A Study for the Bureau of Safety and Environmental Enforcement (BSEE)

Decommissioning Cost Update for Pacific OCS Region Facilities

Volume 1

Conducted by

TSB OFFSHORE

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Decommissioning Cost Update for Pacific OCS Region Facilities

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Section 1: Executive Summary

This report was prepared for the Bureau of Safety and Environmental Enforcement (BSEE) by TSB Offshore, Inc. (TSB). TSB (formerly Proserv Offshore Inc.) has been in business since 1987 and has managed the decommissioning of over 300 offshore oil and gas platforms in the Gulf of Mexico, conducted numerous technical studies, engineering studies and cost assessments for decommissioning oil and gas platforms located on the federal Outer Continental Shelf, state waters, and international locations.

BSEE procured the services of TSB to update the 2010 Proserv report, “Offshore Oil and Gas Facility Decommissioning Costs, Pacific OCS Region”. The purpose of this report is to develop benchmark costs for decommissioning Pacific OCS Region (POCSR) oil and gas facilities and to provide guidance regarding decisions on supplemental bonds.

Pursuant to OCS oil and gas regulations [30 CFR 556.53 (a), (b), (c), and (d)], the Regional Director of BOEM has the authority to require additional security in the form of an additional bond beyond the $200,000 bond that guarantees compliance with all the terms and conditions of the lease. The purpose of the supplemental bond is to ensure sufficient funds are set aside to cover the full cost of decommissioning by another party (e.g. a private decommissioning contractor) in the event the current operator/lessee becomes financially insolvent and is unable to carry out its contractual obligations under the lease agreement. This report provides the benchmark decommissioning costs and is one of the inputs BOEM uses determining whether a supplemental bond is required.

This study reviewed the decommissioning of the POCSR oil and gas facilities and developed benchmark costs for decommissioning the facilities using conventional technology. The report provides a cost assessment based on POCSR operations and current market conditions, including the availability and capability of derrick barges (DB’s) in the region (west coast of U.S.), support vessel services, well plugging and abandonment services, abrasive, mechanical and explosive cutting services, disposal options, and site clearance services. When local/regional decommissioning services were not readily available, these services were estimated based on mobilization and demobilization cost, day-rate cost of the services, spread costs for the operations.

The specific tasks in this study include: reviewing and updating the decommissioning scenarios for OCS platforms, reviewing and updating the engineering cost assumptions and methodologies, and reviewing and updating the costs for each phase of the decommissioning process. This report covers operator compliance with OCS oil and gas regulations (30 CFR 550 and 556) for permanent plugging of wells; removal of well conductors and platform jackets to 15 feet below the mud-line; decommissioning and removal of pipelines and power cables; decommissioning and removal of platform decks and jackets; site clearance; and other lease and permit requirements.

When assessing all major elements and contingencies, viable scenarios were developed where the POCSR decommissioning operations are divided into six projects. The six projects were based on the company operators/ownership, third party agreements and working seasons. Each project is comprised of between 2 and 6 platforms that will be decommissioned together to distribute the high cost of mobilizing/demobilizing DB’s from Asia. The sequence and timing of the projects could change due to economic, technological and other factors.

The estimated costs are broken down into the following phases of the decommissioning process: Project Management, Engineering and Planning, Permitting and Regulatory Compliance, Platform Preparation, Well Plugging and Abandonment, Conductor Removal, Pipeline and Power Cable Decommissioning, Mobilization and Demobilization of DB’s, Platform Removal, Materials Disposal, and Site Clearance. The decommissioning costs from the 2010 report and 2014 are shown below in Table 1.1 by platform. Figure 1.1 shows the breakdown of the total 2014 decommissioning costs by task.

Table 1.1. Decommissioning Costs by Platform

Platform Name	2010 Decommissioning Costs (million USD)	2014 Decommissioning Costs (million USD)	% increase
A	$25.6	$36.2	41.3%
B	$30.5	$32.5	6.3%
C	$23.7	$27.5	16.2%
Edith	$29.2	$30.9	5.9%
Ellen	$35.9	$42.0	16.9%
Elly	$21.4	$24.6	15.3%
Eureka	$94.2	$124.0	31.6%
Gail	$88.8	$103.8	16.9%
Gilda	$42.8	$59.2	38.3%
Gina	$12.0	$16.7	39.0%
Grace	$41.6	$43.2	3.8%
Habitat	$28.7	$34.5	20.5%
Harmony	$155.9	$185.7	19.1%
Harvest	$88.3	$99.7	12.9%
Henry	$18.6	$21.6	16.2%
Heritage	$149.6	$173.6	16.0%
Hermosa	$80.4	$94.0	16.9%
Hidalgo	$67.9	$73.9	8.8%
Hillhouse	$26.0	$31.3	20.4%
Hogan	$34.5	$38.1	10.6%
Hondo	$91.7	$100.1	9.2%
Houchin	$33.0	$36.2	9.5%
Irene	$32.6	$37.3	14.4%
Total	$1253.0	$1466.7	17.1%

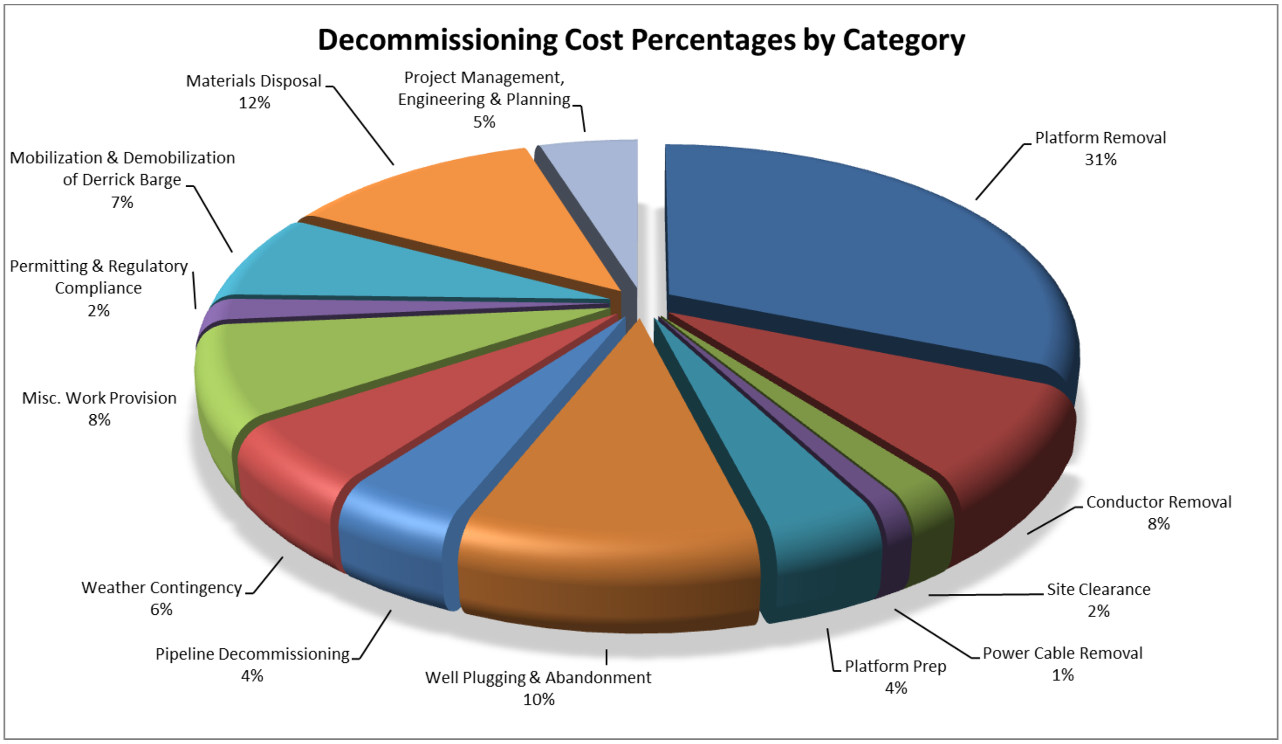

Figure 1.1. Decommissioning Cost Percentages by Category

Section 2: Introduction

This report was prepared for the Bureau of Safety and Environmental Enforcement (BSEE) by TSB Offshore, Inc. (TSB). The report updates the decommissioning cost estimates for Pacific OCS Region (POCSR) oil and gas facilities presented in a 2010 report prepared independently by Proserv entitled "Offshore Oil and Gas Facility Decommissioning Costs, Pacific OCS Region" for BSEE's Technology Assessment Programs (TAP). BSEE's TAP provides a research element encompassed by BSEE Regulatory Program. TAP supports research associated with operational safety and pollution prevention. TAP (formerly known as Technology Assessment & Research (TA&R) Program) was established in the 1970's to ensure that industry operations on the Outer Continental Shelf (OCS) incorporated the use of the Best Available and Safest Technologies (BAST) subsequently required through the 1978 OCSLA amendments and Energy Policy Act of 2005.

This report describes the engineering assumptions and methodologies that were used in developing the cost estimates for decommissioning POCSR oil and gas facilities and presents a summary of the costs for each phase of the decommissioning process. For this study, an assumption is defined as an inference accepted as truth based on over 25 years of decommissioning experience, common industry practice, market evaluation, and specific project information. Assumptions are made to streamline the estimation process allowing focus to be on quality estimation rather than defining unknowns. Volume 2 of the report provides detailed information showing how the costs were estimated.

As of 2014, only seven small structures have been decommissioned. All structures decommissioned were located in California State waters. The most recent decommissioning project occurred in 1996 when Chevron removed Platforms Hope, Heidi, Hilda, and Hazel. The four platforms were located in water depths ranging from 100 to 140 feet with a combined weight of 12,000 tons. In a news release dated April 17, 1996, Chevron reported that the cost of the final phase of dismantling and removing the four platforms was approximately $19 million. This cost did not include the costs to permanently plug and abandon the 134 wells on the platforms. Local media coverage and industry journal articles reported that the total project cost ranged between $35 million and $40 million.

This study reviewed and applied the significant amount of technical and cost data compiled from previous studies on platforms for MMS and private companies that have been decommissioning in the Gulf of Mexico. The majority of this data covers platforms that were located in water depths of less than 200 feet. From 200 to about 400 feet, there is less data available because fewer decommissioning projects have occurred in these water depths in the Gulf of Mexico and in other locations around the world. Over the last 20 years, 16 structures were removed from the GOM OCS from water deeper than 400 feet. During the same time period 3,304 structures were removed from water 400 feet deep or shallower. Industry estimates of structure removals from water deeper than 400 feet are based primarily on projections due to this limited data compared to the abundance of data from shallower removals. Decommissioning service companies agree that decommissioning costs will rise steeply as decommissioning activities move to deeper water environments offshore. Of the 23 platforms located in the POCSR, 14 (61%) are located in water depths exceeding 200 feet and eight (35%) are located in water depths that exceed 400 feet. The removal weight for individual platforms ranges from about 1,100 to nearly 70,000 tons. Table 2.1 provides information on water depth, weight, year installed, and field for each of the 23 Pacific OCS platforms.

Each decommissioning step (Project Management, Engineering and Planning, Permitting and Regulatory Compliance, Platform Preparation, Well Plugging and Abandonment, Conductor Removal, Pipeline and Power Cable Decommissioning, Mobilization and Demobilization of Derrick Barges, Platform Removal, Materials Disposal, and Site Clearance) is discussed individually later in this report. The appendices include detailed specifications for the offshore platforms in the POCSR, estimated decommissioning cost for each platform, detailed cost tables for selected decommissioning elements, information on trends in general inflation, heavy construction inflation, and derrick barge and vessel costs.

The DB mobilization cost is a major individual contributor to the total cost of the project. The cost for mobilizing and demobilizing a derrick barge (DB) is based on distance to point of origin and day rate. Currently, there are no DB500 (DB with capacity to lift 500 tons) or greater class vessels based on the west coast, because there is no market need for these type vessels on the Pacific coast. This market need is not expected to appear in the next 5 years according to vessel service providers. A DB would be mobilized from Asia, and Singapore is the closest port with supply of DB500 or greater class vessels. This mobilization/demobilization cost is then distributed equally across each platform in the defined project.

The local resource rates that were used for decommissioning operations in the POCSR were: diving services, trawling services, and material disposal sites. The remaining equipment and services not available in the POCSR and have been estimated as if they were being mobilized from outside California.

The figures listed below identify the location of the 23 platforms located in the POCSR.

Table 2.1. Pacific OCS Region Platforms

Platform	Water Depth (ft)	Estimated Removal Weight (tons)*	Year Installed**	Field Name
A	188	3,457	1968	Dos Cuadras
B	190	3,457	1968	Dos Cuadras
C	192	3,457	1977	Dos Cuadras
Edith	161	8,038	1983	Beta
Ellen	265	9,600	1980	Beta
Elly	255	9,400	1980	Beta
Eureka	700	29,000	1984	Beta
Gail	739	29,993	1987	Sockeye
Gilda	205	8,042	1981	Santa Clara
Gina	95	1,006	1980	Hueneme
Grace	318	8,390	1979	Santa Clara
Habitat	290	7,564	1981	Pitas Point
Harmony	1,198	65,089	1989	Hondo
Harvest	675	29,040	1985	Pt. Arguello
Henry	173	2,832	1979	Carpinteria
Heritage	1,075	56,196	1989	Pescado, Sacate
Hermosa	603	27,330	1985	Pt. Arguello
Hidalgo	430	21,050	1986	Pt. Arguello, Rocky Point
Hillhouse	190	3,100	1969	Dos Cuadras
Hogan	154	3,672	1967	Carpinteria
Hondo	842	23,550	1976	Hondo
Houchin	163	4,227	1968	Carpinteria
Irene	242	7,100	1985	Pt. Pedernales, Tranquillon Ridge

* Weight consists of Jacket, Deck and Pile Weight.

** Year Installed Date is the jacket installation launch date.

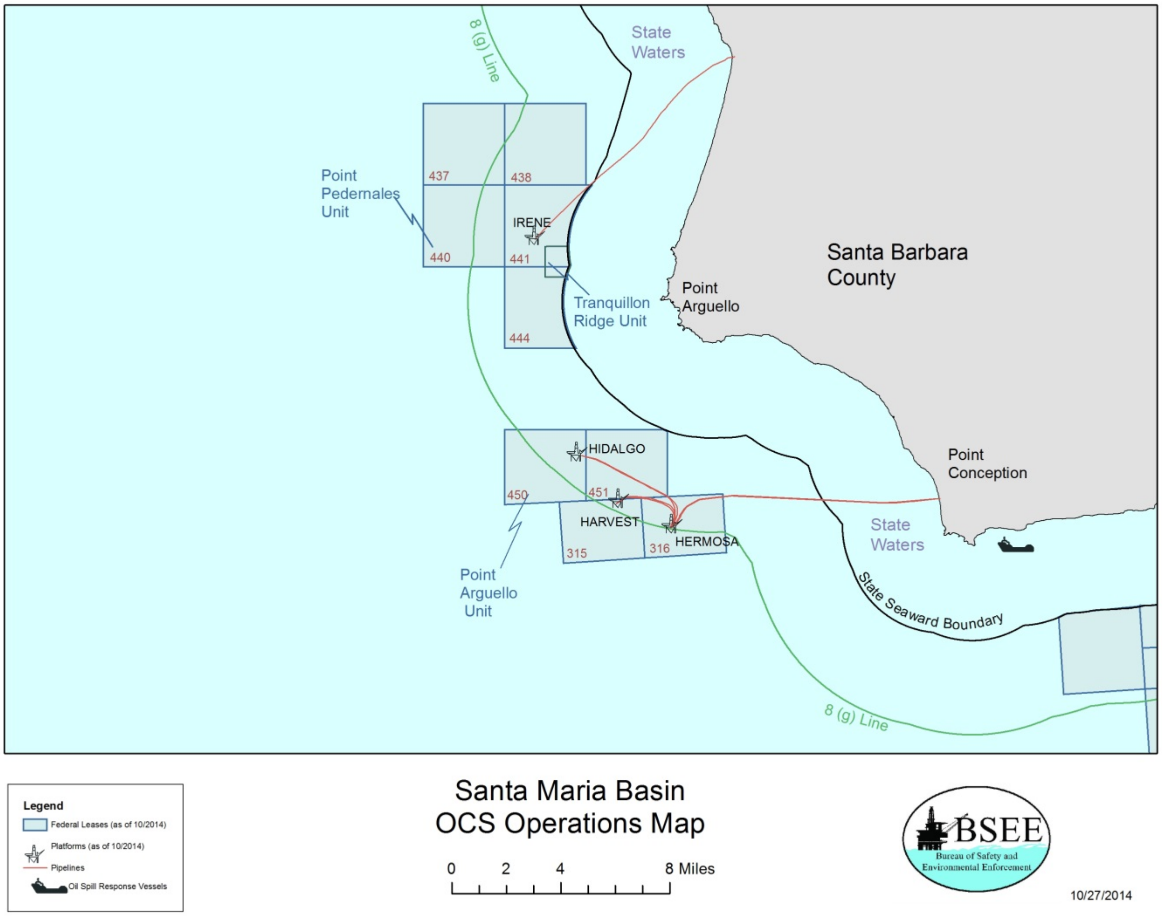

Figure 2.1. Santa Maria Basin OCS Operations Map

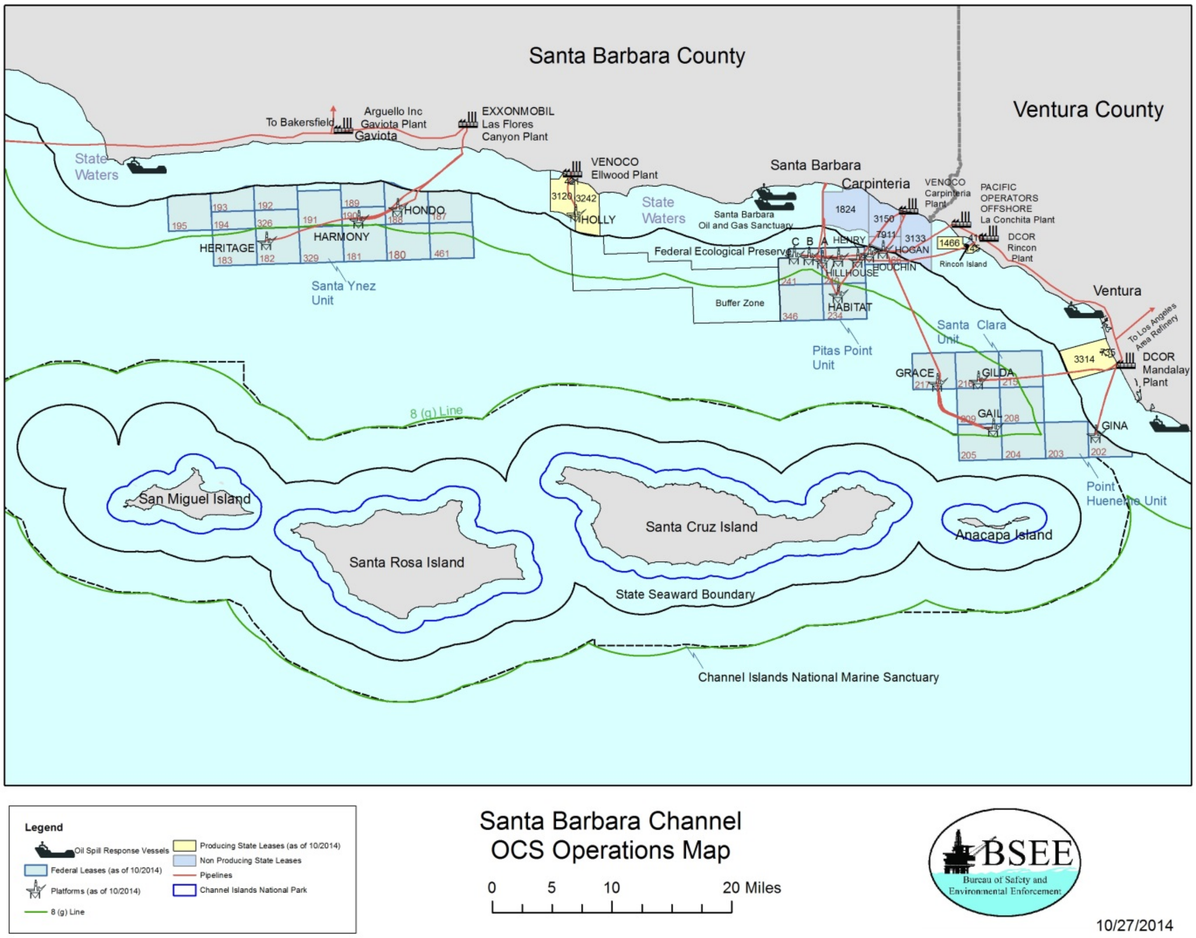

Figure 2.2. Santa Barbara Channel OCS Operations Map

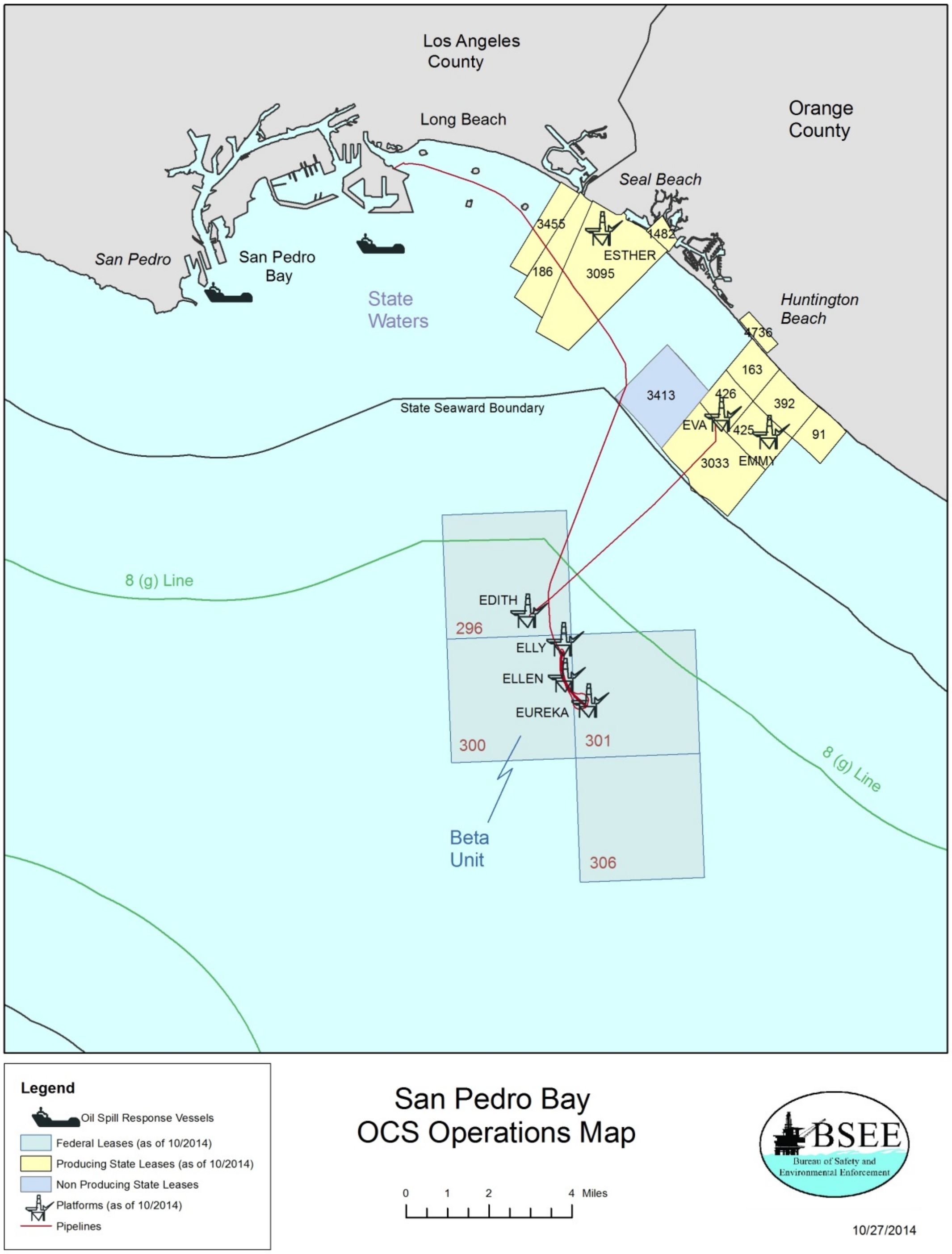

Figure 2.3. San Pedro Bay OCS Operations Map

Section 3: Pacific Region Decommissioning Equipment and Services Market

The market for offshore decommissioning equipment and services is very limited in California relative to the Gulf of Mexico (GOM) where approximately 4,100 offshore structures have been decommissioned to date and between 150 to 200 oil and gas structures are removed annually. The most recent decommissioning project occurred in California State Waters 1996 when Chevron removed four small platforms as noted in Section 2. Due to the lack of offshore oil and gas related construction and decommissioning activity in the POCSR, DB operators and other contractors who provide decommissioning services in the U.S. are concentrated in the GOM. This includes large offshore construction companies which during the past decade have transferred DB's which removed the Chevron 4-H Platforms and other equipment from the POCSR to the GOM, Atlantic coast, and overseas locations to take advantage of the strong market that exists for offshore construction and decommissioning services in those areas. Specialty decommissioning services such as abrasive cutting and rig-less well plugging and abandonment (P&A) services are concentrated in the GOM, North Sea, and Asia, where they provide services to the offshore oil and gas industry.

TSB Offshore (previously Proserv Offshore Inc.) and its personnel have long standing direct and indirect relationships with several oil and gas (operator and service) companies based in the Pacific region. Recently, its personnel have also been directly involved in projects operating in the Pacific Northwest and in support of planning and performing operations in Alaska. In addition, its key personnel have made trips to California to meet with local vendors and operators for current and previous studies to discuss the future operations estimated. Meetings and site visits were performed to convey the scope of the project and elicit responses including vendor capability, potential issues, potential problems and potential solutions to be applied. Visits included port facilities and locations, service providers, rental vendors, operators and government agencies (BSEE, BOEM, and California State Lands Commission CSLC).

After reviewing available service vendors and Pacific market resources, the most cost effective option is to mobilize the DB's from Asia and specialized P&A services (rig-less well P&A services, abrasive cutting services and pipeline P&A services) from the Gulf of Mexico. The viability of local and non-local resources was determined by first identifying all possible sources, analyzing each, then filtering by compliance, compatibility, and performance in OCS (considering best safety and integrity practices). Local resources were utilized first when viable resources were identified.

Factors Considered in Selecting Derrick Barges

One of the most important steps in the decommissioning planning process involves selecting a DB that has the lifting capability necessary to dismantle the platform in a safe, efficient, and cost effective manner. The selection process is influenced by the characteristics of the structure to be removed, including the water depth, deck module weight, jacket weight, and equipment weight. The preferred method of structure removal is the reverse installation method (as described in Section 13). In this method, platform preparation time and the number of lifts are significantly reduced compared to small piece removal or sectioning which requires more engineering analysis (load planning, cut planning, lifting points, truss support, pad eye locations, center of gravity of loads, etc.) and more cutting operations to create smaller lift packages. The reverse installation method limits personnel exposure to high risk operations relative to small piece removal due to the reduced number of crane lifts required to dismantle a platform. Since the derrick barge is the key component for performing the high risk heavy lift operations, decommissioning companies prefer to contract DB's that have extensive decommissioning experience with proven safety records.

For this report, analysis determines that DB's having a maximum lift capability of 500 tons and 2,000 tons will be required to remove the 23 platforms located on the OCS offshore California. These DB's have the capability to remove the platforms using the reverse installation method and are the most likely DB of choice based on standard industry practice, particularly considering the safety considerations described above. In the 2010 Proserv report a DB4000 was used for the larger, deeper jacket removal operations. Although a DB4000 was planned to be used in those operations it did not make use of its lifting capability as it could only effectively lift up to approximately 1600 tons at depths greater than 300 foot water depth. The resulting high mobilization and demobilization cost did not gain any improvement in operational efficiency. The larger platforms and deeper water locations will require jacket sectioning as standard reverse installation is not feasible with current market resources. The jacket sectioning approach requires the use of a lifting barge to perform the deep reach lifting operations for water depths deeper than 300 feet. This approach resulted in similar durations of lifting operations while yielding significant cost savings overall. The jacket sectioning methodology is described in greater detail in Section 13.

For this report, a detailed analysis was conducted of other DB's including those based locally which typically have a maximum full revolving load capacity of approximately 350 tons or less. These DB's have historically operated in inland and near shore waters and have not been used to install or decommission any oil and gas platforms offshore California. Additionally, they do not have berthing capacity to accommodate offshore workers. Any cost savings resulting from reduced day rates and localized mob/demob times are likely to be offset by the added expense of dismantling in smaller pieces (increased durations and risk exposure) and the costs associated with transport of crew between shore and the DB for each shift change. Given the priority industry places on safety considerations, experience, and operating efficiency, industry experts consider it highly unlikely that such a DB will be selected to decommission POCSR platforms, particularly if the current operator is unable to meet its decommissioning obligations and a decommissioning agent is directed to step in manage the decommissioning works. Such a contractor will likely follow standard industry practice in selecting the DB to do the work.

This study also considered lift boats and special purpose vessels that are typically used to decommission caissons or minimal structures in shallow waters in the GOM. These boats and vessels do not have the desired capability required to remove the POCSR platforms in an efficient and cost effective manner.

Dynamic Positioning Dive Vessels

Diving Support Vessels (DSV's) are normally found in 2 classifications, moored – requiring anchors to hold position, or dynamically positioned (DP) – using thrusters to hold a programmed position. DP vessels are normally used in deeper waters and larger, offering more deck space than standard vessels. Diving operations in water depths greater than 200 feet require saturated diving equipment to increase the effective time at depth for divers to perform works and operations. Saturated diving equipment requires additional space and equipment, therefore requiring a larger dive boat for operations. This is why DP DSV normally have a saturated diving package as an option for services. Using a dynamically positioned dive vessel removes the required anchoring system for a standard dive vessel and removes additional diver risk and vessel setup time. This study determined that a dynamic positioning class 2 (DP2) dive vessel will be required to support the equipment and divers needed to decommission the jackets and pipelines located in waters greater than 200 ft. The DP2 system automatically controls a vessels heading and position using its propellers and thrusters, together with wind and motion sensors. The DP2 dive vessel will be mobilized from the GOM, as these vessels are not available currently in the Pacific region. The mobilization and demobilization time will be 60 days total.

Rig-less Well Plugging and Abandonment

Oilfield service providers currently perform standard operations in the POCSR. Different companies perform the cementing, wireline, electric line, cementing, and fluids services utilized during well P&A operations. There are no companies that perform all the services with one spread as a P&A service. The standard mode of well P&A that the POCSR contractors are experienced with is rig based well P&A. Rigless well P&A is more cost effective and time efficient based on a lower day spread and shorter critical path for performing well P&A operations. The rigless well P&A methodology is described in detail in section 9. The experienced rigless well P&A contractors are not available in the POCSR. This report assumed that rig-less crew and equipment will be mobilized/demobilized from the nearest available location, most likely the GOM.

Cutting Services

In the decommissioning market, many contractors offer basic cutting services as part of their services package. These are normally sufficient for sectioning tubulars, pipe, or other items that cut condition does not matter. Subcontractors are used when: decommissioning operations are performed in deep water; involve complicated severing scenarios such as conductor or pile severing; or require specialty severing methods such as explosive, abrasive, diamond wire, or mechanical saw severing. When the cutting operations directly impact project timing, specialist subcontractors are preferred in the market. Diamond wire cutting is most often used in downed or damaged platform decommissioning, is limited to external cutting, and is usually more expensive than the other specialty cutting services mentioned. Mechanical cutting services are generally limited to cutting the conductors during recovery. In the past decade, abrasive cutting technology has become more competitive and is now widely used in the GOM. For this study, abrasive and mechanical cutting methods will be used for POCSR decommissioning projects based on operational efficiency and cost effectiveness. Since the GOM is the closest location the service is available, cutting services will be mobilized from the GOM to the POCSR.

Section 4: Decommissioning Cost Assumptions and Scenario

This section describes the decommissioning cost assumptions and scenario used in this report to estimate decommissioning costs for POCSR platforms, associated pipelines and power cables. For this study, an assumption is defined as an inference accepted as truth based on over 25 years of decommissioning experience, common industry practice, market evaluation, and specific project information. Assumptions are made to streamline the estimation process allowing focus to be on quality estimation rather than defining unknowns. The decommissioning scenario is based upon platforms being completely removed and the materials transported to shore for recycling or disposal. The decommissioning costs were developed based on information obtained from BSEE files, oil and gas operators, consultants, and technical decommissioning studies funded by BSEE and others.

This study reviewed the platform decommissioning scenario developed by Proserv for its 2010 cost report and revised the scenario given the company operators/ownership, third party agreements and working seasons. The scenario is based upon the total of six OCS decommissioning projects which include all of the POCSR oil and gas platforms (23 facilities). Based on oil and gas professionals, market research, in-house experience, demand in the POCSR, and market conditions the scenario assumes that 2-6 platforms will be decommissioned during each project to minimize the high cost of mobilizing/demobilizing DB's from Asia. The sequence and timing of the projects could differ markedly however, due to economic, technological and other factors.

Decommissioning Cost Assumptions

- Costs are estimated in 2014 U.S. Dollars.
- Assumptions based on Rules & Regulations research
    - Explosives will not be used during the decommissioning process.
        - Although explosives are the most time and cost effective option, explosives expose aquatic life and environment to significant risks. Alternative methods will be used.
    - Platforms will be completely removed and transported to shore for disposal.
    - A maximum of 6 platforms will be removed in the decommissioning season/time window.
    - No salvage or resale value has been considered for the structures, pipelines or power cables that are removed.
        - The Financial Accounting Standards Board stipulates that salvage value not be included in decommissioning cost estimates.
    - Pipelines routed to shore will be removed from the 200 foot water depth level to the State Tidelands boundary; pipeline segments between platforms on the OCS will be decommissioned in place; OCS pipeline segments in greater than 200 feet of water depth will be decommissioned in place.
        - These requirements are listed in federal code §250.1750 to §250.1752.
    - Power cables will be completely removed from the OCS to the State Tidelands boundary.
        - These requirements are listed in federal code §250.1750 to §250.1752.

