May 10, 2005

Public Meeting To Discuss Technical Issues Associated With the National Pollutant Discharge Elimination System (NPDES) Stormwater Permit Coverage for Small Oil and Gas Construction Activities

[OW-2002-0068; FRL-7897-2]

RIN 2040-AE71

The Independent Petroleum Association of America (IPAA)* submits these comments to the Public Meeting To Discuss Technical Issues Associated With the National Pollutant Discharge Elimination System (NPDES) Stormwater Permit Coverage for Small Oil and Gas Construction Activities.

IPAA files these comments for itself and on behalf of the International Association of Drilling Contractors (IADC), the International Association of Geophysical Contractors (IAGC), the National Ocean Industries Association (NOIA), the National Stripper Well Association (NSWA), the Natural Gas Supply Association (NGSA), the Petroleum Equipment Suppliers Association (PESA), the US Oil & Gas Association (USOGA),* and the following organizations:

California Independent Petroleum Association
Colorado Oil & Gas Association
East Texas Producers & Royalty Owners Association
Eastern Kansas Oil & Gas Association
Florida Independent Petroleum Association
Illinois Oil & Gas Association
Independent Oil & Gas Association of New York
Independent Oil & Gas Association of Pennsylvania*
Independent Oil & Gas Association of West Virginia
Independent Oil Producers Association Tri-State
Independent Petroleum Association of Mountain States

* Organizations indicated by an asterisk are Petitioners or Intervenors in the appeals pending in *Texas Independent Producers and Royalty Owners Association et al. v. EPA* (5th Circuit Lead No. 03-60506) (relating to the scope of the oil and gas exemption) and *Wisconsin Builders Association et al. v. EPA* (7th Circuit Lead No. 03-2908) (relating to the 2003 Construction General Permit ("CGP") and Fact Sheet) [collectively the "Stormwater Litigation"].

Independent Petroleum Association of New Mexico
Indiana Oil & Gas Association
Kansas Independent Oil & Gas Association
Kentucky Oil & Gas Association
Louisiana Independent Oil & Gas Association*
Michigan Oil & Gas Association
Mississippi Independent Producers & Royalty Association
Montana Oil & Gas Association
National Association of Royalty Owners
Nebraska Independent Oil & Gas Association
New Mexico Oil & Gas Association
New York State Oil Producers Association
Northern Alliance of Independent Producers
Ohio Oil & Gas Association*
Oklahoma Independent Petroleum Association*
Panhandle Producers & Royalty Owners Association
Pennsylvania Oil & Gas Association
Permian Basin Petroleum Association
Petroleum Association of Wyoming
Tennessee Oil & Gas Association
Texas Alliance of Energy Producers*
Texas Independent Producers and Royalty Owners*
Virginia Oil and Gas Association
Wyoming Independent Producers Association

Together, IPAA and these other organizations represent the thousands of independent oil and natural gas explorers and producers who will be most significantly affected by the proposed action. Independent producers drill about 90 percent of domestic oil and natural gas wells, produce over 50 percent of domestic oil, and approximately 85 percent of domestic natural gas.

These organizations appreciate the opportunity to present materials regarding the approaches to managing stormwater during oil and gas construction activities and consequences resulting from those approaches. Before addressing specific issues, it is important to describe our perspective of the regulatory situation.

The Oil and Gas Exemption Under Section 402(*l*)(2) of the Clean Water Act.

It is our firm belief that, under the oil and gas exemption in section 402(*l*)(2) of the Clean Water Act, EPA cannot require permits for oil and gas construction activities, regardless of size, unless the discharge from a site is contaminated. Some of us are petitioners or intervenors in appeals relating to the scope of the oil and gas exemption and the 2003 CGP and Fact Sheet, which are pending before U.S. Courts of Appeals for the Fifth and Seventh Circuits (see previous footnote (*)). Oral argument has been heard in both circuits and the cases have been submitted to the courts for decision.

To the extent that EPA were eventually to propose to regulate oil and gas construction activities without requiring a permit, we would support such an action provided that regulation of oil and gas sites were justified based on scientific evidence of a water-quality need for such regulation; the states are properly consulted before proposal; and any conditions on a non-permit option were non-arbitrary, reasonable and consistent with good oil and gas industry practice, and directly related to the control of "contamination" in stormwater discharges, as Congress intended that term to apply to oil and gas sites.

We would not expect to support a "waiver" option, because the requirement for a "waiver" assumes that there is a permit requirement, which is an assumption with which we firmly disagree.

Common Plan of Development

Any proposal for a non-permit option that were to apply only small oil and gas construction activities would need to address the definition of "common plan." As noted above, we believe that there is a fundamental question of whether EPA is permitted to require a permit under section 402(*l*)(2) for both Phase I (five acres and larger) and Phase II (one to five acres) sites. EPA's requirement for Phase I sites to have a permit is further complicated by the "common plan of development" concept in the Construction General Permit (CGP). The "common plan" concept is inherently flawed and is confusing when applied to oil and gas construction activities. It requires projects to be permitted if, taken together, the components exceed the five acre permitting acreage threshold.

The EPA's "common plan of development" concept provided in its Construction General Permit is impossible to apply to oil and gas construction activities as it requires projects to be aggregated and permitted if the individual activities disturb five acres or greater. Data from the initial project can significantly alter the location or the initiation of any subsequent projects. For the producer, there is no "common plan of development" as compared to residential/commercial construction activities. Therefore any permit could not possibly determine aggregated area, or location of subsequent projects. Clearly the definition of "common plan of development" cannot be applied to the oil and gas industry.

Oil and gas operations are dependent on the success of one before the construction of the next. For the producer, there is no common plan. This common plan of development scheme should not apply. Each single project should be evaluated separately against the five acre threshold. This issue is discussed more fully in Appendix 1.

No-Permit Option Possible If Adequately Justified

EPA has suggested that it is considering using section 402(*p*)(6) as an approach to address oil and gas construction activities. If this approach is to be used, several conditions must be met to satisfy the law.

First, if EPA intends to regulate oil and gas construction activities under section 402(*p*)(6), before proposing any such new rule, it must consult with affected states (including oil and gas regulatory authorities) regarding whether there is a need (based on scientific evidence) for regulation and to what extent regulation is necessary.

Second, section 402(*p*)(6) and section 402(*l*)(2) fit together. We do not believe that EPA can impose additional regulations on oil and gas construction activities under section 402(*p*)(6), beyond and unrelated to the requirement in section 402(*l*)(2) that stormwater discharged from an oil and gas site not be contaminated. If EPA were to attempt to do that, we do not see how such regulations could be justified under section 402(*p*)(6). Congress provided for the protection of water quality under section 402(*l*)(2) by limiting the availability of the oil and gas exemption to stormwater discharged from an oil and gas site that is not "contaminated," as Congress intended that term to be applied to oil and gas activities. EPA has already defined contamination in 40 C.F.R. § 122.26(c)(1)(iii) to include stormwater discharged from an oil and gas site that contributes to a water quality standard violation (or constitutes a reportable-quantity release).

Before proposing a new rule imposing Federal regulation on uncontaminated stormwater from oil and gas construction activities, section 402(*p*)(6) would require that EPA justify the need for and necessary extent of any such regulation. We do not see how Federal regulation of *uncontaminated* stormwater discharges—which by EPA's own definition do not contribute to a water quality standard violation—can be legally or scientifically justified under section 402(*p*)(6) as necessary to protect water quality.

Assuming that these issues can be resolved, EPA should approach its stormwater concerns during oil and gas construction activities through a flexible management process rather than a rigid permitting regime. Management techniques are widely utilized currently to manage stormwater and they are readily available. Correspondingly, the potential consequences of applying a permitting regime raise serious issues regarding lost domestic oil and natural gas production without attendant environmental benefits.

Reasonable And Prudent Practices for Stabilization (RAPPS) Can Effectively Manage Stormwater

The oil and natural gas exploration and production (E&P) industry has managed its construction activities to limit stormwater runoff. Logically, for development activities to occur at its sites, a producer must have a stable and secure pad to support the heavy equipment needed to drill wells. In 2004, the industry compiled a compendium of stormwater management practices in use in the industry to control contamination in stormwater. These controls vary based on terrain and rainfall circumstances. These were documented as *Reasonable And Prudent Practices for Stabilization* (RAPPS). Subsequently, these RAPPS were made widely and freely available for members of the industry through access on IPAA's website and numerous other trade association websites. The RAPPS document provides a straightforward methodology to guide a producer to an array of practices for a given situation. This tool allows the producer the flexibility to find a technology that fits the circumstances and the budget while providing the appropriate environmental protection. A copy is included in Appendix 2.

The Current Construction General Permit Would Result In Severe Adverse Energy and Economic Consequences

While RAPPS create a flexible and effective approach, the current CGP produces significant adverse consequences. An independent economic analysis recently completed on behalf of the U.S. Department of Energy[†] estimates that these EPA regulations could cost the country between 1.3 and 3.9 billion barrels of domestic oil production and between 15 and 45 trillion cubic feet of domestic natural gas production over the next 20 years. Compliance costs and lost revenue to the industry could range between $382 million to $2,883 million per year from the stormwater permit requirement (with the higher number being characterized by DOE as a "higher impact scenario" but "not necessarily . . . a 'worst case' scenario"[‡]). Moreover, these impacts do not include lost reserves, lost tax and royalty revenues, or energy replacement costs, which would increase the estimated impacts to the national economy to $2,725 million to $7,883 million per year. A copy of the Department of Energy analysis is attached as Appendix 3.

Conclusion

We appreciate this opportunity to submit these comments to the Public Meeting To Discuss Technical Issues Associated With the National Pollutant Discharge Elimination System (NPDES) Stormwater Permit Coverage for Small Oil and Gas Construction Activities.

Resolution of the EPA regulatory structure to manage stormwater during oil and gas construction activities is essential to assure that domestic oil and natural gas production will be able to meet its significant role in the national energy framework. We believe that we are effectively managing stormwater during construction. However, if the CGP is implemented it will result in significant lost domestic production, not improved environmental quality. Our joint goal should be to find the path that meets both the nation's energy needs and its environmental values.

If you have any questions about these comments, please do not hesitate to contact Lee Fuller of IPAA at (202) 857-4722 or lfuller@ipaa.org.

[†] Report From Advance Resources International ("ARI"), Inc. to U.S. Department of Energy/Office of Fossil Fuels, Estimated Economic Impacts of Proposed Storm Water Discharge Requirement on Oil and Gas Industry (Final) (Dec. 7, 2004); *see also* Appendix A, Critical Factors and Key Assumptions Contributing to the Economic Impact of Potential New Storm Water Discharge Requirements (Dec. 7, 2004) (both available at www.fe.doe.gov/programs/oilgas/environment/publications)
[‡] ARI Report at 7.

Appendix 1
"Common Plan" Issues

EPA's definition of "small oil and gas construction activities" is limited by 40 C.F.R. § 122.26(b)(15) to activities that disturb five acres or less of land area (and more than one acre). If an oil and gas construction activity disturbs five acres or more, or if it is part of a "common plan" that ultimately will do so, it is not considered a "small oil and gas construction activity." Thus, the issue of "common plan" is crucial to any proposal that is limited to "small oil and gas construction activities."

These comments are submitted without waiver of any objection or legal argument as to the validity of an acreage threshold on the availability of the oil and gas exemption under CWA § 402(*l*)(2). We believe that section 402(*l*)(2) exempts all oil and gas sites from the requirement for National Pollutant Discharge Elimination System (NPDES) permit coverage, regardless of size. It is our view that there is and should be no "common plan" scheme with respect to oil and gas activities and that, if EPA were to give the full intended effect to section 402(*l*)(2), the problems associated with the acreage threshold and the definition of "common plan" would go away.

1. General Concern: "Common Plan" Should Not Apply to Oil and Gas Sites

As a general matter, we believe that the "common plan" approach should not apply to oil and gas sites. The "common plan" approach was devised by EPA in the conventional/residential context to avoid "sham" subdivision of large construction projects into smaller projects to avoid the NPDES permit requirement for more-than-five-acre sites. Conventional projects cover a significant portion if not most of a contiguous site. Oil and gas projects, in contrast, proceed in a series of small, separate projects that cover only a small percentage of the area covered by the oil and gas leases. The "common plan" approach was not intended to force "clumping" of separate, smaller projects into one large project, but that is often the effect of EPA's current definition of "common plan."

The "common plan" approach should not, therefore, apply to oil and gas construction operations. Instead, whether an oil and gas construction activity is "small" should be determined on a single-project-by-single-project basis. A single project should consist of the contiguous land that is disturbed at a given point in time. If the total area under active construction is less than five acres (and equal to or greater than one acre) at a give point in time, the project should be considered a "small oil and gas construction activity." This stabilize-as-you-go approach would partially resolve the seemingly intractable difficulties, discussed below, of applying the "common plan" scheme to oil and gas exploration and production activities.

2. If "Common Plan" Applies, The Following Specific Concerns Should Be Addressed

If the "common plan" scheme is to apply to oil and gas sites, EPA should address certain concerns unique to the oil and gas industry in any new proposal. The concerns include:

(a) Delineation between O&G construction activities and O&G industrial activities;
(b) Delineation between oil and gas construction activities and conventional construction activities;

(c) Spacing Role and Distance;
(d) Effect of Interconnecting Structures;
(e) Handling of Stand-Alone Project Components (e.g., gathering lines);
(f) Definition of "Under Construction" vs. "Ultimately Disturbed";
(g) Effect of different operators.

We have provided in Attachment 1-A a working draft flowchart showing how an operator might calculate the acreage disturbed for oil and gas sites under the "common plan" scheme giving meaning to various terms utilized in EPA's definition based on oil-and-gas industry practice. We believe that the complexity of Attachment 1-A illustrates the difficulty in applying the "common plan" approach to oil and gas exploration and production. We believe that Attachment 1-A shows that a better, more appropriate approach may be simply to measure the contiguous acreage actively disturbed for each project component separately against the acreage threshold.

(a) **Oil and Gas Construction Activities vs. Oil and Gas Industrial Activities**

Both oil and gas industrial activities and oil and gas construction activities are oil and gas operations. Oil and gas industrial activities are activities to which the Multi-Sector General Permit (MSGP) would apply if a permit is required because of contaminated storm water discharged to waters of the U.S. 65 Fed. Reg. 64,746, 64,830 (Oct. 30, 2000) (Sector "I"). Oil and gas construction activities are activities to which the Construction General Permit would apply, if permit coverage is necessary (which we believe should be required only if a discharge to waters of the U.S. is contaminated). Since only oil and gas construction activities would have to comply with the conditions in the proposal being contemplated, we believe it is important to differentiate between oil and gas construction activities and oil and gas industrial activities.

The following activities are oil and gas industrial activities (MSGP), as distinguished from oil and gas construction activities (CGP). This list is not necessarily exhaustive.

- Seismic Surveys;
- Well drilling, completion, re-completion, and stimulation;
- Closure of reserve pit and well pad reduction;
- Installation and operation of production equipment on completed oil and gas pads;
- Production from or through existing oil and gas drill sites or processing, treatment, or transmission facilities;
- Maintenance of existing oil and gas drill sites or processing, treatment, or transmission facilities;
- Maintenance of gathering lines and utilities;
- Site closure (plugging, abandoning, or removing wells or equipment and site restorations).

(b) **Oil and Gas Construction vs. Conventional Construction**

EPA should clarify what is oil and gas construction and what is conventional construction. Any construction activity that necessarily or customarily takes place in the field as part of an oil and gas activity should be considered an oil and gas construction activity. Oil and gas construction activities include (but are not necessarily limited to) clearing, grading, and excavation activities for:

- Access roads;
- Drilling and equipment pads (including initial, pre-drilling construction of rig cellars and reserve pits, with subsequent, post-drilling cellars and reserve pits being considered routine maintenance per EPA's July 1, 2003, Fact Sheet);
- Oil and gas facility pads (including initial construction of compressor stations, tank batteries, treating equipment, etc.)
- Equipment storage/staging areas in the field, close to a drill site, to service one or a few drill sites;
- Borrow pits;
- Gathering lines, flow lines, feeder lines, and transmission lines (consistent with March 10, 2003, Federal Register notice, 68 Fed. Reg. 11325, 11327);
- Utility lines (water, electrical, etc.) to service oil and gas exploration, production, processing or treatment operations or transmission facilities (consistent with March 10, 2003, Federal Register notice).

Oil and gas construction activities would generally not include, for example, construction of office buildings for oil and gas company employees or construction of a central support/service equipment yard to store equipment to be used at any number of drill sites, or similar activities not identified with a specific oil and gas site or few sites. These types of activities would generally be considered conventional construction activities.

(c) **Spacing Role and Distance**

We believe that spacing is an inappropriate criteria on which to determine whether or not there is a common plan at an oil and gas site. Even wells spaced closer together than ¼ mile are independent decisions and separate projects. We believe that a better approach is as described above, to treat contiguous land area disturbed at the same time as a single project, and if the contiguous area under construction at the same time is less than five acres (but greater than or equal to one acre), to define that project as a "small construction activity."

If spacing is to be used as a criteria, the ¼-mile spacing distance is too far apart. Many independent oil and gas sites are drilled at 600 to 900 feet from edge to edge (for example, Pennsylvania has told EPA that it would use 900 feet as its spacing criteria). The ¼-mile spacing would pull these sites into a "common plan, " and two sites together would generally exceed the five-acre threshold (if based on area ultimately disturbed versus under active construction at a given time—see further comment on this point below).

Therefore, we believe that, if there is to be a spacing criteria at all, that it be set at 600 feet from edge of pad to edge of pad, rather than ¼- mile.

In addition, whether the spacing is ¼-mile or 600 feet, it is not clear whether wells spaced at less than ¼ mile apart are automatically counted as part of a common plan (presumably, only if under the control of the same operator—see below), or if they are part of a common plan only if they are "under construction" at the same time. EPA's responses to comments on the July 1, 2003, CGP were confusingly inconsistent on this point. We note that industry trade associations detailed these inconsistencies in their briefs filed in the U.S. Court of Appeals for the Seventh Circuit in 2004. *See Texas Independent Producers and Royalty Owners Assoc. v. U.S. EPA* (7th Cir. Lead No. 03-3277 et seq.), Oil and Gas Petitioners Reply Opening Brief (July 28, 2004) *and* Oil and Gas Petitioners Reply Brief (Nov. 10, 2004).

(d) **Effect of Interconnecting Structures**

It is clear that unconnected sites more than ¼ mile apart (or whatever spacing threshold may eventually be established) are not counted as part of a common plan, even if they are under construction at the same time. However, many oil and gas sites have a road, gathering line, or utility structure connecting them. EPA says that two sites more than ¼ mile apart are to be considered part of a common plan if there is an interconnecting structure "under construction" at the same time.

If there is an interconnecting structure connecting two sites, what has to be "under construction" at the same time for all three projects (*i.e.*, the two sites and interconnecting structure) to be considered part of a "common plan"? Both sites and the interconnecting structure? Either site and the interconnecting structure? If all that is required is that either site and the interconnecting structure be under construction at one time, later-constructed sites would be lumped together with the area disturbed by the earlier site and the interconnecting structure, thereby, in most cases, exceeding a five-acre threshold if based on land area ultimately disturbed (but see below, relating to question on land area ultimately disturbed versus under construction at a given point in time).

(e) **Standalone Projects**

Many times a project is a standalone project. For example, a gathering line would not typically be considered part of a "common plan." An operator does not usually know whether, when and where it will be installing a gathering line at the time the operator is constructing its road and site. Therefore, gathering lines should generally not be considered part of a common plan, unless they are under active construction at the same time as the site to which they connect.

(f) **Definition of "Under Construction" vs. "Ultimately Disturbed**

It appears that whether or not there is a "common plan" will depend in part on whether certain components are "under construction" at the same time (also referred to as "under (active) construction" by EPA in its responses to comments on the July 1, 2003 CGP and Fact Sheet). It is not clear what EPA means by "under construction." It could mean from commencement of land-disturbing activities to "final stabilization." As a matter of prudent practice in the industry, oil and gas sites may be temporarily stabilized but may not be "finally stabilized" as EPA defines that term in the CGP and Fact Sheet.

We believe that "under construction" or "under (active) construction" for oil and gas activities should commence with the commencement of land-disturbing activities and end when the land area involved is in a condition suitable for the use intended and erosion control measures consistent with reasonable and prudent practices used in the oil and gas industry for either temporary or permanent stabilization have been implemented.

A related problem is whether only the land area under construction at a given point in time must be counted against the acreage threshold, or whether all area ultimately to be disturbed that is part of a common plan must be counted against the threshold. Clearly the shorter the duration of disturbed soil, the less the environmental impact from the disturbance. Additionally, the smaller the area disturbed, the lower the impact. The oil and gas industry believes that this type of “stabilize-as-you-go” concept encourages environmentally beneficial behaviors and is consistent with good oil and gas industry practice.

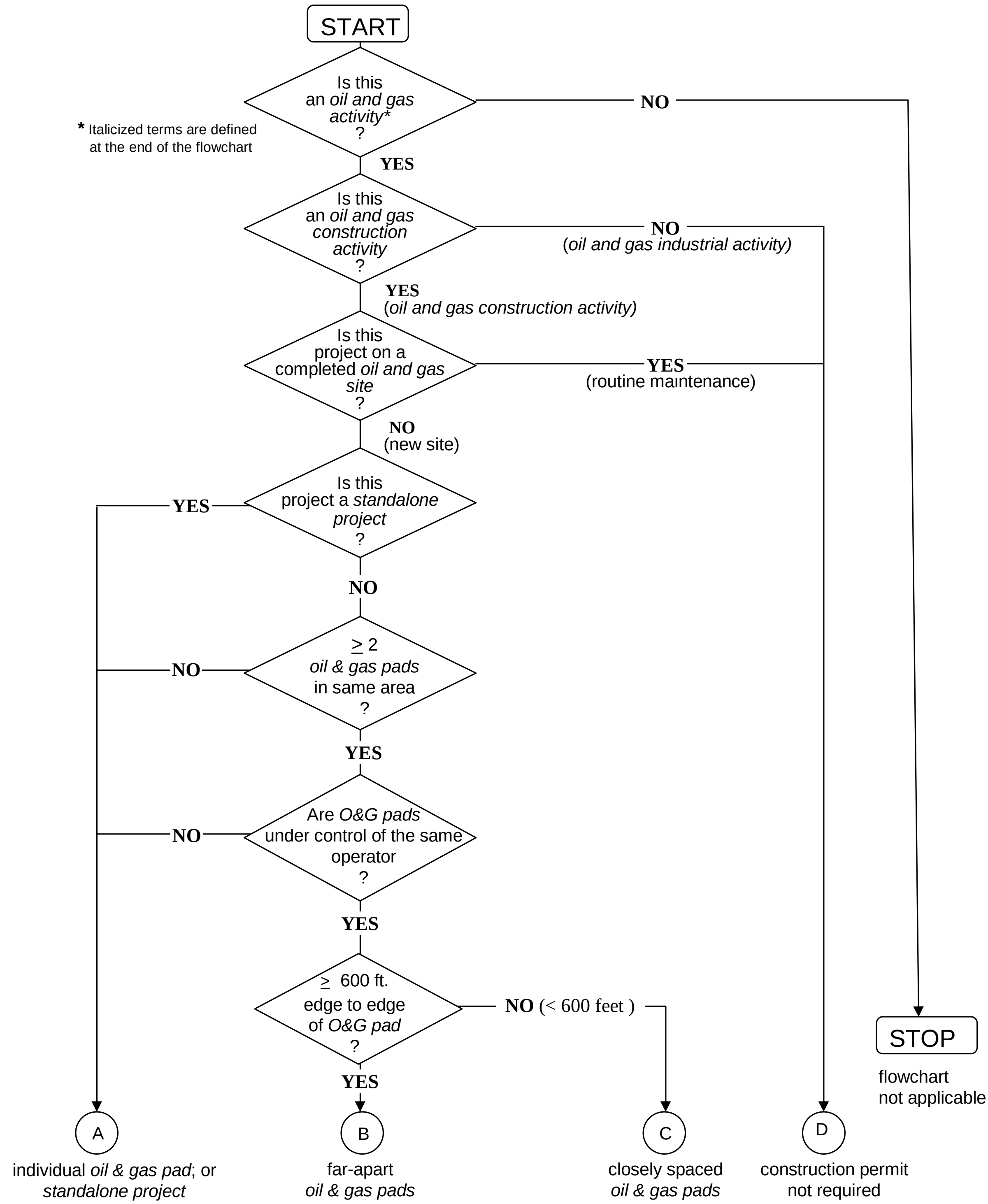
(g) **Effect of Different Operators**

It is not uncommon in the oil and gas industry for different oil and gas operators to be drilling wells in relatively close proximity to each other. It is common for a different operator to be installing gathering and transmission lines from the operator of the oil and gas reserves. When there are different operators undertaking these activities, even if those activities are close together or occurring at the same time, the activities should not be considered to be part of a common plan.

ATTACHMENT 1-A
May 10, 2005

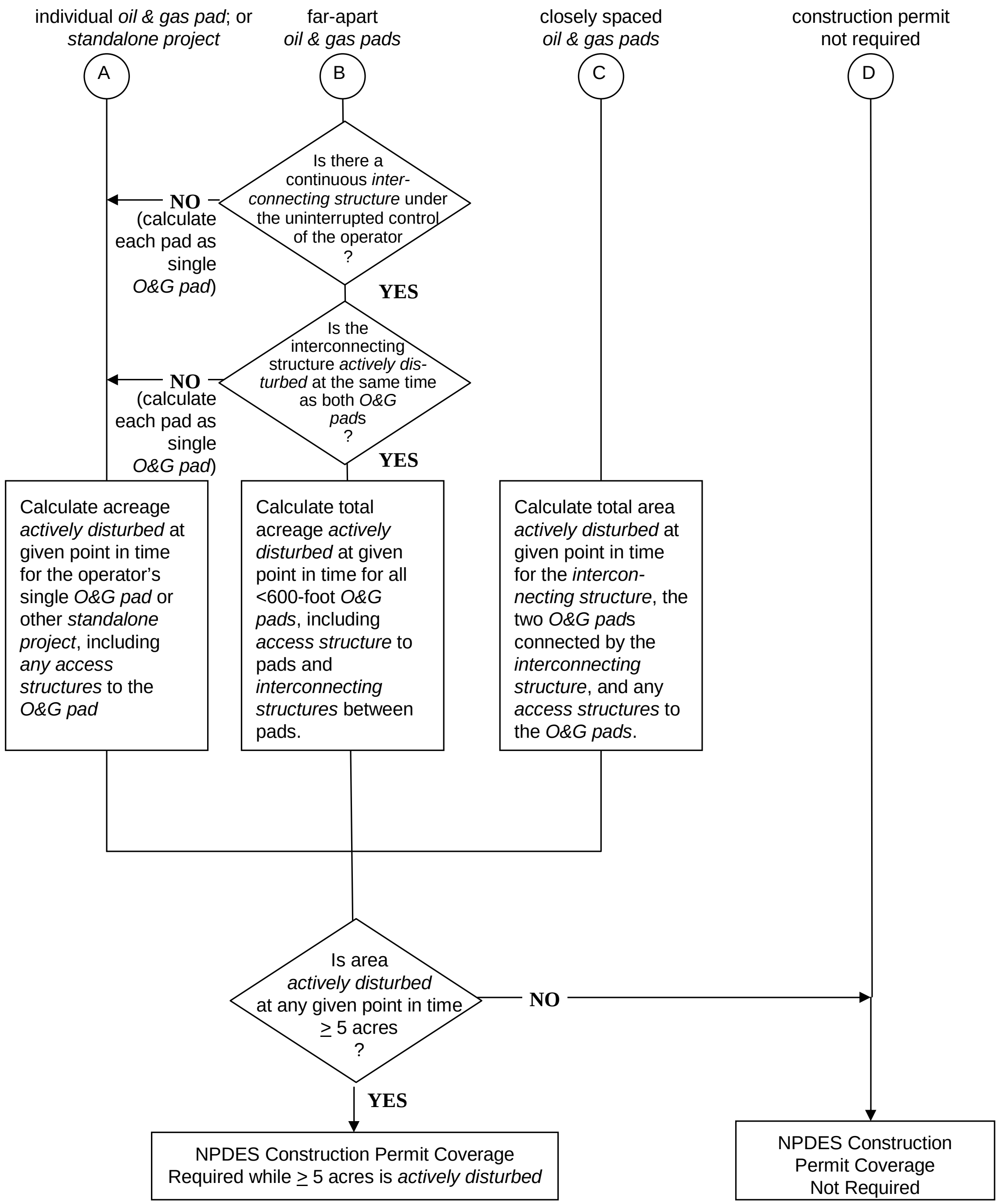
FOR DISCUSSION ONLY
NOT AN ADMISSION OF
FACT OR LAW

WORKING DRAFT FLOWCHART--OIL AND GAS CONSTRUCTION ACTIVITIES



ATTACHMENT 1-A (Cont.)
May 10, 2005

FOR DISCUSSION ONLY
NOT AN ADMISSION OF
FACT OR LAW



FOR DISCUSSION ONLY
NOT AN ADMISSION OF
FACT OR LAW

ATTACHMENT 1-A (Cont.)
May 10, 2005

FLOWCHART DEFINITIONS

Access structure: Means a road, pipeline, or other linear structure to or from an oil and gas pad, other than an interconnecting structure.

Interconnecting structure: Means a road, pipeline, or other linear structure to or from one oil and gas pad to another under the uninterrupted control of the same oil and gas operator.

Oil and gas activity means exploration, production, processing, or treatment operations or transmission of oil or gas.

Oil and gas construction activity: Means site preparation activity, including clearing, grading, excavating operations, at an *oil and gas site*. Does not include *oil and gas industrial activities*.

Oil and gas industrial activity: Includes but is not limited to seismic surveys; well drilling, completion, re-completion, and stimulation; closure of reserve pit and well pad reduction; installation and operation of production equipment on completed oil and gas pads; production from or through existing oil and gas drill sites or processing, treatment, or transmission facilities; maintenance of existing oil and gas drill sites or processing, treatment, or transmission facilities; maintenance of gathering lines and utilities; site closure (plugging, abandoning, or removing wells or equipment and site restorations).

Oil and gas pad: Means a well pad, equipment pad, tank pad, or facility pad, or other pad for oil and gas activity.

Oil and gas site: Means an oil and gas pad or an access structure or interconnecting structure used for oil and gas activity.

Standalone project: An individual *oil and gas pad*. Or another project, generally a linear project such as gathering line, utility, or road, that does not connect to another *oil and gas site* that is actively disturbed at the same time.

Appendix 2

GUIDANCE DOCUMENT
REASONABLE AND PRUDENT PRACTICES FOR STABILIZATION (RAPPS) OF OIL AND GAS CONSTRUCTION SITES
HJN 040027 IM

PROVIDED BY:

Independent Petroleum Association of America

PREPARED BY:

HORIZON ENVIRONMENTAL SERVICES, INC.

APRIL 2004

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF APPENDICES

1.0 INTRODUCTION

The purpose of this document is to compile the various operating practices utilized by reasonable and prudent operators in the oil and gas industry to control erosion and sedimentation associated with storm water runoff from areas disturbed by clearing, grading, and excavating activities related to site preparation associated with oil and gas exploration, production processing, treatment, and transmission activities. Site preparation activities associated with such oil and gas activities are referred to in this document, consistent with EPA's terminology, as "oil and gas construction activities" or "construction activities." The operating practices used to control erosion and sedimentation from oil and gas site construction activities are referred to in this document as "Reasonable and Prudent Practices for Stabilization" or "RAPPS."

In the preparation of this document, emphasis was placed on the selection and practical application of RAPPS, given a variety of basic physical circumstances. This document is provided as a tool to quickly evaluate which RAPPS may be useful at a given construction site. This document anticipates that the user will be prudent and exercise good judgment in evaluating site conditions and deciding which RAPPS or combination of RAPPS is to be used at a specific site. If the RAPPS selected are not effective to prevent discharges of potentially undesirable quantities of sediment to a regulated water body, different or additional RAPPS should be employed.

2.0 CONSTRUCTION SITE PHYSICAL CONSIDERATIONS

There are several physical conditions that can affect the decision about which RAPPS will be effective at a given construction site. Two primary factors that are emphasized within this document are the proximity to a regulated water body and the amount of vegetative cover between the construction site and the regulated water body. Other physical considerations include the slope of the terrain, rainfall, and soil erodibility. For purposes of this guidance document, each of these physical features may further be defined with respect to a designated rank (i.e., slope 0 to 10% or vegetative cover 25 to 75%).

Slope is defined as the amount of elevation gain over a given distance (vertical rise to horizontal run). A hill with 2 feet of elevation gain over 5 feet of horizontal distance has a slope of approximately 40%. A slope of 10% would require 2 feet of elevation gain per 20 feet of horizontal distance. The slope characteristic must be evaluated between the construction activity and the regulated water body.

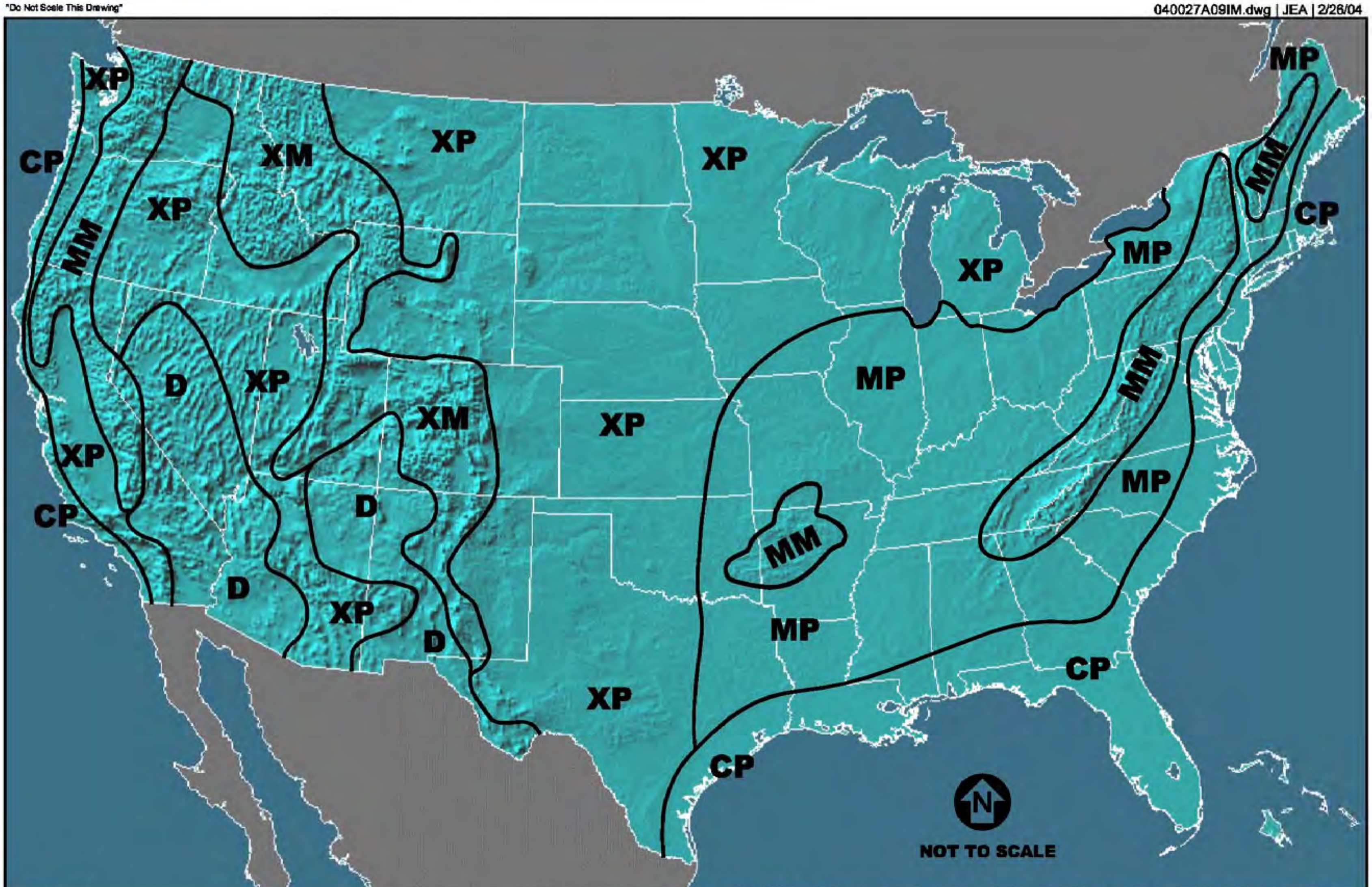
Vegetative cover is defined as the percentage of ground covered with primarily low-growing, herbaceous vegetation (grasses, forbs, and wildflowers). Shrubs and trees may provide some erosion control and filtration, but the amount of filtration is significantly less than that provided by low-growing herbaceous cover. For the purposes of this document, therefore, percentage cover of shrubs and trees should not be factored into the estimate of vegetative cover.

3.0 GEOGRAPHIC LOCATIONS AND IDENTIFICATION OF RAPPS

The following sections describe general geographical categories across the continental United States as outlined on Figure 1. These categories were defined taking into consideration general slope, annual rainfall, major soil types, and vegetative cover.

"Do Not Scale This Drawing"

040027A09IM.dwg | JEA | 2/26/04



MAP SOURCE:
RAY STERNER, JOHN HOPKINS UNIVERSITY
APPLIED PHYSICS LABORATORY (1995)

Horizon
Environmental Services, Inc.

EXPLANATION

CP COASTAL PLAINS	**MP** MESIC PLAINS	**MM** MESIC MOUNTAINS
D DESERTS	**XP** XERIC PLAINS	**XM** XERIC MOUNTAINS

FIGURE 1

GENERAL GEOGRAPHICAL LOCATIONS
WITHIN THE CONTINENTAL UNITED STATES
REASONABLE AND PRUDENT PRACTICES
FOR STABILIZATION (RAPPS) GUIDANCE

The distance between a construction site and a regulated water body should be calculated from the closest boundary of land disturbance due to construction activity to the boundary of the regulated water body. Construction sites determined to be in excess of a minimum distance from a regulated water body for a particular geographical region will not typically require the implementation of any RAPPS. This identified minimum distance was determined using the assumed general physical characteristics for a particular geographical category but may differ within any given geographical category.

The user should first determine which geographical category the construction project falls within, utilizing both the provided map and good field judgment. If local conditions in the immediate area do not meet the conditions described for the geographical category that would be indicated by the provided map, select a decision tree from another geographical category that better meets local conditions. If local conditions do not meet any of the mapped geographical category descriptions, the user should use good judgment selecting RAPPS.

Once the geographical category is determined, the user can determine if the assumptions outlined within that category fit the construction site. One to several physical conditions may be assumed to be constant within any given geographical category. Physical conditions that may not be assumed to be constant include slope, vegetative cover, and distance to regulated water. The area between the construction site and regulated water should be reviewed to determine approximate slope and the percentage of vegetative cover. These values will be utilized within the decision tree to determine a list of RAPPS to consider for that particular construction site.

It should be noted that the list of RAPPS for any given pathway on the decision tree are simply suggestions of RAPPS alternatives, from which one or more of the listed techniques or practices may be selected for a given site under site-specific circumstances. Not all RAPPS listed will necessarily be required for any given project. In addition, the list of RAPPS for any given pathway on the decision tree may not exhaust all of the available RAPPS that may be effective for any given construction site. Other RAPPS, not listed in this document, may be beneficial for controlling surface water runoff from the construction site, in addition to or in lieu of the RAPPS listed in this document.

RAPPS generally considered effective to prevent potentially undesirable quantities of sediment in storm water runoff from construction activities within these geographical categories are referenced within Appendix A of this document. Specific information (e.g., text description, limitations, and conceptual drawing) for each RAPPS is provided in Appendix A. RAPPS presented in Appendix A were derived from both common industry references provided in Section 4.0 of this document and from practical field experience.

A summary of the steps to follow when using this guidance document are below.

1. Determine geographical category that best fits local conditions using Figure 1 and field judgment.
2. Assure that assumptions for geographical category fit construction location. If local conditions do not meet assumptions, use good judgment to select RAPPS.
3. Review area between construction activity and regulated water body to determine distance to the regulated water body, approximate slope, and approximate vegetative cover.
4. Work through decision tree utilizing information from step 3.
5. Select RAPPS from the alternatives listed as being effective for a construction site under similar conditions of distance, slope, and vegetative cover (Note: not all RAPPS alternatives listed will necessarily be required for effective storm water control).
6. Implement RAPPS in appropriate locations.
7. Begin construction.
8. Stabilize disturbed areas following completion of construction.

3.1 COASTAL PLAINS

Description

Generally flat plains along coastal areas with a slope less than 10%; deep erodible soils; highly variable vegetation cover; and relatively high annual precipitation.

Selection of RAPPS

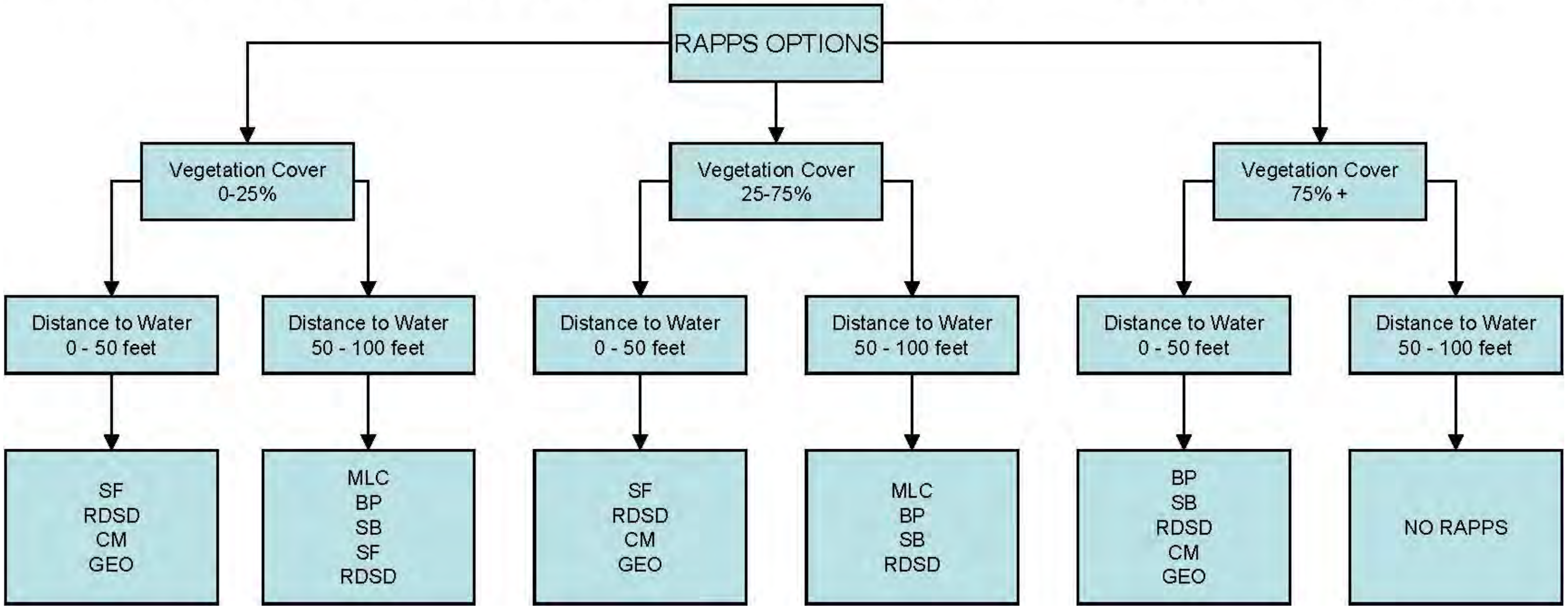
The flat topography of this region along with primarily herbaceous vegetation generally limits the opportunity for potentially undesirable quantities of sediment in storm water discharges to occur. Therefore, construction at oil and gas sites will not require the installation of RAPPS if one of the following exists:

1. The construction site is located in excess of 100 feet from a regulated water body.

2. The area between the construction site and a regulated water body has a vegetative cover in excess of 75% AND the site is located in excess of 50 feet from a regulated water body.

If neither of these two conditions is met, the decision tree in Table 3.1-1 will be useful in determining which RAPPS would be effective under the given circumstances. The decision tree process for this geographical category assumes that slopes are flat (0 to 10%); annual rainfall is high (50 inches and above); and soils are generally highly erodible.

Table 3.1-1 Decision Tree for Coastal Plains Geographical Region



Coastal Plains Assumptions:
1. Slopes are less than 10%
2. Annual precipitation is greater than 50 inches
3. Soils are loams or silts and highly erodable

No RAPPS needed:
1. When construction site is in excess of 100 feet from a regulated water body OR
2. When vegetative cover exceeds 75% AND the site is in excess of 50 feet from a regulated water body.

