The standards for approval are ill defined and the process could drag on and even be appealed to a court.
16. There should be no “fast tracking” of wetland and waterway permit approvals merely because the locations of wetlands impacts and waterway and floodplain impacts have been identified in a CGDP. Fast tracking and expedited review shortchange the local citizens.
17. Will the State consider approving a CGDP near or adjoining state lines where regulations in the adjoining state do not meet requirements of Maryland’s CGDP process and regulations?
18. The planning principles for the CGDP should not reference state policies that have not yet been enunciated, such as using directional drilling for stream crossings and siting compressor stations.
19. The planning element “Sequence of well drilling over the lifetime of the plan that places priority on locating the first well pads in areas removed from sensitive natural resource values” is flawed. It implies that later wells can be located near sensitive natural resources.
20. Why should a CGDP that covers only five years of development remain in effect for ten years?
21. According to the UMCES-AL report the average well pad will be in place for at least 30 years. According to this report, the plans will remain in effect for 10 years. Five years does not seem sufficient given the long-term nature of this activity.
22. The report indicates that an approved CGDP will remain in effect for 10 years. We recommend a provision for renewal be added to the report language.

23. Agencies should review the approved CGDP plan at the 5 year point to ascertain whether any environmental conditions have changed that would require a CGDP modification.
24. If the applicant increases its total surface disturbance by 20% or greater the applicant should be required to resubmit their application for the CGDP and begin a new the process. Those applicants that increase their operations by less than 20% should be allowed to modify the existing application.
25. Adding wells to a pad should require a formal modification to the CGDP. Additional wells on a pad would still have greater social and environmental impact and could create intolerable levels of negative impact on those who live in the "sacrifice zones."
26. Changing the location of a compressor station or pipeline should require a formal modification to the CGDP.
27. There were several comments asking for clarification or changes to the public process for review of the CGDP.
    a. The industry may ignore viable alternatives.
    b. When does the stakeholder review of the CGDP begin relative to the agencies' initial review?
    c. This stakeholder review should not take place only at the request of the applicant.
    d. When can the collection of the 2 years of baseline monitoring begin relative to the submission or approval of the CGDP?
    e. Can the applicant apply for an individual well permit immediately after approval of the CGDP?
    f. There should be adequate time for public review of the CGDP after the completion of the stakeholder group process, and the applicant should be required to provide notice to the public.
    g. Who will be responsible for determine who will be part of the "stakeholders group", how will stakeholders be identified, who will organize the meetings, and who will pay for the facilitated process? Does this include landowners on adjoining properties, who will also be adversely affected by noise, lights, air pollution??
    h. Local planning, historic preservation, and heritage groups should be included as stakeholders.
    i. Requiring the local governments to respond to a plan within 45 days is too short.
    j. 60 days to review a comprehensive plan such as these with as many stakeholders as these is exceedingly and totally unrealistic. There needs to be a lengthier period of time.
28. Local zoning may not be honored because FERC can overrule local zoning by preemption.
29. We commend and strongly supports the requirement for comprehensive gas development plans (CGDPs) to address siting issues at the landscape- or watershed-scale. The CGDP approach addresses environmental impacts at a regulatory scale appropriate to the state's

policy objectives; the alternative, piecemeal permitting, is inadequate for minimizing adverse landscape impacts. Further, comprehensive gas development planning is a necessary tool for minimizing habitat losses and fragmentation, two of our top priorities for better practices in the gas industry. In light of these considerations, we find it essential to establish the type of comprehensive, systematic approach outlined in Section III of the BMPs document.

30. We strongly endorse the Planning Principles set forth. These principles provide a proper framework for BMP development in the context of the charge in Executive Order 01.01.2011.11 to determine whether and how shale gas development in Maryland might be accomplished without unacceptable adverse impacts to public health, safety, the environment and natural resources.
31. The study proffers no Marcellus gas drilling on slopes greater than 15%; consideration should be given to using a range of 10% - 15% so assets and resources down-slope can be better protected.
32. While a CGDP is reasonable on extremely large acreages like the Pennsylvania state lands, no one in our organization can visualize how such a thing would work when a thousand landowners may be involved and there are no proven reserves here to encourage a company to engage in such a process. At the very least, the industry needs to be permitted to drill enough wells under temporary restrictions to prove the reserve before they are required to jump such a hurdle.
33. The agencies should adopt a clearinghouse strategy that would bring the PSC into the permitting process for the CGDP. The agencies and the MSAC should review the process for permitting, siting, construction and operation of all pipelines and ancillary development outside of the CGDP process.
34. The State should develop maps showing where Marcellus gas development, including ancillary operations, is and is not to be allowed. Wetlands, flood plains, steep slopes, rivers and streams, lakes, outcroppings, and local topographic features should be shown.
35. The Toolbox should include complete hydro-geological data for all fractured-rock strata over Maryland's Marcellus shale deposits, documenting location of underground aquifers and understanding their movements. To ensure accuracy this data should not be collected by the applicant, but by contractors approved by or employed by the State.
36. Maryland should not permit fracking to go forward in areas of the state, like Garrett County, where adequate land use protections are not in place.
37. The Comprehensive Gas Development is one of the most important and innovative aspects of the Commission's report and addresses the our organization's concern for the landscape scale impacts of unconventional shale gas development. The Nature Conservancy's Pennsylvania Energy Impacts Assessment released in 2010 highlighted these potential impacts and called for comprehensive planning to minimize these cumulative impacts. The need for landscape level planning has also been identified by the Pennsylvania State University and the U.S. Geological Survey as important in controlling the impacts from shale gas development. We would urge that Comprehensive Gas Development Plans be mandatory and not voluntary.

38. The recommendation is to “submit a CGDP for the area where the applicant may conduct gas exploration or production.” We recommend that the area be defined as that which can be served by shared infrastructure without having to over extend that shared infrastructure to the point where it makes no economic or ecological sense.
39. It is not clear whether the 2% limit on surface development within a high value watershed applies to all development within the watershed or just the surface disturbance caused by gas development. If it applies to gas development over and above existing surface disturbance, high value watersheds that already have some development may be impacted even with the 2% limit. If this is the case, additional mitigation measures may be needed or that watershed should become off limits to gas development.
40. We believe that the development of a comprehensive gas development plan has the potential to not just protect natural, cultural, social and recreational resources, but it could end up saving the gas drilling companies significant development costs due to increased efficiency. In order to make the use of CGDPs more attractive to industry, particularly if CGDPs are not made mandatory, we would support the use of expedited permits and approvals.
41. We would support the conservation of high value forest through easement or fee-simple acquisition as a mitigation option for implementation of the no-net-loss of forest recommendation given the lack of land in Western Maryland for reforestation. We would recommend that the definition of high value forest include inholdings within state forest lands, parcels surrounding existing large protected tracts of forest, and key connectors and corridors linking large forest blocks.
42. If one looks at the complete requirements to obtain a drilling permit, the permit would require the development and approval of a five year CGDP plan, followed by a lengthy approval process. The total time for the development and approval of a CGDP plan is estimated at a minimum of 18 months. Assuming approval of the plan, this would be followed by a minimum two years of pre-development baseline data collection (pages 44 and F-1) on groundwater, surface water, and both aquatic and terrestrial ecological resources prior to obtaining approval to drill the initial well. The total time to perform the baseline study and obtain state approval is estimated at 28 months.
43. (B), (3), “Avoid, minimize and mitigate impact on resources as discussed in Section IV.” Section IV does not address mitigation.
44. (B), (4), “Preferentially locate operations on disturbed, open lands or lands zoned for industrial activity.” Departments should mandate that the state’s first wells be drilled in industrial parks to assure minimal land-use conflicts.
45. It would appear useful, during both CGDP development and review, to consider the tradeoffs between trucking of water and use of water pipelines (e.g., traffic vs. land disturbance impacts) .
46. The Pittsburgh-based Center for Sustainable Shale Development (CSSD) has generated an interesting “performance standard” which calls for establishment of an “Area of Review (AOR)---which covers both the vertical and horizontal legs of the planned well.” Among other stipulations, the standard mandates “a comprehensive characterization of subsurface geology, including a risk analysis’’ as related to

"confining layers" preventing "adverse migration of fracturing fluid". [SOURCE: CSSD Performance Standards dated March 2013]. This "practice" is offered for consideration and relates to the controversy about possible migration of "bad stuff" to "good water" even from 6,000 to 8,000 foot depths

47. This should include the statement –"minimization of impact on existing human population and existing concentrated human population centers" as part of the considerations.
48. I advise caution on location of pipelines along roads because of the explosion hazard.
49. Recent reports from western US fracking sites call our attention to the possibility of frack hits, blow outs that occur when a second drilling and fracking operation goes off course and leads into a drilling hole already in operation. The combined pressure results in the expulsion of fracking fluids under great pressure and spills occurring over a much wider area than would have happened if the second drilling operation had not "hit' the previously existing one. This calls into question the wisdom of the Report's siting of many multiple wells on one fracking pad.
50. The State is proposing a planning principal that the drilling activities comply with local law and regulations, including zoning ordinances. Since the plan is reviewed by the State, how will this determination be made?
51. Reduce land use conflicts with adjacent properties. Protect Maryland's prime agricultural soils and prime farmland.
52. The Comprehensive Gas Development Plan should also include a review of all past land uses, local and State Comprehensive plan consistency analysis and relevant information about local zoning and land development regulations.
53. Allow applicants the opportunity to provide opportunities for meaningful public input in pre-development stages.
54. MALPF preserved property and MALPF easements should be considered in planning and mapped in the toolbox.

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Chemicals

1. The State should prohibit the injection of any toxic chemical into the earth.
2. Information about toxicological profiles and epidemiological evaluations, exposure risks, protective equipment and protective measures for every chemical used should be provided to MDE, DHMH, workers on site, persons living adjacent to the site, health professionals, and emergency responders.
3. A company should have to fully disclose the identity of all chemicals to be used in advance of their use.
4. Disclosure should not be limited to OSHA “hazardous chemicals.”
5. After the well has been drilled and hydraulically fractured, a company should have to disclose the identity and amount of every chemical used. The information should be posted for each well on a publicly accessible and searchable website. Disclosure of chemicals on FracFocus is not sufficient, but it should be mandatory.
6. The State should require the use of unique tracer chemicals in hydraulic fracturing fluids that would allow identification of the source of any contamination. Currently, radioisotopes, nano iron, and DNA fragments are being examined as potential tracers. Although each approach has limitations and a timeline for effectiveness, they may be useful in detecting leaks and failures or accidents in the future.
7. If the companies refuse to list their proprietary chemicals then the State should mandate tracers to track the migration of and source of contaminants.
8. Long-term monitoring of surface water and groundwater should be mandated for the tracer chemical and other constituents of fracking fluid. Groundwater moves very slowly.
9. The State should not recognize any claim of trade secret.
10. If the State recognizes trade secrets, there should be a presumption against the claim of trade secrecy and the burden should be on the claimant to prove the claim by clear and convincing evidence. The State should develop an administrative mechanism by which any citizen can challenge a claim of trade secrecy.
11. The use of confidentiality or non-disclosure agreements should be prohibited.
12. The State should provide a way for health professionals to access trade secret information simply and immediately.
13. Fracking fluids should be tested before and after injection to establish toxicity and evaluate potential harm.

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Contamination of Drinking Water

1. Any spills could contaminate surface and subsurface drinking water supplies. The National Forest Service will likely ban fracking in the George Washington National Forest, which lies in the Mountains of Virginia and West Virginia. The reason: There is enough evidence to suggest that the process and the potential for spills poses risks to the drinking water supply for millions of people, including those living in the Washington, DC. (Article)
2. Methane concentrations in groundwater are higher near natural gas wells
3. Naturally fractured shale is not an impermeable layer, as claimed by industry.
4. Research suggests that the treatment of shale gas waste by treatment plants raises downstream Cl^- concentrations but not TSS concentrations, and the presence of shale gas wells in a watershed raises downstream TSS concentrations but not Cl^- concentrations.
5. Currently available data indicate that the depth to the base of fresh-water aquifers in Garrett County varies greatly, from 400 ft to more than 1,000 ft below land surface, and it is not possible to predict with any confidence a depth to the base of fresh ground water at any given location. Therefore, we strongly recommend that this depth should be determined at each drill site. The best way to determine the depth to base of fresh water is to drill a pilot hole and run a suite of geophysical logs (including but not limited to electrical resistivity, porosity, and spontaneous potential logs) that can be used in conjunction with other well data to accurately characterize the subsurface fluids. In order to determine the base of the deepest fresh-water aquifer at each site, it is recommended that a vertical pilot hole be drilled and evaluated at each drilling site and that appropriate geophysical logs be run in the hole. This determination is best made in a small-diameter hole to minimize effects of drilling fluids on the measurements. If a separate pilot hole is not drilled, then at a minimum, the BMPs should specify that geophysical logging must include all zones from the bottom of the well to the ground surface (to ensure that logging covers the relatively shallow portions of the hole, not just the gas-bearing sections).
6. The majority of “wastewater” remains underground and the poorly understood technology for rock fracturing leaves us vulnerable to polluting our aquifers. The report does not address in any way if such introduction into the aquifers could ever be alleviated.
7. Recent studies by Duke University researchers have verified by isotopic fingerprint methodology that methane gas migrates upwards through fractures from in the Marcellus formation in Pennsylvania water wells located within one kilometer of natural gas wells and contaminates water wells and aquifers. The Departments must to review and significantly enlarge their setback requirements. More importantly, we strongly support programs to require the development and continual evaluation of baseline data on methane in water wells and aquifers in Western Maryland including the isotopic

fingerprint of the methane. We believe that the need to pretest water well and aquifer samples within a kilometer of leased mineral rights for a number of elements along with isotopic fingerprinted methane must be made a requirement of MSGD and to continue periodically over the life of the well.