- Assumptions based on Decommissioning industry and common practices
  - Conventional state-of-the-art technology (reverse installation using DB's) will be used to remove all of the decks.
    - Reverse installation is the most time efficient method currently used in the market limiting cost and risk exposure to personnel.
  - Jackets will be recovered using conventional technology.
    - Where possible, jackets will be recovered in single lift or sections using a DB with sufficient capacity.
  - One DB mobilization/demobilization cost is included for each of the six projects.
    - Projects are separated into feasible platform groupings based on operator obligation, geographic location, and working season.
    - The cost of mobilization and demobilization is distributed across platforms that could be completed as a single project.

- Assumptions based on review of possible technologies and alternatives
  - Jacket sectioning removal method will be utilized on the larger jackets.
    - Larger jackets in deeper water depths (>300 feet) cannot be reached using a standard derrick barge. A market survey yielded a limitation of lifts to 300 feet or shallower.
    - Jackets deeper than 300 feet will be sectioned and recovered using a lifting barge.
  - Reefing platforms in the POCSR is possible, but this has not been done before. Under current legislation there is no end to liability of a platform reefed. Under these circumstances, it is unlikely for this option to be used. There is limited financial upside and unlimited risk of exposure in the future.
  - The lifting barge will be used on Project II: Eureka, Project V: all platforms excluding Irene, and Project VI: all platforms.
    - A market survey determined conventional DB cannot reach a lift deeper than 300 feet water depth.
    - Lifting barge required for all jacket sections deeper than 300 feet water depth.
    - The identified platforms require a lift deeper than 300 feet.
  - The lifting barge cost will be distributed across the project platforms that require its use.
    - Similar to mobilization cost, lifting barge cost is distributed across platforms requiring its use in the same project.

- Assumptions based on market research and locations
  - The weather contingency downtimes for demolition operations are: 15% for the Point Arguello area, 10% for the Santa Barbara Channel area, and 5% for the South Coast area.
    - These weather downtime percentages are based on historical weather conditions when sea operations would not be possible.

    - The area based weather downtime percentages are the same as used in previous POCSR decommissioning reports.
- A general contingency (provisional work) of 15% is applied to all phases of the decommissioning process except project management, engineering and planning, permitting and regulatory compliance, and mobilization and demobilization of the DB's, to cover unanticipated problems and cost overruns.
    - Study analysis of historical data of actual decommissioning costs compared to estimated costs over a 20 year period yielded an approximate 15%.
- Project Management, Engineering & Planning costs are estimated to be 8% of the total cost of the project excluding costs associated with DB mob/demob, permitting and regulatory compliance, materials disposal, weather and provisional work allowances.
    - Study analysis of historical decommissioning costs over a 30 year period yielded an approximate 8% cost for Project Management, Engineering & Planning.
    - This is in line with multiple evaluations of decommissioning projects such as "Asia Pacific Decommissioning & Abandonment Analysis" by Robert McManus, DecomWorld, 2014, where the percentage of operator cost for Operator Project Management is reported at 8%.
- During each project a total of 2-6 platforms will be decommissioned using DB's mobilized from Asia.
    - A minimum of 2 platforms make up a project. Mobilizing a DB from outside the region for a single platform is not cost effective.
    - Asia is the closest mobilization point with DB's available to mobilize for operations.
    - Projects are made up of multiple platforms to distribute the mobilization cost.
- The roundtrip mobilization/demobilization times for derrick barges (DB's) is 100 days for a DB having a 500 or 2,000 ton maximum lift capability (DB 500, DB 2000) mobilized from Southeast Asia.
    - Singapore is the closest port where DB500 and DB2000 class vessels are available.
    - Based on vessel speed of 7 nmph, travel distance of ~8400 nm, the trip duration is 50 days each way.

Scope of Cost Analysis

This section provides a listing of the items that are included in the cost estimates developed for this report. Additional cost assumptions involving the Permitting and Regulatory Process are included in Section 7. Also listed are items for which costs were not estimated.

Costs Included

- Project Management, Engineering and Planning
- Permitting and Regulatory Compliance
- Platform Preparation
- Well Plugging and Abandonment
- Conductor Removal
- Pipeline and Power Cable Decommissioning
- Mobilization and Demobilization of DB's
- Platform Removal
- Materials Disposal
- Site Clearance
- Provisional Work and Weather Contingency Factors

Costs Not Included

Here is a listing of some of the potential costs not included. Additional unforeseen costs not identified could exist.

- All non-federal water items: State and onshore pipelines, power cables, marine terminals, piers, and onshore oil and gas processing facilities.
- The costs of remediating any potential impacts from shell mounds: such costs could include requirements to cap or remove shell mounds, requirements for offsite restoration to offset any adverse impacts of shell mounds that are left in place, or requirements to compensate commercial trawlers for the loss of fishing grounds.
- The costs for downtime due to the presence of whales or other marine life
- Costs for handling NORM or radioactive materials found
- Costs for ship traffic affected by operations (major shipping routes, fishing, tourism)
- Costs for operational delays, equipment breakdown, alternate sourcing, etc.
- Cost from delays in permitting process
- Cost from mitigations that could be placed by stakeholders, and permitting entities
- Costs for equipment modifications or special equipment that could be required to meet the local air emission standards
- Costs for equipment that could be installed on the platforms in the future

- Costs for special/unique expertise required to perform the work (preliminary, during operations, and post operations)
- Costs for worst case scenarios (accidents, earthquakes, blowouts, and leaks)
- Costs for training
- Costs for PR work
- Costs for partial removal

Decommissioning Scenario

This section describes the six decommissioning projects that include 2-6 platforms per project (see Table 4.1.). For each project, a DB is assumed to be mobilized from Asia. The DB's projected to be used have lift capabilities of 500 tons and 2,000 tons. The type of DB selected for each project was determined based on the size (total weight) of each individual platform included in the project, the projected maximum lift packages, and oceanographic considerations. A number of factors were considered in developing the projects, including the size, age, remaining oil and gas reserves, water depth, and company operators/ownership. For each project, the DB mobilization/demobilization (mob/demob) costs are allocated evenly among platforms. Only the projects requiring the use of a lifting barge include its cost. The lifting barge cost is distributed across the platforms requiring its use in the project.

Project I – POO, LLC

- Platforms Hogan and Houchin.
- A DB with a lift capability of 500 tons will be mobilized from Asia.
- The estimated mob/demob time is 100 days.

Project II –Beta Operating Company, LLC

- Platforms Eureka, Elly, Ellen and Edith.
- A DB with a lift capability of 2,000 tons will be mobilized from Asia.
- The estimated mob/demob time is 100 days.
- Lifting barge will be used for Eureka bottom lift of jacket sections using 4 x 500 ton winches.

Project III – DCOR, LLC

- Platforms A, B, C, Henry and Hillhouse.
- A DB with a lift capability of 2,000 tons will be mobilized from Asia.
- The estimated mob/demob time is 100 days.

Project IV – DCOR, LLC

- Platforms Gilda, Gina and Habitat.
- A DB with a lift capability of 2,000 tons will be mobilized from Asia.
- The estimated mob/demob time is 100 days.

Project V – FMO&G LLC and Venoco, Inc.

- Platforms Gail, Grace, Harvest, Hermosa, Hidalgo and Irene.
- A DB with a lift capability of 2,000 tons will be mobilized from Asia.
- The estimated mob/demob time is 100 days.
- Lifting barge will be used for bottom lift of jacket sections using 4 x 500 ton winches.

Project VI – ExxonMobil Corporation

- Platforms Harmony, Heritage and Hondo.
- A DB with a lift capability of 2,000 tons will be mobilized from Asia.
- The estimated mob/demob time is 100 days.
- Lifting barge will be used for bottom lift of jacket sections using 4 x 500 ton winches.

Table 4.1. Projected Decommissioning Projects

Platform	Year Installed	Water Depth (feet)	Deck Weight (tons)	Jacket Weight (tons)[1]	Projected DB Lift Capability for Jackets & Decks (tons)
Project I – POO, LLC[2]					
Hogan	1967	154	2,259	1,263	500
Houchin	1968	163	2,591	1,486	500
Project II – Beta Operating Company, LLC[3] and DCOR					
Eureka	1984	700	8,000	19,000	2,000
Elly	1980	255	4,700	3,300	2,000
Ellen	1980	265	5,300	3,200	2,000
Edith	1983	161	4,134	3,454	2,000
Project III – DCOR, LLC[4]					
A	1968	188	1,357	1,500	2,000
B	1968	190	1,357	1,500	2,000
C	1977	192	1,357	1,500	2,000
Henry	1979	173	1,371	1,311	2,000
Hillhouse	1969	190	1,200	1,500	2,000
Project IV – DCOR, LLC[5]					
Gina	1980	95	447	434	2,000
Gilda	1981	205	3,792	3,220	2,000
Habitat	1981	290	3,514	2,550	2,000
Project V – FMO&G LLC and Venoco, Inc.					
Gail[6]	1987	739	7,693	18,300	2,000
Grace	1979	318	3,800	3,090	2,000
Harvest	1985	675	9,024	16,633	2,000
Hermosa	1985	603	7,830	17,000	2,000
Hildalgo	1986	430	8,100	10,950	2,000
Irene	1985	242	2,500	3,100	2,000
Project VI – ExxonMobil Company[7]					
Harmony	1989	1,198	9,839	42,900	2,000
Heritage	1989	1,075	9,826	32,420	2,000
Hondo	1976	842	8,450	12,200	2,000

Disclaimer Note: These are reasonable removal scenarios based on the most likely grouping of decommissioning projects due to the lack of existing cost-sharing agreements between operators. (Alternate scenarios may also be feasible, but will require additional information from the individual liable parties at the relevant time.)

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[1] Jacket weight is the weight of the jacket only and does not include the weight of the deck, conductors or piles.

[2] Project I – Platforms Hogan and Houchin will be grouped together based upon ownership and DB requirements.

[3] Project II – Due to the routing of pipelines and power cables from the Edith platform to the Ellen/Elly platforms their decommissioning operations will be grouped together.

[4] Project III – The DCOR platforms A, B, C, Henry and Hillhouse will be grouped together based upon ownership, location and a six month working season.

[5] Project IV – The DCOR platforms Gina, Gilda and Habitat will be grouped together based upon ownership, location and a six month working season.

[6] Project V – There are abandonment liability agreements in place between various parties for platforms Gail, Grace, Harvest, Hermosa and Hidalgo.

[7] Project VI – ExxonMobil's platforms will be grouped together due to the operator/ownership.

Section 5: Decommissioning Methodology

This section describes the methodology on which the decommissioning costs in this report are based. The methodology is consistent with the cost assumptions previously referred in Section 4 and with BSEE decommissioning requirements (30 CFR 250, Subpart Q, Decommissioning Activities, NTL 2009-P04, NTL 2010-P05. 43 U.S. Code 1334) and factors listed in Section 3, 6 and 7.

Well Plugging and Abandonment

- All unplugged wells will be permanently plugged and abandoned (P&A) consistent with BSEE requirements.
- Rig-less methods will be used to P & A wells.
- Rig-less equipment and crews will be mobilized/demobilized from the Gulf of Mexico.
- This work will be completed prior to arrival of the DB.

Conductor Removal

- Abrasive cutting methods will be used to sever and remove all conductors 15 feet below the original mud-line.
- Casing jacks will be used to make the initial lift to confirm that conductors have been severed completely and to pull the conductors.
- Mechanical cutting methods will be used to cut the recovered conductors into 40-foot-long sections to allow safe handling.
- A rental crane located on the platform will be used to back-load the 40 foot conductor sections to a workboat for transport to an onshore site for processing and disposal.

Platform Preparation

- A platform inspection, above and below the water line, will be conducted to determine the condition of the platform and identify potential problems that would affect removal procedures. The inspection will be conducted by divers or remotely operated vehicles (ROVs).
- All piping and equipment on the platform that contained hydrocarbons will be flushed and cleaned. All industrial wastes will be removed from the platforms prior to decommissioning.
- All modules to be removed separately from the deck will be detached from the platform structure using oxygen-acetylene cutting torches.
- The piping, electrical, and instrumentation connections between modules will also be cut.
- Modules and captrusses (support frames) will be prepared for removal; new padeyes and lift supports will be installed; welds around bearing joints will be removed; and external equipment obstructing module lifts will be removed.
- It is assumed that 50% of the number of padeyes necessary for making the deck structure lifts must be fabricated and installed.
- Diving crews will use 10,000 psi water blasters to remove marine growth from the jacket to a water depth of approximately 100 feet; the dive spread will be set up on the platform; this work will be completed prior to the arrival of the DB.
- The remaining marine growth attached to the deeper jacket sections will be removed after the DB places the sections on the cargo barges or at the offloading facility/scrap yard; topside or onshore crews will use 10,000 psi water blasters to remove the remaining marine growth.

Pipeline Decommissioning

- All pipelines will be flushed and cleaned.
- Divers or an ROV will then expose the ends of the pipeline and cut the line above the riser bend and approximately 100 feet from the base of the jacket.
- Pipelines will be evaluated by BSEE on a case-by-case basis during the permitting process to determine whether they will be approved to be left in place or required to be partially or totally removed.
- For this study, costs were developed based on the following assumptions:
    - for pipelines routed to shore, pipeline segments will be removed from the 200 foot water depth level to the State Tidelands boundary;
    - pipeline segments between platforms on the OCS will be decommissioned in place;
    - OCS pipeline segments in greater than 200 feet of water depth will be decommissioned in place.
- Pipeline segments will be cut into 30 to 40 foot segments on the crane barge, and then loaded on to cargo barges for transport to shore, where they will be transported by truck to recycling facilities or a disposal site.
- A 50 ton crane barge will be mobilized from the southern California area to recover the pipelines to be placed on a cargo barge for transport to shore for material disposal.

Power Cable Decommissioning

- Power cables will be completely removed from the OCS.
- A local workboat mobilized from the Port of Los Angeles or Long Beach will be used to pull up cable and cut into sections.
- The power cables will be transported to shore by cargo barge and taken to a disposal site.

Mobilization and Demobilization of Vessels

- Dynamically positioned dive vessels will be mobilized from the Gulf of Mexico (closest port with capable resources to mobilize).
- Dynamically positioned DB's will be mobilized from Asia (closest port with capable resources to mobilize).
- Cargo barges and anchor handling tugs will be mobilized from the Ports of Los Angeles or Long Beach.
- Cargo barges will be outfitted at a fabrication yard with steel pads (load spreaders) to support the point loads of the deck modules and jacket sections.
- Local crew boats, workboats, support vessels and non-dynamically positioned dive boats will be utilized to the maximum extent possible.

Topsides Removal

- Topside modules will be removed (reverse installation) and placed on cargo barges.
- The deck section or support frames (captrusses) will be removed by cutting the welded connections between the piles and the deck legs with oxygen-acetylene torches.
- Slings will be attached to the deck/captrusses lifting eyes and to the DB crane.
- The DB crane will lift the deck sections from the jacket and position the sections in load spreaders.
- The deck sections will be secured by welding steel pipe from the deck legs to the deck of the cargo barge.

Topsides Transport and Onshore Disposal

- Tugboats and cargo barges will transport the topside modules and deck structures to an offloading facility/scrap yard located at the Port of Los Angeles or Long Beach.
- The modules will be lifted off the cargo barges by dockside cranes or skidded off the barge.
- All of the structural components will be cut into small pieces and scrapped.
- Non-metallic materials (cement, plastics, wood, etc.) will be transported to shore for disposal in a landfill.

Jacket Removal

- Jackets will be sectioned in situ (in place) and removed by a DB.
- Conventional state-of-the-art technology will be used to remove the smaller jackets.
- Piece small removal method will be utilized on the larger jackets.
- Piles and skirt piles will be severed 15 feet below the original mud-line by abrasive cutting tools.
- Divers or ROV's will be deployed to sever structural members and section the jackets.
- Saturation diving techniques will be required below 200 foot water depths.
- Lifting barge will be used for bottom lift (>300' water depth) of jacket pieces for Project II: Eureka, Projects V: all platforms excluding Irene, and Project VI: all platforms, using 4 x 500 ton winches.

Jacket Transport and Onshore Disposal

- Tugboats and cargo barges will transport the jacket sections to an onshore offloading facility/scrap yard located at the Port of Los Angeles or Long Beach.
    - Both Ports are located next to each other. The specific location will depend on Port activities at that time.
- The jacket sections will be lifted off the barges by dockside cranes or skidded off the barge.
- The jacket sections will be cut into small pieces and transported to a scrap yard.

Site Clearance

- Site clearance and verification shall be in accordance with BSEE requirements (30 CFR 250.1740-1743) and procedures described in the site clearance section of this report.
    - The seafloor impacted as a result of oil and gas exploration, development, production, and decommissioning operations will be restored to a condition that ensures the area has been cleared of all obstructions to other activities.
- Site clearance procedures will include the following elements:
    1. Pre-decommissioning high resolution side-scan sonar survey (SSS).
    2. Post-decommissioning high resolution SSS
    3. ROV/diver target identification and recovery of obstructions
    4. Test-trawling
- The pre-decommissioning SSS will cover all areas of the lease where operations occurred, including pipeline and power cable routes, and anchoring and mooring locations to identify any potential oil and gas related obstructions.
- The post-decommissioning SSS will cover all areas where decommissioning activities occurred to identify debris and obstructions resulting from decommissioning operations.
- A dive/ROV boat will be deployed to inspect and retrieve debris or obstructions identified during the SSS surveys.
- Test trawling will be conducted to verify that all potential obstructions have been cleared from the OCS lease(s).

Section 6: Project Management, Engineering and Planning

The project management, engineering and planning phase of the decommissioning process in POCSR will need to begin two to three years before production ceases at a minimum and involves (1) a review of contractual obligations, (2) engineering analysis, (3) operational planning, and (4) contracting. The first step involves conducting a detailed review of all records and decommissioning requirements including lease, operating, production/unit, pipeline, and production sales agreements. A detailed engineering analysis is also conducted of drilling records, as-built drawings, construction reports, maintenance records and inspection reports. Field inspections are done to verify the structural integrity of the platform and examine the present condition of the wellheads and equipment. Based on this information, detailed engineering plans are developed for plugging and abandoning the wells, severing the conductors and piles, removing the topsides and jacket, and disposing of the materials. Concurrently, a comprehensive survey of decommissioning vessels and equipment is made to determine their availability and cost. Bids are then solicited and contractors selected.

Due to the limited availability of DB's, contracting for such vessels is typically done two to three years in advance. Although some engineering functions can be conducted in-house if expertise exists, many steps in the decommissioning process require specialized expertise and the operator/lessee must contract for this expertise. These steps include the selection of mechanical, abrasive, or explosive cutting services, civil engineering services to design and prefabricate the modules for individual lifts, and diving services. In addition, the services of firms having project management and engineering expertise specific to decommissioning are often secured to manage the complex logistics of the overall project.

Cost Assumptions

The costs of project management, engineering and planning for decommissioning an offshore structure can vary widely, depending on the type of structure, its size and water depth, removal procedures, and transportation and disposal options. For this study, project management, engineering and planning costs are estimated to be 8% of the total decommissioning cost excluding DB mob/demob, permitting and regulatory compliance, materials disposal, weather and provisional work allowances. Study analysis of historical decommissioning costs over a 30 year period yielded an approximate 8% cost for Project Management, Engineering & Planning. This is in line with multiple evaluations of decommissioning projects such as "Asia Pacific Decommissioning & Abandonment Analysis" by Robert McManus, DecomWorld, 2014, where the percentage of operator cost for Operator Project Management is reported at 8%. The cost information was obtained from in-house data base that compiles annual cost data on oil and gas platform decommissioning projects in the Gulf of Mexico. POCSR cost percentages are expected to be comparable as the 8% is seen in multiple markets (GOM, Far East, West Africa).

Cost Estimates

The range of costs for the engineering and planning cost component is shown in Table 6.1. The costs range from a low of approximately $0.57 million (Gina) to a high of approximately $8.9 million (Harmony). The 8% cost figure is calculated from total decommissioning cost excluding DB mob/demob, permitting and regulatory compliance, materials disposal, and weather and provisional work allowances.

Table 6.1. Project Management, Engineering and Planning Costs

Platform	Factor	Pre-Engineering Costs	Total Engineering Costs
A	0.08	$21,676,762	$1,734,141
B	0.08	$19,558,756	$1,564,700
C	0.08	$15,871,982	$1,269,759
Edith	0.08	$17,322,315	$1,385,785
Ellen	0.08	$25,075,537	$2,006,043
Elly	0.08	$12,202,872	$976,230
Eureka	0.08	$83,642,058	$6,691,365
Gail	0.08	$65,013,293	$5,201,063
Gilda	0.08	$35,744,850	$2,859,588
Gina	0.08	$7,167,336	$573,387
Grace	0.08	$27,152,752	$2,172,220
Habitat	0.08	$18,037,688	$1,443,015
Harmony	0.08	$110,788,275	$8,863,062
Harvest	0.08	$60,439,768	$4,835,181
Henry	0.08	$11,956,703	$956,536
Heritage	0.08	$105,588,802	$8,447,104
Hermosa	0.08	$56,890,466	$4,551,237
Hidalgo	0.08	$44,981,987	$3,598,559
Hillhouse	0.08	$18,671,026	$1,493,682
Hogan	0.08	$20,305,206	$1,624,417
Hondo	0.08	$62,799,143	$5,023,931
Houchin	0.08	$18,746,611	$1,499,729
Irene	0.08	$22,591,839	$1,807,347
Total	-	-	$70,578,082

Note: Engineering costs for Conductor removal are based on a combination of varied and fixed costs.

Pre-Engineering Costs include Platform Prep and Marine Growth Removal, Well P&A, Conductor Removal, Pipeline Abandonment Costs, Power Cable Removal, Platform Removal and Site Clearance.

Section 7: Permitting and Regulatory Compliance

This section describes permitting requirements and associated costs for the decommissioning of POCSR oil and gas platforms, pipelines and power cables. The cost estimate for permitting and regulatory compliance assumes the platforms will be completely removed and the projects will not generate any significant or controversial environmental issues that would extend the environmental review process and result in delays in obtaining permit approvals from regulatory agencies. Such issues could include proposals to convert an offshore platform to an artificial reef (California has enacted Rigs to Reefs legislation in 2010 - AB 2503) or controversy regarding the fate of shell mounds which if removed could release deleterious materials in the marine environment, or if left in place could pose a hazard to commercial trawlers.

Permitting and regulatory compliance costs are incurred in obtaining the necessary Federal, State, and local permits required to conduct decommissioning operations and prepare the environmental documentation to satisfy the requirements of the National Environmental Policy Act (NEPA) and the California Environmental Quality Act (CEQA). The costs to satisfy special environmental mitigation requirements that typically are placed on the project by regulatory agencies are also included in this cost component. Examples include marine mammal protection measures, air emission mitigation measures, commercial fishermen preclusion agreements, and pre- and post- decommissioning biological surveys. For decommissioning projects offshore California, these costs can be significant.

Regulatory Agency Jurisdiction

The decommissioning of a Federal OCS oil and gas platform(s) will involve the removal of the structure and associated offshore oil and gas pipelines and power cables that connect the platforms and onshore processing facilities and electrical grids. The project may also involve the decommissioning of an associated onshore processing facility if it is the only facility servicing those platform(s). The agencies that have primary regulatory jurisdiction over such a project are BOEM/BSEE, which regulates oil and gas activities on the Federal OCS, the California State Lands Commission (CSLC) which has authority over State Tidelands located within 3 miles from the coastline, and the County/City agency regulating the related onshore facilities. In addition, the California Coastal Commission will have permitting authority over all aspects of the decommissioning program within the State's recognized Coastal Zone Boundary.

In addition to the BOEM/BSEE, Federal agencies that have regulatory authority over various aspects of decommissioning projects include, National Marine Fisheries Service, U.S. Army Corps of Engineers, U.S. Fish and Wildlife Service, U.S. Environmental Protection Agency, U.S. Coast Guard, and the U.S. Department of Transportation, Office of Pipeline Safety. Additional State and local agencies having regulatory jurisdiction over decommissioning operations in California include the California Department of Fish and Wildlife, California Division of Oil, Gas and Geothermal Resources, California State Fire Marshal, County Planning and Resource Management Departments, and local Air Pollution Control Districts. Tables 7.1 and 7.2 list the major regulatory agencies and their permitting requirements and authority.

Permitting Process

The process of obtaining all of the permits necessary to conduct decommissioning operations is a complex and challenging process that typically requires a minimum of 3 to 5 years to complete. Planning the project needs to start 2-3 years before production ceases with initiating the permitting process. The final 2-3 years of production (when production is still profitable prior to start of decommissioning), plus 1 year of idle iron, and time for well P&A should provide enough time for the permitting process for structure removal. Any unforeseen problems could delay this process. Due to the numerous permits required and the complexity of the process, companies that have decommissioned offshore oil and gas facilities have historically contracted with local consulting firms that have the technical, environmental and regulatory expertise required to navigate through the regulatory framework.

The first step in the process involves preparing and submission of an Initial Platform Removal application (Decommissioning Plan) two years prior to the end of production to BOEM/BSEE (30 CFR 250.1726). This application provides a preliminary description of proposed project activities, the associated equipment and personnel requirements, and the schedule for completing the activities. Within two years of the initial plan submission, a Final Platform Removal Plan (Decommissioning Plan) must be submitted to BOEM/BSEE (30 CFR 250.1727) as well as the necessary permit application materials needed to secure permits from Federal, State and local regulatory agencies with responsibility for these facilities. During the preparation of the final Decommissioning Plan, it is recommended that environmental baseline information be collected and field surveys are conducted to evaluate the project site.

Once the Final Platform Removal Application and associated project application packages are deemed complete by BOEM/BSEE and the lead State and/or local agency (CSLC and/or County Planning and Development Department), a joint environmental review of the project pursuant to the National Environmental Policy Act (NEPA) and the California Environmental Quality Act (CEQA) will be conducted. To coordinate the process and minimize duplication of effort, BSEE (Federal Lead Agency) and the lead CEQA agency (CSLC or County Planning and Development Department) generally prepare a joint Environmental Impact Statement/Environmental Impact Report (EIS/EIR) for the project. The EIS/EIR analyzes the environmental impacts of the project and describes mitigation measures proposed by the project applicant or recommended by agencies to eliminate or minimize those impacts. Upon completion, the draft EIS/EIR is circulated for public and agency review, including review by the California Coastal Commission (CCC) who must issue a Federal Consistency Determination for activities in OCS waters and Coastal Development Permit (CDP) for any activities that occur within State waters and adjacent onshore coastal zone. Following action by the CCC, BSEE and the lead CEQA agency and can proceed with approving the project by respectively issuing a Record of Decision (ROD) and Notice of Determination (NOD) for the project.

TSB OFFSHORE

Table 7.1. Federal Permitting Requirements Applicable to Decommissioning Projects

Agency	Permit/Approval	Regulated Activity	Applicable Project Components	Review Period*	Authority
Federal Agencies					
Bureau of Ocean Energy Management (BOEM)	Coordinates NEPA Analysis	Responsible for OCS lease administration (including lease adjudication), and ensuring compliance with bonding requirements and lease terms and conditions. Performs environmental analysis on behalf of BSEE.	OCS facilities including platforms, wells and pipelines.	Conducted in coordination with BSEE NEPA review	Outer Continental Shelf Lands Act, 30 CFR § 550 and 30 CFR § 556
Bureau of Safety and Environmental Enforcement (BSEE)	Approval of Final Decommissioning Application	Responsible for approving OCS decommissioning applications and enforcing safety and environmental regulations.	OCS facilities including platforms, wells and pipelines.	Approximately 6 months to 3 years to complete NEPA review and project component decommissioning procedures. (Duration mainly depends on external reviews.)	Outer Continental Shelf Lands Act 30 CFR 250 Subpart Q, Decommissioning Activities NTL 2009-P04 NTL 2010-P-05 43 U.S. Code 1334
US Army Corps of Engineers (ACOE)	Section 404 permit Section 10 permit	Responsible for: (1) issuing permits for discharges of dredged or fill material in U.S. waters; (2) issuing permits for construction of any structure in or over the navigable waters of the U.S.	Marine components	3-4 months including certification of NEPA/CEQA document	Clean Water Act, Section 404 Rivers and Harbors Act, Section 10
United States Fish & Wildlife Service (USFWS)		Responsible for ensuring protection of threatened and endangered species (e.g., sea otters and certain bird species), pursuant to the Endangered Species Act (ESA).	Both terrestrial & marine components	Unspecified	Endangered Species Act 16 USCA 1513 50 CFR Section 17
Environmental Protection Agency	NPDES permits	Responsible for issuing National Pollution Discharge Elimination System (NPDES) permits for discharges of pollutants from point sources to surface waters.	Discharge	Unspecified	Clean Water Act
United States Coast Guard (USCG)	Navigation consultation Notice to Mariners	Responsible for ensuring navigation safety, proper use of aids to navigation, and managing responses to any unauthorized discharges including oil spills.	Activities in navigable waters	Unspecified	Ports and Waterways Safety Act Oil Pollution Act of 1990 33 CFR – Coast Guard
U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration	Pipeline abandonment applications	Responsible for ensuring pipeline safety and overseeing abandonment of pipelines for DOT jurisdictional pipelines.	Pipeline components Hazardous materials	Unspecified	Natural Gas Pipeline Safety Act Hazardous Liquid Pipeline Safety Act Hazardous Materials Transportation Act
National Marine Fisheries Service	ESA, Section 7 for marine species Marine Mammal Protection Act Essential Fish Habitat Assessment	Impacts to federally-listed and species proposed for listing. Protection of Marine Mammals including impacts associated with explosives use. Managed Marine Fish Resources	Marine components	Review period: 6 months to 1 year Review period: 18 months or more Review period: Similar to ESA Completed prior to NEPA completion	Endangered Species Act Marine Mammal Protection Act Magnuson-Stevens Fishery Conservation and Management Act

*The Review Period is an estimated duration. The actual time required may be longer or shorter.

Table 7.2. State and Local Permitting Requirements Applicable to Decommissioning Projects

Agency	Permit/Approval	Regulated Activity	Applicable Project Components	Review Period*	Authority
State of California Agencies					
California State Lands Commission (CSLC)	Lead agency for CEQA documentation. Pipeline lease agreement termination	Review of environmental impacts in area of jurisdiction. Removal of components in State Territorial Waters.	State Waters portion of project.	6-12 months for certification of CEQA document. Lease termination agreement	CEQA California Public Resources Code Section 6500
California Coastal Commission (CCC)	Coastal Development Permit/Federal Consistency	Any development within designated coastal zone.	Marine component and onshore facilities within Coastal Zone.	2-3 month review process, partially concurrent with CEQA review.	California Coastal Act Coastal Zone Management Act
California Department of Fish and Wildlife	Explosives Use Approval and State Endangered Species Consultation. Section 1601	Activities in our effecting State Waters resources. Onshore activities effecting onshore resources including streams and wetlands	Marine component and onshore facilities within Coastal Zone.	2-3 month review process, partially concurrent with CEQA review.	CEQA Section 1601 State Endangered Species Act
Regional Water Quality Control Board (RWQCB)	Section 401 certification	Discharges that may affect surface and ground water quality.	Marine and onshore operations	Concurrent with ACOE review and approval.	Clean Water Act (CWA) Porter-Cologne State Water Quality Act (1969).
State Historical Preservation Officer (SHPO)	Section 106 review and compliance	Impacts to historic and pre-historic resources.	None identified at this time.	3-6 months after certification of CEQA document.	National Historic Preservation Act 36 CFR 800
Local Agencies (Santa Barbara, Ventura and Los Angeles Counties)					
County Department of Planning and Building (County)	Coastal Development Permit Conditional Use Permit	Removal of project components located landward of State Lease within unincorporated portions of County (beach & onshore segments). Activities within designated coastal zone.	Onshore facilities within Coastal Zone.	2-3 month review process, partially concurrent with CEQA review.	County General Plan / Coastal Plan
County Air Pollution Control Board (APCD)	Air quality emissions review; Permit to Operate/Authority to Construct (PTO/ATC) and Portable Engine Permits	Air emission outputs associated with project decommissioning activities.	Combined marine and onshore project components.	6 month review process, concurrent with CEQA review.	1990 Clean Air Act CEQA review

*The Review Period is an estimated duration. The actual time required may be longer or shorter.

Cost Assumptions

The factors considered in developing cost estimates for permitting and regulatory compliance for this report are described below. The factors were selected based on input received from oil and gas companies and consulting firms that have been involved in previous decommissioning projects offshore California. Additional input was received during site visits to California POCSR in 2014.

(1) Initial and Final Platform Removal Plan (Decommissioning Plan): The project applicant, with assistance provided by a consulting firm, will prepare a Plan that provides a detailed description of proposed project activities, the associated equipment and personnel requirements, and the schedule for completing the activities. Typically these materials are based on detailed engineering plans developed by engineering firms and/or marine contractors with expertise in marine decommissioning operations.

(2) Data Collection and Field Surveys: The project applicant will contract with a environmental consulting firm that will compile existing baseline environmental information and conduct field surveys to evaluate the project site and identify the presence of any sensitive marine species and habitats that could potentially be impacted by decommissioning operations. The field surveys will include pre- and post-construction surveys. Such surveys were required by regulatory agencies for previous decommissioning projects conducted offshore California.

(3) NEPA and CEQA Documents: The project applicant will be required to fund the preparation of EIS/EIR. Upon submission of an application package that is deemed complete, BSEE and lead CEQA agency will oversee the preparation of an EIS/EIR that will be conducted by a third party (consulting firm) selected by the agencies.

(4) Agency Processing Fees and Staff Time: The project applicant will be responsible for covering these expenses. Federal, State and local regulatory agencies in California impose fees for processing applications or require applicants to reimburse the agencies for staff time required to review and process permits.

(5) Environmental Mitigation Requirements: The project applicant will be responsible for mitigating impacts to air quality and commercial fishermen who would be precluded from fishing in the area where decommissioning operations are conducted. This mitigation involves payments to fishermen for lost catch and fees paid the local air pollution control districts for technology demonstration projects and other air quality improvement programs. Regulatory agencies have also required project applicants to prepare Marine Wildlife Protection Plans and post trained marine mammal observers to monitor decommissioning operations to ensure protection of whales and other marine mammals. Such requirements were imposed by regulatory agencies on Chevron when it decommissioned Platforms Hope, Heidi, Hilda and Hazel in State waters in 1996.

(6) Mitigation Monitoring and Compliance: The project applicant, with the assistance of a consultant, will develop and implement a Mitigation Monitoring and Compliance Plan for the project Regulatory agencies require project applicants to develop and implement these plans to ensure that environmental mitigation measures and other conditions placed on the project by the approving authorities are satisfied by the project applicant. The monitoring activities are typically performed by consultants and regulatory agency personnel. Monitoring plans were developed and implemented by Chevron and other companies for previous decommissioning projects conducted offshore California. The shell mounds monitoring at the 4H locations continue in 2014.