Index

BP = Brush Pile
CM = Construction Mat
CULV = Cross-Drain Culvert
DD = Diversion Dike
DIP = Drainage Dip
GEO = Geotextiles
MLC = Mulch
RB = Rock Berm
RDSD = Road-Side Ditch
RDSS = Road Surface Slope
RGHN = Roughening
SB = Straw Bale
SF = Silt Fence
ST = Sediment Trap
TO = Turnout

The list of RAPPS for any given pathway on the decision tree are suggestions of RAPPS alternatives, from which one or more of the listed techniques or practices may be selected for a given site under site-specific circumstances. Not all RAPPS listed will necessarily be required for any given project.

The list of RAPPS for any given pathway on the decision may not exhaust all of the available RAPPS that may be effective for any given construction site. Other RAPPS, not listed in this flowchart, may be beneficial for controlling surface water runoff from the construction site, in addition to or in lieu of the RAPPS listed in this document.

3.2 XERIC PLAINS

Description

Generally inland flat plains within the western portions of the US; slopes less than 40%; low soil erodibility; highly variable vegetation cover; and relatively low annual precipitation.

Selection of RAPPS

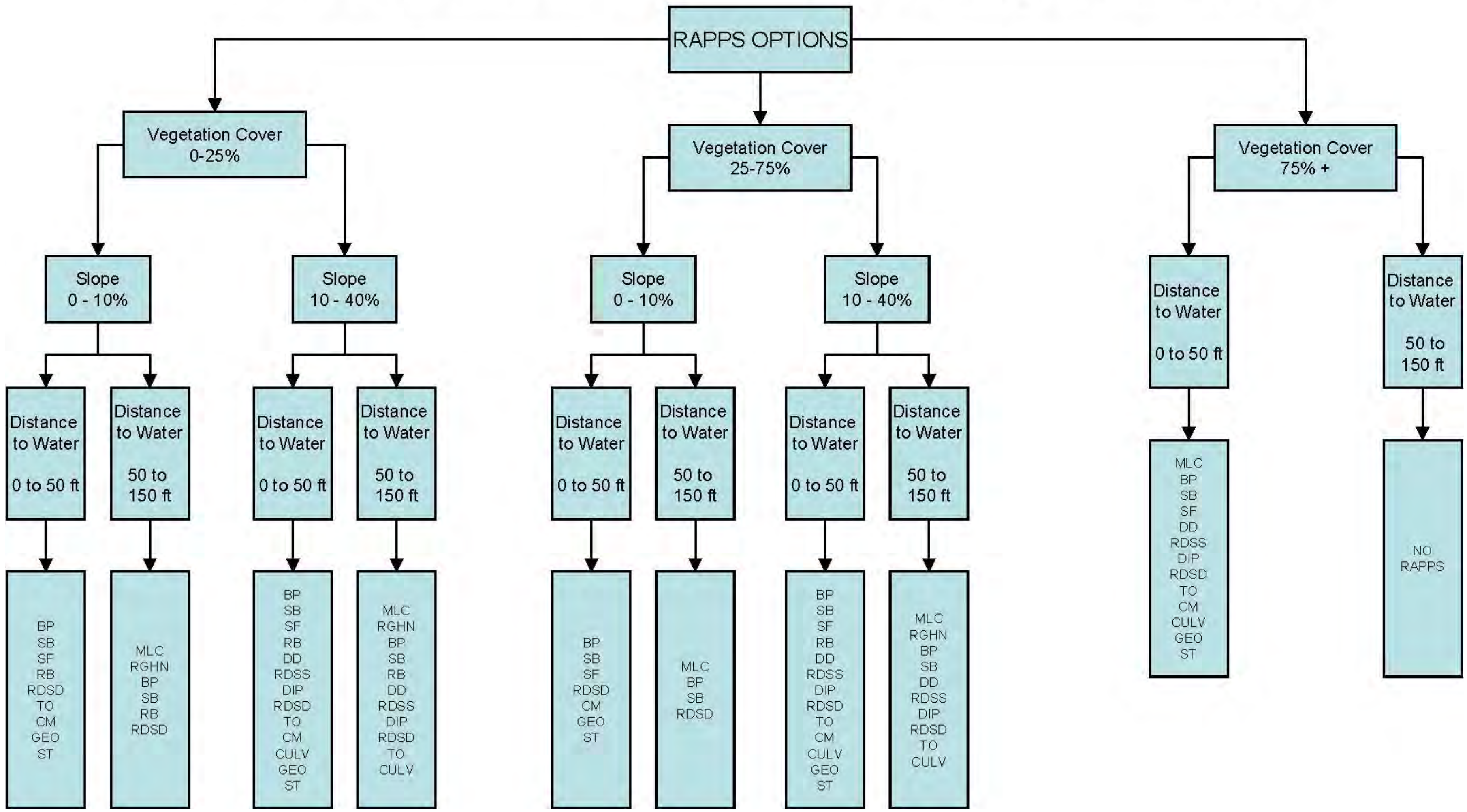
This region typically has fewer rainfall events with lower total annual precipitation than does the Mesic Plains. Dominant soils are sand and rock. These factors reduce the opportunity for potentially undesirable quantities of sediment in storm water discharges to occur. Therefore, construction at oil and gas sites will not require the installation of RAPPS if one of the following exists:

1. The construction site is located in excess of 150 feet from a regulated water body.

2. The area between the construction site and a regulated water body has a vegetative cover in excess of 75% AND the site is located in excess of 50 feet from a regulated water body.

If neither of these two conditions is met, the decision tree in Table 3.2-1 will be useful in determining which RAPPS would be effective under the given circumstances. The decision tree process for this geographical category assumes that annual precipitation is low (less than 35 inches) and soils have generally low erodibility.

Table 3.2-1 Decision Tree for Xeric Plains Geographical Region



Interior Xeric Plains Assumptions:
1. Annual precipitation is less than 35 inches
2. Soils are primarily sandy with low erodability

No RAPPS needed:
1. When construction site is in excess of 150 feet from a regulated water body OR
2. When vegetative cover exceeds 75% AND the site is in excess of 50 feet from a regulated water body.

Index

BP = Brush Pile
CM = Construction Mat
CULV = Cross-Drain Culvert
DD = Diversion Dike
DIP = Drainage Dip
GEO = Geotextiles
MLC = Mulch
RB = Rock Berm
RDSD = Road-Side Ditch
RDSS = Road Surface Slope
RGHN = Roughening
SB = Straw Bale
SF = Silt Fence
ST = Sediment Trap
TO = Turnout

The list of RAPPS for any given pathway on the decision tree are suggestions of RAPPS alternatives, from which one or more of the listed techniques or practices may be selected for a given site under site-specific circumstances. Not all RAPPS listed will necessarily be required for any given project.

The list of RAPPS for any given pathway on the decision may not exhaust all of the available RAPPS that may be effective for any given construction site. Other RAPPS, not listed in this flowchart, may be beneficial for controlling surface water runoff from the construction site, in addition to or in lieu of the RAPPS listed in this document.

3.3 MESIC PLAINS

Description

Generally inland flat plains within the eastern portions of the US; slopes less than 40%; moderately erodible soils including clays and loams; highly variable vegetation cover; and moderate annual precipitation.

Selection of RAPPS

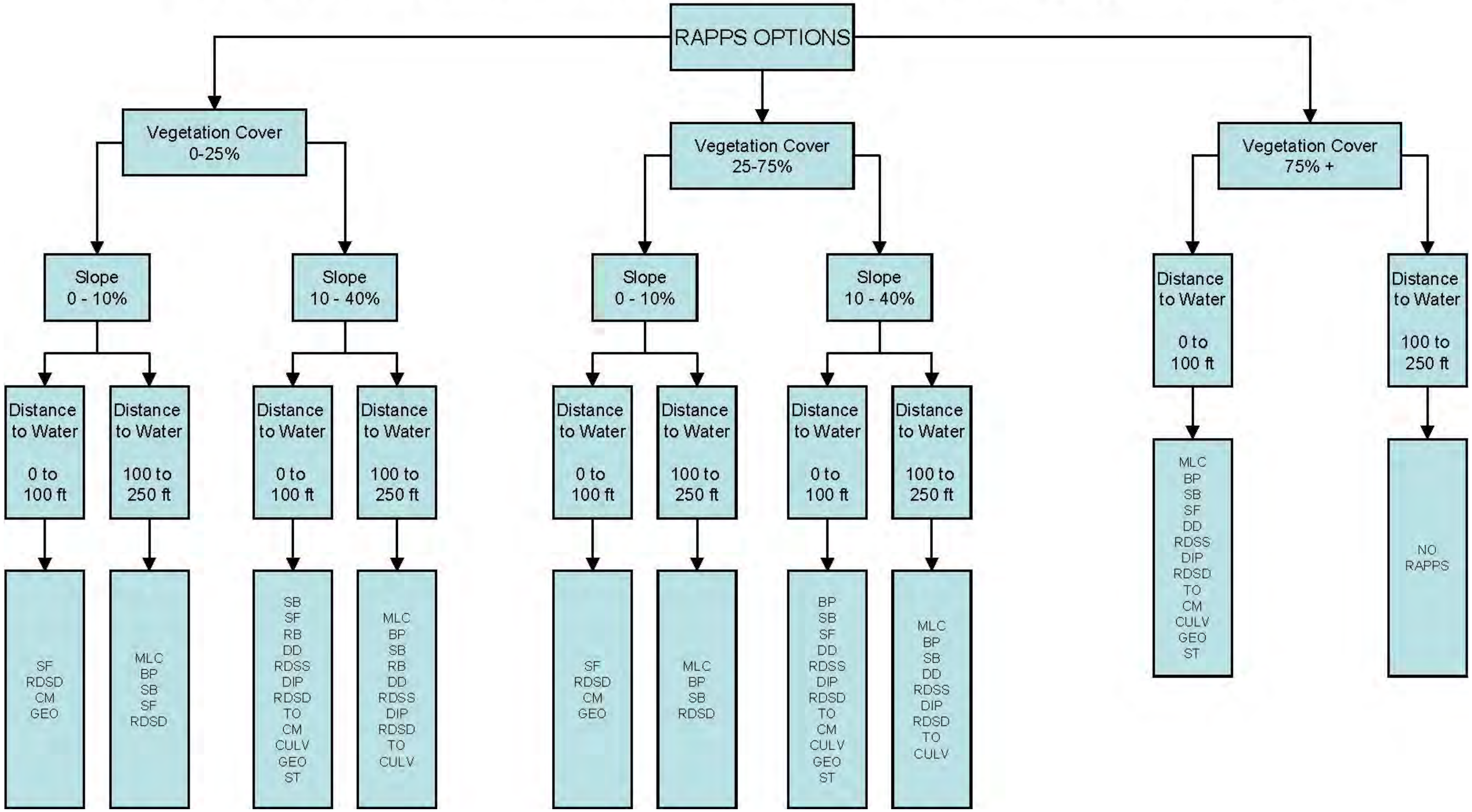
Since this region tends to have moderate annual precipitation, regular rainfall events, and clay-and-loam-dominated soils that are somewhat erodible, the opportunity for potentially undesirable quantities of sediment to be found in uncontrolled storm water discharges from an oil and gas construction site is increased over the Xeric Plains. Therefore, distance and slope are adjusted accordingly. Construction at oil and gas sites will not require the installation of RAPPS if one of the following exists:

1. The construction site is located in excess of 250 feet from a regulated water body.

2. The area between the construction site and a regulated water body has a vegetative cover in excess of 75% AND the site is located in excess of 100 feet from a regulated water body.

If neither of these two conditions is met, the decision tree in Table 3.3-1 will be useful in determining which RAPPS would be effective under the given circumstances. The decision tree process for this geographical category assumes that annual precipitation is moderate (35 inches and above) and soils have moderate erodibility.

Table 3.3-1 Decision Tree for Mesic Plains Geographical Region



Interior Mesic Plains Assumptions:
1. Annual precipitation is greater than 35 inches
2. Soils are moderately erodable

No RAPPS needed:
1. When construction site is in excess of 250 feet from a regulated water body OR
2. When vegetative cover exceeds 75% AND the site is in excess of 100 feet from a regulated water body.

Index

BP = Brush Pile	RDSD = Road-Side Ditch
CM = Construction Mat	RDSS = Road Surface Slope
CULV = Cross-Drain Culvert	RGHN = Roughening
DD = Diversion Dike	SB = Straw Bale
DIP = Drainage Dip	SF = Silt Fence
GEO = Geotextiles	ST = Sediment Trap
MLC = Mulch	TO = Turnout
RB = Rock Berm	

The list of RAPPS for any given pathway on the decision tree are suggestions of RAPPS alternatives, from which one or more of the listed techniques or practices may be selected for a given site under site-specific circumstances. Not all RAPPS listed will necessarily be required for any given project.

The list of RAPPS for any given pathway on the decision may not exhaust all of the available RAPPS that may be effective for any given construction site. Other RAPPS, not listed in this flowchart, may be beneficial for controlling surface water runoff from the construction site, in addition to or in lieu of the RAPPS listed in this document.

3.4 DESERTS

Description

Lowlands of the southwestern US; slopes from 0 to 40%, but can be greater then 40%; shallow rocky or sandy soils with low erodibility; low to no vegetation cover; and low annual precipitation.

Selection of RAPPS

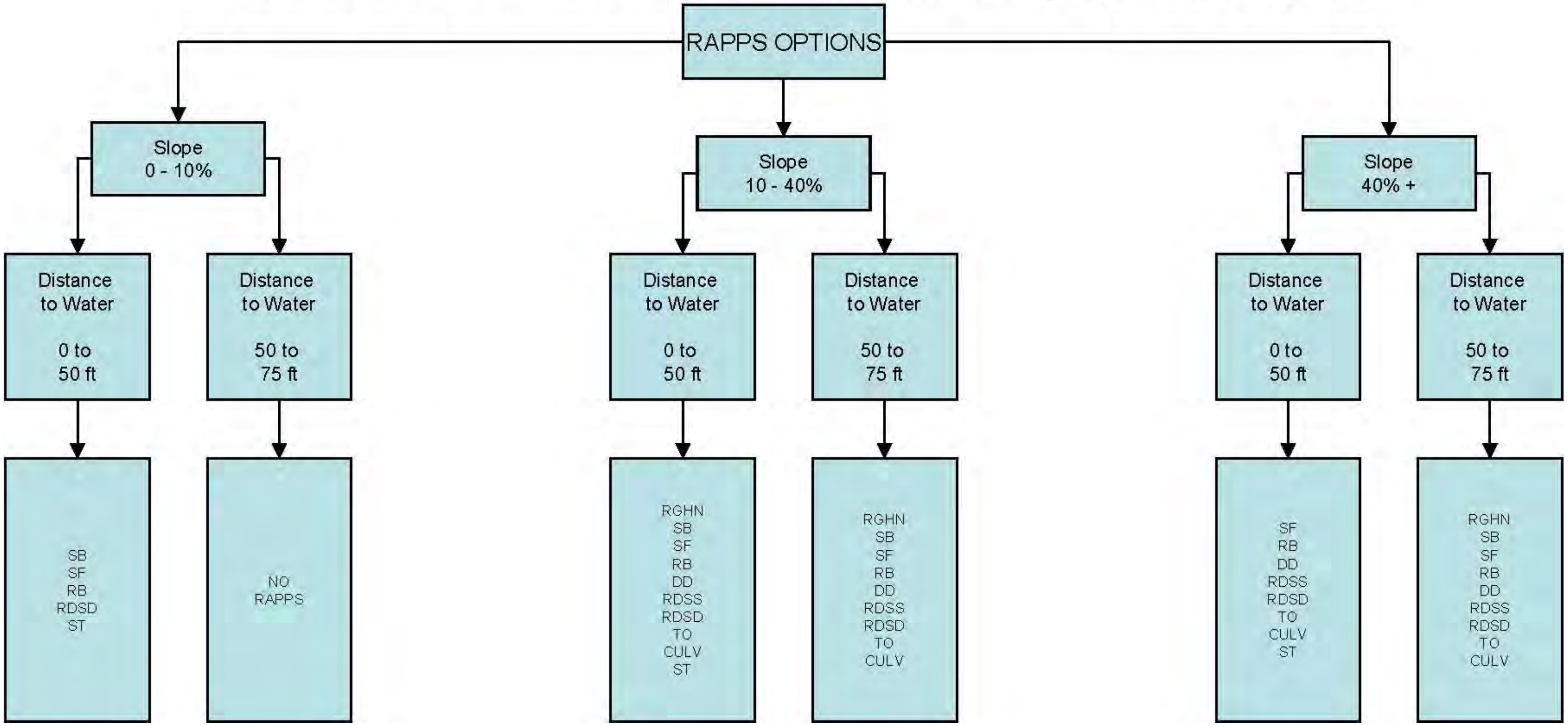
The lack of significant annual rainfall and the infrequency of rainfall events along with sand-and-rock-dominated soils limit the amount of sediment in storm water discharges from an oil and gas construction site in this type of geographical region. Therefore, construction at oil and gas sites will not require the installation of RAPPS if one of the following exists:

1. The construction site is located in excess of 75 feet from a regulated water body.

2. The area between the construction site and a regulated water body has a slope of less than 10% AND the site is in excess of 50 feet from a regulated water body.

If neither of these two conditions is met, the decision tree in Table 3.4-1 will be useful in determining which RAPPS would be effective under the given circumstances. The decision tree process for this geographical category assumes vegetation cover is low (0 to 25% coverage); annual precipitation is low (less than 15 inches); and soils are primarily sand and rock.

Table 3.4-1 Decision Tree for Deserts Geographical Region



Desert Assumptions:
1. Vegetation cover is below 25%
2. Annual precipitation is less than 15 inches
3. Soils are primarily sand and/or rock

No RAPPS needed:
1. When construction site is in excess of 75 feet from a regulated water body OR
2. When construction site has a slope of less than 10% AND is in excess of 50 feet from a regulated water body.

Index

BP = Brush Pile
CM = Construction Mat
CULV = Cross-Drain Culvert
DD = Diversion Dike
DIP = Drainage Dip
GEO = Geotextiles
MLC = Mulch
RB = Rock Berm
RDSD = Road-Side Ditch
RDSS = Road Surface Slope
RGHN = Roughening
SB = Straw Bale
SF = Silt Fence
ST = Sediment Trap
TO = Turnout

The list of RAPPS for any given pathway on the decision tree are suggestions of RAPPS alternatives, from which one or more of the listed techniques or practices may be selected for a given site under site-specific circumstances. Not all RAPPS listed will necessarily be required for any given project.

The list of RAPPS for any given pathway on the decision may not exhaust all of the available RAPPS that may be effective for any given construction site. Other RAPPS, not listed in this flowchart, may be beneficial for controlling surface water runoff from the construction site, in addition to or in lieu of the RAPPS listed in this document.

3.5 XERIC MOUNTAINS

Description

Generally mountainous areas within the western US; slopes exceeding 10%; variable vegetation cover; shallow rocky soils with low erodibility; and low to moderate annual precipitation.

Selection of RAPPS

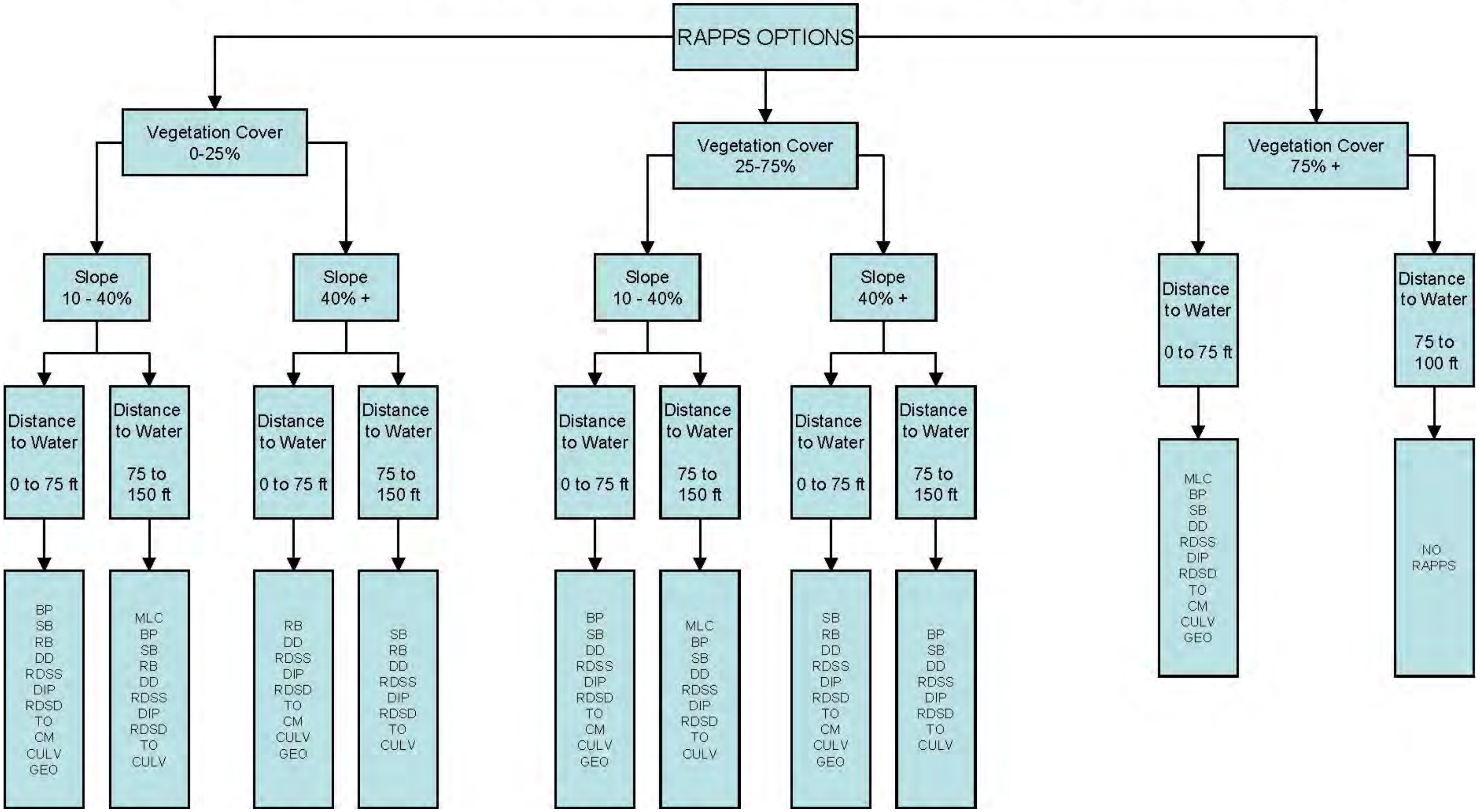
This region is dominated by very rocky, low-erodibility soils and typically only experiences rainfall events during warmer months. Snowmelt can cause erosion, but the opportunity for sediment in storm water runoff to be discharged to a regulated water body in undesirable quantities is low in comparison to the Mesic Mountains, and distance and slope are adjusted accordingly compared to the Mesic Mountains. Therefore, construction at oil and gas sites will not require the installation of RAPPS if one of the following exists:

1. The construction site is located in excess of 150 feet from a regulated water body.

2. The area between the construction site and a regulated water body has vegetative cover in excess of 75% AND the site is in excess of 75 feet from a regulated water body.

If neither of these two conditions is met, the decision tree in Table 3.5-1 will be useful in determining which RAPPS would be effective under the given circumstances. The decision tree process for this geographical category assumes annual precipitation is low to moderate (from 10 to 50 inches) and soils are primarily rock.

Table 3.5-1 Decision Tree for Xeric Mountains Geographical Region



Xeric Mountains Assumptions:
1. Annual precipitation is between 10 and 50 inches
2. Soils are rocky with low erodability

No RAPPS needed:
1. When construction site is in excess of 150 feet from a regulated water body OR
2. When vegetative cover exceeds 75% AND the site is in excess of 75 feet from a regulated water body.

Index

BP = Brush Pile	RDSD = Road-Side Ditch
CM = Construction Mat	RDSS = Road Surface Slope
CULV = Cross-Drain Culvert	RGHN = Roughening
DD = Diversion Dike	SB = Straw Bale
DIP = Drainage Dip	SF = Silt Fence
GEO = Geotextiles	ST = Sediment Trap
MLC = Mulch	TO = Turnout
RB = Rock Berm	

The list of RAPPS for any given pathway on the decision tree are suggestions of RAPPS alternatives, from which one or more of the listed techniques or practices may be selected for a given site under site-specific circumstances. Not all RAPPS listed will necessarily be required for any given project.

The list of RAPPS for any given pathway on the decision may not exhaust all of the available RAPPS that may be effective for any given construction site. Other RAPPS, not listed in this flowchart, may be beneficial for controlling surface water runoff from the construction site, in addition to or in lieu of the RAPPS listed in this document.

3.6 MESIC MOUNTAINS

Description

Rolling highlands and steep mountains within the eastern and northwestern portions of the US; slopes exceeding 10%; variable vegetative cover; loamy soils with moderate erodibility; and very high annual precipitation.

Selection of RAPPS

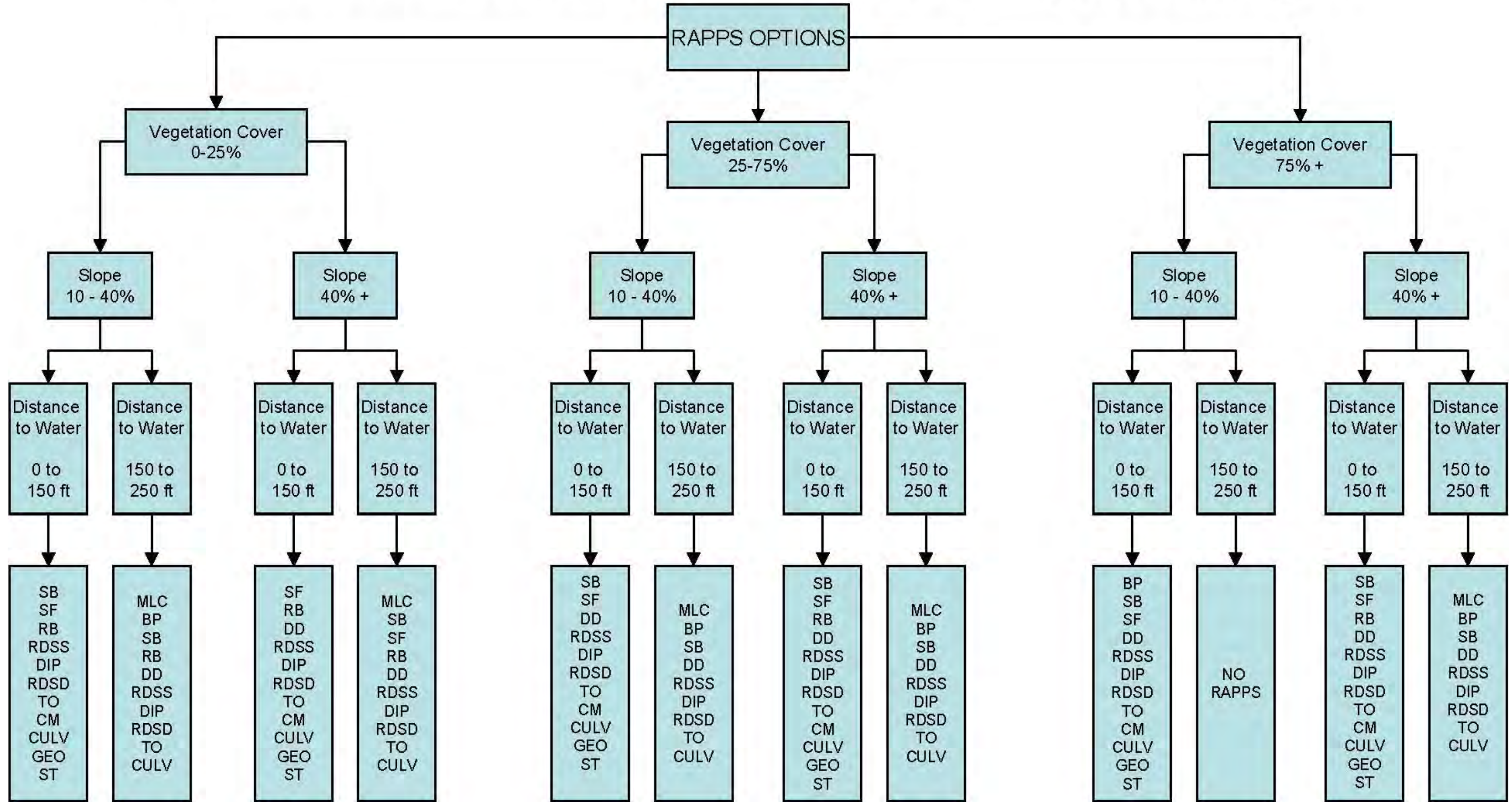
This region has high annual precipitation with frequent rainfall events. Additionally, vegetative cover tends to be dominated by forest, slopes are steep, and soils are dominated by loams. The opportunity for sediment to be discharged to a regulated water body in potentially undesirable quantities is increased over the Xeric and Mesic Plains and Xeric Mountains, and distance and slope for the Mesic Moutains are adjusted accordingly. Therefore, construction sites will not require the installation of RAPPS in the Mesic Mountains if one of the following exists:

1. The construction site is located in excess of 250 feet from a regulated water body.

2. The area between the construction site and a regulated water body has vegetative cover in excess of 75%; the slope is less than 40%; AND the site is in excess of 150 feet from a regulated water body.

If neither of these two conditions is met, the decision tree in Table 3.6-1 will be useful in determining which RAPPS would be effective under the given circumstances. The decision tree process for this geographical category assumes annual precipitation is high (in excess of 60 inches) and loamy soils are moderately erodible.

Table 3.6-1 Decision Tree for Mesic Mountains Geographical Region



Mesic Mountains Assumptions:
1. Annual precipitation is in excess 60 inches
2. Soils are loamy with moderate erodability

No RAPPS needed:
1. When construction site is in excess of 250 feet from a regulated water body OR
2. When vegetative cover exceeds 75%; the slope is less than 40%; AND the site is in excess of 150 feet from a regulated water body.

Index

BP = Brush Pile
CM = Construction Mat
CULV = Cross-Drain Culvert
DD = Diversion Dike
DIP = Drainage Dip
GEO = Geotextiles
MLC = Mulch
RB = Rock Berm
RDSD = Road-Side Ditch
RDSS = Road Surface Slope
RGHN = Roughening
SB = Straw Bale
SF = Silt Fence
ST = Sediment Trap
TO = Turnout

The list of RAPPS for any given pathway on the decision tree are suggestions of RAPPS alternatives, from which one or more of the listed techniques or practices may be selected for a given site under site-specific circumstances. Not all RAPPS listed will necessarily be required for any given project.

The list of RAPPS for any given pathway on the decision may not exhaust all of the available RAPPS that may be effective for any given construction site. Other RAPPS, not listed in this flowchart, may be beneficial for controlling surface water runoff from the construction site, in addition to or in lieu of the RAPPS listed in this document.

4.0 CONSTRUCTION CROSSING A REGULATED WATER BODY

Construction of crossing at regulated water bodies increases the opportunity for pollution entering these areas. Several listed RAPPS will likely be necessary for water protection given the particular circumstances. Appendix B includes some general diagrams indicating RAPPS used effectively to protect regulated waters during oil and gas construction activity. The general recommendations listed below should also be considered to help control discharges of sediment to the regulated water in undesirable quantities during construction at regulated water bodies.

- Bore under regulated water body to prevent disturbance.

- Generally, construction activities should be limited to the extent practicable within regulated waters.

- Locate staging areas and spoil storage areas a minimum of 10 feet from the water's edge. Additionally, good vegetative cover and/or sediment barriers will be needed between the stored spoil and regulated water.

- Operate tracked equipment on construction mats within regulated waters to limit soil compaction or disturbance within these areas.

- Refuel equipment a minimum of 100 feet from the regulated water body.

- Cut vegetation at ground level and limit removal of root zones and stumps where possible.

- Maintain the maximum amount of vegetative ground cover as possible.

- Install temporary equipment crossings after initial clearing to allow for equipment access during construction. Flume pipe will be necessary at flowing streams.

- Stream flows at crossings should be flumed or dammed and pumped past the construction area.

- Dewater trench in a manner to prevent sediment-laden water from entering the regulated water. Trench water should be pumped into an area with good vegetative cover or into a filter bag and dewatering structure.

- Water body banks should be stabilized following construction to prevent sloughing or erosion.

5.0 STABILIZATION

5.1 ACTIVELY DISTURBED

Area of land disturbed during preparation of oil and gas sites or portion thereof is considered “actively disturbed” during the time period starting with the commencement of land disturbing activities (such as clearing, grading, or excavating activities) until the area of land disturbed is in a state suitable for the use and capacity for which it was intended and RAPPS have been implemented, if necessary.

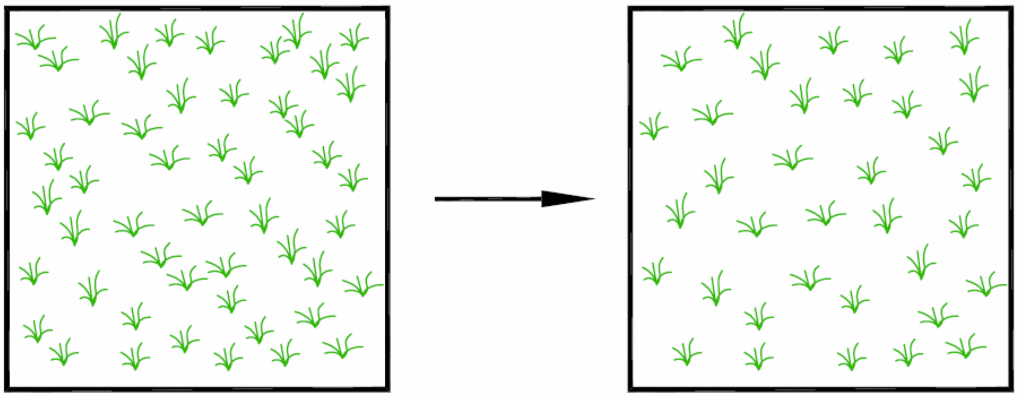
5.2 FINAL STABILIZATION

RAPPS should be maintained in good condition for the area disturbed during and after the period of active disturbance until final stabilization of the area disturbed. Final stabilization will limit and/or prevent potentially undesirable quantities of sediment from leaving the site in storm water runoff and entering a regulated water body. Final stabilization can be achieved in several different fashions.

After construction of roads and/or well or equipment pads is completed, the area covered by the road and/or equipment pad considered immediately and finally stabilized because of the placement of a base material on these areas, such as asphalt, caliche, rock, or just compaction of existing dirt in place. Once the base material is stabilized sufficiently for use in the use and capacity intended, it is considered finally stabilized.

In disturbed areas within Coastal Plains, Mesic Plains, Mesic Mountains, and Xeric Mountains where no base material will be placed, the area disturbed is considered finally stabilized when a uniform perennial vegetative cover with a density of 70% of the native background vegetative cover is established. When background native vegetation cover is less than 100%, the amount of vegetative cover needed to meet stabilization criteria needs to be determined. For example (see diagram below), if the native background vegetative cover is estimated at 50%, then 70% of the original 50% vegetative cover must be established. This would mean the area disturbed would need 35% vegetative cover to be considered finally stabilized (0.70 x 0.50 = 0.35 or 35%).

Alternatively, for sites located within the Desert and Xeric Plains in disturbed areas where no base material will be placed, the area disturbed may be considered finally stabilized prior to obtaining 70% of the native background vegetative cover as long as the following alternative final stabilization criteria are met: (1) Active disturbance of the land area to be considered stabilized has been completed, (2) RAPPS have been selected and installed appropriately, and (3) native seed has been dispersed in such a fashion as to be expected to achieve 70% background vegetative cover within 3 years under normal climate conditions for the region.



50% NATIVE BACKGROUND COVER

35% STABILIZED COVER

6.0 DEFINITIONS

Concentrated Flow – water run-off with increased volume and velocity

Construction Activity – construction activity including clearing, grading, and excavating operations that disturb land area, including construction of access roads, flow/gathering pipelines, well/tank battery pads, equipment/facility pads, regulated water body crossings

Construction Site – area of land disturbance

RAPPS – Reasonable and Prudent Practices for Stabilization – device, method, or procedure used to prevent or reduce sediment from oil and gas construction activity from entering a regulated water body in undesirable quantities

Regulated Water Body – A water body that is subject to the U.S. Environmental Protection Agency's (EPA's) jurisdiction under the Clean Water Act. EPA's jurisdiction extends over "waters of the U.S." EPA's definition of "waters of the U.S." is set out in Appendix C of this document.

NOTE: If there is a water body in the vicinity of your construction site and you are not sure whether it is a "regulated water body," you should contact an environmental professional or attorney to help you make this evaluation. The definition of the phrase "waters of the U.S." has been extensively litigated, and there is a large body of case law interpreting it. The definition of "regulated water body" may, therefore, vary between different areas of the country, because the courts in different parts of the country have reached different conclusions about the extent of EPA's jurisdiction.

Vegetative Cover – existing or planted low-growing, herbaceous plant species

7.0 REFERENCES

Cooperative Extension Service, Division of Agricultural Sciences and Natural Resources. Oklahoma State University. *Pollution Prevention at Exploration and Production Sites in Oklahoma.* Water Quality Series E-940, April 2002.

North Carolina Sedimentation Control Commission; North Carolina Department of Natural Resources and Community Development; and North Carolina Agricultural Extension Service. *Erosion and Sediment Control Planning and Design Manual.* September 1988.

US Department of Agriculture – Soil Conservation Service. *Erosion and Sediment Control Guidelines for Developing Areas in Texas*. 1976.

Alabama Soil and Water Conservation Committee. *Alabama Handbook for Erosion Control, Sediment Control, and Stormwater Management on Construction Sites and Urban Areas.* Volumes 1 and 2. June 2003.

US Environmental Protection Agency – National Pollutant Discharge Elimination System (NPDES). Construction Site Storm Water Runoff Control. http://cfpub.epa.gov/npdes/stormwater/menuofbmps/con_site.cfm (12 Feb. 2004).

Pennsylvania Department of Environmental Protection – Chapter 4, Oil and Gas Management Practices. http://www.dep.state.pa.us/eps/default.asp?P=fldr200149e0051190%5Cfldr200149e10561a8%5Cfldr20026f8082801d (12 Feb. 2004).

West Virginia Department of Environmental Protection – Office of Oil and Gas. http://www.dep.state.wv.us/publications.cfm?ssid=23 (12 Feb. 2004).

Protecting Water Quality in Urban Areas: A Manual – Minnesota Pollution Control Agency. http://www.pca.state.mn.us/water/pubs/sw-bmpmanual.html (12 Feb. 2004).

APPENDIX A

DESCRIPTION OF RAPPS

(RAPPS presented were derived from both common industry references provided in Section 4.0 of this document and from practical field experience)

1. VEGETATIVE COVER

Vegetative cover is an effective natural means of filtering runoff and preventing erosion. Preservation of existing vegetation to the maximum extent practicable keeps soils stabilized and provides a natural filter. The most effective vegetative cover consists of low-growing, herbaceous species with a high percentage of ground coverage. Shrubs and trees provide some means of preventing erosion; however, the filtering ability is greatly reduced.

Limitations:

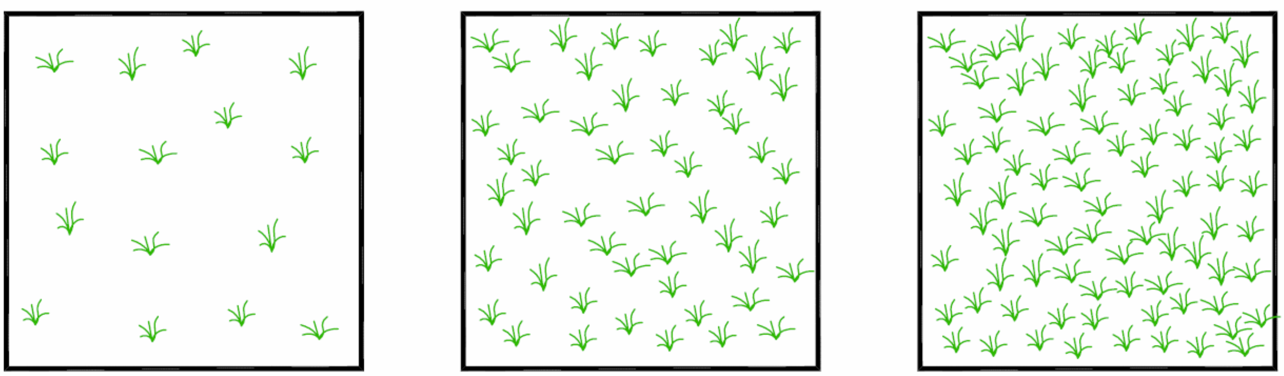
- Primarily filters sheet flow
- Minimum width of vegetative strip dependent on slope (greater slope requires wider strip)
- Vegetation must be established
- High percentage of ground cover

Installation:

- Limit vegetation clearing to the extent practicable during construction
- Plant fast-growing annual grasses for temporary controls
- Plant perennial seed mixes recommended by the local soil conservation office

Construction Activities:

Access roads, well/tank battery pads, and flow/gathering pipelines



15% COVER 50% COVER 85% COVER

2. **MULCH** (MLC)

Mulching is the use of vegetative fibers (e.g., straw, wood chips) to minimize rainfall impact, reduce suspended solids from runoff, protect seeds from erosion, prevent moisture loss from soil, and reduce predation of seeds by birds.

Limitations:

- Gradual slopes only
- Not for use immediately adjacent to wetlands or streams
- Can be lost with sheet flow runoff

Installation:

- Chop or chip wood, straw, or cellulose
- Mulch should be anchored by crimping or other technique
- Incorporate seed mix for permanent stabilization
- Hydro-mulch can be applied by spraying

Construction Activity:

Flow/gathering pipelines

3. ROUGHENING (RGHN)

This technique uses the horizontal grooves created by tracks of construction equipment to reduce runoff flow velocities. Tracks are established on the slopes perpendicular to water flow.

Limitations:

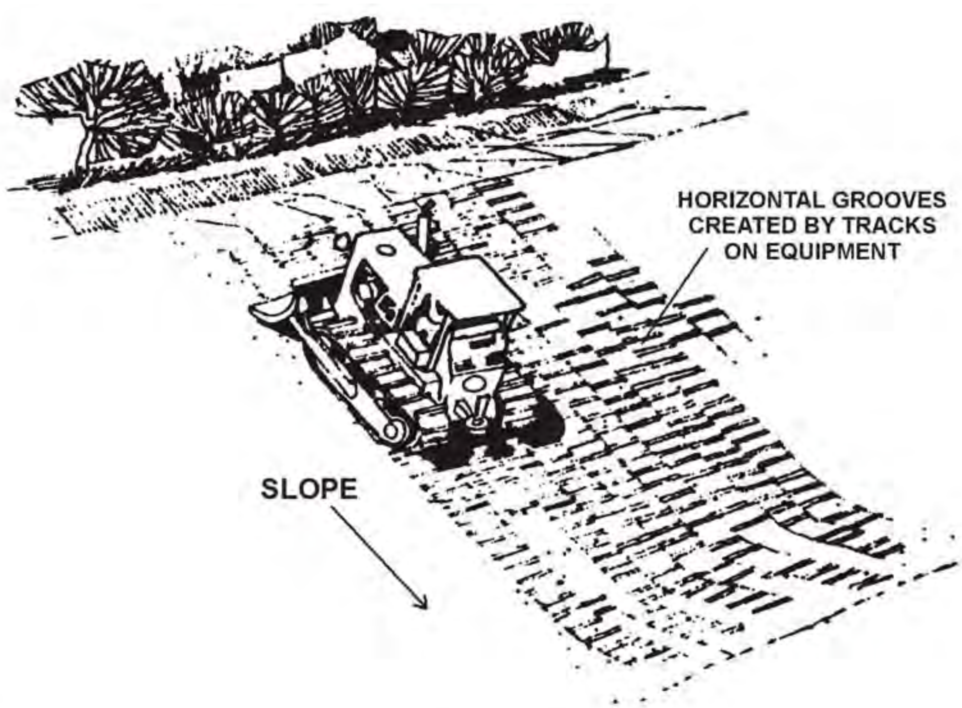
- Not for use on rocky slopes
- May cause soil compaction which limits vegetation re-growth
- Roughening may have to be re-established if lost due to heavy sheet flow runoff

Installation:

- Operate tracked equipment in a direction parallel to water flow as so to create tracks perpendicular to water flow

Construction Activity:

Access Roads, Well/Tank Battery Pads, and Flow/Gathering Pipelines



Source: Pennsylvania Department of Environmental Quality, 2004.

4. BRUSH PILES (BP)

Brush piles can be used to filter sediment from runoff of construction sites with small drainage areas on gradual slopes.

Limitations:

- Not effective on concentrated flows
- Large amounts of brush are typically needed
- Removal may be necessary after stabilization is complete

Installation:

- Cut up brush into small pieces and compact tightly
- Avoid bulky material
- Eliminate large voids within pile
- Pile brush up to 3 feet high with a minimum width of 5 feet at base
- Anchor brush piles
- The brush may be secured with photodegradable liner fabric

Construction Activities:

Access roads, well/tank battery pads, and flow/gathering pipelines

5. **STRAW (HAY) BALES (SB)**

This technique utilizes bound straw bales to filter sediment from runoff of small areas.