8. Gas migration from the Marcellus formation may be followed by brine containing liquids in the future that contain any number of elements and radioactive isotopes to further contaminate water wells and aquifers.
9. The Departments should require monitoring of all water wells within 2500 feet of a vertical borehole before, during and after drilling and operation.
10. If more than one industry operator is working in the same area, the problem becomes more complex in assigning responsibility for a groundwater contamination and could lead significant delays while trying to establish responsibility. Possible solutions:
    a. require the industry to develop the hydrology data for the areas in which they have lease holdings;
    b. develop aquifer data at each well site
    c. use tracers that are unique to each operator .
11. We believe that liability of water well contamination within 2500 feet of a drilled gas well must be incorporated into the permitting process and the time period extended beyond one year of the drilling activity to ensure water quality and public health are protected. A process must be developed to deal with and assign responsibility for unexpected problems especially if more than one industry operator is working in the same area.
12. Allowing the oil and gas industry to ride out this fracking treadmill in Maryland would turn the state into a pincushion of fracked gas wells. Over years and decades, these wells would age, degrade and be abandoned, creating pathways through which injected chemicals and natural contaminants can seep into underground sources of drinking water.
13. The Culpeper Basin underlies the Poolesville Area Sole Source Aquifer, the primary source of drinking water for the area, as well as geological formations such as the shale barrens, the serpentine barrens and the diabase bedrock formation, which provide rare and unique habitats within Montgomery County. Protection of such resources are included in our local land use, zoning, and forest conservation codes and laws. Currently, hydraulic fracturing is not an allowed use in Montgomery County. As part of the Marcellus Shale Safe Drilling Initiative, we request the addition of a statement to indicate that the State will not seek to preempt local zoning and land use controls.
14. The report specifies that the vertical casing extend below the “deepest known stratum bearing clear water” by a minimum of 100 vertical feet. This vertical distance seems

small. Casings should extend at least below the brine level, and we've seen a study for the European Commission calling for a large distance of 600 meters (1,950 feet).

15. The setback distances in general sound okay, but when dealing with drinking water reservoirs, such as the Frostburg Reservoir and others in Garrett County, the distances should be greater than those recommended by Eshleman and Elmore. If horizontal boreholes can extend 7000 feet, I think that the setback distance from key drinking water resources should be at least 7000 feet.
16. The UMCES-AL report states that, since the freshwater/saltwater interface has not been mapped in Maryland, the prudent approach would be to rely on the 2,000 ft criterion to provide an adequate margin of safety. Specifying vertical depth offsets presumes that the physical characteristics of geological units remain unchanged. Assuming such a statically safe buffer zone is questionable. Changes in the vertical permeability will occur and cannot be ignored. This occurrence is dynamic because the changes migrate upward with time.

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Environmental Assessment and Environmental Impact Statements

1. The preliminary Environmental Assessment for the CGDP addresses the ancillary facilities as well as the well pad, but the Environmental Assessment for the individual well permit addresses only the well and well pad. The ancillary facilities will escape full environmental assessment under Env. Code Section 14-104. The indirect and cumulative impacts of ancillary facilities and infrastructure, such as gathering lines, compressor stations and interstate pipelines should be considered, even though the state does not currently have the ability to regulate these.
2. It appears that a full environmental assessment may not be required for both the CGDP and the individual permit.
3. The CGDP must be similar to a full Environmental Impact Study (EIS) which takes cumulative impacts and viewsheds into account, rather than a form of abbreviated Environmental Assessment.
4. The State has acknowledged that the current guidelines for an Environmental Assessment are inadequate. The State should require the same type of statement of environmental impact for all unconventional natural gas development as it does for leasing of state land for drilling.
5. Are there regulations for basic requirements for an environmental assessment? Are the requirements similar to NEPA?
6. The Environmental Assessments should include an analysis of alternatives and past land uses.
7. I know that the natural environment, is a focus of the Department of Natural Resources, but there seems to be more concerned with the survival of small populations of endangered species, than we do about the disrupting the lives of people.
8. The Government Accountability Office could not quantify the risks of shale gas development because (1) it couldn't predict where the wells would be constructed; (2) not all operators use best practices to the same extent; (3) there are few studies comparing pre- and post-development conditions; (4) changes to laws and regulations will affect future activities; (5) risks will vary across business practices, which may vary among companies. Without this, GAO could not conclude that fracking is "safe."
9. The minimum 2-year pre-development baseline data needs to be a mandatory part of the CGDP or the Departments need to require a comprehensive Environmental Impact Statement (EIS) to compile baseline data to access cumulative impacts and mitigation strategies.

November 25, 2013

Earthquakes

1. The independent studies conducted by University researchers across the state of Texas have determined that fracking causes earthquakes of 4.0 and higher within miles of fracking sites. Insurance companies do not cover earthquake damage in Maryland.
2. Hydraulic fracturing has been definitively linked to earthquakes in Ohio.
3. Fracking by its very nature brings an increased incidence of earthquakes, even in areas of the world where earthquakes had been nonexistent. Fracking drills a series of deep holes in the earth’s crust and in so doing creates areas of weakness. Frequent earthquakes result in many areas where extensive fracking has taken place. Recently fracking was discontinued in the United Kingdom because of earthquake occurrences.
4. The report lacks any substantive analysis regarding potential risks of fracking and geologic faults. Seismic events can release the fracking fluids that are intended to be contained.
5. Pre-existing planes or surfaces of weakness within the overlying shale influence the direction of upward fracture migration. The next earthquake could be triggered when the upward migration of a zone of fractures or enhanced porosity intersects the plane of an active fault zone and then follows this plane of weakness preferentially. This would essentially “lubricate” the opposing faces of the fault and trigger the next earthquake.

November 25, 2013

Emergency Response

1. Under the BMPs, company emergency response plans must include information on specially trained crews that can arrive within 24 hours of a blowout, fire or other accident.
    a. Twenty-four hours is an eternity when a high-pressure drilling operation malfunctions and toxins are spewed freely. That BMP is insufficient to protect everything in the well’s path: workers, nearby residents and the environment.
    b. The BMPs should require plans for a 12 hour emergency response plan as 24 hours is much too long in case of a blowout, fire or other accident.
    c. Maryland should require an eight (8) hour or less response to an incident.
    d. The 24-hour emergency response by drillers is irresponsible and inadequate and all drillers should have methods in place locally to fix issues within a 4-hour timeframe.
    e. Trained crews should be required to arrive immediately.
2. The security and social costs to our rural communities if drilling occurs must be considered. An influx in population creates demand on police, fire and EMS. These services are paid for by local taxpayers and sometimes the people are volunteers. They are not trained for blow-outs - nor do they know how to handle accidents dealing with gas-well chemicals. "A list" will not help them or me if a blow-out occurs on a dead-end road. And a few days worth of training sponsored by the gas company does not cut it.
3. Rural areas with aging populations such as Allegany and Garrett Counties are challenged to find adequate numbers of emergency responders, as well as providing training and equipment. The cost of this additional responsibility should be borne by the drilling companies.
4. In the event of accidents, spills, or any emergency situation, first responders have a right to know what dangerous materials they are in contact with.
5. There is no detailed “best practice” regarding safety planning. The Natural Gas Industry best practice is to clear the area, call 911 and watch it burn.
6. The industry, and gas compressors in particular, is vulnerable to terrorist attack.
7. "Spills . . . cleaned up as soon as practicable." Too vague –allowing time for spills to spread and contaminate further.
8. The BMPs should require that drilling operations report chemical releases to the federal Toxic Release Inventory, or to a publicly accessible on-line database managed by the state.

9. There should be a sharing and coordination of emergency management drills by the Maryland environmental agencies with their counterparts in Pennsylvania and West Virginia.

Enforcement and Inspections

1. The BMPs are very weak on enforcement. The BMPs do not mention fines or punishments when regulations are broken and local citizens incur damages. I think that companies with bad records in other states should be banned from Maryland.
2. Conducting inspection and enforcement activities is challenging due to limited information, such as data on groundwater quality prior to drilling. Hiring and retaining staff and educating the public are challenges. I have great concern about the availability of qualified individuals to perform these functions.
3. We want the State to secure and fund an external independent environmental consulting and auditing entity or capability (firm) to perform daily independent inspection of all on-the-ground drilling activities to ensure full compliance of all regulations. This firm will host bi-monthly or monthly public meetings to address current concerns and complaints with local stakeholders. Oversight of this firm will be provided by a small Board of Directors composed of local civic leaders. And lastly, that "drilling fees" be established by MDE with a line-item breakdown of drilling fees and what they include so that it is possible to ensure that adequate funds for inspection and enforcement is possible. This firm will fill the following roles:
    a. insure that the enforcement and inspection function is adequately funded, well managed and staffed with qualified personnel;
    b. promote transparency via bi-monthly or monthly public meetings to address issues in a timely manner;
    c. protect the enforcement and inspection function from political and energy sector intimidation or influence;
    d. perform ongoing auditing and reporting functions to track the effectiveness of regulatory enforcement practices; and
    e. provide an external source of objective expertise relating to drilling practices.
4. There is a strong need for a Comprehensive Gas Drilling Inspection Program (CGDIP) that would:
    a. Require special training for inspectors in Maryland to follow for inspection compliance,
    b. Show all phases of development and the inspections for each phase,
    c. Allow for random visits and spot inspections
    d. Mandate compliance with each phase for work to continue,
    e. Establish a community/citizen watch program, that would train individuals on how to report incidents and/or violations,
    f. Establish a Natural Gas hot line for reporting
    g. Mandate the number of inspectors in relationship to the number of permits,
    h. Establish a sliding scale penalty for repeat violations,

i. Establish a three strikes and out program that would keep repeat violators from receiving permits,

j. Establish an Ombudsman commission for review of complaints and compliance issues,

k. Establish a website for licensure, permitting and inspection, which would include public notification of CGDP planning and permitting. This site could also be used for the CGDP Toolbox.

l. Establish a field office of the Natural Gas division of MDE/DNR in Garrett County.

5. All companies performing any monitoring or assessment should be approved by the State to ensure that no conflict of interest exists which could call into question the accuracy of the results.

6. The applicant should not be allowed to do its own baseline monitoring. Either the State should do the monitoring (using permit fees) itself or the company should be required to use an independent entity, chosen or accredited by the State, and subject to oversight similar to the way the Food and Drug Administration monitors foods and drugs to ensure the reliability of the testing results.

7. The collection of pre-development baseline data is good, but the same kind of data should be required during the production and for at least 3 to 5 decades after decommissioning and capping**.**

8. Landowners should have easy access to information about violations. The design of reports and records are important and can help streamline enforcement activities. Digital records help share information with the many stakeholders involved in this process.

9. Each well site will have one or more continuous air monitoring systems in operation either in real time or at reasonably short intervals during the lifetime of the operation of the well. The monitors must be able to trigger alarms at the well site and at a remote monitoring site that is staffed 24/7 when established pollutant levels are exceeded. Ideally all toxic chemicals used in the drilling and any expected to be in effluents from the wells should be monitored as well as fugitive methane. After eventual capping of the well periodic monitoring at the site should continue to be conducted.

10. I suggest Maryland require 24 hour video surveillance of all well pads to allow remote monitoring and inspection and provide verifiable data in the event of incidents. This is especially important if Maryland adopts its recommendation that specially trained and equipped personnel must be capable of arriving at the site within 24 hours of the incident.

11. There should be a clear mechanism for citizens to report violations of the law or of permits or lodge complaints.

12. The protocols for monitoring, recordkeeping and reporting should be submitted for public comment. It should be clear about testing of water wells – who will test, what they will test for, and how the tests should be conducted.

13. All storage containers and transportation vehicles that handle wastewater, flowback, drilling muds, cuttings, fuel and chemicals should have GPS tracking, placards and radioactive monitors.
14. Responsibility and monitoring of gas and chemical contamination of aquifers should continue for three to five decades after decommissioning of the well. All horizontal lines are potential sources of contamination by vertical-flow.
15. The coal strip mining rules in MD contain provisions that I think should be included in Marcellus drilling regulations. In particular when there are cases where a person's water source or other property is damaged by gas production, the State should have the authority to compel the offending party to make proper restitution or replacement.
16. Companies permitted to conduct a fracking operation in Maryland should be required to post a bond sufficient to cover penalties for any violations that might occur in the course of their work, regardless of any showing of negligence on their part. These penalties need to be sufficient to cover the costs of restoring the environment to a safe and livable condition.
17. Money for state inspectors and independent inspectors should come from higher permit fees, not tax payer dollars. In the strongest possible way, I want to emphasize that the resources to pay for regulators, monitors and enforcers of such vital functions as water quality, air quality and noise monitoring should be borne by the drilling companies.
18. A "designated agency" should be set up and maintained through the county or state government for permit issuance, reporting purposes, inspections, and legal action. All of which would be considered a reimbursable fee to the shale fracking/drilling companies reimbursed on a monthly basis.
19. Companies should not be allowed to conduct their own inspections or to hire inspectors. Inspectors should to be hired by our county or state government, through the "designated agency" and the funds to pay for their salaries and benefits are to be reimbursed by the shale fracking/drilling companies on a monthly basis through an invoice provided by the "designated agency." This also includes any fees incurred, such as mileage, maintaining and office, etc.
20. Any illnesses resulting from the shale fracking/drilling companies for families, and employees of the shale fracking/drilling company, must be reported to the "designated agency." All information regarding hazards, illnesses, contamination, road spills, etc. will be a part of public record and maintained by the "designated agency".
21. All legal fees acquired by a landowner, affected party, or the government will be reimbursed by the shale fracking/drilling companies for any reason.
22. There should be adequate bonding and insurance requirements, lasting beyond the closure of the well. Bonds for delayed contamination caused by triggering hydro-geo-mechanical events should be added, such as the inevitable upward migration of enhanced vertical permeability.
23. Demand that companies engaged in fracking are financially liable for any and all costs incurred by residents including health expenses, soil contamination, legal fees, loss of property values and reduced quality of life during and after the operation.

24. Any and all hazards, such as well contamination, explosions, death, crop destruction/contamination, hazardous fuel transportation accidents, business loss, etc. that are directly associated with fracking/drilling will be paid for by the company. This includes, but is not limited to emergency personnel costs, funeral costs, loss of income, land devaluation, legal fees, injuries, and any costs associated with the hazard.
25. The company will be held completely responsible for expenses relating to the clean-up and maintenance of any capped well that may later leak after being closed, as well as any other issues resulting from this leak. There will be no time limit on this maintenance. A designated trust fund is to be set aside to cover these expenses and is to be used only for the purpose of maintaining closed wells. This amount will be provided by the "designated agency."
26. There should be an explanation of what the State would do, or compel the company to do, if gas were to flow from somewhere in the gas field into a person's home or into the atmosphere. What are the requirements for restoration of trout streams should fluids pollute the water? What types of restitution should citizens expect if their property and or health is negatively impacted, or are locals expected to work with the oil & gas firm directly? A process must be developed to deal with and assign responsibility for unexpected problems especially if more than one industry operator is working in the same area.
27. There should be clearly identified state agency points-of contacts, processes, open damage claim reporting and detailed restitution when issues arise. There should be a mechanism to fairly compensate people for economic loss and personal harm, especially people who did not lease their mineral rights but are impacted by gas development nearby. The State should consider denying a CGDP permit if any landowner within the CGDP does not own his mineral rights (i.e. a split estate).
28. We believe that liability of water well contamination within 2500 feet of a drilled gas well must be incorporated into the permitting process and the time period extended beyond one year of the drilling activity to ensure water quality and public health are protected.
29. There should be a sharing and coordination of environmental monitoring data by the Maryland environmental agencies with their counterparts in Pennsylvania and West Virginia.
30. While there is Federal regulation of new construction of pipelines with the attendant compressor stations, no State agency exists to oversee the siting, construction and operation of these assets.
31. Currently, federal oversight of pipelines in Maryland is inadequate. To expand the number of pipelines by authorizing increased production via well permitting while the regulatory system is already struggling under current conditions would only increase the likelihood of accidents or failures.
32. Post-operational sampling of air quality should be required for ancillary facilities, such as compressor stations, that have the potential to emit gases.

