Louisiana as of July 1996. Costs are calculated without taking into account the regulatory effects of the zero discharge requirement imposed by the EPA Region VI General Permits (See Section II.C. of this preamble).

In determining the costs associated with zero discharge for the Gulf coast area, EPA utilized the following factors in the costing analyses:

General

* The only areas that will incur compliance costs are Cook Inlet in Alaska, Texas, and parts of Louisiana since all other coastal areas that have oil and gas activities currently practice zero discharge.

For Texas and Louisiana

* Produced water would be injected into Class II UIC injection wells. The capacity of each Class II injection well is 5,000 BPD.

* 90 percent of the injection wells would be converted from previously producing wells or dry holes.

* If a discharge is greater than 108 bpd (for water-based facilities) and 71 bpd (for land-based facilities), then the produced water would be injected onsite; if the discharge is less than those flows then it would be more cost effective to send the produced water offsite to a commercial facility for injection. (EPA's data from Texas and Louisiana coastal permits show that 77 percent of the produced water discharges would inject on-site).

* For purposes of estimation, all Texas separation/treatment facilities are located on land and all Louisiana separation/treatment facilities are located over water. EPA is aware that this is not entirely the case, *i.e.* some facilities in Louisiana are located over land and some Texas facilities are located over water. In the absence of specific location information on all of the 216 discharging facilities, EPA determined this to be a good approximation since the coastal topography of Louisiana consists of more extensive wetlands than that of Texas. (Location is an important factor when determining the cost of drilling an injection well, and the cost of produced water transportation. EPA's state permit data base shows that 24 percent of the produced water discharges are in Texas and the separation/treatment facilities are therefore considered to be on land).

* No pretreatment beyond BPT technology is required prior to injection for land-based facilities because it is more cost effective to perform downhole well workovers twice a year. Pretreatment beyond BPT treatment prior to injection consists of cartridge filtration for water-based facilities. For flows greater than 64,000 bpd, granular filtration is used as pretreatment.

* Capital costs are based on sizing equipment to accommodate future produced water volume, estimated to be approximately 1.5 times current flow.

* Where more than one produced water discharge location exists from one or more production facilities owned by the same operator in the same field, EPA combined the discharges to be injected into a single injection system. By combining discharges a savings would result due to installation of fewer injection wells.

For Cook Inlet

* No geological formations are available for produced water injection except the producing formations.

* No geological formations are available near or below the existing onland separation/treatment facilities. Thus, the produced waters would be required to be piped back to the platforms for injection.

* Pretreatment prior to injection consists of gas flotation and multimedia filtration. However, operators will use existing equipment where it currently exists, and no costs would be incurred for such existing equipment.

* During the development of this proposal, industry provided EPA with information on reservoir plugging and souring that may result from injecting produced water in the Cook Inlet. EPA, in its cost analysis, included costs for the addition of chemicals that would be added to the produced water being injected to alleviate the scaling and hydrogen sulfide (H2S) formation problems associated with injection in this area. Such chemicals include biocides and scale inhibitors. Annual workovers must also be performed on the injection wells.

EPA believes that the cost estimates are conservative for a number of reasons. As discussed previously, EPA determined costs to comply with a zero discharge requirement in the Gulf of Mexico based on the number of facilities that would be discharging after the expected date of promulgation for this rule (July 1996). A total of 216 facilities would still be discharging by then. However, 28 of these facilities in Louisiana will be required to cease discharging by January 1, 1997, because of the state water quality standard's no discharge requirement. Taking this January 1997 requirement into account as a portion of the baseline would further reduce costs by 25 percent.

Furthermore, EPA's cost estimates for zero discharge in the Gulf of Mexico are based on sizing produced water treatment equipment to accommodate future produced water volumes estimated to be approximately 1.5 times current flow. EPA believes using this factor, which is standard engineering practice, has resulted in a conservative cost estimate overall because many operators have indicated that they typically use a factor of 1.2 to 1.25 when sizing and costing produced water treatment equipment. Capital costs would be approximately 12 percent lower if a factor of 1.2 were used. Additionally, while EPA's costing included combining of operator discharges for injection within fields, the analysis showed that costs are not significantly different if they are not combined. This is because the high costs of piping to join discharges closely equal the costs of individual injection well installation.

EPA also calculated capital costs of produced water treatment on the basis that produced water flows increase the same for oil as for gas wells. While produced water volumes from gas producing wells will generally not increase at the rate of 1.5, EPA did not differentiate between the two.

EPA determined that no costs would be attributed to zero discharge for California, Florida, Alabama, certain parts of Louisiana, and the North Slope of Alaska because operators in these areas are already practicing zero discharge of all produced waters.

For improved gas flotation, costs were estimated based on an evaluation of this technology during development of the Offshore Guidelines (58 FR 12463). Improved performance of gas flotation units includes improved operation and maintenance of gas flotation treatment systems and chemical pretreatment to enhance system effectiveness. Costs are based on vendor-supplied data, industry information, cost analyses conducted by the Department of Energy, and EPA projections. Capital and O & M costs were applied specifically to the coastal oil and gas operations using nine modeled flows for land- and water-access production facilities. From these nine modeled flows, EPA conducted regression analyses to derive cost equations that would vary based on flow. These equations were then applied to the actual 216 discharging facilities to estimate costs on a site specific basis. Capital costs include equipment purchase, installation, and platform or concrete pad (for land based operations) retrofit. Operation and maintenance costs are estimated to be 10 percent of capital costs.

EPA solicits comments on these costs and also information regarding the longitude and latitude locations of