Limitations:

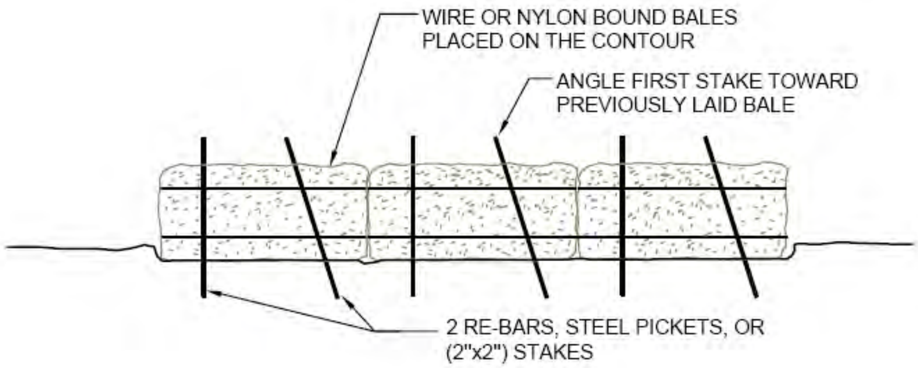
- Filters sheet flow from small drainage areas
- Short-term use
- Decomposes
- Consumed by livestock
- Removal of anchor stakes will be necessary after stabilization is complete

Installation:

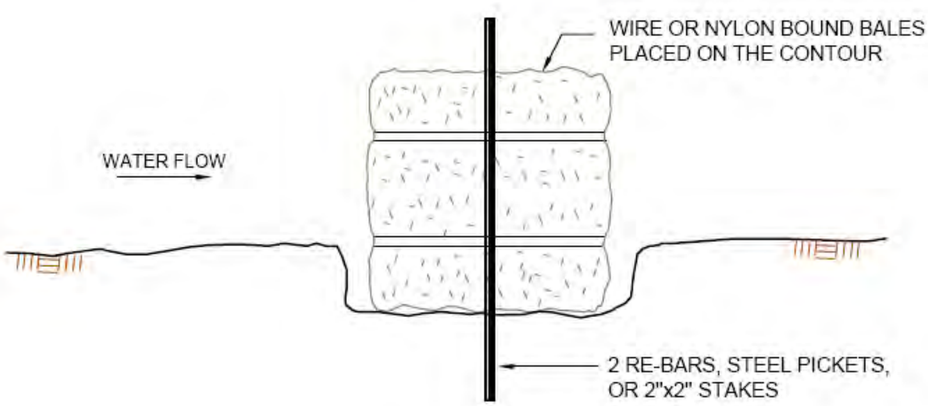
- Embed into trench
- Anchor with 2 support stakes
- Compact backfill on upgradient side
- Straw bales should extend across grade and upslope for short distance
- Use at outfall points from diversion dikes, turnouts, etc.

Construction Activities:

Access roads, well/tank battery pads, and flow/gathering pipelines



ANCHORING DETAIL



EMBEDDING DETAIL

6. SILT FENCE/FABRIC (SF)

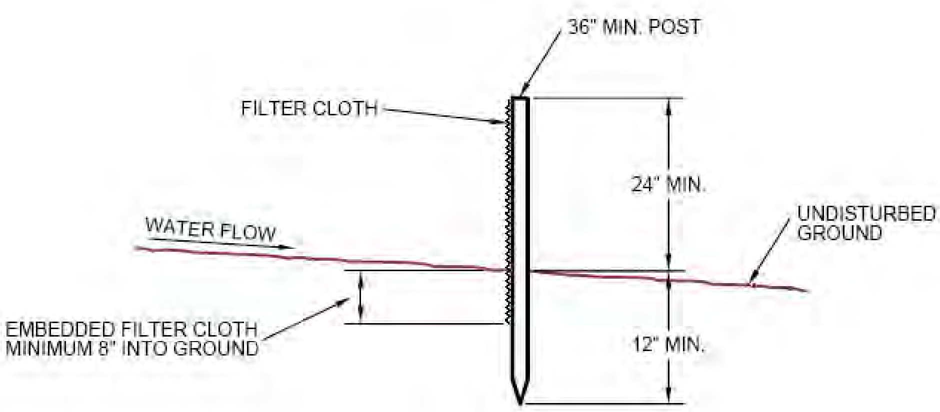
Silt fence/fabric is utilized to filter sediment from runoff of small areas. Silt fence/fabric may also be utilized as a perimeter control around the construction site when the site is relatively small.

Limitations:
- Not for concentrated flows
- Not for use in rocky situations
- Removal will be necessary after stabilization is complete
- Not for large watersheds

Installation:
- Embed bottom of fabric into soil
- Support posts spaced no greater than 10 feet apart
- Compact backfill at base of fabric
- Extend silt fence across grade and upslope for short distance
- Use at outfall points where concentrated flows are not expected

Construction Activities:

Access roads, well/tank battery pads, and flow/gathering pipelines



CROSS-SECTION
N.T.S.

7. **ROCK BERM** (RB)

This technique is useful to filter sediment from concentrated flows and/or runoff of moderate grades and larger drainage areas. Additionally, rock berms may be utilized to reduce velocity of flows within constructed channels.

Limitations:

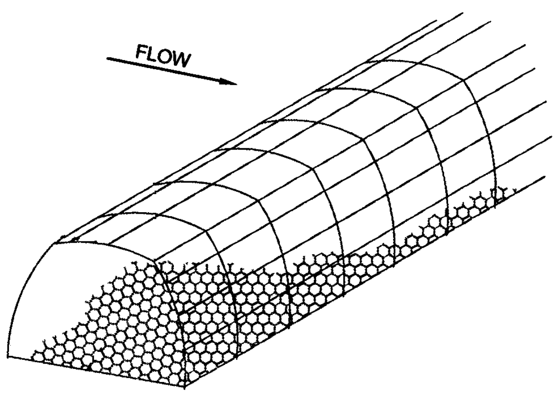
- Availability of rock
- Anchor rock into soil
- Difficult to remove after construction
- Require regular maintenance due to sediment build-up

Installation:

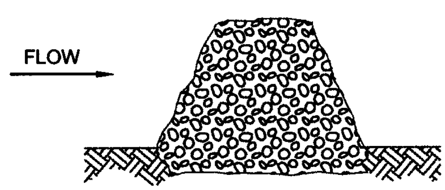
- Use medium to large diameter rock
- May secure rock within woven wire sheathing but not required
- Berm side slopes should be 3:1 or flatter
- Top of berm should be a minimum of 2 feet wide

Construction Activities:

Access roads, well/tank battery pads, and flow/gathering pipelines



ROCK BERM
N.T.S.



CROSS SECTION
N.T.S.

8. DIVERSION/EARTHEN DIKES (WATER BARS) (DD)

This technique may be used to collect runoff from undisturbed areas and divert around construction activity. Additionally, dikes are used to limit the accumulation of water volume by diverting runoff from construction area into a stabilized outlet or well-vegetated area.

Limitations:

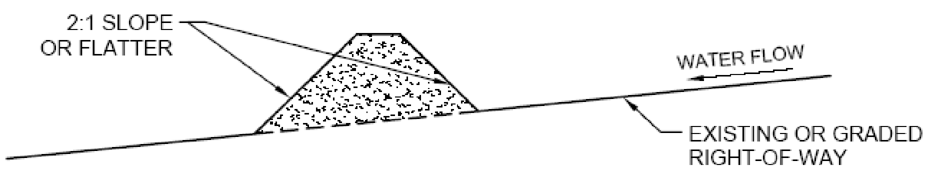
- Not for use on concentrated flows
- May cause concentrated flows from sheet flow
- Requires vegetative cover or other filter at discharge point

Installation:

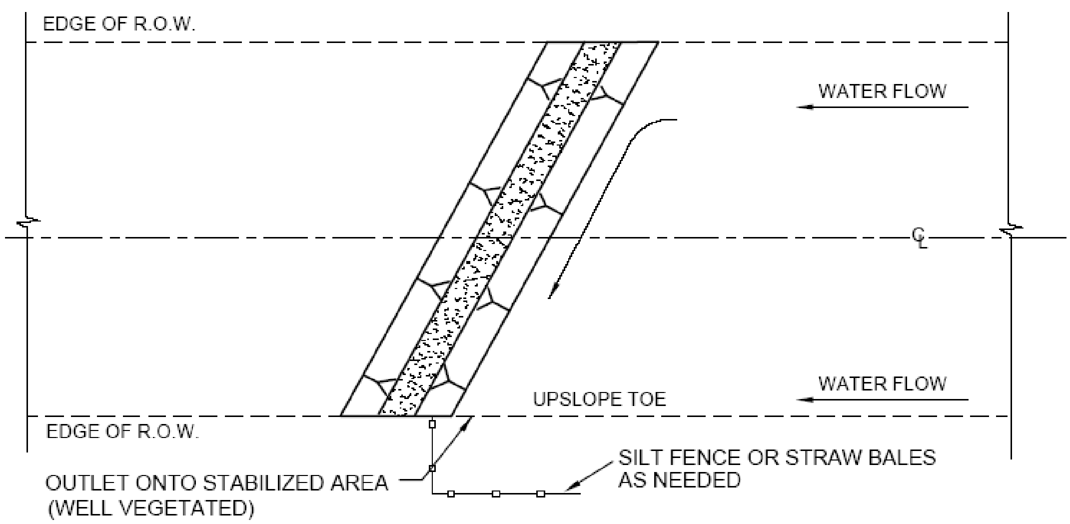
- Pile and compact soil
- Dike sideslopes should be 2:1 or flatter
- Angle dike at approximately 30° to slope
- Increase frequency with increased slope
- Outlet dike into well-vegetated area or install secondary control such as rock filter or straw bales

Construction Activities:

Access roads, well/tank battery pads, and flow/gathering pipelines



CROSS SECTION
N.T.S.



PLAN VIEW
N.T.S.

9. ROAD SURFACE SLOPE (RDSS)

This technique sheds runoff water from road surface into stabilized ditches or vegetation. Roads may be crowned, in-sloped, or out-sloped.

Limitations:

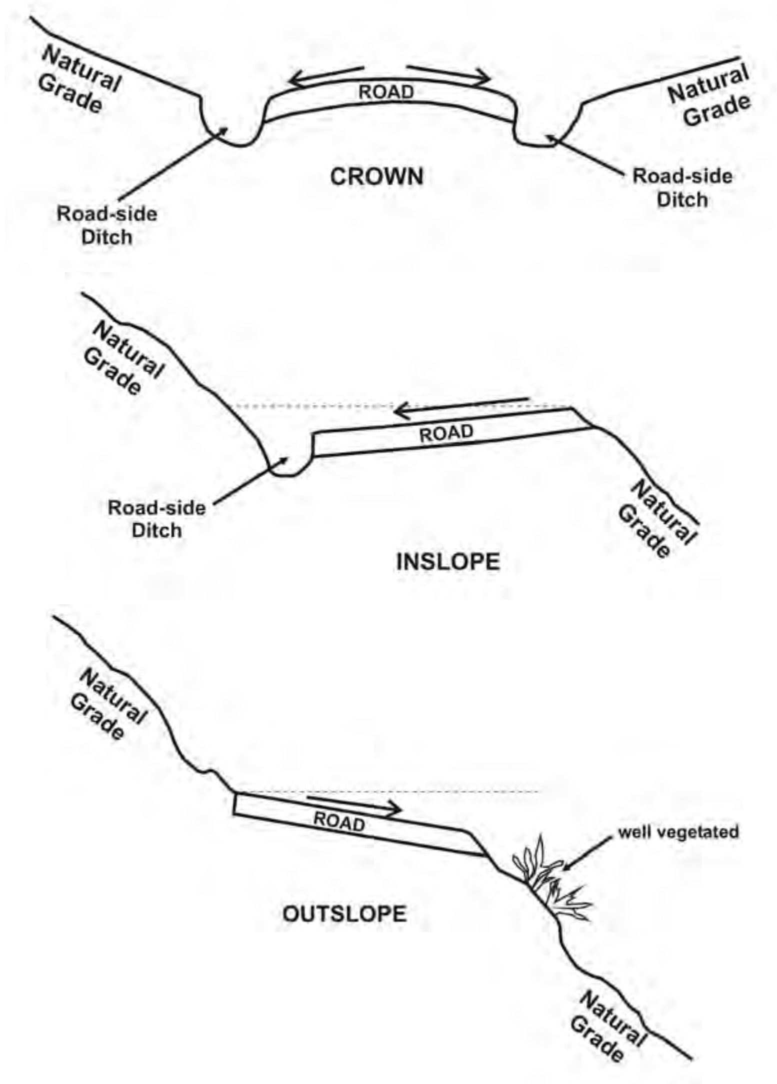
- Only sheds runoff collected from surface of road
- May cause concentrated flows from sheet flow
- Require vegetative ditches, turnouts, and/or cross-drains

Installation:

- Compact soil or road base material to direct runoff
- Crowning design directs runoff to both sides of the road requiring 2 road-side ditches
- Inslope design directs runoff toward the hillside and requires cross-drain installation
- Outslope design is most effective on moderate slopes with dense vegetative cover

Construction Activity:

Access roads



10. **DRAINAGE DIPS** (DIP)

This technique captures and directs runoff from the road into vegetative filter strips or other filter system. Ridges and associated dips are constructed diagonally across and as part of the road surface.

Limitations:

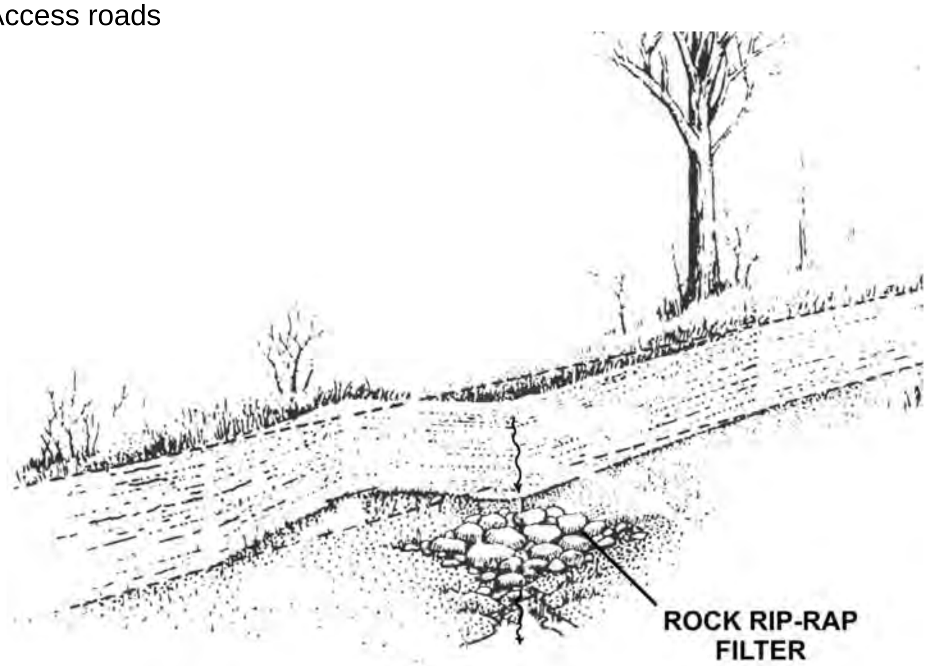
- Size limited by the safe passage of trucks and equipment
- May cause concentrated flows from sheet flows
- Require vegetative cover or other filter at discharge point

Installation:

- Need to be deep enough to carry expected flow
- Need to be wide enough to allow traffic to pass
- Increase frequency with increase slope
- Pile and compact soil
- Angle dips up to 25^o to slope
- Place rock at outlet

Construction Activity:

Access roads



PLAN VIEW
N.T.S.

Source: Cooperative Extension Service, 2002.

11. STABILIZED CONSTRUCTION ENTRANCE

Stabilized construction entrances limit the amount of tracked materials (mud and dust) from leaving the construction site. Mud and sediment are removed from vehicle tires when leaving the site as tires pass over rock pad.

Limitations:

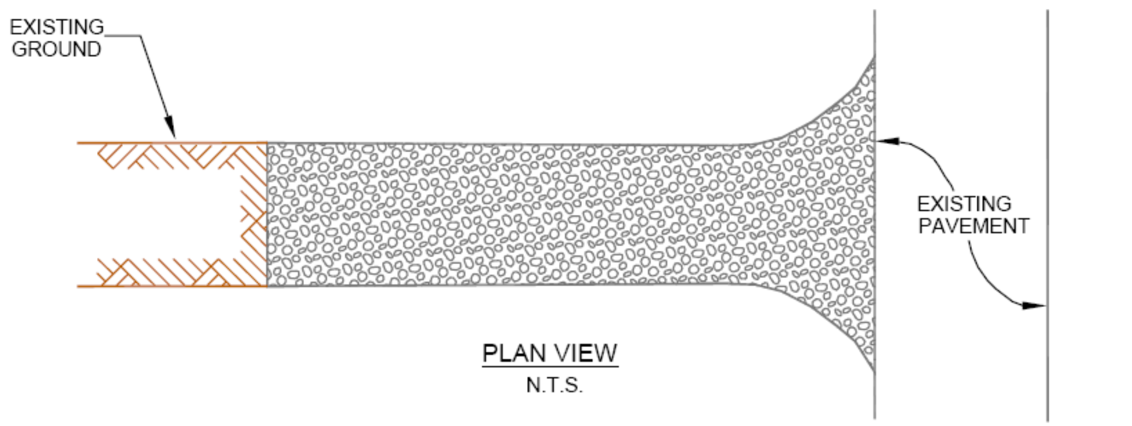
- Less effective with increased rain and mud
- Additional sweeping of paved road will be necessary
- Removal necessary after completion of construction
- Availability of rock

Installation:

- Install at entrances/exits to paved roads
- Place geotextile filter fabric under medium to large diameter crushed rock
- Length and width of entrance should be adequate to allow large vehicles to access site

Construction Activities:

Access roads, well/tank battery pads, and flow/gathering pipelines



PLAN VIEW
N.T.S.

CROSS-SECTION
N.T.S.

12. **ROAD-SIDE DITCHES** (RDSD)

This technique requires constructing channels parallel to roads. The ditches convey concentrated runoff of surface water from roads and surrounding areas to a stabilized area.

Limitations:

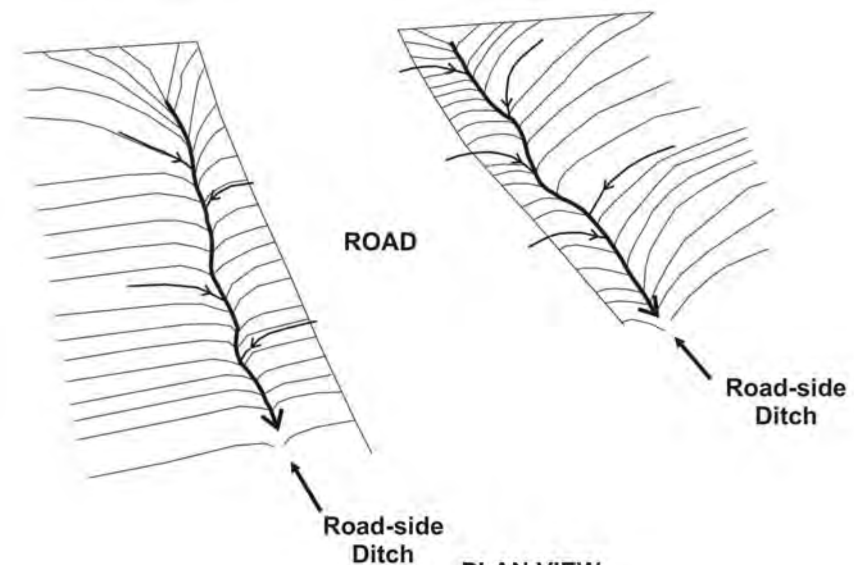
- Erosion occurs within channel
- Channel does not necessarily filter sediment from runoff

Installation:

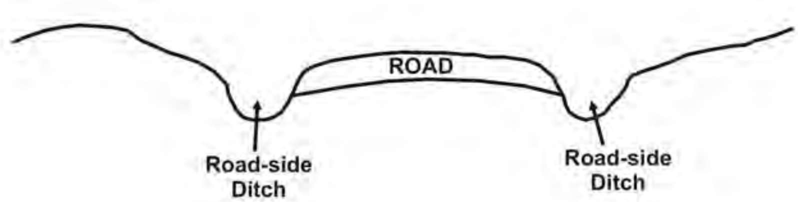
- Excavate channel along roadside to a width and depth that can handle expected flows
- Slope channels so that water velocities do not cause excessive erosion
- Shape and level channel removing excess spoil so water can flow
- Vegetate or line channel with material to prevent erosion

Construction Activity:

Access roads



PLAN VIEW
N.T.S.



CROSS-SECTION
N.T.S.

13. TURNOUTS OR WING DITCHES (TO)

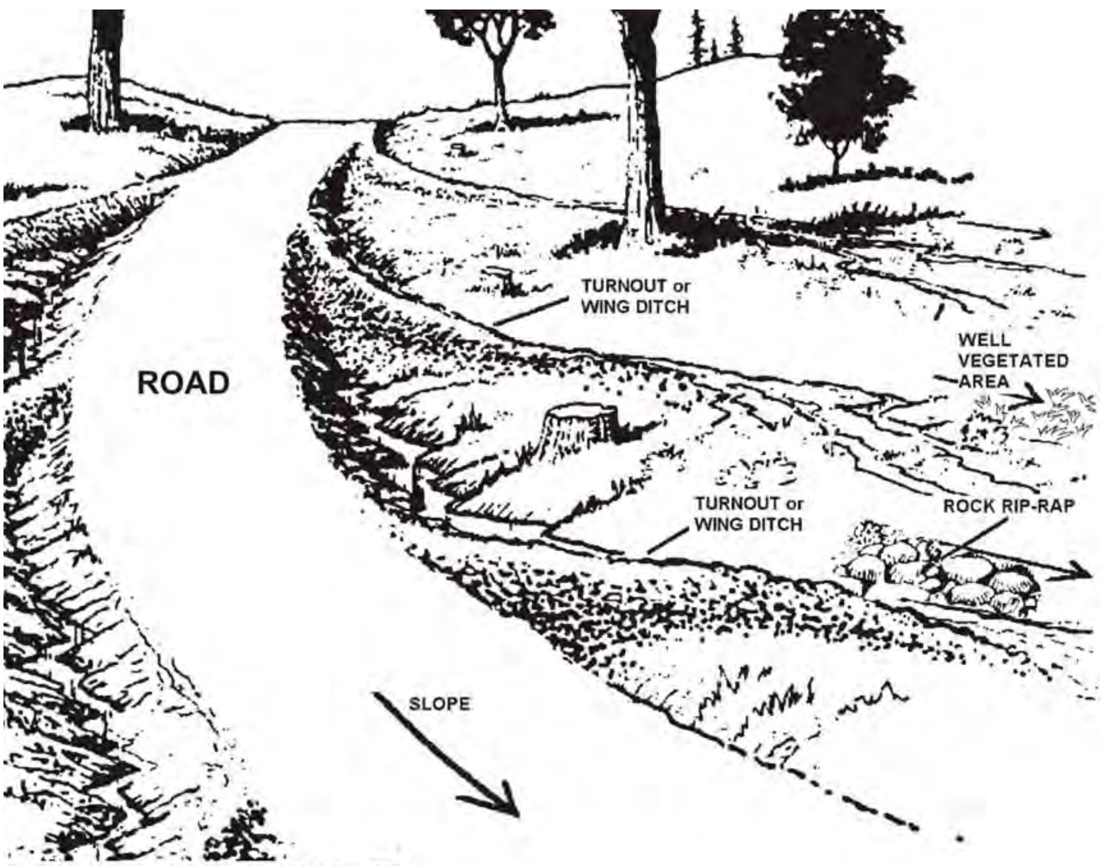
These structures are extensions of road-side ditches and will effectively remove run-off water from the ditch into well-stabilized areas.

Limitations:
- Gradual slopes only
- Require vegetative cover or other filter at discharge point

Installation:
- Slope turnout gradually down from bottom of road ditch
- Angle turnout at approximately 30° to road ditch
- Discharge turnout into well-vegetated area or install secondary control such as rock filter or straw bales
- Space turnouts according to slope

Construction Activities:

Access roads



Source: Cooperative Extension Service, 2002.

14. <u>CONSTRUCTION MATS</u> (CM)

This technique spreads the weight of construction equipment over a broad area to help prevent soil compaction and soil exposure.

Limitations:

- Useful on wet, soggy, and/or inundated soils
- Mats are bulky and difficult to move
- Does not filter sediment from runoff

Installation:

- Mats are constructed of large timber tied together
- Mats are placed ahead of operating equipment to provide stable work area

Construction Activities:

Flow/gathering pipelines

15. CROSS-DRAIN CULVERTS (CULV)

This technique can be used to direct road-side ditch flow across road or may be used to direct stream flow under road or construction area. Culverts passing construction sites will allow for continued flow of stream with minimal siltation.

Limitations:

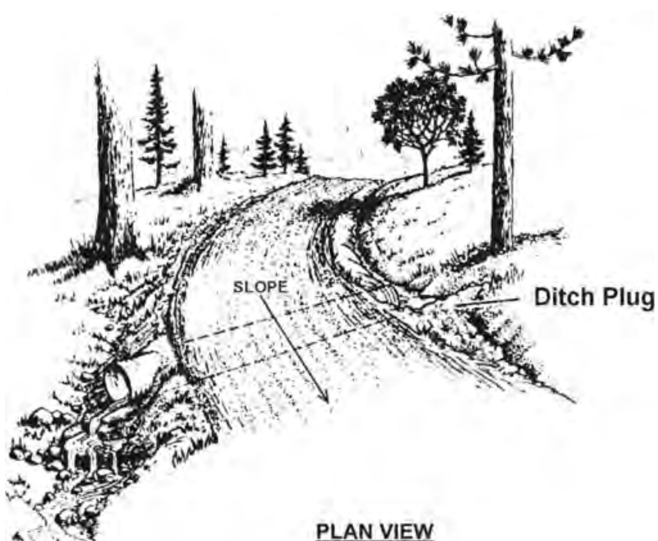
- Culverts may become clogged
- Not a sediment filter

Installation:

- Culverts may be steel, aluminum, or concrete
- Culverts should be placed at surface grades to allow normal low-flow water to be conveyed
- Soil or road base should be compacted over culverts to a minimum of 12 inches
- Culvert size should be adequate to convey anticipated flow
- Ditch plug will be needed within road-side ditch to direct water into culvert
- Culvert drop grade should be adequate to convey flows
- Increase frequency of culverts with increased slope
- Rock rip-rap often needed at outlet

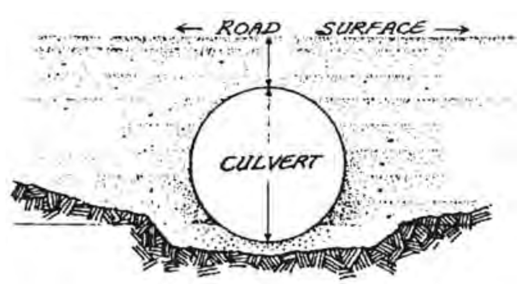
Construction Activities:

Access roads and flow/gathering pipelines



PLAN VIEW
N.T.S.

Source: Cooperative Extension Service, 2002.



CROSS SECTION
N.T.S.

Source: Cooperative Extension Service, 2002.

16. GEOTEXTILES/EROSION BLANKETS (GEO)

Geotextiles are typically a porous fabric constructed of woven fibers. They are useful for stabilizing and preventing erosion on slopes, especially adjacent to streams.

Limitations:

- Decompose
- Effectiveness depends on proper installation
- Expensive

Installation:

- Select appropriate fabric type for necessary purpose
- Smooth soil prior to installation
- Fabric needs to be in continuous contact with exposed soil
- Anchor fabric securely
- Apply seed prior to fabric installation for final stabilization of construction sites

Construction Activities:

Well/tank battery pads and flow/gathering pipelines

17. <u>SEDIMENT TRAPS</u> (ST)

This technique uses a basin or pond to hold sediment-laden water so that sediment can settle and water is absorbed into the soil. Sediment traps are useful for construction sites where excessive runoff will need to be captured and filtered and other RAPPS are insufficient.

Limitations:

- Not for use in rocky situations
- Larger drainage areas require larger traps
- Overflow can result during large rainfall events
- Water will remain in trap for extended periods

Installation:

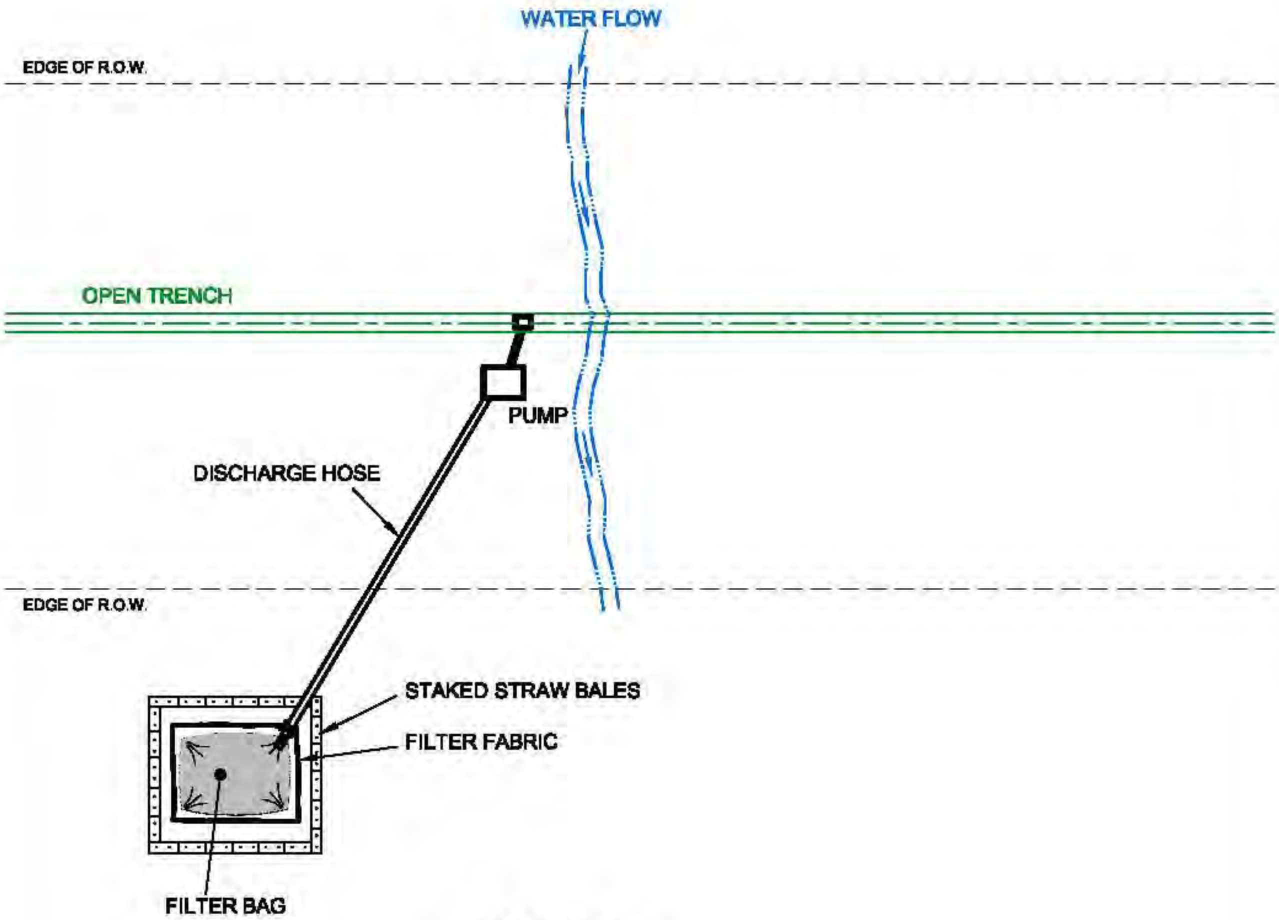
- Excavate trap or basin within area where runoff may be directed toward
- Sideslopes should be machine compacted
- Sideslopes should be 2:1 or flatter
- Volume of trap should handle runoff from 2-year storm events
- Soil within trap should allow for water absorption, no bedrock
- Construct spillway or outfall structure with rock rip-rap at outlet

Construction Activities:

Access roads, well/tank battery pads, and flow/gathering pipelines

APPENDIX B

DIAGRAMS OF TYPICAL REGULATED WATER BODY CROSSINGS



PLAN VIEW
N.T.S.

CONSTRUCTION NOTES:

1. DISCHARGE ONTO STABILIZED AREA (i.e. HEAVILY VEGETATED)
2. DISCHARGE LOCATION MUST BE A MINIMUM OF 25' FROM OPEN WATER BODY OR INTO DISCHARGE STRUCTURE.

TRENCH DEWATERING & DISCHARGE

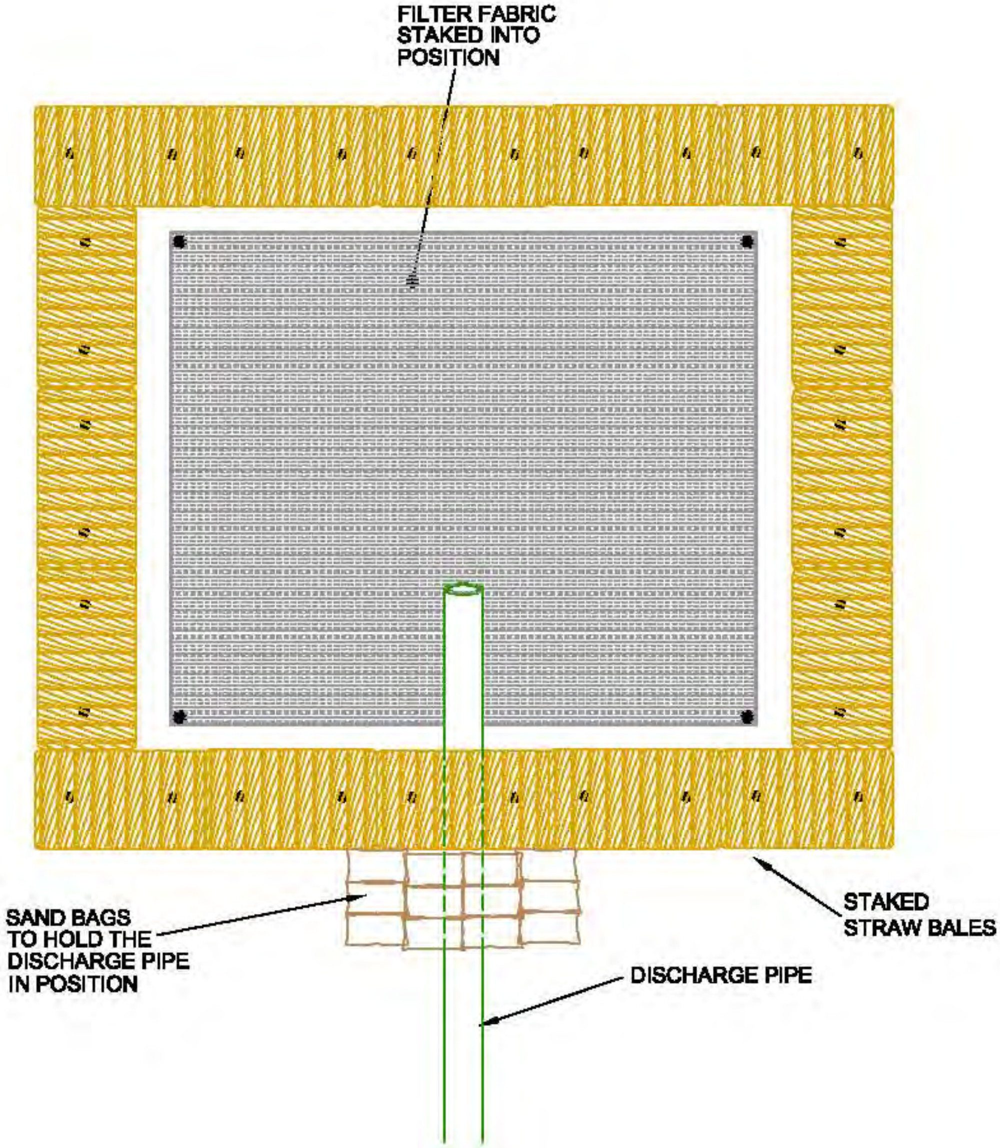
THE ARCHITECT/ENGINEER ASSUMES RESPONSIBILITY FOR APPROPRIATE USE OF THIS STANDARD.

Horizon Environmental Services, Inc.

040027A01IM.dwg | JEA | 2/26/04

"Do Not Scale This Drawing"

040027A02IM.dwg | JEA | 2/26/04



PLAN VIEW
N.T.S.

CONSTRUCTION NOTES:

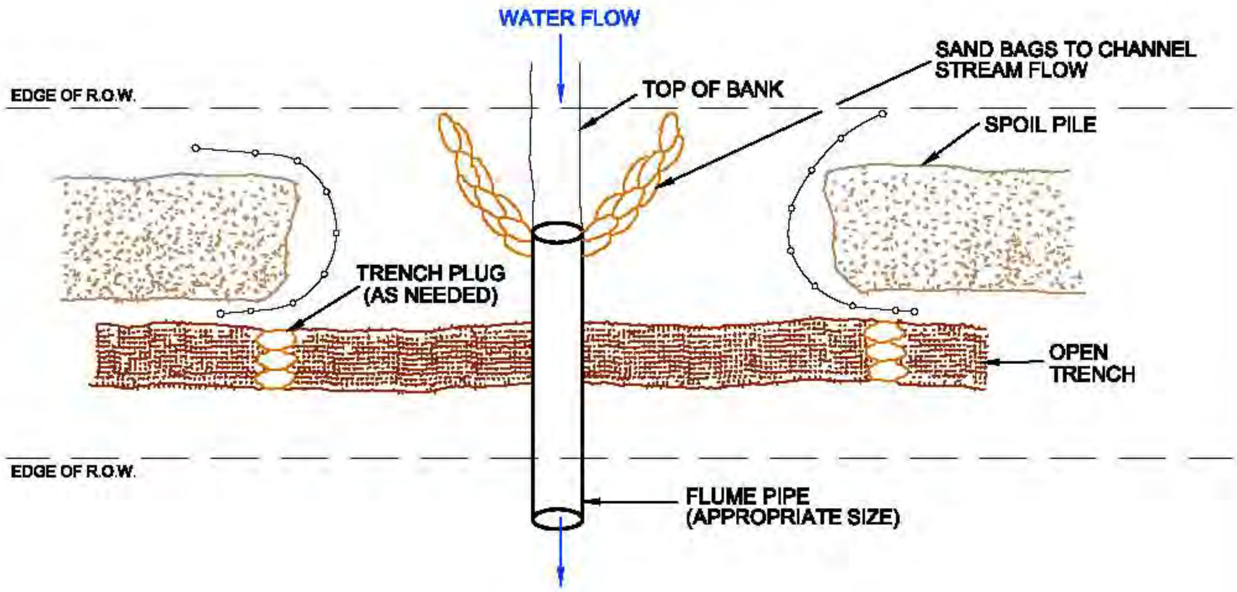
1. THIS DESIGN FOR FLAT OR RELATIVELY FLAT GROUND.
2. THIS DESIGN FOR SMALL DISCHARGES.

THE ARCHITECT/ENGINEER ASSUMES RESPONSIBILITY FOR APPROPRIATE USE OF THIS STANDARD.

DEWATERING STRUCTURE

"Do Not Scale This Drawing"

Horizon
Environmental Services, Inc.



PLAN VIEW
N.T.S.

CONSTRUCTION NOTES:

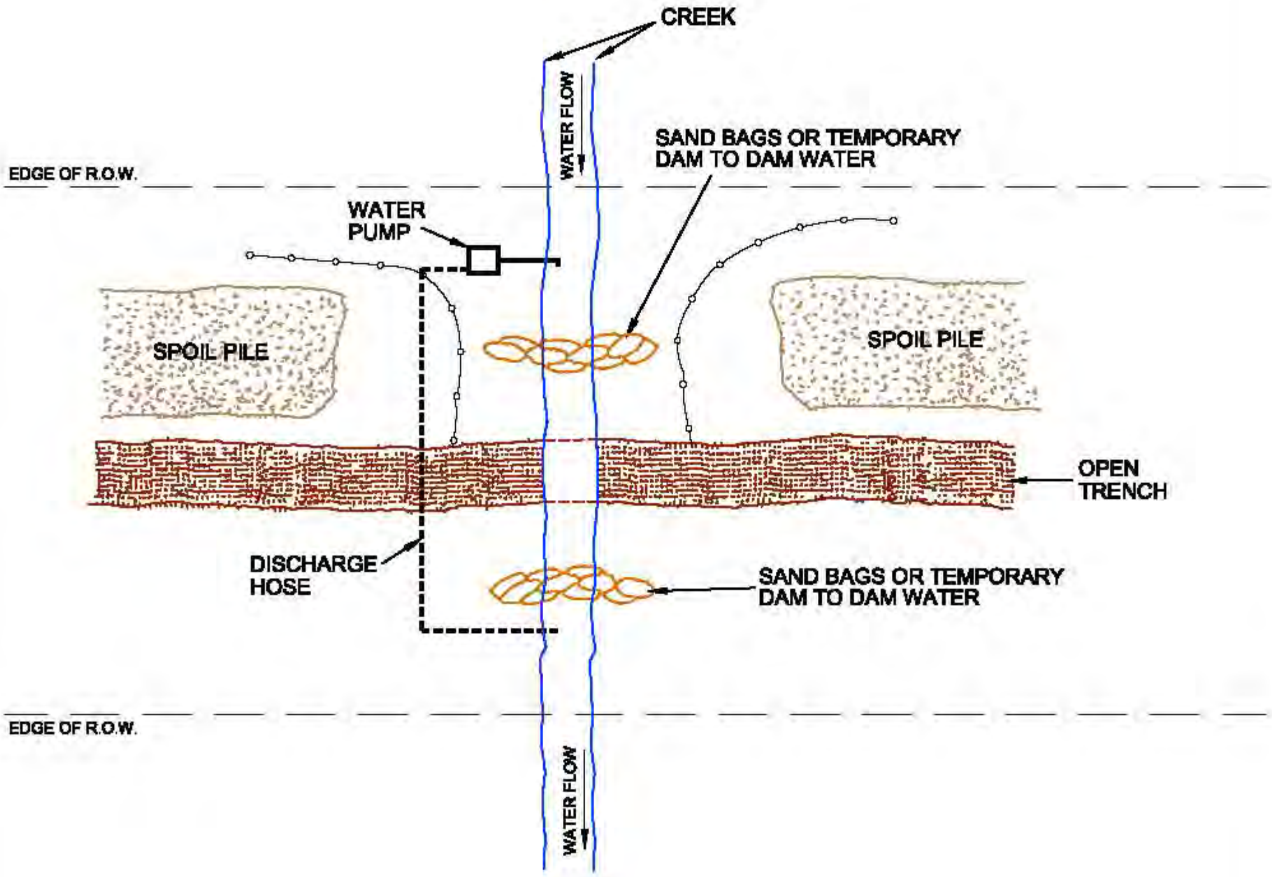
1. TRENCH SPOIL SHOULD BE PLACED APPROXIMATELY 10' FROM THE TOP OF THE BANK.
2. RAPPS NEEDED BETWEEN SPOIL AND WATERBODY.
3. FLUME PIPE SHOULD ADEQUATELY CONVEY NORMAL STREAM FLOWS.

THE ARCHITECT/ENGINEER ASSUMES RESPONSIBILITY FOR APPROPRIATE USE OF THIS STANDARD.

TYPICAL OPEN CUT FLOWING STREAM CROSSING FLUME PIPE

Horizon
Environmental Services, Inc.

040027A04IM.dwg | JEA | 2/26/04



CONSTRUCTION NOTES:

1. REROUTE WATER VIA DAM AND PUMP.
2. EXCAVATE TRENCH.
3. TRENCH SPOIL SHOULD BE PLACED APPROXIMATELY 10' FROM THE TOP OF BANK.
4. RAPPS NEEDED BETWEEN SPOIL AND WATERBODY.
5. MONITOR PUMP(S) - REFUELING IN SPILL CONTAINMENT DEVICE.