Engineering, Design and Environmental Controls and Standards

1. Ponds should be used only to collect or store fresh water; all other material shall be stored in tanks.
2. We support the proposed prohibition on open impoundments for the storage of flowback and produced waters as a necessary safeguard. Open impoundments create unnecessary risks of wildlife exposure to chemical-laden fluids and environmental damages from impoundment spills. MDE and MDNR have laid out an appropriate approach, allowing open impoundments to be used only for fresh water storage.
3. The use of reconditioned casing should not be permitted.
4. The State and the MSAC needs to do more to study and address the causes of casing integrity failure and to propose better practices that continually improve performance of casing integrity.
5. The state needs to coordinate closely with the local municipalities on construction standards for ponds.
6. Our organization supports the Report's recommendation in Section VI part H that "Diesel fuel shall not be used in hydraulic fracturing fluids."
7. Closed loop mud systems are commonly used where non-aqueous drilling fluids are used. There may be unintended consequences of requiring closed loop mud systems for all drill sites. A closed loop system will add costs to the drilling operation and will require additional space on the drilling pad to incorporate the technology. To allow for spotting the needed tanks for the process can require up to 6 acres for the drill site. This increases the surface footprint of the drilling pad above what would be required for non-closed loop systems.
8. How will the Department determine whether to approve additives for drilling fluids?
9. The recommendation is all coupling threads meet the API specifications and casing strings be assembled to the correct torque. This requirement eliminates proprietary threads that may exceed API specifications and also does not allow for the use of couplings that are made up to a particular depth rather than a minimum torque. The recommendation should allow for the use of API threads or threads that exceed API requirements based on an engineering analysis and judgment.
10. There is a recommendation that the operators "must use a sufficient number of centralizers to properly center the casing in each borehole." There is no definition of what degree of centralization is required, the allowable type of centralizers, or the proposed installation methods. This information can be found in the API technical documents, recommended practices, and specifications for centralizers. It is recommended the recommendation include these documents by reference.
11. Requiring the cement to remain in a static state for a minimum of 12 hours and to achieve a compressive strength of 500 psi is excessive. Modern cement additives and slurry designs can achieve the 500 psi requirement in much less time than 12 hours. It is recommended the recommendation be changed to allow for continuation of activities if the cement has reached a minimum of 500 psi.

12. For cementing, centralization, and wellbore isolation, it is suggested the recommendation incorporate API Standard 65-2, “Isolating Potential Flow Zones During Construction” in the document. This standard contains design and engineering practices for isolation of potential flow zones and goes beyond the limited recommendations found in the current document. API Standard 65-2 has been adopted into both federal and state regulations and serves as an industry guidance document for proper well design and construction.
13. “Permeability” is the wrong word in the sentence: “Drill pads must be underlain with a synthetic liner with a maximum permeability of 10^{-7} centimeters per second …” [The commenter is correct; permeability will be replaced with hydraulic conductivity.]
14. The berm should be made impermeable with the use of the liner. In the event of a high volume, high pressure liquid release an earthen dam will likely fail and use of a liner would prevent or minimize a failure.
15. Containment around tanks and containers should be underlain with a synthetic liner with a maximum permeability of 10^{-7} centimeters per second to prevent leeching into the soil.
16. Use of data obtained through open hole logging to “fine tune” processes and information (as recommended by UMCES-AL) should not be considered sufficient stand-alone information in the absence of a complete study of hydrology of the site. We should not be drilling blind in Maryland and using the drilling process to document the strata.
17. Due to concerns about casing integrity discussed above, the plan for integrity and pressure testing submitted by applicants for individual well permits should include integrity tests not only at drilling and re-fracturing, but also at annual intervals until the well is plugged, and at regular intervals going forward.
18. Rather that specifying that blow out preventers should be tested at a pressure in excess of that which may be expected at the production casing point before drilling the plug on the surface casing; and penetrating the target formation, the regulations needs to specify that blow out preventers the pressure to be 1.2 times the pressure during stimulation, which is the highest pressure normally experienced during the life of the blowout preventer.
19. If drill pads are located within 1,000 feet of aquatic habitat or a private residence, screens or restrictions on the hours of operation may be required to further reduce light pollution.
20. The report says that restrictions on hours of operation can only be applied to activities that could be planned in advance or temporarily suspended. This statement gives the industry an escape clause to use lighting at any time during development activities. It should be strengthened to say, in the last sentence: For this reason, activities should be planned in advance so that all measures can be in place to protect surrounding communities from light pollution.
21. There is a long list of plans and information that must be submitted with an application for a drilling permit. Will regulations provide “standards” for most of these, or are the approval criteria viewed as inherently case-by-case?
22. The specified safety margin of 1.2 for reconditioned casing seems small; a factor of 2.0 is viewed as more common.
23. Given the view that mandating particular technology is neither appropriate nor necessarily productive, the question becomes how the adoption of “better” as well as

more efficient technologies might be motivated. An option for consideration: require industry to discuss their plan for adoption of "better" technology as part of the CGDP's and/or the individual well applications

24. Ban flaring during hours of darkness, and also ban lighting that destroys the night sky.
25. Part J (4) (e) of Section VI of the draft report states that engines that power equipment or electrical generators that do not stay on site for more than 12 months are required to comply with the requirements of 40 CFR 60 Subpart IIII or Subpart JJJJ. Quite simply, federal law and US EPA regulations define any engine or equipment that remains at a site for less than 12 months as a nonroad, mobile source engine and not a stationary engine. The State of Maryland is preempted from regulating nonroad engines by Section 209(e) of the Clean Air Act. Consequently, the State cannot define, as proposed in this section, nonroad engines as stationary engines or require compliance to Subpart IIII or JJJJ since those standards apply only to stationary internal combustion engines. The federal preemption provision applies to both new and non-new nonroad equipment.
26. Owners and operators need to have the flexibility to use the equipment best designed for the task and opposes a mandate to only use electrically-powered equipment or gaseous-fueled equipment. Other important factors such as safety, power, efficiency, availability, reliability, and cost-effectiveness need to be considered when selecting the equipment to be used. First and foremost, the owner or operator needs to be able to select equipment at drill sites and other facilities that are capable of completing the task at hand. In many cases, heavy-duty equipment with sufficient power, torque and reliability is needed for drilling and finishing operations in order to get the job done, and to do so in an efficient manner. In many cases, the electrically-powered equipment needed to get the job done may not be available. Second, the environmental impacts of siting and adding new power lines are likely to be larger and more permanent than using self-powered equipment at the site. Issues associated with rights-of-way, adjacent property owners, vegetation disturbance and aesthetic impacts of power lines will be significant and will only serve to increase costs and delay project start-ups. Third, today's nonroad and stationary engines and equipment emit very low emissions with Tier 4 compliant equipment producing over 90% fewer emissions compared to just several years ago. As a result, owners and operators can utilize equipment designed to complete a task efficiently while minimizing on-site emissions. Furthermore, today's diesel-powered compression ignition engines emit at levels comparable to, or even lower than, comparable engines powered by natural gas or propane. With the options available for today's very low emission engines, there is no need for the Department to require grid-based electrical power or gaseous-fueled powered equipment.
27. All on-highway and nonroad vehicles are already required to use ultralow-sulfur diesel fuel, so Section IV.J.4.a should be removed as unnecessary. US EPA regulations already require the use of ULSD fuel by on-highway, nonroad, and stationary compression ignition engines. Those requirements have been in place since 2007 for on-highway vehicles and are now effective for nonroad vehicles as well. There is no need for Section IV.J.4.a, and it should be removed from the final report.
28. All clean-up will be provided by the fracking/gas drilling company within 3 months of vacating any site.

29. Specifying vertical depth offsets presumes that the physical characteristics of geological units remain unchanged. Assuming such a statically safe buffer zone is questionable. Changes in the vertical permeability will occur and cannot be ignored. This occurrence is dynamic because the changes migrate upward with time.
30. Maryland should adopt the Center for Sustainable Shale Development performance standards as a baseline. Deviations from those standards, if any, should be limited to those necessary to reflect conditions that are unique to Maryland.
31. How did the Departments determine that pilots can be “safely cased through” coal mines?
32. The permit should require photographs of the site before the activity starts. This information will be very helpful for reclamation assessments later on. Because mines operate for such a long timeframe, very few people remember what the conditions were 30 years ago.
33. Given the levels of traffic and the size of equipment used, even gravel roads will need to be planned and engineered to be safe. Additional design standards are needed.
34. Recreation is not the only light sensitive use. Additional light sensitive uses include residential units, educational facilities, hospitals, critical facilities and agricultural uses including livestock. Maryland should consider developing light standards for pre and post curfew time periods when sensitive land uses are near-by.
35. All construction of well-pads and associated uses should be prohibited in areas that are dominated by invasive species.
36. Keeping equipment clean is important for controlling the spread of invasive species, but it is also important to monitor construction materials such as any soil, gravel or fill dirt that is brought to the site for construction. If there are existing invasive species, pre-treatment activities should be required before construction starts.
37. Annual monitoring for invasive species should occur at the appropriate time of year to identify early infestations. Annual monitoring should occur throughout the entire lease cycle plus one year. Because many plants have seasons, it will be important to have the last inspection in the growing season after activity has stopped.
38. In some cases, grading and plantings will be needed to return the site to pre-construction conditions. For example, a formerly forested area might be re-planted with trees. The use of seeds should be expanded to include soil, mulch and plant materials.
39. Gathering lines are already adequately regulated. The rural gathering lines from the Accident Dome underground storage wells are under very high pressure when gas is being injected into the wells during warm months and extracted during the winter months. The standards for material and construction adequately addresses this activity.
40. There is no need to establish standards for the construction of roads. Allegany and Garrett County have standard specification and roads department personnel to review and approve plans for roads. Let the two counties determine road requirements as they do for all need development in the counties.
41. The recommendation that drilling should avoid times of peak outdoor recreational periods is unreasonably restrictive.

42. The recommendation about lighting should state that nothing in this section should be construed to compromise safety of operation at the drilling site.
43. The regulations recommend pressure testing of Marcellus shale gas wells. That isn't sufficient. The BMP practice recommended in the UMCES report to require pressure testing should instead be adopted. Doing so would greatly increase the likelihood that all wells would function as they should.
44. Light pollution as well as noise pollution should be addressed because light pollution corrupts the wildlife cycles and destroys the sense of solitude for residents and tourists.
45. Compressor stations also run on diesel fuel, are noisy, and are in general the largest contributor to air pollution of the entire gas production process.
46. This is not a difference of opinion, this is basic physics. Gas when released goes straight up. Therefore, gas in a distant fissure far from the bore is not going to make its way into the pipe. It will be released into the air.

November 25, 2013

Forced pooling

1. I have serious concerns about your suggestion of "forced pooling" of properties. Forced pooling is a violation of property rights.
2. Citizens of Maryland should be assured that the State will never force landowners who own their mineral rights to allow extraction of the resources (gas) under their land without their consent

November 25, 2013

Impact on Chesapeake Bay

1. Fracking and its associated infrastructure, including well pads, pipelines and compressor stations, will result in additional deforestation, increased impervious surfaces, construction run-off, and other land-use degradation that will likely impact the Bay TMDL. Fracking fluid spills or waste would also contaminate the Bay watershed.
2. The Department's treatment of stormwater runoff from increased oil and gas development bears particular importance in light of Maryland's efforts to comply with EPA's mandates under the Chesapeake Bay Total Maximum Daily Load (TMDL). First, some of the lands proposed for hydraulic fracturing drain in to the Potomac River that feeds the Chesapeake Bay. Increased industrial development within the Chesapeake Bay watershed will likely have substantial effects on stormwater pollution levels. Second, as a result of recent legislation, most Marylanders will soon pay more in stormwater utility fees designed to fund the TMDL compliance efforts. Requiring Marylanders to pay more for stormwater protection while largely absolving the oil and gas industry from these efforts everywhere except the well pad is unjust.

November 25, 2013

Individual Well Permit

1. It is noted that on page 20 operators are required to consider API standards and guidance documents in the preparation of well plans. This is consistent with some other states inclusions of API standards in their regulatory process and may work to improve the well planning process by incorporating the engineering rigor found in these documents. However, caution should be exercised in the application of these requirements. This is due to the fact that as performance based standards, a variety of engineering solutions can be found in these documents. The requirement that the plans must "follow a normative element of a relevant API standard" or otherwise "explain why and demonstrate that the plan is at least as protective as the normative element" could lead to conflicting requirements as performance-based standards often contain multiple normative elements which allow for the use of engineering judgment in their application.
2. The applicant should be required to notify the owners of any drinking water well within one kilometer (3,300 ft) of active development area outlined in the permit.
3. COMAR 26.19.01.10 V requires the permittee to provide the state with a copy of all electric, radiation, sonic, caliper, directional, and any other type of logs run in the well. The statement is too weak because it does not require the permittee to run all these logs.
4. The list of items from 1 to 26 is incomplete and is basically a list of terms. The list should specify what is required such as: locations of; project plans and specifications, plans, procedures and schedules. Requirements should be clear about the level of detail expected for each item.