Cost Estimates

Table 7.3 provides a breakdown of the cost estimates for permitting and regulatory compliance that were developed for this study based on the cost assumptions described above. The costs are shown on a per project basis.

Table 7.3. Permitting and Regulatory Compliance Costs – Base Case

Cost Factors	Cost Per Project
1. Initial and Final Platform Removal Plan (Decommissioning Plan) Preparation (does not included decommissioning engineering costs)	$250,000
2. Data Collection and Field Surveys	$100,000
3. Prepare NEPA and CEQA Documents (EIS/EIR)	$2,500,000
4. Agency Processing Fees and Staff Time	
• Application Fees	$100,000
• Agency Staff Time	$120,000
• Applicant Consultant Support	$160,000
5. Environmental Mitigation Requirements	
• Mitigation Fees (Air and Fisheries)	$1,000,000
• Marine Mammal Monitoring	$120,000
6. Mitigation Monitoring and Compliance	$200,000
Total Cost Per Project	**$4,550,000**

The cost factors 1, 2, 5, and 6 vary due to number of platforms. This is due to the additional locations and processes required to generate the required documentation. Table 7.4 shows the values for the factors that vary with the number of platforms.

Table 7.4. Permitting and Regulatory Compliance Costs Variance by Number of Platforms per Project

Cost Factors	Cost Per Project (Base Case)	# of platforms in project				
		2	3	4	5	6
1.Initial and Final Platform Removal Plan (Decommissioning Plan) Preparation (does not included decommissioning engineering costs)	$250,000	$200,000	$220,000	$250,000	$275,000	$295,000
2.Data Collection and Field Surveys	$100,000	$70,000	$90,000	$110,000	$130,000	$150,000
3.Prepare NEPA and CEQA Documents (EIS/EIR)	$2,500,000					
4. Agency Processing Fees and Staff Time						
·Application Fees	$100,000					
·Agency Staff Time	$120,000					
·Applicant Consultant Support	$160,000					
5.Environmental Mitigation Requirements						
·Mitigation Fees (Air and Fisheries)	$1,000,000	$762,000	$886,000	$1,011,000	$1,134,000	$1,261,000
·Marine Mammal Monitoring	$120,000	$90,000	$110,000	$130,000	$150,000	$170,000
6.Mitigation Monitoring and Compliance	$200,000	$130,000	$170,000	$210,000	$250,000	$290,000

Table 7.5 shows the total permitting costs by project. The project permitting costs are distributed across the platforms within the project based on the percentage of the total offshore operations for the platform relative to the total offshore operation costs for the entire project. Table 7.6 shows the permitting costs divided accordingly to individual platforms.

Table 7.5. Permitting and Regulatory Compliance Costs Per Project

Project	Cost per Project	Qty of Platforms
Project I	$ 4,132,000	2
Project II	$ 4,591,000	4
Project III	$ 4,819,000	5
Project IV	$ 4,356,000	3
Project V	$ 5,046,000	6
Project VI	$ 4,356,000	3

Table 7.6. Permitting and Regulatory Compliance Costs Per Platform

Platform Name	Project	Cost Per Platform*
A	Project III	$ 1,180,645
B	Project III	$ 1,069,808
C	Project III	$ 891,505
Edith	Project II	$ 564,723
Ellen	Project II	$ 830,961
Elly	Project II	$ 482,045
Eureka	Project II	$ 2,713,271
Gail	Project V	$ 1,190,846
Gilda	Project IV	$ 2,565,674
Gina	Project IV	$ 509,672
Grace	Project V	$ 494,498
Habitat	Project IV	$ 1,280,654
Harmony	Project VI	$ 1,720,616
Harvest	Project V	$ 1,115,156
Henry	Project III	$ 650,555
Heritage	Project VI	$ 1,650,938
Hermosa	Project V	$ 1,004,204
Hidalgo	Project V	$ 827,534
Hillhouse	Project III	$ 1,026,487
Hogan	Project I	$ 2,144,518
Hondo	Project VI	$ 984,446
Houchin	Project I	$ 1,987,482
Irene	Project V	$ 413,762

*Cost per platform distributed based on percentage cost of platform relative to the total offshore operations of the project.

Section 8: Platform Preparation

Platform preparation includes the procedures associated with shutting down and preparing the facility for removal. Level I topside inspections and Level II underwater inspections are generally conducted to determine the condition of the structure and to identify any problems for removal. Divers will perform the underwater inspection in water depths ranging from 0' to 200' and remotely operated vehicles (ROV's) will perform the underwater inspections from water depths ranging from 201' to 1,200'. After the inspections have been completed, a crew paid on a day rate prepares the structure for decommissioning after the wells have been permanently plugged and abandoned.

On the surface (topside of the platforms), the work includes the flushing/cleaning and degassing/purging of tanks, processing equipment and piping, disposal of residual hydrocarbons, removal of platform equipment, cutting of piping and cables between deck modules, separation of modules into individual units, installation of padeyes for deck module lifting, removal of obstructions to lifting, and structural reinforcement. Below the water surface, the jacket can be prepared to aid in jacket facilities removal, including the removal of marine growth from the structure.

The key factors affecting the cost of platform preparation include structure size and complexity, topsides equipment (especially the amount of processing equipment), and age of the facility. The costs can vary widely depending on the type of facility, removal procedures, and transportation and disposal options.

For this report, the marine growth will be removed from the structure, including the conductors and boat landings by divers down to approximately 100 feet below the ocean surface. This will remove most of the heavy and, hard marine growth. The balance of the marine growth will be removed at the offloading facility/scrap yard or by topside crews on the DB using 10,000 psi high-pressure water blasters and/or fixed firewater monitors (nozzles) once the jacket or jacket section is on the deck of the barge. The in-water cleaning operations will be completed with the dive equipment set up on the platform to eliminate the need and added cost that would be incurred if the operations were conducted from a dedicated dive vessel.

Range of Costs and Assumptions

Past Technology Assessment Programs (published by BSEE), other studies conducted by engineering and consulting companies were consulted to develop the platform preparation costs. Additional rates and information were provided by a local diving service contractor. Table 8.1 shows the cost estimate of the number based on the number of days and platform preparation spread rate, marine growth removal cost, and total cost that would be required to prepare each of the 23 POCSR platforms for decommissioning as described above. The platform preparation spread consists of a utility boat, helicopter use (1 trip/3 days), a preparation crew, materials and supplies. A higher spread rate and cost, due to a larger platform preparation crew and more equipment was applied for the larger, more complex topside structures based upon previous cost studies.

Table 8.1. Platform Preparation Costs

Platform	Topside Platform Preparation Days	Topside Platform Preparation Spread Rate	Topside Preparation Cost	Marine Growth Removal Cost	U/W Inspection Cost	Total Cost*
A	19	$29,310	$556,890	$510,081	$26,400	**$1,093,371**
B	19	$29,310	$556,890	$510,081	$26,400	**$1,093,371**
C	19	$29,310	$556,890	$510,081	$26,400	**$1,093,371**
Edith	18	$29,310	$527,580	$765,120	$27,000	**$1,319,700**
Ellen	20	$29,310	$586,200	$765,120	$38,500	**$1,389,820**
Elly	46	$29,310	$1,348,260	$765,120	$38,500	**$2,151,880**
Eureka	31	$58,620	$1,817,220	$1,113,483	$38,500	**$2,969,203**
Gail	43	$58,620	$2,520,660	$1,113,483	$35,667	**$3,669,809**
Gilda	44	$29,310	$1,289,640	$765,120	$41,333	**$2,096,094**
Gina	22	$29,310	$644,820	$191,280	$28,000	**$864,100**
Grace	35	$29,310	$1,025,850	$765,120	$35,667	**$1,826,637**
Habitat	39	$29,310	$1,143,090	$765,120	$41,333	**$1,949,544**
Harmony	59	$58,620	$3,458,580	$2,017,137	$41,333	**$5,517,050**
Harvest	55	$58,620	$3,224,100	$1,113,483	$35,667	**$4,373,249**
Henry	31	$29,310	$908,610	$510,081	$26,400	**$1,445,091**
Heritage	55	$58,620	$3,224,100	$1,613,710	$41,333	**$4,879,143**
Hermosa	55	$58,620	$3,224,100	$1,113,483	$35,667	**$4,373,249**
Hidalgo	47	$58,620	$2,755,140	$916,986	$35,667	**$3,707,793**
Hillhouse	32	$29,310	$937,920	$510,081	$26,400	**$1,474,401**
Hogan	19	$29,310	$556,890	$510,081	$30,000	**$1,096,971**
Hondo	50	$58,620	$2,931,000	$1,113,483	$41,333	**$4,085,816**
Houchin	19	$29,310	$556,890	$510,081	$30,000	**$1,096,971**
Irene	35	$29,310	$1,025,850	$765,120	$35,667	**$1,826,637**
Totals	-	-	**$35,377,170**	**$19,232,936**	**$783,167**	**$55,393,273**

* Total Cost includes Topside Platform Preparation Cost plus Marine Growth Removal Cost and Underwater (U/W) Inspection Cost.

TSB OFFSHORE

Section 9: Well Plugging and Abandonment

Requirements

One of the major cost components of a decommissioning project is the plugging and abandonment of platform wells. Regulations for well plugging and abandonment are found in Subpart Q of 30 CFR 250 in subsections 250.1710 - 1717 and are summarized below.

- All wells shall be abandoned in a manner to assure downhole isolation of hydrocarbon zones, protection of freshwater aquifers, clearance of sites so as to avoid conflict with other uses of the OCS, and prevention of migration of formation fluids within the wellbore or to the seafloor.

Procedures

Planning and operations are two distinct phases in the well plugging process. The planning and actual abandonment process entails: data collection (including review of existing well design encompassing degree of deviation, maximum angles, and dog leg severities, past performance, and present geological and reservoir conditions), preliminary inspection (including inspection of wellhead and tree to verify that valves and gauges are operational, with repairs made as necessary), selection of abandonment methods(s) (including consideration of using either rig methods, rig-less methods, or coiled tubing methods, or a combination of these three methods), and submittal of an application for BSEE approval.

For this study, alternative methods of plugging and abandoning wells using both a contracted platform rig, and rig-less techniques were compared and has determined that rig-less methods are significantly more economic and time efficient. The rig-less method has therefore been used in developing the well plugging and abandonment cost estimates.

Developed in the 1980's, rig-less methods are now used in the majority of the plugging and abandonment jobs in the Gulf of Mexico. Decommissioning companies agree rigless well P&A is most likely to be used in the POCSR based on the scenario described in Section 3 (Pacific Region Decommissioning Equipment and Services Market). A small rental crane would be contracted to provide assistance with rig-less equipment spread set-up and breakdown, as well as tool, cement, and equipment handling assistance during plugging and abandonment operations. In the rig-less method, a load spreader spans the top of a conductor, providing a base to launch tools, plugs, and other equipment downhole. This load spreader is the primary economic savings mechanism because the plugging process will take slightly less time than with a rig, and the load spreader is significantly cheaper and can be set-up and broken down quicker than a platform rig. This allows for switching to different wells during any waiting on cement time (WOC) reducing the critical path for operations significantly. Rigless well P&A reduced the critical path from 10 days using a rig to 3-8 days (average) performed rigless.

The actual well abandonment operation in a standard setting involves: well entry preparations (including setting-up load spreaders, installation of back pressure valve, and the nippling-up and testing of blowout prevention equipment), use of slick line unit (including confirmation of the presence or absence of wellbore obstructions, verification of measured depths, and the pulling of downhole safety valves), filling the well with fluid (including establishing an injection rate into open perforations, and pressuring-up the tubing and annulus to verify integrity), removal of downhole equipment (including the pulling of pumps and tubing strings), cleaning out the wellbore (utilizing casing scrapers and a variety of special purpose fluids), plugging open-hole and perforated intervals(s) at the bottom of the well (including squeeze cementing, setting cast-iron bridge plugs, or the placement of cement plugs), plugging casing stubs (where casing has been cut and recovered), plugging of annular space (using squeeze cementing techniques), placement of a surface plug, and placement of fluid between plugs. Regardless of the technique used, plugs must be tagged to ensure proper placement and/or pressure-tested to verify integrity.

Figure 9.1 provides a schematic view of the typical wellbore configuration.

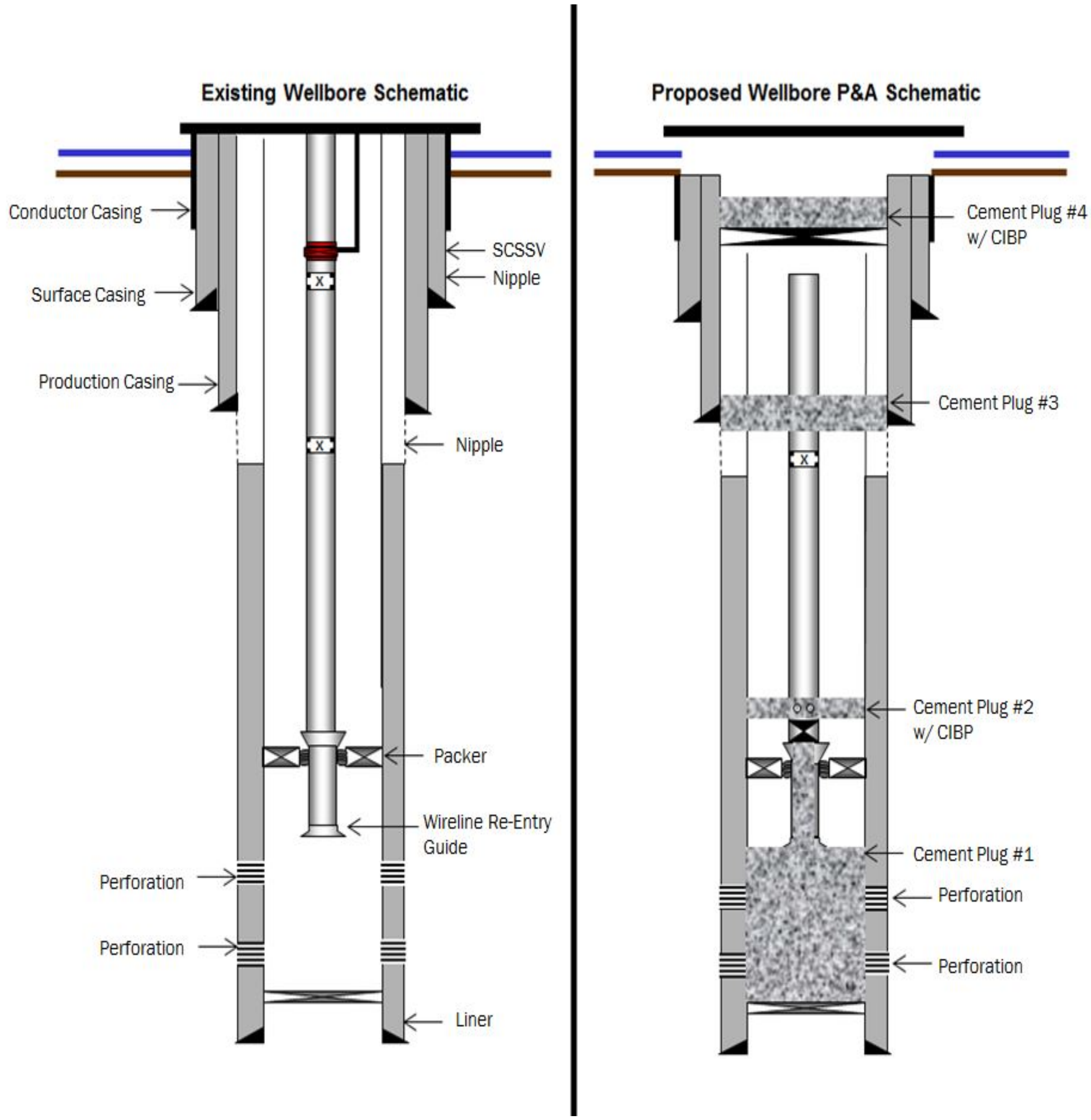

Figure 9.1. Typical Wellbore Configuration (Existing & PA Schematics)

Cost Factors

The primary factors in determining costs to plug wells are the time required to complete the operation, which depends on the difficulty of each well, and the number of wells per platform. The difficulty of each plugging and abandonment procedure is tied to the complexity of the well. For this study, the following four cost categories are used in estimating well plugging and abandonment costs. Appendix 6 provides a breakdown of number of wells in each cost category by platform.

- A low cost well will be a straightforward well without deviation problems or sustained annular pressures, and without pumps. A well of this type could be plugged in three days.

- A medium low cost well would be more complex with mid-range horizontal displacements with deviations less than 50° at the surface casing shoe. A medium low cost well could have minor complications such as stuck pipe or short-term milling or fishing operations. A medium low cost well can be plugged in four days.

- A medium high cost well could have high deviations between 50° and 60° at the surface casing shoe or extended reach wells. They may contain electric submersible pumps or sucker rod pumps. A medium high cost well would have greater operational difficulties and time delays due to hydrogen sulfide concerns, longer fishing or milling operations. A medium high cost well would take five days to plug.

- A high cost well could have high deviations with greater than 60° maximum angles, severe dog legs or extended reach. A high cost well can have operational difficulties including sustained annular pressures, parted casing, long term fishing or milling work, repeated trips in and out of the hole, etc. A high cost well would take eight days or longer to plug.

Well depth is a less significant cost factor than well complexity. Deeper wells involve longer tripping times and may include additional cement volumes. Measured depths of productive intervals for wells in the POCSR range from less than 1,000 feet to more than 17,000 feet.

Service and supply companies are highly competitive and offer substantial discounts (up to 35%) for multiple well packages. Costs associated with plugging of wells in all four well categories are based on multiple-well price packages, and represent the lowest daily unit costs for some goods and services.

Rig-less spreads are not anticipated to be available in the POCSR, so equipment and crew have been assumed to be mobilized/demobilized to Los Angeles by land for the spreads and by airline for the crew. Then spreads and crew are mobilized/demobilized to/from the platform via boat. The average cost of plugging each well by complexity category is shown in Table 9.1. There are 752 wellbores that require plugging and abandonment in the POCSR. Three wells were added to the Gail platform and two wells were added to the Irene platform since the 2010 study. Table 9.2 shows well plugging and abandonment costs by platform and the total cost for plugging and abandoning all POCSR wells. Detailed well plugging and abandonment cost information is presented in Volume 2.

Table 9.1. Average Well Plugging and Abandonment Costs by Well Type

Well Type (Level of Complexity)	Average Cost/Well
Low cost well (3 days to plug and abandon)	$140,112
Med low cost well (4 days to plug and abandon)	$170,116
Med high cost well (5 days to plug and abandon)	$224,120
High cost well (8+ days to plug and abandon)	$328,532
Mobilization cost (shared across number of wells per platform)	$152,600

Assumptions:
1. Costs do not include cost of conductor removal.
2. All costs include shipment and airfare associated with mob/demob of rig-less equipment from GOM.

Table 9.2. Well Plugging and Abandonment Costs Per Platform (Rig-less Well P&A)

Platform	Wells to P&A	Average Well Depth (ft)	Rig-less P&A Costs
A	52	2,500	$7,860,872
B	57	2,500	$8,591,436
C	38	2,500	$5,839,296
Edith	18	4,500	$3,067,060
Ellen	63	6,700	$10,650,264
Elly	0	0	$0
Eureka	50	6,500	$8,906,812
Gail	27	8,400	$5,487,404
Gilda	63	7,900	$11,270,732
Gina	12	6,000	$2,196,384
Grace	28	-	$5,934,732
Habitat	20	12,000	$3,791,340
Harmony	34	11,900	$9,234,448
Harvest	19	10,000	$4,932,940
Henry	23	2,500	$3,677,608
Heritage	48	10,300	$13,311,836
Hermosa	13	9,500	$3,379,396
Hidalgo	14	10,700	$3,916,752
Hillhouse	47	2,500	$7,160,312
Hogan	39	5,400	$7,246,752
Hondo	28	12,700	$6,845,608
Houchin	35	5,100	$6,491,880
Irene	26	9,800	$6,289,360
Total:	**754**	-	**$146,083,224**
Average per well:	-	6,814	$193,744
Average per platform:	33	6,814	$6,351,445

Assumptions:
1. Costs do not include cost of conductor removal.
2. All costs include shipment and airfare associated with mob/demob of rig-less equipment from GOM.
3. Average per platform only includes platforms with wells.

Section 10: Conductor Removal

Requirements

Regulations for conductor removal and well plugging and abandonment are found in Subpart Q of 30 CFR 250, in subsections 250.1710 - 1723 and are summarized below.

a) Per subsection 250.1716, unless the District Manager approves an alternate depth under paragraph (b) of this section, you must remove all wellheads and casings to at least 15 feet below the mud line.

b) The District Manager may approve an alternate removal depth if:

1. The wellhead or casing would not become an obstruction to other users of the seafloor or area, and geotechnical and other information you provide demonstrate that erosional processes capable of exposing the obstructions are not expected; or
2. You determine, and BSEE concurs, that you must use divers, and the seafloor sediment stability poses safety concerns; or
3. The water depth is greater than 800 meters (2,624 feet).

Procedures

Conductor casing removal combines three distinct procedures: severing, pulling/sectioning, and offloading. Severing of the conductor casings requires the use of explosive, mechanical and or abrasive cutting methods. For this study, the costs are estimated using abrasive cutting methods to sever the conductor and mechanical cutting methods for sectioning the conductor during recovery. These two methods are commonly used and will likely to be the preferred in the POCSR due to environmental considerations. This study has reviewed and determined that the most economic method for pulling the conductors is using a casing jack removal method. Alternatives considered for pulling the conductors included platform rig and derrick barge removal methods, but both alternatives, although shorter in duration, resulted in significantly higher cost due to expensive derrick barge or platform rig rental rates. In the casing jack removal method, casing jacks are utilized to make the initial lift to confirm that conductors have been completely severed prior to pulling. Pulling the conductor and casings entails using the casing jacks to raise the conductors which are cut into 40 feet-long segments. Offloading involves utilization of a rental crane to lay down each conductor casing segment in a platform staging area, offloading sections to a vessel, and offloading at a port. The conductors are then transported to an onshore disposal site as described in the Materials Disposal section of this report.

Cost Assumptions and Factors

For this study, law and regulation review has determined that explosives will not be used to sever conductors. The use of explosives was deemed unnecessary due to the advances that have been made in abrasive and mechanical cutting technologies, and the fact that abrasive cutting is now the most commonly used method to sever conductors. The use of explosives offshore California was also considered to be problematic due to presence of whales and other sensitive marine mammals. Although explosive use has not been considered in developing costs for this study, it has included cost information on explosives use in Volume 2 of this report.

The primary factors in determining conductor casing removal costs are water depth and number of conductors per platform. Water depths in the POCSR range from 95 feet to 1,198 feet. The number of conductors to be removed from each platform in the POCSR ranges from 12 to 64.

The cost to plug the wells and to remove the conductors is essentially the same regardless of whether all wells are plugged before any of the conductors are removed, or if individual conductors are removed immediately after each well is plugged as long as there is sufficient space on the platform to perform simultaneous operations.

Conductors are assumed to be coated with marine growth which will be removed as they are pulled. The majority of the marine growth will have been removed as a part of the platform preparation that occurs immediately prior to the conductor removal operations. The remaining marine growth will be minimal and easily removed during conductor recovery.

Conductors extend approximately 65 feet above the water line to the wellhead on the platform. It is also assumed that the conductors and casing have cemented annuli and will therefore have to be removed in conjunction with one another. The average size of the conductors for a platform are estimated based on available drawings and well information. Conductor size ranges from 13-3/8” to 24”. The average weight of each conductor is calculated using available information and assuming annuli filled with 16.2 ppg (pound per gallon) cement. The conductor weight per foot ranges from 187 ppf (pound per foot) to 654 ppf. Disposal costs are not included in these estimates but are included in the Materials Disposal Section. Complete cost estimates of casing jack removal methods can be found in Volume 2. Average conductor removal cost was found to be $288 per foot. Table 10.1 shows the conductor and casing data by platform. Table 10.2 shows the removal costs by platform.

Table 10.1 Conductor and Casing Data

Platform	Water Depth	Conductor Count	Conductor Lenghts (ft)	Total Conductor Lenghts (ft)	Conductor OD (in)	Conductor Weight per Foot (lbs)	Casing #1 OD (in)	Casing #1 Weight per Foot (lbs)	Casing #2 OD (in)	Casing #2 Weight per Foot (lbs)	Casing #3 OD (in)	Casing #3 Weight per Foot (lbs)	Total Weight per Foot (lbs)	Total Weight per Conductor (tons)	Total Weight (tons)
A	188	55	268	14,740	13.375	68.0	9.625	40.0	6.625	24.0	-	-	195.2	26.16	1,439
B	190	56	270	15,120	13.375	68.0	9.625	40.0	6.625	24.0	-	-	195.2	26.36	1,476
C	192	37	272	10,064	20.000	106.5	13.375	54.5	-	-	-	-	386.6	52.57	1,945
Edith	161	29	241	6,989	13.375	54.5	9.625	36.0			-	-	187.1	22.54	654
Ellen	265	64	345	22,080	13.375	54.5	9.625	36.0	-	-	-	-	187.1	32.27	2,065
Elly	255	0	0	0	-	-	-	-	-	-	-	-	-	-	-
Eureka	700	60	780	46,800	13.375	54.5	9.625	36.0	-	-	-	-	187.1	72.95	4,377
Gail	739	29	819	23,751	24.000	201.0	18.625	94.5	13.375	68.0	9.625	43.5	638.9	261.62	7,587
Gilda	205	62	285	17,670	20.000	94.0	13.375	54.5	9.625	43.5	-	-	356.4	50.79	3,149
Gina	95	12	175	2,100	20.000	94.0	13.375	54.5	9.625	43.5	-	-	356.4	31.19	374
Grace	318	38	398	15,124	24.000	201.0	18.625	106.0	13.375	72.0	9.625	47.0	653.8	130.11	4,944
Habitat	290	21	370	7,770	24.000	201.0	18.625	87.5	13.375	72.0	-	-	553.3	102.36	2,149
Harmony	1,198	54	1,278	69,012	24.000	201.0	18.625	87.5	13.375	68.0	7.0	26.0	644.8	412.00	22,248
Harvest	675	25	755	18,875	24.000	201.0	18.625	106.0	13.375	68.0	9.625	43.5	647.4	244.41	6,110
Henry	173	24	253	6,072	20.000	106.5	13.375	54.5	-	-	-	-	386.6	48.90	1,174
Heritage	1,075	49	1,155	56,595	20.000	133.0	16.000	75.0	13.375	68.0	9.625	47.0	459.3	265.22	12,996
Hermosa	603	29	683	19,807	24.000	201.0	18.625	106.0	13.375	68.0	9.625	43.5	647.4	221.10	6,412
Hidalgo	430	14	510	7,140	24.000	201.0	18.625	106.0	13.375	72.0	9.625	47.0	653.8	166.72	2,334
Hillhouse	190	50	272	13,600	20.000	106.5	13.375	54.5	-	-	-	-	386.6	52.18	2,609
Hogan	154	39	234	9,126	18.625	87.5	10.750	40.5	9.625	47.0	-	-	312.5	36.56	1,426
Hondo	842	28	922	25,816	20.000	133.0	16.000	75.0	13.375	68.0	9.625	47.0	459.3	211.72	5,928
Houchin	163	35	243	8,505	18.625	87.5	10.750	40.5	7.000	23.0	-	-	317.4	38.56	1,350
Irene	242	28	322	9,016	20.000	133.0	13.375	61.0	9.625	47.0	-	-	396.9	63.90	1,789
Totals	-	**838**	-	**425,772**	-	-	-	-	-	-	-	-	-	**2,570.19**	**94,536**

Table 10.2 Total Conductor Removal Costs (Using Casing Jacks)

Platform	Water Depth	Conductor Count	Conductor Lengths (ft)	Total Conductor Lengths (ft)	Total Removal Cost w/ Casing Jacks
A	188	55	268	14,740	**$4,461,149**
B	190	56	270	15,120	**$4,567,877**
C	192	37	272	10,064	**$3,127,066**
Edith	161	29	241	6,989	**$2,186,159**
Ellen	265	64	345	22,080	**$6,378,165**
Elly	255	0	0	0	-
Eureka	700	60	780	46,800	**$12,622,709**
Gail	739	29	819	23,751	**$6,566,624**
Gilda	205	62	285	17,670	**$5,338,098**
Gina	95	12	175	2,100	**$819,314**
Grace	318	38	398	15,124	**$4,466,019**
Habitat	290	21	370	7,770	**$2,403,884**
Harmony	1,198	54	1,278	69,012	**$18,874,783**
Harvest	675	25	755	18,875	**$5,319,490**
Henry	173	24	253	6,072	**$1,965,108**
Heritage	1,075	49	1,155	56,595	**$15,542,468**
Hermosa	603	29	683	19,807	**$5,605,618**
Hidalgo	430	14	510	7,140	**$2,188,946**
Hillhouse	190	50	272	13,600	**$4,169,988**
Hogan	154	39	234	9,126	**$2,906,310**
Hondo	842	28	922	25,816	**$7,252,563**
Houchin	163	35	243	8,505	**$2,706,725**
Irene	242	28	322	9,016	**$2,807,010**
Totals	-	**838**	-	**425,772**	**$122,276,073**

Section 11: Pipeline and Power Cable Decommissioning

Requirements

The BSEE regulations for pipeline and power cable decommissioning are found at 30 CFR 250.1750 – 250.1754. The regulations allow an operator to decommission a pipeline or power cable in place if BSEE determines that the pipeline or power cable "does not constitute a hazard (obstruction) to navigation and commercial fishing operations, unduly interfere with other uses of the OCS, or have adverse environmental effects." If BSEE determines that the pipeline or power cable is an obstruction, it must be removed per the regulations at 30 CFR 250.1754.

Procedures

Since 1990, the POCSR has required pipeline operators to conduct biennial ROV pipeline surveys to assess a pipeline's external integrity and to monitor 3rd party impacts. The surveys have verified that the majority of pipelines historically have not been obstructions and could therefore be decommissioned in place. However, a decision on the final disposition of a specific pipeline or power cable cannot be made until a thorough technical and environmental review is conducted during the decommissioning permitting process.

To decommission a pipeline in place, the pipeline must first be cleaned by flushing water through the pipeline. The pipeline is then disconnected from the OCS platform. The cut end is plugged and buried at least 3 feet below the seafloor or covered with protective concrete mats. In addition to cutting and burying the ends, all pipeline valves/fittings, pipeline crossings and spanned areas that could unduly interfere with other uses of the OCS must be removed from the pipeline.

Cost Factors

Detailed cost estimates for pipelines and power cables using a workboat removal method are shown in Volume 2. The factors used to calculate the cost estimates are based on information provided by BSEE and researched in this study.

The pipeline cost estimates assume that all project vessels (small crane barge, etc.) would be available locally except for a DP2 dive vessel which would need to be mobilized from the Gulf of Mexico. DP2 Dive Vessels are not available locally, but will be necessary for deepwater operations (water depths exceeding 200 feet) due to the difficulty of anchoring in deep water.

The costs incurred during the decommissioning operations reflect hourly rates for vessels and diver-related services. The two factors which have the greatest influence on the cost estimates are the water depth and the number of obstructions per pipeline that would have to be removed.

For this study, costs are developed based on the following assumptions: pipelines routed to shore will be removed from the 200 foot water depth level to the State Tidelands boundary; pipeline segments between platforms on the OCS will be decommissioned in place; OCS pipeline segments in greater than 200 feet of water depth will be decommissioned in place.

The estimated costs rely on data input values for: 1) mobilization/demobilization, 2) daily rate for on-site operations, and 3) estimated time to complete the decommissioning activity. Below is a description of the type of work included in each of the data input values.

The mobilization/demobilization cost includes the mobilization/demobilization of the diving support vessel, diving system equipment, small crane barge(s), and any required third party equipment needed; planning and engineering; pigging and testing the pipeline(s); mooring installation/removal; and miscellaneous equipment or work needed.

The on-site daily rate includes 24-hour diving operations from a diving support vessel, 24-hour barge with crane, tug and construction crew, materials barge for transport and onshore support and project management.

The estimated time to complete a pipeline decommissioning is based on the number of risers and pipeline sections that would need to be cut out, rigged and lifted to a barge. The time is also dependent on the water depth in which the work is to take place. Tables 11.1 and 11.2 show the originating and terminating locations of each pipeline, and the pipeline decommissioning costs.

Power cables on the OCS will be completely removed to the State Tidelands boundary. Table 11.3 shows the estimated costs using local vessels and equipment. The cables would be cut using an ROV and then pulled onto a workboat before being placed on a cargo barge for transport to shore. This study has determined diving services will not be required. This study investigated the use of a cable reel barge to perform the power cable removal operations. Although there is considerable time saved by using a cable removal vessel, the cost to mobilize a vessel from other areas is so great that it is far more economical to use equipment available locally. Recycling of the power cables is highly unlikely; therefore no credit for recycling has been included.