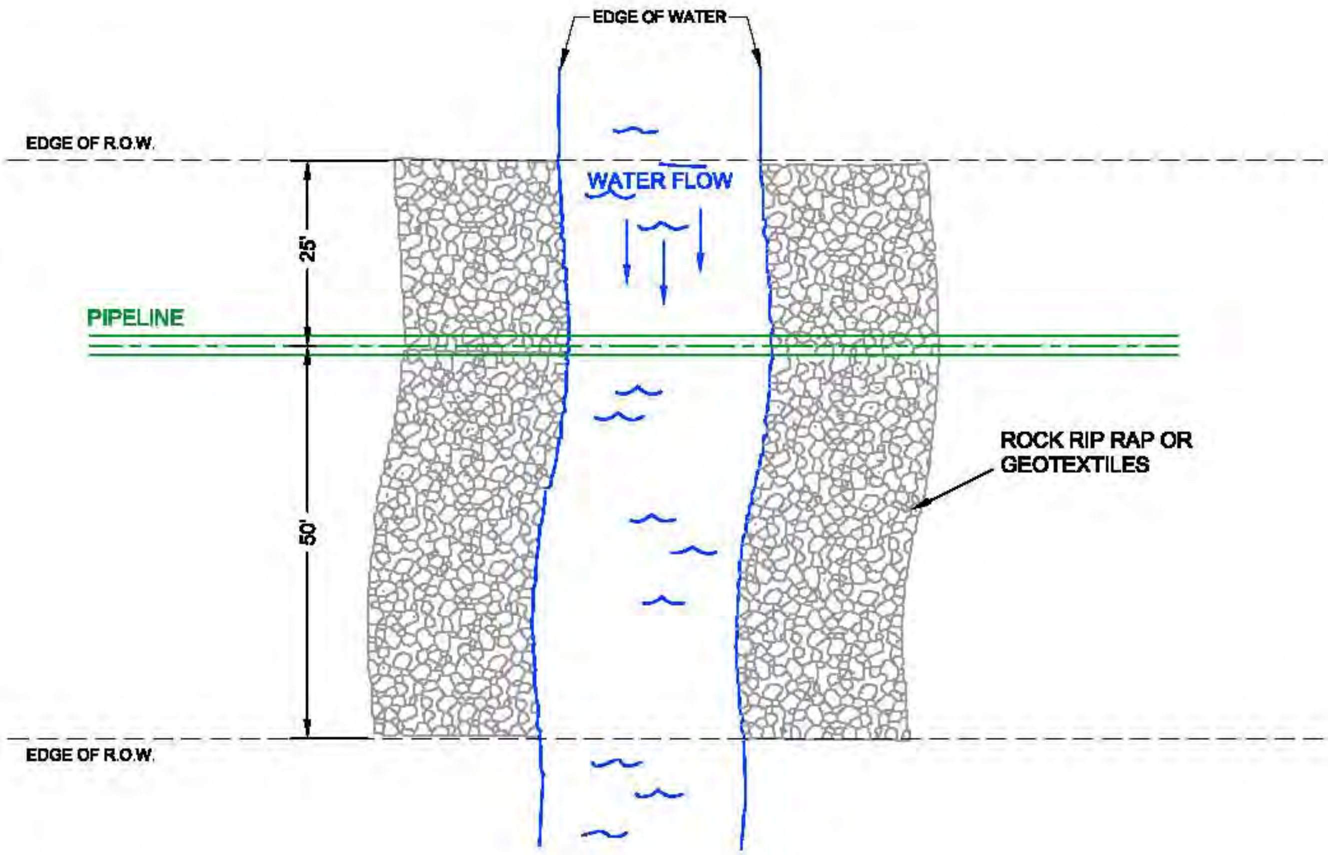
TYPICAL OPEN CUT MINOR FLOWING STREAM CROSSING DAM AND PUMP

THE ARCHITECT/ENGINEER ASSUMES RESPONSIBILITY FOR APPROPRIATE USE OF THIS STANDARD.

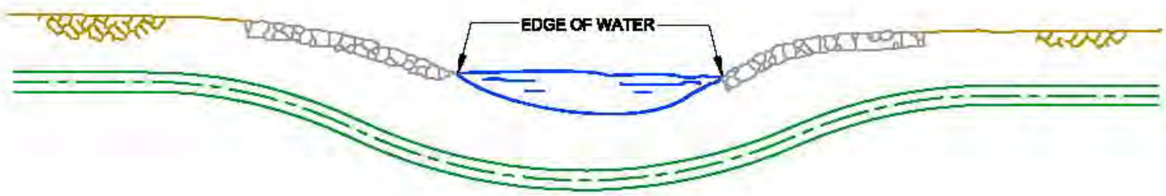
"Do Not Scale This Drawing"

Horizon Environmental Services, Inc.

040027A05M.dwg | JEA | 2/26/04



PLAN VIEW
N.T.S.



CROSS-SECTION
N.T.S.

NOTES:

1. GEOTEXTILES MUST BE SECURED.

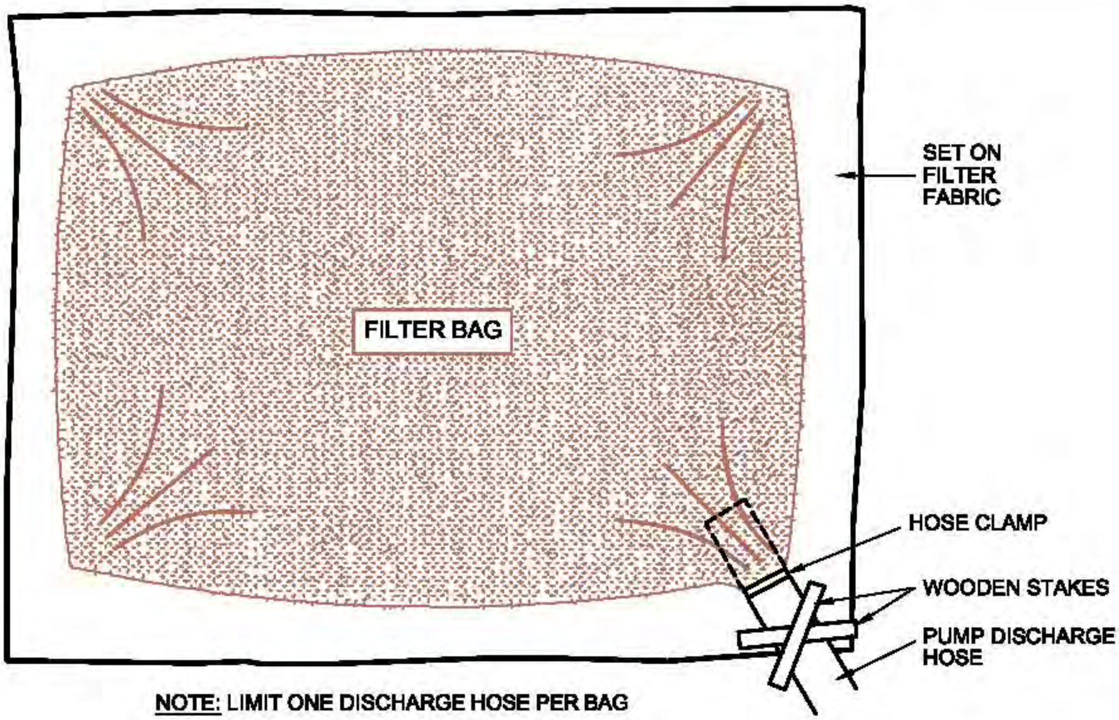
THE ARCHITECT/ENGINEER ASSUMES RESPONSIBILITY FOR APPROPRIATE USE OF THIS STANDARD.

POST CONSTRUCTION STREAM BANK STABILIZATION

"Do Not Scale This Drawing"

Horizon Environmental Services, Inc.

040027A06IM.dwg | JEA | 2/26/04



NOTE: LIMIT ONE DISCHARGE HOSE PER BAG

PLAN VIEW
N.T.S.

CROSS-SECTION
N.T.S.

CONSTRUCTION NOTES:

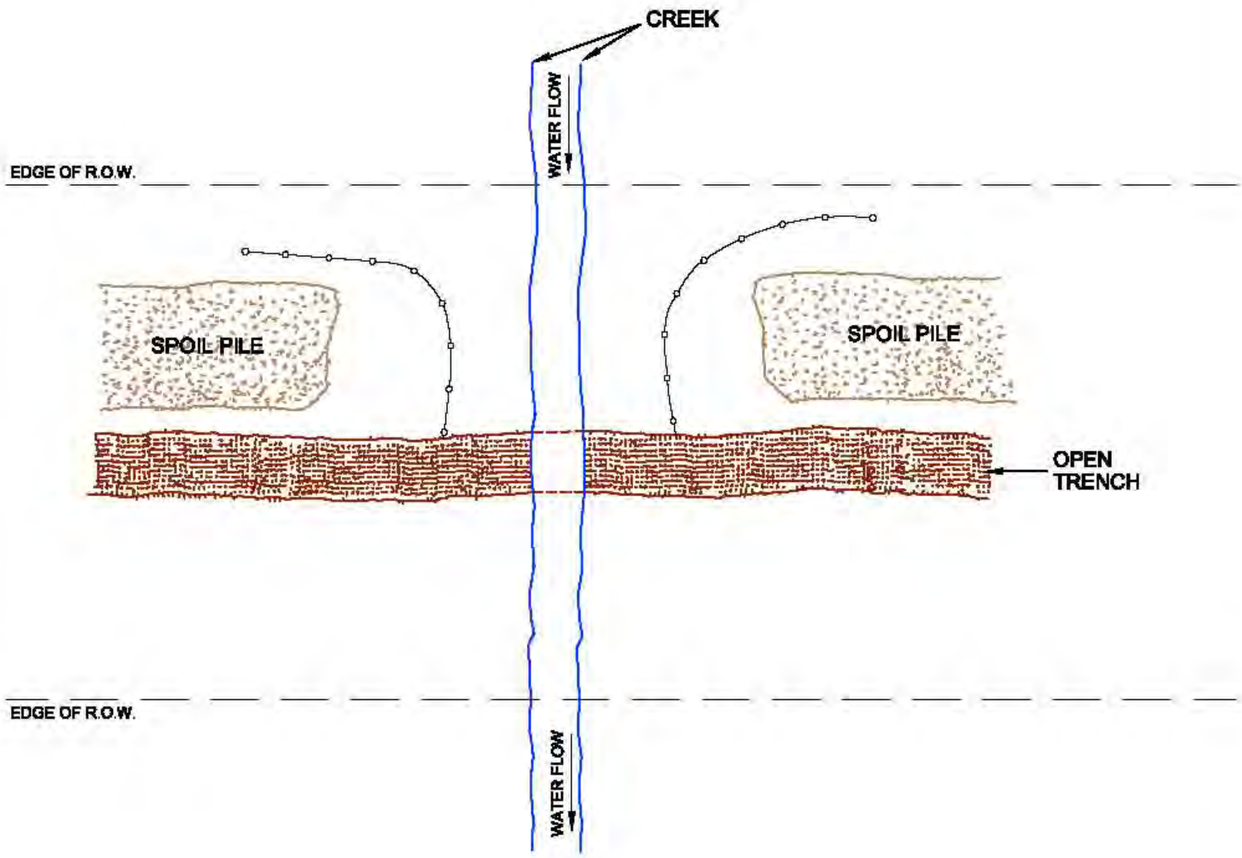
1. FILTER BAG SHOULD BE REPLACED WHEN SEDIMENT BUILD-UP OCCURS.

THE ARCHITECT/ENGINEER ASSUMES RESPONSIBILITY FOR APPROPRIATE USE OF THIS STANDARD.

FILTER BAG DETAIL

"Do Not Scale This Drawing"

Horizon
Environmental Services, Inc.



CONSTRUCTION NOTES:

1. EXCAVATE TRENCH.
2. TRENCH SPOIL SHOULD BE PLACED APPROXIMATELY 10' FROM THE TOP OF BANK.
3. RAPPS NEEDED BETWEEN SPOIL AND WATERBODY.
4. INSTALL FLUME PIPE TO CONVEY WATER FLOW, IF STREAM BEGINS TO FLOW DURING CONSTRUCTION.

THE ARCHITECT/ENGINEER ASSUMES RESPONSIBILITY FOR APPROPRIATE USE OF THIS STANDARD.

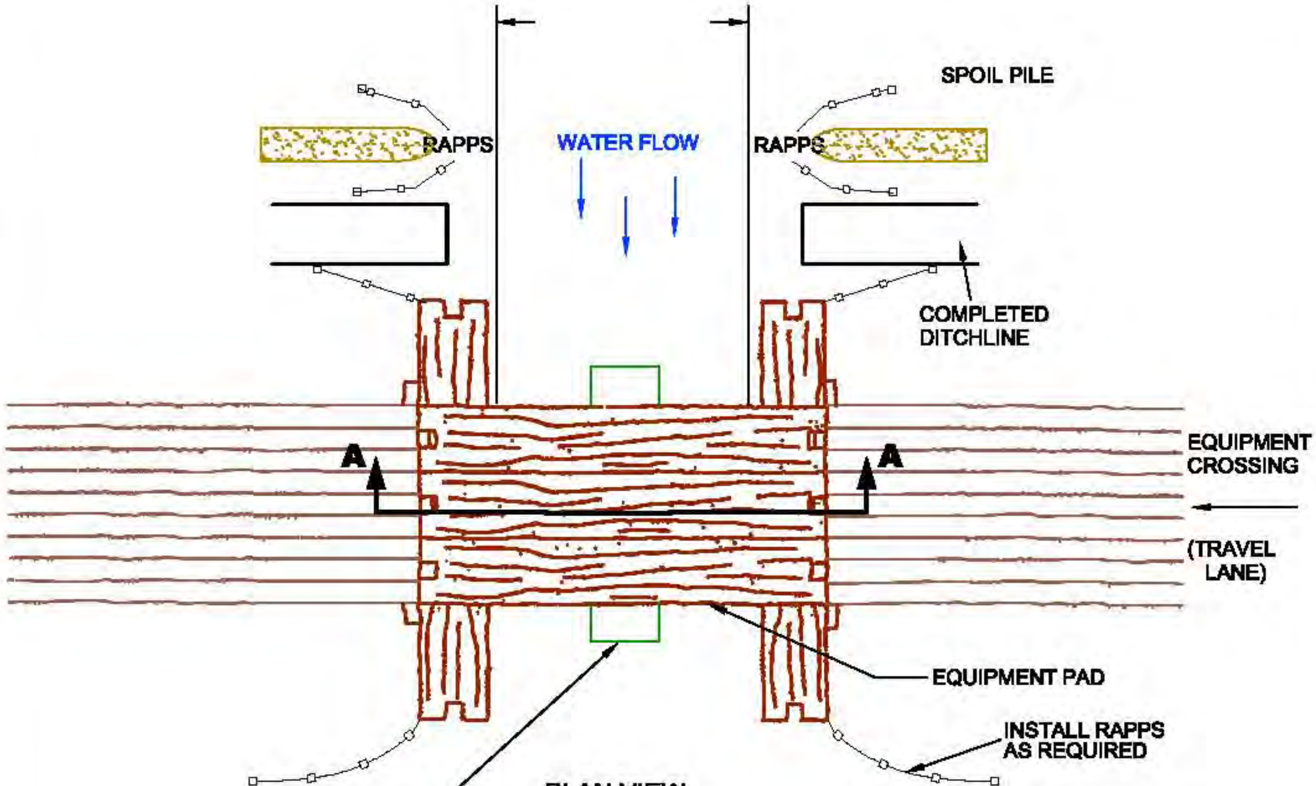
TYPICAL OPEN CUT DRY STREAM CROSSING

Horizon Environmental Services, Inc.

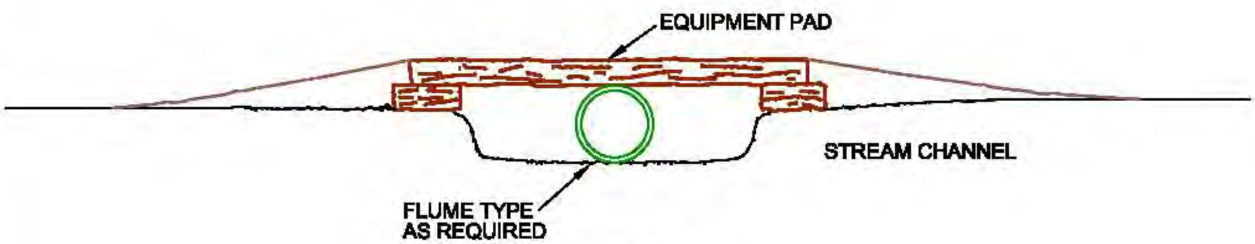
040027A07IM.dwg | JEA | 2/26/04

"Do Not Scale This Drawing"

040027A08IM.dwg | JEA | 2/26/04



PLAN VIEW
N.T.S.



SECTION A-A
N.T.S.

CONSTRUCTION NOTES:

1. UTILIZE CULVERT PIPE(S) IF ADDITIONAL SUPPORT IS NEEDED.
2. ADDITIONAL EQUIPMENT PADS CAN BE PUT SIDE BY SIDE IF EXTRA WIDTH IS NEEDED.
3. EQUIPMENT PAD TYPICALLY CONSTRUCTED OF HARDWOOD. SHOULD ACCOMMODATE THE LARGEST EQUIPMENT USED.

THE ARCHITECT/ENGINEER ASSUMES RESPONSIBILITY FOR APPROPRIATE USE OF THIS STANDARD.

TEMPORARY EQUIPMENT CROSSING OF FLOWING CREEK (BRIDGED)

"Do Not Scale This Drawing"

Horizon
Environmental Services, Inc.

APPENDIX C

EPA'S DEFINITION OF "WATERS OF THE US" FROM 40 C.F.R. 122.2

[Code of Federal Regulations]
[Title 40, Volume 19]
[Revised as of July 1, 2003]
From the U.S. Government Printing Office via GPO Access
[**CITE**: **40CFR122.2**]

[Page 134-141]

TITLE 40--PROTECTION OF ENVIRONMENT

CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY (CONTINUED)

PART 122--EPA ADMINISTERED PERMIT PROGRAMS: THE NATIONAL POLLUTANT DISCHARGE
ELIMINATION SYSTEM--Table of Contents

Subpart A--Definitions and General Program Requirements

Sec. 122.2 Definitions.

The following definitions apply to parts 122, 123, and 124. Terms not defined in this section have the meaning given by CWA. When a defined term appears in a definition, the defined term is sometimes placed in quotation marks as an aid to readers.

Waters of the United States or waters of the U.S. means:

(a) All waters which are currently used, were used in the past, or may be susceptible to use in interstate or foreign commerce, including all waters which are subject to the ebb and flow of the tide;

(b) All interstate waters, including interstate ``wetlands;''

(c) All other waters such as intrastate lakes, rivers, streams (including intermittent streams), mudflats, sandflats, ``wetlands,'' sloughs, prairie potholes, wet meadows, playa lakes, or natural ponds the use, degradation, or destruction of which would affect or could affect interstate or foreign commerce including any such waters:

(1) Which are or could be used by interstate or foreign travelers for recreational or other purposes;

(2) From which fish or shellfish are or could be taken and sold in interstate or foreign commerce; or

(3) Which are used or could be used for industrial purposes by industries in interstate commerce;

(d) All impoundments of waters otherwise defined as waters of the United States under this definition;

(e) Tributaries of waters identified in paragraphs (a) through (d) of this definition;

(f) The territorial sea; and

(g) ``Wetlands'' adjacent to waters (other than waters that are themselves wetlands) identified in paragraphs (a) through (f) of this definition.

Waste treatment systems, including treatment ponds or lagoons designed to meet the requirements of CWA (other than cooling ponds as defined in 40 CFR 423.11(m) which also meet the criteria of this definition) are not waters of the United States. This exclusion applies only to manmade bodies of water which neither were originally created in waters of the United States (such as disposal area in wetlands) nor resulted from the impoundment of waters of the United States. [See Note 1 of this section.] Waters of the United States do not include prior converted cropland. Notwithstanding the determination of an area's status as prior converted cropland by any other federal agency, for the purposes of the Clean Water Act, the final authority regarding

[[Page 141]]

Clean Water Act jurisdiction remains with EPA.

Wetlands means those areas that are inundated or saturated by surface or groundwater at a frequency and duration sufficient to support, and that under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions. Wetlands generally include swamps, marshes, bogs, and similar areas.

Whole effluent toxicity means the aggregate toxic effect of an effluent measured directly by a toxicity test.

Note: At 45 FR 48620, July 21, 1980, the Environmental Protection Agency suspended until further notice in Sec. 122.**2**, the last sentence, beginning ``This exclusion applies . . .'' in the definition of ``Waters of the United States.'' This revision continues that suspension.\1\

\1\ Editorial Note: The words ``This revision'' refer to the document published at 48 FR 14153, Apr. 1, 1983.

(Clean Water Act (33 U.S.C. 1251 et seq.), Safe Drinking Water Act (42 U.S.C. 300f et seq.), Clean Air Act (42 U.S.C. 7401 et seq.), Resource

----

Conservation and Recovery Act (42 U.S.C. 6901 et seq.))

[48 FR 14153, Apr. 1, 1983, as amended at 48 FR 39619, Sept. 1, 1983; 50 FR 6940, 6941, Feb. 19, 1985; 54 FR 254, Jan. 4, 1989; 54 FR 18781, May **2**, 1989; 54 FR 23895, June **2**, 1989; 58 FR 45039, Aug. 25, 1993; 58 FR 67980, Dec. 22, 1993; 64 FR 42462, Aug. 4, 1999; 65 FR 30905, May 15, 2000]

Appendix 3

ADVANCED RESOURCES INTERNATIONAL, INC.

MEMORANDUM

To: U.S. Department of Energy/Office of Fossil Energy
Date: December 7, 2004
From: Advanced Resources International, Inc.
Re: Estimated Economic Impacts of Proposed Storm Water Discharge Requirements on the Oil and Natural Gas Industry (Final)

SUMMARY

This memo summarizes the results and methodology employed to estimate the potential economic impacts of possible new storm water discharge requirements on the domestic oil and natural gas industry.

In this analysis, the economic impacts of the proposed requirements were assessed as they relate to three aspects of oil and gas operations:

- The increased costs that the industry must bear in order to comply with the proposed requirements, including consideration of the impacts on "construction" sites associated with oil and gas drilling, gas gathering, and natural gas and liquids transportation operations.
- The project delays that could result from the new requirements and the impact of these delays on the productivity of the nation's rig fleet, on the delay in revenues received from oil and gas production, and from other increased costs that could be attributable to project delays.
- The wells that would not be drilled because of permitting delays associated with the new requirements, the production lost from this foregone drilling, and the economic impacts associated with this lost production.

Critical Assumptions and Uncertainties

The economic impacts of the new storm water discharge requirements on the oil and natural gas industry will depend on a number of factors, including:

- Future levels of domestic drilling (production and injection wells), and the "construction" sites associated with these wells that are between 1 and 5 acres in size and thus could potentially be subject to the new requirements.
- Estimated number of "construction" projects of 1 to 5 acres in size that could fall under the proposed requirements that would be associated with natural gas gathering and gas and liquids transportation operations.
- The portion of these sites that would in fact be subject to the new requirements:

JAF024243.DOC

4501 Fairfax Drive, Suite 910, Arlington, VA 22203 Phone: (703) 528-8420 Fax: (703) 528-0439

- In some states, existing regulations may already meet or exceed the proposed federal requirements; thus sites in these states would not incur incremental costs to comply.
- Some sites may be eligible for waivers based on prevailing climatic and environmental conditions related to potential erosion and pollutant loading.

- The portion of sites that could be required to conduct endangered species and/or archeological or historic reviews (as required under the Endangered Species Act (ESA) and the National Historical Preservation Act (NHPA)).
- Where potential concerns are identified, the portion of sites undergoing endangered species or historic reviews that would require consultation with appropriate oversight agencies to determine how potential impacts could be mitigated.
- The costs associated with complying with these requirements, for impacted sites.
- The "unscheduled" delays that would result because of the processes imposed by complying with the new requirements, and the estimated economic implications associated with these delays.
- The portion of wells that would not be drilled because of delays and/or extra costs imposed by the new requirements that would make development unfeasible or undesirable, and the lost production and resulting economic impacts associated with wells not drilled.

Scenarios Considered

Two scenarios were defined in this analysis to represent the potential range of impacts that could result from these new requirements:

- The *Base Case* is based on citable, mostly conservative assumptions, based on published data, on estimates or assumptions derived from EPA's own economic analyses performed in 2002, and on the current requirements of the Construction General Permit (CGP) regulating storm water discharges. This scenario essentially assumes routine, systematic permitting processes, adequately staffed regulatory agencies to oversee the process, waivers and exclusions are available, and minimal use of the system to cause project delays.
- The *Higher Impact* scenario assumes that permitting processes are cumbersome and lengthy, regulatory agencies overseeing the process are inadequately staffed, some additional requirements currently under consideration get implemented in a modified CGP, waivers and exclusions are difficult to obtain, and environmental groups and discontented landowners use the permitting and project review process to delay and/or stop drilling on some leases.

Summary of Potential Impacts

Under Base Case conditions, the imposition of the proposed storm water discharge requirements could result in economic impacts to the domestic oil and gas industry amounting to the following:

- Annualized incremental costs over the 2005-2010 time period of over $380 million per year (undiscounted). Of this, over $110 million per year would be associated with increased compliance expenses, and $270 million per year would be associated with delayed production, other costs associated with project delays, and underutilized domestic drilling capacity.
- Assuming a discount rate of 5% per year, the annualized economic impacts over this same time period would amount to nearly $340 million per year, with $100 million per year associated with increased compliance expenses, and $240 million per year associated with project delays.

In addition, the proposed requirements under Base Case conditions could result in an average impact of nearly 100,000 barrels per day reduction in domestic oil production and 350 billion cubic feet (Bcf) per year loss in domestic natural gas production over the 2005 to 2010 time period. Over this time period, this could result in:

- $675 million (discounted) per year increase in the nation's expenditures for oil imports ($800 million undiscounted).
- $60 million per year less in royalties collected by the federal government ($70 million undiscounted).
- $155 million per year less paid to private landowners in oil and gas royalties ($180 million undiscounted).
- $75 million per year in lost tax revenues accruing to state government from severance taxes ($90 million undiscounted).

(*The impact due to lost sales tax and income tax revenue to federal, state, and local governments was not considered in this analysis*.)

Finally, this could result in natural gas consumers paying from $370 million to $2.3 billion more for natural gas per year due to higher natural gas prices over the 2005-2010 time period ($440 million to $2.7 billion undiscounted). The range in these estimates represents diversity of perspectives on the relative impact of decreased supplies on future natural gas prices.

These results are summarized in Table ES-1.

Cumulatively, as much as 1.3 billion barrels of oil and 15 Tcf of natural gas supplies would not be produced by 2025 under Base Case conditions.

In contrast, under the Higher Impact scenario, the imposition of the proposed storm water discharge requirements could result in the following annualized incremental costs over the 2005-2010 time period:

- On an undiscounted basis, over $2.9 billion per year. Of this, over $0.3 billion per year would be associated with increased compliance expenses, with nearly $2.6 billion per year associated with project delays.
- On a discounted basis, the economic impacts over this same time period would average $2.4 billion per year, with $270 million per year associated with increased compliance expenses, and nearly $2.2 billion per year associated with delays.

In addition, the proposed requirements under the Higher Impact scenario could result in an average impact of 280,000 barrels per day reduction in domestic oil production and over one trillion cubic feet (Tcf) per year loss in domestic natural gas production over the 2005 to 2010 time period, resulting in the following:

- $2.0 billion (discounted) per year increase in the nation's expenditures for oil imports ($2.4 billion undiscounted).
- $180 million per year less in royalties collected by the federal government ($210 million undiscounted).
- $465 million per year less paid to private landowners in oil and gas royalties ($545 million undiscounted).
- $225 million per year in lost tax revenues accruing to state government from severance taxes alone ($265 million undiscounted).

This could result in natural gas consumers paying from $1.1 to $6.5 billion more for natural gas per year due to higher natural gas prices ($1.3 to $7.9 billion undiscounted).

Cumulatively, as much as 3.9 billion barrels of oil and 45 Tcf of natural gas supplies could be lost by 2025 under the Higher Impact scenario.

Substantial uncertainty is associated with many of the assumptions used in this analysis. Moreover, since EPA has yet to publish its proposed requirements for Phase II as applied the oil and gas sector (if it is determined that this sector is not exempt), certain assumptions about compliance requirements may turn out to be different than what EPA currently requires under the CGP. For the most part, the characterization of new compliance requirements in this analysis is based on requirements for sites that are currently subject to storm water discharge requirements under the CGP.

The uncertainties characterizing the range of potential economic impacts presented in this assessment primarily relate to the permitting delays that would result under the new requirements. These pertain to the anticipated processes required for endangered species and historic reviews, and the time it might take to process permit applications, make determinations, and grant approvals. If these processes proceed efficiently and according to schedule, anticipated economic impacts (although still considerable) can be minimized. On the other hand, if these processes are cumbersome, contentious, and prone to delays, the economic impacts can be quite large, with substantial impacts on domestic energy supplies, our nation's balance of trade and dependence on foreign energy supplies, and the price Americans pay for the energy they consume.

Table ES-1

Estimated Economic Impacts of Phase II Stormwater Discharge Requirements on the Domestic Oil and Natural Gas Industry

	Estimated Annualized Impacts (2005 - 2010)			
	Base Case		Higher Impact Scenario	
	Discounted	Undiscounted	Discounted	Undiscounted
Costs of Compliance (MM $/yr)	$99	$112	$268	$319
Costs of Delays (MM$/yr)	$239	$270	$2,157	$2,564
Total	**$338**	**$382**	**$2,425**	**$2,883**
Crude Oil Prod. (MMB/day)	0.094		0.282	
Natural Gas Prod. (Bcf/year)	349		1,048	
Increased Imports Exp. (MM $/yr)	$676	$799	$2,029	$2,398
Lost Federal Royalties (MM $/yr)	$60	$71	$181	$212
Lost Private Royalties (MM $/yr)	$155	$182	$464	$545
Lost State Sev. Taxes (MM $/yr)	$75	$88	$226	$265
Inc. Exp. for Natural Gas (MM $/yr)				
EIA Basis	$367	$443	$1,063	$1,281
NPC Basis	$2,259	$2,725	$6,538	$7,883

BACKGROUND

Amendments to the Clean Water Act (CWA) require that the Environmental Protection Agency (EPA) establish tiered regulations for storm water discharges under its National Pollutant Discharge Elimination System (NPDES). In the early 1990s, EPA adopted regulations for Phase I, to include industrial runoff, runoff from municipal storm sewers serving 100,000 or more, and construction activities greater than 5 acres. EPA developed several model general permits to cover these categories. Because most oil and gas sites do not disturb more than 5 acres, few oil and gas sites were covered under these permits.

In 1999, EPA published proposed regulations for Phase II, as stipulated in the CWA, to cover smaller separate municipal storm sewers and construction sites that disturb from 1 to 5 acres. Most onshore oil and gas well sites disturb from 1-5 acres (including lease road and well pad) and therefore, based on EPA's determination, should be subject to the Phase II requirements.

On March 10, 2003, EPA issued a decision (Federal Register, Vol. 68, No. 46, pp. 11325-11330) where the determination of the applicability of the storm water discharge permit requirements on oil and gas operations was deferred to March 10, 2005, because EPA concluded that it had not adequately performed economic impact analyses related to this industry sector.

The objective of this effort is to build upon the earlier assessment and develop a more accurate, up-to-date, citable and industry-reviewed quantitative assessment of the potential economic impacts of the Phase II storm water discharge requirements, if implemented, on the domestic oil and gas industry.

OVERVIEW OF APPROACH

Thousands of onshore oil and gas wells may be required to comply with the requirements of the Construction General Permit (GCP) for storm water discharges if EPA determines that the construction activities at oil and gas drilling sites are subject to Phase II requirements. In addition, activities associated with gas gathering, processing, and liquids and gas transportation operations that impact between 1 and 5 acres could also be subject to the proposed Phase II requirements. Complying with the CGP could delay the process of preparing sites by one to several months, could cause operators additional compliance expenses, and could result in some operators deciding to forego some drilling because of the constraints imposed by the permitting process.

Industry maintains that the environmental impact from isolated small oil and gas sites in mostly rural areas is likely to be minimal, and that incremental compliance requirements are not justified based on these impacts. They claim that this is especially true given the fact that the "construction" prior to drilling operations (since drilling operations themselves are exempt under Section 403(1)(2) of the CWA) generally only lasts from 3 to 7 days at most locations. However, EPA's current position is that the exemption does not apply to clearing, grading, and excavating activities, primarily related to site clearing and road building, prior to the drilling rig arriving on site.

Two scenarios were defined in this analysis to represent the potential range of impacts that could result from these new requirements on oil and gas operations:

- The *Base Case* is based on citable, mostly conservative, assumptions, based on published data, on estimates or assumptions derived from EPA's own economic analyses performed in 2002, and on the current requirements of the CGP. This scenario essentially assumes routine, systematic permitting processes, adequately staffed regulatory agencies to oversee the process, waivers and exclusions are available, and minimal use of the system to cause project delays.
- The *Higher Impact* scenario assumes that permitting processes are cumbersome and lengthy, regulatory agencies overseeing the process are inadequately staffed, some additional requirements currently under consideration get implemented in a modified CGP, waivers and exclusions are difficult to obtain, and environmental groups and discontented landowners use the permitting and project review process to delay and/or stop drilling on some leases. *It is important to note, however, that the impacts estimated for this scenario should not necessarily be considered to be those associated with a "worst case" scenario*. As illustrated in this memo and in Appendix A, in many cases, assumptions that could lead to even greater assessed impacts could have been used.

The approach used for developing the estimated economic impacts on the oil and gas industry resulting from the Phase II requirements is described in the following paragraphs. Some of the justification for this approach and the assumptions underlying it, along with other potential assumptions considered, is provided in Appendix A.

Estimate of the number of production well drilling sites between 1 and 5 acres

The estimated number of oil and gas well sites potentially subject to the Phase II requirements corresponds to forecasts of domestic oil and gas drilling. In this analysis, future well drilling levels are assumed to be consistent to drilling forecasts of the Energy Information Administration (EIA) in its Reference Case of the 2004 Annual Energy Outlook (AEO) (Reference 9). For gas well drilling, AEO 2004 forecasts are comparable to those assumed by the National Petroleum Council (NPC) in their most recent natural gas study (Reference 14). The NPC did not report their forecasts for oil wells.

All sites associated with these forecast wells drilled were assumed to fall within the 1-to-5-acre size category.

<u>Estimate of the number of injection well drilling sites between 1 and 5 acres</u>

Estimates of the number of injection wells sites in the U.S. are based on current ratios of operating injection wells to oil production wells in Texas and California. This results in approximately 1 injection well for every 4 oil production wells. This includes all enhanced recovery (both water and gas injection) and brine disposal wells, but not injection wells used for gas or hydrocarbon storage. Rough estimates nationally, using EPA data for all Class II injection wells (http://www.epa.gov/safewater/uic/classii.html), which includes storage wells, and *World Oil* magazine estimates (Reference 15) of producing oil wells in the U.S., would make this number more like 1 injector for every 3 oil production wells, implying the 1 in 4 estimate may be somewhat conservative..

All injection well sites were assumed to fall within the 1-to-5-acre size category.

<u>Estimate of the number of gas gathering/processing sites between 1 and 5 acres</u>

For this project, the Gas Processors Association (GPA) submitted an estimate of the number of sites associated with gas gathering and/or processing operations that are between 1 and 5 acres in size and thus could fall within the purview of the Phase II requirements. GPA is the trade organization (with approximately 100 members) of companies engaged in the processing of natural gas, or in the manufacture, transportation, or further processing of liquid products from natural gas. GPA's membership accounts for approximately 92% of all natural gas liquids produced by the midstream energy sector in the United States.

GPA estimated that there are currently 2,370 construction projects in the natural gas midstream sector that are between 1 and 5 acres in area. These projects primarily pertain to sties associated with the gathering and transportation of natural gas and natural gas liquids from the wellhead to the initial processing facility. A 50-foot right-of-way width was assumed for determining the total footprint area of an average or representative project (Reference 13)

For purposes of this analysis, this number of projects is assumed to be applicable annually.

<u>Estimate of the number of gas and liquids transportation sites between 1 and 5 acres</u>

The number of current projects associated with gas and liquid transportation operations that would fall under the Phase II requirements in the 1-5 acre size range was estimated based on estimates made by a major U.S. gas transportation company for its own operations. They developed their estimate based on the number of currently permitted company projects (under Phase I requirements), compared to the estimated number of projects they have in the 1 to 5 acre size range. This included both identified projects and an estimate of the number of projects that are currently "unidentified," but that were determined to be likely based on the number of identified projects. This estimate of sites associated with natural gas pipeline activities included the installation of small segments of new pipelines, surface facility additions or expansions, and repair/replacement activities in which the original intent was to repair or replace a segment of pipeline. The estimate does not include situations where the original intent complied with EPA's definition of maintenance, but at some point in the work it is determined that it is necessary to repair or replace a segment of pipeline.

Based on this company's estimate, and the miles of gas pipeline within this company to which their estimate applies, it was determined that, nation-wide, there would be approximately one project falling under the Phase II requirements per 278 miles of pipeline. Based on the number of miles of natural gas and liquid pipelines in the U.S., this would amount to about 1,500 sites, assumed to be applied annually.

Portion of these 1-5-acre sites subject to new requirements

Taking into consideration all of the potential sites described above results in an average of 29,600 sites annually. However, only a portion of these sites will be in states with requirements currently less stringent than the proposed Phase II requirements. In the Development Document for the Phase II rulemaking, EPA estimated that 41% of developed acreage is in states with existing state programs, and would not have to modify their permits to meet the new requirements (Reference 2). Based on this, under Base Case conditions, this analysis assumed that 60% of the sites would be subject to the proposed requirements.

Industry is concerned that a large portion of oil and gas well sites would be subject to the new requirements. For example, EPA is the jurisdictional agency for gas pipeline construction activities in three of the major oil and gas producing states -- New Mexico, Oklahoma, and Texas. Of the nine states which manage the storm water permit program, eight have adopted EPA's two-year postponement: Arkansas, Colorado, Illinois, Iowa, Kansas, Louisiana, Nebraska, and Wyoming. Most of these are major oil and gas producing states. The one remaining state, Missouri, has developed a state program. Since all of these states have followed EPA's lead on the postponement for the oil and gas industry, it is reasonable to assume that they will follow EPA's lead on implementation of the Phase II permit requirements to the oil and gas industry. Given this scenario, the Higher Impact scenario assumes that 90% of the sites would be subject to the new requirements.

Portion of these 1-5-acre sites potentially subject to waivers

A portion of sites could be subject to one of several waivers that may be obtainable based on certain criteria. One pertains to a Rainfall Erosivity Factor (REF), which is used to predict soil loss from construction sites. Another is based on a Total Maximum Daily Load (TMDL) calculation, which pertains to the maximum amount of pollutant that a water body can receive and still meet water quality standards. In this analysis, based on estimates developed by EPA (Reference 5), it was assumed in the Base Case that 15% of sites will receive either an REF or TMDL waiver (Reference 5), beginning in 2005.

In contrast, some claim that few, if any, sites would likely be subject to such waivers. Permitting authorities have the option to not allow waivers. In many cases, the times of year during which the waivers could be obtained are minimal and sporadic. Moreover, a waiver may not necessarily waive <u>all</u> permit requirements, but only allows EPA to waive "otherwise applicable requirements in a general permit." Finally, should operators try to schedule drilling to coincide with time windows during the year when waivers could be obtainable, it could further complicate the logistics of leasing, permitting, and scheduling drilling rigs (see discussion below).

Therefore, under the Higher Impact scenario, it is assumed that no such waivers could be obtainable.

Estimate of costs to be incurred by wells subject to the new requirements

Taking into consideration those in states where oil and gas sites would be subject to the new requirements, and those sites potentially subject to the TMDL or the REF waivers, an estimated 15,100 sites per year, on average, could be impacted under the Base Case. Under the Higher Impact scenario, 24,700 sites would be subject to the new requirements per year, on average. Of these, 83% correspond to well drilling sites.

In this analysis, the costs assumed to be associated with compliance requirements for these sites are consistent with estimates by industry and/or EPA (in the case of EPA, they are generally associated with small construction sites; EPA did not originally look at oil and gas drilling sites specifically). *The compliance costs considered are only those associated with filing the necessary documents under the CGP*. They do not include any incremental operational costs that may be required to ensure compliance (such as implementing Best Management Practices (BMPs)) or to mitigate any possible impacts to endangered species or historic sites.

EPA believes that only a portion of the sites falling under the Phase II requirements would need to conduct endangered species reviews, and an even smaller portion would require consultation with appropriate regulatory or oversight agencies to determine how potential impacts could be mitigated.

In contrast, industry believes that most (if not all) sites could be subject to an ESA review. Moreover, they believe that the costs and efforts associated with conducting these reviews are likely to be more complicated and lengthy than EPA assumed, especially given industry's concern that current personnel levels in responsible agencies are not sufficient to handle the major increase in the number of reviews that these new requirements would impose on them. Finally, some in industry feel that these requirements will be used by environmental groups and a few landowners to indefinitely stall and/or stop drilling operations at certain locations.

In the draft Phase II requirements, provisions were proposed to require storm water discharge permit applicants to conduct reviews to ensure the protection of historic places under the National Historical Preservation Act (NHPA). However, the final CGP does not include these requirements. However, EPA is continuing discussions with the Advisory Council on Historic Preservation on potential future requirements, and the current CGP contains a "re-opener clause" which can allow EPA, at a later date, to modify the GCP based on the results of those discussions.

Given these two possibilities, the estimated proportion of sites subject to the new requirements, for the two scenarios considered in this assessment, were estimated based on the following:

- Based on EPA's economic impact assessment (Reference 1), both the Base Case and Higher Impact Scenario assume 40% of sites would have endangered species in proximity and would require a review. Of these, 3% of sites would require a consultation in the Base Case, and, in the Higher Impact scenario, 20% of sites would either require consultation or landowners and/or parties opposing drilling would initiate a consultation.
- A lower proportion of sites are likely to be subjected to a historic review, compared to the endangered species review. For this analysis, no sites are assumed to be subject to a historic review in the Base Case, while, in the Higher Impact scenario, 20% of the sites are assumed to require a historic review, and of these, 10% are assumed to require consultation.

A significant and growing proportion of the onshore oil and gas wells drilled in the U.S. are on lands managed by the federal government. As part of the process of issuing leases on these lands, an Environmental Impact Statement (EIS) must be developed, which would include an assessment of the impact of oil and gas leasing and development on endangered species and historical places. In general, this is conducted for the entire area subject to leasing, and not at the level of individual leases or wells. Moreover, public participation is a critical aspect of the process for issuing permits on federal leases. In this regard, there may be some overlap between the assumptions developed by EPA on the portion of sites requiring endangered species reviews and those sites corresponding to activities on federal lands. Unfortunately, sorting out this overlap, if it exists, would be difficult. Consequently, for purposes of this economic impact assessment, EPA's assumptions are used.

The estimated costs associated with compliance, for the two scenarios considered in this assessment, were assumed as follows:

- Incremental compliance costs would be incurred by activities associated with developing the information and meeting the requirements for filing a Notice of Intent (NOI), which would be required for each site subject to the new requirements. This would include activities to ensure that a Storm Water Pollution Prevention Plan (SWPPP) is completed, BMPs are installed according to SWPPP, periodic inspections are conducted, and the site is stabilized prior to filing a Notice of Termination (NOT). This analysis assumes that this will require approximately 72 person-hours, amounting to $6,000 per well. This applies to both the Base Case and the Higher Impact scenario.
- In the Base Case, 36 person-hours are assumed to be required for the endangered species review, amounting to $3,000 per site. For the consultation, 160 person-hours, amounting to $13,333 per site, are assumed to be required under Base Case conditions. Under the Higher Impact scenario, it is assumed that the consultation process takes twice as long, amounting to 320 person-hours and $26,667.
- 48 person-hours are assumed to be required to conduct the historic review, amounting to $4,000 per site. For consultation, 320 hours, amounting to $26,667 per site, are assumed. These are assumed to be applicable in the Higher Impact scenario only.

Estimate of economic impacts associated with delayed production

The new proposed requirements are likely to impose additional delays for drilling projects, because of the burdens potentially posed by new endangered species and historic reviews and/or consultations. A routine, informal endangered species consultation may take several months or more, assuming that approval is forthcoming. A surface owner or environmental group that opposes drilling can use this process to impose unending delays, even if the endangered species allegations are unsubstantiated.

This analysis assumes some "unscheduled" delays are likely to result from this process. The nature and extent of these delays are hard to predict, and may decrease with time as experience is gained and/or staffing levels are adjusted in the appropriate oversight agencies. For this analysis, the characterization of these effects is based on industry and EPA characterization of the activities involved, current review and consultation processes for larger sites in representative states, and the assumption that delays would be inevitable given the substantially increased review burden imposed on regulatory agencies once the Phase II requirements are in place.

Estimated length of time associated with project delays. The following delays associated with the endangered species and archeological review and consultation process were assumed in this analysis:

- An “unscheduled” delay of one week for the endangered species review, and 3 weeks for the consultation, was assumed for the Base Case.
- Under the Higher Impact scenario, delays of 3 weeks for the endangered species review and one month for the historic review, and 9 weeks for the endangered species consultation and 3 months for the historic consultation, were assumed.