November 25, 2013

Legislation

1. The State and the Advisory Commission should advocate for legislative protections like a Surface Owners Protection Act (SOPA). The Act needs to be comprehensive and address reasonable and fair consideration for the surface owner, with monetary compensation commensurate with the highest possible loss the surface owner could suffer as a result of drilling practices and drilling malpractices. The consideration for problems that are caused by drilling that will be discovered only as a matter of time need to be included.
2. The Best Practices Policy, and any legal rights therein, should apply to contracts that were signed in the past.
3. Landowners should be allowed to cancel any lease they entered into, even if it is after the company has begun drilling.
4. Maryland should adopt an adequate State severance tax; the funds could be administered by a publicly appointed commission similar to the Marcellus Shale Advisory Commission or by an ombudsman panel.
5. We strongly urge the funding (via a severance tax) of a special conservation fund of $100 million for restoration activities resulting from drilling legacy issues. The funds collected to address legacy issues are in addition and separate from funds that will be collected to address short-term environmental damages resulting from drilling.
6. The rights of resident communities should supersede any rights afforded to corporate interests and absentee owners.
7. The agencies/MSAC should advocate in the 2014 Legislative session for a bill moving the PSC to regulate and permit rural gas gathering lines within the state. The regulations in COMAR Title 20, Subtitles 56, 57 and 58 are inadequate. The bill could also address permitting, siting, construction and operation of all pipelines outside the CGDP process.
8. UMCES-AL recommends that applicants wishing to drill wells be required to notify property owners residing within the established setback that an application has been filed for development. This notification requirement should also apply to citing of compressor stations and other ancillary equipment. Applicants who wish to construct ancillary infrastructure are required to notify all landowners whose property line falls within the current required setback (1,000 feet.)
9. Any and all fracking companies that may be allowed to do business in Maryland should have to contribute substantially to a fund that helps significantly increase our renewable energy portfolio. That way at the very least the damage that fracking will inevitably do every step of the way will pave a path toward a green, healthy environment, economy and future.
10. All legal hearings related to fracking/drilling will be held in the court system of that county. However, if it involves federal issues, it may be heard in the federal court system.
11. Any intimidation or bribes on the part of the shale fracking/drilling companies or their subsidiaries will result in a direct cancellation of permits immediately and in the future. In addition, steep fines will be placed on the shale fracking/drilling company, along with possible incarceration of any and all parties involved in the intimidation or bribe.

November 25, 2013

Noise

1. We strongly recommend that the BMP's recommend local zoning be adopted in Garrett County so that it can better protect its citizens in this regard. If the Commission will not recommend that local zoning is integral to best management practices, then would they, at a minimum, provide recommendations for specific zoning elements; e.g., noise.
2. Maryland noise statutes appear to be limited regarding low frequency noise. However, there is data to indicate that low frequency noise may be associated with natural gas infrastructure and specifically compressor stations. Noise can cause permanent medical conditions such as hypertension and heart disease, hearing impairment, communication problems, sleep disturbance, cognitive effects such as memory problems, reduced performance, behavioral symptoms, and more. Low-frequency noise [LFN] can also cause Vibroacoustic disease, leading to cardiovascular symptoms and decreased cognitive skills. We believe it is incumbent upon Maryland to ensure that adequate protections are in place to protect against LFN. Typical noise mitigation measures for gas supply and storage infrastructure include acoustic cladding for buildings, the use of sound attenuators on ventilation systems, acoustic lagging on pipework, multi-stage control valves, gas turbine exhaust silencers, acoustic enclosures on pumps, low speed cooler fans and the use of electric rather than gas powered compressors.
3. Making the industry responsible to monitor and report excess noise levels may not produce accurate reporting. The permittee should be required to have continuous monitoring for sound during high development activity; such as stimulation of the well. Funding for this monitoring will be paid by the permittee, with all reports to be received by MDE for compliance of the permit. We recommend that the Departments require the County to select and hire an independent contractor—at the expense of the permittee— to conduct periodic noise monitoring and additional noise monitoring in response to a complaint.
4. “Noise” is viewed as a potentially significant industrialization issue. We are having difficulty rationalizing the largely noise-driven setbacks appearing in this section with the noise discussion in Section VI.M. For instance, the setback table specifies 1,000 ft. between an occupied building and a compressor station, while Section VI.M seems to call for at least 3,000 ft. unless the only engine/motor source is electric. Something to be changed or explained? Are we misreading?
5. Require that all compressors and other above ambient levels noise-creating equipment be fully enclosed and muffled to normal ambient levels.
6. You should address noise from drilling rigs and compressor stations and idling trucks, especially at NIGHT!
7. Wouldn’t it be useful to calculate the implied setback distance from, say, active drilling rigs or compressor stations whose noise level at the source is surely known or readily measured?? Has this been done?? Is this the basis for Section IV setbacks though not explicit??
8. Beyond specifying setbacks broadly based on state-level standards as above, one could (1) identify specific residential or commercial facilities around a particular proposed well/well pad, (2) specify maximum noise levels at these specific locations as part of the

application for each well (per local standards), and (3) mandate that the plan for each well/well pad include an analysis of how the standards will be met for the specific "noise sources" that are part of the industry application. (Will the well plans include locations and design parameters of compressor stations as well as drilling rigs??)

9. Instead of using "residential" consider using "noise-sensitive locations." This would allow expansion to incorporate a number of other non-residential noise sensitive areas including areas identified for environmental considerations in this report. Noise sensitive uses may include uses such as hospitals and parks.
10. Add: Sound levels should not exceed 115 dBa at any time.

November 25, 2013

Pre-development baseline data

1. We believe that there is a strong need for pre-development testing of water wells and aquifer samples within a kilometer of leased mineral rights for a number of elements, along with isotopic fingerprinted methane.
2. The State needs to develop specific requirements for surface water testing parameters, whether there will be baseline monitoring of air quality, and what living species and habitat will be monitored.
3. Two years of background data is not necessary. At least, consideration should be given to whether there is already sufficient data available. The need for monitoring and the area to be monitored should be related to the tract size.
4. Pre-operational sampling to establish background air quality should also be required for ancillary facilities, such as compressor stations, that have the potential to emit gases.

November 25, 2013

Process

1. We are concerned about the Marcellus Shale Safe Drilling Initiative Advisory Commission as it relates specifically to transparency in decision-making process. How are reports developed: is it by vote, by building consensus, are votes public, can there be dissenting reports, and specifically, are all the stakeholders' positions made public? These are concerns we have so that we understand better how decisions and reports are accomplished. We wish to know whether all stakeholders views are represented and where divided opinion exists.
2. We are concerned that, in some cases, the UMCES-AL Best Management Practices Report and Recommendations are weakened rather than followed or strengthened. Will Commissioners be able to vote on these changes made by MDE?
3. The BMPs are vague: the proposed BMP's have language such as "where practicable," "encouraged," and "reasonable use." "Where practicable" is used six times in the proposal, "encouraged" is used three times, and "reasonable use" is used eight times. That is a total of 17occurrences where common understanding is likely not to occur. Also, monitoring and enforcement are far more difficult when regulations and/or BMP's use such language. How can penalties be instituted, if at all, with such vagueness?
4. The report should not be limited to the Marcellus Shale because the Utica and other formations may also be tapped in the future.
5. We reiterate our recommendation that this “Study Part II” include a new section that outlines and states the goals and policy direction for Marcellus gas development in Maryland. By clearly stating the direction Maryland is taking, all stakeholders (the industry, landowners, local government, interested and concerned parties, and statewide parties) can see and understand the purposes and intended uses of the best practices.
6. The report is based on the recommendations of the contractor, UMES-AL, and therefore does not take a “systems” view of the full breadth of Marcellus gas development. First, this report should identify additional best management practices that are recommended for other state and local government departments and agencies so their activities can be coordinated and responsive to the overall thrust of the Safe Drilling Initiative. Second, the report appears to have selectively identified BMP’s for the industry, but does not clearly identify the BMP’s that should be adopted by state agencies. It is important that BMP’s be recommended and adopted by state departments as well as the drilling industry as the Marcellus is developed.
7. The CGDP as presented by the Departments is a conceptual outline and has not come under broad scrutiny by the public, the industry, and elected government representatives
8. The study should explicitly acknowledge the political reality that the proposed “best practices” amount to an initial negotiating position held by Maryland, in the face of oil and gas industry pressure.
9. Standards and practices are changing constantly. What was a good practice or standard last year when the study was conducted may have been superseded with better practices or proven to not provide protections it was designed to provide. We could not find a process by which there is on-going updating and evaluation of BMPs as the study process moves forward.

10. I much prefer a regulation that requires the introduction of new best practices by the industry as new technologies emerge that can provide more protection to public health and safety and to the environment. Better technology requirements could be a requirement every five (?) years if improvements exceed some pre-set thresholds, e.g. a reduction of some air pollutant by 20%.
11. We are very supportive of the best practices report as drafted. As an organization that works on the issue of unconventional gas development across the country, these BMPs, if adopted into regulation in Maryland, would be some of the best, if not the best, in the country. However, we are concerned that the timeframe for the development of regulations from these recommended Best Practices is indefinite. We understand that there are public concerns about the development of new oil and gas regulations before the full report from the Commission is available. However, current Maryland regulations on oil and gas are outdated. Regardless of whether someone supports or opposes shale gas development, it serves the State to have the best regulations in place to protect the health, safety, and natural resources of Maryland.

November 25, 2013

Comments on best practices and risk assessments

1. Best practices cannot be established without first performing a risk assessment. Until these risks are thoroughly studied, any attempts to set regulations for fracking are premature.
2. Your draft "Best Management Practices” report on fracking in Maryland fails to adequately address the full scale and severity of these risks. The report puts the cart before the horse since the state has yet to even begin a thorough analysis of the unique risks of drilling in Maryland. Without this risk analysis, the state is moving blindly in developing “best practices.”
3. As fracking has occurred in neighboring states, concerns about harm to water, air quality, health, and local economies have increased. I believe these potential impacts must be weighed closely against the benefits these operations offer to the LOCAL economy.
4. I do not believe that it is possible to know how to minimize the impact to sensitive resources, without first fully understanding the specifics and the magnitude of the impact.
5. Fracking uses immense amounts of fresh water which is irreplaceable, and that effect occurs even when other damage might (or might not) be successfully minimized.
6. Spend and/or acquire the funding to do a comprehensive Risk Assessment. Identify any data gaps in the BMPs, issue requests for studies to complete those missing components, complete all of the other studies and then inform the BMPs from those studies.
7. The CGDP section mentions mitigation in several places but fails to mention or recognize that mitigation is an integral part of the risk analysis process in which activities that have high risk are addressed by risk management alternatives to address mitigation as well as alternatives that will lower a risk. We believe that the Departments must not circumvent details for critical planning, siting, and environmental assessment needed for the large landscape level development plans.

November 25, 2013

Spread of fractures

1. The CGDP will require more wells from a single pad and this may lead to closer consolidation of well bores. Research shows that fractures created by fracking "communicate," or connect, with existing fractures, which can eventually reach aquifers. Maryland is encouraging drillers to place well pads close together to protect the land, but will their proximity lead to unforeseen problems involving existing fractures?
2. MDE scales back the seismic mapping requirements recommended by UMC ES-AL, requiring only one test per well on the pad. If we are to permit pads with up to 18 well bores, repeated fracturing of all these closely-clustered well bores & laterals could result in seismic changes. MDE should require seismology of the area to be developed and identify the area or areas where HVHF may communicate with naturally occurring geological faults.
3. A recent study (ongoing) by the National Energy Technology Laboratory (NETL) for the Department of Energy (DOE) found that fractures in 1 in 8 wells had traveled up to 1,800 feet beyond the well bore, and federal regulators have accepted industry arguments that fractures may travel up to 2,000 feet.
4. The Environmental Working Group's extensive study found that the horizontal fractures can extend over 2,000 feet and fracture older gas wells that may not be identified and sealed and then create a perfect path for chemical and methane migration into aquifers.
5. Dominion wrote in a filing before FERC that there is no proven model or technology that can accurately predict the location and extent of encroachment of a hydraulically fractured shale well. The horizontal laterals may deviate from the intended path trajectory.
6. Microseismic and tiltmeter data should be gathered for each well. Once again the UMCES-AL recommendations are being ignored. As work progresses and wells are repeatedly fracked additional surveys should be required to monitor subterranean conditions and prevent nasty surprises
7. The technique of hydraulic fracturing enhances the permeability of the host rock so that the trapped resident gas can be released to the land surface. When the fracking fluid is depressurized, solid-particle proppants, which were introduced along with the fracking fluid, remain behind to keep the fractures propped open, which maintains the immensely enhanced permeability.

   The disciplines of Geomechanics and Geohydraulics are central to understanding and predicting the initial hydraulic generation and propagation of fractures within the host rock. Multiphase Flow is central to understanding the initial inrushing movement of the proppants and the subsequent non-movement of proppants in response to depressurization within the newly formed fractures. Aquifer Mechanics is central to predicting the gradual upward migration of zones of enhanced permeability that will bring methane and possibly other contaminants into the overlying freshwater aquifers. These hydro-geo-mechanisms could result in seismic events and the introduction of chemical pollutants. In this view, hydrogracking wells inherently function as injection wells. The initial response of the subsurface geologic beds to quantifiable injection stresses would be identical. The likely time-delayed deformational effects on overlying aquifers must be addressed whether the wells inject waste materials in Pennsylvania that are collected at a well site in Maryland or, even more drastically from the mechanics point of view, whether the Maryland wells simply inject water, proppants, and undisclosed chemical additives within a concurrently expanding and extending new fracture at depth.

The gradual upward migration of newly formed fractures in massive rock and the correlated upward migration of zones of enhanced permeability in saturated particulate-based beds such as aquifers, should be considered. Laboratory tests indicate unequivocally that any slight change of porosity of particulate-based aquifers (sand, clay, sandstone, claystone, etc.) changes the corresponding permeability exponentially. This enhancement, in turn, directly affects the upward density flow of gas into and through any aquifer towards the land surface and into the overlying atmosphere.

Aquifer mechanics and the upward migration of fractures have been studied, measured, and modeled in the American southwest. This is because such features and their results are more observable in arid regions. The water table is often hundreds to thousands of feet below land surface and an upward migration of a crack can be identified through the brittle unsaturated overburden. Initially, arid zone hydrogeologists borrowed concepts and equations from the mining industry who appropriately use a bending beam analogy. But a crack in a bending beam that is applicable to underground mines migrates from the top downwards, contrary to hydrogeological observations in the field. These same mechanisms, empirically corroborated in the American southwest, are applicable to hydraulic fracturing anywhere and to the likely unavoidable gradual upward migration of these fractures, especially when proppants remain in place.

It is important that the required microseismic and tiltmeter data gathered early at each well be made available to State authorities, MDE, MDNR, the academic community, and to the general public, along with any interpretations.

While gathering this microseismic and tiltmeter data, the operator can use other early data in order to determine the principal directions of in situ regional stresses at MDE and MDNR designated locales of interest. Such a determination can be made by the operator from a well-known standard procedure while inducing an initial or a more modest pre-initial hydraulic fracture. This information will help greatly to map in advance the direction of fracture propagation induced from any specified horizontal line or vertical borehole. After reaching a reasonably short distance from the borehole or line, the direction of propagation becomes controlled by the pre-existing regional stress field.