Table 11.1. OCS Pipeline Specifications

From	Pipeline			To		Pipeline Operator
Platform	Type	Flow	Length*	Platform	Onshore Facility	
Hogan	10" Oil/Water	→	30,250		La Conchita	Pacific Operators Offshore, LLC (POO, LLC)
	10" Gas Lift	←	30,250			
	12" Gas	→	30,250			
	4" Water	←	30,250			
Houchin	10" Oil/Water	→	3,800	Hogan		
	10" Gas Lift	→	3,800			
	12" Gas	→	3,800			
	4" Water	→	3,800			
Eureka	10" Oil/Water	→	8,350	Ellen/Elly		Beta Operating Company, LLC
	10" Gross Fluids	←	8,400			
	6" Gas	→	8,500			
	12” OOS	-	8,400			
	10” OOS	-	8,400			
Ellen/Elly	16" Oil	→	80,200		San Pedro	
Edith	6" Gas	→	35,000	Eva**		DCOR, LLC
	6" Oil	→	6,000	Ellen/Elly		
C	6" Oil/Water	→	2,600	B		
	6" Gas	→	2,600			
	6" Water	←	2,600			
B	6" Water	→	2,600	A		
	8" Gas	→	2,600			
	8" Oil	→	2,600			
	12” OOS	-	2,600			
	12” OOS	-	2,600			
A	6" Water	→	59,200		Rincon	
	12" Oil/Water	→	59,200			
	12" Gas	→	59,200			
	12” OOS	-	59,200			
	12” OOS	-	59,200			
Henry	8" Oil	→	12,900	Hillhouse		
	6" Gas	→	12,900			
	8" Water	→	12,900			
Hillhouse	8" Oil	→	2,560	A		
	6" Gas	→	2,560			
	6" Spare	→	2,560			
	8” OOS	-	2,560			

From	Pipeline			To		Pipeline Operator
Platform	Type	Flow	Length	Platform	Onshore Facility	
Gina	10" Oil/Water	→	31,690		Mandalay	DCOR, LLC
	6" Gas	→	31,690			
Gilda	12" Oil/Water	→	52,000		Mandalay	
	10" Gas	→	52,000			
	6" Water	←	52,000			
Habitat	12" Gas	→	43,980		Carpinteria	
Gail	8" Gas	→	32,000	Grace		Venoco, Inc.
	8" Oil	→	32,500			
	8" Sour Gas	→	33,200			
Grace	10" Gas	→	80,600		Carpinteria	
	12" Oil	→	80,600			
Harvest	12" Oil/Water	→	15,500	Hermosa		Freeport-McMoRan Oil & Gas (FMO&G)
	8" Sour Gas	→	15,050			
Hermosa	24" Oil/Water	→	54,900		Gaviota	
	20" Sour Gas	→	54,800			
Hidalgo	16" Oil/Water	→	25,450	Hermosa		
	10" Sour Gas	→	25,100			
Irene	20" Oil/Water	→	53,050		Orcutt	
	8" Water	←	53,050			
	8" Sour Gas	→	53,050			
Heritage	20" Oil/Water	→	35,800	Harmony		ExxonMobil Corporation
	12" Gas	→	35,350			
Harmony	20" Oil	→	50,950		Las Flores Canyon	
	12" Water	←	51,000			
	12" Gas	→	15,350	Hondo		
Hondo	14" Oil/Water	→	15,350	Harmony		
	12" Gas	→	36,400		Las Flores Canyon	

* The lengths listed in the table above are the total lengths of the pipelines.
** Denotes State Platform

Table 11.2. Pipeline Decommissioning Costs

Platform	Water Depth (ft)	Total Length of OCS Pipeline (mi)	Length of Pipeline to be removed (mi)	Total Pipeline Cost
A	188	33.6	33.7	$3,819,491
B	190	1.5	0.0	$864,193
C	192	1.5	0.0	$528,022
Edith	161	7.8	0.0	$331,960
Ellen	265	0.0	0.0	$0
Elly	257	15.2	4.5	$2,392,826
Eureka	700	4.8	0.0	$8,876,961
Gail	739	18.5	0.0	$3,440,911
Gilda	205	29.5	12.5	$9,094,834
Gina	95	12.0	0.6	$485,330
Grace	318	30.5	4.6	$3,090,490
Habitat	290	8.3	0.9	$2,506,038
Harmony	1198	22.2	1.1	$4,993,843
Harvest	675	5.8	0.0	$2,240,868
Henry	173	7.3	0.0	$495,927
Heritage	1075	13.5	0.0	$2,909,824
Hermosa	603	20.8	1.1	$2,763,334
Hidalgo	430	9.6	0.0	$2,286,225
Hillhouse	192	1.5	0.0	$704,681
Hogan	154	22.9	0.6	$1,014,770
Hondo	842	9.8	0.6	$3,158,141
Houchin	163	2.9	0.0	$639,259
Irene	242	30.1	4.6	$3,951,074
Average Cost per mile	-	-		$935,404
Total	**-**	**309.6**	**64.8**	**$60,588,999**

Table 11.3. Power Cable Removal Costs

Cable Origin	Cable Terminus	Water Depth (ft)	Length of cable to be removed (mi)	Total Cost
A	B	188	0.5	$180,575
B	C	190	0.5	$180,575
C	Shore	192	5.0	$953,587
Edith	Shore	161	7.0	$1,230,590
Ellen^	Elly	265	0.0	$0
Elly		257	0.0	$0
Eureka*	Ellen (qty. 2)	700	2.9	$373,589
Gail		739	0.0	$0
Gilda	Shore	205	7.0	$1,267,549
Gina	Shore	95	0.3	$243,574
Grace		318	0.0	$0
Habitat	P/F A	290	3.7	$769,029
Harmony*	Shore (qty. 2)	1,198	11.3	$1,096,054
Harvest		675	0.0	$0
Henry	Hillhouse	173	2.5	$575,920
Heritage	Harmony	1,075	7.4	$3,221,819
Heritage	Shore	1,075	19.8	$1,348,592
Hermosa		603	0.0	$0
Hildalgo		430	0.0	$0
Hillhouse	Shore	192	3.4	$711,880
Hogan	Shore	154	0.9	$369,971
Hondo*	Harmony (qty. 2)	842	9.0	$922,327
Houchin	Hogan	163	0.7	$342,733
Irene	Shore	242	2.8	$656,477
Average Cost per mile	-	-	-	$170, 541
Total	-	-	**84.7**	**$14,444,841**

* Data represents combined length and cost of both cables
^ Connects to Elly by bridge, no sub-sea cable

Section 12: Mobilization and Demobilization of Derrick Barges

Mobilization and demobilization (mob/demob) costs cover the transit time required to bring a DB to the project site and return the DB to its point of origin. In the POCSR, the market infrastructure is not in place to support the level of decommissioning operations required. There are currently no DB's having a rotating lift capability exceeding 350 tons stationed in southern California that have the capability to remove deepwater platforms. The DB's possessing this type of capability will likely be mobilized to southern California from the North Sea, Gulf of Mexico, Southeast Asia or other distant locations. It is very unlikely that DB's having this type of heavy lift capability will be stationed permanently in southern California unless there was a strong and prolonged market demand for such vessels. This situation is not likely to change in the foreseeable future.

Cost Assumptions

This report assumes DB's having 500 and 2,000 ton lift capabilities will be mobilized from Southeast Asia. Singapore offers the closest port with the resources providing the lift capacities. The route for mobilization from Singapore to Port of LA is significantly shorter than from the Gulf of Mexico (7,662 nm vs. 14,372 nm via Cape Horn) and does not require passage through the Panama Canal. Following the Panamax expansion, this path option will need to be reevaluated. The factors considered in selecting the DB's to be used for each of the projects are discussed in Sections 3 and 13 of this report. The mob/demob time for DB's having lift capabilities of 500 and 2,000 tons is estimated to be 100 days round trip, which will be mobilized from Southeast Asia.

This study determined day rate costs for the DB's by reviewing recent bids for projects currently underway or completed in the past 2013 summer working season in the Gulf of Mexico, Asia, and the North Sea. Additional costs were obtained from an annual market survey of DB's. The current day rates for the DB's that are projected to be used are shown in the table below. The costs shown include the costs for fuel, crew, and the DB's accompanying anchor handling tug. Due to decreased resources required in mob/demob, the day rates have been reduced to 90% of the normal daily operating rate of the DB.

Range of Costs

The mob/demob costs for the DB's projected to be used to remove POCSR platforms are shown in Table 12.1. The costs range by project from $3.1 million to $7.4 million per platform. The calculation was made by taking the day rate of the DB, multiplying that figure by the mob/demob time (100 days), multiplying by a 90% mob/demob operating cost factor, and dividing by the number of platforms that would be removed during the project.

Table 12.1. Derrick Barge Mob/Demob Cost

Project	DB Lift Capability	Mob/Demob Cost Calculation	Cost Per Platform
Project I	500 ton	$ 165,000 x 100 days x 90% / 2 platforms	$7,425,000
Project II	2,000 ton	$ 209,000 x 100 days x 90% / 4 platforms	$4,702,500
Project III	2,000 ton	$ 209,000 x 100 days x 90% / 5 platforms	$3,762,000
Project IV	2,000 ton	$ 209,000 x 100 days x 90% / 3 platforms	$6,270,000
Project V	2,000 ton	$209,000 x 100 days x 90% / 6 platforms	$3,135,000
Project VI	2,000 ton	$209,000 x 100 days x 90% / 3 platforms	$6,270,000

Section 13: Platform Removal

BSEE regulations on the decommissioning of OCS platforms are found in 30 CFR 250.1725 through 1731.

The depth of removal requirements for platforms and other facilities are at 30 CFR 250.1728 and are as follows:

- Unless the Regional Supervisor approves an alternate depth under (b) of this section, you must remove all platforms and other facilities (including templates and pilings) to at least 15 feet below the mud-line.

As defined by regulation, platforms and other structures will be removed to a depth of 15 feet below the ocean floor (or mud-line). The preferred method is removal in the reverse order in which they were installed. Figures 13.1 and 13.2 provide schematics representative of typical platform deck and jacket configurations.

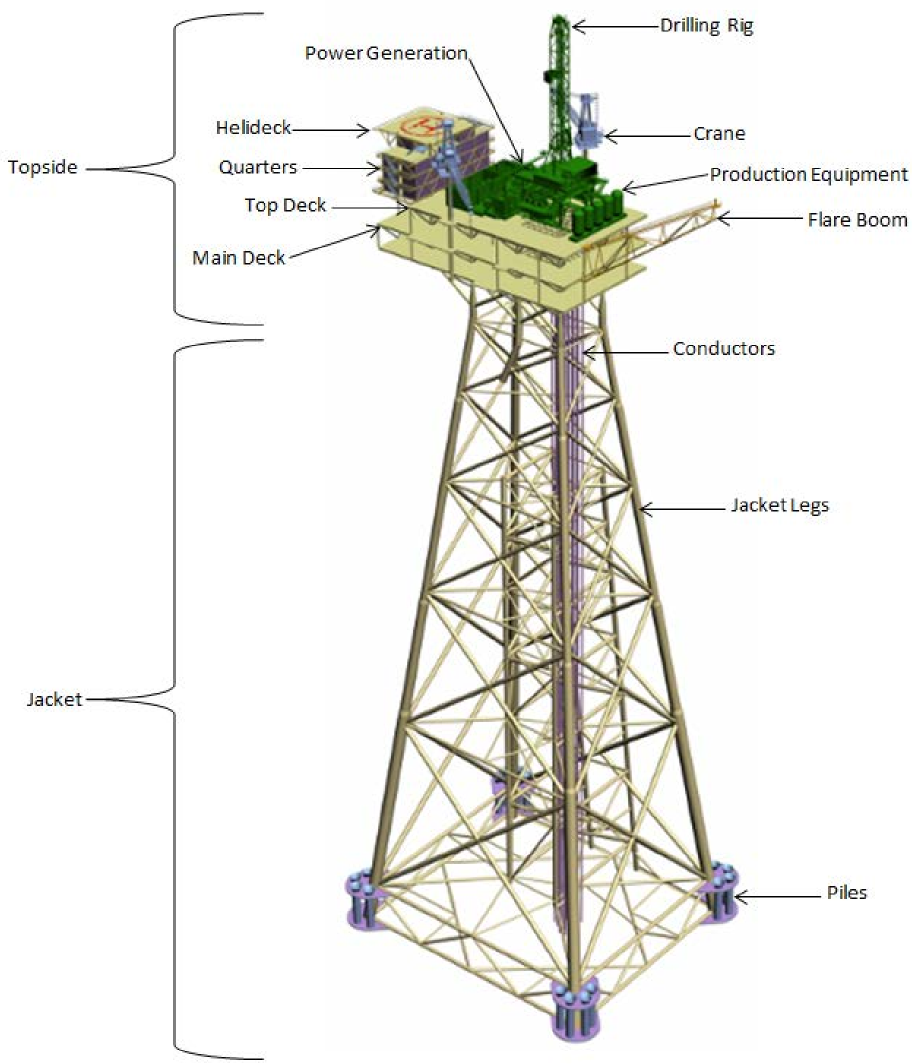

Figure 13.1. Typical Platform

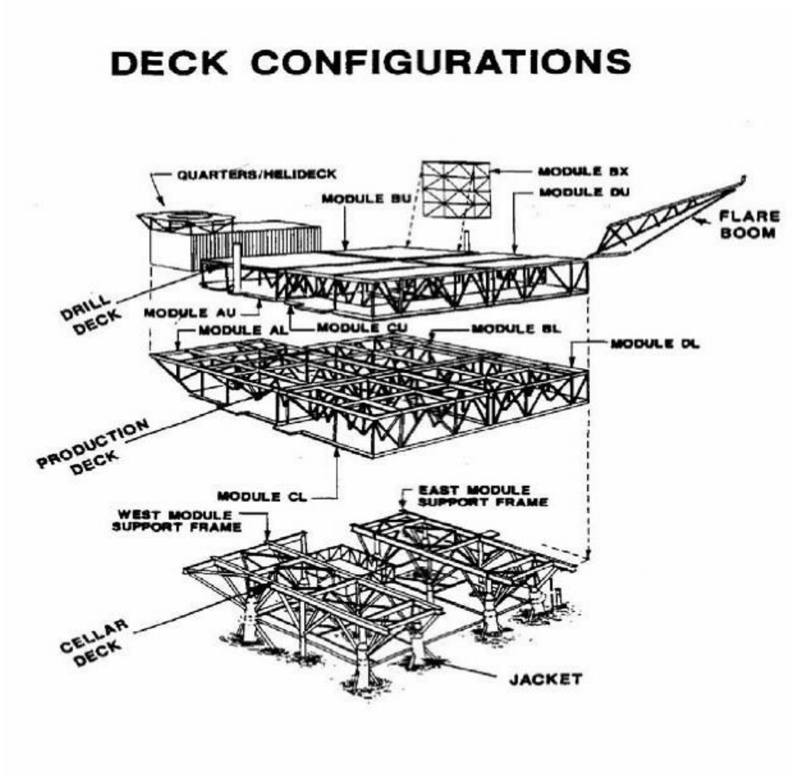

Figure 13.2. Deck Configurations

Deck/Topside Removal

The platform demolition process begins with the removal of the topsides. Topsides can vary significantly in size, functionality and complexity, so we have identified a range of decommissioning options. The diversity and range of complexity suggest that no one option is likely to be the most appropriate in all cases. In the POCSR, platforms have topside facilities that range in weight from approximately 447 to almost 9,839 tons. Generally between 6 and 17 lifts were required to install these topsides. The largest lift for the modules or the modular support structures during installation was approximately 2,000 tons. With planning and preparation, this allows for use of a DB2000 for all platform removal operations.

Topsides may be integrated, modular, or hybrid in design. Integrated topside refers to a system where the process facilities are installed in the deck structure in the fabrication yard. Integrated facilities are usually installed by a single offshore lift. A modular design is used for larger topsides where the deck structure is subdivided into modules that can be lifted by the derrick barge. The modules are typically supported on the jacket by a modular support frame. Many of the very large topsides use a combined approach.

Topsides can be removed by any of the following methods:

- Remove in one piece
- Remove groups of modules together
- Remove in reverse order of installation
- Remove in small pieces

Removal of the entire topsides in one piece requires a DB with sufficient lifting capacity, or a large specialized decommissioning vessel, or an alternative heavy lift technology such as the Versatruss lifting system, GM Heavy Lift Vessel, or other innovative lifting systems. One piece removal is more practical for small platforms. Although topsides may be able to be removed in one piece, this may not be practicable if the offloading site is not large enough to accommodate large pieces or the lift capability of the cranes at the offloading site or scrap yard is limited.

The removal of combined modules is another method that can be used to remove the topsides. The advantage of this method is that it reduces DB time since fewer lifts are needed. Additional strengthening to allow for combined lifting will probably be needed. The position of the modules on the platform and their weight will dictate whether or not combined removal is possible and which modules may be lifted at one time.

Reverse installation is one of the most common methods used to remove topsides. This involves dismantling the topsides in the reverse order in which they were installed. If the topsides were installed as modules, they would be removed as modules. If they were not installed as modules, topside structural components would be removed in the reverse order that they were installed.

Removal of the topsides by cutting them into small pieces is another method of removal. In this method the topsides are dismantled using mechanical and other cutting devices along with platform cranes, temporary deck mounted cranes, or other cranes on a small DB. The time required to remove a platform using this method is much longer than that required for reverse installation. Consequently, any savings in costs that result from using a smaller, less expensive DB can be largely offset or exceeded due to the additional DB time required. Due to the potential for limited cost savings and safety considerations (see discussion in Section 3) it is generally common practice within the industry to employ a DB that has capability to remove the platform in a much more expeditious manner using the reverse installation method.

Jacket Removal

The removal of the jacket is typically the most costly phase in the demolition process, due to the large and expensive equipment that is required for the lifting and removal operations. Some of the major considerations that have to be made when evaluating the cost of removal are the weight and size of the structure, the oceanographic conditions of the area where the platforms are located, the heavy lifting method used, the method of cutting the main piles and skirt piles, piling access for the cutting operations, diving requirements, water depth, tie-down and transportation considerations of each removed component, and the planned disposition of the salvaged equipment and structure. Extensive saturation diving can add greatly to the cost of any removal project. Jacket removal is initiated after bottom cuts have been made below the mud-line on the piles. The entire jacket is removed in sections or as a single lift. Single lifting of the jacket is not likely except for the smaller structures located in less than 200 feet water depth.

In the POCSR, platform jacket weights range from approximately 434 tons to 42,900 tons. The platforms are located in 95 to 1,198 feet of water, respectively. Appendix 3 lists the projected weight that will be required to be removed when the POCSR platforms are decommissioned. These numbers are only approximate as additional modifications (i.e., deck extensions, equipment additions or removals, etc.) have been made at many facilities. The jacket and conductor weights are the weights projected to be removed assuming the jacket legs, piles and conductors will be removed to a depth of 15 feet below the mud-line. Much of this information was obtained from BSEE which compiled information from its files on design, installation, load-out, or fabrication reports, installation manuals, operator correspondence, seismic analyses, etc. A deck and jacket specification table in Appendix 4 details the background information obtained from BSEE records and used for this report. In some cases in this specification table, not all the information and numbers for every block in the table were available for each platform. Subject matter experts applied professional experience and judgment concerning which numbers to use in the various sections of this decommissioning cost report.

The DB is normally the highest single item day rate on location. The use of less expensive support equipment to minimize the heavy lifting equipment time is often justifiable. Reducing the DB time is one of the best ways to reduce overall removal costs. Heavy lifting equipment must be evaluated for its lifting capability at the required working radius and oceanographic conditions in which it is to operate, and also for its height capability. Safety must always be the prime consideration in any removal project.

Jacket Removal Challenges

Deepwater structures present greater challenges for complete removal. The immense weight and extreme water depth of many of the structures on the west coast places a one piece removal outside the limits of current proven and demonstrated technology. A method known as progressive transport or jacket hopping was considered by some operators at one time, but because of the difficulty in the POCSR of clearing large areas of the ocean floor to set down the jacket and reset the DB anchors, this method appears unlikely to be used on the west coast due to increased environmental impact due to multiple sites. Each site would require additional permits (increased permitting time and cost) and post action monitoring (additional cost). Jacket hopping, however, would reduce the risk to divers as less diving time would be needed compared to in-situ dismantlement. In the hopping method, the structure would be rigged up and lifted after severing the piles. The jacket would be winched vertically off the bottom and moved into shallower water and set down. The upper portion of the jacket would then be cut and the rigging reattached underwater for another lift. The process is repeated until the structure is completely removed. It may be possible to re-float the jacket or use additional buoyancy assist to remove some of the deepwater structures, but the technology is still in very early stages of testing.

The most common method of jacket removal is dismantlement in place (in-situ) in which the jacket is cut (with divers using cutting torches, abrasive cutting, or other systems) into manageable lift packages (sections). For this study, the estimates are based on platform jackets cut into sections that range in size from 300 to 1,600 tons for removal using DB's that have respective lift capabilities of 500 and 2,000 tons.

For platforms located in less than 200 feet of water, structure removal analysis has determined a single lift with the 2,000 ton DB after the topsides are removed. Platforms Hogan and Houchin are estimated being removed using a 500 ton DB. The use of a DB500 is more cost effective than a DB2000 for a project with 2 platforms. If a 500 ton DB is used to remove these platforms, the jackets would be cut in-situ into sections weighing less than 300 tons for removal. Table 13.1 shows the platform information and projected DB to be used.

Table 13.1. Projected Decommissioning Projects

Platform	Water Depth (feet)	Deck Weight (tons)	Jacket Weight (tons)	Projected DB Lift Capability for Jackets & Decks (tons)
Project I – POO, LLC				
Hogan	154	2,259	1,263	500
Houchin	163	2,591	1,486	500
Project II – Beta Operating Company, LLC and DCOR				
Eureka	700	8,000	19,000	2,000
Elly	255	4,700	3,300	2,000
Ellen	265	5,300	3,200	2,000
Edith	161	4,134	3,454	2,000
Project III – DCOR, LLC				
A	188	1,357	1,500	2,000
B	190	1,357	1,500	2,000
C	192	1,357	1,500	2,000
Henry	173	1,371	1,311	2,000
Hillhouse	190	1,200	1,500	2,000
Project IV – DCOR, LLC				
Gina	95	447	434	2,000
Gilda	205	3,792	3,220	2,000
Habitat	290	3,514	2,550	2,000
Project V – FMO&G LLC and Venoco, Inc.				
Gail	739	7,693	18,300	2,000
Grace	318	3,800	3,090	2,000
Harvest	675	9,024	16,633	2,000
Hermosa	603	7,830	17,000	2,000
Hildalgo	430	8,100	10,950	2,000
Irene	242	2,500	3,100	2,000
Project VI – ExxonMobil Company				
Harmony	1,198	9,839	42,900	2,000
Heritage	1,075	9,826	32,420	2,000
Hondo	842	8,450	12,200	2,000

Disclaimer Note: These are reasonable removal scenarios based on the most likely grouping of decommissioning projects due to the lack of existing cost-sharing agreements between operators. (Alternate scenarios may also be feasible, but will require additional information from the individual liable parties at the relevant time.)

For the larger, deeper platforms, the reach below water depth to attach the derrick barge rigging to the pieces is the challenge. A standard DB4000 is limited to 1000 to 1700 ton lift capacity at depths of up to 1200 feet. A standard DB2000 is limited further to only 200 – 300 foot below sea level. The limiting factor for the depth of a derrick barge reach is the amount of wire installed on the derrick barge. Derrick barge lifting systems are designed with multiple passes (over 20+ times). This means for a derrick barge with 25 passes, the movement of the hook and the load move 1 foot for every 25 feet spooled at the main winch. In this example, an additional reach of 500 feet requires an additional 12,500 feet of cable (25x1). This limitation cannot be improved significantly without structural remodeling of the derrick barge and re-rigging the main block rigging with changing the main winch capacity, motors, location, shifting any structure in the way, possibly restructuring supports, and any other engineered change required.

An alternative method needs to be employed to lift the sectioned pieces of the jacket and recover them to a depth that can be reached by the DB using main block. The platforms facing the deep reach challenge using a DB2000 are: Project II – Eureka, Project V – Gail, Grace, Harvest, Hermosa, Hidalgo, and Project VI – Harmony, Heritage, Hondo.

Jacket Removal Alternatives

Alternative heavy lift vessels/systems can be considered for lifting the large jackets such as Versabuild, Seametric TML vessel and various buoyancy systems, such as the Control Variable Buoyancy System (CVBS). These approaches are in various stages of development and may eventually be proposed to decommission these large structures in the future.

Two alternatives of existing technologies considered for moving the planned sections to within reach of a standard DB2000 were buoyant lifts or using a lifting barge.

Buoyant lift bags can be used to enhance lifting or to lift sections to a shallow depth. Then, the load can be transferred to a DB. The drawbacks of using lift bags are exposure to ocean currents, increased risk to divers, and the large number of high capacity buoyant air bags required. Buoyant lift bags are limited that they can only lift weight equivalent to the amount of water they displace. Custom built lifting bags of 50 ton each would still require 10-20 to be attached to a single lift. The total displacement required for a lift is 10,000 – 15,000 cubic meters. The increased risk exposure to divers for using this methodology and limited control during the load ascent limits the application of this method. This option is not feasible at this time with current equipment.

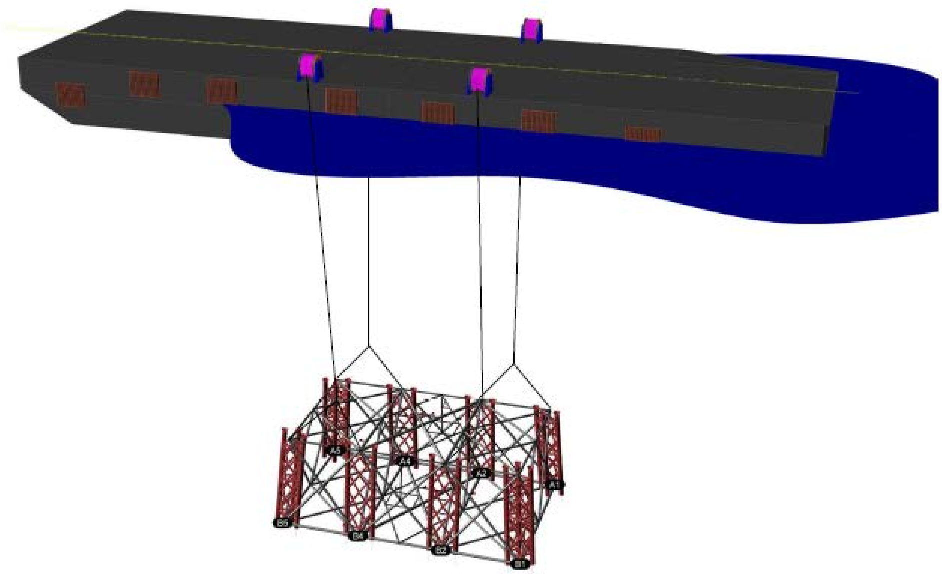

Figure 13.3. Lifting Barge Conceptual Drawing

A lifting barge can be utilized to lift the sectioned jacket lifts at depth and then transfer the loads to the derrick barge. This process will take additional time for the jacket sectioning as well as for the load transfer. An example for the jacket sectioning approach is shown in Figure 13.4 below. When compared to the cost of mobilizing a larger DB, this method will still result in significant savings. A CB400 (cargo barge 400' in length) will be outfitted with four 500 ton winches. These winches will be centrally controlled for the lifting process as the CB is tied alongside the DB. After the lift has ascended to a depth allowing it to be transferred to the DB2000, the barge will move to a standoff position and use side winches to pull the load to the side. This allows for the load to slowly be transferred to the DB. The load transfer is the critical step in the process and needs to be performed slowly and safely. This will take anywhere from 8-12 hours per lift.

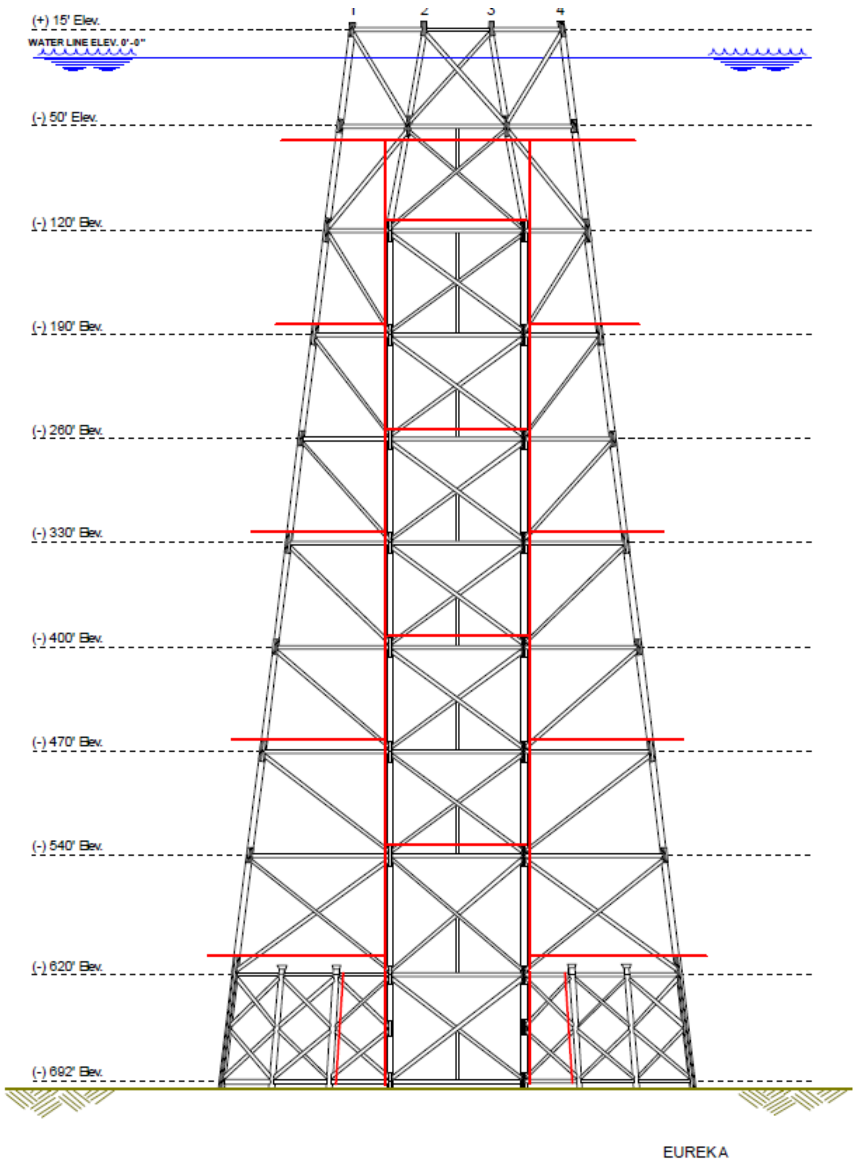

Figure 13.4. Example Cut Plan for Jacket Sectioning of Eureka Platform

Cutting Method

Piles can be cut using explosives, mechanical means, abrasive technology, or torches. The bottom cut required to remove the jacket must be clean to allow for a safe lift from the surface. A barge making such a lift at sea may exceed its lift capability if an incomplete cut left the load secured to the sea floor. The use of torches by divers poses risks due to the hazardous nature of diving operations and the hazards faced by divers who enter excavated areas to make cuts 15 feet below the mud-line. For this study, explosives will not be used to sever piles. The use of explosives was deemed unnecessary due to improvements in abrasive cutting technology (the most commonly used cutting method). The use of explosives offshore California was also considered to be problematic due to presence of whales and other sensitive marine mammals. Although, the use of explosives is not projected in this study, explosive cost information is provided in Volume 2 of this report.

Range of Costs and Assumptions

Lifting analysis has determined that reverse installation is the most likely method of platform removal on the west coast for the foreseeable future. For this study, topsides will be decommissioned using this method.

Based upon the sizes and weights of the structures, the number of modules, the number of lifts needed and other factors, as described above, including the maximum weights of the lifts that will be needed, we believe all the POCSR platforms can be removed using DB's having lift capabilities of 500 and 2,000 tons. The lifting barge will be required for Eureka in Project II, all platforms in Project V, and all platforms in Project VI except for Irene. Irene is in shallow water and the lifts are small enough that the use of a lifting barge is not required. Eureka has a larger jacket in deeper water requiring the lift barge. The estimate for the Lifting Barge cost is shown below in Table 13.2 Lifting Barge Costs. The costs of the lifting barge are distributed across the platforms as shown in Table 13.3 Lifting Barge Costs Per Platform.

Table 13.2. Lifting Barge Costs

Lifting Barge Costs				
	Price Per Unit	Unit	Qty	Total
Winches	$ 2,500,000	ea	4	$ 10,000,000
Wire	$ 20	ft	20000	$ 400,000
Control panel	$375,000	ea	1	$ 375,000
Testing and Cert	$375,000	ea	1	$ 375,000
Barge for Install & removal	$ 6,240	day	140	$ 873,600
Total				$ 12,023,600

Table 13.3. Lifting Barge Costs Per Platform

Project	Lifting Barge Cost	Lifting Barge Cost Per Platform
Project II - Eureka (only)	$12,023,600	$12,023,600
Project V	$ 12,023,600 / 5 platforms (excluding Irene)	$2,404,720
Project VI	$ 12,023,600 / 3 platforms	$4,007,867

The platform removal costs were developed using the costs shown for the DB's in Section 12 and the lifting barge costs shown above when required. In addition to the DB, lifting barge (when requires), cargo barges, and anchor-handling tug costs, this study has included costs for diver support, survey and other required vessels and equipment, including ROV and abrasive cutting equipment spreads, which are detailed in Volume 2. We assumed that in most cases topside module removal would take approximately 0.5 days per module. Topsides that do not have modules would take longer and be cut up into manageable pieces for removal.

The cost of cargo barges to transport the deck and jacket sections depends on barge size, mob/demob time of the cargo barges and accompanying tugs, and the amount of transported material. Cargo barges and accompanying tugs are assumed to be mobed/demobed from the Ports of Los Angeles and Long Beach. Details of deck and jacket transportation, and offloading times can be found in Volume 2.

The information presented in Volume 2 includes detailed estimates and the cost calculations for each platform by decommissioning project including contingencies for provisional work, weather delays, and project management, engineering and planning costs. The platform deck and jacket removal costs for each of the 23 platforms are shown in Table 13.4.

Table 13.4. Platform, Deck and Jacket Decommissioning Costs

Platform Name	Water Depth (ft)	Estimated Removal Weight (tons)*	Platform Removal Cost
A	188	3,457	$3,377,304
B	190	3,457	$3,377,304
C	192	3,457	$3,446,640
Edith	161	8,038	$8,302,845
Ellen	265	9,600	$5,773,287
Elly	255	9,400	$6,774,166
Eureka	700	29,000	$48,420,784
Gail	739	29,993	$44,376,544
Gilda	205	8,042	$5,793,544
Gina	95	1,006	$1,674,634
Grace	318	8,390	$10,362,874
Habitat	290	7,564	$5,733,854
Harmony	1,198	65,089	$69,600,097
Harvest	675	29,040	$42,101,220
Henry	173	2,832	$2,913,049
Heritage	1,075	56,196	$62,903,120
Hermosa	603	27,330	$39,296,869
Hidalgo	430	21,050	$31,410,271
Hillhouse	190	3,100	$3,565,764
Hogan	154	3,672	$6,786,432
Hondo	842	23,550	$39,062,688
Houchin	163	4,227	$6,585,043
Irene	242	7,100	$6,177,281
Total	-	-	**$457,815,614**

*Weight consists of Jacket, Deck and Pile Weight

Section 14: Materials Disposal

There are three primary methods of disposal for steel and other materials associated with dismantling a platform: refurbish and reuse, scrap and recycle, and dispose of in designated landfills. Opportunities for refurbishing and reusing facilities in the POCSR are very limited due to the age of the platforms, the current lack of additional oil and gas development in the POCSR, and inherent limitations associated with meeting the strict technical standards now required. Thus, it is assumed that the steel and other materials removed from platforms will be transported to shore for scrapping and recycling or disposal in landfills.