It is important to note that these estimated delays could be considerably greater than assumed here. In a brief filed by the National Resources Defense Council (NRDC) with the 7th Circuit Court on July 28, 2004, they argue, among other things, that the self-implementing ESA provisions of the CGP should not be allowed under the ESA, and that EPA should be required to review each operator's ESA and, in consultation with the U.S. Fish and Wildlife Service (FWS) and the National Marine Fisheries Service (NMFS), determine that no adverse effects are likely to any endangered species in each project area. In this assessment, the delays assumed only apply to those traditionally experienced for projects currently seeking storm water discharge permits, which do not traditionally involve EPA review. The implications associated with the NRDC recommendations that EPA review each permit were not considered, but if NRDC were to prevail, the likely delays in the endangered species reviews would be longer that assumed in this assessment, increasing the potential for lease forfeiture and lost reserves.

The NRDC also argues in their brief that the general permit does not comply with the CWA because EPA does not individually review the NOIs and SWPPPs prepared under the general permit process and the permit process does not provide for public notice, comment, and opportunity for public hearing on NOI's and SWPPPs. NRDC successfully made the public participation argument to the 9th Circuit with respect to NOIs submitted for storm water discharges from Municipal Separate Storm Sewer Systems. However, in this assessment, no delays associated with the process of submitting NOIs and SWPPPs are assumed.

Impact of project delays on drilling fleet efficiency and/or drilling costs. The delays imposed by the new endangered species and historic reviews and/or consultations would likely result in an increase in the time rigs will be idle waiting for permit approval. In some cases, operators would lose access to the scheduled rig, because of other scheduled obligations for the rig, and the well would not be drilled. For purposes of this analysis, one impact is represented by an increase in drilling expenses (rig operators would still need to recover their costs even if the rigs are idle), associated with the time rigs would be idle waiting for approvals. This was based on an average well cost of $711,000 per well (average for 2002, according to Reference 11), and an average rig utilization rate of 70% (average for the 1988 to 2001 time period, according to Reference 12). *It is important to note that the impact associated with these increased rig costs on the economic viability of drilling prospects was not explicitly considered, except to the extent that it's included in the assessment of energy supply and economic impacts due to lost production discussed below.*

<u>Lost value associated with project delays</u>. Because of delays associated with the review and consultation process, income from production from wells subject to these delays will come later than would otherwise be the case. Consequently, the ultimate value of this production, on the basis of discounted cash flow, will be less. The impact on the value of production was estimated by the following approach:

- The amount of production associated with each well impacted was estimated by using EIA forecasts of reserve additions, production, and well drilling (Reference 9) to estimate average production per well drilled.
- The value associated with the delayed production for the impacted wells was estimated by multiplying the estimated production per well, times the number of days associated with the "unscheduled" delays, times the price of that production, times the daily discount rate applied to the delayed production.
- The average daily discount rate assumed was based on the average annual return on investment for the domestic exploration and production (E&P) industry for 2001 and 2002, which was 9.7% (Reference 10).

<u>Increased operator royalty payments due to project delays</u>. Many mineral lease agreements have development commitments that require that drilling occur within a specified period of performance, with financial penalties (often in the form of increased royalty payments) for failure to perform. This analysis estimates the impacts of project delays on operator royalty obligations, assuming that 5% of the impacted wells would incur higher royalty obligations under Base Case conditions, and that a 2.5% increase in royalty rate would have to be paid because of the delay for the affected wells (Reference 3). The Higher Impact scenario assumes twice as many wells would incur the higher royalty obligations.

<u>Estimate of energy supply and economic impacts associated with lost production</u>

Ownership of mineral interests has become increasingly fractured, with numerous undivided owners. Thus, the acquisition of drilling rights can become very expensive, time consuming, and a major risk concerning the development of a prospect. The process for obtaining drilling rights can take several years. Moreover, the primary terms of these leases vary; while most terms are around three years, many are one year or less. By the time an operator obtains the right to drill; only a few weeks or days may remain within many of the leases in which to drill. Many prospects can be dropped, and reserves and potential production associated with them lost, due to problems and difficulties associated with fulfilling all of these multiple lease obligations.

Wells not drilled due to proposed Phase II requirements. One independent operator reported that his last 14 oil and gas exploration and development prospects averaged over 100 negotiated leases from separate mineral interest owners for each prospect. Several of his larger prospects required over 300 separately negotiated leases. Of these 14 prospects, this operator believes that from four to six (28% - 42%) would most likely not have been pursued had the new storm water discharge requirements been in place, due to the difficulties the process would cause in the logistics associated with acquiring leases, obtaining permit approvals, scheduling rigs, and meeting lease commitments.

In addition, because of title, surface issues, and ongoing geology, engineering and environmental studies, the initial drill site location is often not established until the majority of the leases have been negotiated. A permit application would not be submitted until the drill site has been established. Moreover, often the location of subsequent wells to be drilled is dependent on the reservoir geology that is determined from prior drilling efforts. When more than one well is drilled, time is of the essence to keep drilling wells. If there is any delay, the operator may lose access to his rig.

In this analysis, under the Base Case, 5% of the wells otherwise forecast in the 2004 EIA AEO Reference Case are assumed not to be drilled, and the leases forfeited, with the resulting production and economic impacts. Under the Higher Impact scenario, 15% of the wells otherwise forecast in the 2004 EIA AEO Reference Case are assumed not to be drilled.

Lost production from wells not drilled. The estimated production associated with these wells not drilled was based on the AEO 2004 Reference Case results for well drilling, average reserve additions associated with these wells, and the average ratio of production-to-reserves over the 2005 to 2025 forecast time period.

Forfeited bonus and lease rental payments due to project delays. Similarly, many lease agreements have performance specifications that require lease development and drilling occur within a certain period of time or the lease is forfeited. In these cases, lease bonus payments and rentals costs incurred would be wasted. For this, impacts are estimated assuming that the wells affected would lose their leases and not be drilled, having paid bonus and rental payments associated with the forfeited leases of $125/acre, with an average lease size of 320 acres/well (Reference 3).

Lost transfer payments from wells not drilled. Estimates of the lost federal royalties, private royalties, and severance taxes associated with the oil and gas not produced were based on the forecast lost production; EIA forecast oil and gas prices, an average 12.5% royalty rate, and an average 5% severance tax rate, and an estimate, based on previous analyses, of the amount of forecast production coming from federal lands. In this assessment, 28% of total oil and gas production was assumed to come from federal leases, based on previous DOE analyses (Reference 22).

The impact due to lost sales tax and income tax revenue to federal, state, and local government was not considered in this analysis.

Higher import payments due to lost domestic production. In the case of crude oil, it was assumed that every barrel of domestic production lost would need to be replaced by a barrel of imported oil. Estimates were made of the amount spent on purchasing imported oil to replace the domestic production foregone by multiplying the estimated increase in imports by the forecast world oil prices.

Higher consumer expenditures for natural gas. In addition, based on a number of previous runs performed by EIA's National Energy Modeling System (NEMS), a rule of thumb was developed to establish the impact of lost natural gas production on future natural gas prices. Based on a review of these previous runs (References 9 and 16), it was determined that natural gas prices increase by $0.13 for every Tcf loss in natural gas production. A similar analysis was conducted of various supply-related sensitivity cases in a recent NPC natural gas study (Reference 14). This analysis showed the impact to be over six times as large, with natural gas prices increasing by $0.82, on average, for every Tcf loss in natural gas production.

In this assessment, results were developed using both the EIA and NPC characterizations. In each case, the assumed change was applied to the decrease in production in 2025, and the increase in price due to lost production was assumed to accumulate linearly over the 2005 to 2025 time period.

The estimated increase in expenditures associated with these increased gas prices were estimated by this change in price multiplied by EIA forecasts of future natural gas consumption at the higher prices.

Estimate of benefits in present value (discounted) dollars

In this analysis, economic impacts were estimated year-by-year through 2025. This timeframe is consistent with the forecast horizon of the AEO 2004, which presently extends to 2025. Because these impacts were calculated in the form of an annual time series, the time series of impacts are estimated in two ways:

- In terms of average annualized and cumulative impacts in present day dollars (2002 dollars).

- In terms of average annualized and cumulative impacts in present value terms, or discounted dollars, using an assumed discount rate of 5 percent.

The choice of the discount rate is one of the most controversial and important topics within cost-benefit analysis. The Office of Management and Budget (OMB) recommends a 7 percent discount rate for social benefit-cost analysis (References 17 and 18). In an EPA report of guidelines for its economic analyses (Reference 19), a 3 percent discount rate is recommended. However, EPA's recent financial impact analysis of the Clear Skies Act used a 5.3 percent discount rate (Reference 20) and their benefit analysis of the Clear Skies Act forecasts benefits using both a 3 percent and 7 percent rate (Reference 21).

Therefore, for this study, a discount rate of 5 percent was selected as a reasonable "mid-point" rate.

This report provides the benefits both discounted and non-discounted, leaving the reader to decide which values are most appropriate.

In addition, average annual and cumulative benefits were estimated over two different time series:

- For the time period from 2005 to 2025, to represent the full time frame for which the AEO 2004 forecasts future oil and gas industry activity.
- For the time period from 2005 to 2010, to represent the impact over the first five years after which the proposed requirements are assumed to be in place.

SUMMARY OF RESULTS

Given the assumptions used in this analysis, under Base Case conditions, as shown in Table 1, the imposition of the proposed storm water discharge requirements could result in increased compliance and delay costs to the domestic oil and gas industry of $370 to $380 million per year (the range represents the difference in impacts annualized (and undiscounted) over a five-year (2005-2010) time horizon or a 20-year (2005 to 2025) time period). Of this, $110 to $115 million per year would be associated with increased compliance expenses, with the majority of the costs associated with filing of the NOI. From $255 to $270 million per year would be associated with the impacts associated with delayed production, forfeited leases and increased royalty obligations by operators; and the costs associated with underutilized domestic drilling capacity (which represents the largest portion of these costs). By 2025, these requirements would result in cumulative cost impacts on the order of $7.8 billion.

Under the Higher Impact scenario, the imposition of the proposed storm water discharge requirements could result in cost impacts to domestic oil and gas industry of on the order of $2.8 to $2.9 billion annually. Of this, from $320 to $330 million per year would be associated with increased compliance expenses, and $2.5 to $2.6 billion per year would be associated with project delays and delayed production. By 2025, these requirements would result in cumulative cost impacts on the order of over $66 billion.

Table 1
Estimated Impacts of Potential New Stormwater Discharge Requirements on Domestic Oil and Gas Drilling Operations (Undiscounted 2002 Dollars)

	Base Case			Higher Impact Scenario		
	Est. Impacts Annualized (MM$/year)		Cum. Impacts to 2025 (MM $)	Est. Impacts Annualized (MM$/year)		Cum. Impacts to 2025 (MM $)
	2005-2025	2005-2010		2005-2025	2005-2010	
Costs of Compliance						
NOI Permit Costs	$91	$89	$1,901	$149	$143	$2,963
ESA Review & Consultation	$24	$24	$507	$128	$124	$2,568
NHPA Review & Consultation	$0	$0	$0	$53	$51	$1,054
	$115	**$112**	**$2,408**	**$330**	**$319**	**$6,585**
Costs of Delays						
Increased Royalties	$36	$33	$759	$117	$106	$2,337
Forfeited Lease Bonuses	$25	$24	$523	$120	$116	$2,408
Increased Expenses for Idle Rigs	$119	$116	$2,504	$1,587	$1,526	$31,736
Lost Value of Delayed Production	$75	$96	$1,578	$649	$816	$22,962
	$255	**$270**	**$5,363**	**$2,473**	**$2,564**	**$59,442**
Grand Total	**$371**	**$382**	**$7,771**	**$2,802**	**$2,883**	**$66,027**

As illustrated in Table 2 for one set of cost impacts, showing only the compliance cost impacts over the 2005 to 2025 time period (undiscounted) associated with the different types of oil and gas industry sites considered in this assessment, the vast majority of impacts are associated with oil and gas well drilling.

Discounted economic impacts, assuming a 5% per year discount rate, are summarized in Table 3. As shown, the imposition of the proposed storm water discharge requirements could result in cost impacts to domestic oil and gas industry of nearly $340 million per year annualized over a five-year (2005-2010) time horizon, or nearly $240 million over a 20-year (2005 to 2025) time period. By 2025, these requirements would result in cumulative economic impacts on the order of $4.9 billion discounted.

Under the Higher Impact scenario, the imposition of the proposed storm water discharge requirements could result in discounted cost impacts to domestic oil and gas industry of on the order of $2.4 billion annually for the first five years, and $1.8 billion per year over the next 20 years, on average. By 2025, these requirements would result in cumulative discounted cost impacts on the order of nearly $36 billion.

Table 2

**Estimated Impacts of New Stormwater Discharge Requirements
Cost Impacts by Site Type, 2005 to 2025 Time Period
(Undiscounted Dollars)**

	Base Case		Higher Impact Scenario	
	Est. Impacts Annualized (MM$/year)	Cum. Impacts to 2025 (MM $)	Est. Impacts Annualized (MM$/year)	Cum. Impacts to 2025 (MM $)
Compliance Costs by Site Type				
Production Wells	$95	$1,989	$268	$5,351
Injection Wells	$5	$104	$15	$305
Gas Gathering/Processing	$9	$193	$28	$569
Gas and Liquids Transporatation	$6	$122	$18	$360
Total	**$115**	**$2,408**	**$330**	**$6,585**

Table 3

**Estimated Impacts of Potential New Stormwater Discharge
Requirements on Domestic Oil and Gas Drilling Operations
(Discounted Dollars)**

	Base Case			Higher Impact Scenario		
	Est. Impacts Annualized (MM$/year)		Cum. Impacts to 2025 (MM $)	Est. Impacts Annualized (MM$/year)		Cum. Impacts to 2025 (MM $)
	2005-2025	2005-2010		2005-2025	2005-2010	
Costs of Compliance						
NOI Permit Costs	$61	$78	$1,189	$101	$120	$1,899
ESA Review & Consultation	$15	$21	$317	$82	$104	$1,646
NHPA Review & Consultation	$0	$0	$0	$34	$43	$675
	$76	**$99**	**$1,506**	**$217**	**$268**	**$4,220**
Costs of Delays						
Increased Royalties	$22	$29	$467	$67	$89	$1,343
Forfeited Lease Bonuses	$16	$21	$327	$77	$97	$1,543
Increased Expenses for Idle Rigs	$74	$103	$1,564	$1,017	$1,282	$20,336
Lost Value of Delayed Production	$50	$85	$1,055	$412	$689	$8,233
	$163	**$239**	**$3,413**	**$1,573**	**$2,157**	**$31,454**
Grand Total	**$238**	**$338**	**$4,918**	**$1,789**	**$2,425**	**$35,674**

As described above, the new Phase II storm water discharge requirements, if imposed on the oil and gas industry, could also lead to oil and gas wells not being drilled, resulting in lost domestic oil and natural gas production, and significant economic impacts associated with this foregone production. For example, as shown in Table 4, under Base Case conditions, the proposed requirements could result in nearly 100,000 barrels per day reduction in domestic oil production over the first five years, and a 170,000 barrel per day loss in production, on average, over the 2005 to 2025 time period. Similarly, nearly 350 Bcf per year of natural gas would not be produced on average, in the first 5 years, and an average of over 710 Bcf per year would be lost over the 2005 to 2025 time horizon. Cumulatively, as much as 1.3 billion barrels of oil and 15 Tcf of natural gas supplies could be lost over the 2005 to 2025 time period under the Base Case.

Table 4

Estimated Impacts of Potential New Stormwater Discharge Resulting from Reduced Drilling

	ANNUALIZED IMPACTS (DISCOUNTED AND UNDISCOUNTED)							
	Base Case				Higher Impact Scenario			
	2005-2025		2005-2010		2005-2025		2005-2010	
	Disc	Undisc	Disc	Undisc	Disc	Undisc	Disc	Undisc
Crude Oil Production Lost								
Annual (MMB/day)	0.171		0.094		0.513		0.282	
Cumulative (Billion Barrels)	1,310		206		3,930		617	
Natural Gas Production Lost								
Annual (Bcf per year)	714		349		2,143		1,048	
Cumulative (Bcf)	15,002		2,096		45,005		6,288	
Increased Crude Oil Imports								
Annual (MMB per day)	0.171		0.094		0.513		0.282	
Increased Exp. For Imports								
Annual ($ Million)	$879	$1,562	$676	$799	$2,636	$4,686	$2,029	$2,398
Increased Federal Royalties								
Annual ($ Million)	$87	$158	$60	$71	$260	$473	$181	$212
Increased Private Royalties								
Annual ($ Million)	$223	$405	$155	$182	$668	$1,215	$464	$545
Increased State Severence Taxes								
Annual ($ Million)	$108	$197	$75	$88	$325	$591	$226	$265
Increase in WH Gas Prices ($/Mcf)								
EIA Basis	$0.04	$0.07	$0.01	$0.02	$0.11	$0.21	$0.04	$0.05
NPC Basis	$0.22	$0.44	$0.09	$0.11	$0.67	$1.31	$0.27	$0.33
Increased Expenditures for Natural Gas								
Annual ($ Million)								
EIA Basis	$1,024	$2,030	$367	$443	$2,892	$5,716	$1,063	$1,281
NPC Basis	$6,302	$12,487	$2,259	$2,725	$17,795	$35,169	$6,538	$7,883

Over the 2005 to 2010 time period this could result in:

- $675 million (discounted) per year increase in the nation's expenditures for oil imports ($800 million undiscounted).
- $60 million per year less in royalties collected by the federal government ($70 million undiscounted).
- $155 million per year less paid to private landowners in oil and gas royalties ($180 million undiscounted).
- $75 million per year in lost tax revenues accruing to state government from severance taxes alone ($90 million undiscounted).

Significantly larger impacts could result if averaged over the entire 2005 to 2025 time period for which the analysis was performed. Over this time period, the following impacts would result:

- $880 million (discounted) per year increase in the nation's expenditures for oil imports ($1.6 billion undiscounted).
- $90 million per year less in royalties collected by the federal government ($160 million undiscounted).
- $220 million per year less paid to private landowners in oil and gas royalties ($400 million undiscounted).
- $110 million per year in lost tax revenues accruing to state government from severance taxes alone. ($200 million undiscounted).

This does not include consideration of the impact due to lost sales tax and income tax revenue to federal, state, and local governments.

Finally, this could result in natural gas consumers paying from $1.0 to $6.3 billion more (discounted) for natural gas per year, on average, over the 2005 to 2025 time horizon due to higher natural gas prices ($2.0 to $12.5 billion undiscounted). Over the 2005 to 2010 time period, from $370 million to $2.3 billion more (discounted) more will be paid for natural gas per year, on average, ($440 million to $2.7 billion undiscounted)

In contrast, under the Higher Impact scenario, the proposed requirements could result in 280,000 barrels per day reduction in domestic oil production over the first five years, and over 500,000 barrel per day loss in production, on average, over the 2005 to 2025 time period. Similarly, over one Tcf per year of natural gas would not be produced on average, in the first 5 years, and an average of over 2.1 Tcf per year would be lost over the 2005 to 2025 time horizon. Cumulatively, as much as 3.9 billion barrels of oil and 45 Tcf of natural gas would not be produced by 2025.

Under the Higher Impact scenario, over the 2005 to 2010 time period this could result in:

- $2.0 billion (discounted) per year increase in the nation's expenditures for oil imports ($2.4 billion undiscounted).
- $180 million per year less in royalties collected by the federal government ($210 million undiscounted).
- $465 million per year less paid to private landowners in oil and gas royalties ($545 million undiscounted).
- $225 million per year in lost tax revenues accruing to state government from severance taxes alone ($265 million undiscounted).

Over this time period, natural gas consumers would pay from $1.1 to $6.5 billion (discounted) more for natural gas per year, on average, over the 2005 to 2010 time horizon ($1.3 to $7.9 billion undiscounted) higher due to higher natural gas prices

Over the entire 2005 to 2025 time period for which the analysis was performed, the following impacts would result:

- $2.6 billion (discounted) per year increase in the nation's expenditures for oil imports ($4.7 billion undiscounted).
- $260 million per year less in royalties collected by the federal government ($470 million undiscounted).
- $670 million per year less paid to private landowners in oil and gas royalties ($1.2 billion undiscounted).
- $325 million per year in lost tax revenues accruing to state government from severance taxes alone ($590 million undiscounted).

Moreover, the proposed requirements under the Higher Impact scenario could result in natural gas consumers paying from $2.9 to $17.8 billion more (discounted) for natural gas per year, on average, by 2025 due to higher natural gas prices ($5.7 to $35 billion undiscounted).

Again, it is worth noting that the impacts estimated for this Higher Impact scenario should not be considered to be those associated with a "worst case" scenario, as discussed in the following section.

CAVEATS

Nature of Assumptions

Substantial uncertainty is associated with many of the assumptions used in this analysis. Moreover, since EPA has yet to publish any proposed requirements specifically for the oil and gas sector, certain assumptions about compliance requirements may turn out to be different than what EPA proposes, or what is currently required under the CGP. For the most part, the characterization of new compliance requirements in this analysis is based on current requirements in the CGP.

Some of the more important, though uncertain, assumptions are described below.

Length of Project Delays. The major uncertainties characterizing the range of potential economic impacts on the oil and gas industry presented in this assessment primarily relate to the permitting delays that could take place as a result of implementation of the Phase II requirements. These pertain to the anticipated processes required for endangered species and historical/archeological reviews, and the time it might take to process permit applications, make determinations, and grant approvals. If these processes proceed efficiently and according to schedule, anticipated economic impacts (although still considerable) can be minimized. If these processes are cumbersome, contentious, and prone to delays, the economic impacts can be quite large, with substantial impacts on domestic energy supplies, our nation’s balance of trade and dependence on foreign energy supplies, and the price Americans pay for the energy they consume.

Definition of Construction. The assessment only considered activities associated with new “construction” projects, i.e., one-time activities at the initiation of operations. Maintenance or repair projects associated with drilling and production operations (such as well workovers and other well services), are not considered "construction" projects in this assessment. In the area of gas and liquids transportation, EPA has redefined maintenance to exclude repairs and replacement; as such, these activities are subject to permitting requirements. While it can be argued that pipeline integrity management activities are an intrinsic component of pipeline operations and are therefore industrial activities not subject to storm water permitting, EPA's narrowing of the maintenance definition requires that such activities be included in estimating potential impacts of the proposed Phase II requirements. In this analysis, the pipeline activities included installation of small segments of new pipelines, surface facility additions or expansions, and repair/replacement activities in which the original intent was to repair or replace a segment of pipeline. However, it did not include situations where the original intent complied with EPA's definition of maintenance, and at some point in the work it was identified that it was necessary to repair or replace a segment of pipeline. If such activities must comply with the Phase II requirements, the economic impacts presented here are grossly understated.

Delays Associated with Permit Reviews. In this assessment, it was assumed that NRDC does not prevail in its argument requiring EPA to individually review the NOIs and SWPPPs prepared under the general permit process, and to require a process for public notice, comment, and opportunity for public for every NOI and SWPPP submitted. Similarly, it was assumed that NRDC does not prevail in its argument that EPA should be required to review each operator's permit application and, in consultation with the U.S. Fish and Wildlife Service (FWS) and the National Marine Fisheries Service (NMFS), determine the extent to which adverse effects may occur to endangered species in the project area. However, if NRDC were to prevail, the case-by-case review and public participation requirements they seek to impose would increase still further the already very significant potential of the CGP requirements to delay oil and gas drilling, increasing the potential for lease forfeiture and lost reserves.

Learning Curve Efficiencies. Like most economic impact assessments of this type, no consideration was given to the fact that over time, processes for compliance, performed by both operators and by regulatory agencies, would improve, and become more efficient and subsequently less costly and/or with less delay. Recognizing this, the presentation of results focused on the annualized impacts over the first five years after promulgation – the period of time where the impacts of such efficiency gains would be least likely to be realized.

Impacts not Considered

It is also important to note that these impacts represent only some of the costs associated with increased compliance costs and potential project delays. Other possible impacts that were not considered in this impact assessment include:

- *Any incremental costs that may be incurred to ensure compliance* (such as installing erosion control systems) or to mitigate possible impacts to endangered species or historic sites. The only costs considered are only those associated with filing NOIs, ensuring that a SWPPP has been completed, demonstrating that BMPs are installed according to SWPPP, completing periodic inspections, and demonstrating that the site has been stabilized prior to filing a NOT.
- *Other delay costs other that rig costs*. These would include increased fees associated with delaying work by well service contractors, stimulation contractors, and other service companies that could not perform their services on schedule because of project delays.
- *Increased costs of project financing*, as a result of greater project uncertainty that could impact the ability of potential operators to secure financing and/or joint venture partners for specific projects. Some believe that the new requirements will substantially increase the risks associated with drilling prospects, impacting the risk/reward profile of prospective lenders and investors.

- *Decreased value of oil and gas company stocks*. Some believe that these Phase II requirements may impact the SEC reserve calculations for public companies, which may have to write down their reserve base, resulting in a loss of investor confidence and lower stock price valuations.

Finally, no estimate was developed for the potentially significant economic impacts to industry and to communities resulting from Phase II permitting delays in performing pipeline maintenance and repair work, primarily because the impacts are so significant that it is highly unlikely that society would permit this to occur. Under the integrity management program of the Department of Transportation (DOT), pipelines with certain anomalies are required to be repaired within a given time frame or to reduce or shut down throughput. In many instances, this can mean shutting down or reducing service to an entire community until the anomaly can be repaired or replaced.

Under the current CGP, EPA redefined such maintenance to exclude repairs and replacement, with these activities subject to the Phase II permitting requirements. The delays associated with permitting may be as short as 7 days, but have traditionally often been much longer. In one state, permit processing by the agency can, by regulation, take up to 90 days; several other states have adopted agency review periods of 30-60 days. Under the current EPA interpretation of such maintenance activities, the potential cost per day of eliminating gas service to an entire community to await permit approval for pipeline repairs could be economically catastrophic for that community.

Moreover, in all aspects of the oil and gas industry, there are potential situations when actions which must be taken immediately to protect employees, the public, and the environment, and/or to comply with other regulations. The most obvious of these are spill response activities or the repair of a pipeline failure. The current Phase II requirements provide no mechanism for emergency responses to protect human health and safety and the environment. This could apply to both emergencies (e.g., containment of the spill may be an emergency response) and non-emergency actions (e.g., the cleanup may not be an emergency but requires timely and prudent non-emergency action). Under the current Phase II process, a company must either respond quickly, and thus not comply with the requirements, or wait for the permitting process to proceed, and thus delay responding expeditiously to the emergency.

Because it is likely that the public will find this situation unacceptable, the estimated economic impacts associated with this type of circumstance was not estimated in this assessment. However, it further demonstrates how the Phase II requirements, as currently set forth in the CGP, have severe limitations if applied to oil and gas industry operations.

Key References

1. Environmental Protection Agency, *Economic Analysis of Proposed Effluent Limitation Guidelines and Standards for the Construction and Development Category*, May 2002
2. Environmental Protection Agency, *Development Document for Proposed Effluent Limitation Guidelines and Standards for the Construction and Development Category*, June 2002
3. Henry Petroleum LP, Presentation to the White House Energy Task Force, October 2002
4. Goldston Oil Corporation, *NPDES Phase II General Permit Requirements and its Effects on Oil and Gas Exploration and Development of Privately Held Lands within the United States*, presentation to the White House Energy Task Force, October 2002
5. Environmental Protection Agency, Responses to Questions from White House Energy Task Force on EPA's National Pollutant Discharge Elimination System Storm Water Program and the Oil and Gas Industry, undated.
6. Letter to Bryan Rittenhouse, USEPA from LIOGA, OIPA, and TIPRO Re Phase II NPDES Storm Water Permitting, Clean Water Act, dated May 23, 2002
7. Letter to Honorable Christine Todd Whitman, Administrator, USEPA, from numerous industry association representatives Re NPDES Permits for Storm Water Phase I and II Rules in Relation to Oil and Gas Construction Activities, dated June 25, 2002.
8. Letter to Honorable Carl Michael Smith, Assistant Secretary of Fossil Energy, USDOE, from Texas Alliance of Energy Producers, dated September 5, 2002.
9. Energy Information Administration, *Annual Energy Outlook 2004*, DOE/EIA 0383(2004), January
10. Energy Information Administration, *Performance Profiles of Major Energy Producers 2002*, DOE/EIA-0206 (04), January 2004
11. American Petroleum Institute, *2002 Joint Association Survey on Drilling Costs*, December 2003
12. Reed Survey of Drilling Activity, various years
13. Memorandum to Mike Godec, Advanced Resources International, from Thomas E. Fisk, re: EPA Phase II Stormwater Economic Impact Assessment Data, Gas Processors Association Data Submittal, Midstream Sector -- Natural Gas and Liquids Processing, dated July 13, 2004
14. National Petroleum Council, *Balancing Natural Gas Policy: Fueling the Demands of a Growing Economy*, Volume II, Integrated Report, September 2003
15. Anonymous, "Industry cost cutting hits older fields, *World Oil*, February 2003, p.46
16. Energy Information Administration, *Analysis of Restricted Natural Gas Supply Cases*, SR/OIAF/2004-03, February 2004
17. Office of Management and Budget, Circular No. A-94: Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs, 1992 www.whitehouselgov/OMB/circulars/a094/a094.html
18. Office of Management and Budget. Economic Analysis of Federal Regulations Under Executive Order 12866, 1996 www.whitehouse.gov/OMB/inforeg/reiguide.html
19. Environmental Protection Agency, U.S. Guidelines for Preparing Economic Analyses. EPA 240-R-00-003. Washington, D.C., U.S. EPA, Office of the Administrator, 2000
20. Environmental Protection Agency. Documentation of EPA Modeling Applications (V.2.1) Using the Integrated Planning Model, EPA 430/R-02-004, 2002 http://www.epa.gov/airmarkets/epa-ipm/index.html#documentation
21. Environmental Protection Agency, Technical Addendum: Methodologies for the Benefit Analysis of the Clear Skies Act of 2003, 2003. http://www.epa.gov/air/clearskies/tech_addendum.pdf
22. U.S. Department of Energy/Office of Natural Gas and Petroleum Technology*, Oil and Gas Environmental Metrics 2000 Analysis and Results,* August 2000.

APPENDIX A

7-Dec-04

CRITICAL FACTORS AND KEY ASSUMPTIONS CONTRIBUTING TO THE ECONOMIC IMPACT OF POTENTIAL NEW STORM WATER DISCHARGE REQUIREMENTS

Key Data Elements and Assumptions	Assumption Used in this Analysis	Alternative Potential Sources of Information, Data, and/or Critical Assumptions		
		Industry/NGOs	**EPA (2002) Economic Impact Assessment**	**Prev. DOE Assumptions**
Number of Sites Impacted				
Number of wells drilled per year	Uses forecast well counts in the EIA 2004 AEO Reference Case Forecast -- average about 26,400 wells per year from 2003 to 2025. (Reference 9) This includes both successful and dry wells. However, it does not consider the fact that, in some cases, multiple wells are drilled from a single pad. However, this is the exception, not the rule. To indicate this, in 2002, of the 23,955 onshore wells drilled in the U.S., 890 were horizontal wells, and 705 were sidetrack wells (Reference 11), or approximately 6-7% of the total wells drilled.	Analysis by Texas Alliance of Producers based on 2001 drilling levels of nearly 32,000 wells per year (Reference 8). The most recent NPC natural gas study's (Reference 14) forecast of gas well drilling is comparable to the 2004 AEO (the NPC did not report a forecast for oil well drilling).	EPA's analysis did not explicitly examine "construction activities" in the oil and gas industry distinctly, but lumped these activities with all other "construction activities" considered.	DOE generally tends to use the most recent EIA forecast, usually the most recent Reference Case from the latest AEO.
Number of injection wells	Estimates of the number of injected wells in the U.S. are based on the ratio of operating injection wells to oil production wells in Texas and California. This results in approximately 1 injection well for every 4 oil production wells. This includes all enhanced recovery (both water and gas injection) and brine disposal wells, but not injection wells used for gas or hydrocarbon storage. All injection well sites were assumed to fall within the 1-to-5-acre size category.	Rough estimates nationally, using EPA data for Class II injection wells. (http://www.epa.gov/safewater/uic/classii.html), which includes storage wells, and *World Oil* magazine estimates (Reference 15) of producing oil wells in the U.S., would make this number more like one injector for every 3 oil production wells, implying the 1 in 4 estimate may be somewhat conservative.		DOE generally uses EPA estimates of the number of Class II injection wells nationally.The 1990 DOE Cumulative Impacts Study assumed 172,000 injection wells nation-wide, based on work for API during the Class II program mid-course correction process. At the time, this compared to 420,486 producers, or one injector to every 2.44 oil production wells.
Number of construction sites associated with gas gathering activities.	This analysis used the Gas Processors Association recommendations. For purposes of this analysis, this number is assumed to be applicable annually.	The Gas Processors Association estimates that there are currently approximately 2,370 projects in the natural gas midstream sector that would fall between 1 and 5 acres (Reference 13).		

APPENDIX A **7-Dec-04**

CRITICAL FACTORS AND KEY ASSUMPTIONS CONTRIBUTING TO THE ECONOMIC IMPACT OF POTENTIAL NEW STORM WATER DISCHARGE REQUIREMENTS

Key Data Elements and Assumptions	**Assumption Used in this Analysis**	**Alternative Potential Sources of Information, Data, and/or Critical Assumptions**		
		Industry/NGOs	**EPA (2002) Economic Impact Assessment**	**Prev. DOE Assumptions**
Number of construction sites associated with gas transportation activities.	Estimate based on the number of current projects estimated for one company that would fall under the new requirements in the 1-5 acre range. Using the estimated miles of gas pipelines within this company, to which this number applies, it was determined that there would be an estimated one 1-5 acre project falling under the new requirements per 278 miles of pipe. Based on the number of miles of natural gas and liquid pipelines in the U.S., this would amount to about 1,500 sites per year, assumed to be applied annually.	The one company developed their estimate based on the number of currently permitted projects (under Phase I requirements), compared to the estimated number of projects they have in the 1 to 5 acre size range. This included both identified projects and an estimate of the number of projects that are currently “unidentified,” but that were determined to be likely based on the number of identified projects.Company requested that they remain confidential.		
Portion of Sites Impacted				
Estimated proportion of sites impacted	For this exercise, uses the number of sites estimated above as the unit for analysis; assuming other facilities are > 5 acres or < 1 acre, and therefore not subject to the new requirements. In reality, for example, some well sites are > 5 acres, especially where associated facilities, such as gathering systems, production processing facilities, tank batteries, etc., are included. The analysis assumes all well sites are within 1-5 acres, and the separate construction projects associated with gathering system and pipeline-related activities are in addition to those associated with a well site.	No explicit assumptions stated, but most industry commentors expressed concern that essentially all sites would be impacted.	EPA's analysis did not explicitly examine "construction activities' in the oil and gas industry distinctly, but lumped these activities with all other "construction activities" considered.	

APPENDIX A

7-Dec-04

CRITICAL FACTORS AND KEY ASSUMPTIONS CONTRIBUTING TO THE ECONOMIC IMPACT OF POTENTIAL NEW STORM WATER DISCHARGE REQUIREMENTS

Key Data Elements and Assumptions	Assumption Used in this Analysis	Alternative Potential Sources of Information, Data, and/or Critical Assumptions: Industry/NGOs	EPA (2002) Economic Impact Assessment	Prev. DOE Assumptions
Portion of wells subject to new requirements	EPA states that 41% of nation's acreage is in states with existing state programs that would not have to be modified to meet new requirements under Phase II (Reference 2). Therefore, in the Base Case, it was assumed that 60% of the sites (wells, gathering facilities and pipeline projects) would be subject to the new requirements. In the Higher Impact Scenario, given industry concerns, it is assumed that 90% of the sites would be subject to the new requirements.	On a well basis, roughly 60% of the wells drilled in the U.S. in 2002 were in states where EPA would have regulatory authority or where the wells would likely be drilled on federal lands (Reference 11). Many in industry, however, believe that nearly all wells (over 90%) in the country would be subject to the new requirements. For example, EPA is the jurisdictional agency for gas pipeline construction activities in three of the major oil and gas producing states -- New Mexico, Oklahoma, and Texas. Of the nine states which manage the storm water permit program, eight have adopted EPA's 2 year postponement: Arkansas, Colorado, Illinois, Iowa, Kansas, Louisiana, Nebraska, and Wyoming. Several of these are major oil and gas producing states. The one remaining state, Missouri, has developed a state program. Since all of these states have followed EPA's lead on the postponement for the oil and gas industry, it is reasonable to assume that they will follow EPA's lead on implementation of the Phase II permit requirements to the oil and gas industry.	States w/ EPA oversight that produce O&G include TX,OK, NM,AZ,ID,AK, Native Lands. In the Development Document for this rulemaking (Reference 2), EPA estimates that 41% of developed acreage is in states with existing state programs, and would not have to modify their permits to meet the new requirements (Reference 2). In answers to questions posed by the White House Energy Task Force in 2002, EPA cited numbers of 4,000 impacted well sites in OK, 8,000 - 9,000 in TX (Reference 5). I	.
Erosivity factor waiver	For this analysis, it was assumed that 15% of sites will receive <u>either</u> an erosivity factor or TMDL waiver (Reference 5), beginning in 2005. The Higher Impact scenario assumes that no sites are subject to either waiver.	Some in industry claim that few, if any, sites would likely be subject to such waivers. Permitting authorities have the option to not allow waivers. In many cases, the times of year during which the waivers could be obtained are minimal and sporadic. Moreover, a waiver may not necessarily waive <u>all</u> permit requirements, but only allows EPA to waive "otherwise applicable requirements in a general permit." Finally, should operators try to schedule drilling to coincide with time windows during the year when waivers could be obtainable, it could further complicate the logistics of leasing, permitting, and scheduling drilling rigs	In EPA's response to questions from the White House Energy Task force (Reference 5), EPA estimates that 15% of sites in TX and OK would be eligible for a waiver, based on the ICR conducted as part of developing the Phase II requirements.	

APPENDIX A **7-Dec-04**

CRITICAL FACTORS AND KEY ASSUMPTIONS CONTRIBUTING TO THE ECONOMIC IMPACT OF POTENTIAL NEW STORM WATER DISCHARGE REQUIREMENTS

Key Data Elements and Assumptions	Assumption Used in this Analysis	Alternative Potential Sources of Information, Data, and/or Critical Assumptions		
		Industry/NGOs	**EPA (2002) Economic Impact Assessment**	**Prev. DOE Assumptions**
TMDL waiver	For this analysis, it was assumed that 15% of sites will receive either an erosivity factor or TMDL waiver (Reference 5), beginning in 2005. The Higher Impact scenario assumes that no sites are subject to either waiver.	No explicit assumptions stated.	No explicit assumptions stated.	
Portion of facilities subject to ESA review	Based on EPA assessment, assumes 40% of sites would have endangered species in proximity and would require ESA review (Reference 2). This was assumed for both the Base Case and Higher Impact scenario.	Industry believes that nearly all sites in the country would have to conduct some type of ESA review to comply. Some are also concerned that drilling opponents or reluctant landowners will use the process to delay or stop drilling; implying the portion subject to review could be considerably higher than that assumed by EPA. Furthermore, a brief filed by the National Resources Defense Council (NRDC) in the 7th Circuit on July 28, 2004 argues, among other things, that the self-implementing ESA provisions of the CGP should not be allowed under the ESA, and that EPA should be required to review each operator's ESA and, in consultation with USFWS/NMFS, determine that no adverse effects are likely to any endangered species in the project area	EPA's Phase II ICR determined that 60% of all "small construction projects" nationwide would have no endangered species in proximity (so 40% would be subject to ESA review). (Reference 2).	
Portion requiring ESA consultation	Based on an EPA assessment, assumes 3% of sites would have endangered species in proximity and would require ESA consultation (Reference 2). The Higher Impact scenario assumes that 15% of sites would require consultation, based on endangered species in proximity and/or assuming challenges by landowners or others to initial ESA determinations.	No explicit assumptions stated, though, like that above, some are concerned that drilling opponents or reluctant landowners will use process to delay or stop drilling; implying the portion subject to consultation could be considerably higher than that assumed by EPA.	EPA's Phase II ICR determined that 3% of all "small construction projects" nationwide would have endangered species in proximity and would require consultation (Reference 2).	

CRITICAL FACTORS AND KEY ASSUMPTIONS CONTRIBUTING TO THE ECONOMIC IMPACT OF POTENTIAL NEW STORM WATER DISCHARGE REQUIREMENTS

Key Data Elements and Assumptions	Assumption Used in this Analysis	Alternative Potential Sources of Information, Data, and/or Critical Assumptions: Industry/NGOs	EPA (2002) Economic Impact Assessment	Prev. DOE Assumptions
Portion of facilities subject to NHPA review	Since a NHPA review is currently not addressed in the Construction General Permit, no NHPA review is assumed to be required in the Base Case. In the Higher Impact scenario, 20% of sites are assumed to require review, based on the OK experience.	In OK, according to industry comments (Reference 6) , local office requires evaluations on 805 of requests (out of about 4,000 wells), even though in only small portion will historic sites be discovered.	In the draft Phase II requirements, provisions were proposed to require storm water discharge permit applicants to conduct historic or archeological reviews to ensure the protection of historic places under the National Historical Preservation Act (NHPA). However, the final CGP does not include these requirements. However, EPA is continuing discussions with the Advisory Council on Historic Preservation on potential future requirements. The current CGP contains a “re-opener clause” which can allow EPA, at a later date, to modify the CGP based on those discussions.	
Portion requiring consultation	The Higher Impact scenario assumes that 10% of sites would require consultation, based on important sites in proximity and/or assuming challenges by landowners or others to initial NHPA determinations.	No explicit assumptions stated.	No explicit assumptions stated.	
Required activities imposing costs				
Submitting NOI, preparing SWPPP, implementing Best Management Practices (BMPs), and performing post-construction inspections.	Process of submitting NOI will involve efforts to certify SWPPP has been completed, BMPs installed according to SWPPP, periodic inspections have been completed, and the site has been stabliized prior to filing NOT. Assumes 72 person-hours, at $75,000/year salary, and associated overhead. Amounts to $6,000 per well.	Total increase in cost per well estimated by Texas Alliance of Energy Producers to range from $3,000 to $8,000 per well. One company estimates the costs to be on the order of $7,000, and the Gas Processors Association (Reference 13) assumes costs on the order of $5,300.	EPA estimates that it will take approximately 16 hours, for sites 10 acres and smaller, to certify SWPPP has been completed, BMPs installed according to SWPPP, periodic inspections have been completed, and the site has been stabliized prior to filing NOT.	In DOE's Environmental Metrics Analyses (2000), assumed that $1,000 would be required to submit NOI and implement SWPPP, and $2,560 would be requried to establish soil erosion control for a 2-acre site (Based on 1997 EPA analysis of Phase I rulemaking.) No costs assumed for post construction inspections.

APPENDIX A

7-Dec-04

CRITICAL FACTORS AND KEY ASSUMPTIONS CONTRIBUTING TO THE ECONOMIC IMPACT OF POTENTIAL NEW STORM WATER DISCHARGE REQUIREMENTS

Key Data Elements and Assumptions	Assumption Used in this Analysis	Alternative Potential Sources of Information, Data, and/or Critical Assumptions		
		Industry/NGOs	**EPA (2002) Economic Impact Assessment**	**Prev. DOE Assumptions**
Obtaining ESA clearance	For ESA review, assumes 36 person-hours, amounting to $3,000 per well. For consultation, assumes 160 hours, amounting to $13,333 per well. Higher Impact scenario assumes consultation requires twice as much effort, at a cost of $26,667	In the NPC study (Reference 14), costs for conducting an intensive field survey for threatened and endangered (T&E) species, or candidate T&E species, were estimated as $3,500.	No explicit assumptions stated.	
Obtaining NHPA clearance	Under the Higher Impact scenario, for NHPA review, assumes 48 person-hours, amounting to $4,000 per well. Assumes consultation requires 320 hours, at a cost of $26,667	In OK, only "approved archeologists can be used. Typical review will cost $3,000 to $5,000, depending on complexity of the site. NPC study (Reference 14) estimates costs for Class III survey with no resouces to be $1,500 to $4,000, and up to $6,000 if sites are present. Consultation costs, if requiring a date recovery and treatment plan, are estimated at $10,000 minimum, but could be as much as $250,000 per site for implementation.	No explicit assumptions stated.	
Required activities imposing delays				
Individual review of NOIs and SWPPPs, and allowance of public participation	In this assessment, the implications associated with the NRDC recommendations were not considered, but if NRDC were to prevail, the case-by-case review and public participation requirements they seek to impose would increase still further the already very significant potential of the CGP requirements to delay oil and gas drilling, increasing the potential for lease forfeiture and lost reserves.	NRDC argues that the general permit does not comply with the CWA because EPA does not individually eview the NOIs and SWPPPs prepared under the general permit process and the permit process does not provide for public notice, comment, and opportunity for public hearing ("public participation") on NOI's and SWPPPs. NRDC made the public participation argument with to the Ninth Circuit with respect to NOIs submitted for stormwater discharges from Municipal Separate Storm Sewer Systems (MS4s), and won in Envt'l Defense enter v EPA, 344 F.3d 832, 856-58 (9th Cir. 2003). .		