Methane gas WILL enter the drinking water. The only question is when, where, and at what rate. The answer to this question is location specific. Polluting chemicals may well follow the gas. The physical and chemical characteristics of these pollutants will determine if, when, and where. The entirety of all horizontal lines are likely sources of vertical-flow contamination.

The recommendation to analyze groundwater flow by developing flow nets tacitly presumes unchanging flow conditions and therefore is preliminary. We cannot estimate the response to dynamic events (such as fracking events and also aquifer pumpage by county residents) with static presuppositions. Depending on the available data, it might, however, give a glimpse into the initial regional groundwater flow conditions and directions. Such a glimpse is highly beneficial but is not sufficient. Changes to the quality of water cannot be foreseen or forestalled if the directions and timings of groundwater flow remain unknown and ignored even by the State. Actual measurements and knowledge of already changed chemicals in the water are necessary, but such knowledge may be too late to affect a timely response. Aquifer amelioration, if possible, in response to such knowledge may be too expensive. Accurate and informed modeling of future changing flow patterns is not only critical, it is cheaper.

Assuming a statically safe buffer zone is questionable. Changes in the vertical permeability will occur and cannot be ignored. This occurrence is dynamic because the changes migrate upward with time.

In order to hydrofrack in the first place, the water pressure had to have been larger than the minimum in situ principal stress within the shale. Any induced fracture whose interior tensile pressure is maintained at depth, whether by continuing to inject new water (to maintain its interior hydraulic pressure) or by proppant-to-proppant stresses, will continue to expand in the local direction of minimum resistance. In order to accomplish this feat most easily and efficiently, the fracture's interior walls migrate upward rather than outward. In principle, such a fracture will gradually increase its length forever.

November 25, 2013

Stormwater management

1. The well pad, according to the BMPs, would have to be surrounded by a berm designed to hold at least 2.7 inches of rain within a 24-hour period, so that spills of gasoline, oils and other hazardous chemicals wouldn’t flow onto surrounding land. Maryland weather records show more than that amount of rain has fallen in 24 hours on several occasions in the past few years, including during Superstorm Sandy. Climate change guarantees more deluges, so this BMP is not sufficient to protect the land, water, human health or wildlife.
2. Please modify the draft regulations to handle 4" of rainfall within a 24 hour period.
3. BMPs to address storm water management and erosion control must be extremely comprehensive and innovative. BMPs should also be more expansive and address short- and long-term (legacy) issues.
4. No discharge of potentially contaminated stormwater or pollutants from the pad shall be allowed and must be enforced.
5. The linear nature of pipelines and the amount of clearing, grading and trenching involved makes pipelines a potential significant source of sediment pollution during the construction phase. Unfortunately, the BMP report is silent on how the Departments plan to handle stormwater runoff from pipelines, access roads, and other construction activity. We recommend that limits be placed on the length of open trench and non-stabilized soil exposed at any time. Pipelines rights of way should be cleared, pipe laid, filled, and stabilized in segments to avoid excessive erosion. In addition, the right of way should be vegetated within an appropriate timeframe.
6. The Departments should make a determination whether the “hotspot” designation would provide better stormwater management protection than what is otherwise contemplated by the BMP Report. Hydraulic fracturing operations should be treated the same as similar heavy industrial activity.
7. The requirement to capture, store and transport all storm water can result in a large increase in truck traffic to haul the storm water from the entire pad. Capturing and storing only that water which could potentially be contaminated would be an adequate approach to meet the environmental safeguards sought without unnecessarily increasing truck traffic. Establishing a clearer definition of what constitutes a “drilling pad” could also be helpful. Potential contamination sources would be the drilling rig and associated equipment, excluding areas occupied by temporary housing, parking lots, etc.
8. Require gas companies to complete Storm Water Pollution Prevention Plans that severely limit toxic run off and erosion.
9. Require gas companies to complete Storm Water Pollution Prevention Plans that completely contain toxic run off and erosion. No "mitigation" or "minimization" weasel-wording.

November 25, 2013

Comments on the stringency of the proposed best practices

1. The net result of these recommendations will reduce any interest in shale gas production in Maryland because they are so stringent and time-consuming, especially the CGDP and the two years of baseline monitoring. Unless the Commission establishes a shorter and more realistic time frame, drilling will be delayed while we are seeking to expand upon economic opportunities and diversity through job and industry growth.
2. The Governor's call for a "Gold Standard" has Maryland proposing the strictest set of drilling requirements in the United States. But in its effort to propose the strongest standards, the State has drafted its own Best Practices, a number of which are not required by any other state or a voluntary consensus Industry standard and that, if adopted, may not allow for reasonable development. While learning from other states or Industry experiences makes sense, creating an untested Best Practice in a vacuum does not.
3. Maryland should leverage the best practices from other states deeply involved in fracking.
4. These are weak guidelines that cater to the natural gas industry.
5. I believe the MDE/DNR recommendations are more of a political statement than based on good science, are excessive and unnecessarily cause, gas rights owners in Maryland, extreme barriers to realizing value from our land and minerals that we are granted by the constitution of the United States. These proposals are, once again, an attempt by those who reside in areas where these natural resources do not exist, to impose their preferences and beliefs on those of us who rightfully own these resources.
6. The Practices as recommended rely primarily upon the environmental science report and focus, almost entirely, on suggestions for the ultimate environmental protections without adequate review and consideration of practices for efficient production of shale gas. This is not the proper focus of a best practices study.
7. The Practices recommendation was undertaken pursuant to an Executive Order directing a study to include recommendations for best practices for all aspects of natural gas exploration and production in the Marcellus Shale in Maryland. A popular definition of a best practice defines it as the "best way to do something; the most effective or efficient method of achieving an objective or completing a task." [Bing Dictionary]. By focusing primarily on the environmental science report and largely ignoring industry recommendations for the most efficient and effective means of production, the Practices recommendations fail to fulfill the stated purposes.
8. Although the environmental study suggested voluntary plans, the Practices require a mandatory plan, thereby adding an additional, time consuming and expensive planning requirement to review locations of all contemplated facilities intended by a prospective driller who may not yet even have obtained the leases, options, rights-of-way and other property rights. Besides the huge preparation difficulties, this requirement also lacks defined standards of review and allows approval/disapproval virtually at the discretion of the "State" (presumably meaning MDE). In addition, the process of plan reviews is to include a complex process of State review, local government review, stakeholder comments and public comments following a public meeting. Then, the

approval/disapproval decision would probably be appealable to a court in a de novo proceeding. Although there are some benefits to such a plan in coordination and siting, these can be accomplished by a regulation in regard to pooling and siting of facilities, without the addition of an entire pre-development level of planning reviews, hearings and potential litigation.

9. No justification is identified for the imposition of predevelopment data collection, which will be lengthy and expensive data collection and reporting requirement. The effect is to add an additional two (2) years on top of the potential two to four year period required to obtain an approved Comprehensive Plan before application for a specific drilling permit. Because an eventual drilling permit would be subject a review/appeal process, there is the likelihood that the recommended Practices would involve a five to seven year span before drilling could occur. Such Practices, in effect, would prolong the de facto moratorium on shale gas drilling in Maryland.
10. These are excessive requirements that are more stringent than those in neighboring states:
    a. High financial assurance requirements, including a periodic updating of closure cost estimates.
    b. Closed-loop drilling
    c. Zero discharge pads
    d. Prohibition of impoundments for anything except fresh water
    e. On-site management of flowback and produced water
    f. Mandatory chemical disclosure that does not protect proprietary trade secret information.
11. Therefore, there is a major risk that the numerous additional requirements suggested in the draft Practices will have the effect of extending a de facto moratorium on shale gas development in Maryland. We strongly encourage rethinking and revision of the proposed Practices, to reduce the burden of additional requirements wherever possible while retaining reasonable protections for the environment.
12. I am in favor of being allowed to drill for my gas and to take it to market. As it stands now, my State government is blocking me from selling property that I bought with hard earned dollars. I am extremely disturbed by this action. I can still sell the timber from my land if I so choose, or even a big rock, if someone wants to buy it. But not MY gas. Certain people in our state are so concerned about drilling for this gas that it has been, for all practical purposes, stopped / blocked.
13. How do the risks and regulation of drilling for gas compare to other things that the government either allows or does little to stop
    a. The construction of windmills on ridgetops, with damage from the site pads, access roads, and power line rights of way
    b. The tons of salt used on highways each year, that damage water wells, water sources, trout streams and forests.

   c. The wooly adelgid and red rust fungus are destroying out hemlocks, which will damage trout streams.

14. The intention of the BMPs should be to protect human and environmental health, however, the research has not been done to provide a scientific basis for these practices.
15. All permits should have a requirement that if more stringent regulations are passed, the new regulations must be followed. Operations must be shut down until the company can comply.
16. An industry group estimates that, given the recommended processes, a well operator will have to dedicate four years of resources and expense before obtaining any information on the viability of production from the Marcellus formations in Maryland. Given the choice of proceeding through Maryland's cumbersome processes or dedicating resources elsewhere, well operators will almost certainly choose to operate in other states, further decreasing Maryland's economic competitiveness in this arena. A more realistic time frame should be considered.
17. We believe that some of the proposed mandates and testing requirements including the CGDP are some of the most stringent regulations in the Country but are also very costly and time consuming, while offering minimal environmental protection. These recommendations rely upon state protocols and plans that have yet to be established; or assessed for practicality in real time applications. Therefore, we urge the commission to seek a shorter and more realistic timeframes to be considered for the CGDP and allow the exploration for shale gas to be done earlier in the process to provide for more accurate and detailed information for the approval of the a final CGDP. Please remember that we are competing against other states for this economic activity while protecting our natural resources.
18. We consider the CGDP requirement to be above and beyond the standard set for any other industries in Maryland and maintain that it will impair the economic viability of the gas play. Therefore, we would like the department to withdraw or completely revise the regulations regarding the CGDP. We also feel that it should be voluntary, not mandatory, with incentives to encourage companies to comply.
19. Our biggest concern lies with the process of the Comprehensive Gas Development Plan. With only approximately 1% of the shale play lying in our area and Dr. Eshleman's report recommending that this type of plan be voluntary, the proposed regulations are too time consuming and expensive compared to our neighboring states. In my view, this discourages the entry of multiple companies into the Maryland fields and at this point has completely run the gas companies "out of town" so far as considering leases or development of wells. It may be an unintentional consequence, but this limits competition and works to the disadvantage of all. I do not quite understand how the effort to develop an oversight process turned into a focus of creating a "gold standard" that makes Maryland regulations more stringent than any other state in the nation.
20. As we continue the effort to define the balance between the rights of property owners and the protection of the environment, the accountability of state officials to oversee the regulatory side of the equation with a timely and balanced approach is a major concern. Of all of the studies that have been ordered, I don't believe I have seen a calculation of

what the cost of existing regulations for any kind of development already on the books amounts to with the gas industry, much less the cost of all the newly proposed regulations that are being proposed (such as the CGDP). It is a simplification to just say that these are “gas company costs.” Every cent eventually leads to a reduction to the property owner, which in turn is a reduction to our communities and the state in taxes that will be paid.

21. As an overall view of the recommendations from the document, this appears to be geared toward requiring a great deal of initial reporting from the operator to identify all of the future plans for drilling and production in Maryland prior to any exploration drilling. The processes outlined require considerable reliance on state agencies developing protocols, plans, and toolboxes that currently do not exist. Coupled with requirements for extensive multiple-year testing prior to the initiation of drilling, if an operator worked diligently to drill an exploratory well in Maryland today, these draft requirements and recommendations would put the well spud date at minimum of five to six years into the future, assuming the state develops the maps and protocols within one year of approval of the final report, a goal that would prove challenging to achieve. Our organization believes that a realistic and shorter time frame should be considered for the combined CGDP and baseline activities (perhaps 12 months or less) which would allow for exploratory wells to be drilled earlier in the process to help provide more accurate and detailed information necessary for the development of the CGDP. Should this revision be accepted our organization would be happy to meet with the MDE to further discuss and refine this concept.

22. The Governor's call for a "Gold Standard" has Maryland proposing the strictest set of drilling requirements in the United States. But in its effort to propose the strongest standards, the State has drafted its own Best Practices, a number of which are not required by any other state or a voluntary consensus industry standard and that, if adopted, may not allow for reasonable development. While learning from other states or Industry experiences makes sense, creating an untested Best Practice in a vacuum does not.

23. A de facto taking occurs when government laws, regulations, or restrictions in fact take your property because you can't use it. You've been deprived of your property rights without being paid. My first question is: Has or will the committee consider the cost to the State of Maryland if the Courts were to determine that because of all the regulations and restrictions imposed on natural gas drilling in Maryland, the result is a de facto taking of property rights. (Natural Gas) Maryland seems intent on setting an extremely high bar for the natural gas industry and setting standards that are tougher than in any other state. Eminent Domain, the governments taking of property, is ultimately a federal constitutional question.

24. Can the State of Maryland under the Federal Constitution set a higher standard for drilling than all the other states where natural gas development is taking place? If the people of Garrett County with natural gas rights had those same rights just across the line in West Virginia or Pennsylvania, they could be worth a fortune. In Maryland those rights are worth nothing, and they may never be worthy anything. How constitutional is that?

25. Regarding the constraint analysis, it is inappropriate for Maryland's agencies to develop regulations with the intention of maximizing industry's ability to recover resources under our communities.
26. We believe they go above-and-beyond what the Governor has called a "Gold Standard" for drilling for natural gas. The permitting proposals would add an increase in cost (upfront in particular), and the time consuming process would make it extremely unlikely that any company would be willing to meet all of these requirements, especially under the present market conditions.
27. For certain common activities, these proposed Best Practices would treat the drilling industry differently than everyone else without any justification. One example is the proposal for storm water management. We strongly question with the present natural gas market, the sizable acreage of leases not being renewed in Western Maryland, and these overly stringent requirements whether there will be any significant development of the Marcellus Shale in Maryland before 2020. This proposal could result in a continuation of the de-facto drilling moratorium. The draft BMPs and the potential "Gold Standard" for development only mean something if they are balanced enough to allow drilling in Western Maryland while offering sufficient protections to the environment and the citizens of Maryland.
28. The magnitude of the effort to prevent drilling using the technique called horizontal drilling and hydraulic fracturing until the report is completed and recommendations adopted leads one to believe that there is a presumption that this activity is much more destructive than any other industrial activity that takes place in Maryland. No other industrial activity in Maryland has ever been singled out for this degree of scrutiny. There seems to be very little concern about the clear message that Maryland is sending to those who would desire to do business in Maryland. The message currently is simply that they are not welcome in this state. If all of the recommendations of this study and report are implemented in law, regulation, or permit conditions it is highly unlikely that any drilling will occur in Maryland (at least in the foreseeable future). If it is the intent of those that commissioned the study to prevent the development of natural gas in Maryland, then their mission has truly been accomplished.
29. The report portrays a very negative viewpoint toward the natural gas industry. If every new applicant for permits to engage in any new industrial development in Maryland was required to meet every stringent requirement outlined in this report, there would undoubtedly be a complete lack of interest by any person, firm or company to do business in Maryland.
30. After reviewing the content of the draft report I conclude that it will be 2020 or later before any drilling for natural gas can occur if all of the recommendations are accepted to create the "GOLD STANDARD" in Maryland. Permits are being processed and drilling is taking place in our neighboring states. The process to get a drilling permit in our neighboring states and other states in the Union takes weeks or months, certainly less than a year.
31. We have waited long enough. We see drilling all around Garrett County and we are not allowed to take advantage of it. Reasonable controls are appropriate. The proposed

requirements are too restrictive and designed to slow or stop drilling. PA WV seems to do ok. Let’s not reinvent the wheel. Follow their experience and parallel their regulation.