Due to the limited number of offshore decommissioning projects that have occurred in the POCSR, information on disposal costs is limited to that which was made available by Chevron for the 4-H Project. As noted Section 2, this project involved the decommissioning of four platforms having a combined weight of approximately 12,000 tons. The materials were transported by barge from the Santa Barbara Channel a distance of 100 miles to San Pedro, California. Chevron reported that the steel was sold as scrap for $330,000 and that it cost $1.3 million to process the steel, resulting in a net loss of $1.0 million or $333.00 per ton of steel. In addition, Chevron had to dispose of 3,000 tons of marine growth ($800,000), 1,000 tons of cement ($275,000), and 300 tons of drilling muds and cuttings ($275,000) which aggregates to approximately $1.4 million for disposal materials other than steel.

Based on a tour of local POCSR scrap facilities, this study has concluded that the two scrap yards operated by SA Recycling (Long Beach and Los Angeles) contained sufficient land area and equipment for disposal of the POCSR platforms. Standard Industries located in Ventura, CA also has sufficient capacity. This location may be an option if offloading facility is located at or near Port Hueneme. The preferred location is Port of Long Beach or Port of Los Angeles. Other disposal locations considered were Asia, Oregon, and Mexico, but the transportation costs would be significantly higher.

Cost Assumptions

This report assumes that platform structures will be transported by cargo barges from southern California to offloading facilities/scrap yards located in Long Beach and Los Angeles. It is assumed that other materials (nonferrous metals, cement, plastics, wood, etc.) will be transported to landfills in southern California for disposal. According to a disposal proposal by Schnitzer Steel Products Company (see Volume 2), platform disposal costs were estimated to be $444 per ton with a 15% contingency factor included in that value. The value of $444 was developed by updating the Schnitzer Steel Products Company estimate for current rates for site preparation, materials handling, materials offloading, materials demolition, and materials scrap processing costs for POCSR platforms. It was confirmed that although these estimates were produced assuming the scrapping facility was in the Pacific Northwest, these costs are considered current and applicable to any scrap facility in the Port of Los Angeles or Long Beach area. Table 14.1 shows platform disposal costs.

Conductor, power cable and pipeline disposal costs are estimated separately. This study has assumed the conductors, power cables and pipelines will be transported from the offloading site to disposal sites near Bakersfield, California. This assumption is consistent with previous decommissioning projects conducted in the POCSR including the Chevron 4-H Project and the Exxon Santa Ynez Unit power cable removal and repair projects that were conducted in 2003 and 2009. Transportation and disposal costs were calculated based on the assumption that one truck could carry 21.5 tons per load and the transportation cost would be $1,200 per load. In addition, there would be a dump disposal fee of $120 per ton. The information used to estimate costs was obtained from Standard Industries of Ventura, California.

Disposal costs for conductors, power cable and pipelines are presented in Tables 14.2, 14.3, 14.4. The disposal costs do not include any credits for the resale of any refurbished structures or equipment, or scrapping credit, nor do they include marine transportation costs from the decommissioning site to port because these costs were included in the platform structure removal costs described in Section 13 and detailed in Volume 2. Table 14.5 shows total material disposal costs.

Table 14.1. Platform Disposal Costs

Platform	Water Depth (ft)	Platform Weight[1] (Tons)	Disposal Costs Per Ton[2]	Total
A	188	3,457	444	$1,534,908
B	190	3,457	444	$1,534,908
C	192	3,457	444	$1,534,908
Edith	161	8,038	444	$3,568,872
Ellen	265	9,600	444	$4,262,400
Elly	257	9,400	444	$4,173,600
Eureka	700	29,000	444	$12,876,000
Gail	739	29,993	444	$13,316,892
Gilda	205	8,042	444	$3,570,648
Gina	95	1,006	444	$446,664
Grace	318	8,390	444	$3,725,160
Habitat	290	7,564	444	$3,358,416
Harmony	1,198	65,089	444	$28,899,516
Harvest	675	29,040	444	$12,893,760
Henry	173	2,832	444	$1,257,408
Heritage	1,075	56,196	444	$24,951,024
Hermosa	603	27,330	444	$12,134,520
Hidalgo	430	21,050	444	$9,346,200
Hillhouse	192	3,100	444	$1,376,400
Hogan	154	3,672	444	$1,630,368
Hondo	842	23,550	444	$10,456,200
Houchin	163	4,227	444	$1,876,788
Irene	242	7,100	444	$3,152,400
Total	-	**364,590**		**$161,877,960**

Note 1: Platform Weight is the estimated platform removal weight and includes the weights of the jacket, deck, piles and assumes that they are removed to a depth of 15ft below the mudline. Conductor disposal weights and costs are calculated separately.

Note 2: Includes a 15% Contingency Factor, does not include conductor disposal.

Table 14.2. Conductor Disposal Costs

Platform	Conductor Count	Single Conductor Length (ft)	Total Conductor Length (ft)	Conductor Weight per Foot (lb)	Total Conductor Weight (Tons)[1]	Total Cost [2]
A	55	268	14,740	195.2	1,439	$252,964
B	56	270	15,120	195.2	1,476	$259,485
C	37	272	10,064	386.6	1,945	$341,980
Edith	29	241	6,989	187.1	654	$114,922
Ellen	64	345	22,080	187.1	2,065	$363,068
Elly	0	0	0	-	0	$0
Eureka	60	780	46,800	187.1	4,377	$769,546
Gail	29	819	23,751	638.9	7,587	$1,333,884
Gilda	62	285	17,670	356.4	3,149	$553,668
Gina	12	175	2,100	356.4	374	$65,801
Grace	38	398	15,124	653.8	4,944	$869,260
Habitat	21	370	7,770	553.3	2,149	$377,907
Harmony	54	1,278	69,012	644.8	22,248	$3,911,538
Harvest	25	755	18,875	647.4	6,110	$1,074,253
Henry	24	253	6,072	386.6	1,174	$206,330
Heritage	49	1,155	56,595	459.3	12,996	$2,284,845
Hermosa	29	683	19,807	647.4	6,412	$1,127,297
Hidalgo	14	510	7,140	653.8	2,334	$410,375
Hillhouse	50	272	13,600	386.6	2,629	$462,135
Hogan	39	234	9,126	312.5	1,426	$250,705
Hondo	28	922	25,816	459.3	5,928	$1,042,240
Houchin	35	243	8,505	317.4	1,350	$237,267
Irene	28	322	9,016	396.9	1,789	$314,590
Total	**838**		**425,772**		**94,555**	**$16,624,059**

Note 1: Conductor weight includes weight of conductor, inner casing strings and annulus cement.

Note 2: Costs are calculated based on a disposal rate of $1200/truckload at 21.5 tons/truck plus a $120 per ton disposal fee.

Table 14.3 Power Cable Disposal Costs

Cable Origin	Cable Terminus	Length of OCS Cable to be Removed (mi)	Total Cost ($8,000 per mile)
A	B	0.5	$4,000
B	C	0.5	$4,000
C	Shore	5.0	$40,000
Edith	Shore	7.0	$56,000
Ellen[1]	Elly	0.0	$0
Elly		0.0	$0
Eureka[2]	Ellen (qty. 2)	2.9	$23,200
Gail		0.0	$0
Gilda	Shore	7.0	$56,000
Gina	Shore	0.3	$2,400
Grace		0.0	$0
Habitat	Platform A	3.7	$29,600
Harmony[2]	Shore (qty. 2)	11.3	$90,400
Harvest		0.0	$0
Henry	Hillhouse	2.5	$20,000
Heritage	Harmony	7.4	$59,200
Heritage	Shore	19.8	$158,400
Hermosa		0.0	$0
Hildalgo		0.0	$0
Hillhouse	Shore	3.4	$27,200
Hogan	Shore	0.9	$7,200
Hondo[2]	Harmony (qty. 2)	9.0	$72,000
Houchin	Hogan	0.7	$5,600
Irene	Shore	2.8	$22,400
Total	-	**84.7**	**$677,600**

Note 1: Connects to Elly by bridge, no sub-sea cable.
Note 2: Data represents combined length and cost of both cables.

Table 14.4 Pipeline Disposal Costs

Platform	Total Pipeline Length on OCS[1] (mi)	Length of Pipeline Removed from OCS[2] (ft)	Weight of Pipeline Removed from OCS[3] (ST)	Total Cost[4]
A	56.0	106,656	2,834	$913,966
B	2.5	0	0	$0
C	1.5	0	0	$0
Edith	7.8	0	0	$0
Ellen/Elly	15.2	23,760	983	$174,186
Eureka	15.2	0	0	$0
Gail	18.5	0	0	$0
Gilda	29.5	66,000	1,743	$308,693
Gina	12.0	3,168	74	$13,048
Grace	30.5	24,288	788	$139,668
Habitat	8.3	4,752	155	$27,535
Harmony	22.2	5,808	274	$48,492
Harvest	5.8	0	0	$0
Henry	7.3	0	0	$0
Heritage	13.5	0	0	$0
Hermosa	20.8	5,808	427	$75,723
Hidalgo	9.6	0	0	$0
Hillhouse	1.9	0	0	$0
Hogan	22.9	3,168	83	$14,679
Hondo	9.8	3,168	104	$18,356
Houchin	2.9	0	0	$0
Irene	30.1	24,288	850	$150,507
Total(s)	**343.8**	**270,864**	**8,315**	**$1,884,853**

Note 1: Total pipeline length is the cumulative length of all pipelines in the OCS.

Note 2: Length of pipelines to be removed is based on all pipelines being removed from the OCS.

Note 3: Weight of pipelines from 4.500" to 12.750" per foot is based on schedule 80/80XS and the weight of the pipelines from 14.000" to 24.000" per foot is based on schedule 40.

Note 4: Costs are calculated based on a disposal rate of $1,200/truckload at 21.5 tons/truck plus a $120 per ton disposal fee.

Table 14.5. Total Materials Disposal Costs

Platform	Total Platform Disposal Costs	Conductor Disposal Costs	Power Cable Disposal Costs	Pipeline Disposal Costs	Total Disposal Costs
A	$1,534,908	$252,964	$4,000	$913,966	**$2,705,838**
B	$1,534,908	$259,485	$4,000	$0	**$1,798,393**
C	$1,534,908	$341,980	$40,000	$0	**$1,916,888**
Edith	$3,568,872	$114,922	$56,000	$0	**$3,739,794**
Ellen	$4,262,400	$363,068	$0	$0	**$4,625,468**
Elly	$4,173,600	$0	$0	$174,186	**$4,347,786**
Eureka	$12,876,000	$769,546	$23,200	$0	**$13,668,746**
Gail	$13,316,892	$1,333,884	$0	$0	**$14,650,776**
Gilda	$3,570,648	$553,668	$56,000	$308,693	**$4,489,009**
Gina	$446,664	$65,801	$2,400	$13,048	**$527,913**
Grace	$3,725,160	$869,260	$0	$139,668	**$4,734,088**
Habitat	$3,358,416	$377,907	$29,600	$27,535	**$3,793,458**
Harmony	$28,899,516	$3,911,538	$90,400	$48,492	**$32,949,946**
Harvest	$12,893,760	$1,074,253	$0	$0	**$13,968,013**
Henry	$1,257,408	$206,330	$20,000	$0	**$1,483,738**
Heritage	$24,951,024	$2,284,845	$217,600	$0	**$27,453,469**
Hermosa	$12,134,520	$1,127,297	$0	$75,723	**$13,337,540**
Hidalgo	$9,346,200	$410,375	$0	$0	**$9,756,575**
Hillhouse	$1,376,400	$462,135	$27,200	$0	**$1,865,735**
Hogan	$1,630,368	$250,705	$7,200	$14,679	**$1,902,952**
Hondo	$10,456,200	$1,042,240	$72,000	$18,356	**$11,588,796**
Houchin	$1,876,788	$237,267	$5,600	$0	**$2,119,655**
Irene	$3,152,400	$314,590	$22,400	$150,507	**$3,639,897**
Total	**$161,877,960**	**$16,624,059**	**$677,600**	**$1,884,853**	**$181,064,472**

Section 15: Site Clearance

Site clearance operations are performed to ensure that OCS leases and the operational area surrounding platforms are free of obstructions that would interfere with other uses of the OCS, such as commercial trawling operations. Requirements for site clearance are found at 30 CFR 250.1740-1743.

Site clearance procedures for decommissioning a platform and associated pipelines and power cables in the POCSR will typically involve the following four step process: (1) pre-decommissioning survey, (2) post decommissioning survey, (3) Remotely Operated Vehicle (ROV)/diver target identification and recovery, and (4) test trawling. A survey vessel equipped with high-resolution side-scan sonar is used to conduct the pre- and post- decommissioning surveys. The pre-decommissioning survey documents the location and quantity of suspected debris targets. The survey is also used to map the location of pipelines, power cables, and sensitive environmental habitats (hard bottom areas and kelp beds) to ensure that the deployment and retrieval of anchors is done in a safe and environmentally sound manner. The post-decommissioning survey identifies debris lost during the project and documents any impacts from the operations such as anchor scars. An ROV and divers are deployed to further identify and remove any debris that could interfere with other uses of the area. Test trawling is conducted to verify that the area is free of any potential obstructions.

Cost Assumptions

Site clearance costs can vary significantly from project to project due to factors such as: water depth; the size of the area to be cleared and verified; the quantity, size, and type of debris; and weather conditions. The site clearance cost estimates presented below include costs for pre and post-decommissioning side-scan-sonar surveys (SSS), ROV deployment, diving spreads, test trawl operations, and shell mound geotechnical and biological sampling. The costs do not include any expenses that would be incurred to remove shell mounds or mitigate impacts to commercial trawlers who may be precluded from trawling areas where shell mounds are located. The costs are based on information obtained from oil and gas companies and contractors that have conducted site clearance operations in the POCSR.

For platforms located in water depths up to 300 feet, this study uses an air/gas diving spread. For platforms located in water depths exceeding 300 feet, this study used a saturation diving spread to allow for sufficient operational dive time. This study determined the time required to conduct ROV and test trawl operations will increase from 7 days for platforms located in less than 300 feet of water to 14 days for platforms located in greater than 300 feet of water to allow for sufficient timing of operations.

Site Clearance Costs

The estimated costs for site clearance and verification are $884,000 per platform in less than 300 feet of water depth and $1,472,000 per platform in greater than 300 feet of water. The cost calculations are shown in Table 15.1 below.

Table 15.1 Site Clearance Cost Calculations

Platform Water Depth (<300 feet)		Platform Water Depth (>300 feet)	
Pre-Decommissioning SSS 3 days x $17,000	$51,000	Pre-Decommissioning SSS 3 days x $17,000	$51,000
Mob/Demob	$17,000	Mob/Demob	$17,000
Data Analysis	$15,000	Data Analysis	$15,000
	$83,000		$83,000
Post-Decommissioning SSS 3 days x $17,000	$51,000	Post-Decommissioning SSS 3 days x $17,000	$51,000
Mob/Demob	$17,000	Mob/Demob	$17,000
Data Analysis	$15,000	Data Analysis	$15,000
	$83,000		$83,000
ROV Deployment 7 days x $19,000	$133,000	ROV Deployment 14 days x $19,000	$226,000
Diving Spread (air/gas diving) 10 days x $30,000	$300,000	Diving Spread (saturation diving) 10 days x $76,000	$760,000
Test Trawl Program 7 days x $5,000	$35,000	Test Trawl Program 14 days x $5,000	$70,000
Shell Mound Surveys Geotechnical & Biological	$250,000	Shell Mound Surveys Geotechnical & Biological	$250,000
Total Cost	**$884,000**	**Total Cost**	**$1,472,000**

Section 16: References

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Appendices Volume 1

Appendix 1: Total Cost by Decommissioning Category

Platform Name	Platform Removal	Platform Prep	Well Plugging & Abandonment	Conductor Removal	Pipeline Decommissioning	Power Cable Removal	Site Clearance	Weather Contingency	Misc. Work Provision	Permitting & Regulatory Compliance	Mobilization & Demobilization of Derrick Barge	Materials Disposal	Project Management, Engineering & Planning	Total
A	$ 3,377,304	$ 1,093,371	$ 7,860,872	$ 4,461,149	$ 3,819,491	$ 180,575	$ 884,000	$ 2,043,837	$ 3,065,755	$ 1,180,645	$ 3,762,000	$ 2,705,838	$ 1,734,141	**$ 36,168,978**
B	$ 3,377,304	$ 1,093,371	$ 8,591,436	$ 4,567,877	$ 864,193	$ 180,575	$ 884,000	$ 1,889,992	$ 2,834,988	$ 1,069,808	$ 3,762,000	$ 1,798,393	$ 1,564,700	**$ 32,478,638**
C	$ 3,446,640	$ 1,093,371	$ 5,839,296	$ 3,127,066	$ 528,022	$ 953,587	$ 884,000	$ 1,522,691	$ 2,284,036	$ 891,505	$ 3,762,000	$ 1,916,888	$ 1,269,759	**$ 27,518,860**
Edith	$ 8,302,845	$ 1,319,700	$ 3,067,060	$ 2,186,159	$ 331,960	$ 1,230,590	$ 884,000	$ 797,075	$ 2,391,226	$ 564,723	$ 4,702,500	$ 3,739,794	$ 1,385,785	**$ 30,903,419**
Ellen	$ 5,773,287	$ 1,389,820	$ 10,650,264	$ 6,378,165	$ -	$ -	$ 884,000	$ 1,189,223	$ 3,567,670	$ 830,961	$ 4,702,500	$ 4,625,468	$ 2,006,043	**$ 41,997,402**
Elly	$ 6,774,166	$ 2,151,880	$ -	$ -	$ 2,392,826	$ -	$ 884,000	$ 481,268	$ 1,443,804	$ 482,045	$ 4,702,500	$ 4,347,786	$ 976,230	**$ 24,636,504**
Eureka	$ 48,420,784	$ 2,969,203	$ 8,906,812	$ 12,622,709	$ 8,876,961	$ 373,589	$ 1,472,000	$ 3,139,331	$ 9,417,994	$ 2,713,271	$ 4,702,500	$ 13,668,746	$ 6,691,365	**$ 123,975,264**
Gail	$ 44,376,544	$ 3,669,809	$ 5,487,404	$ 6,566,624	$ 3,440,911	$ -	$ 1,472,000	$ 5,857,546	$ 8,786,319	$ 1,190,846	$ 3,135,000	$ 14,650,776	$ 5,201,063	**$ 103,834,843**
Gilda	$ 5,793,544	$ 2,096,094	$ 11,270,732	$ 5,338,098	$ 9,094,834	$ 1,267,549	$ 884,000	$ 2,895,640	$ 4,343,460	$ 2,565,674	$ 6,270,000	$ 4,489,009	$ 2,859,588	**$ 59,168,222**
Gina	$ 1,674,634	$ 864,100	$ 2,196,384	$ 819,314	$ 485,330	$ 243,574	$ 884,000	$ 665,057	$ 997,585	$ 509,672	$ 6,270,000	$ 527,913	$ 573,387	**$ 16,710,950**
Grace	$ 10,362,874	$ 1,826,637	$ 5,934,732	$ 4,466,019	$ 3,090,490	$ -	$ 1,472,000	$ 2,212,254	$ 3,318,381	$ 494,498	$ 3,135,000	$ 4,734,088	$ 2,172,220	**$ 43,219,194**
Habitat	$ 5,733,854	$ 1,949,544	$ 3,791,340	$ 2,403,884	$ 2,506,038	$ 769,029	$ 884,000	$ 1,483,552	$ 2,225,328	$ 1,280,654	$ 6,270,000	$ 3,793,458	$ 1,443,015	**$ 34,533,694**
Harmony	$ 69,600,097	$ 5,517,050	$ 9,234,448	$ 18,874,783	$ 4,993,843	$ 1,096,054	$ 1,472,000	$ 10,059,593	$ 15,089,390	$ 1,720,616	$ 6,270,000	$ 32,949,946	$ 8,863,062	**$ 185,740,882**
Harvest	$ 42,101,220	$ 4,373,249	$ 4,932,940	$ 5,319,490	$ 2,240,868	$ -	$ 1,472,000	$ 8,090,763	$ 8,090,763	$ 1,115,156	$ 3,135,000	$ 13,968,013	$ 4,835,181	**$ 99,674,644**
Henry	$ 2,913,049	$ 1,445,091	$ 3,677,608	$ 1,965,108	$ 495,927	$ 575,920	$ 884,000	$ 1,132,804	$ 1,699,207	$ 650,555	$ 3,762,000	$ 1,483,738	$ 956,536	**$ 21,641,543**
Heritage	$ 62,903,120	$ 4,879,143	$ 13,311,836	$ 15,542,468	$ 2,909,824	$ 4,570,411	$ 1,472,000	$ 9,677,484	$ 14,516,226	$ 1,650,938	$ 6,270,000	$ 27,453,469	$ 8,447,104	**$ 173,604,023**
Hermosa	$ 39,296,869	$ 4,373,249	$ 3,379,396	$ 5,605,618	$ 2,763,334	$ -	$ 1,472,000	$ 7,521,140	$ 7,521,140	$ 1,004,204	$ 3,135,000	$ 13,337,540	$ 4,551,237	**$ 93,960,726**
Hidalgo	$ 31,410,271	$ 3,707,793	$ 3,916,752	$ 2,188,946	$ 2,286,225	$ -	$ 1,472,000	$ 5,789,512	$ 5,789,512	$ 827,534	$ 3,135,000	$ 9,756,575	$ 3,598,559	**$ 73,878,679**
Hillhouse	$ 3,565,764	$ 1,474,401	$ 7,160,312	$ 4,169,988	$ 704,681	$ 711,880	$ 884,000	$ 1,801,778	$ 2,702,666	$ 1,026,487	$ 3,762,000	$ 1,865,735	$ 1,493,682	**$ 31,323,373**
Hogan	$ 6,786,432	$ 1,096,971	$ 7,246,752	$ 2,906,310	$ 1,014,770	$ 369,971	$ 884,000	$ 1,875,489	$ 2,813,234	$ 2,144,518	$ 7,425,000	$ 1,902,952	$ 1,624,417	**$ 38,090,816**
Hondo	$ 39,062,688	$ 4,085,816	$ 6,845,608	$ 7,252,563	$ 3,158,141	$ 922,327	$ 1,472,000	$ 5,379,072	$ 8,068,609	$ 984,446	$ 6,270,000	$ 11,588,796	$ 5,023,931	**$ 100,113,997**
Houchin	$ 6,585,043	$ 1,096,971	$ 6,491,880	$ 2,706,725	$ 639,259	$ 342,733	$ 884,000	$ 1,755,599	$ 2,633,398	$ 1,987,482	$ 7,425,000	$ 2,119,655	$ 1,499,729	**$ 36,167,474**
Irene	$ 6,177,281	$ 1,826,637	$ 6,289,360	$ 2,807,010	$ 3,951,074	$ 656,477	$ 884,000	$ 2,871,929	$ 2,871,929	$ 413,762	$ 3,135,000	$ 3,639,897	$ 1,807,347	**$ 37,331,704**
Total	**$ 457,815,614**	**$ 55,393,273**	**$ 146,083,224**	**$ 122,276,073**	**$60,588,999**	**$ 14,444,841**	**$ 25,624,000**	**$ 80,132,630**	**$ 116,472,622**	**$ 27,300,000**	**$ 108,900,000**	**$ 181,064,472**	**$ 70,578,082**	**$ 1,466,673,830**

Note: Engineering costs for Conductor removal are based on a combination of varied and fixed costs.

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Appendix 2: Platform Removal Weights (tons)*

Platform	Water Depth (ft)	Jacket	Piles	Conductors	Deck	Total Weight*
A	188	1,500	600	1,439	1,357	4,896
B	190	1,500	600	1,502	1,357	4,959
C	192	1,500	600	2,261	1,357	5,718
Edith	161	3,454	450	518	4,134	8,556
Ellen	265	3,200	1,100	2,065	5,300	11,665
Elly	255	3,300	1,400	0	4,700	9,400
Eureka	700	19,000	2,000	4,377	8,000	33,377
Gail	739	18,300	4,000	7,064	7,693	37,057
Gilda	205	3,220	1,030	3,251	3,792	11,293
Gina	95	434	125	374	447	1,380
Grace	318	3,090	1,500	4,684	3,800	13,074
Habitat	290	2,550	1,500	2,047	3,514	9,611
Harmony	1,198	42,900	12,350	21,424	9,839	86,513
Harvest	675	16,633	3,383	6,110	9,024	35,150
Henry	173	1,311	150	1,174	1,371	4,006
Heritage	1,075	32,420	13,950	12,996	9,826	69,192
Hermosa	603	17,000	2,500	3,538	7,830	30,868
Hidalgo	430	10,950	2,000	2,334	8,100	23,384
Hillhouse	190	1,500	400	2,734	1,200	5,834
Hogan	154	1,263	150	1,426	2,259	5,098
Hondo	842	12,200	2,900	5,928	8,450	29,478
Houchin	163	1,486	150	1,388	2,591	5,615
Irene	242	3,100	1,500	1,662	2,500	8,762

* Total Weight is the estimated platform removal weight and includes the weights of the jacket, deck, piles and conductors and assumes that they are removed to a depth of 15 feet below the mud-line.

Appendix 3: Platform, Deck and Jacket Removal Details

Project I

Platform Name	Hogan	Houchin
Water Depth (feet)	154	163
Derrick Barge Capacity (tons)	500	500
Deck Weight (tons)	2,259	2,591
Deck Modules		
Max Weight Per module (tons)	350	430
Number of Modules	8	9
Jacket Weight (tons)	1,263	1,486
Jacket Sections		
Max Weight per Section (tons)	300	300
Number of Sections	5	5
Number of Piles	12	8

Project II

Platform Name	Edith	Elly	Ellen	Eureka
Water Depth (feet)	161	255	265	700
Derrick Barge Capacity (tons)	2000	2000	2000	2000
Deck Weight (tons)	4,134	4,700	5,300	8,000
Deck Modules				
Max Weight Per module (tons)	585	697	867	1,200
Number of Modules	12	10	12	10
Jacket Weight (tons)	3,454	3,300	3,200	19,000
Jacket Sections				
Max Weight per Section (tons)	1,200	1,100	1,600	1,000
Number of Sections	3	3	2	19
Number of Piles	12	12	8	24 skirt

Project III

Platform Name	A	B	C	Henry	Hillhouse
Water Depth (feet)	188	190	192	173	190
Derrick Barge Capacity (tons)	2,000	2,000	2,000	2,000	2,000
Deck Weight (tons)	1,357	1,357	1,357	1,371	1,200
Deck Modules					
Max Weight Per module (tons)	425	425	425	550	425
Number of Modules	4	4	4	4	4
Jacket Weight (tons)	1,500	1,500	1,500	1,311	1,500
Jacket Sections					
Max Weight per Section (tons)	1,500	1,500	1,500	1,311	1,500
Number of Sections	1	1	1	1	1
Number of Piles	12	12	12	8	8

Project IV

Platform Name	Gina	Gilda	Habitat
Water Depth (feet)	95	205	290
Derrick Barge Capacity (tons)	2,000	2,000	2,000
Deck Weight (tons)	447	3,792	3,514
Deck Modules			
Max Weight Per module (tons)	418	1,004	1,363
Number of Modules	2	6	6
Jacket Weight (tons)	434	3,220	2,550
Jacket Sections			
Max Weight per Section (tons)	434	1,100	1,300
Number of Sections	1	3	2
Number of Piles	6	12	8

Project V

Platform Name	**Gail**	**Grace**	**Harvest**	**Hermosa**	**Hidalgo**	**Irene**
Water Depth (feet)	739	318	675	603	430	242
Derrick Barge Capacity (tons)	4,400	4,400	4,400	4,400	4,400	2,000
Deck Weight (tons)	7,693	3,800	9,024	7,830	8,100	2,500
Deck Modules						
Max Weight Per module (tons)	1,894	1,000	1,698	1,269	1,378	1,000
Number of Modules	7	6	9	8	8	5
Jacket Weight (tons)	18,300	3,090	16,633	17,000	10,950	3,100
Jacket Sections						
Max Weight per Section (tons)	1,000	1,100	1,000	1,000	1,000	1,600
Number of Sections	19	3	17	17	11	2
Number of Piles	8 main 12 skirt	12 main 8 skirt	8 main 20 skirt	8 main 8 skirt	8 main 8 skirt	8

Project VI

Platform Name	**Hondo**	**Heritage**	**Harmony**
Water Depth (feet)	842	1075	1198
Derrick Barge Capacity (tons)	4,400	4,400	4,400
Deck Weight (tons)	8,450	9,826	9,839
Deck Modules			
Max Weight Per module (tons)	1,310	1,310	1,310
Number of Modules	13	13	13
Jacket Weight (tons)	12,200	32,420	42,900
Jacket Sections			
Max Weight per Section (tons)	1,000	1,000	1,000
Number of Sections	13	33	43
Number of Piles	8 main 12 skirt	8 main 26 skirt	8 main 20 skirt

Appendix 4: Deck and Jacket Specifications

Platform	Module Weights or Lift Weights (tons)		Number of Jacket Legs	Number of Piles & Size	Number of Lifts to Install Decks
A	Drill Deck Structure	425	12	12/40" to 80' BML	4 main lifts
	Drilling Rig	237			
	Production Deck	325			
	Pipe Rack	370			
B			12		
C			12		
Edith	Mod 1-471 Piperacks	246	12	12/54"	6 modules
	Helipad	118		200' to 280' BML	
	Quarters	438			2 Cap Trusses
	Cap Trusses	341			misc. other lifts
	Flare	19			
Ellen	E Deck	867	8	4/66" to 260' BML	17 main lifts
	W Deck	816			
	C Deck	813		4/48" to interior	12 modules
	Sub Structure 1	445		230' BML	
	Sub Structure 2	445			
Elly	Cap Trusses	395	12	4-48" to 250' BML	16 main lifts
	SW Deck			2-42" interior to 220' BML	10 modules
	NW Deck				
	E Deck	697		6-48" exterior to 220' BML	
	Control Building	260			
	C Deck				
	Others				
	Production Skid	418			

Platform	Module Weights or Lift Weights (tons)		Number of Jacket Legs	Number of Piles & Size	Number of Lifts to Install Decks
Eureka	Modules up to 1,200 tons		8	Main 0 Skirt 24/60”	10 modules
Gail	East Deck West Deck Drilling Mod. Comp. Mod. Gen. SG Mod. Flare Crew Quarters	1,894 1,850 953 869 1,178 77 873	8	Main 8/60” Skirt 12/72”	9 main lifts
Gilda	Drill Deck Equip. Drill Deck Steel Drill Rig Prod. Deck Equip. Prod. Deck Steel Vert. added mass	1,004 260 227 798 305 1,192	12	12/48” 150’ to 190’ BML	6 main lifts
Gina	Deck Helideck Others	418 29 ---	6	6/42” to 140’ BML*	2 main lifts
Grace			12	12/42” Main 8/48” Skirt	

Platform	Module Weights or Lift Weights (tons)	Number of Jacket Legs	Number of Piles & Size	Number of Lifts to Install Decks
Habitat	Skid Base 70 Derrick w/ Sub. 562 Pump Package 1,363 Engine Package 639 Quarters 200 Reserve Mud/P Tank 680	8		6 main lifts
Harmony	WMSF 509 AU 1,025 EMSF 403 CU 804 AL Mod. 896 Quarters 957 CL 866 BU 1,310 BL 1,046 DU 800 DL 854 BX 242	8	Main 8/72” Skirt 20/84”	13 main lifts
Harvest	N Deck 1,698 Flare #1 127 S Deck 1,425 Flare #2 50 G/SG 1,429 Comp. 1,445 C/U 931 Quarters 921 Prod. 1,125	8	Main 8/60” to 255’ BML Skirt 20/72” to 235’ BML	10 main lifts
Henry	Drilling Deck 465 Production Deck #1 356 Production Deck #2* 550 *(incl. some equip., but excluding rig & other equip.)	8	8/42” w/ 36” inserts to 170’ BML	3 main lifts

Platform	Module Weights or Lift Weights (tons)	Number of Jacket Legs	Number of Piles & Size	Number of Lifts to Install Decks
Heritage	WMSF 509 AU Mod. 1,040 EMSF 403 Quarters 947 AL. Mod. 886 CU/DU 804/800 CL Mod. 861 BU 1,310 BL 1,050 BX 237	8	Main 8/72” Skirt 26/84”	13 main lifts
Hermosa	W/H Module 1,203 Production Module 1,269 Compressor Module 1,113 Utility Module 1,150 Power Module 1,297 Pipe Rack 320 Cap Trusses 777 Crew Quarters 700	8	Main 8/60” Skirt 12/72”	9 main lifts
Hidalgo	W/H Module 1,378 Production Module 1,254 Compressor Module 1,171 Utility Module 955 Power Module 1,233 Pipe Rack 266 Cap Trusses 1,071 Crew Quarters --- DL 854 Flare 125		Main 8/60” Skirt 8/72”	8 main lifts

Platform	Module Weights or Lift Weights (tons)		Number of Jacket Legs	Number of Piles & Size	Number of Lifts to Install Decks
Hillhouse			8		
Hogan	Drilling Deck & Equip. Workover Rig Deck Structure	302 315 997	12	12/36”	12 main lifts
Hondo			8	Main 8/48” & 42” inserts to 340’ BML Skirt 12/54” & 48” to 250’ BML	30 lifts
Houchin	Drilling Deck Structure Production Deck Structure Drilling Rig Piperack & Equipment Other item of Equipment	432 314 220 289 ---	8	8	9 main lifts
Irene	West Section East Section Cranes Flare Misc.	1,000 860 0 25 ---	8	8/60”	2 main lifts

Appendix 5: Well Data

Platform	Water Depth	Average Well Depth	Well Count	Low # of Wells	Med Low # of Wells	Med High # of Wells	High # of Wells
A	188	2,500	52	45	5	1	1
B	190	2,500	57	49	6	1	1
C	192	2,500	38	33	3	1	1
Edith	161	4,500	18	12	4	1	1
Ellen	265	6,700	63	18	41	3	1
Elly	0	0	0	0	0	0	0
Eureka	700	6,500	50	6	38	5	1
Gail	739	8,400	27	0	21	2	4
Gilda	205	7,900	63	8	47	6	2
Gina	95	6,000	12	7	3	1	1
Grace	318	-	28	0	13	13	2
Habitat	290	12,000	20	1	16	2	1
Harmony	1.198	11,900	34	0	0	20	14
Harvest	675	10,000	19	0	0	14	5
Henry	173	2,500	23	20	1	1	1
Heritage	1,075	10,300	48	0	0	25	23
Hermosa	603	9,500	13	0	0	10	3
Hidalgo	430	10,700	14	0	0	8	6
Hillhouse	192	2,500	47	40	5	1	1
Hogan	154	5,400	39	13	18	4	4
Hondo	842	12,700	28	0	0	24	4
Houchin	163	5,100	35	12	15	5	3
Irene	242	5,800	26	0	2	20	4
Totals:	**-**	**-**	**754**	**264**	**238**	**168**	**84**

- Platform Gail had two Med Low Wells and one High Well added since 2010.
- Platform Irene had two High Wells added since 2010.
- Houchin was corrected reducing the number of High wells by one and increasing Med High one.