CRITICAL FACTORS AND KEY ASSUMPTIONS CONTRIBUTING TO THE ECONOMIC IMPACT OF POTENTIAL NEW STORM WATER DISCHARGE REQUIREMENTS

Key Data Elements and Assumptions	Assumption Used in this Analysis	Alternative Potential Sources of Information, Data, and/or Critical Assumptions		
		Industry/NGOs	**EPA (2002) Economic Impact Assessment**	**Prev. DOE Assumptions**
Obtaining ESA clearance	Assumes some delay in expectations could be "scheduled" in terms of rig contracting. For purposes of this analysis, assume 7 days of "unscheduled" delay for review, 21 days of "unscheduled" delay for consultation (due to large increase in workload on existing goverment staff, without any increase in staffing levels). Higher Impact scenario assumes that this process could be three times longer.	Currently, when consultation is required, USFWS is allowed 90 days to consult, and 45 days to prepare biological opinion. In 2002, industry comments stated that USFWS consultation requires 45 days or longer. Longer delays anticipated due to the substantial increase in workload due to new requirements, and shortage of available staff to perform reviews. The Texas Alliance of Energy Producers estimates typical delays in construction and development of from 1 to 4.5 months (Reference 8). Another operator (wishing to remain anonymous) stated that a routine consultation could take from 6-12 weeks, and with adverse parties involved, could take 3-6 months or more.		
Obtaining HP clearance	Assume some delay expectations could be "scheduled" in terms of rig contracting. For purposes of this analysis, assumes, under the Higher Impact scenario, based on OK experience, assumes a 30 day delay for review, and 90 day delay for consultation.	Industry concerns are that timing delays are likely with historical preservation and historical reviews. In OK, operators typically incur delays on order of at least 30 days. (Reference 8)	No explicit assumptions stated.	
Other Pertinent Data/Assumptions for Estimating Potential Impacts				
Oil and gas price assumptions used for estimating impacts	Uses EIA oil and gas price forecasts based on the EIA 2004 AEO. Oil prices average $25/Bbl over 2003-2025 time period, gas prices average nearly $4.00/Mcf over same time period (Reference 9).	Industry based its analysis on average 2001 wellhead prices of $21.66/Bbl of oil and $4.12/Mcf of natural gas (Reference 8).	Not considered in EPA's economic impact assessment.	DOE generally tends to use the most recent EIA forecast, usually the most recent Reference Case from the latest AEO.

APPENDIX A

7-Dec-04

CRITICAL FACTORS AND KEY ASSUMPTIONS CONTRIBUTING TO THE ECONOMIC IMPACT OF POTENTIAL NEW STORM WATER DISCHARGE REQUIREMENTS

Key Data Elements and Assumptions	Assumption Used in this Analysis	Alternative Potential Sources of Information, Data, and/or Critical Assumptions		
		Industry/NGOs	**EPA (2002) Economic Impact Assessment**	**Prev. DOE Assumptions**
Drilling day rates associated with idle rigs waiting for approval from ESA and/or NHPA review	Assumes average drilling costs (for all wells) for 2002 as reported by API, or $711,000 per well (Reference 11). Over the 1995-2002 time period, the average rig utilitzation rate was 70% (Reference 12). This was used for estimating rig day rates, resulting in an average drilling day rate of ~$2,800 per day.	No explicit assumptions stated.	Not considered in EPA's economic impact assessment.	
Average reserve additions per new well drilled (used for estimating the value "lost" due to production delays).	Based on EIA forecast drilling levels and reserve additions for oil and gas in the 2004 AEO Reference Case. On average, over the 2003-2025, a typical well drilled will add ~ 85,000 BOE of new reserves (Reference 9).	No explicit assumptions stated.	Not considered in EPA's economic impact assessment.	
Industry average discount rate (used for estimating the value "lost" due to production delays).	According to EIA's Performance Profiles for Major Energy Producers, 2002 (Reference 10), FRS reporting companies earned an annual return on investment for domestic O&G production of 13.3% in 2001 and 6.1% in 2002. The average of these -- 9.7% -- was used in this analysis (for estimating the value of delayed production). This amounts to a daily discount rate of 0.0266%.	No explicit assumptions stated.	Not considered in EPA's economic impact assessment.	

APPENDIX A

7-Dec-04

CRITICAL FACTORS AND KEY ASSUMPTIONS CONTRIBUTING TO THE ECONOMIC IMPACT OF POTENTIAL NEW STORM WATER DISCHARGE REQUIREMENTS

Key Data Elements and Assumptions	Assumption Used in this Analysis	Alternative Potential Sources of Information, Data, and/or Critical Assumptions		
		Industry/NGOs	**EPA (2002) Economic Impact Assessment**	**Prev. DOE Assumptions**
Discount rate of estimating economic impacts	For this study, a discount rate of 5 percent was selected as a reasonable "mid-point" rate based on the literature reviewed.		Choice of the discount rate is one of the most controversial and important topics within cost-benefit analysis. The available literature was reviewed to provide some insight into the choice of a discount rate to use in this study. The Office of Management and Budget (OMB) recommends a 7 percent discount rate for social benefit-cost analysis (References 17 and 18)]. In an EPA report of guidelines for its economic analyses [Reference 19], a 3 percent discount rate is recommended. However, EPA's recent financial impact analysis of the Clear Skies Act uses a 5.3 percent discount rate [Reference 20] and their benefit analysis of the Clear Skies Act forecasts benefits using both a 3 percent and 7 percent rate [Reference 21].	
Portion of wells experiencing increased royalty costs associated with project delays; and impact of those increased rates	Assumes Henry Petroleum estimated 5% of wells will have to pay increased royalties, with an increase of 2.5% in the royalty rate (Reference 3). Higher Impact assumes that 10% of wells have to pay increased royalties.	Henry Petroleum presentation estimates that 5% of wells will have to pay increased royalties, with an increase of 2.5% in the royalty rate (Reference 3)	Not considered in EPA's economic impact assessment.	
Average daily prodution rate per well	Average daily prodution rate per well assumed to be 13 BOE/day for oil and gas wells (Reference 9)			
Portion of wells experiencing forfeited lease bonuses and rentals associated with project delays	Uses Henry Petroluem estimate of 5% (Reference 3) Higher Impact scenario assumes 20%	Henry Petroleum presentation estimates that 5% of wells will forfeit bonuses (Reference 3)		

CRITICAL FACTORS AND KEY ASSUMPTIONS CONTRIBUTING TO THE ECONOMIC IMPACT OF POTENTIAL NEW STORM WATER DISCHARGE REQUIREMENTS

Key Data Elements and Assumptions	Assumption Used in this Analysis	Alternative Potential Sources of Information, Data, and/or Critical Assumptions		
		Industry/NGOs	**EPA (2002) Economic Impact Assessment**	**Prev. DOE Assumptions**
Lease rental cost	Uses Henry Petroluem estimate of $25/acre (Reference 3)	Henry Petroleum presentation estimates rental costs of $25/acre (Reference 3)		
Lease bonus cost	Uses Henry Petroluem estimate of $100/acre (Reference 3)	Henry Petroleum presentation estimates that lease bonus costs of $100/acre (Reference 3)		
Well site acreage	Uses Henry Petroluem estimate of 320 acres (Reference 3)	Henry Petroleum presentation estimates average well site size at 320 acres (Reference 3)		
Estimated proportion of wells not pursued because of difficulties with the permitting process.	Estimated 5% of wells not pursued because leases are lost due to project delays. Higher Impact scenario assumes 15%.	One small independent operator (who requested anonymity) reported that his last 14 oil and gas exploration and development prospects averaged over 100 negotiated leases from separate mineral interest owners for each prospect. Of these, this operator believes that from four to six (28% - 42%) would most likely not have been pursued had the new storm water discharge requirements been in place, due to the difficulties the process would cause in the logistics associated with acquiring leases, obtaining permit approvals, scheduling rigs, and meeting lease commitments.		
Estimated impact of lost production from wells not pursued on natural gas prices	Based on a number of previous runs performed by EIA's National Energy Modeling System (NEMS), a rule of thumb was developed to establish the impact of lost natural gas production on future natural gas prices. Based on this review (Reference 9 and 16), it was determined that gas prices increase by $0.13 for every Tcf loss in natural gas production. Analysis of various sensitivity cases in the NPC natural gas study (Reference 14) showed this impact to be over six times as large, with natural gas prices increasing by $0.82 for every Tcf loss in natural gas production. The impact of lost gas production on gas prices was estimated using both sets of assumptions in this assessment.	.		

GUIDANCE DOCUMENT
REASONABLE AND PRUDENT PRACTICES FOR STABILIZATION (RAPPS) OF OIL AND GAS CONSTRUCTION SITES
HJN 040027 IM

PROVIDED BY:

____

____

____

____

PREPARED BY:

HORIZON ENVIRONMENTAL SERVICES, INC.

APRIL 2004

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF APPENDICES

APPENDIX **PAGE**

1.0 INTRODUCTION

The purpose of this document is to compile the various operating practices utilized by reasonable and prudent operators in the oil and gas industry to control erosion and sedimentation associated with storm water runoff from areas disturbed by clearing, grading, and excavating activities related to site preparation associated with oil and gas exploration, production processing, treatment, and transmission activities. Site preparation activities associated with such oil and gas activities are referred to in this document, consistent with EPA's terminology, as "oil and gas construction activities" or "construction activities." The operating practices used to control erosion and sedimentation from oil and gas site construction activities are referred to in this document as "Reasonable and Prudent Practices for Stabilization" or "RAPPS."

In the preparation of this document, emphasis was placed on the selection and practical application of RAPPS, given a variety of basic physical circumstances. This document is provided as a tool to quickly evaluate which RAPPS may be useful at a given construction site. This document anticipates that the user will be prudent and exercise good judgment in evaluating site conditions and deciding which RAPPS or combination of RAPPS is to be used at a specific site. If the RAPPS selected are not effective to prevent discharges of potentially undesirable quantities of sediment to a regulated water body, different or additional RAPPS should be employed.

2.0 CONSTRUCTION SITE PHYSICAL CONSIDERATIONS

There are several physical conditions that can affect the decision about which RAPPS will be effective at a given construction site. Two primary factors that are emphasized within this document are the proximity to a regulated water body and the amount of vegetative cover between the construction site and the regulated water body. Other physical considerations include the slope of the terrain, rainfall, and soil erodibility. For purposes of this guidance document, each of these physical features may further be defined with respect to a designated rank (i.e., slope 0 to 10% or vegetative cover 25 to 75%).

Slope is defined as the amount of elevation gain over a given distance (vertical rise to horizontal run). A hill with 2 feet of elevation gain over 5 feet of horizontal distance has a slope of approximately 40%. A slope of 10% would require 2 feet of elevation gain per 20 feet of horizontal distance. The slope characteristic must be evaluated between the construction activity and the regulated water body.

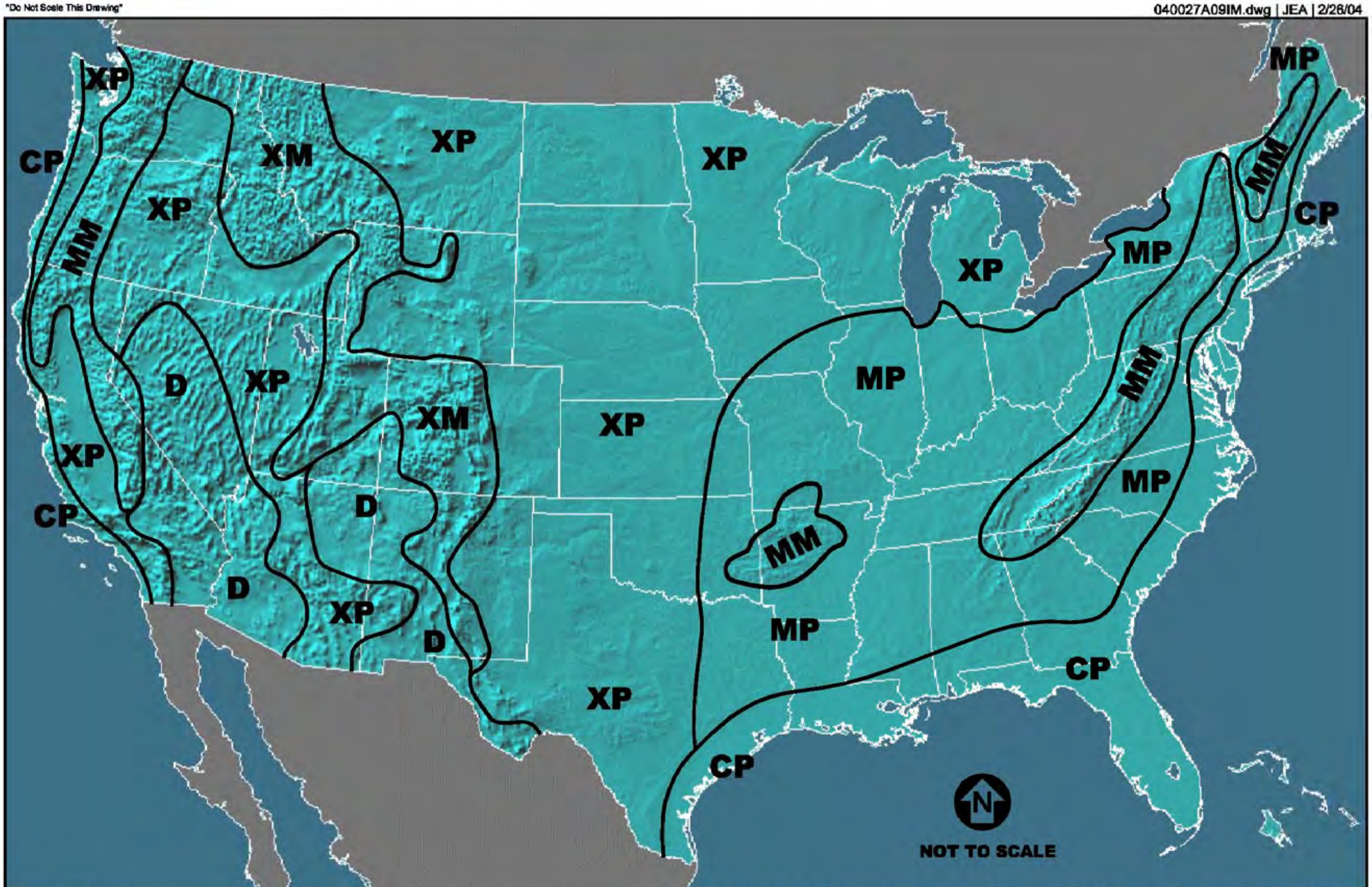
Vegetative cover is defined as the percentage of ground covered with primarily low-growing, herbaceous vegetation (grasses, forbs, and wildflowers). Shrubs and trees may provide some erosion control and filtration, but the amount of filtration is significantly less than that provided by low-growing herbaceous cover. For the purposes of this document, therefore, percentage cover of shrubs and trees should not be factored into the estimate of vegetative cover.

3.0 GEOGRAPHIC LOCATIONS AND IDENTIFICATION OF RAPPS

The following sections describe general geographical categories across the continental United States as outlined on Figure 1. These categories were defined taking into consideration general slope, annual rainfall, major soil types, and vegetative cover.

"Do Not Scale This Drawing"

040027A09IM.dwg | JEA | 2/26/04



MAP SOURCE:
RAY STERNER, JOHN HOPKINS UNIVERSITY APPLIED PHYSICS LABORATORY (1995)

Horizon Environmental Services, Inc.

EXPLANATION

CP	COASTAL PLAINS	**MP**	MESIC PLAINS	**MM**	MESIC MOUNTAINS
D	DESERTS	**XP**	XERIC PLAINS	**XM**	XERIC MOUNTAINS

FIGURE 1

GENERAL GEOGRAPHICAL LOCATIONS WITHIN THE CONTINENTAL UNITED STATES REASONABLE AND PRUDENT PRACTICES FOR STABILIZATION (RAPPS) GUIDANCE

The distance between a construction site and a regulated water body should be calculated from the closest boundary of land disturbance due to construction activity to the boundary of the regulated water body. Construction sites determined to be in excess of a minimum distance from a regulated water body for a particular geographical region will not typically require the implementation of any RAPPS. This identified minimum distance was determined using the assumed general physical characteristics for a particular geographical category but may differ within any given geographical category.

The user should first determine which geographical category the construction project falls within, utilizing both the provided map and good field judgment. If local conditions in the immediate area do not meet the conditions described for the geographical category that would be indicated by the provided map, select a decision tree from another geographical category that better meets local conditions. If local conditions do not meet any of the mapped geographical category descriptions, the user should use good judgment selecting RAPPS.

Once the geographical category is determined, the user can determine if the assumptions outlined within that category fit the construction site. One to several physical conditions may be assumed to be constant within any given geographical category. Physical conditions that may not be assumed to be constant include slope, vegetative cover, and distance to regulated water. The area between the construction site and regulated water should be reviewed to determine approximate slope and the percentage of vegetative cover. These values will be utilized within the decision tree to determine a list of RAPPS to consider for that particular construction site.

It should be noted that the list of RAPPS for any given pathway on the decision tree are simply suggestions of RAPPS alternatives, from which one or more of the listed techniques or practices may be selected for a given site under site-specific circumstances. Not all RAPPS listed will necessarily be required for any given project. In addition, the list of RAPPS for any given pathway on the decision tree may not exhaust all of the available RAPPS that may be effective for any given construction site. Other RAPPS, not listed in this document, may be beneficial for controlling surface water runoff from the construction site, in addition to or in lieu of the RAPPS listed in this document.

RAPPS generally considered effective to prevent potentially undesirable quantities of sediment in storm water runoff from construction activities within these geographical categories are referenced within Appendix A of this document. Specific information (e.g., text description, limitations, and conceptual drawing) for each RAPPS is provided in Appendix A. RAPPS presented in Appendix A were derived from both common industry references provided in Section 4.0 of this document and from practical field experience.

A summary of the steps to follow when using this guidance document are below.

1. Determine geographical category that best fits local conditions using Figure 1 and field judgment.
2. Assure that assumptions for geographical category fit construction location. If local conditions do not meet assumptions, use good judgment to select RAPPS.
3. Review area between construction activity and regulated water body to determine distance to the regulated water body, approximate slope, and approximate vegetative cover.
4. Work through decision tree utilizing information from step 3.
5. Select RAPPS from the alternatives listed as being effective for a construction site under similar conditions of distance, slope, and vegetative cover (Note: not all RAPPS alternatives listed will necessarily be required for effective storm water control).
6. Implement RAPPS in appropriate locations.
7. Begin construction.
8. Stabilize disturbed areas following completion of construction.

3.1 COASTAL PLAINS

Description

Generally flat plains along coastal areas with a slope less than 10%; deep erodible soils; highly variable vegetation cover; and relatively high annual precipitation.

Selection of RAPPS

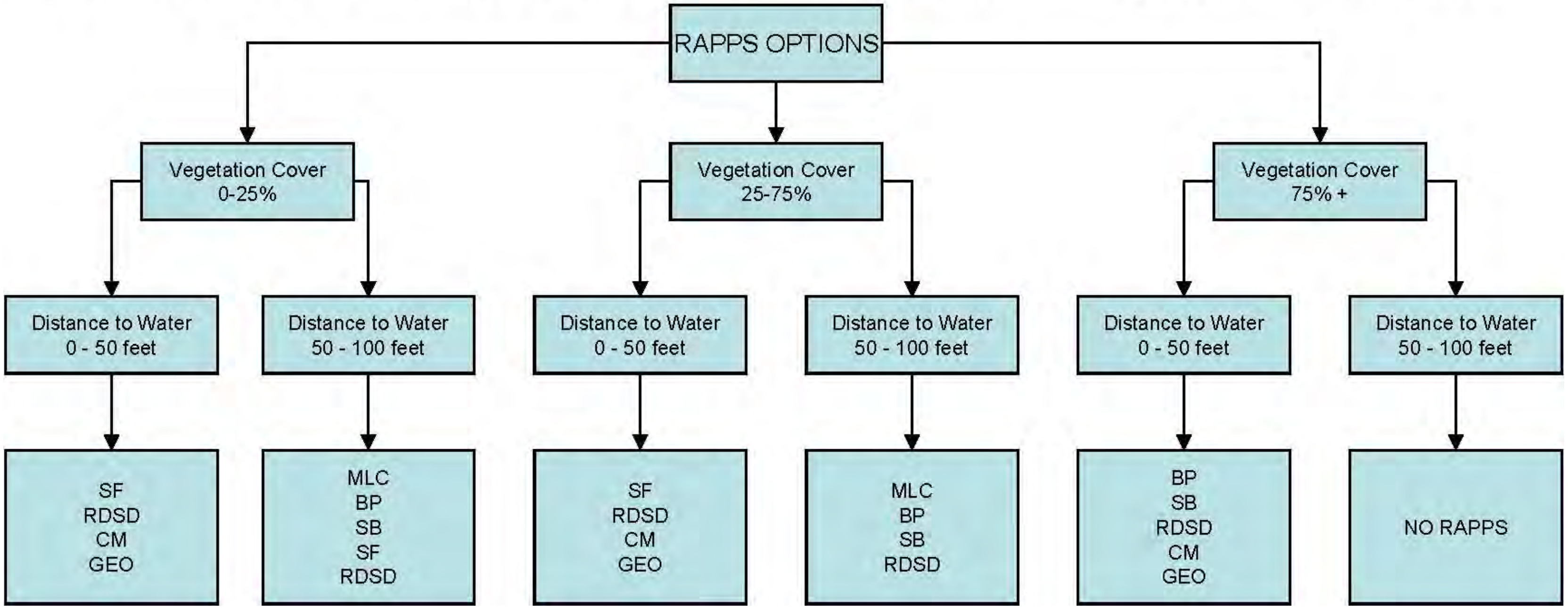
The flat topography of this region along with primarily herbaceous vegetation generally limits the opportunity for potentially undesirable quantities of sediment in storm water discharges to occur. Therefore, construction at oil and gas sites will not require the installation of RAPPS if one of the following exists:

1. The construction site is located in excess of 100 feet from a regulated water body.

2. The area between the construction site and a regulated water body has a vegetative cover in excess of 75% AND the site is located in excess of 50 feet from a regulated water body.

If neither of these two conditions is met, the decision tree in Table 3.1-1 will be useful in determining which RAPPS would be effective under the given circumstances. The decision tree process for this geographical category assumes that slopes are flat (0 to 10%); annual rainfall is high (50 inches and above); and soils are generally highly erodible.

Table 3.1-1 Decision Tree for Coastal Plains Geographical Region



Coastal Plains Assumptions:
1. Slopes are less than 10%
2. Annual precipitation is greater than 50 inches
3. Soils are loams or silts and highly erodable

No RAPPS needed:
1. When construction site is in excess of 100 feet from a regulated water body OR
2. When vegetative cover exceeds 75% AND the site is in excess of 50 feet from a regulated water body.

<u>Index</u>

BP = Brush Pile
CM = Construction Mat
CULV = Cross-Drain Culvert
DD = Diversion Dike
DIP = Drainage Dip
GEO = Geotextiles
MLC = Mulch
RB = Rock Berm
RDSD = Road-Side Ditch
RDSS = Road Surface Slope
RGHN = Roughening
SB = Straw Bale
SF = Silt Fence
ST = Sediment Trap
TO = Turnout

The list of RAPPS for any given pathway on the decision tree are suggestions of RAPPS alternatives, from which one or more of the listed techniques or practices may be selected for a given site under site-specific circumstances. Not all RAPPS listed will necessarily be required for any given project.

The list of RAPPS for any given pathway on the decision may not exhaust all of the available RAPPS that may be effective for any given construction site. Other RAPPS, not listed in this flowchart, may be beneficial for controlling surface water runoff from the construction site, in addition to or in lieu of the RAPPS listed in this document.

3.2 XERIC PLAINS

Description

Generally inland flat plains within the western portions of the US; slopes less than 40%; low soil erodibility; highly variable vegetation cover; and relatively low annual precipitation.

Selection of RAPPS

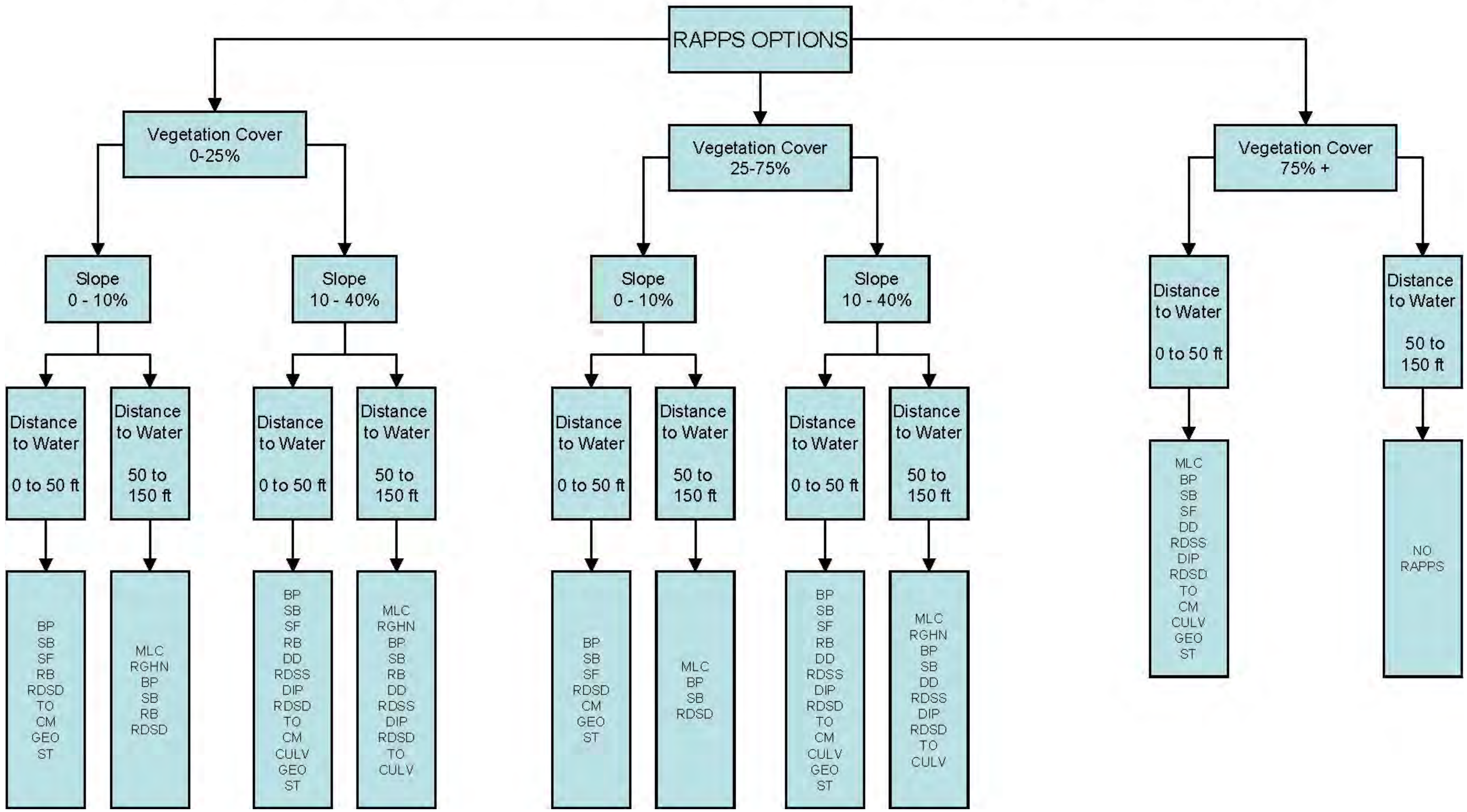
This region typically has fewer rainfall events with lower total annual precipitation than does the Mesic Plains. Dominant soils are sand and rock. These factors reduce the opportunity for potentially undesirable quantities of sediment in storm water discharges to occur. Therefore, construction at oil and gas sites will not require the installation of RAPPS if one of the following exists:

1. The construction site is located in excess of 150 feet from a regulated water body.

2. The area between the construction site and a regulated water body has a vegetative cover in excess of 75% AND the site is located in excess of 50 feet from a regulated water body.

If neither of these two conditions is met, the decision tree in Table 3.2-1 will be useful in determining which RAPPS would be effective under the given circumstances. The decision tree process for this geographical category assumes that annual precipitation is low (less than 35 inches) and soils have generally low erodibility.

Table 3.2-1 Decision Tree for Xeric Plains Geographical Region



Interior Xeric Plains Assumptions:
1. Annual precipitation is less than 35 inches
2. Soils are primarily sandy with low erodability

No RAPPS needed:
1. When construction site is in excess of 150 feet from a regulated water body OR
2. When vegetative cover exceeds 75% AND the site is in excess of 50 feet from a regulated water body.

Index

BP = Brush Pile
CM = Construction Mat
CULV = Cross-Drain Culvert
DD = Diversion Dike
DIP = Drainage Dip
GEO = Geotextiles
MLC = Mulch
RB = Rock Berm
RDSD = Road-Side Ditch
RDSS = Road Surface Slope
RGHN = Roughening
SB = Straw Bale
SF = Silt Fence
ST = Sediment Trap
TO = Turnout

The list of RAPPS for any given pathway on the decision tree are suggestions of RAPPS alternatives, from which one or more of the listed techniques or practices may be selected for a given site under site-specific circumstances. Not all RAPPS listed will necessarily be required for any given project.

The list of RAPPS for any given pathway on the decision may not exhaust all of the available RAPPS that may be effective for any given construction site. Other RAPPS, not listed in this flowchart, may be beneficial for controlling surface water runoff from the construction site, in addition to or in lieu of the RAPPS listed in this document.

3.3 MESIC PLAINS

Description

Generally inland flat plains within the eastern portions of the US; slopes less than 40%; moderately erodible soils including clays and loams; highly variable vegetation cover; and moderate annual precipitation.

Selection of RAPPS

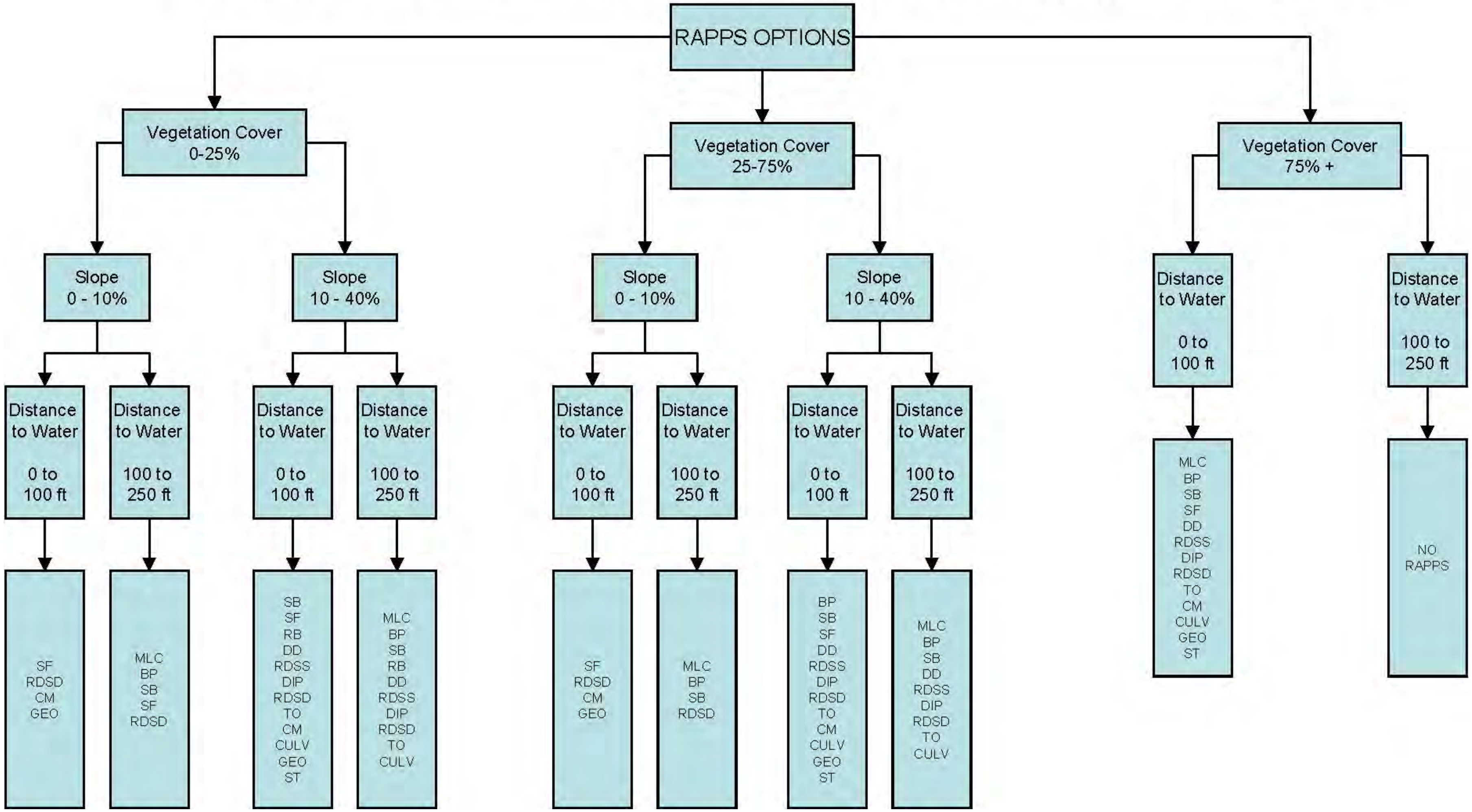
Since this region tends to have moderate annual precipitation, regular rainfall events, and clay-and-loam-dominated soils that are somewhat erodible, the opportunity for potentially undesirable quantities of sediment to be found in uncontrolled storm water discharges from an oil and gas construction site is increased over the Xeric Plains. Therefore, distance and slope are adjusted accordingly. Construction at oil and gas sites will not require the installation of RAPPS if one of the following exists:

1. The construction site is located in excess of 250 feet from a regulated water body.

2. The area between the construction site and a regulated water body has a vegetative cover in excess of 75% AND the site is located in excess of 100 feet from a regulated water body.

If neither of these two conditions is met, the decision tree in Table 3.3-1 will be useful in determining which RAPPS would be effective under the given circumstances. The decision tree process for this geographical category assumes that annual precipitation is moderate (35 inches and above) and soils have moderate erodibility.

Table 3.3-1 Decision Tree for Mesic Plains Geographical Region



Interior Mesic Plains Assumptions:
1. Annual precipitation is greater than 35 inches
2. Soils are moderately erodable

No RAPPS needed:
1. When construction site is in excess of 250 feet from a regulated water body OR
2. When vegetative cover exceeds 75% AND the site is in excess of 100 feet from a regulated water body.

Index

BP = Brush Pile
CM = Construction Mat
CULV = Cross-Drain Culvert
DD = Diversion Dike
DIP = Drainage Dip
GEO = Geotextiles
MLC = Mulch
RB = Rock Berm
RDSD = Road-Side Ditch
RDSS = Road Surface Slope
RGHN = Roughening
SB = Straw Bale
SF = Silt Fence
ST = Sediment Trap
TO = Turnout

The list of RAPPS for any given pathway on the decision tree are suggestions of RAPPS alternatives, from which one or more of the listed techniques or practices may be selected for a given site under site-specific circumstances. Not all RAPPS listed will necessarily be required for any given project.

The list of RAPPS for any given pathway on the decision may not exhaust all of the available RAPPS that may be effective for any given construction site. Other RAPPS, not listed in this flowchart, may be beneficial for controlling surface water runoff from the construction site, in addition to or in lieu of the RAPPS listed in this document.

3.4 DESERTS

Description

Lowlands of the southwestern US; slopes from 0 to 40%, but can be greater then 40%; shallow rocky or sandy soils with low erodibility; low to no vegetation cover; and low annual precipitation.

Selection of RAPPS

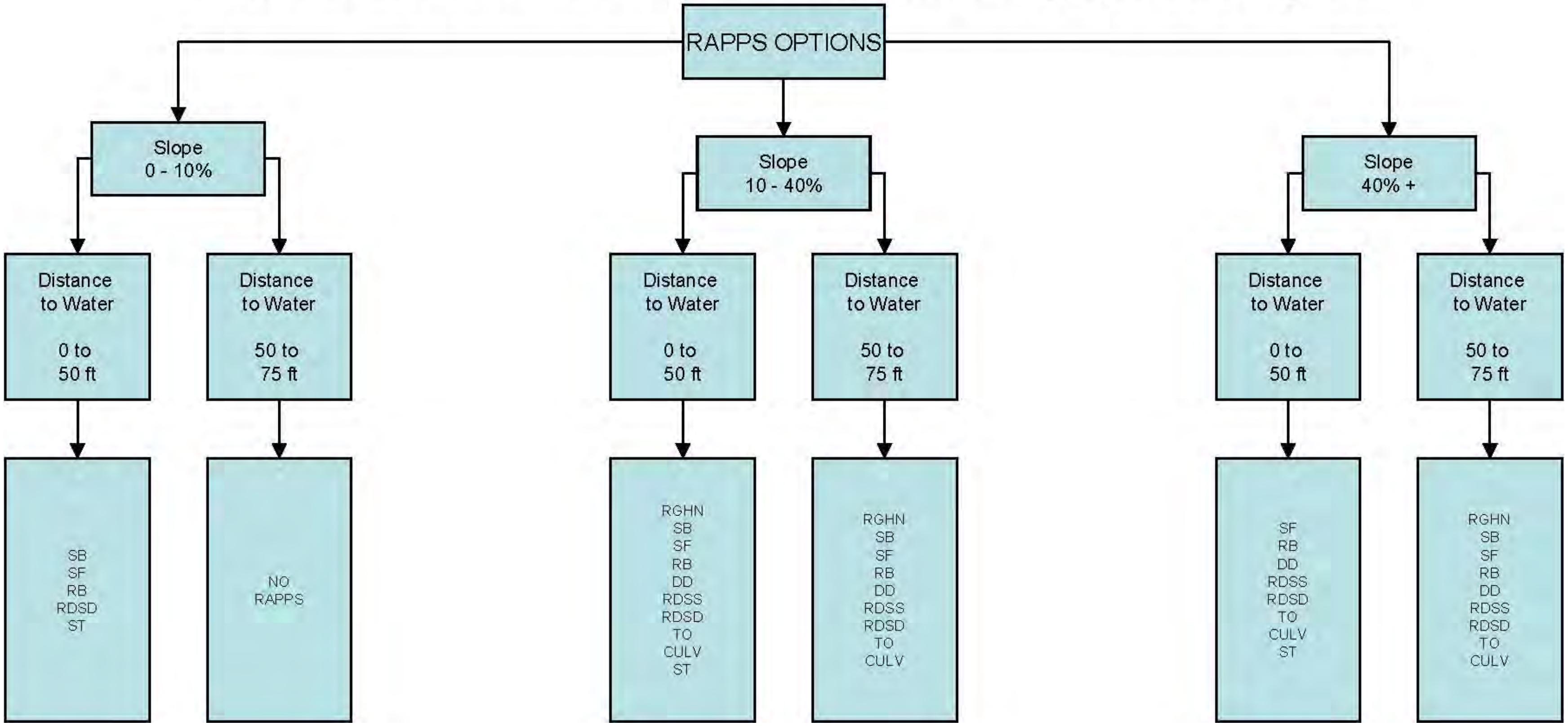
The lack of significant annual rainfall and the infrequency of rainfall events along with sand-and-rock-dominated soils limit the amount of sediment in storm water discharges from an oil and gas construction site in this type of geographical region. Therefore, construction at oil and gas sites will not require the installation of RAPPS if one of the following exists:

1. The construction site is located in excess of 75 feet from a regulated water body.

2. The area between the construction site and a regulated water body has a slope of less than 10% AND the site is in excess of 50 feet from a regulated water body.

If neither of these two conditions is met, the decision tree in Table 3.4-1 will be useful in determining which RAPPS would be effective under the given circumstances. The decision tree process for this geographical category assumes vegetation cover is low (0 to 25% coverage); annual precipitation is low (less than 15 inches); and soils are primarily sand and rock.

Table 3.4-1 Decision Tree for Deserts Geographical Region



Desert Assumptions:
1. Vegetation cover is below 25%
2. Annual precipitation is less than 15 inches
3. Soils are primarily sand and/or rock

No RAPPS needed:
1. When construction site is in excess of 75 feet from a regulated water body OR
2. When construction site has a slope of less than 10% AND is in excess of 50 feet from a regulated water body.

Index

BP = Brush Pile	RDSD = Road-Side Ditch
CM = Construction Mat	RDSS = Road Surface Slope
CULV = Cross-Drain Culvert	RGHN = Roughening
DD = Diversion Dike	SB = Straw Bale
DIP = Drainage Dip	SF = Silt Fence
GEO = Geotextiles	ST = Sediment Trap
MLC = Mulch	TO = Turnout
RB = Rock Berm	

The list of RAPPS for any given pathway on the decision tree are suggestions of RAPPS alternatives, from which one or more of the listed techniques or practices may be selected for a given site under site-specific circumstances. Not all RAPPS listed will necessarily be required for any given project.

The list of RAPPS for any given pathway on the decision may not exhaust all of the available RAPPS that may be effective for any given construction site. Other RAPPS, not listed in this flowchart, may be beneficial for controlling surface water runoff from the construction site, in addition to or in lieu of the RAPPS listed in this document.

3.5 XERIC MOUNTAINS

Description

Generally mountainous areas within the western US; slopes exceeding 10%; variable vegetation cover; shallow rocky soils with low erodibility; and low to moderate annual precipitation.

Selection of RAPPS

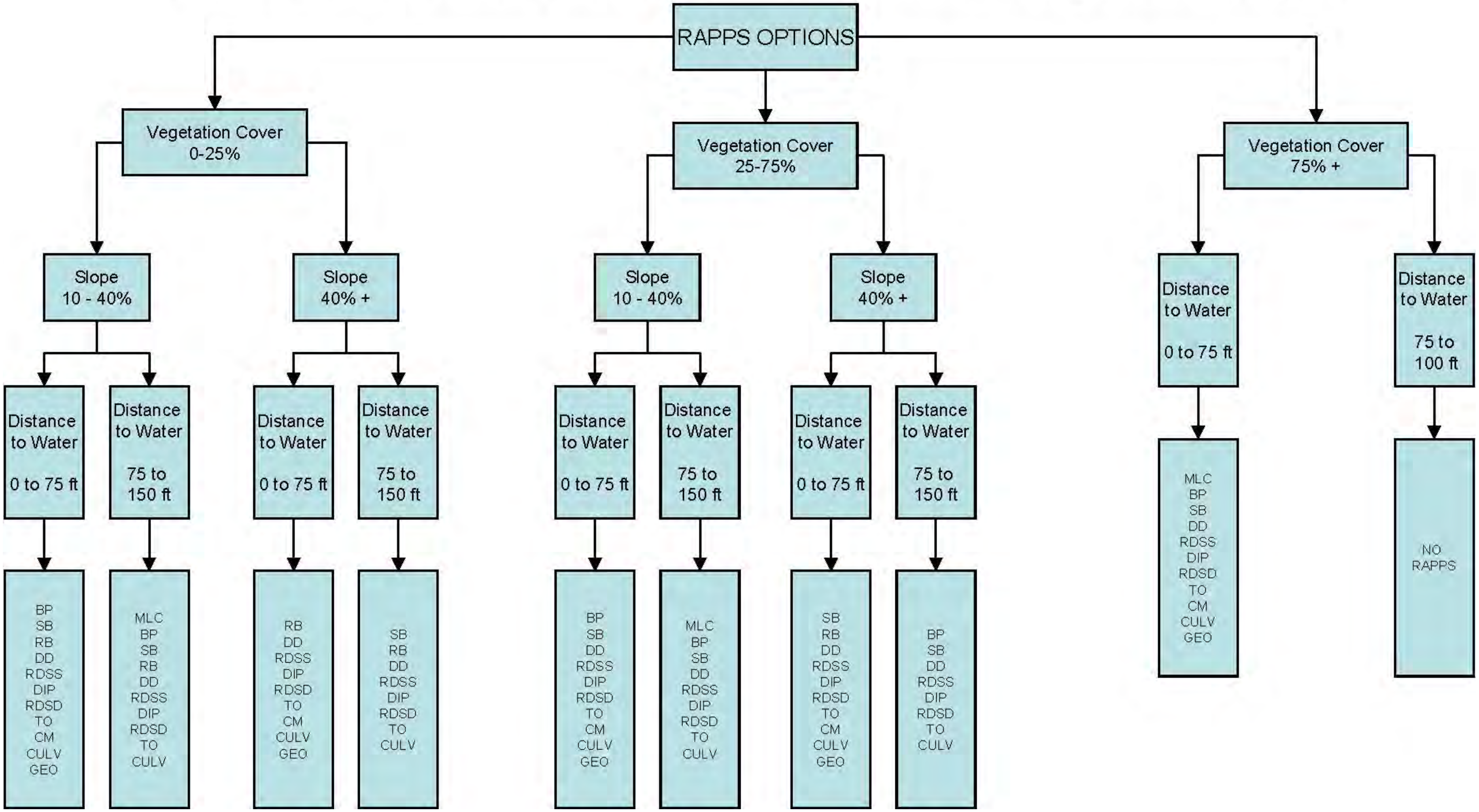
This region is dominated by very rocky, low-erodibility soils and typically only experiences rainfall events during warmer months. Snowmelt can cause erosion, but the opportunity for sediment in storm water runoff to be discharged to a regulated water body in undesirable quantities is low in comparison to the Mesic Mountains, and distance and slope are adjusted accordingly compared to the Mesic Mountains. Therefore, construction at oil and gas sites will not require the installation of RAPPS if one of the following exists:

1. The construction site is located in excess of 150 feet from a regulated water body.

2. The area between the construction site and a regulated water body has vegetative cover in excess of 75% AND the site is in excess of 75 feet from a regulated water body.