Surface Impacts and Setbacks

1. Fracking is an industrial activity best confined to areas zoned for industry, and the state should indicate so in the BMPs and eventual regulations.
2. How much buffer is enough to protect the water, air, and quality of life for those living near such an industrial zone? Keep in mind that Garrett County is currently a rural area of farms and forests. How will those who live near these areas be compensated for these impacts? If compelled to move due to the insults associated with this industrial zone who would buy their homes and land? Remember, these are most likely people who have not signed gas leases and who will not be receiving any royalties.
3. There should be a limit on the amount of land surface that can be disturbed by gas exploration. The Eshleman report recommended that gas drilling activities be limited to only 1-2% of Maryland's land surface. This should be applied throughout the State because gas-bearing shales are present in other places in Maryland. The state will not require that multiple companies submit comprehensive drilling plans together; rather, it will "encourage" them to work together on drawing up their plans. Asking the gas industry to voluntarily work together and share information about its drilling sites does nothing to guarantee that the public's interest is taken into account during planning.
4. Proposed setbacks allow drilling 600 feet from “irreplaceable natural areas” and “wildlands” and a mere 300 feet from a stream, river, spring, wetland, pond, reservoir and 100-year floodplain. Drilling so close to these fragile areas is unacceptable.
5. Under the proposed BMPs, the drill rig can be as close as 1,000 feet from an occupied building (house, school, medical office, store), 1,000 feet from a private well and 2,000 from public groundwater wells or surface water intakes and reservoirs. We do not think private wells and public groundwater wells should be treated differently.
6. We recommend that all setbacks—whether from streams, springs, rivers, wetlands, ponds, scenic byways, reservoirs, schools, homes or shops—be at least 3,500 feet. (If the health study shows that even greater setbacks are needed to protect residents and wildlife from air pollution, then these setbacks will have to be revisited.) Proposed New York regulations call for a buffer of 4,000 feet from “unfiltered surface drinking-water-supply watersheds.” We recommend the state consider that distance as well. A Duke University Study found that 82% of drinking water wells monitored within a 5 kilometer radius of drill bore were likely to contain stray methane. Of those, the wells within one kilometer (3280 feet) were 6 times more likely to contain stray methane. (report) University of Texas Arlington has released a report establishing a 3 kilometer distance of impact between drill pads and drinking water wells. This study was similar to the Duke study that measured methane concentrations in drinking water. The Texas study shows significant risk to drinking water wells within 3 kilometers, not of methane contamination, but of metals, including arsenic. Three kilometers is near the length of most horizontal well-bores. The setbacks should be extended at least to 3300 feet.
7. The BMP report calls for 1,000 foot setbacks from water wells, and 2,000 feet from public water supplies. Since finding out that contamination can occur when any fracked well is as far away as 3,280 feet. There was another study that found different contaminants

associated with fracking within up to 5 miles of gas development. As it is not certain how far these substances can migrate, setbacks need to be at the greatest distance possible.

8. Pads may be permanent or nearly permanent fixtures if the wells are subject to enhanced gas recovery and then for geologic sequestration of CO_2.
9. Include wildlands and all public lands under III.E.2.
10. Section IV.B.2 suggests that forest loss could be evaluated differently depending on whether the loss is temporary or permanent. How could a forest loss be temporary?
11. Setbacks for well pads and infrastructure from private and public water wells, homes, schools, and office buildings should be at least 3,500 feet. A recent Duke study found methane in wells up to 1 kilometer away from drilling sites.
12. The noise, truck traffic and lights 24/7 are not only for thirty days as industry would like the public to believe. Some well pads may have more than one well, as many as 6-10, drilled in sequence. Companies may continue with these wells for years. Completion may not happen in our life-time.
13. Fracking infrastructure, like compressor stations and pipelines, has caused explosions and fires in communities in PA, NJ, CA, OK, and more. Your current setbacks of as little as 300 feet are not sufficient to protect Marylanders from these risks.
14. In neighboring states, we have seen severe disruption to agriculture, vegetation and to the topography
15. The wells and wastewater sites desecrate beautiful natural landscapes and deprive local flora and fauna of habitat.
16. The State should provide oversight on placement of MSGD infrastructure.
17. If setbacks are minimally protective distances, they should never be waived. Parents should not be allowed to consent to waivers on behalf of their children.
18. It is problematic to apply standard setback requirements to local geological conditions; site-specific formations must be considered.
19. There should be no waivers, and current setbacks are not sufficient.
20. Ecologically sensitive areas and irreplaceable habitats should be protected from the adverse impacts of all aspects of gas and oil development and supply, including drilling, pipelines, associated infrastructure and sand mining; the high value habitats in Important Bird Areas should be protected from industry activities.
21. The logic evades me; commission the UMCES-AL study, pay for it, then disregard the findings. The setback distances, almost unilaterally have been halved when they should have been doubled or tripled according to the latest research findings.
22. The open-ended set-back waiver leaves open the exact door that so many states, specifically West Virginia with only 200 feet, that has been left open where large, industrial HVHF well pads and processes are within a stone's throw of family's homes, churches, schools and public areas. Set-backs should be black & white to keep industrial zoning separate from residential and community zoning regardless of what one party thinks it appropriate.

23. Setback requirements for the several categories appear to somewhat arbitrary and not based in topographic realities. Each proposed setback should be reviewed and analyzed against protections for environment; public health, welfare and safety; defense of Garrett County's tourism and outdoor / adventure industries; and for protection of property values of contiguous and nearby properties to Marcellus gas operations.

24. Considerations of setback requirements should be expanded to include the gas delivery system (gathering lines, etc).

25. Further, while we recognize Garrett County does not currently have county-wide zoning, the study recommends exceptions "for good cause shown and with the consent of the landowner protected by the setback, MDE may approve exceptions to the setback requirements." Setback provisions, and exceptions, should be developed for contiguous and adjacent properties to protect those landowners.

26. The setbacks presented for the protection of scenic and wild rivers, special conservation areas, is determined without consideration of methane migration via rock fractures well outside the limits collected from other states and offered as "Best Practices". The suggestion that setbacks may be expanded on a case by case basis merely suggests that the issue has not been seriously considered

27. Setbacks are distances in the BP Report from the well bore or well pad and as mentioned in the setback table from the disturbed area to water supplies or other important natural resources that need to be protected from contamination, damage, view, or other object in need of separation. The initial distances for state parks, scenic and wild rivers and for special conservation areas (e.g., irreplaceable natural areas, wildlands) are grossly inadequate and require reevaluation after a formal risk analysis has been completed.

28. The setback distances in general sound okay, but when dealing with drinking water reservoirs, such as the Frostburg Reservoir and others in Garrett County, the distances should be greater than those recommended by Eshleman and Elmore. If horizontal boreholes can extend 7000 feet, I think that the setback distance from key drinking water resources should be at least 7000 feet.

29. The Departments must use existing statute provisions (Md. Env. Code, Section 14-108) to protect special and unique areas.

30. The potential for ground water contamination from spills or other conditions where chemicals from fracking mixtures may be involved indicate that the Departments need to review their setback requirements and equally important and to develop baseline data on various chemical parameters as well as methane in water wells and aquifers in Western Maryland.

31. Mention is made "Avoid surface development beyond 2% of the watershed area in high value watersheds. " There is no "should" or "must" associated with the stated threshold. MAC believes that a 2% surface development on the Savage River watershed would have a huge impact not only to the environment and streams that brook trout inhabit but also to the natural setting and recreational experience that the watershed provides.

32. A 300-foot setback on a body of water used by wildlife and for human recreation is so small that the drill site would be visible from the waterway; disrupting water use would

have serious economic consequences for the tourism sector, in addition to threatening wildlife, especially endangered species.

33. The draft BMPs recommend a 1,000 ft. setback between a compressor station and an occupied structure. At the very least this restriction should also apply to distance of compressor from cultural assets, waterways and roadways.

34. The proposed 1000′ for private and 2000′ public drinking water setbacks in the draft Best Management Practice are not enough. Proposed setbacks allowing drilling 600 feet from “irreplaceable natural areas” and “wild lands” and a mere 300 feet from a stream, river, spring, wetland, pond, reservoir and 100-year floodplain is an unacceptable risk. Based on evidence of methane, ethane, and propane contamination documented by Duke University researchers, MDE and DNR should increase the proposed setbacks to 3,500 feet and should not treat private wells and public groundwater wells differently.

35. Natural fractures of the bedrock beneath central and western Maryland contain potential drinking water resources, and shale gas boreholes should be set back from these geological features. These fractures complicate the casing and cementing of wells that pass through them, increasing the risk of subsurface leaks.

36. UMCES-AL recommendations with regard to setbacks from mapped underground coal mines to the borehole are unnecessarily restrictive, as appropriately noted by the Departments in the August, 2013 Draft Marcellus Shale Safe Drilling Initiative Study Part II. The Board of Directors and committee members of the Casselman Coal Poolee Association endorse the Departments recommendations with regard to this critical issue. Pre-drill planning including careful site evaluation and pilot hole investigations is the safest and most effective method to identify these features. As noted by MDE’s mining program, Maryland’s deep coal mines cover thousands of acres, but are only several hundred feet deep, and can be safely cased through, utilizing pilot holes to precisely identify and locate any voids. The MDE and DNR have appropriately proposed that the best practice is to conduct pre-drill planning in any area where underground mining is suspected within 500 feet of the prospective borehole, based on a review of available records. The Departments have recommended that the pre-drill planning shall include selection of drill hole locations that avoid all mine voids and assures lateral support of drill holes during drilling and casings during well construction. If such locations cannot be found, voids must be filled or isolated with multiple concentric strings of casing and cement. We fully endorse these recommendations.

37. As a watershed organization we know there are 18 mineral leases in the DCL watershed. We are concerned that the set backs for drilling are insufficient to provide the protections needed within our watershed and in the County.

38. Setbacks of 300 feet from trails or 600 feet from “irreplaceable natural areas” and “wildlands," 1,000 feet from drinking water wells and 2,000 feet from public groundwater wells, surface water intakes and reservoirs all seem inadequate. Setbacks should be increased to 3,000 feet to 4,000 feet.

39. Depending on how the terms “stream” and “seep” are defined, these aquatic habitats may not be adequately mapped.

40. In addition to historic gas wells, there should be consideration to setbacks or conditions placed on fracking near existing production wells. Fracking near existing wells can result in a “frack hit” on an active production well that could result in a blowout of the well equipment on the production well. This problem can be avoided either by setbacks or by special preparation of the production well to handle a possible “frack hit”.

41. Setback from Compressor station – The table does not make it clear whether the setback from an occupied buildings for compressor stations is from the actual building housing the compressor, or from the building and associated infrastructure, or from the limits of the property that houses the compressor station. This should be clarified.

42. It would be helpful to have a definition of “for good cause shown” in connection with waivers of setbacks.

43. There are a number of proposed setbacks within the document, many of which are in conflict with each other. For example, it is unclear on page 30 with respect to the drilling of a pilot hole within 500 feet of the proposed borehole, whether the setbacks for the pilot hole would be the same as for the final developed well. There are no provisions for using the same pilot hole for the main borehole of the well if no issues are identified during its drilling.

44. Another example of significant uncertainty in the document is with the 300 feet setback from various “recreational use areas” clearly recommended on page 16, versus the suggestion on page 18 that it may be doubled to 600 feet based on a workshop anticipated later this year.

45. The 1320 foot setback from historic gas wells (from both the vertical and horizontal well bore) is being recommended with no real technical basis. It may be reasonable to recommend “identification” of existing wells within a certain, somewhat arbitrary, distance as part of the permitting process to ensure those wells are appropriately recognized and considered, but it’s an entirely different issue to establish that as a mandatory setback. Setbacks should be established to balance environmental protection and development. Overly restrictive setbacks can have the unintended consequence of essentially reducing the area available for drilling.

46. The setback requirements should not be arbitrarily picked and there should be some criteria and a scientific basis rather than a "farther is better" approach.

47. A setback of 1,000 feet is inadequate on its own terms and close to meaningless if horizontal drilling extends the exploitation zone thousands of feet in every direction from the well pad.

48. If the State mandates a 2,000 setback from existing and historic gas extraction activities, it is unclear how the State can also permit much larger, deeper and more complex wells to be drilled in close proximity to other wells on a CGDP well pad.

49. Allowing individual landowners to waive setback requirements infringes on rights of all other nearby residents to expect full protections from the State’s regulations and from the CGDP process. The provision for exceptions can easily be abused by industry, effectively negating protections put in place in this section. It also opens the possibility of aquifer contamination to occur in a shared water source that might otherwise have been afforded protections if original setback guidance was observed. Setback waivers should only be

permitted with the approval of all surrounding landowners who would have been afforded more complete protection if the original setback remained in force.

50. In Table I-2, the “to” section describes from the “edge of the drill pad disturbance” and should include a descriptive outline that includes the sedimentation and erosion controls and storm water controls as the limits of disturbance (LOD) for the setbacks.

51. A setback of 300 feet from aquatic habitat (defined as all streams, rivers, seeps, springs, wetlands, lakes, ponds, reservoirs, and 100 year floodplains) is not sufficient protection for waterways used by boaters and fishermen. Drill pads should not be visible from a waterway or body of water; disrupting river/reservoir use would have serious economic consequences for tourism.

52. In Garrett County alone, approximately 14,394 households rely on groundwater wells for their drinking water supply. Given the wider radius of contamination of shallow groundwater resources demonstrated by the most current science, I recommend setbacks for residential and public water supplies no less than 1 kilometer (3,280 ft.)