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Appendix 6: Trends in Inflation and Recommendations on Updating Decommissioning Costs

For this study, information on inflationary trends related to offshore construction were compiled, and reviewed to make a recommendation on an appropriate index to apply to the decommissioning costs in the 5 year interval between decommissioning cost report updates. To make a determination of the appropriate inflation factor to use for POCSR decommissioning project cost estimates, we have evaluated construction trends using several construction and economic indices.

Recommended Inflation Rate for the POCS Decommissioning Projects

A review of the various rates shows a wide range of variation by category and from year to year. The largest impacts to vessel rates are due to storms and storm damage. Accordingly, the overall increase of vessel rates over the last 6 years has been limited as there has been no major tropical storm or hurricane during this time. The impact of weather on the vessel market is largely recognized but also not easily predicted. Barring any weather related events or another general economic downturn; the vessel rates should follow market inflation.

We have reviewed the available inflation data and propose the following inflation factor of 2.3% (CPI Average 2005 - 2014 in Table A.2) for use in updating decommissioning costs in the five year interval between decommissioning report updates.

Table A.1. POCS Decommissioning Projects Cost Adjustment Factor

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	Average
Derrick Barge Average Change (%)	1.524%	13.892%	15.198%	0.474%	-3.491%	-1.062%	9.326%	-21.435%	8.789%	6.814%	3.0%
Consumer Price Index (%)	3.42%	3.10%	3.52%	0.09%	2.72%	1.50%	2.96%	1.74%	1.50%	2.07%	2.3%

General Construction Inflation

Since 2003, the U.S. Consumer Price Index (CPI) has seen an almost steady rise of 29% compared to 2003 levels for an average annual rate of 2.365%. [(1)] General construction rates, shown in Figure A.7, have increased faster than the CPI since 2003. Construction rates have increased by 55% from 2003 levels for an average annual rate of 4.08%, which is 26% higher than the 29% CPI rise since 2003.

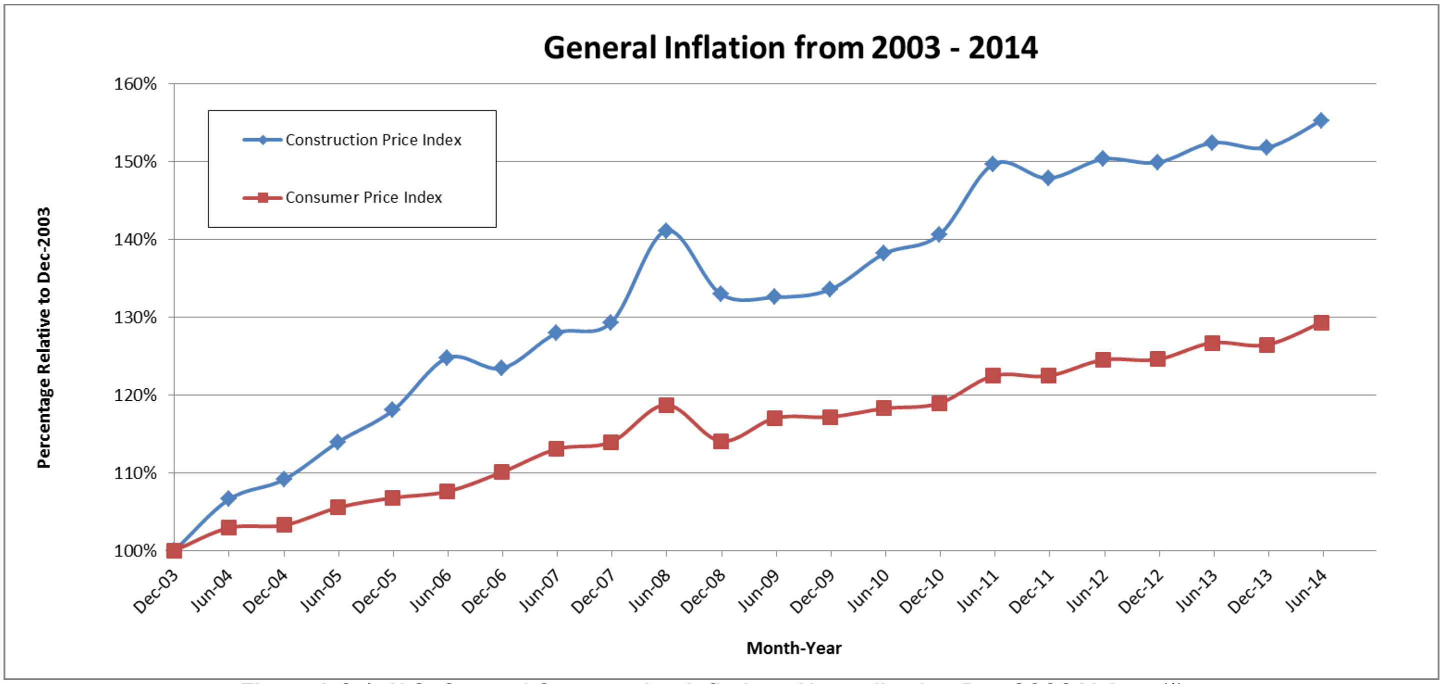


Figure A.6-1 U.S. General Construction Inflation - Normalized to Dec-2003 Values [1]

Since 2009, the U.S. Consumer Price Index (CPI) has risen of 10% for an average annual rate of 2%. [1] Construction rates have increased by 16% for an average annual rate of 4.08%, which is 6% higher than the total CPI increase since 2009.

When viewing the Construction Price Index and CPI normalized to Dec-2009, the indeces follow the same trends. Construction Price Index responds with larger relative increases.

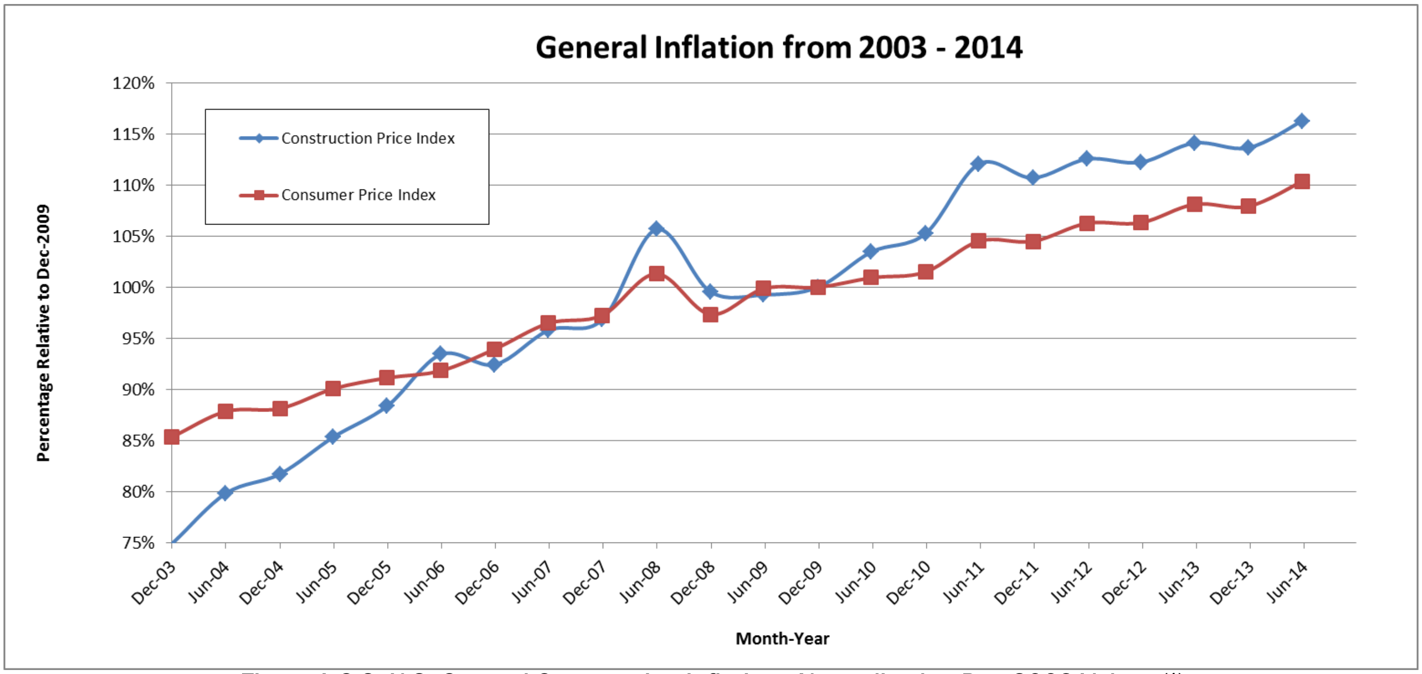


Figure A.6-2 U.S. General Construction Inflation - Normalized to Dec-2009 Values [1]

Heavy construction has shown a greater increase in cost since 2003 primarily due to energy costs involved in operating heavy machinery. Figure A.9 shows a 46% increase in heavy construction costs from Dec-2003 to Jun-2010, 27% higher than the CPI values, for an average annual rate of 5.56% by Jun-2010. At this date, the index was modified by the Bureau of Labor from BHVY to BONS. The BHVY index was rendered obsolete and the BONS index including oilfield construction as Other Non-residential construction (BONS). Combining the increase in the BONS index from 2010 to 2014 added to the increase seen in BHVY from 2003 to 2010 yields a maximum theoretical increase for heavy construction of 58.9% (4.3% average annual increase).

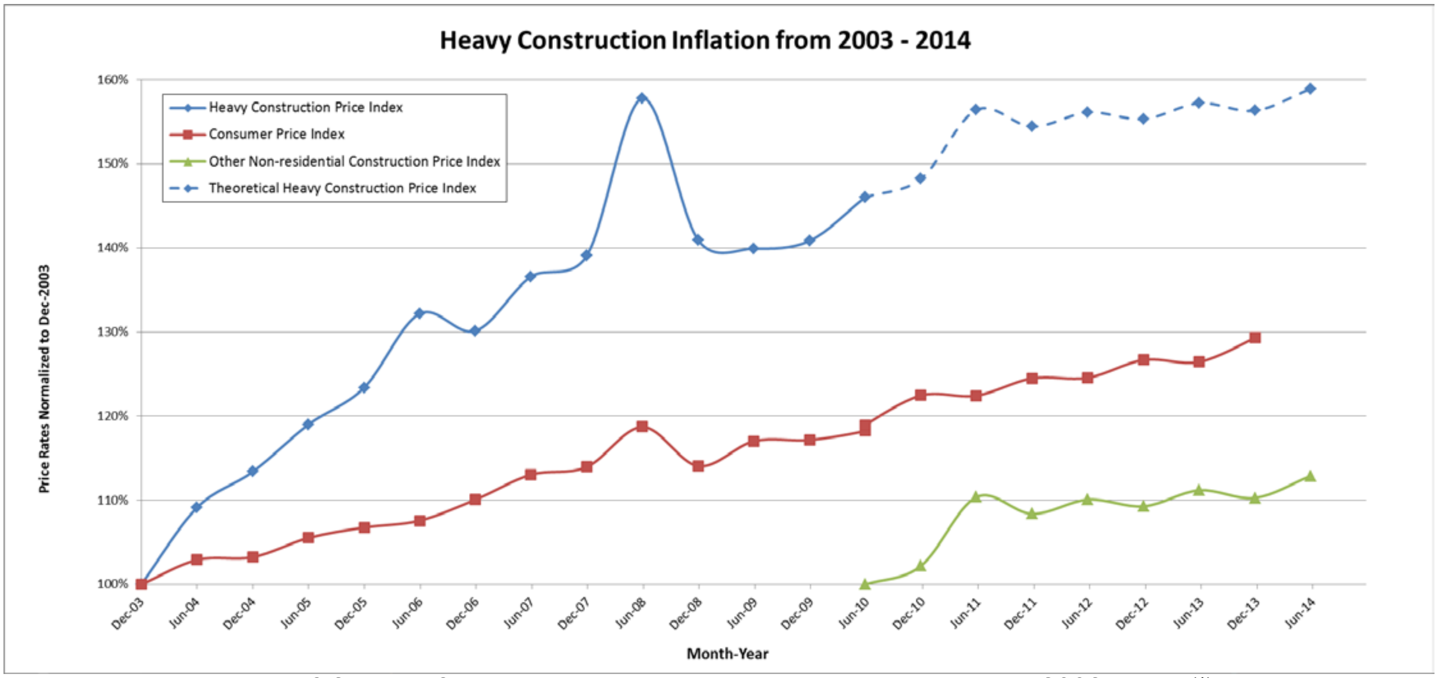


Figure A.6-3 Heavy Construction Price Rates vs. Year - Normalized to Dec-2003 Values (1)

When you normalize the Heavy Construction Price Index to Dec-2009, the Construction price index and CPI are approaching matching increasing trends. The construction market has stabilized over the past 5 years without large swings in prices relative to CPI.

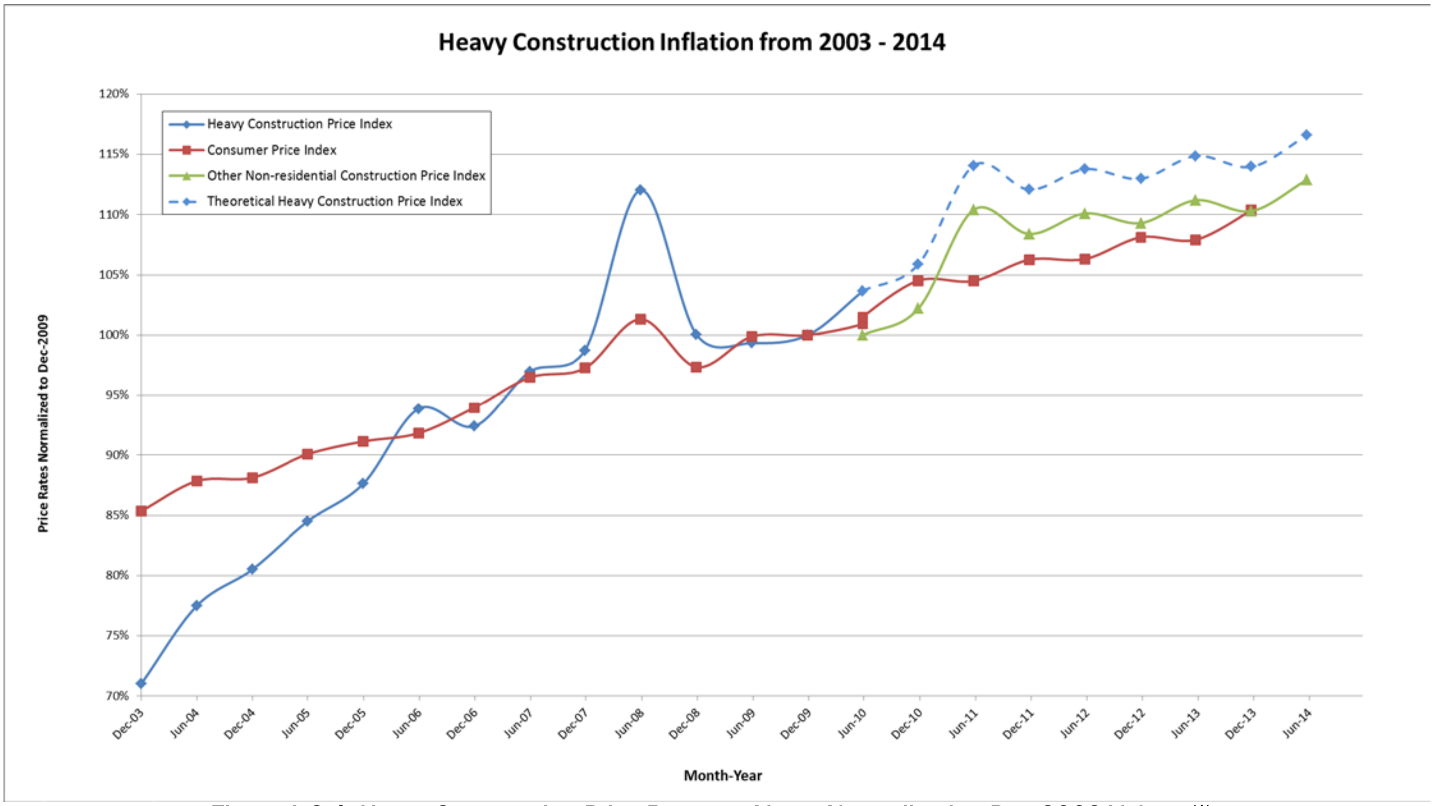


Figure A.6-4 Heavy Construction Price Rates vs. Year - Normalized to Dec-2009 Values (1)

Many components contributed to this higher rate inflation in heavy construction, including #2 diesel, concrete, gypsum, copper mill, and steel mill product prices. These components all showed large increases in the lead in to the 2008 economic downturn. Following the economic downturn, component prices increased again. All of these components, most notably #2 diesel fuel, showed a higher normalized price increase compared to the CPI since 2003 as shown in Figure A.11. There was a greater relative drop in the construction components, but they recovered and increased greater relative to inflation during the economic recovery period.

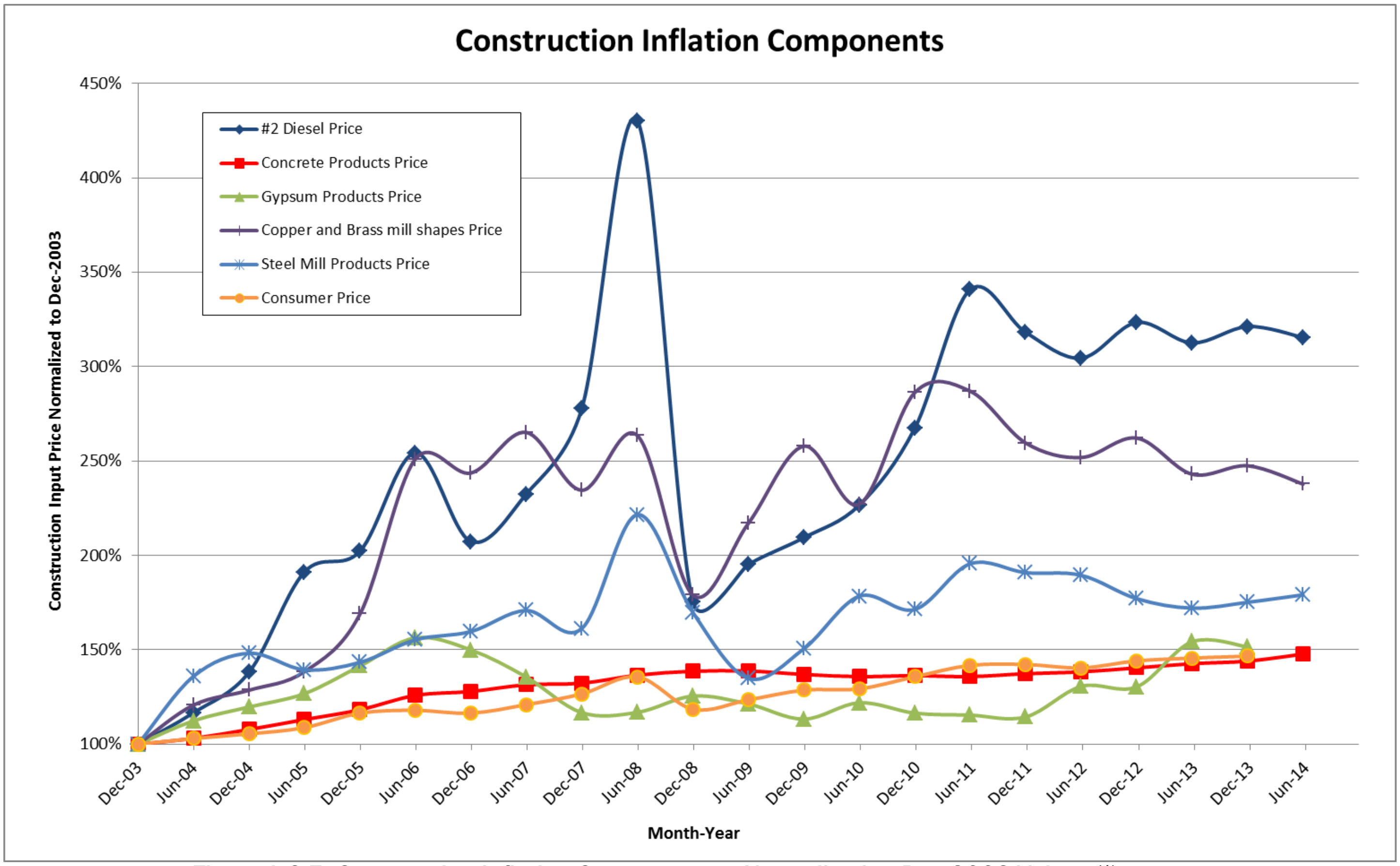


Figure A.6-5 Construction Inflation Components – Normalized to Dec-2003 Values (1)

When you normalize the Construction price inputs to Dec-2009, the component prices vary relative to each other and to CPI. The average of the components mirror the CPI trend but with a larger value by 50% to 100% relative to CPI.

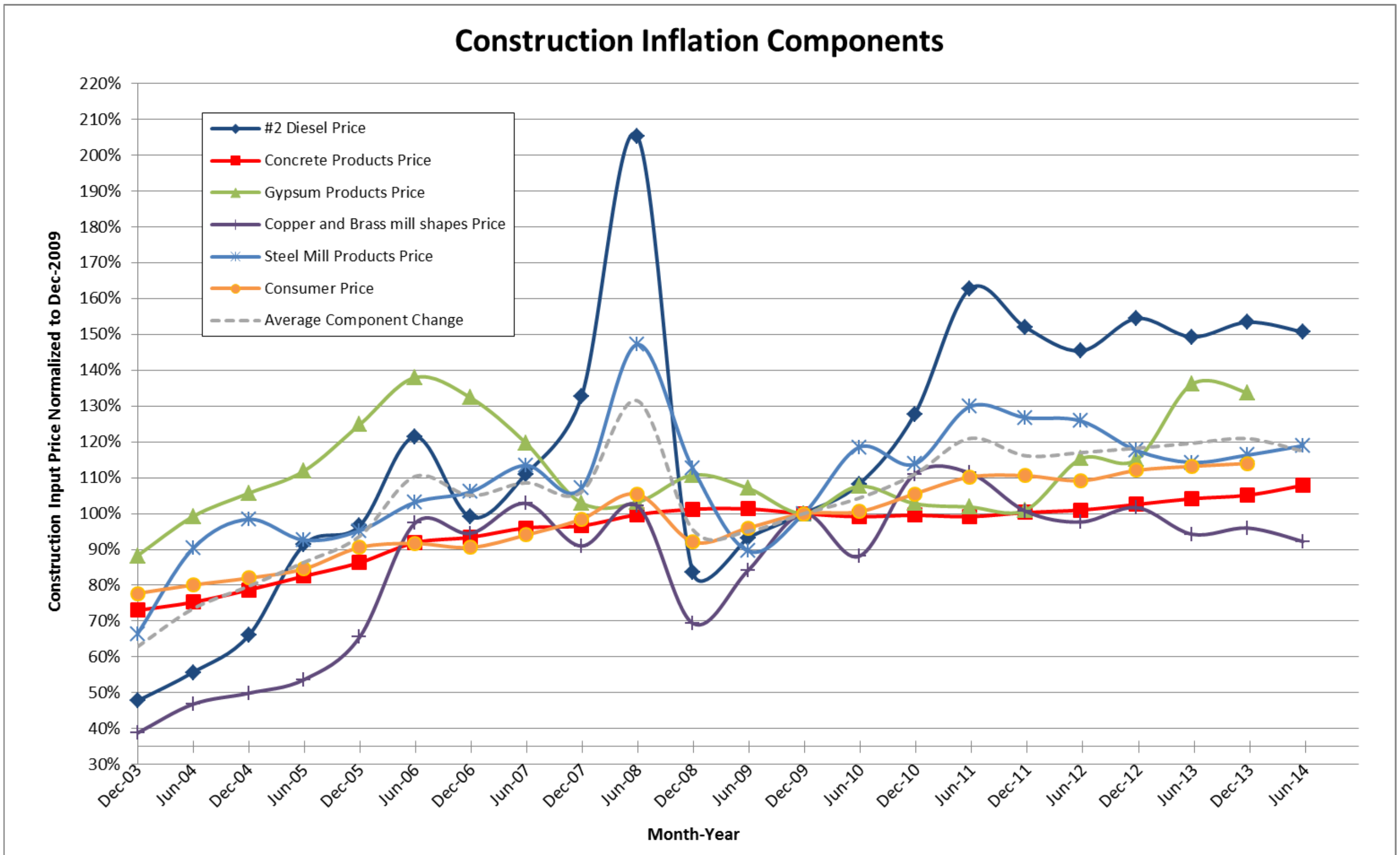


Figure A.6-6 Construction Inflation Factors (1)

Offshore vessel rates provide a strong correlation to overall offshore construction prices and therefore are a good indicator of offshore construction prices used in the inflation rate recommendation for POCSR decommissioning projects. Offshore vessel rates in Figure A.13 show an overall trend of staying below CPI from 1996 to 2008, but since 2003 rates are shown to be rising significantly faster than the CPI in Figure A.14. A major factor in this recent trend is the increase of #2 diesel fuel at a rate 170% higher than the CPI since 2003 (see Figure A.11 and A.12 above). [2] The general offshore vessel rate trend, excluding lift boats, has shown an annual average increase of 14.2% since 2003.

Vessel rates respond quickly to market events such as weather related (hurricanes, tropical storms, damage due to these) or market impacting (field divestitures or aggressive field work by an operator). During the 2005 storm season, hurricanes Katrina and Rita entered the Gulf of Mexico reaching landfall in Louisiana and Texas. Later in 2008, hurricane Ike passed through the Gulf of Mexico reaching landfall near Houston. Following these catastrophic storms, there were step change increases in vessel rates in the Gulf of Mexico that impacted the overall vessel market. First, lift boats were hired for immediate repair actions and other works causing the immediate increase in Lift boat rates. Later, dive boat, cargo barge, and derrick barge rates increased. This is seen to occur over the time period required for planning and permitting decommissioning operations (1-2 years).

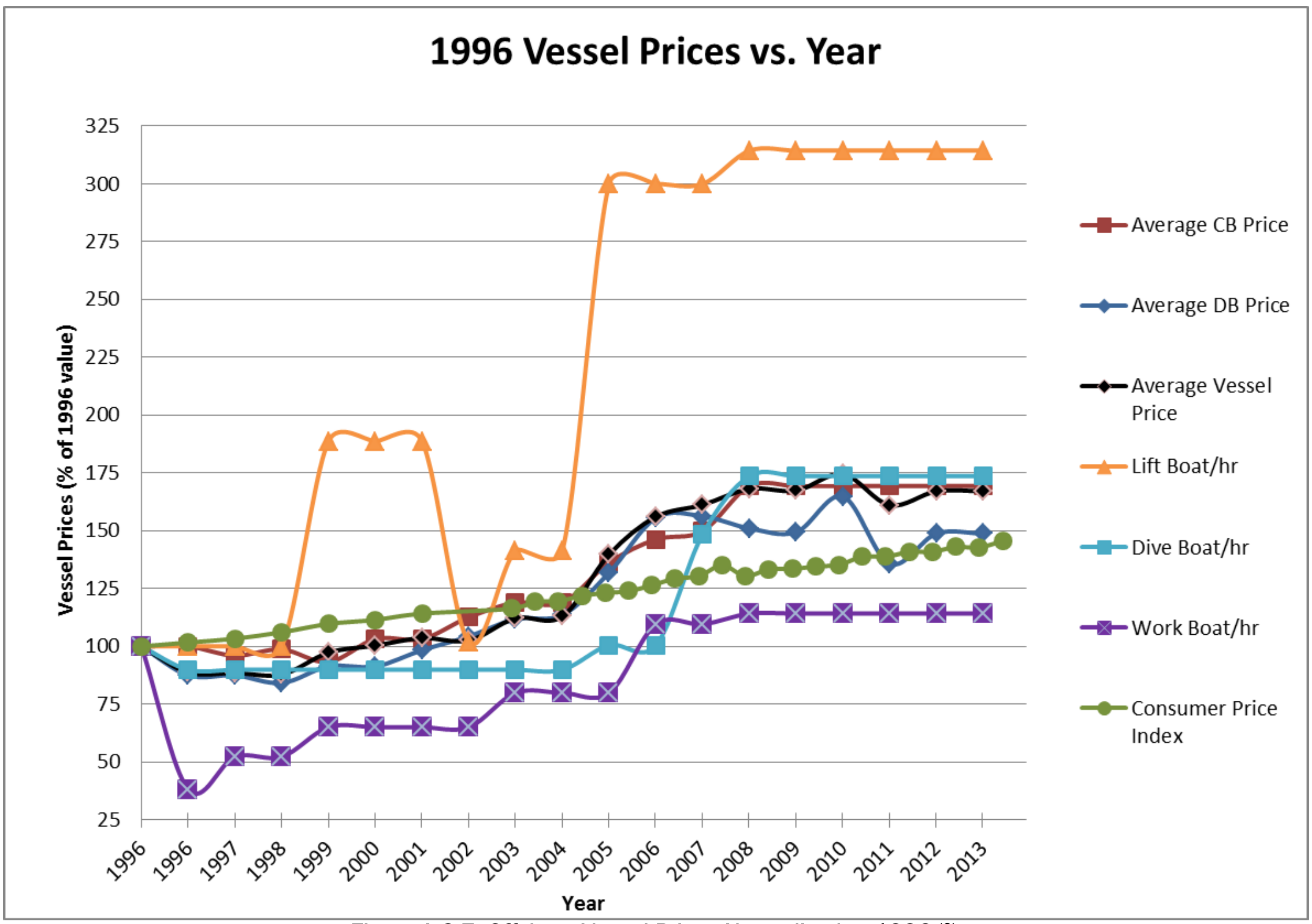


Figure A.6-7 Offshore Vessel Prices Normalized to 1996 [2]

Since 2008, there has not been a significant storm in the Gulf of Mexico. There have been no significant changes to the rates of vessels in the Gulf of Mexico since 2008. Individual rates for certain class vessels have changed dramatically (DB2000 rate increased 26.7% year on year from 2013 to 2014, DB4000 rate increased 81% year on year from 2012 to 2013), but the overall average rates (average of all derick bar sizes) have remained very steady with a small increase of 8.4% from 2008 to 2014 (average yearly increase of 1.35%).