If neither of these two conditions is met, the decision tree in Table 3.5-1 will be useful in determining which RAPPS would be effective under the given circumstances. The decision tree process for this geographical category assumes annual precipitation is low to moderate (from 10 to 50 inches) and soils are primarily rock.

Table 3.5-1 Decision Tree for Xeric Mountains Geographical Region



Xeric Mountains Assumptions:
1. Annual precipitation is between 10 and 50 inches
2. Soils are rocky with low erodability

No RAPPS needed:
1. When construction site is in excess of 150 feet from a regulated water body OR
2. When vegetative cover exceeds 75% AND the site is in excess of 75 feet from a regulated water body.

Index

BP = Brush Pile	RDSD = Road-Side Ditch
CM = Construction Mat	RDSS = Road Surface Slope
CULV = Cross-Drain Culvert	RGHN = Roughening
DD = Diversion Dike	SB = Straw Bale
DIP = Drainage Dip	SF = Silt Fence
GEO = Geotextiles	ST = Sediment Trap
MLC = Mulch	TO = Turnout
RB = Rock Berm	

The list of RAPPS for any given pathway on the decision tree are suggestions of RAPPS alternatives, from which one or more of the listed techniques or practices may be selected for a given site under site-specific circumstances. Not all RAPPS listed will necessarily be required for any given project.

The list of RAPPS for any given pathway on the decision may not exhaust all of the available RAPPS that may be effective for any given construction site. Other RAPPS, not listed in this flowchart, may be beneficial for controlling surface water runoff from the construction site, in addition to or in lieu of the RAPPS listed in this document.

3.6 MESIC MOUNTAINS

Description

Rolling highlands and steep mountains within the eastern and northwestern portions of the US; slopes exceeding 10%; variable vegetative cover; loamy soils with moderate erodibility; and very high annual precipitation.

Selection of RAPPS

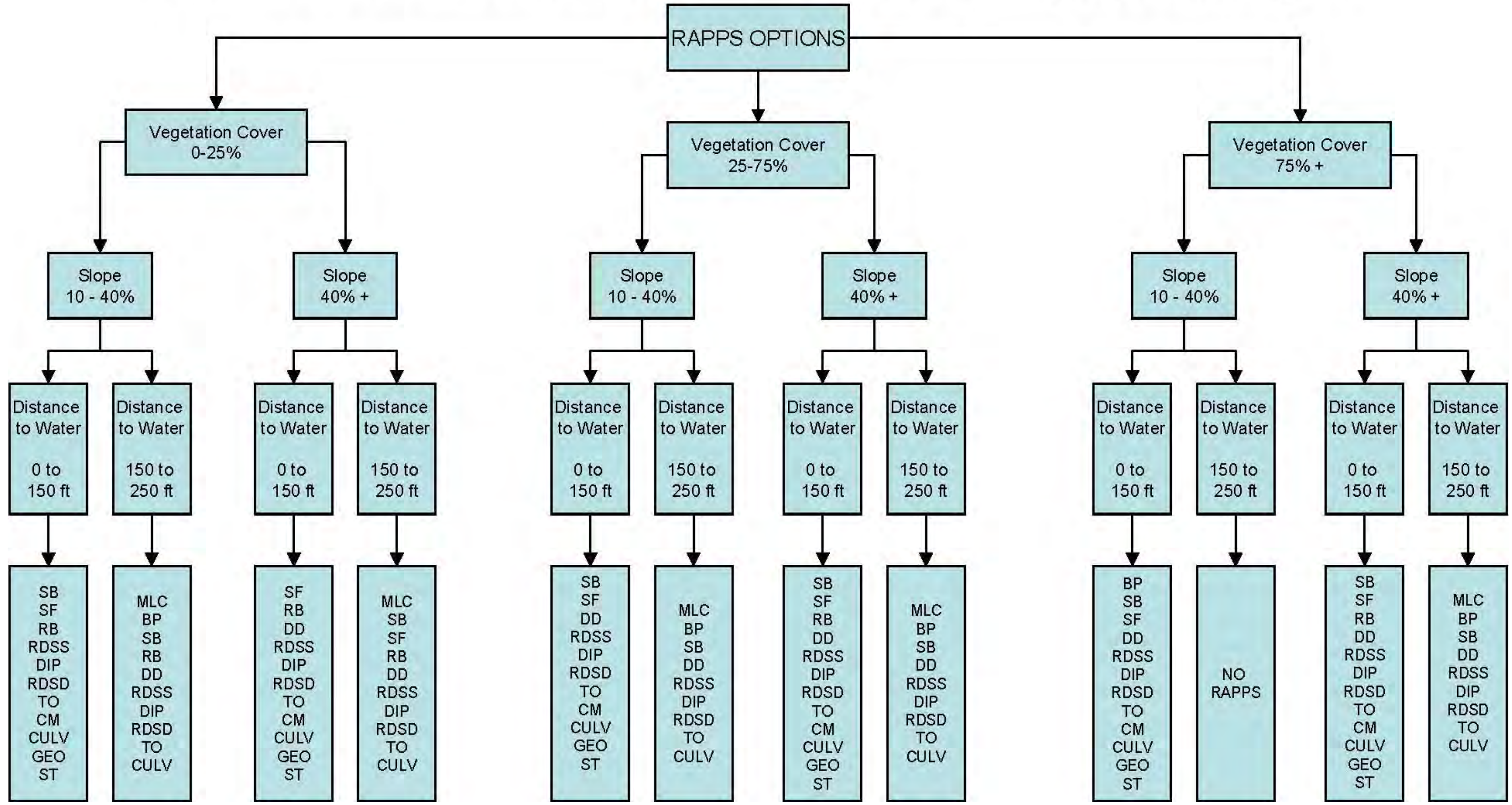
This region has high annual precipitation with frequent rainfall events. Additionally, vegetative cover tends to be dominated by forest, slopes are steep, and soils are dominated by loams. The opportunity for sediment to be discharged to a regulated water body in potentially undesirable quantities is increased over the Xeric and Mesic Plains and Xeric Mountains, and distance and slope for the Mesic Moutains are adjusted accordingly. Therefore, construction sites will not require the installation of RAPPS in the Mesic Mountains if one of the following exists:

1. The construction site is located in excess of 250 feet from a regulated water body.

2. The area between the construction site and a regulated water body has vegetative cover in excess of 75%; the slope is less than 40%; AND the site is in excess of 150 feet from a regulated water body.

If neither of these two conditions is met, the decision tree in Table 3.6-1 will be useful in determining which RAPPS would be effective under the given circumstances. The decision tree process for this geographical category assumes annual precipitation is high (in excess of 60 inches) and loamy soils are moderately erodible.

Table 3.6-1 Decision Tree for Mesic Mountains Geographical Region



Mesic Mountains Assumptions:
1. Annual precipitation is in excess 60 inches
2. Soils are loamy with moderate erodability

No RAPPS needed:
1. When construction site is in excess of 250 feet from a regulated water body OR
2. When vegetative cover exceeds 75%; the slope is less than 40%; AND the site is in excess of 150 feet from a regulated water body.

Index

BP = Brush Pile
CM = Construction Mat
CULV = Cross-Drain Culvert
DD = Diversion Dike
DIP = Drainage Dip
GEO = Geotextiles
MLC = Mulch
RB = Rock Berm
RDSD = Road-Side Ditch
RDSS = Road Surface Slope
RGHN = Roughening
SB = Straw Bale
SF = Silt Fence
ST = Sediment Trap
TO = Turnout

The list of RAPPS for any given pathway on the decision tree are suggestions of RAPPS alternatives, from which one or more of the listed techniques or practices may be selected for a given site under site-specific circumstances. Not all RAPPS listed will necessarily be required for any given project.

The list of RAPPS for any given pathway on the decision may not exhaust all of the available RAPPS that may be effective for any given construction site. Other RAPPS, not listed in this flowchart, may be beneficial for controlling surface water runoff from the construction site, in addition to or in lieu of the RAPPS listed in this document.

4.0 CONSTRUCTION CROSSING A REGULATED WATER BODY

Construction of crossing at regulated water bodies increases the opportunity for pollution entering these areas. Several listed RAPPS will likely be necessary for water protection given the particular circumstances. Appendix B includes some general diagrams indicating RAPPS used effectively to protect regulated waters during oil and gas construction activity. The general recommendations listed below should also be considered to help control discharges of sediment to the regulated water in undesirable quantities during construction at regulated water bodies.

- Bore under regulated water body to prevent disturbance.
- Generally, construction activities should be limited to the extent practicable within regulated waters.
- Locate staging areas and spoil storage areas a minimum of 10 feet from the water's edge. Additionally, good vegetative cover and/or sediment barriers will be needed between the stored spoil and regulated water.
- Operate tracked equipment on construction mats within regulated waters to limit soil compaction or disturbance within these areas.
- Refuel equipment a minimum of 100 feet from the regulated water body.
- Cut vegetation at ground level and limit removal of root zones and stumps where possible.
- Maintain the maximum amount of vegetative ground cover as possible.
- Install temporary equipment crossings after initial clearing to allow for equipment access during construction. Flume pipe will be necessary at flowing streams.
- Stream flows at crossings should be flumed or dammed and pumped past the construction area.
- Dewater trench in a manner to prevent sediment-laden water from entering the regulated water. Trench water should be pumped into an area with good vegetative cover or into a filter bag and dewatering structure.
- Water body banks should be stabilized following construction to prevent sloughing or erosion.

5.0 STABILIZATION

5.1 ACTIVELY DISTURBED

Area of land disturbed during preparation of oil and gas sites or portion thereof is considered “actively disturbed” during the time period starting with the commencement of land disturbing activities (such as clearing, grading, or excavating activities) until the area of land disturbed is in a state suitable for the use and capacity for which it was intended and RAPPS have been implemented, if necessary.

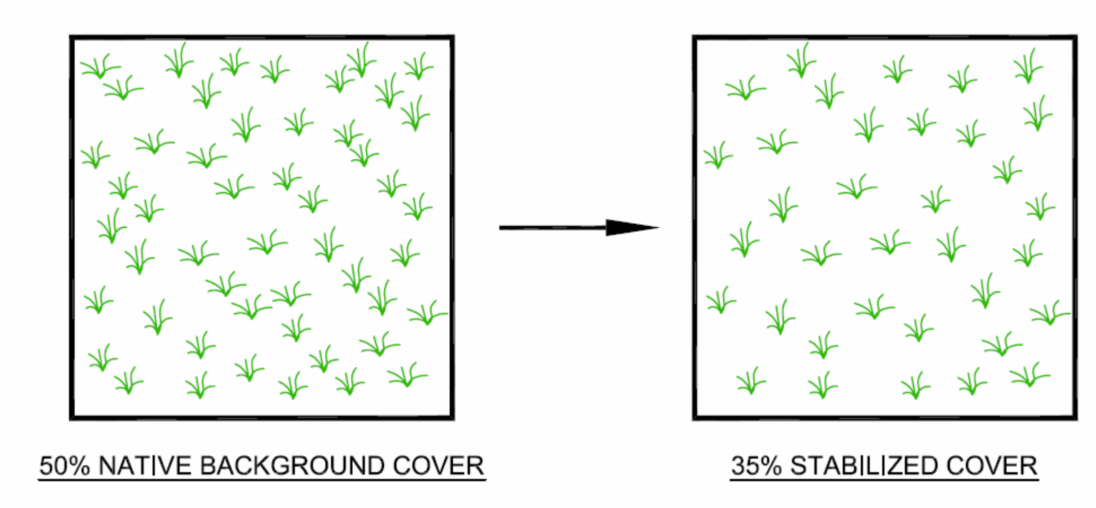
5.2 FINAL STABILIZATION

RAPPS should be maintained in good condition for the area disturbed during and after the period of active disturbance until final stabilization of the area disturbed. Final stabilization will limit and/or prevent potentially undesirable quantities of sediment from leaving the site in storm water runoff and entering a regulated water body. Final stabilization can be achieved in several different fashions.

After construction of roads and/or well or equipment pads is completed, the area covered by the road and/or equipment pad considered immediately and finally stabilized because of the placement of a base material on these areas, such as asphalt, caliche, rock, or just compaction of existing dirt in place. Once the base material is stabilized sufficiently for use in the use and capacity intended, it is considered finally stabilized.

In disturbed areas within Coastal Plains, Mesic Plains, Mesic Mountains, and Xeric Mountains where no base material will be placed, the area disturbed is considered finally stabilized when a uniform perennial vegetative cover with a density of 70% of the native background vegetative cover is established. When background native vegetation cover is less than 100%, the amount of vegetative cover needed to meet stabilization criteria needs to be determined. For example (see diagram below), if the native background vegetative cover is estimated at 50%, then 70% of the original 50% vegetative cover must be established. This would mean the area disturbed would need 35% vegetative cover to be considered finally stabilized (0.70 x 0.50 = 0.35 or 35%).

Alternatively, for sites located within the Desert and Xeric Plains in disturbed areas where no base material will be placed, the area disturbed may be considered finally stabilized prior to obtaining 70% of the native background vegetative cover as long as the following alternative final stabilization criteria are met: (1) Active disturbance of the land area to be considered stabilized has been completed, (2) RAPPS have been selected and installed appropriately, and (3) native seed has been dispersed in such a fashion as to be expected to achieve 70% background vegetative cover within 3 years under normal climate conditions for the region.



6.0 DEFINITIONS

Concentrated Flow – water run-off with increased volume and velocity

Construction Activity – construction activity including clearing, grading, and excavating operations that disturb land area, including construction of access roads, flow/gathering pipelines, well/tank battery pads, equipment/facility pads, regulated water body crossings

Construction Site – area of land disturbance

RAPPS – Reasonable and Prudent Practices for Stabilization – device, method, or procedure used to prevent or reduce sediment from oil and gas construction activity from entering a regulated water body in undesirable quantities

Regulated Water Body – A water body that is subject to the U.S. Environmental Protection Agency's (EPA's) jurisdiction under the Clean Water Act. EPA's jurisdiction extends over "waters of the U.S." EPA's definition of "waters of the U.S." is set out in Appendix C of this document.

NOTE: If there is a water body in the vicinity of your construction site and you are not sure whether it is a "regulated water body," you should contact an environmental professional or attorney to help you make this evaluation. The definition of the phrase "waters of the U.S." has been extensively litigated, and there is a large body of case law interpreting it. The definition of "regulated water body" may, therefore, vary between different areas of the country, because the courts in different parts of the country have reached different conclusions about the extent of EPA's jurisdiction.

Vegetative Cover – existing or planted low-growing, herbaceous plant species

7.0 REFERENCES

Cooperative Extension Service, Division of Agricultural Sciences and Natural Resources. Oklahoma State University. *Pollution Prevention at Exploration and Production Sites in Oklahoma.* Water Quality Series E-940, April 2002.

North Carolina Sedimentation Control Commission; North Carolina Department of Natural Resources and Community Development; and North Carolina Agricultural Extension Service. *Erosion and Sediment Control Planning and Design Manual.* September 1988.

US Department of Agriculture – Soil Conservation Service. *Erosion and Sediment Control Guidelines for Developing Areas in Texas*. 1976.

Alabama Soil and Water Conservation Committee. *Alabama Handbook for Erosion Control, Sediment Control, and Stormwater Management on Construction Sites and Urban Areas.* Volumes 1 and 2. June 2003.

US Environmental Protection Agency – National Pollutant Discharge Elimination System (NPDES). Construction Site Storm Water Runoff Control. http://cfpub.epa.gov/npdes/stormwater/menuofbmps/con_site.cfm (12 Feb. 2004).

Pennsylvania Department of Environmental Protection – Chapter 4, Oil and Gas Management Practices. http://www.dep.state.pa.us/eps/default.asp?P=fldr200149e0051190%5Cfldr200149e10561a8%5Cfldr20026f8082801d (12 Feb. 2004).

West Virginia Department of Environmental Protection – Office of Oil and Gas. http://www.dep.state.wv.us/publications.cfm?ssid=23 (12 Feb. 2004).

Protecting Water Quality in Urban Areas: A Manual – Minnesota Pollution Control Agency. http://www.pca.state.mn.us/water/pubs/sw-bmpmanual.html (12 Feb. 2004).

APPENDIX A

DESCRIPTION OF RAPPS

(RAPPS presented were derived from both common industry references provided in Section 4.0 of this document and from practical field experience)

1. VEGETATIVE COVER

Vegetative cover is an effective natural means of filtering runoff and preventing erosion. Preservation of existing vegetation to the maximum extent practicable keeps soils stabilized and provides a natural filter. The most effective vegetative cover consists of low-growing, herbaceous species with a high percentage of ground coverage. Shrubs and trees provide some means of preventing erosion; however, the filtering ability is greatly reduced.

Limitations:

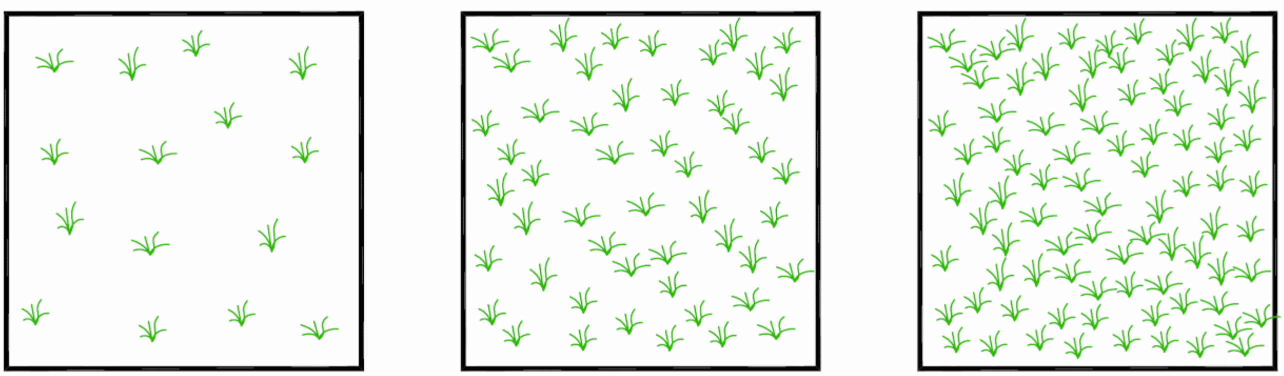
- Primarily filters sheet flow
- Minimum width of vegetative strip dependent on slope (greater slope requires wider strip)
- Vegetation must be established
- High percentage of ground cover

Installation:

- Limit vegetation clearing to the extent practicable during construction
- Plant fast-growing annual grasses for temporary controls
- Plant perennial seed mixes recommended by the local soil conservation office

Construction Activities:

Access roads, well/tank battery pads, and flow/gathering pipelines



15% COVER | 50% COVER | 85% COVER

2. MULCH (MLC)

Mulching is the use of vegetative fibers (e.g., straw, wood chips) to minimize rainfall impact, reduce suspended solids from runoff, protect seeds from erosion, prevent moisture loss from soil, and reduce predation of seeds by birds.

Limitations:

- Gradual slopes only
- Not for use immediately adjacent to wetlands or streams
- Can be lost with sheet flow runoff

Installation:

- Chop or chip wood, straw, or cellulose
- Mulch should be anchored by crimping or other technique
- Incorporate seed mix for permanent stabilization
- Hydro-mulch can be applied by spraying

Construction Activity:

Flow/gathering pipelines

3. ROUGHENING (RGHN)

This technique uses the horizontal grooves created by tracks of construction equipment to reduce runoff flow velocities. Tracks are established on the slopes perpendicular to water flow.

Limitations:

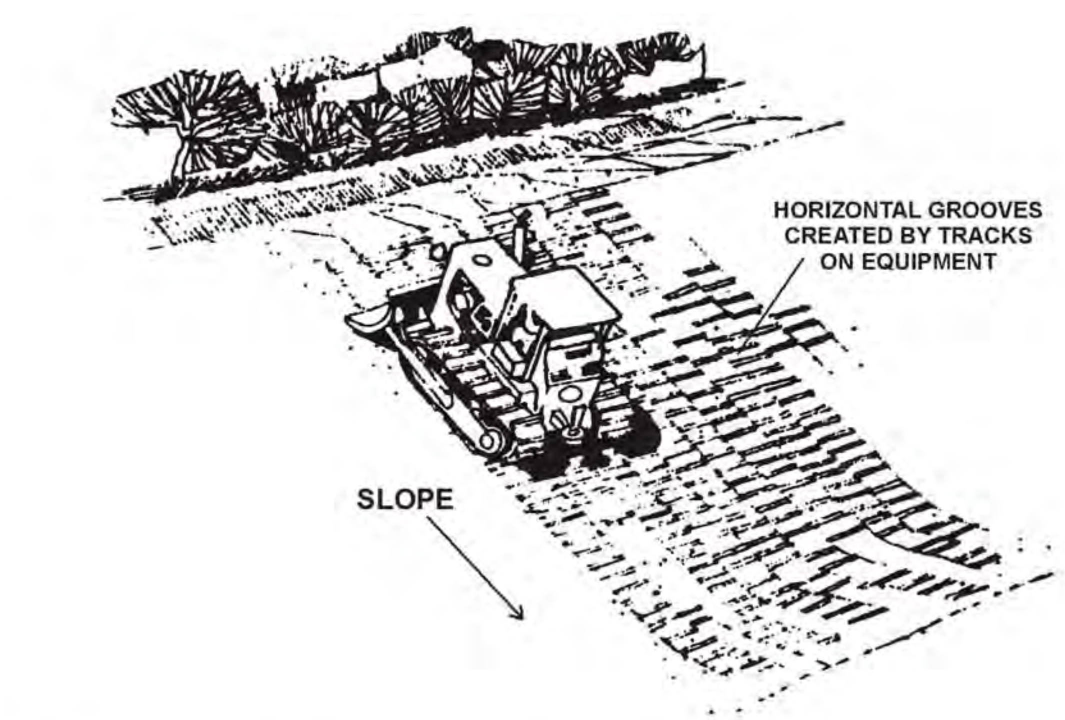
- Not for use on rocky slopes
- May cause soil compaction which limits vegetation re-growth
- Roughening may have to be re-established if lost due to heavy sheet flow runoff

Installation:

- Operate tracked equipment in a direction parallel to water flow as so to create tracks perpendicular to water flow

Construction Activity:

Access Roads, Well/Tank Battery Pads, and Flow/Gathering Pipelines



Source: Pennsylvania Department of Environmental Quality, 2004.

4. BRUSH PILES (BP)

Brush piles can be used to filter sediment from runoff of construction sites with small drainage areas on gradual slopes.

Limitations:

- Not effective on concentrated flows
- Large amounts of brush are typically needed
- Removal may be necessary after stabilization is complete

Installation:

- Cut up brush into small pieces and compact tightly
- Avoid bulky material
- Eliminate large voids within pile
- Pile brush up to 3 feet high with a minimum width of 5 feet at base
- Anchor brush piles
- The brush may be secured with photodegradable liner fabric

Construction Activities:

Access roads, well/tank battery pads, and flow/gathering pipelines

5. STRAW (HAY) BALES (SB)

This technique utilizes bound straw bales to filter sediment from runoff of small areas.

Limitations:

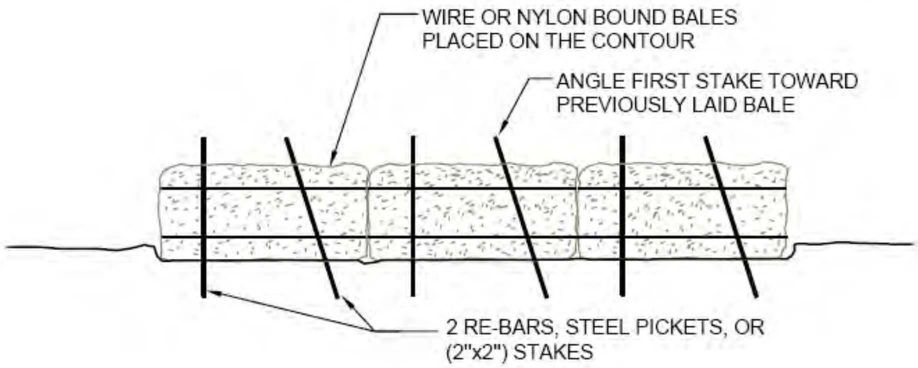
- Filters sheet flow from small drainage areas
- Short-term use
- Decomposes
- Consumed by livestock
- Removal of anchor stakes will be necessary after stabilization is complete

Installation:

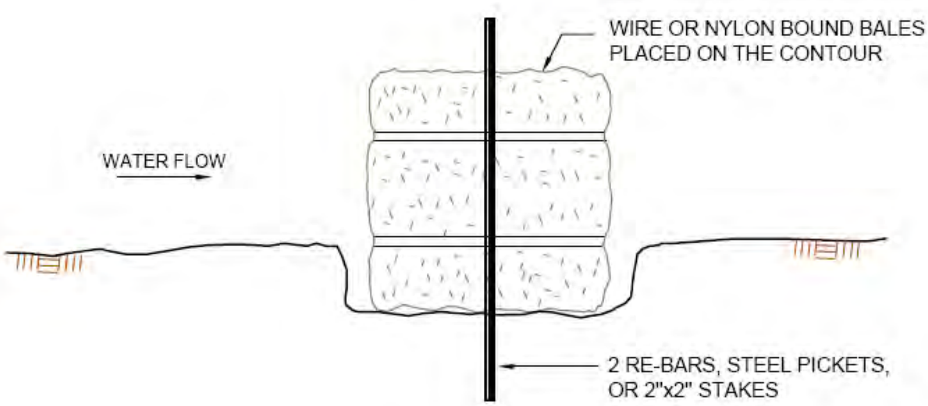
- Embed into trench
- Anchor with 2 support stakes
- Compact backfill on upgradient side
- Straw bales should extend across grade and upslope for short distance
- Use at outfall points from diversion dikes, turnouts, etc.

Construction Activities:

Access roads, well/tank battery pads, and flow/gathering pipelines



ANCHORING DETAIL



EMBEDDING DETAIL

6. **<u>SILT FENCE/FABRIC</u> (SF)**

Silt fence/fabric is utilized to filter sediment from runoff of small areas. Silt fence/fabric may also be utilized as a perimeter control around the construction site when the site is relatively small.

Limitations:

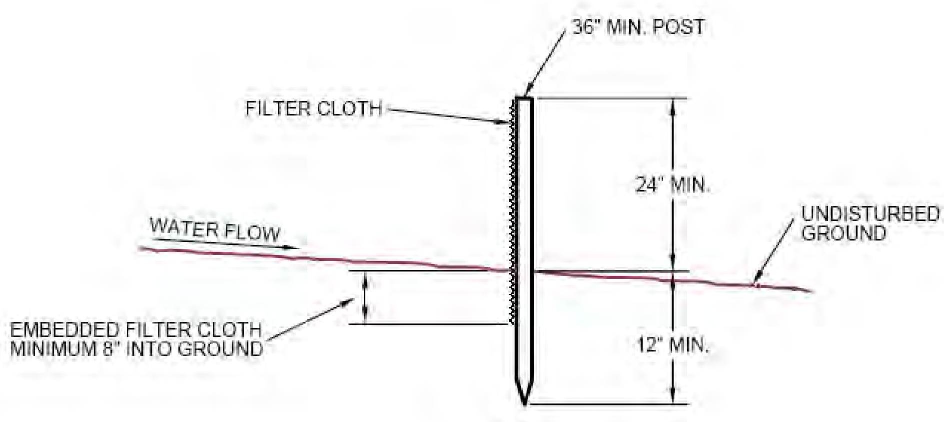
- Not for concentrated flows
- Not for use in rocky situations
- Removal will be necessary after stabilization is complete
- Not for large watersheds

Installation:

- Embed bottom of fabric into soil
- Support posts spaced no greater than 10 feet apart
- Compact backfill at base of fabric
- Extend silt fence across grade and upslope for short distance
- Use at outfall points where concentrated flows are not expected

Construction Activities:

Access roads, well/tank battery pads, and flow/gathering pipelines



CROSS-SECTION
N.T.S.

7. **ROCK BERM (RB)**

This technique is useful to filter sediment from concentrated flows and/or runoff of moderate grades and larger drainage areas. Additionally, rock berms may be utilized to reduce velocity of flows within constructed channels.

Limitations:

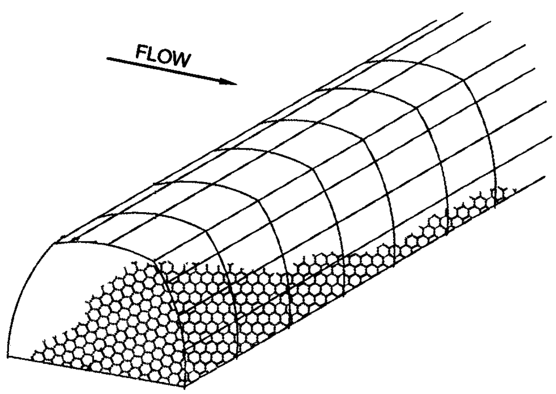
- Availability of rock
- Anchor rock into soil
- Difficult to remove after construction
- Require regular maintenance due to sediment build-up

Installation:

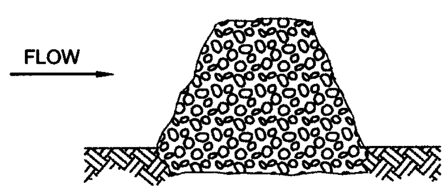
- Use medium to large diameter rock
- May secure rock within woven wire sheathing but not required
- Berm side slopes should be 3:1 or flatter
- Top of berm should be a minimum of 2 feet wide

Construction Activities:

Access roads, well/tank battery pads, and flow/gathering pipelines



ROCK BERM
N.T.S.



CROSS SECTION
N.T.S.

8. **<u>DIVERSION/EARTHEN DIKES (WATER BARS)</u> (DD)**

This technique may be used to collect runoff from undisturbed areas and divert around construction activity. Additionally, dikes are used to limit the accumulation of water volume by diverting runoff from construction area into a stabilized outlet or well-vegetated area.

Limitations:

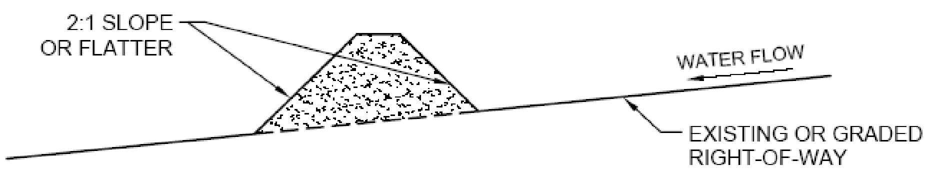
- Not for use on concentrated flows
- May cause concentrated flows from sheet flow
- Requires vegetative cover or other filter at discharge point

Installation:

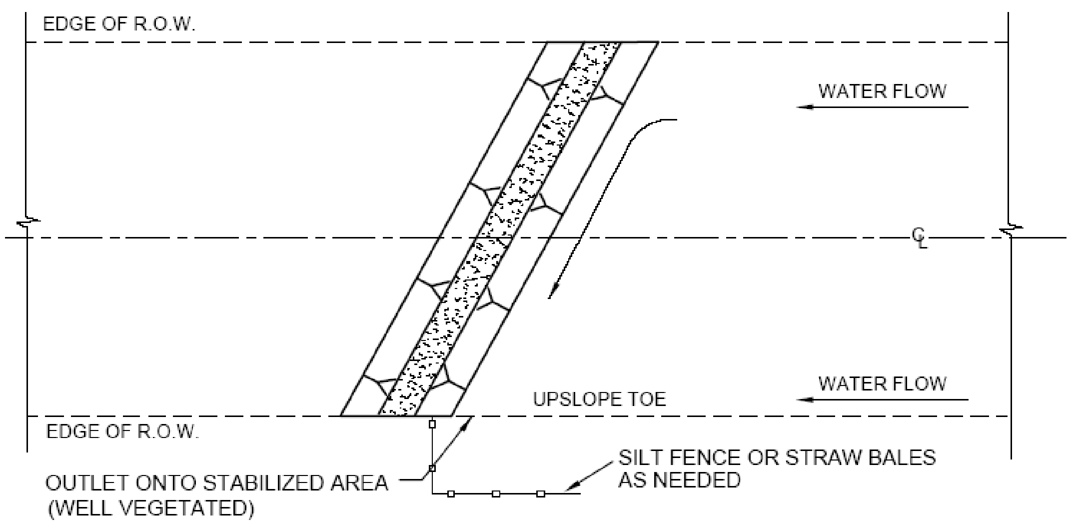
- Pile and compact soil
- Dike sideslopes should be 2:1 or flatter
- Angle dike at approximately 30^{o} to slope
- Increase frequency with increased slope
- Outlet dike into well-vegetated area or install secondary control such as rock filter or straw bales

Construction Activities:

Access roads, well/tank battery pads, and flow/gathering pipelines



CROSS SECTION
N.T.S.



PLAN VIEW
N.T.S.

9. ROAD SURFACE SLOPE (RDSS)

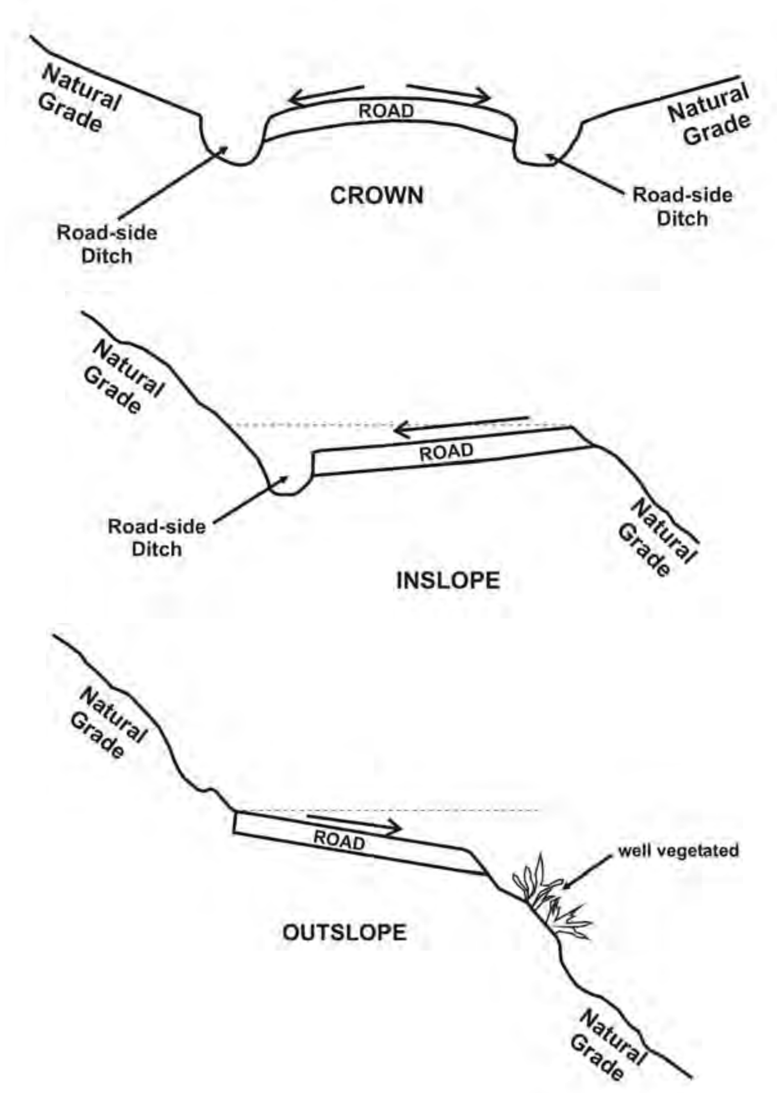
This technique sheds runoff water from road surface into stabilized ditches or vegetation. Roads may be crowned, in-sloped, or out-sloped.

Limitations:
- Only sheds runoff collected from surface of road
- May cause concentrated flows from sheet flow
- Require vegetative ditches, turnouts, and/or cross-drains

Installation:
- Compact soil or road base material to direct runoff
- Crowning design directs runoff to both sides of the road requiring 2 road-side ditches
- Inslope design directs runoff toward the hillside and requires cross-drain installation
- Outslope design is most effective on moderate slopes with dense vegetative cover

Construction Activity:

Access roads



10. **DRAINAGE DIPS** (DIP)

This technique captures and directs runoff from the road into vegetative filter strips or other filter system. Ridges and associated dips are constructed diagonally across and as part of the road surface.

Limitations:

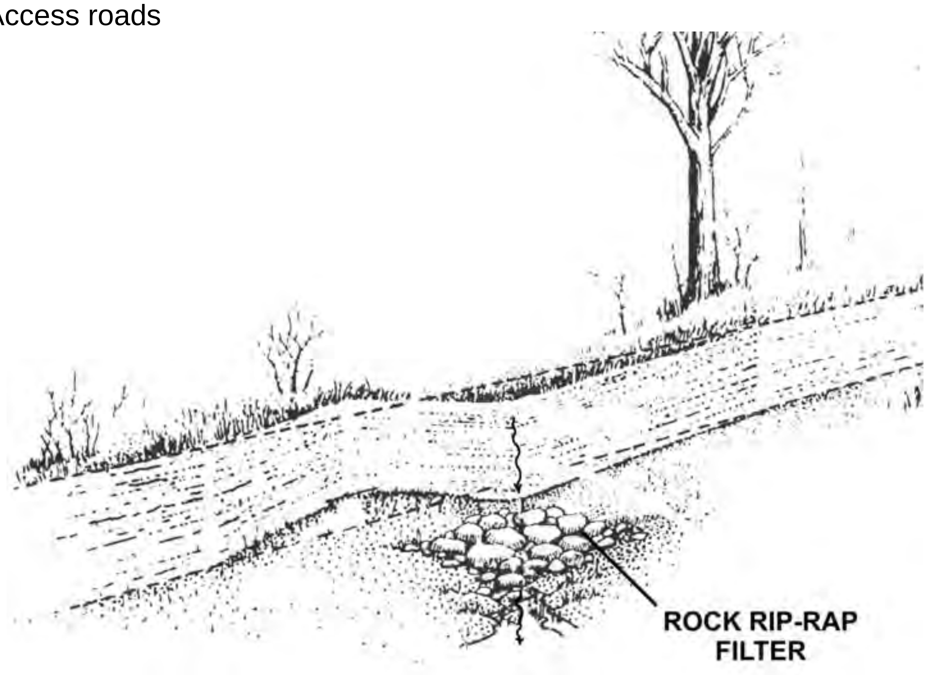
- Size limited by the safe passage of trucks and equipment
- May cause concentrated flows from sheet flows
- Require vegetative cover or other filter at discharge point

Installation:

- Need to be deep enough to carry expected flow
- Need to be wide enough to allow traffic to pass
- Increase frequency with increase slope
- Pile and compact soil
- Angle dips up to 25^o to slope
- Place rock at outlet

Construction Activity:

Access roads



PLAN VIEW
N.T.S.

Source: Cooperative Extension Service, 2002.

11. STABILIZED CONSTRUCTION ENTRANCE

Stabilized construction entrances limit the amount of tracked materials (mud and dust) from leaving the construction site. Mud and sediment are removed from vehicle tires when leaving the site as tires pass over rock pad.

Limitations:

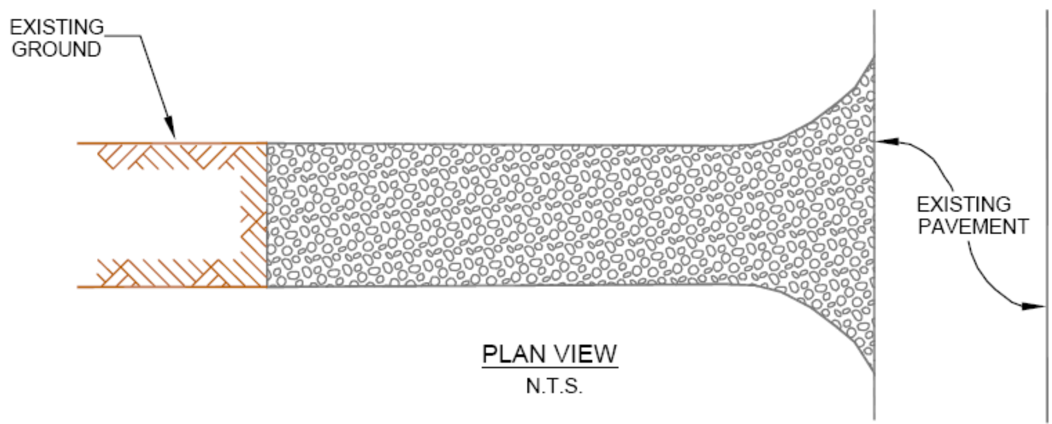
- Less effective with increased rain and mud
- Additional sweeping of paved road will be necessary
- Removal necessary after completion of construction
- Availability of rock

Installation:

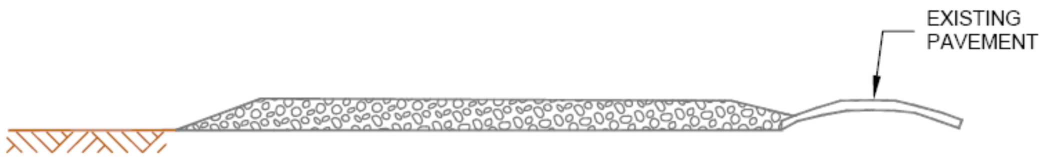
- Install at entrances/exits to paved roads
- Place geotextile filter fabric under medium to large diameter crushed rock
- Length and width of entrance should be adequate to allow large vehicles to access site

Construction Activities:

Access roads, well/tank battery pads, and flow/gathering pipelines



PLAN VIEW
N.T.S.



CROSS-SECTION
N.T.S.

12. ROAD-SIDE DITCHES (RDSD)

This technique requires constructing channels parallel to roads. The ditches convey concentrated runoff of surface water from roads and surrounding areas to a stabilized area.

Limitations:

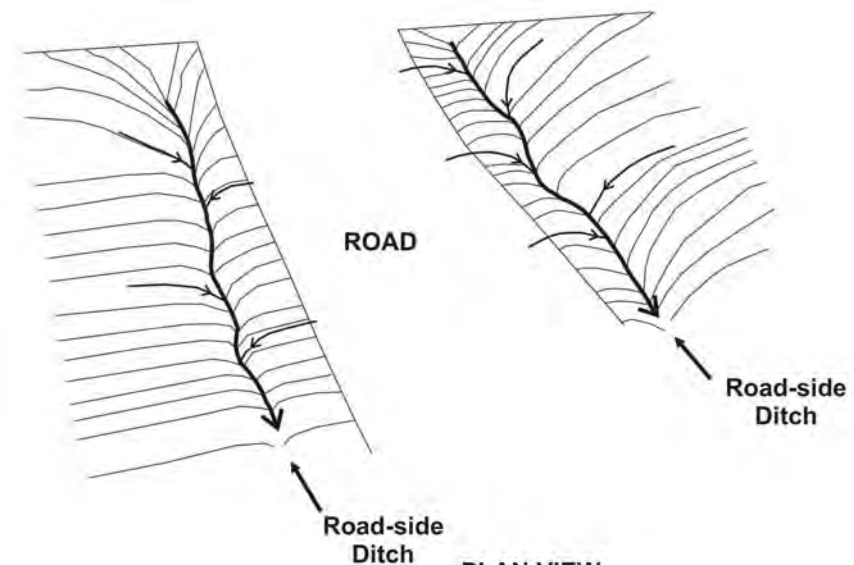
- Erosion occurs within channel
- Channel does not necessarily filter sediment from runoff

Installation:

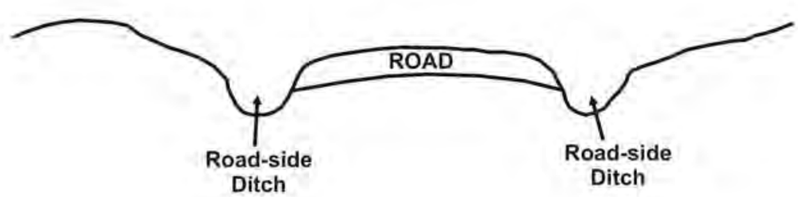
- Excavate channel along roadside to a width and depth that can handle expected flows
- Slope channels so that water velocities do not cause excessive erosion
- Shape and level channel removing excess spoil so water can flow
- Vegetate or line channel with material to prevent erosion

Construction Activity:

Access roads



PLAN VIEW
N.T.S.