53. The setbacks should consider not only contamination from events at the land surface, but also those that occur beneath.

54. The recommendation on conservation banking for forests [a Siting Best Practice] does not make clear how conservation banking will be used. Does this mean that the drilling company can undertake or contribute to conservation efforts elsewhere if impacts in western Maryland cannot be avoided? Will the Agencies consider credit trading to satisfy forest conservation mitigation for western Maryland forests? Will a local stakeholder be a part of decision-making regarding the use of conservation banking?

55. The UMCES-AL report recommended that hydraulic fracturing should avoid times of peak outdoor recreational periods such as holiday weekends, first day of trout season, and during sensitive wildlife migratory or mating seasons. The Departments accept the proposed timing on hydraulic fracturing recommendations; however, the State realizes that this could only apply to the initiation of fracturing operations that could be planned in advance or temporarily suspended. Once fracturing operations have begun, it is generally not safe to halt activities. This exception will diminish the State’s ability to restrict the timing of fracturing activities. The driller is essentially enabled to ignore peak recreational periods and wildlife needs, conduct the hydraulic fracturing phase at will, and claim that it is unsafe to halt activities because they have already begun.

56. A 300-foot setback for aquatic habitat, (all streams, rivers, seeps, springs, wetlands, lakes, ponds, reservoirs and 100-yeat floodplains) is totally inadequate as are a 600-foot setback for special conservation areas (irreplaceable natural areas and wildlands) and 300 feet for all cultural and historical sites, state and federal parks, trails, wildlife management areas, scenic and wild rivers and scenic byways. Surface disturbance in areas with sensitive resources should be limited to 3,000 feet.

57. No CGDP plan or permits should be issued for fracking on public land.

58. In general, we recommend inclusion---in the table and/or the accompanying text---of the rationale for the specified setbacks. Some appear arbitrary.

59. Recommend including a 2 mile "disaster mitigation" set back from existing incorporated town limits to emphasize human population safety. See data on recent natural gas compressor station explosions and evacuation actions by local public safety authorities- usually a 2 mile radius.

60. There should be a setback from existing communities and concentrated population centers.

61. The use of open space/agricultural sites or TRULY ZONED industrial sites for compressor stations should be chosen preferentially over sites within 2 miles of established population centers.

62. A setback of 3500 feet should be required to keep drill pads and support facilities such as roads, pipelines and compressors away from water wells (both public and private), schools, homes and office buildings. This is essential to protect clean drinking water and public health and safety.

63. All drinking water setbacks in the Best Management Practices report should be increased to 3,300 feet.

64. No waivers should be allowed to the 1000 feet rule for water wells on private property unless the surface owner is also the mineral rights owner.

65. I live adjacent to a river canyon and can show you how and where a simple tire track off the side of a road, can become a channel through which rain finds its way to an underground spring or drainage field that eventually finds its way to a creek and a river. I consider the 300 foot setback from waterways to be highly problematic and, I have to believe, an arbitrary and uninformed criterion for ecosystem protection.

66. All BMPs of setbacks from "occupied building" should be changed to property line. Rural areas are sparsely populated and have more land parcels than occupied buildings. Setbacks are more appropriately set from property boundaries to afford equal protection to all landowners, regardless of the extent of the current development and use of their property. Setbacks from property lines are the standard approach in almost all land use regulations.

67. Compressor station setbacks should be from property lines. As drafted, the BMPs provide a 0' setback from property lines. This creates a safety issue for the adjoining property owner who does not have the benefit of an "occupied building" on their land or near their property line, precluding the peaceful and safe use of their property, as well as limiting future improvement and development of their property.

68. Provide a BMP setback for pipes, tanks, valves, and related infrastructure after drilling. This infrastructure presents significant safety, health and environmental hazards should failure or accidents occur. To the extent that these regulatory issues are not in the purview of the MDE or DNR, the Commission should issue a strong statement calling for these to be developed in Maryland, by the appropriate entity, and that no drilling should occur until such time as these protections are put in place

69. The BMPs provide minimum setbacks for public drinking water protection - only public groundwater wells or surface water intakes have setbacks. Public drinking water source areas outside of the intake or well setback zone receive only the 300' aquatic habitat setback.

70. The 2000' public drinking water supply setback should also apply to public drinking water tributary streams and impoundment borders.

71. The towns of Friendsville and Oakland use the Youghiogheny River as a public drinking water source. Setback protections from the main stem of the Youghiogheny River upstream from Friendsville and Oakland should be the most stringent – 2000' as a drinking water source and not the 300' aquatic habitat standard.

72. Setbacks for well pads and infrastructure from private and public water wells, rivers, creeks, homes, schools, and office buildings should be at least 4,500 feet.

73. Setbacks for well pads and infrastructure from private and public water wells, homes, schools, and office buildings should be at least 1 mile.

74. Our county, state and federal lands and resources cannot be used to drill by the fracking/gas companies, in order to preserve nature, protect our wildlife, and the water that flows through it.

75. Fracking and or drilling cannot take place within 200 yards of any private well or public water sanitation areas.

76. Fracking underground of personal property without their express written permission of the landowner, would not be permitted. In addition, that landowner would also receive a royalty fee from the company and eligible to make claims against the shale fracking/drilling companies, if warranted.

77. For aquatic habitat (riparian), the UMCES-AL Report cited recommended varying setbacks based on biodiversity. The lowest setback was 330 feet and the greatest was 1,240 feet (Table 5-2 and page 6-4). Why are the Departments recommending a setback of 300 feet? Does the setback provide adequate protection? Usually riparian areas are protected by vegetated buffers. Will these buffer areas be factored into the setback calculation?

78. For drinking water wells and surface water intakes, the UMCES-AL report recommends "extended" setbacks from on-site storage areas, hazardous materials and collection tanks for produced water. Should additional setbacks be proposed?

79. Since setbacks offer the primary protection, it is extremely important that they are correctly identified, including whether they are measured from the borehole or the edge of the pad.

80. Greater setbacks for critical facilities such as hospitals, police and fire stations should be considered. A hospital would be hard to evacuate if needed. Police and fire stations will need to remain operable if there are problems. Are there existing setback requirements from a cemetery?

81. Are there no setbacks proposed for "infrastructure improvements" such as access roads and pipelines? Road and pipeline construction could impact critical and sensitive areas.

82. Why is there a setback for wildlife but not for livestock?

83. The recommendation should provide a provision that the owner(s) of leased property, the lessor, can allow the well to be located closer than 1000 feet to his own water supply.

84. The report recommends expanding drill pad location restrictions and setbacks listed in Table 1-1 to all gas Development activities resulting in permanent surface alteration that

would negatively impact natural, cultural and historic resources. This would severely restrictive for roads and infrastructure. This provision could make it impossible to put in gas pipelines through or along county roads in state parks and lands and perhaps even difficult to construct a road from public right of way to a well site. This provision conflicts with the intent of the report to limit development impacts and forest bifurcation.

85. Expanding the setbacks from public outdoor recreational use areas would give the State control over massive amounts of private property and restrict landowner's ability to lease or have natural gas development on their property that borders on state land if these setbacks include all aspects of natural gas development.

86. There should be a setback from land on which MALPF holds an easement.

87. Setbacks from all occupied buildings and recreational facilities should be at least 2,000 feet.

88. The provision recommending that drilling should avoid times of peak outdoor recreational periods is unreasonably restrictive. What purpose is served by restricting drilling on first day of trout season verses any other day of trout fishing? Not likely that the trout will quit biting in the Potomac River if a gas well drilling operation starts near Keyser's Ridge.

89. If the horizontal part of the well could be drilled as far as 8,000 feet, property lines are not protected if the setback is 1,000 feet!

90. It is appalling and shameful to propose different setback standards for municipal waters and for private wells.

91. The report proposes a setback of 2,000 feet for public water supplies but only 1,000 feet for private wells. In essence, you are saying that safety and health is not important for the few or if only a few families are adversely affected.

92. The setbacks from streams and rivers should be more than 300 feet – maybe 1,000 feet from the drilling pad.

93. I am also appalled that the state has no control over the siting of compressor stations and gathering lines.

94. 300 feet as a setback from historic sites would certainly destroy any historical site or park. The industrial nature of a drilling operation is in direct conflict with the goal of preserving cultural and historic or scenic and wild byways. These unique resources need protection of at least 2000 feet if not much further.

95. The total disturbance limit to 2% on high value acreage should be extended to all extraction zones A different limit might be appropriate but no limit is not reasonable.

96. For aquatic habitat (riparian), the UMCES-AL Report cited recommended varying setbacks based on biodiversity. The lowest setback was 330 feet and the greatest was 1,240 feet (Table 5-2 and page 6-4). Why are the Departments recommending a setback of 300 feet? Does the setback provide adequate protection? Usually riparian areas are protected by vegetated buffers. Will these buffer areas be factored into the setback calculation?

97. For drinking water wells and surface water intakes, the UMCES-AL report recommends "extended" setbacks from on-site storage areas, hazardous materials and collection tanks for produced water. Should additional setbacks be proposed?

98. Since setbacks offer the primary protection, it is extremely important that they are correctly identified, including whether they are measured from the borehole or the edge of the pad.

99. Setbacks from floodplains should increase and be based on a minimum distance and elevation, whichever is greater.

100. The setback for occupied buildings should be 1,000 feet from the well site and compressor equipment (if located off-site) instead of the proposed borehole. Should a structure holding livestock be defined as "occupied?" Noise, vibrations, odors and light will impact adjacent buildings. In addition, setback consideration should be made for unoccupied agricultural buildings (such as hay storage).

101. The "Location restrictions" discussion ignores the effects on wetlands, fresh water aquifers, etc., of the upward migration of induced zones of enhanced vertical permeability. Unfortunately, criteria for "setbacks" are applied only to the pad and to other activities and events taking place at the land surface. These applications are necessary, but are not sufficient. Though one can expect historic gas wells (and environs) to mark locations where vertical upward flow of gas and pollutants may occur, they do not mark the only locations where one can expect to find sooner or later zones of enhanced vertical permeability that eventually will reach the land surface and hence will introduce future upward flow of methane gas not only to fresh water aquifers and wetlands, but also to the atmosphere. One should also consider the effect that formation-to-formation geologic heterogeneities have on the mapping of where zones of enhanced permeability may be expected to migrate. Ditto for the locations and geometries of deep coal mines.

102. The currently specified setback from any drinking water well presumes that contamination comes from pollution events that occur at or near the land surface (on the pad, in collection ponds, whatever). Events that are inevitably occurring beneath the land surface are ignored. Ignorance is no excuse when protection of natural resources and the health of citizens are involved.

November 25, 2013

Truck Traffic

1. Consideration should be given to truck traffic adjacent to schools. The amount of dust and particle emissions from the diesel engines would impact the health of school children, especially those on playgrounds. It is common practice for truck owners to modify their diesel injection systems to generate more power. However, the result of these modifications is a large increase in black soot from the trucks' tailpipes. This will need to be regulated if the trucks are to go pass a school.
2. The report's recommendations fail to recognize that most of the truck traffic generated from Marcellus Shale drilling is short-term, typically occurring over a few months during site preparation of the well (e.g., hauling pipe, water, etc.). Once a well is established, truck traffic significantly decreases as gas is transported via pipeline.
3. Do we demand the companies profiting from MSGD be financially responsible for the effect of the increased heavy vehicle traffic on our roads, or go the way of Texas and just let our roads revert to gravel?
4. Not only will the road and bridge infrastructure be damaged, but we also foresee very significant safety issues particularly where the large trucks and concentration of activity on small county and park roads will undoubtedly lead to a significant increase in accidents. Traffic patterns and road usage would have to be closely monitored or prohibited in some cases.
5. Please change "should" to "shall" in "Trucking should be closely monitored during high-use and wet periods if it is not possible to suspend activities."
6. It may be politically difficult for local officials to enforce agreements with companies to fix roads or pay for them. It might be better for the State to take on this responsibility.
7. There are several comments on timing of heavy trucking. The highlighted times listed on page 26 are an extension of API recommendations that a transportation plan be incorporated into the overall project plan and that the plan address traffic needs. A more complete review of the recommendations contained in the API recommended practices associated with transportation planning could assist the state in this area.
8. Many of the recommendations included are unrealistic. For example, encouraging "maximum movement of heavy equipment by rail to protect road systems and prevent accidents" is idealistic. While rail is a viable long-haul transportation option, the last miles traveled in the geographic region will ultimately be made on a truck. The requirement that "all trucks, tankers and dump trucks transporting liquid or solid wastes be fitted with GPS tracking systems" is virtually impossible in an industry that is deregulated, highly fragmented, and uses a large number of independent contractors to meet short-term transportation needs.
9. "Encourage local jurisdictions to develop adequate transportation plans." The Transportation study funded in the Governor's 2013 budget has not yet begun. When developing the scope of this study, the Departments should include the "local jurisdictions" to assure compliance with the policies to be adopted. In addition, there are several road projects under consideration (495 Truck Route) in the region that will have impacts on truck traffic and early involvement in developmental strategies at the state and local level would assure a unified approach to that development.

10. All trucks associated with the development of a well permit must have GPS real time spatial data to allow for tracking.
11. As part of the CGDP, MDE should mandate trucking routes and haul times.
12. The implementation and oversight of transportation and trucking to coordinate the timing of oil and gas activities to avoid conflict and minimize damage to roads on public lands is voluntary and thus unenforceable.
13. The discussion of road construction standards appears comprehensive. However, the topic of who pays for public road maintenance is not addressed.
14. Trucks should be prohibited from hauling anything except during the following times: 8:30 AM-4:30 PM, as not to disrupt the peace of the local community and provide safe travel for school buses. In addition, the trucks should be prohibited from traveling through sensitive areas, such as towns and schools, because of hazardous risks.
15. The report recommends that the applicant enter into agreements with the local government and or public land managers to maintain roads which it makes use of, in the same or better condition prior to mining operations. Is this permitted by State law? Would it be acceptable for the applicant to make repairs on public roads? What options might be available for the community to collect funds from the applicant and make the repairs themselves?
16. There appears to be a serious lack of regulation/enforcement regarding transportation of volatile and dangerous materials (waste water) via trucks as they navigate our rural roads and, in particular, towns and villages. BMP's should include recommendations for truck routes, for example.