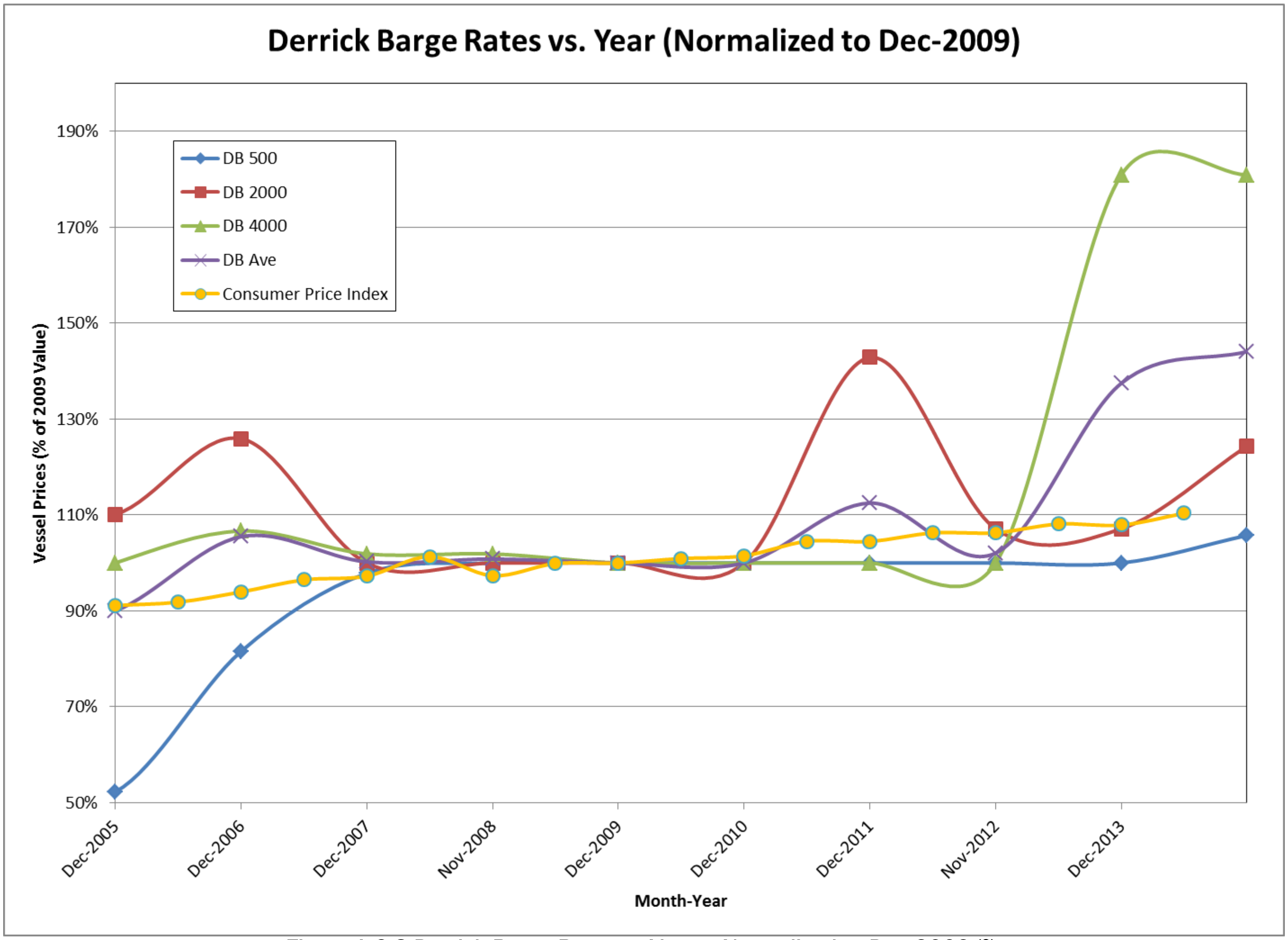


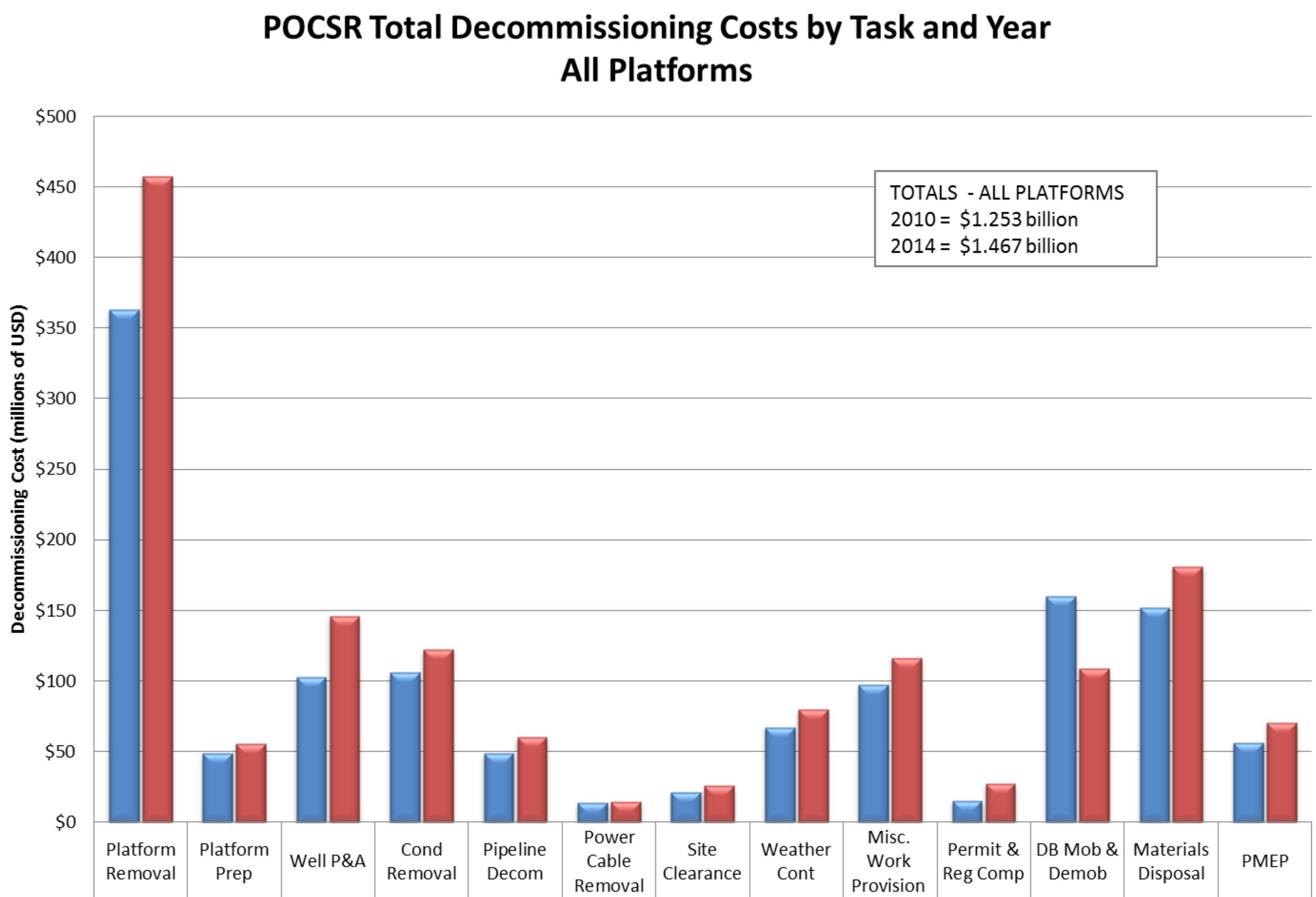
Figure A.6-8 Derrick Barge Rates vs Year – Normalized to Dec-2009 (2)

Inflation References

1. Bureau of Labor Statistics: http://data.bls.gov/timeseries/PCUBONS--BONS--
2. TSB Offshore's "PAES®" Rates Database

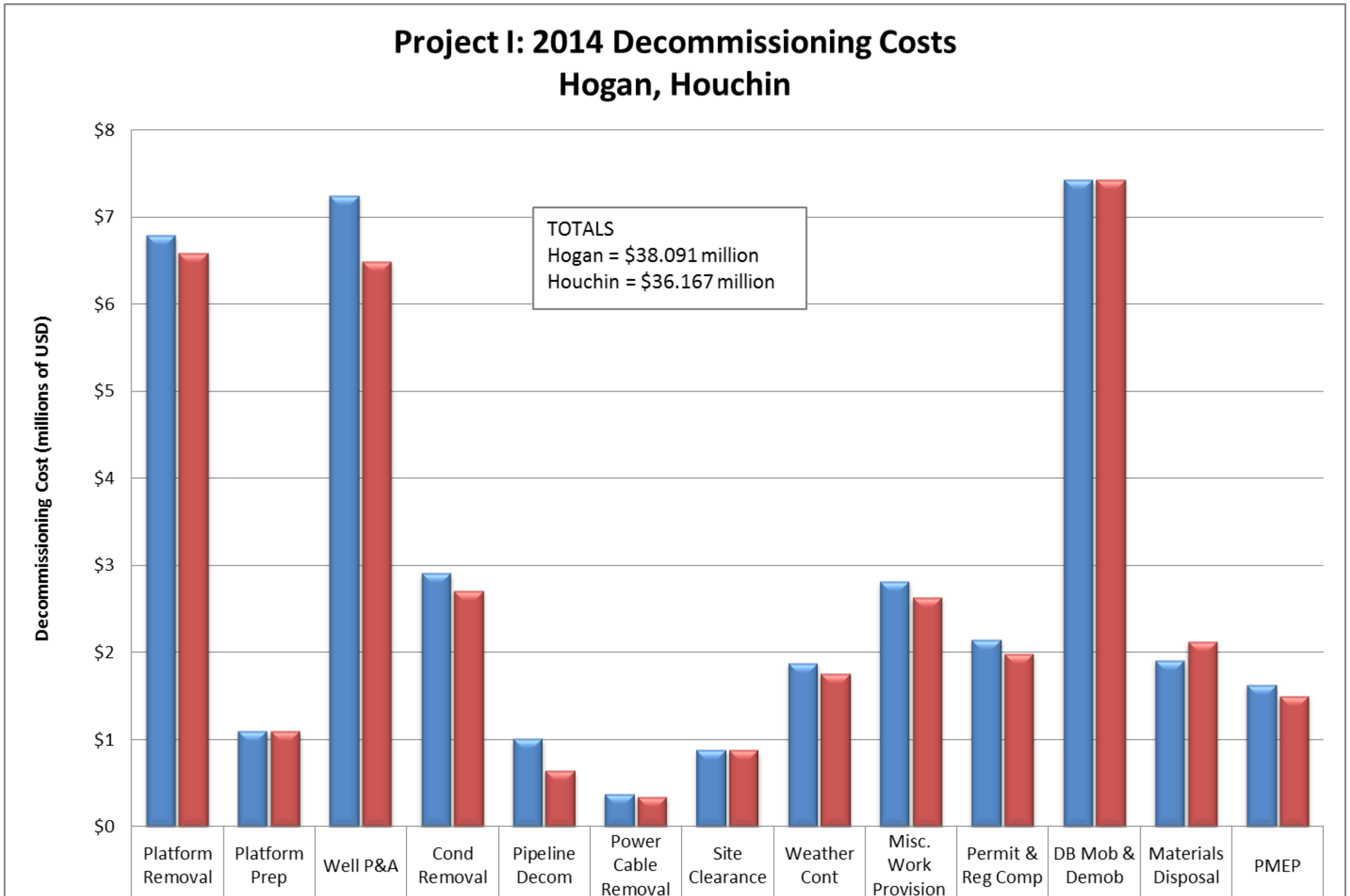
Appendix 7: Decommissioning Costs and Graphical Analysis

The following graphs show the decommissioning costs from the 2014 study and comparisons to 2010 study costs by platform.



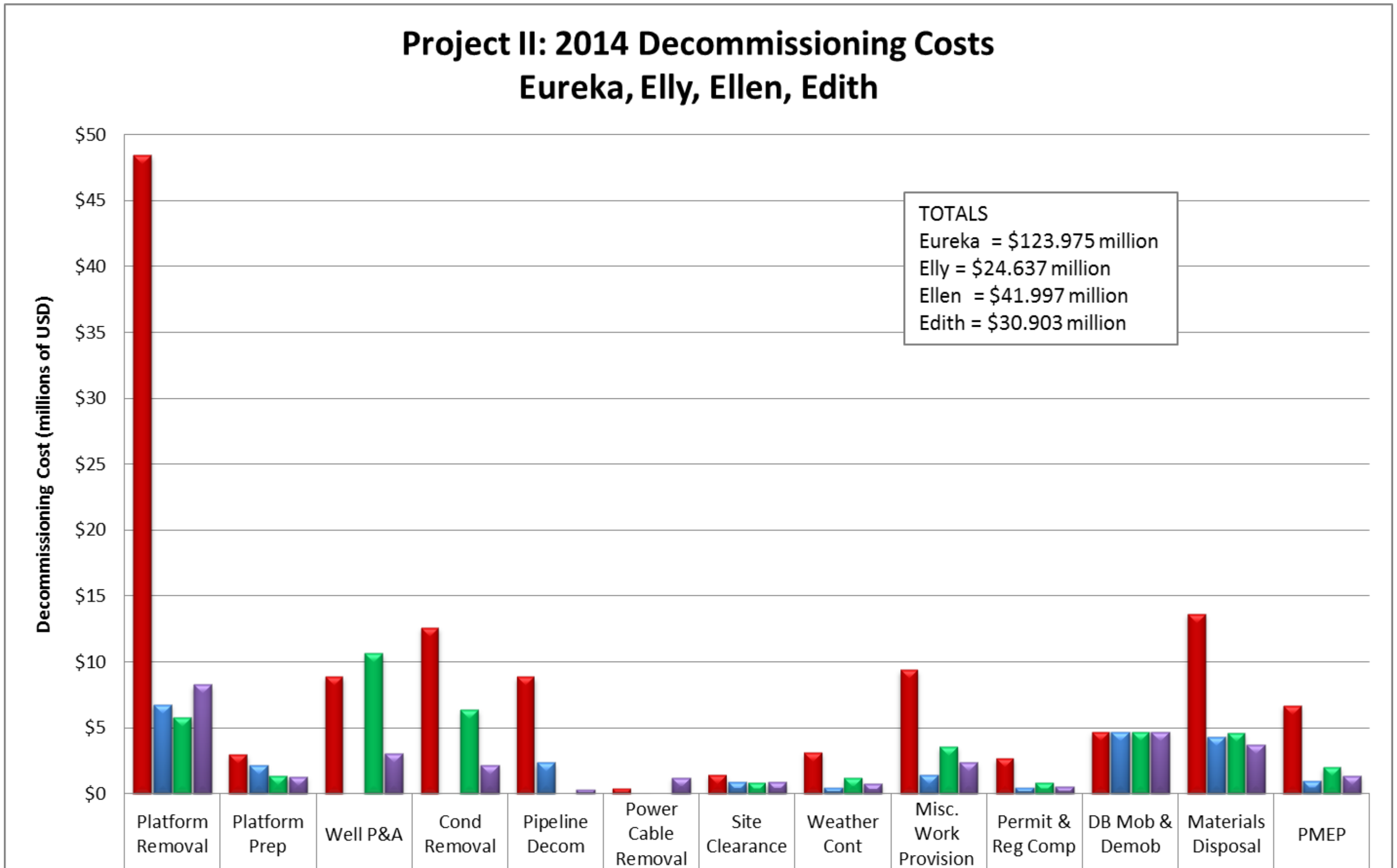
	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
2010	$363.276	$48.934	$103.092	$105.995	$49.027	$13.463	$21.464	$66.961	$97.471	$15.330	$159.840	$151.723	$56.420
2014	$457.816	$55.393	$146.083	$122.276	$60.589	$14.445	$25.624	$80.133	$116.473	$27.300	$108.900	$181.064	$70.578

Figure A.7-1 POCSR Decommissioning Costs by Task and Year All Platforms



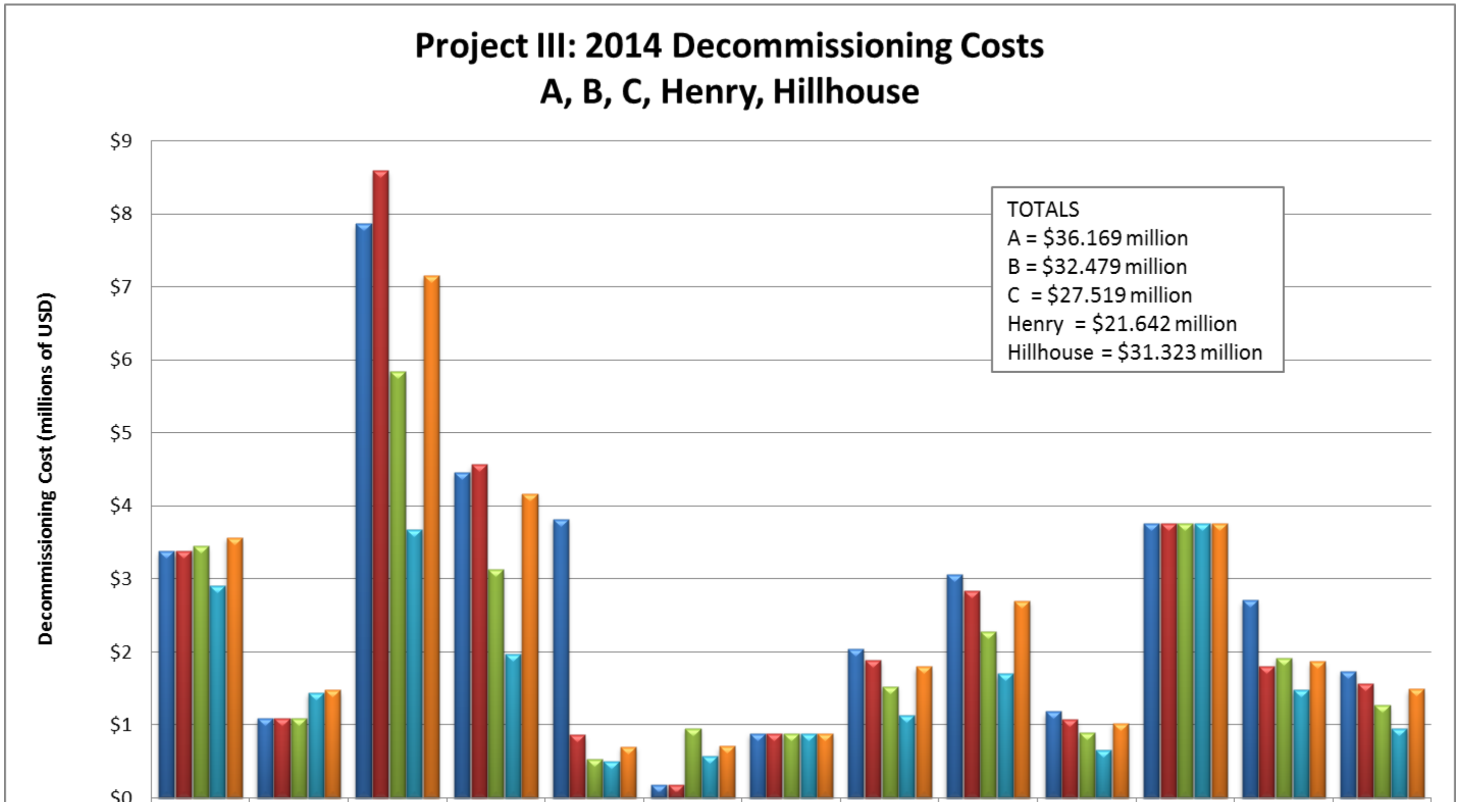
	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
Hogan	$6.787	$1.097	$7.247	$2.906	$1.015	$0.370	$0.884	$1.875	$2.813	$2.145	$7.425	$1.903	$1.624
Houchin	$6.585	$1.097	$6.492	$2.707	$0.639	$0.343	$0.884	$1.756	$2.633	$1.987	$7.425	$2.120	$1.500

Figure A.7-2 Project I: Decommissioning Costs Hogan, Houchin



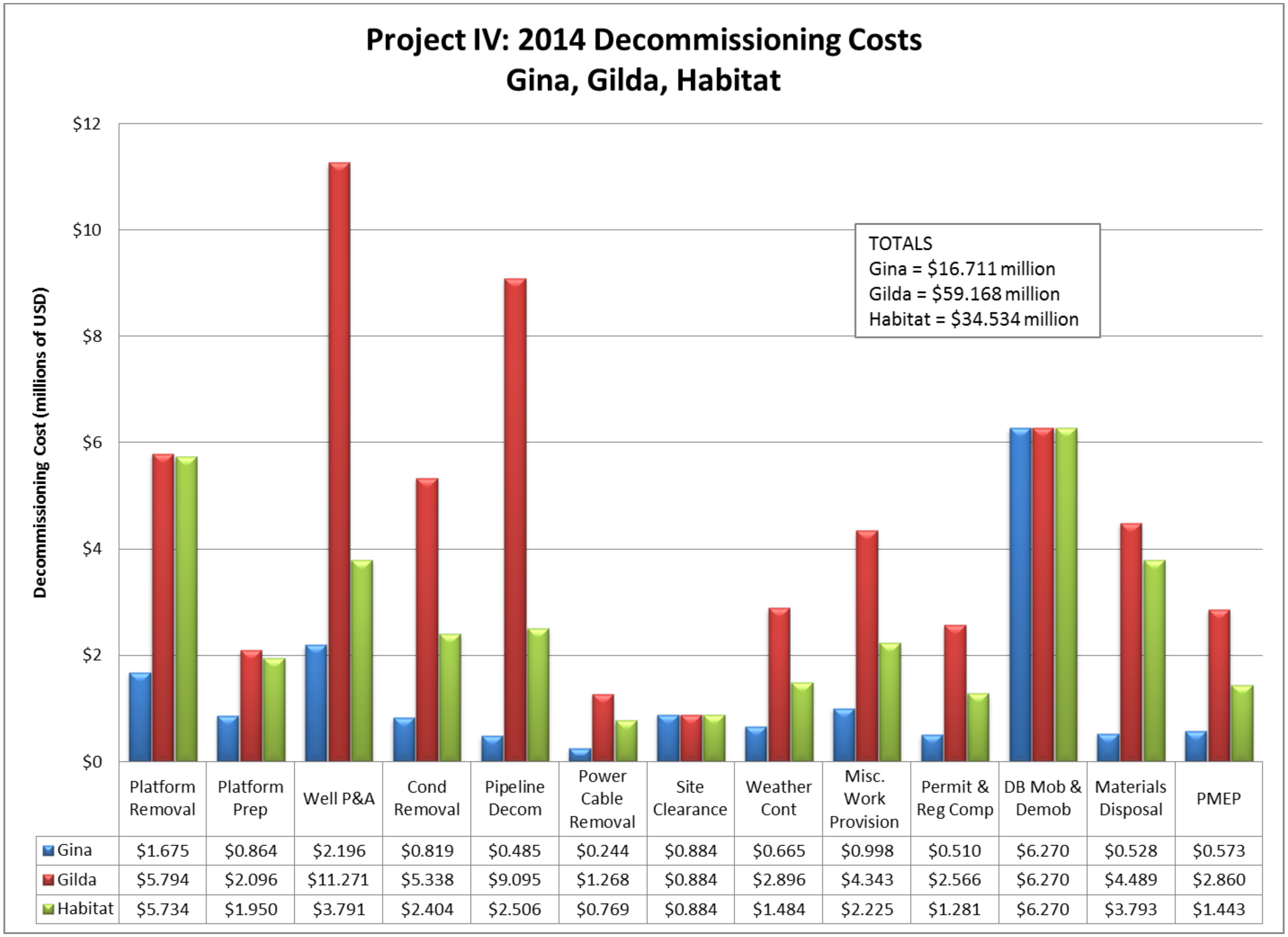
	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
Eureka	$48.421	$2.969	$8.907	$12.623	$8.877	$0.374	$1.472	$3.139	$9.418	$2.713	$4.703	$13.669	$6.691
Elly	$6.774	$2.152	$0.000	$0.000	$2.393	$0.000	$0.884	$0.481	$1.444	$0.482	$4.703	$4.348	$0.976
Ellen	$5.773	$1.390	$10.650	$6.378	$0.000	$0.000	$0.884	$1.189	$3.568	$0.831	$4.703	$4.625	$2.006
Edith	$8.303	$1.320	$3.067	$2.186	$0.332	$1.231	$0.884	$0.797	$2.391	$0.565	$4.703	$3.740	$1.386

Figure A.7-3 Project II: 2014 Decommissioning Costs Eureka, Elly, Ellen, Edith



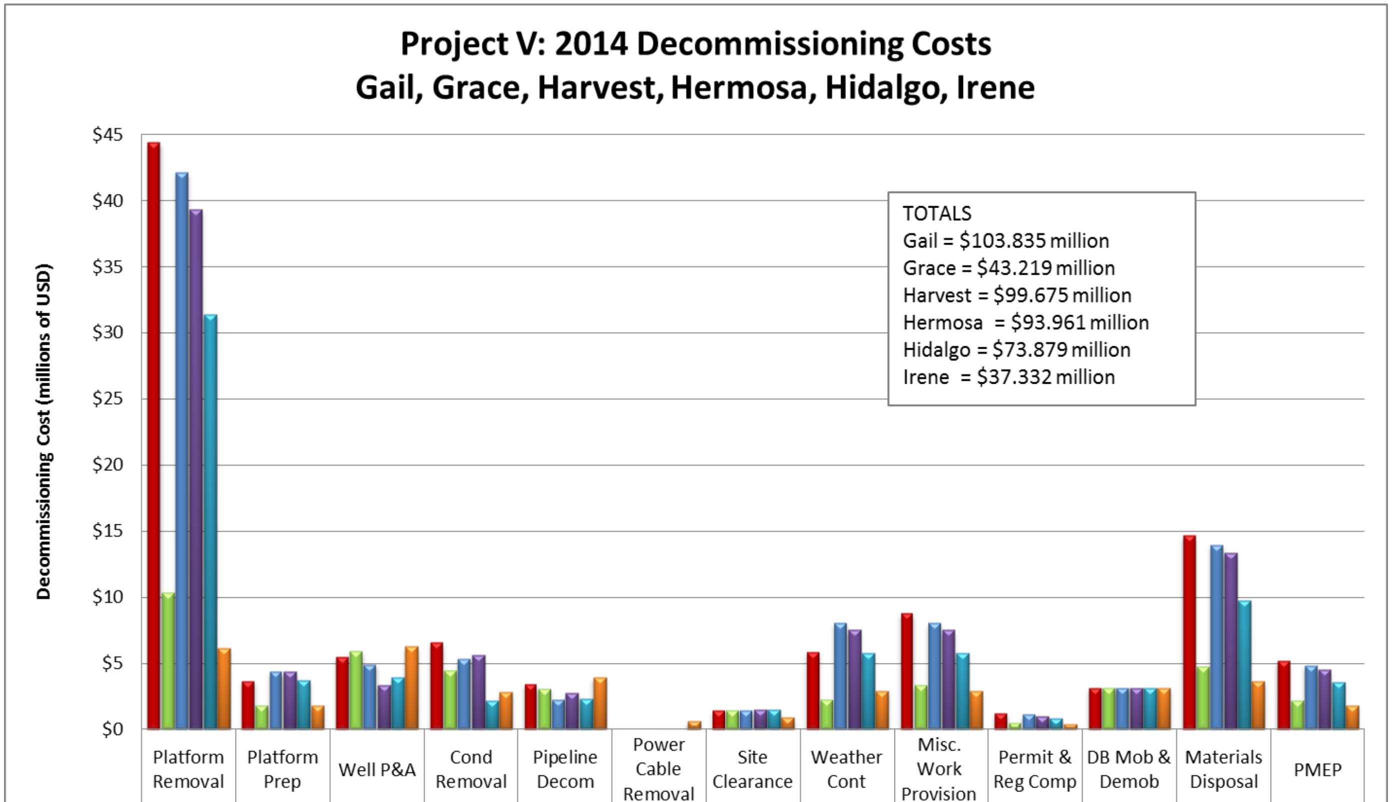
	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
A	$3.377	$1.093	$7.861	$4.461	$3.819	$0.181	$0.884	$2.044	$3.066	$1.181	$3.762	$2.706	$1.734
B	$3.377	$1.093	$8.591	$4.568	$0.864	$0.181	$0.884	$1.890	$2.835	$1.070	$3.762	$1.798	$1.565
C	$3.447	$1.093	$5.839	$3.127	$0.528	$0.954	$0.884	$1.523	$2.284	$0.892	$3.762	$1.917	$1.270
Henry	$2.913	$1.445	$3.678	$1.965	$0.496	$0.576	$0.884	$1.133	$1.699	$0.651	$3.762	$1.484	$0.957
Hillhouse	$3.566	$1.474	$7.160	$4.170	$0.705	$0.712	$0.884	$1.802	$2.703	$1.026	$3.762	$1.866	$1.494

Figure A.7-4 Project III: 2014 Decommissioning Costs A, B, C, Henry, Hillhouse



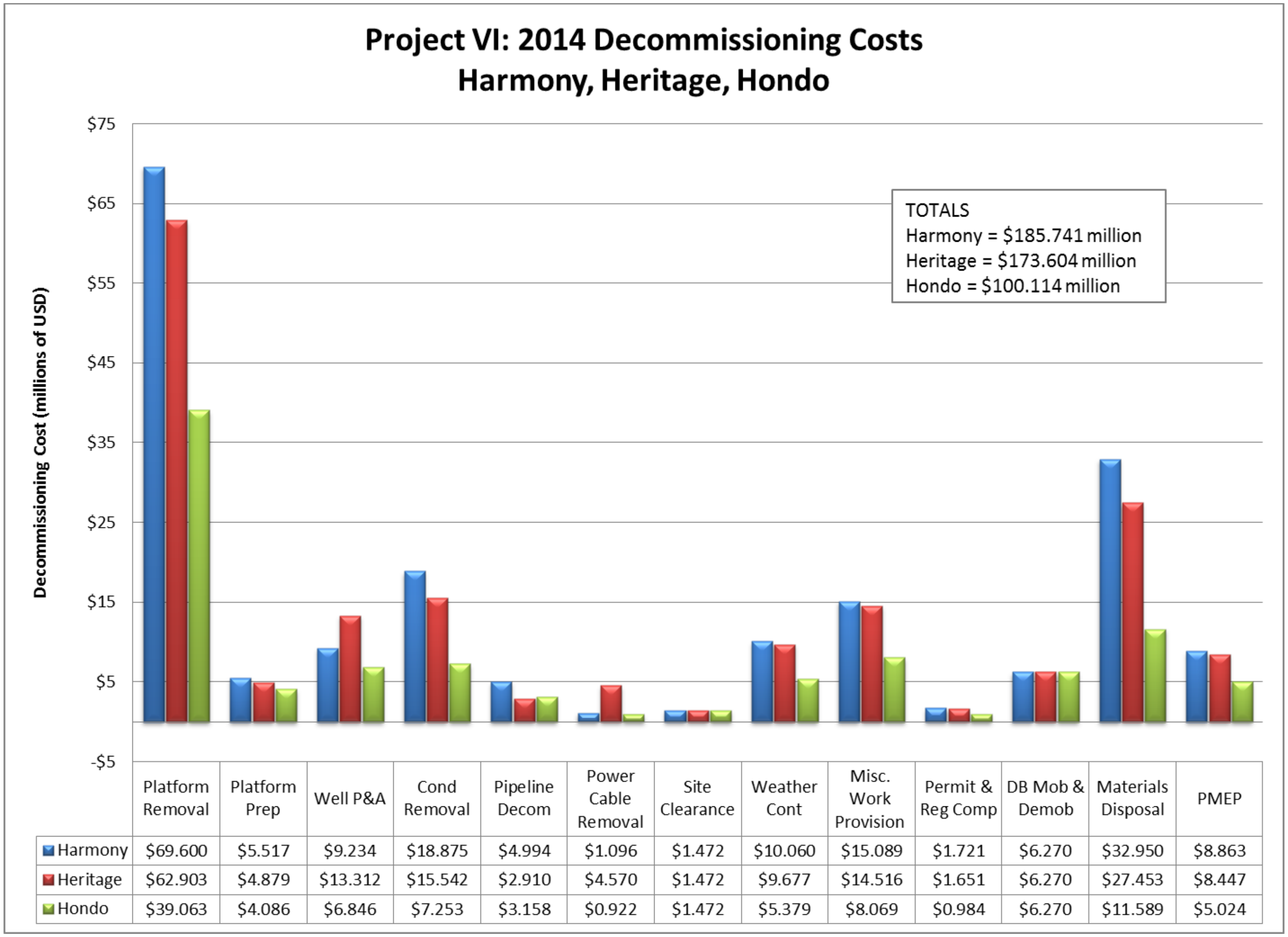
	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
Gina	$1.675	$0.864	$2.196	$0.819	$0.485	$0.244	$0.884	$0.665	$0.998	$0.510	$6.270	$0.528	$0.573
Gilda	$5.794	$2.096	$11.271	$5.338	$9.095	$1.268	$0.884	$2.896	$4.343	$2.566	$6.270	$4.489	$2.860
Habitat	$5.734	$1.950	$3.791	$2.404	$2.506	$0.769	$0.884	$1.484	$2.225	$1.281	$6.270	$3.793	$1.443

Figure A.7-5 Project IV: 2014 Decommissioning Costs Gina, Gilda, Habitat



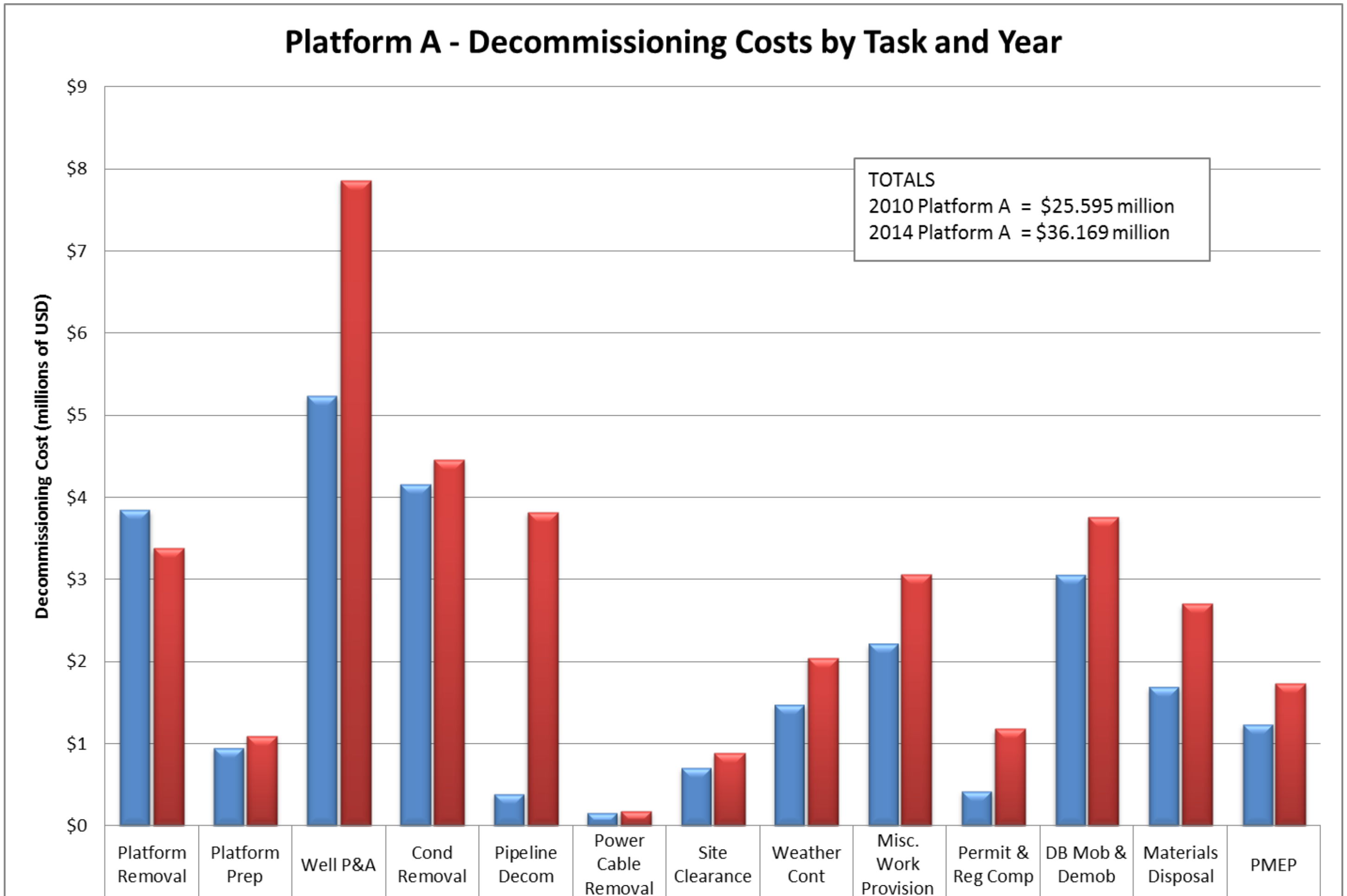
	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
Gail	$44.377	$3.670	$5.487	$6.567	$3.441	$0.000	$1.472	$5.858	$8.786	$1.191	$3.135	$14.651	$5.201
Grace	$10.363	$1.827	$5.935	$4.466	$3.090	$0.000	$1.472	$2.212	$3.318	$0.494	$3.135	$4.734	$2.172
Harvest	$42.101	$4.373	$4.933	$5.319	$2.241	$0.000	$1.472	$8.091	$8.091	$1.115	$3.135	$13.968	$4.835
Hermosa	$39.297	$4.373	$3.379	$5.606	$2.763	$0.000	$1.472	$7.521	$7.521	$1.004	$3.135	$13.338	$4.551
Hidalgo	$31.410	$3.708	$3.917	$2.189	$2.286	$0.000	$1.472	$5.790	$5.790	$0.828	$3.135	$9.757	$3.599
Irene	$6.177	$1.827	$6.289	$2.807	$3.951	$0.656	$0.884	$2.872	$2.872	$0.414	$3.135	$3.640	$1.807