CROSS-SECTION
N.T.S.

13. TURNOUTS OR WING DITCHES (TO)

These structures are extensions of road-side ditches and will effectively remove run-off water from the ditch into well-stabilized areas.

Limitations:

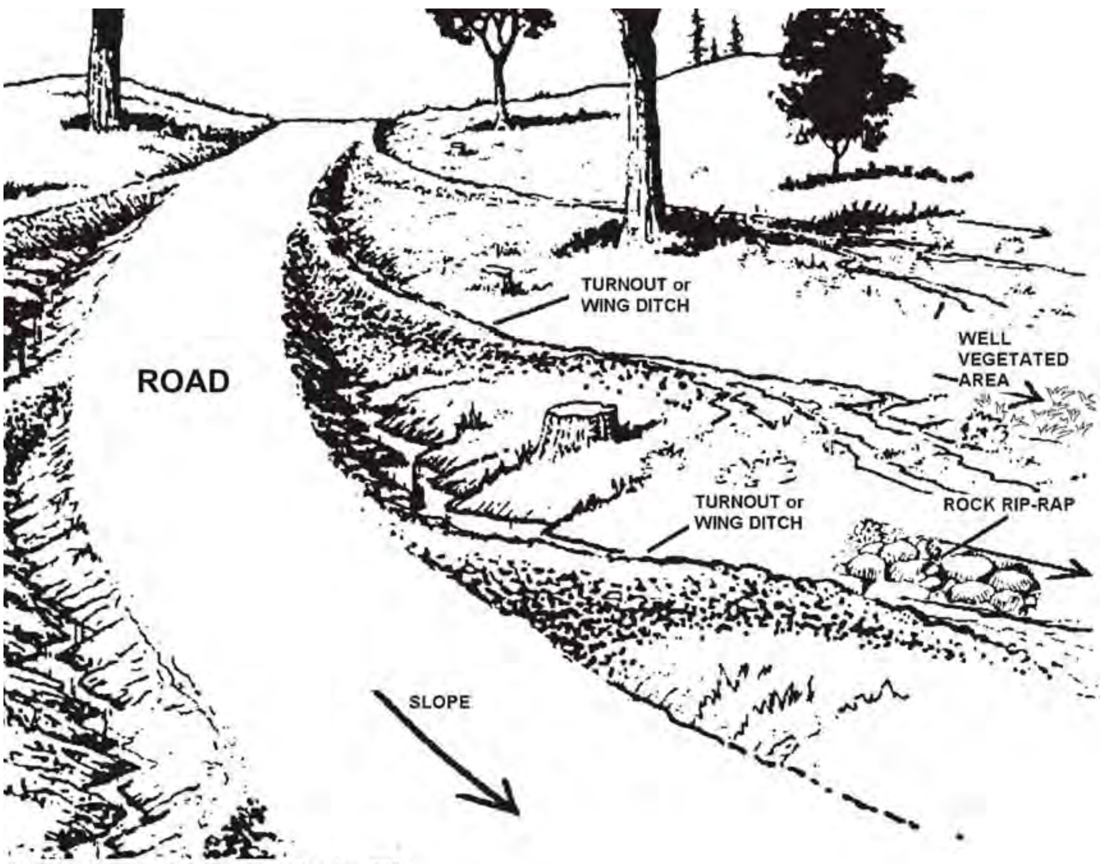
- Gradual slopes only
- Require vegetative cover or other filter at discharge point

Installation:

- Slope turnout gradually down from bottom of road ditch
- Angle turnout at approximately 30^o to road ditch
- Discharge turnout into well-vegetated area or install secondary control such as rock filter or straw bales
- Space turnouts according to slope

Construction Activities:

Access roads



Source: Cooperative Extension Service, 2002.

14. **CONSTRUCTION MATS** (CM)

This technique spreads the weight of construction equipment over a broad area to help prevent soil compaction and soil exposure.

Limitations:

- Useful on wet, soggy, and/or inundated soils
- Mats are bulky and difficult to move
- Does not filter sediment from runoff

Installation:

- Mats are constructed of large timber tied together
- Mats are placed ahead of operating equipment to provide stable work area

Construction Activities:

Flow/gathering pipelines

15. CROSS-DRAIN CULVERTS (CULV)

This technique can be used to direct road-side ditch flow across road or may be used to direct stream flow under road or construction area. Culverts passing construction sites will allow for continued flow of stream with minimal siltation.

Limitations:

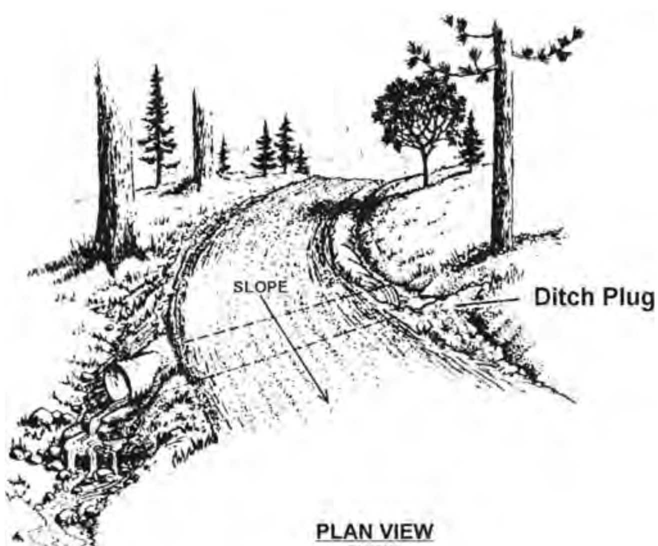
- Culverts may become clogged
- Not a sediment filter

Installation:

- Culverts may be steel, aluminum, or concrete
- Culverts should be placed at surface grades to allow normal low-flow water to be conveyed
- Soil or road base should be compacted over culverts to a minimum of 12 inches
- Culvert size should be adequate to convey anticipated flow
- Ditch plug will be needed within road-side ditch to direct water into culvert
- Culvert drop grade should be adequate to convey flows
- Increase frequency of culverts with increased slope
- Rock rip-rap often needed at outlet

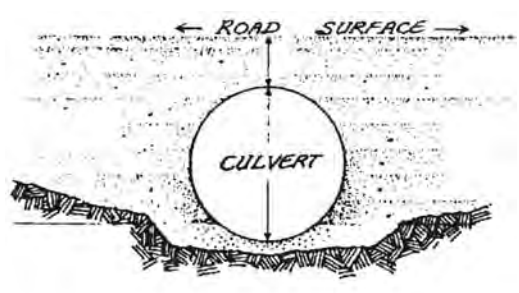
Construction Activities:

Access roads and flow/gathering pipelines



PLAN VIEW
N.T.S.

Source: Cooperative Extension Service, 2002.



CROSS SECTION
N.T.S.

Source: Cooperative Extension Service, 2002.

16. GEOTEXTILES/EROSION BLANKETS (GEO)

Geotextiles are typically a porous fabric constructed of woven fibers. They are useful for stabilizing and preventing erosion on slopes, especially adjacent to streams.

Limitations:

- Decompose
- Effectiveness depends on proper installation
- Expensive

Installation:

- Select appropriate fabric type for necessary purpose
- Smooth soil prior to installation
- Fabric needs to be in continuous contact with exposed soil
- Anchor fabric securely
- Apply seed prior to fabric installation for final stabilization of construction sites

Construction Activities:

Well/tank battery pads and flow/gathering pipelines

17. <u>SEDIMENT TRAPS</u> (ST)

This technique uses a basin or pond to hold sediment-laden water so that sediment can settle and water is absorbed into the soil. Sediment traps are useful for construction sites where excessive runoff will need to be captured and filtered and other RAPPS are insufficient.

Limitations:

- Not for use in rocky situations
- Larger drainage areas require larger traps
- Overflow can result during large rainfall events
- Water will remain in trap for extended periods

Installation:

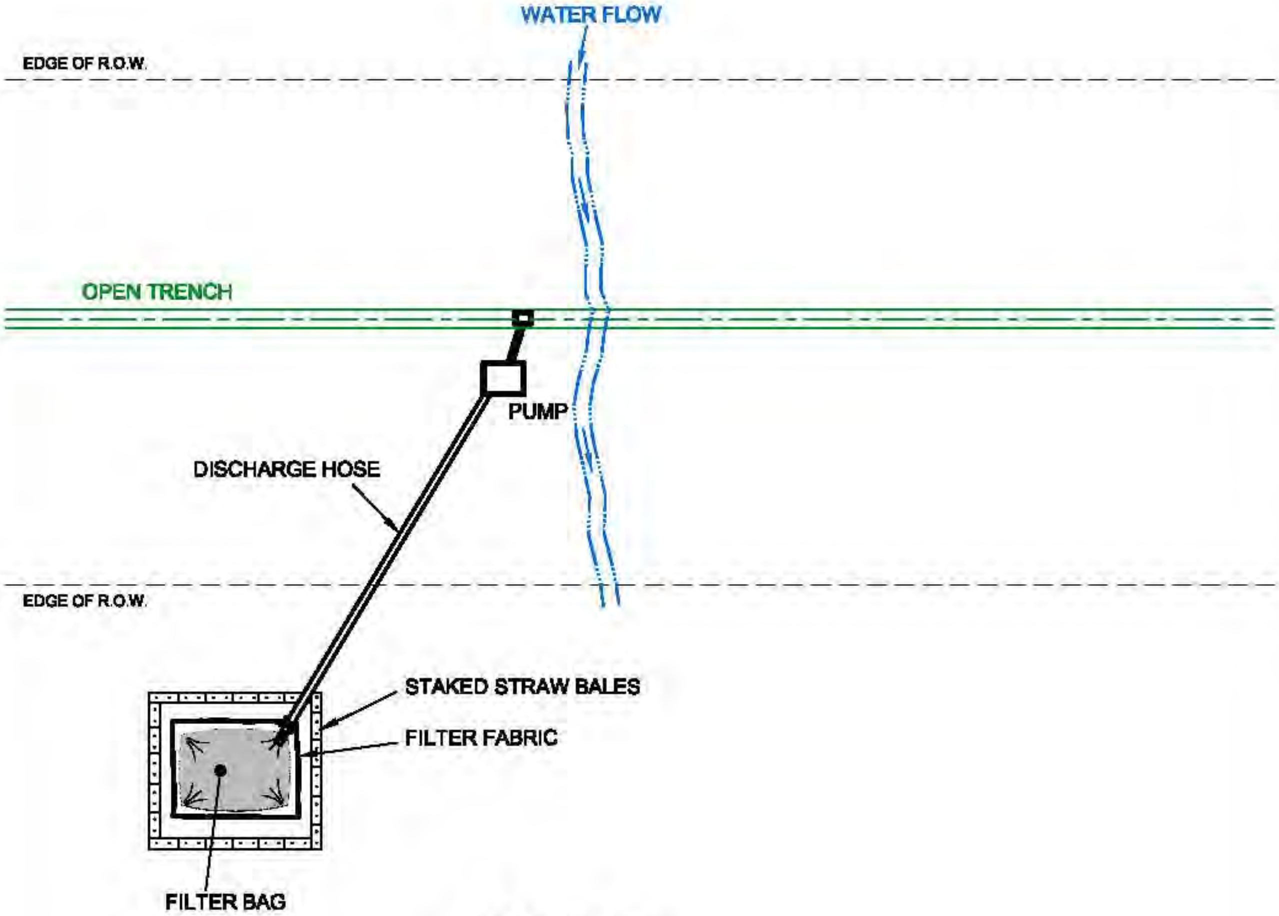
- Excavate trap or basin within area where runoff may be directed toward
- Sideslopes should be machine compacted
- Sideslopes should be 2:1 or flatter
- Volume of trap should handle runoff from 2-year storm events
- Soil within trap should allow for water absorption, no bedrock
- Construct spillway or outfall structure with rock rip-rap at outlet

Construction Activities:

Access roads, well/tank battery pads, and flow/gathering pipelines

APPENDIX B

DIAGRAMS OF TYPICAL REGULATED WATER BODY CROSSINGS



PLAN VIEW
N.T.S.

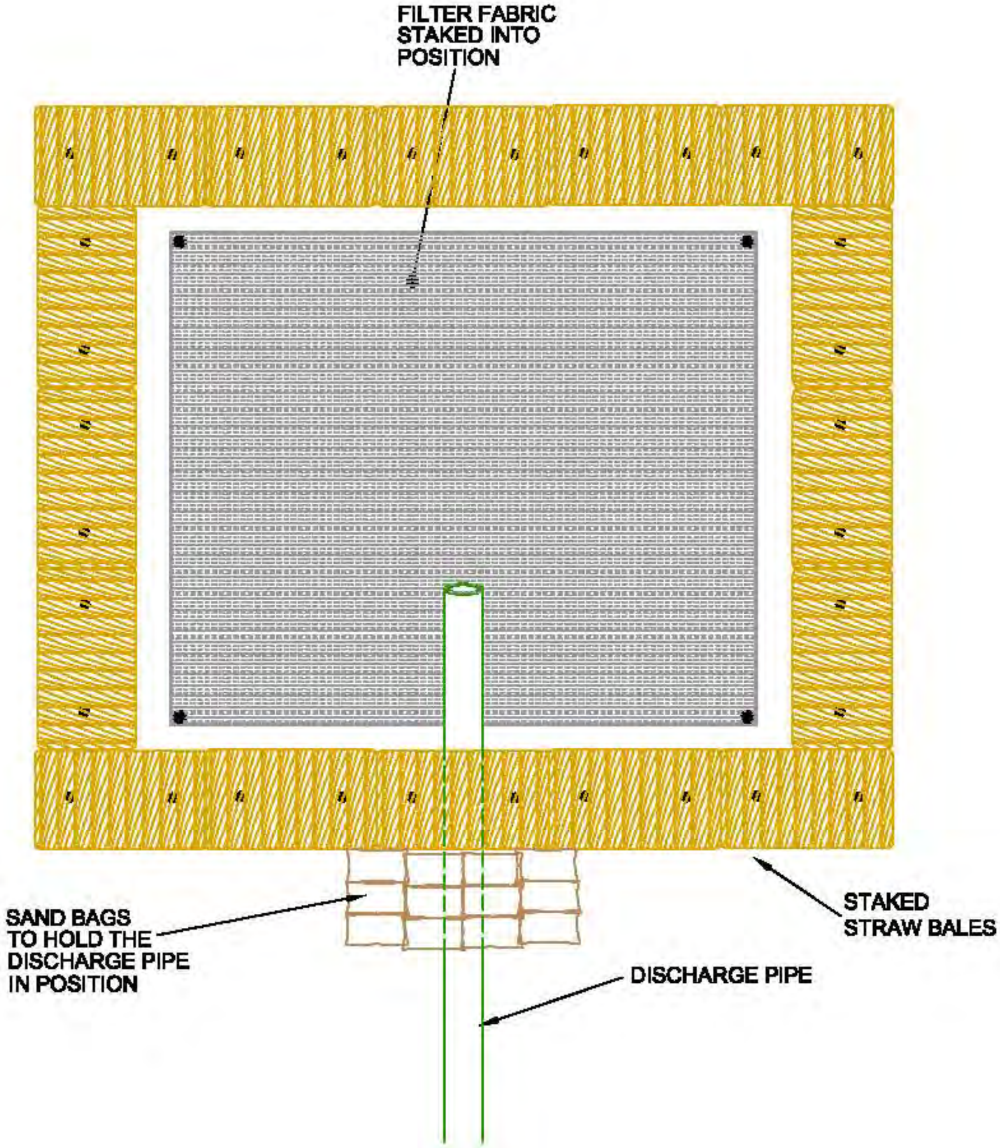
CONSTRUCTION NOTES:

1. DISCHARGE ONTO STABILIZED AREA (i.e. HEAVILY VEGETATED)
2. DISCHARGE LOCATION MUST BE A MINIMUM OF 25' FROM OPEN WATER BODY OR INTO DISCHARGE STRUCTURE.

TRENCH DEWATERING & DISCHARGE

THE ARCHITECT/ENGINEER ASSUMES RESPONSIBILITY FOR APPROPRIATE USE OF THIS STANDARD.

Horizon
Environmental Services, Inc.



PLAN VIEW
N.T.S.

CONSTRUCTION NOTES:

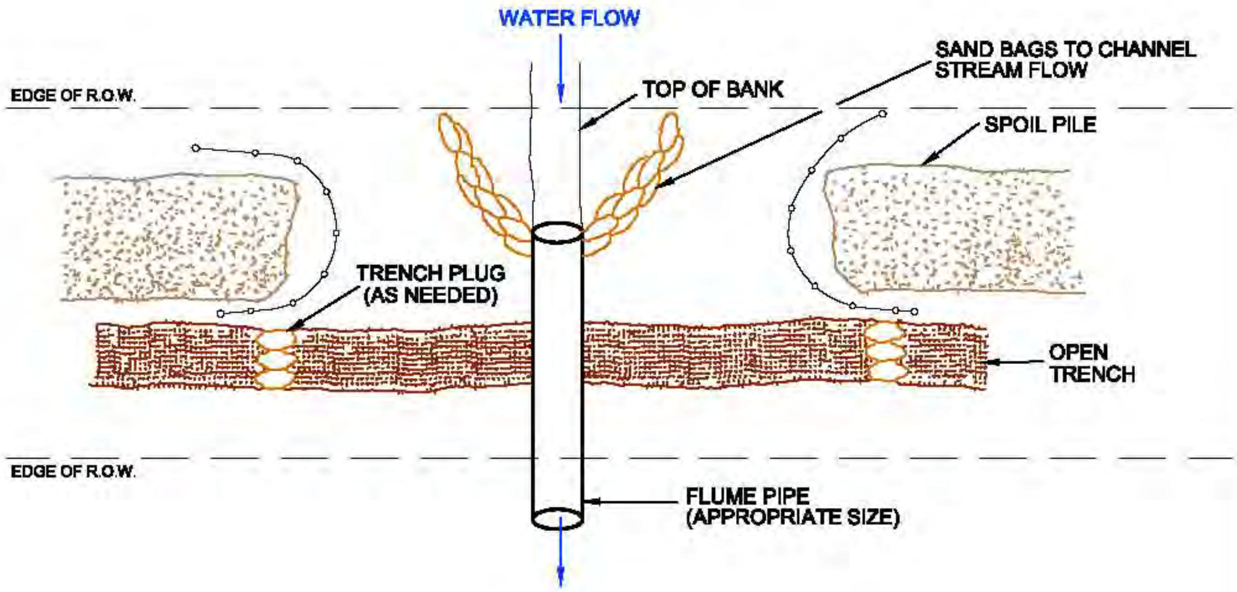
1. THIS DESIGN FOR FLAT OR RELATIVELY FLAT GROUND.
2. THIS DESIGN FOR SMALL DISCHARGES.

THE ARCHITECT/ENGINEER ASSUMES RESPONSIBILITY FOR APPROPRIATE USE OF THIS STANDARD.

DEWATERING STRUCTURE

"Do Not Scale This Drawing"

Horizon
Environmental Services, Inc.



PLAN VIEW
N.T.S.

CONSTRUCTION NOTES:

1. TRENCH SPOIL SHOULD BE PLACED APPROXIMATELY 10' FROM THE TOP OF THE BANK.
2. RAPPS NEEDED BETWEEN SPOIL AND WATERBODY.
3. FLUME PIPE SHOULD ADEQUATELY CONVEY NORMAL STREAM FLOWS.

THE ARCHITECT/ENGINEER ASSUMES RESPONSIBILITY FOR APPROPRIATE USE OF THIS STANDARD.

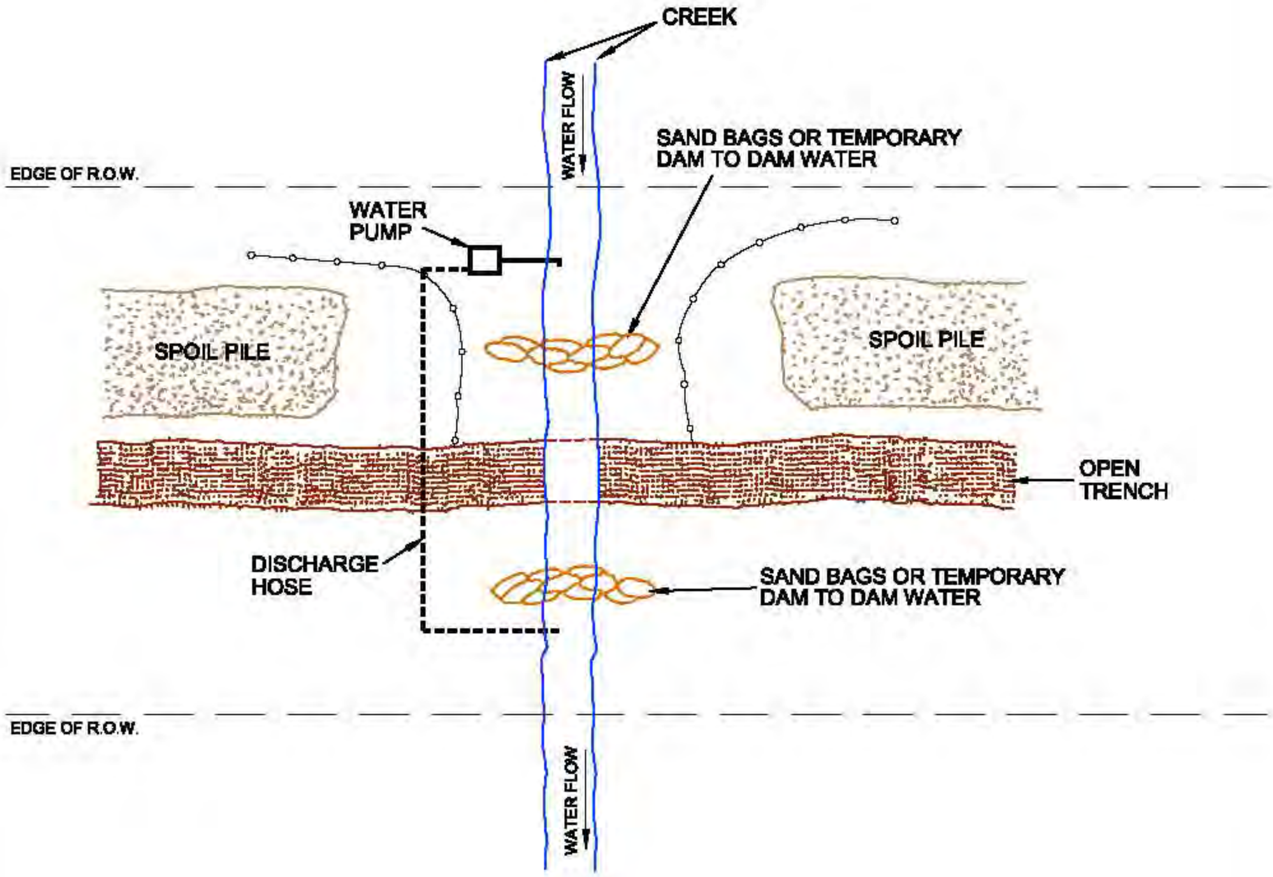
TYPICAL OPEN CUT FLOWING STREAM CROSSING FLUME PIPE

Horizon Environmental Services, Inc.

040027A03IM.dwg | JEA | 2/26/04

"Do Not Scale This Drawing"

040027A04IM.dwg | JEA | 2/26/04



CONSTRUCTION NOTES:

1. REROUTE WATER VIA DAM AND PUMP.
2. EXCAVATE TRENCH.
3. TRENCH SPOIL SHOULD BE PLACED APPROXIMATELY 10' FROM THE TOP OF BANK.
4. RAPPS NEEDED BETWEEN SPOIL AND WATERBODY.
5. MONITOR PUMP(S) - REFUELING IN SPILL CONTAINMENT DEVICE.

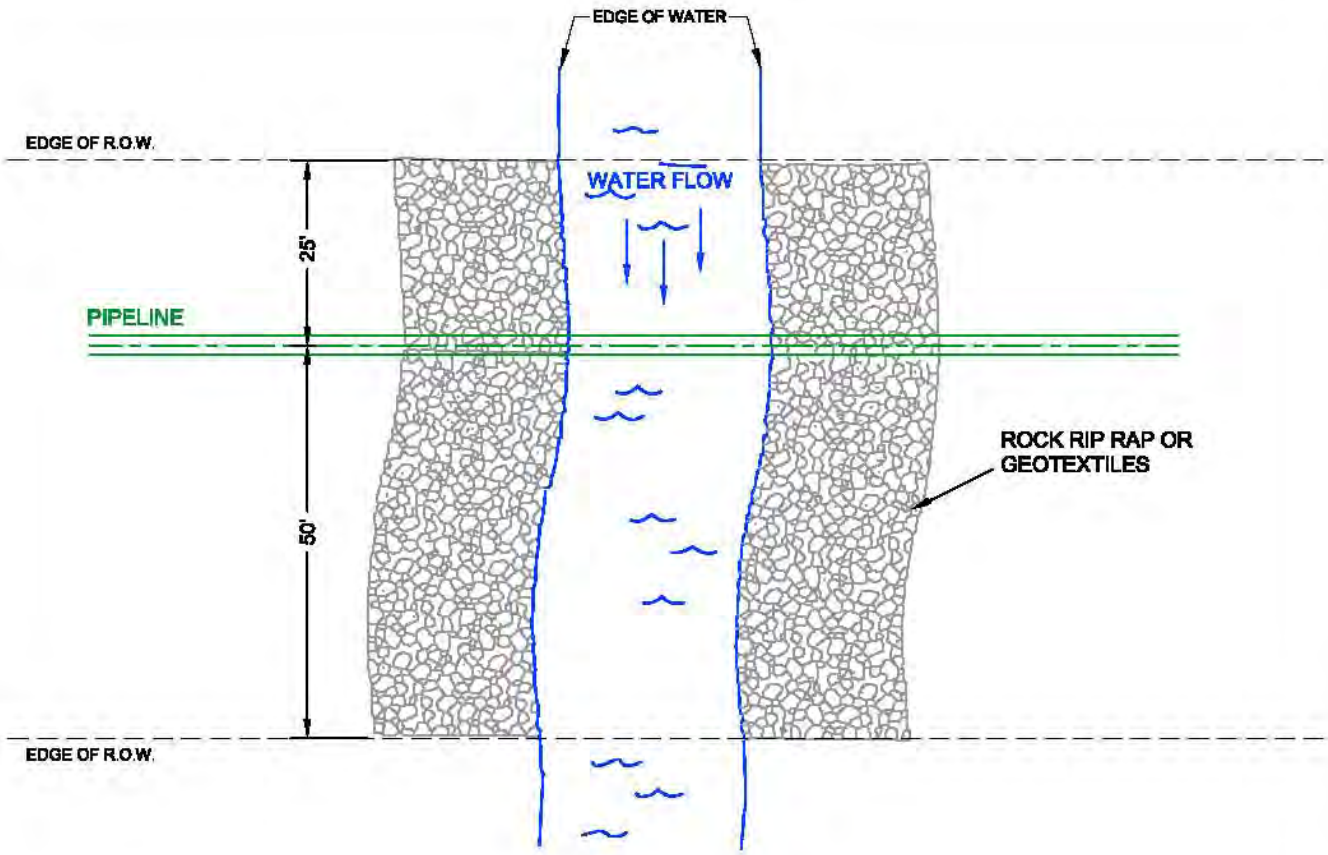
TYPICAL OPEN CUT MINOR FLOWING STREAM CROSSING DAM AND PUMP

THE ARCHITECT/ENGINEER ASSUMES RESPONSIBILITY FOR APPROPRIATE USE OF THIS STANDARD.

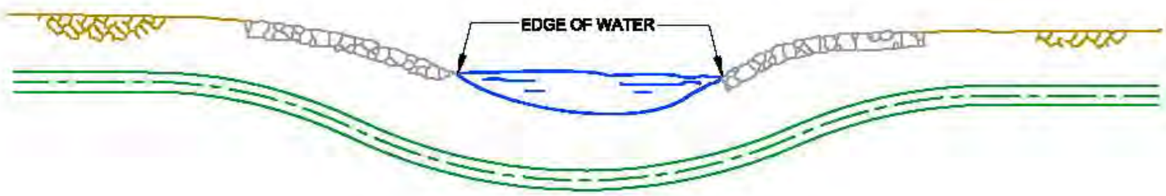
"Do Not Scale This Drawing"

Horizon Environmental Services, Inc.

040027A05M.dwg | JEA | 2/26/04



PLAN VIEW
N.T.S.



CROSS-SECTION
N.T.S.

NOTES:

1. GEOTEXTILES MUST BE SECURED.

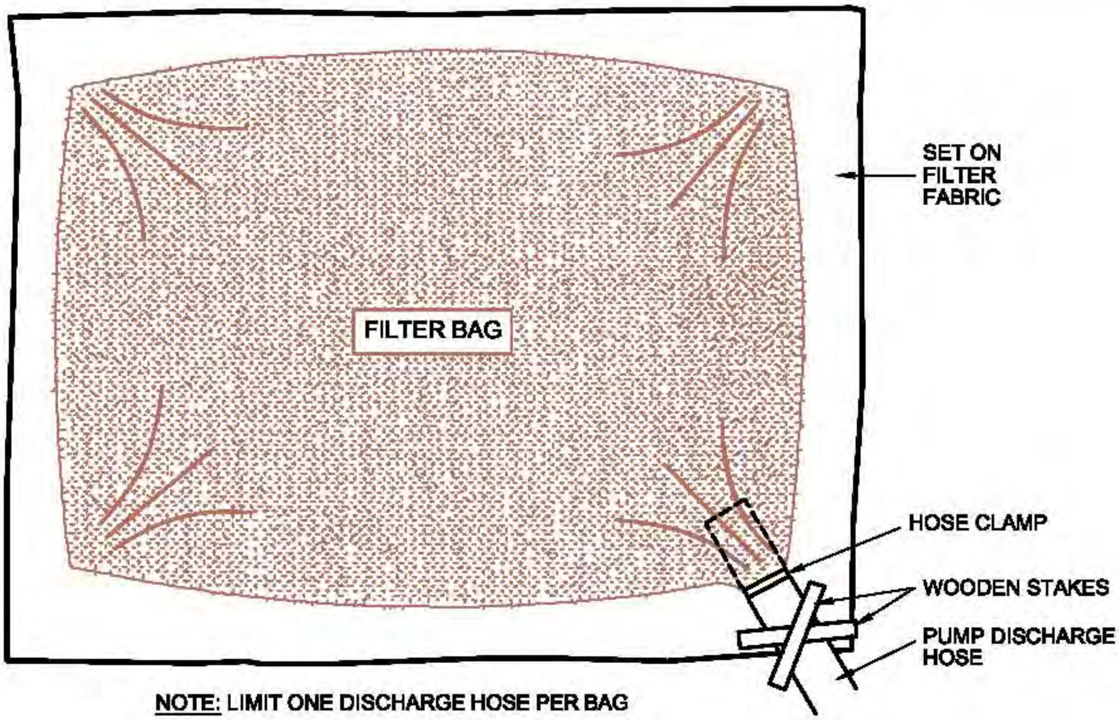
THE ARCHITECT/ENGINEER ASSUMES RESPONSIBILITY FOR APPROPRIATE USE OF THIS STANDARD.

POST CONSTRUCTION STREAM BANK STABILIZATION

"Do Not Scale This Drawing"

Horizon
Environmental Services, Inc.

040027A06IM.dwg | JEA | 2/26/04



NOTE: LIMIT ONE DISCHARGE HOSE PER BAG

PLAN VIEW
N.T.S.

CROSS-SECTION
N.T.S.

CONSTRUCTION NOTES:

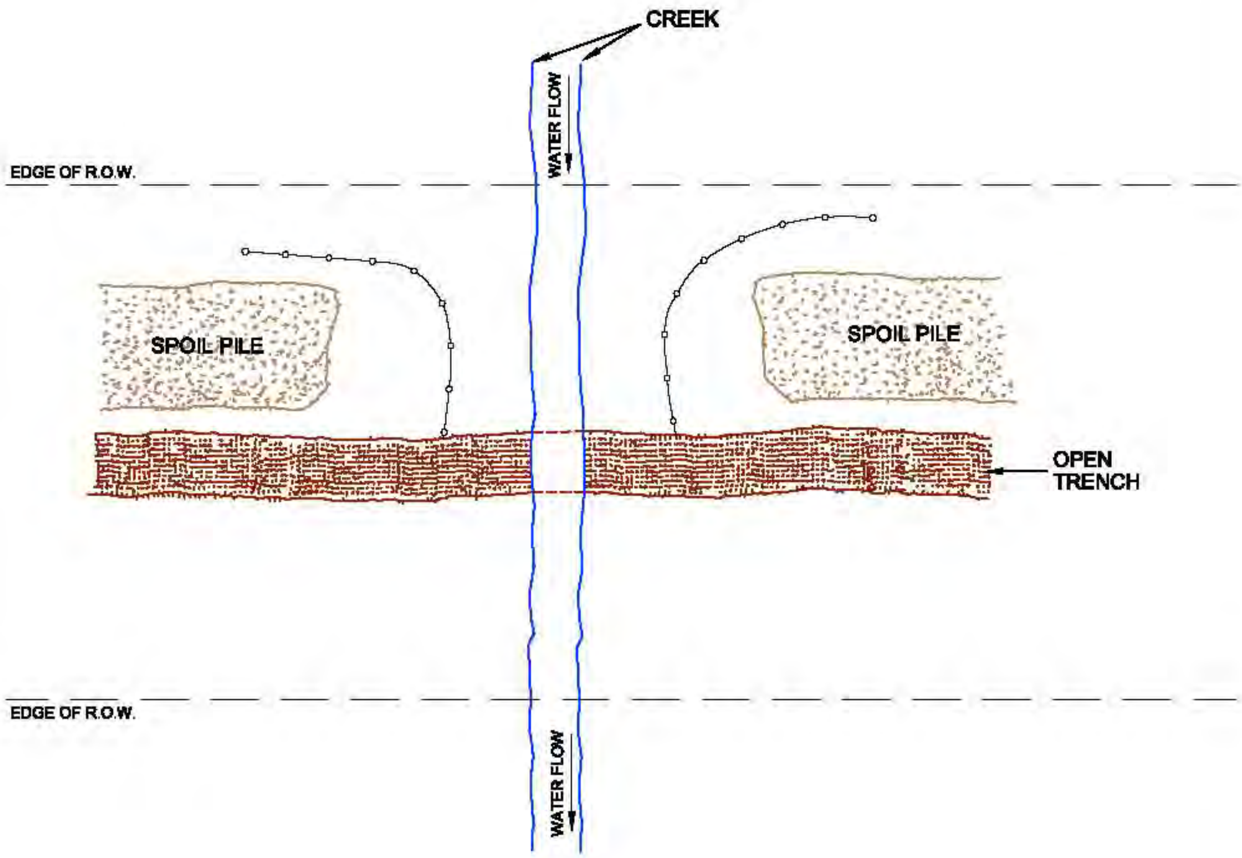
1. FILTER BAG SHOULD BE REPLACED WHEN SEDIMENT BUILD-UP OCCURS.

THE ARCHITECT/ENGINEER ASSUMES RESPONSIBILITY FOR APPROPRIATE USE OF THIS STANDARD.

FILTER BAG DETAIL

"Do Not Scale This Drawing"

Horizon
Environmental Services, Inc.



CONSTRUCTION NOTES:

1. EXCAVATE TRENCH.
2. TRENCH SPOIL SHOULD BE PLACED APPROXIMATELY 10' FROM THE TOP OF BANK.
3. RAPPS NEEDED BETWEEN SPOIL AND WATERBODY.
4. INSTALL FLUME PIPE TO CONVEY WATER FLOW, IF STREAM BEGINS TO FLOW DURING CONSTRUCTION.

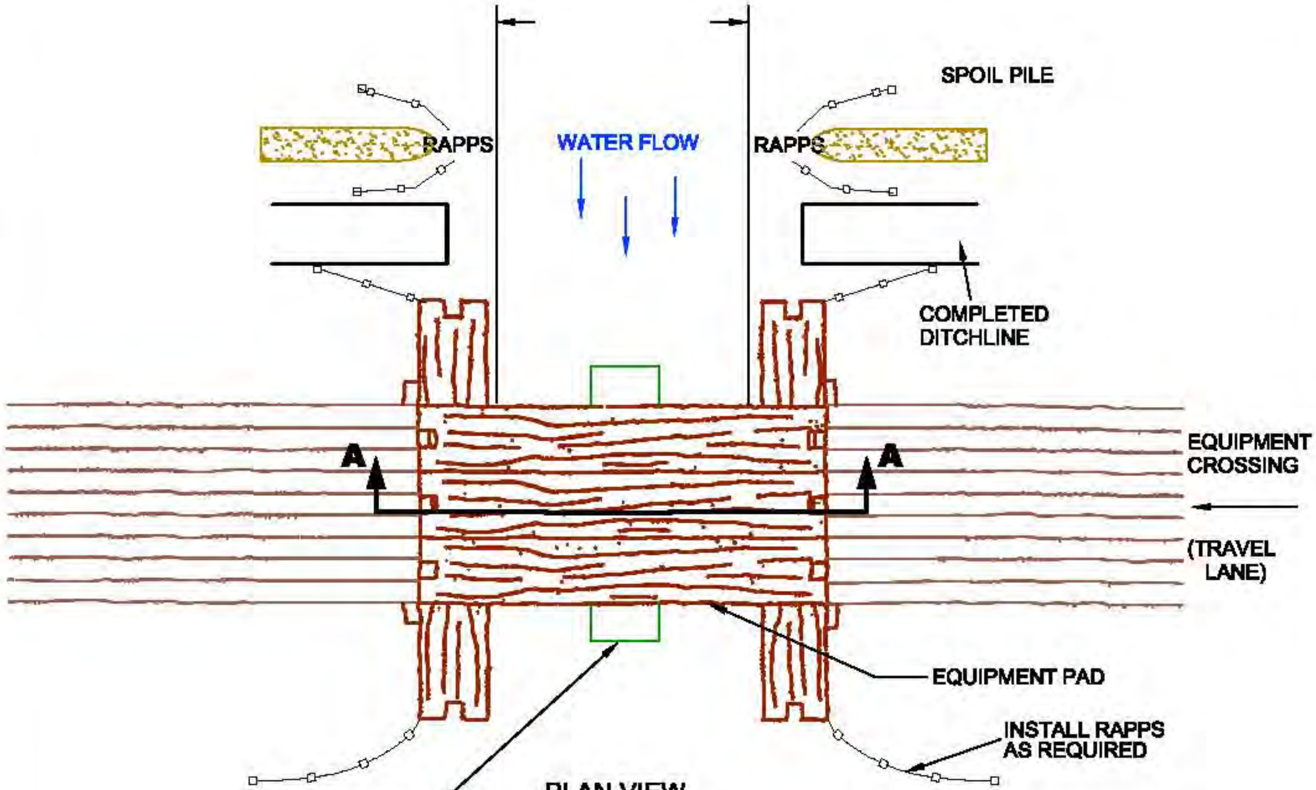
THE ARCHITECT/ENGINEER ASSUMES RESPONSIBILITY FOR APPROPRIATE USE OF THIS STANDARD.

"Do Not Scale This Drawing"

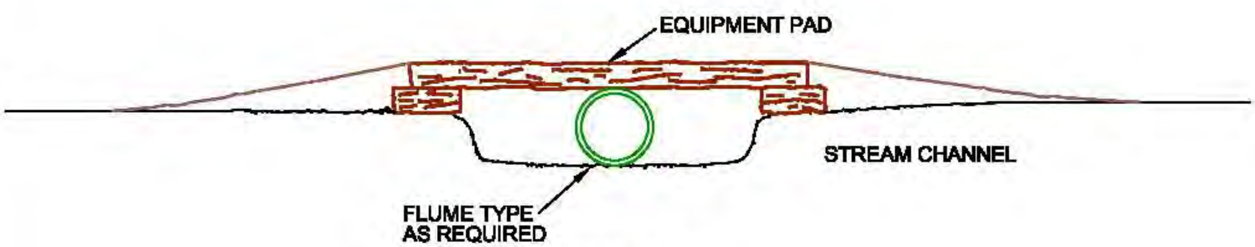
Horizon
Environmental Services, Inc.

TYPICAL OPEN CUT DRY STREAM CROSSING

040027A08IM.dwg | JEA | 2/26/04



PLAN VIEW
N.T.S.



SECTION A-A
N.T.S.

CONSTRUCTION NOTES:

1. UTILIZE CULVERT PIPE(S) IF ADDITIONAL SUPPORT IS NEEDED.
2. ADDITIONAL EQUIPMENT PADS CAN BE PUT SIDE BY SIDE IF EXTRA WIDTH IS NEEDED.
3. EQUIPMENT PAD TYPICALLY CONSTRUCTED OF HARDWOOD. SHOULD ACCOMMODATE THE LARGEST EQUIPMENT USED.

THE ARCHITECT/ENGINEER ASSUMES RESPONSIBILITY FOR APPROPRIATE USE OF THIS STANDARD.

TEMPORARY EQUIPMENT CROSSING OF FLOWING CREEK (BRIDGED)

"Do Not Scale This Drawing"

Horizon
Environmental Services, Inc.

APPENDIX C

EPA'S DEFINITION OF "WATERS OF THE US" FROM 40 C.F.R. 122.2

[Code of Federal Regulations]
[Title 40, Volume 19]
[Revised as of July 1, 2003]
From the U.S. Government Printing Office via GPO Access
[**CITE**: **40CFR122.2**]

[Page 134-141]

TITLE 40--PROTECTION OF ENVIRONMENT

CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY (CONTINUED)

PART 122--EPA ADMINISTERED PERMIT PROGRAMS: THE NATIONAL POLLUTANT DISCHARGE
ELIMINATION SYSTEM--Table of Contents

Subpart A--Definitions and General Program Requirements

Sec. 122.2 Definitions.

The following definitions apply to parts 122, 123, and 124. Terms not defined in this section have the meaning given by CWA. When a defined term appears in a definition, the defined term is sometimes placed in quotation marks as an aid to readers.

Waters of the United States or waters of the U.S. means:
(a) All waters which are currently used, were used in the past, or may be susceptible to use in interstate or foreign commerce, including all waters which are subject to the ebb and flow of the tide;
(b) All interstate waters, including interstate ``wetlands;''
(c) All other waters such as intrastate lakes, rivers, streams (including intermittent streams), mudflats, sandflats, ``wetlands,'' sloughs, prairie potholes, wet meadows, playa lakes, or natural ponds the use, degradation, or destruction of which would affect or could affect interstate or foreign commerce including any such waters:
(1) Which are or could be used by interstate or foreign travelers for recreational or other purposes;
(2) From which fish or shellfish are or could be taken and sold in interstate or foreign commerce; or
(3) Which are used or could be used for industrial purposes by industries in interstate commerce;
(d) All impoundments of waters otherwise defined as waters of the United States under this definition;
(e) Tributaries of waters identified in paragraphs (a) through (d) of this definition;
(f) The territorial sea; and
(g) ``Wetlands'' adjacent to waters (other than waters that are themselves wetlands) identified in paragraphs (a) through (f) of this definition.

Waste treatment systems, including treatment ponds or lagoons designed to meet the requirements of CWA (other than cooling ponds as defined in 40 CFR 423.11(m) which also meet the criteria of this definition) are not waters of the United States. This exclusion applies only to manmade bodies of water which neither were originally created in waters of the United States (such as disposal area in wetlands) nor resulted from the impoundment of waters of the United States. [See Note 1 of this section.] Waters of the United States do not include prior converted cropland. Notwithstanding the determination of an area's status as prior converted cropland by any other federal agency, for the purposes of the Clean Water Act, the final authority regarding

[[Page 141]]

Clean Water Act jurisdiction remains with EPA.

Wetlands means those areas that are inundated or saturated by surface or groundwater at a frequency and duration sufficient to support, and that under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions. Wetlands generally include swamps, marshes, bogs, and similar areas.

Whole effluent toxicity means the aggregate toxic effect of an effluent measured directly by a toxicity test.

Note: At 45 FR 48620, July 21, 1980, the Environmental Protection Agency suspended until further notice in Sec. 122.**2**, the last sentence, beginning ``This exclusion applies . . .'' in the definition of ``Waters of the United States.'' This revision continues that suspension.\1\

\1\ Editorial Note: The words ``This revision'' refer to the document published at 48 FR 14153, Apr. 1, 1983.

(Clean Water Act (33 U.S.C. 1251 et seq.), Safe Drinking Water Act (42 U.S.C. 300f et seq.), Clean Air Act (42 U.S.C. 7401 et seq.), Resource

----

Conservation and Recovery Act (42 U.S.C. 6901 et seq.))

[48 FR 14153, Apr. 1, 1983, as amended at 48 FR 39619, Sept. 1, 1983; 50 FR 6940, 6941, Feb. 19, 1985; 54 FR 254, Jan. 4, 1989; 54 FR 18781, May **2**, 1989; 54 FR 23895, June **2**, 1989; 58 FR 45039, Aug. 25, 1993; 58 FR 67980, Dec. 22, 1993; 64 FR 42462, Aug. 4, 1999; 65 FR 30905, May 15, 2000]