Waste disposal

1. There is no safe disposal method.
2. The report does little to address how fracking wastewater will be disposed of in Maryland. In other states that failure to regulate wastewater disposal, the underground injection of this toxic fluid has been linked to earthquakes and contaminated drinking water.
3. The current permit does not address the disposal requirements for natural gas development.
4. Placarding and GPS tracking/logs should be required for all waste hauling vehicles because of increased truck traffic carrying toxic fracking waste
5. If those transporting this had tracking and kept logs as well as using tracer chemicals to track illegally dumped water I might feel a bit safer.
6. Since the waste is toxic all trucks/vehicles hauling the waste should be well labeled and their routes logged. Placarding and GPS tracking/logs should be required for all waste hauling vehicles because of increased truck traffic carrying toxic fracking waste.
7. In addition to the risks of chemicals pumped into the ground, large volumes of water return to the surface with the same chemicals, plus radiotoxic brine. The Report calls for recycling of this water "to the maximum extent practicable". This language is vague and leaves many questions of risk: how is 'practicable' determined? How clean must the 'recycled' water be? What is done with the contaminants that are removed in the water recycling? There are many such unresolved questions, and in most cases, there is a financial incentive to underestimate the long-term costs and complications.
8. Substances that are buried in the earth and come to the surface with the fracking-released gases or fluids. They include toxic chemical salts, salts of boron, cadmium, arsenic and a variety of heavy metals, including radioactive ones. These salts cannot be disposed of by local wastewater treatment plants, nor can they be safely consigned to regional landfills. The EPA has successfully filed a number of suits against firms that have attempted these ways of disposing of frack-induced undesirable salts.
9. Accidental spills at handling facilities, leakage from trucks and railroad tank cars, spillage due to human error, worn out equipment, wrecks, etc. Furthermore, neither underground nor surface storage facilities are fully foolproof, accident-proof, or earthquake proof. One way or another, an unacceptable quantity of these chemicals will eventually end up in the environment, “best practices” notwithstanding.
10. Water from this industrial process should not be treated at a local sewage treatment facility which is not equipped to handle these kinds of chemicals.
11. The handling and disposal of radioactive wastewater and sludge needs to be addressed.
12. Research suggests that the treatment of shale gas waste by treatment plants in a watershed raises downstream Cl^- concentrations but not TSS concentrations, and the presence of shale gas wells in a watershed raises downstream TSS concentrations but not Cl^- concentrations.

13. The requirement that "all trucks, tankers and dump trucks transporting liquid or solid wastes be fitted with GPS tracking systems" is virtually impossible in an industry that is deregulated, highly fragmented, and uses a large number of independent contractors to meet short-term transportation needs.
14. Audubon further supports the proposed guideline for recycling 90% of flowback and produced waters in subsequent drilling activities and for the policy preference for on-site re-use.
15. Wells require 4 to 5 million gallons of fresh water to frack, multiply that by 1000 wells and that by the 2 or 3 times a well will need to be refracked in its lifetime and you have up to 20 billion gallons of hopelessly polluted water that need to be disposed of. Piped or trucked out, some kind of permitting and tracking of this waste is called for.
16. MDE should consider eliminating Class II injection wells as a wastewater disposal option.
17. The decision to not allow for waste disposal in Maryland is important and requirements by the Departments for logging and identifying shipments, materials being hauled, hauler, date, and name, address, shipment amount, and date of the receiving facility are all critical to protecting Maryland’s environment and the safety of its citizens. However, MAC believes that a final requirement for this important process would be to add a real time manifest reporting and a GPS truck tracking system to the process. The lack of an effective monitoring system will like all other critical parts of MSGD is a flaw that leads to the inability to detect and manage significant problems when they occur.
18. Shouldn’t we consider all HVHF wells Class II UTI wells if waste is, essentially, stored in them? If we are actually “storing” waste in every well we drill, does it matter that our geology is not considered suitable for this purpose?
19. Unique tracer chemicals should be included in fracking wastewater, so that illegal dumpers can be more easily tracked.
20. Tens of millions of gallons of toxic waste, as well as large amounts of residual solid waste from the recycling process that would require safe disposal. The report fails to address this problem.
21. Rock cuttings, about the size of coarse grains of sand, must be disposed of, and they are coated with used drilling fluids that can contain contaminants such as benzene, cadmium, arsenic, mercury and radium-226. These wastes may present other problems for landfills, beyond radioactivity
22. The requirement that all drilling related trucks be equipped with monitoring devices is an excellent idea. There must be official logging and storage of this data during the drilling operations so the data can be reviewed if there is a question of inappropriate disposal of waste products or an accidental spillage.
23. The waste from glycol dehydrators should be disposed of properly.
24. If drilling were to proceed in Maryland, COMAR regulations should treat wastes from oil and gas facilities as RCRA hazardous materials. As the Departments are aware, the EPA in 1988 determined oil and gas wastes as nonhazardous despite acknowledging that known toxics like benzene appear at high levels. While many of the same chemicals

found in oil and gas production the EPA already regulates as hazardous, once these same materials emerge from gas wells as flowback or produced water, the law exempts them from this treatment. The reason Maryland should treat oil and gas waste as RCRA hazardous is that EPA's 1988 determination is out of date.

25. Although EPA has committed to develop standards to ensure that hydraulic fracturing wastewaters receives proper treatment and can be properly handled by POTWs. However, their plan is not to propose rules for wastewater until 2014. Until these regulations are in place, the Agencies must create the most prohibitive practices and regulations on disposal and/or treatment of hydraulic fracturing flowback.
26. While encouraging recycling and reuse of water is appropriate, the requirement for 90% recycling "on the pad site of generation" is unrealistic due to the number of inherent operational variables. To achieve that high level of recycling can require use of specialized equipment that not only requires additional space, but also needs enough volume through-put to be practicable. Allowing for transport of flow back and produced waters to a centralized recycling facility has the 4 potential to improve reuse and recycling of the water. Again, this topic is covered in the API recommended practices with respect to water use and reuse for hydraulic fracturing operations.
27. For cuttings disposal, there is an unclear criteria that if the cuttings meet other criteria established by MDE, then on site disposal of the cuttings could be allowed. There is no information as to what the other criteria may be. This means for planning purposes, all wells would require hauling off of cuttings and the initial plan would include increased trucking to move the cuttings. This creates an immediate bias in the plan and artificially inflates the potential traffic from the drilling site.
28. The 90% water reuse is a sound goal which some companies are already doing on some sites but this should not be a fixed requirement which will allow companies to adapt to the appropriate conditions.
29. A county not far north of where I live has taken to using diluted produced water to melt roadway ice, and a mechanic our family knows states that the frequency of vehicles brought in for repairs following catastrophic undercarriage/frame failure has gone up five- to ten-fold.
30. Maryland should not permit onsite disposal of cuttings and drilling mud.
31. Provide for disposal of the water that returns from the well – laden with sand, antibiotics, salts and sometimes radioactive material from miles down in the earth.
32. The report does little to address how fracking wastewater will be disposed of in Maryland. In other states that fail to regulate wastewater disposal, the underground injection of this toxic fluid has been linked to earthquakes and contaminated drinking water.
33. Just like any other industrial activity, Maryland should prepare to permit and regulate treatment and pretreatment of industrial waste from natural gas drilling activity. I do believe that every POTW and public WWTP is required to have pretreatment requirements for any industrial discharge into the WWTP. The EPA rule for shale gas wastewater if available by 2014 should be used as the standard for pretreatment if discharges are to occur into a POTWs or public WWTPs. Until these regulations are in

place MDE should require that POTWs and WWTPs not accept these wastewaters without prior consultation with MDE.

November 25, 2013

Water use

1. The amount of water needed is too great for the benefit.
2. Every frack uses up to 4 million gallons of water. In the western states where fracking continues, whole towns have run out of water. One frack in Maryland would use about one day's worth of water for the people living over the shale. Fracking uses immense amounts of fresh water which is irreplaceable, and that effect occurs even when other damage might (or might not) be successfully minimized.
3. Maryland must revise its permitting regulations to address these water issues, Maryland must require withdrawals be only from large rivers or reservoirs.
4. If there is a dry spell or water level decrease, the State should intermediately cut off the water supply for fracking until the supply is deemed sufficient. Constant monitoring should be done.
5. Given the massive amounts of water required to perform fracking, we wish to see recommendations limiting water withdrawals to areas where more than an "adequate reserve" is present such as reservoirs, lakes, and large rivers. "Adequate reserve" needs to be operationally defined, and we support the UMCES recommendation that MDE regulations be reviewed, and revised as necessary, regarding water withdrawal. Members of our Board have observed trucks illegally withdrawing water from Savage River, a premier brook trout stream, when water levels have been very low. Current water appropriation regulations are insufficient to address this matter even without fracking. We recommend that MDE establish a citizen reporting program for water withdrawals, and funding for such an educational program must be budgeted, as well as additional MDE enforcers.
6. Yet again the findings of UMCES-AL have been put aside by the BMPs. If the current water appropriation regulations are stringent enough then why would the study recommend that they be tightened?
7. The study continues to rely on the Susquehanna River Basin Commission water appropriation methodology to determine if sufficient ground and water surface capacity exists in Allegany and Garrett Counties. There are significant differences between water availability in the Appalachian basin than the remainder of Maryland, and there may need to be changes in the Maryland appropriations process to more adequately establish a set of best management practices for Appalachian Maryland prior to allowing withdrawals for Marcellus gas drilling. Changes include but are not limited to permitting, reporting and monitoring by MDE personnel.
8. The Departments state that their requirements for water withdrawal permits are sufficiently robust and therefore will retain their current procedures for permitting water withdrawals. Water taken from local streams can jeopardize the habitat of fish as well as requirements needed for macroinvertebrates. These concerns for prudent water use sources are critical to the health of Maryland's coldwater resources. Given that the current procedure provide only limited public comment on water withdrawal permits would, if we requested a hearing for each application, become resource intensive and cumbersome as well as providing an additional source of public contention that could be

avoided by developing large resource solutions for significant amounts of water needed over short time frames.

9. Maryland's regulations for water withdrawal need to include a way to track cumulative effects of natural gas development on regional water resources.
10. The requirement that all drilling related trucks be equipped with monitoring devices is an excellent idea. There must be official logging and storage of this data during the drilling operations so the data can be reviewed if there is a question of inappropriate water acquisition.
11. The regulation of water withdrawal strictly for human use may disregard the ecological flow requirements of species that occur in those waters. We would encourage MDE and DNR to review current policies and regulations to ensure that water withdrawals for HVHF also protect the ecological flow requirements of plant and animal species that use waters of the State that might experience HVHF.
12. As with transportation, the current API recommendations address water withdrawal and usage should be evaluated by the state in the development of final recommendations.
13. The departments should adopt the water appropriations standards of the Susquehanna River Basin Commission (SRBC) for appropriations and fees. The SRBC fee structure allows for stream monitoring from areas where water withdraws are likely to impact water turbidity, ph, and temperature.
14. There is no fee for a water appropriations request. However, this may prove to be a very time consuming endeavor for MDE, which may backlog the current 18-month turnaround for permits of over 10,000 gallons per day. Permit fees with the SRBC (which MDE partners with) allow for water monitoring from identified specific sites of surface water.
15. Currently there are no provisions within the permitting structure to track water appropriations requests from parent companies, subsidiaries, or subcontractors for multiple permit requests.
16. There is no provision for the multi-well CGDP process.
17. Under the current system municipalities with a permit are not required to report to MDE withdrawals sold to companies for MSGD, as long as they do not exceed the permit threshold. This gap needs to be addressed to track cumulative effects of natural gas development on regional water resources.
18. We support the Appalachian Lab report which recommended that Maryland revise its permitting regulations to address water withdrawal issues, by requiring withdrawals only from large rivers or reservoirs.
19. Drilling companies should have to purchase the surface water used – much of this water does not return to the surface water cycle.
20. The report should include a provision for encouraging usage of acidic coal mining discharges and or treated acid mine water for drilling purposes.
21. If private wells run dry because water is taken for fracking, will those citizens be provided with potable water from deeper wells?

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Well casing

1. When wells or casings or cement fails, fracking fluid, flowback, and methane can be released. The following failure rates have been reported:
    a. 5 or 6 percent of the time;
    b. Industry studies find up to 60 percent will fail after 30 years.
    c. PA reports a 7.2% failure rate
    d. EPA reports at 8.9% well casing failure rate for 2012, and a 7.1% failure rate in 2011 in Pennsylvania
2. We recommend that current industry standards be exceeded for pipeline construction and well casings. Maryland should either come up with best practices for minimizing the long-term degradation of the oil and gas industry's wells, or propose best practices for monitoring and resealing degraded wells.
3. The industry, in consultation with the Agencies, should be required to address the causes of casing integrity failure and to propose better practices that continually improve its standards for casing integrity.
4. Maryland needs to find a way to adopt a standard that allows for 0% failure upon installation of casing.
5. Companies should be required to run a test on every well to ensure adequate cementing, and inspections to ensure the compliance must be paramount if drilling is permitted.
6. The recommendation calls for the production casing to be run the entire length of the well and cemented. This requirement does not appear to allow for the use of production liners and tie backs, and would also appear to require cementing the entire production casing back to surface. Requiring cementing of the entire production casing back to surface will create a number of design challenges that may actually reduce the effectiveness of the cement seal. Bringing cement from the total well depth back to surface could require the use of cements with very long fluid times (pump times) that would result in a delay of the set of the cement at the lower temperatures near surface. Cementing back to surface also eliminates the potential to monitor annular pressures between the production casing and intermediate casing, a needed safety measure during fracturing operations. The recommendation should clarify isolation in the production casing, allow for use of liner and tie back technologies, and better define what is meant by the statement referencing cementing.
7. The recommendation is for the use of a segmented radial cement bong log (SRCBL) rather than the conventional omnidirectional cement bond log (CBL), but there is no statement regarding which casing strings would be required to be tested by SRCBL. This should be clarified. Further, there is no provision for the evaluation and analysis of the

SRCBL, or who would determine the effectiveness of the cementing operation. It is noted there are no recommendations for capturing data during the cementing operation that would supplement the logging operation.

8. The incorporation of API Standard 65-2 would address cement evaluation in its full form, using surface data during the cement job, laboratory design data as well as post job logging information. The Standard correctly notes that one single data point (or data set) should be used to make the evaluation of cement isolation.
9. Maryland regulations should include more detailed requirements for timing of the casing construction so that the process and monitoring can be completed consecutively during one work shift. Reports from rig workers in Pennsylvania have stated that casing cure times have been shortened in order to accommodate work shift schedules, thus compromising the integrity of the cement strength.
10. Maryland should forbid the use of reconditioned casing.
11. The method for testing the cement for compressive strength of 500 psi within 12 hours should be specified.
12. When a log (e.g., SRCBL) shows a failure, corrective action should be specified.