Figure A.7-6 Project V: 2014 Decommissioning Costs Gail, Grace, Harvest, Hermosa, Hidalgo, Irene



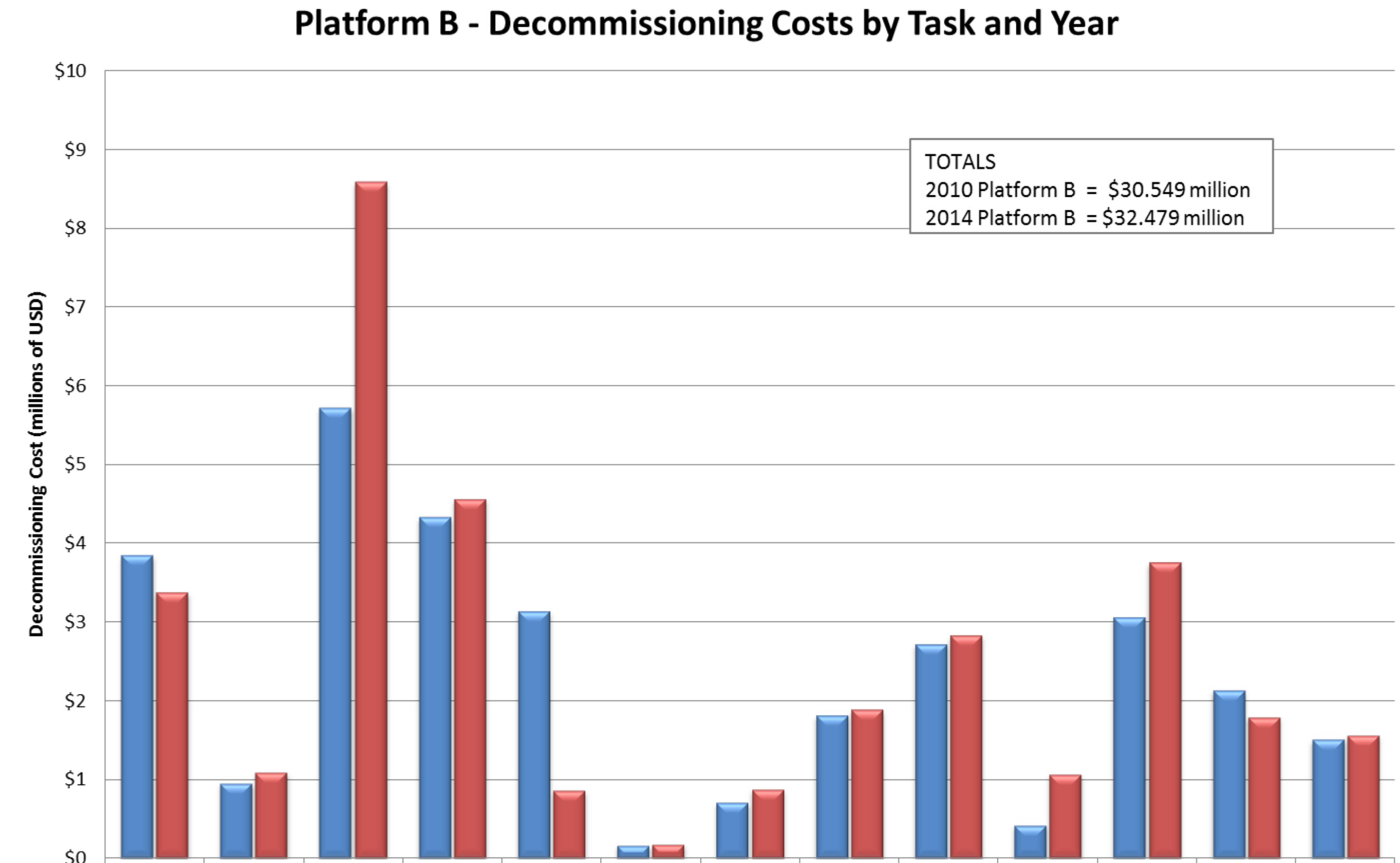
	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
Harmony	$69.600	$5.517	$9.234	$18.875	$4.994	$1.096	$1.472	$10.060	$15.089	$1.721	$6.270	$32.950	$8.863
Heritage	$62.903	$4.879	$13.312	$15.542	$2.910	$4.570	$1.472	$9.677	$14.516	$1.651	$6.270	$27.453	$8.447
Hondo	$39.063	$4.086	$6.846	$7.253	$3.158	$0.922	$1.472	$5.379	$8.069	$0.984	$6.270	$11.589	$5.024

Figure A.7-7 Project VI: 2014 Decommissioning Costs Harmony, Heritage, Hondo



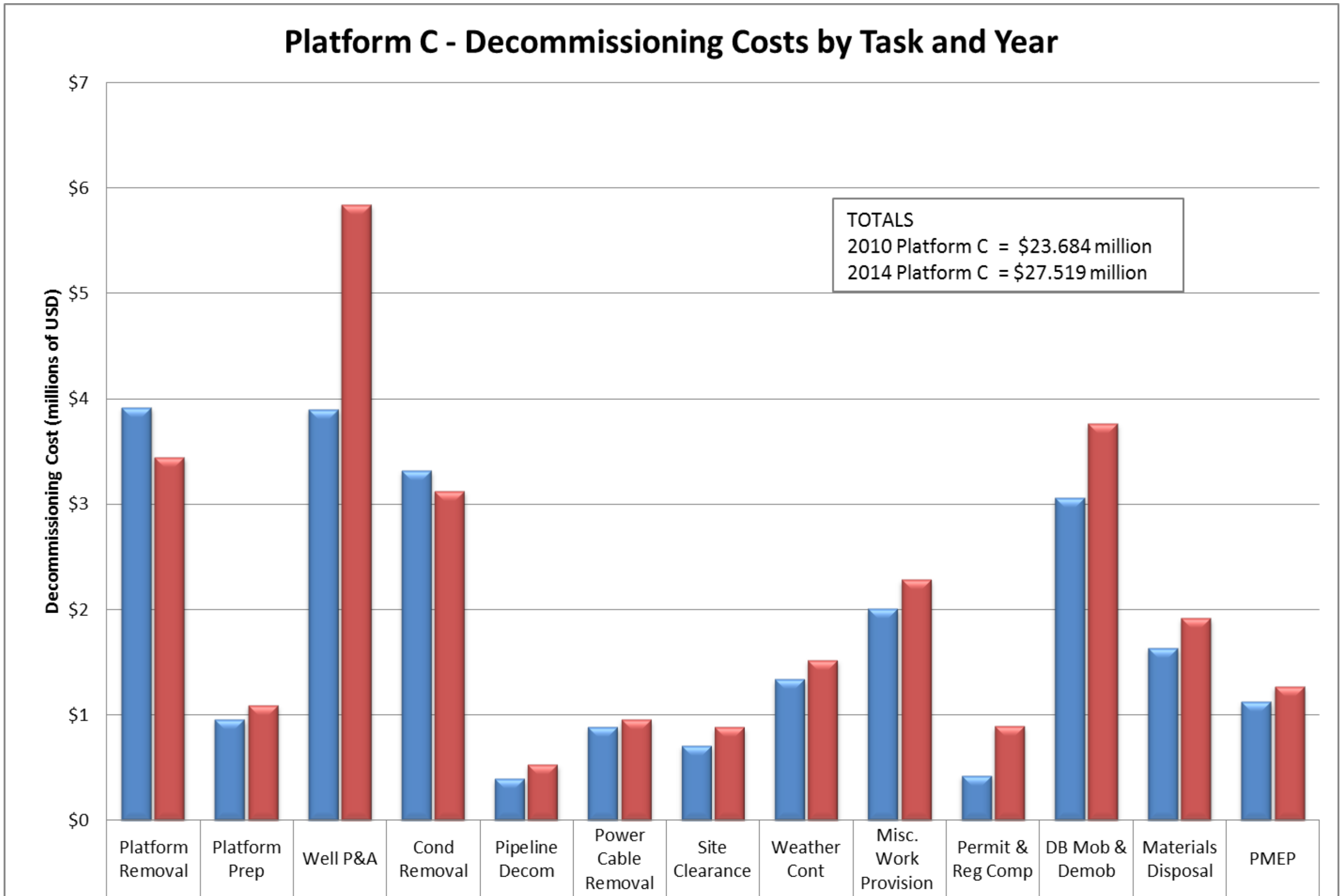
	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
2010	$3.848	$0.958	$5.239	$4.157	$0.398	$0.169	$0.709	$1.480	$2.220	$0.426	$3.060	$1.694	$1.238
2014	$3.377	$1.093	$7.861	$4.461	$3.819	$0.181	$0.884	$2.044	$3.066	$1.181	$3.762	$2.706	$1.734

Figure A.7-8 Platform A Decommissioning Costs by Task and Year



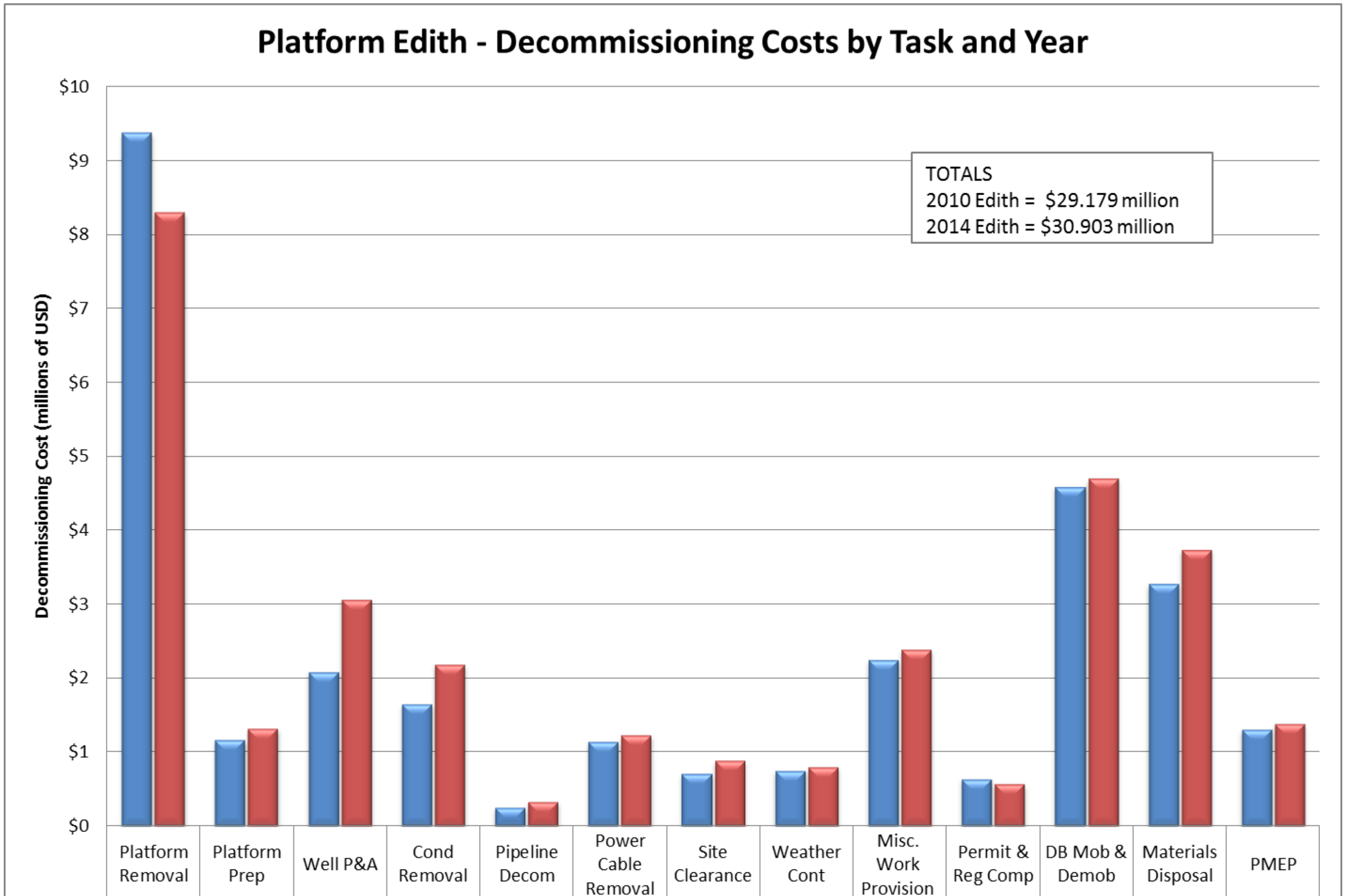
	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
2010	$3.848	$0.958	$5.725	$4.330	$3.139	$0.169	$0.709	$1.816	$2.724	$0.426	$3.060	$2.138	$1.510
2014	$3.377	$1.093	$8.591	$4.568	$0.864	$0.181	$0.884	$1.890	$2.835	$1.070	$3.762	$1.798	$1.565

Figure A.7-9 Platform B Decommissioning Costs by Task and Year



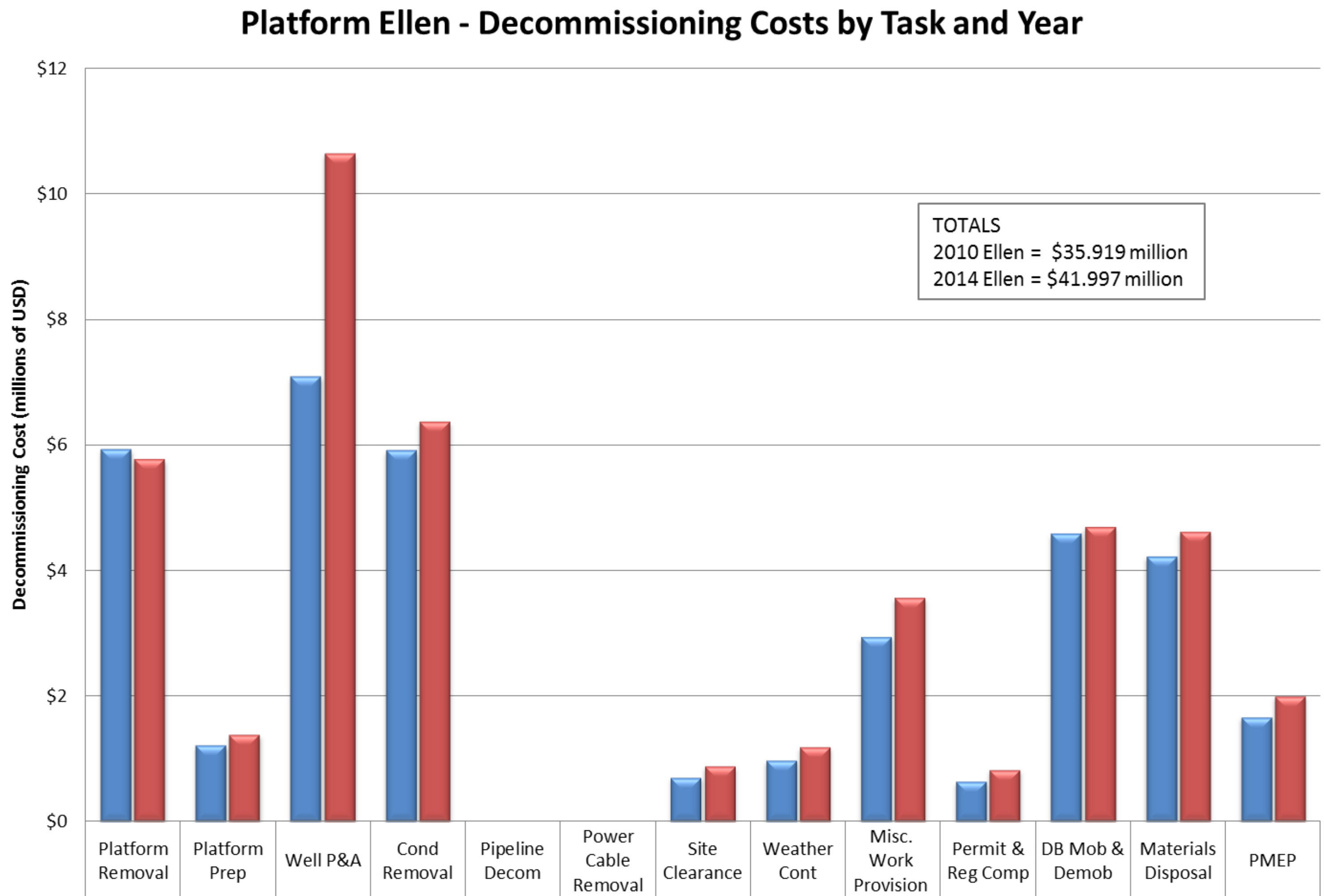
	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
2010	$3.917	$0.958	$3.900	$3.317	$0.394	$0.889	$0.709	$1.340	$2.011	$0.426	$3.060	$1.637	$1.127
2014	$3.447	$1.093	$5.839	$3.127	$0.528	$0.954	$0.884	$1.523	$2.284	$0.892	$3.762	$1.917	$1.270

Figure A.7-10 Platform C Decommissioning Costs by Task and Year



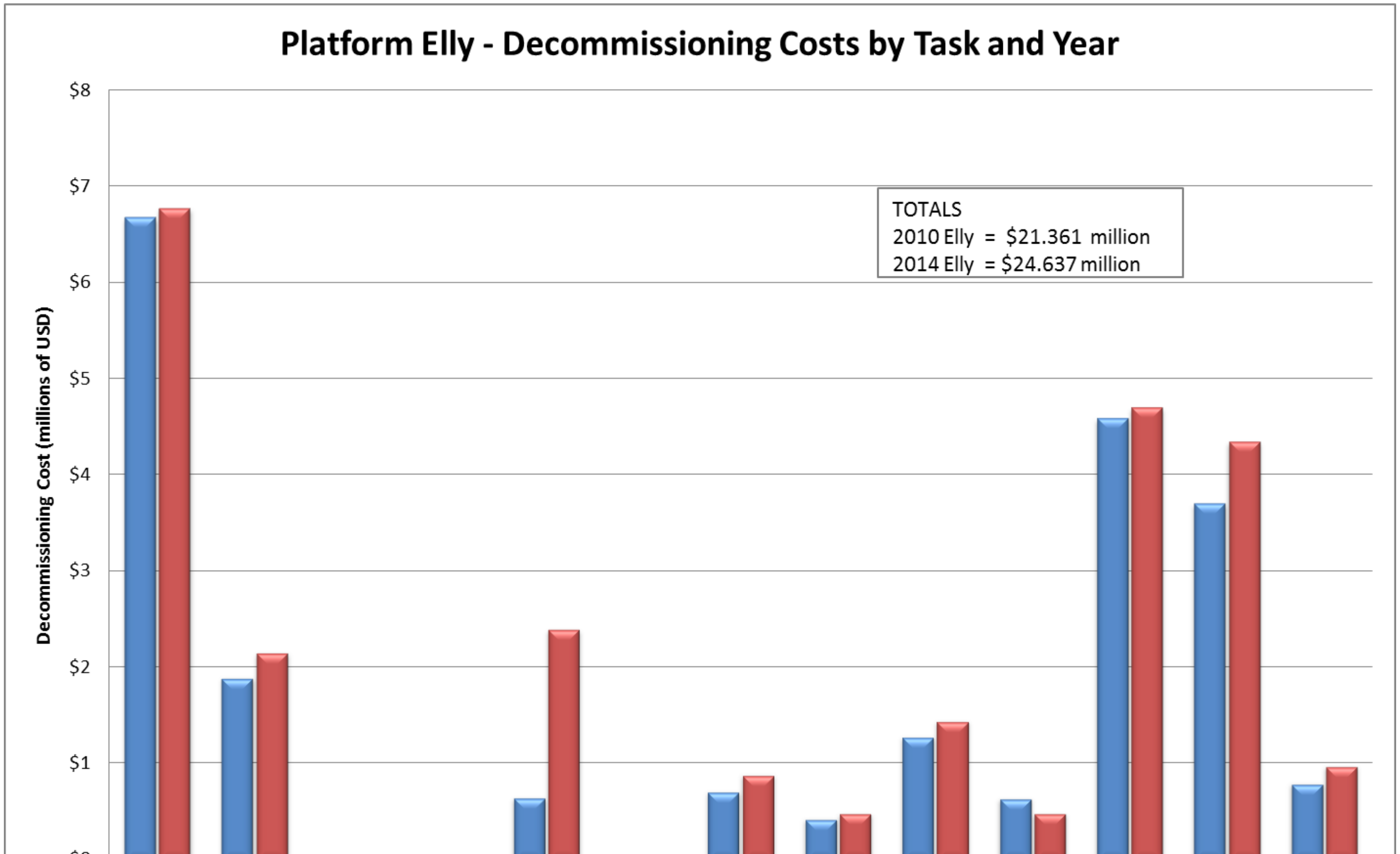
	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
2010	$9.372	$1.164	$2.087	$1.650	$0.247	$1.146	$0.709	$0.748	$2.244	$0.639	$4.590	$3.272	$1.310
2014	$8.303	$1.320	$3.067	$2.186	$0.332	$1.231	$0.884	$0.797	$2.391	$0.565	$4.703	$3.740	$1.386

Figure A.7-11 Platform Edith Decommissioning Costs by Task and Year



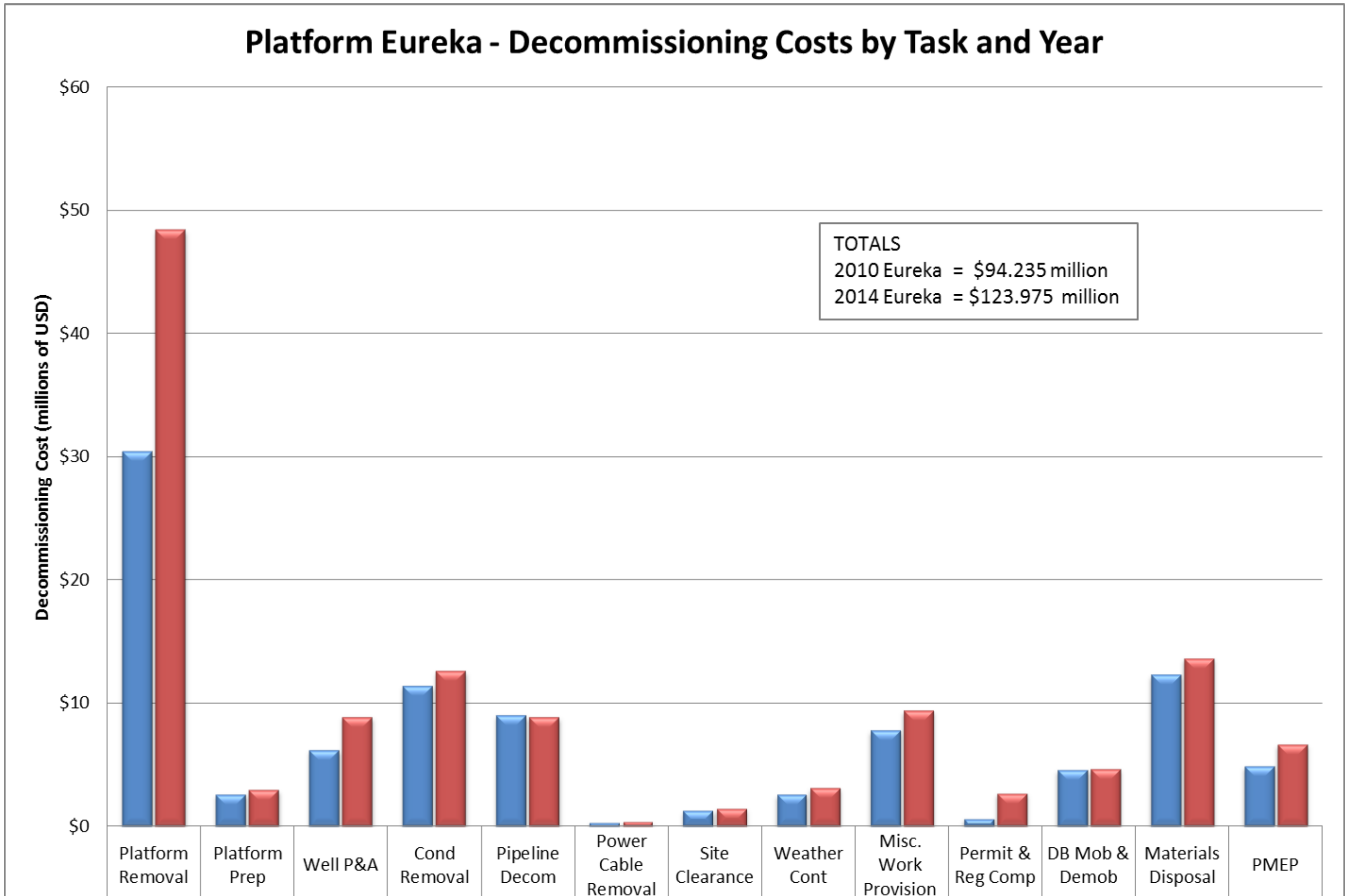
	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
2010	$5.938	$1.216	$7.095	$5.911	$0.000	$0.000	$0.709	$0.980	$2.941	$0.639	$4.590	$4.231	$1.670
2014	$5.773	$1.390	$10.650	$6.378	$0.000	$0.000	$0.884	$1.189	$3.568	$0.831	$4.703	$4.625	$2.006

Figure A.7-12 Platform Ellen Decommissioning Costs by Task and Year



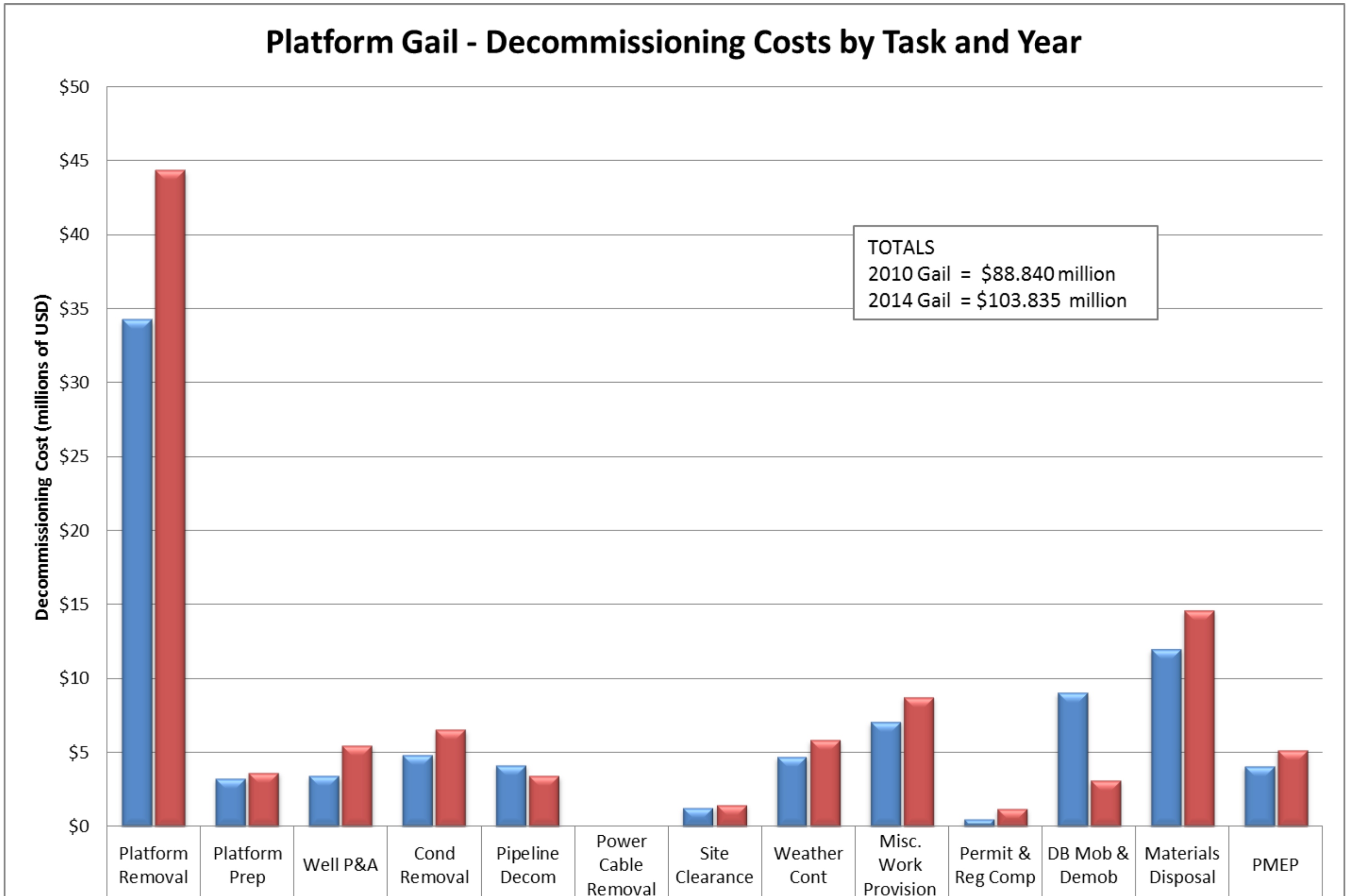
	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
2010	$6.682	$1.892	$0.000	$0.000	$0.645	$0.000	$0.709	$0.426	$1.279	$0.639	$4.590	$3.705	$0.794
2014	$6.774	$2.152	$0.000	$0.000	$2.393	$0.000	$0.884	$0.481	$1.444	$0.482	$4.703	$4.348	$0.976

Figure A.7-13 Platform Elly Decommissioning Costs by Task and Year



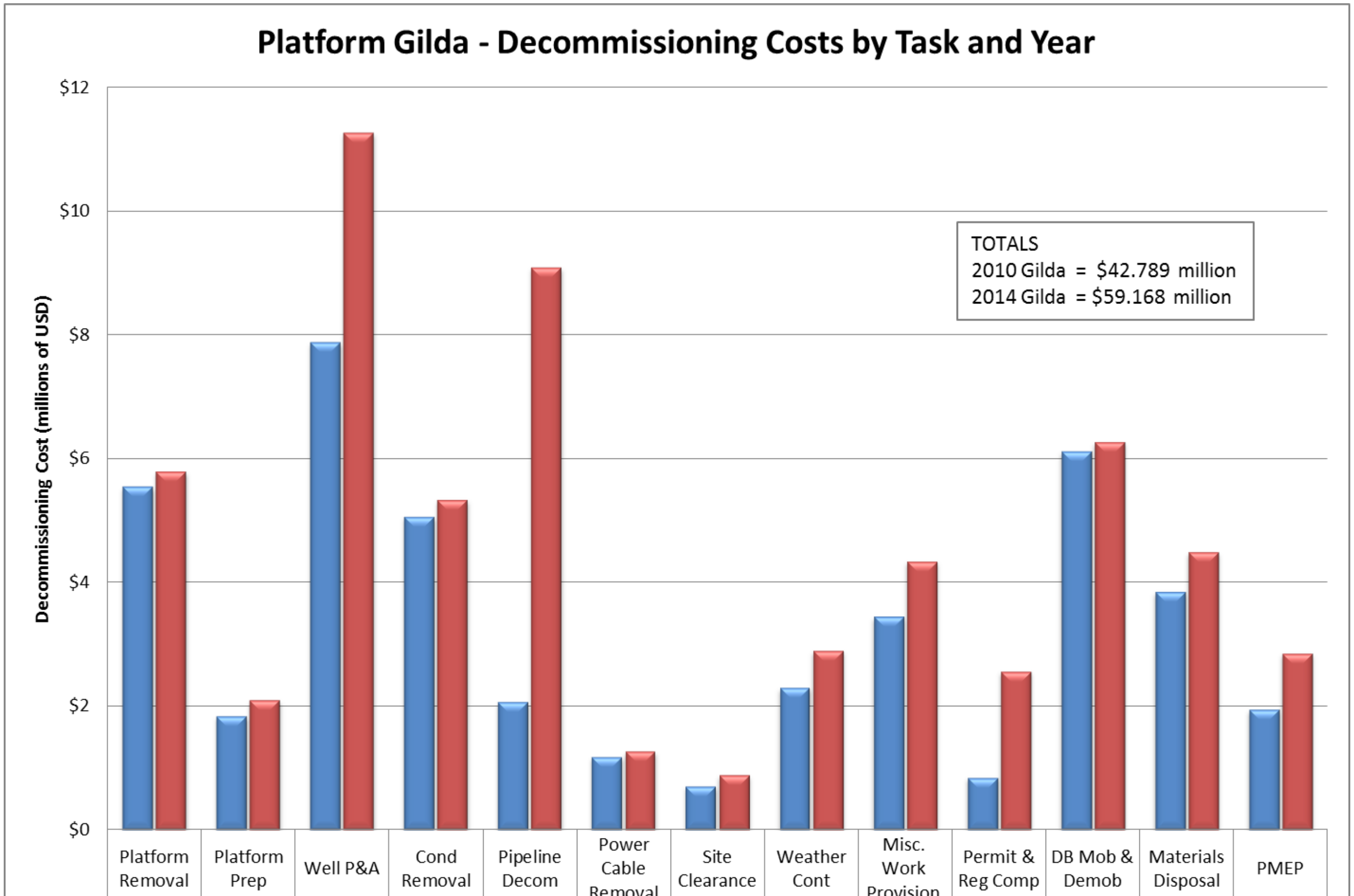
	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
2010	$30.426	$2.628	$6.209	$11.450	$9.044	$0.349	$1.282	$2.599	$7.797	$0.639	$4.590	$12.310	$4.911
2014	$48.421	$2.969	$8.907	$12.623	$8.877	$0.374	$1.472	$3.139	$9.418	$2.713	$4.703	$13.669	$6.691

Figure A.7-14 Platform Eureka Decommissioning Costs by Task and Year



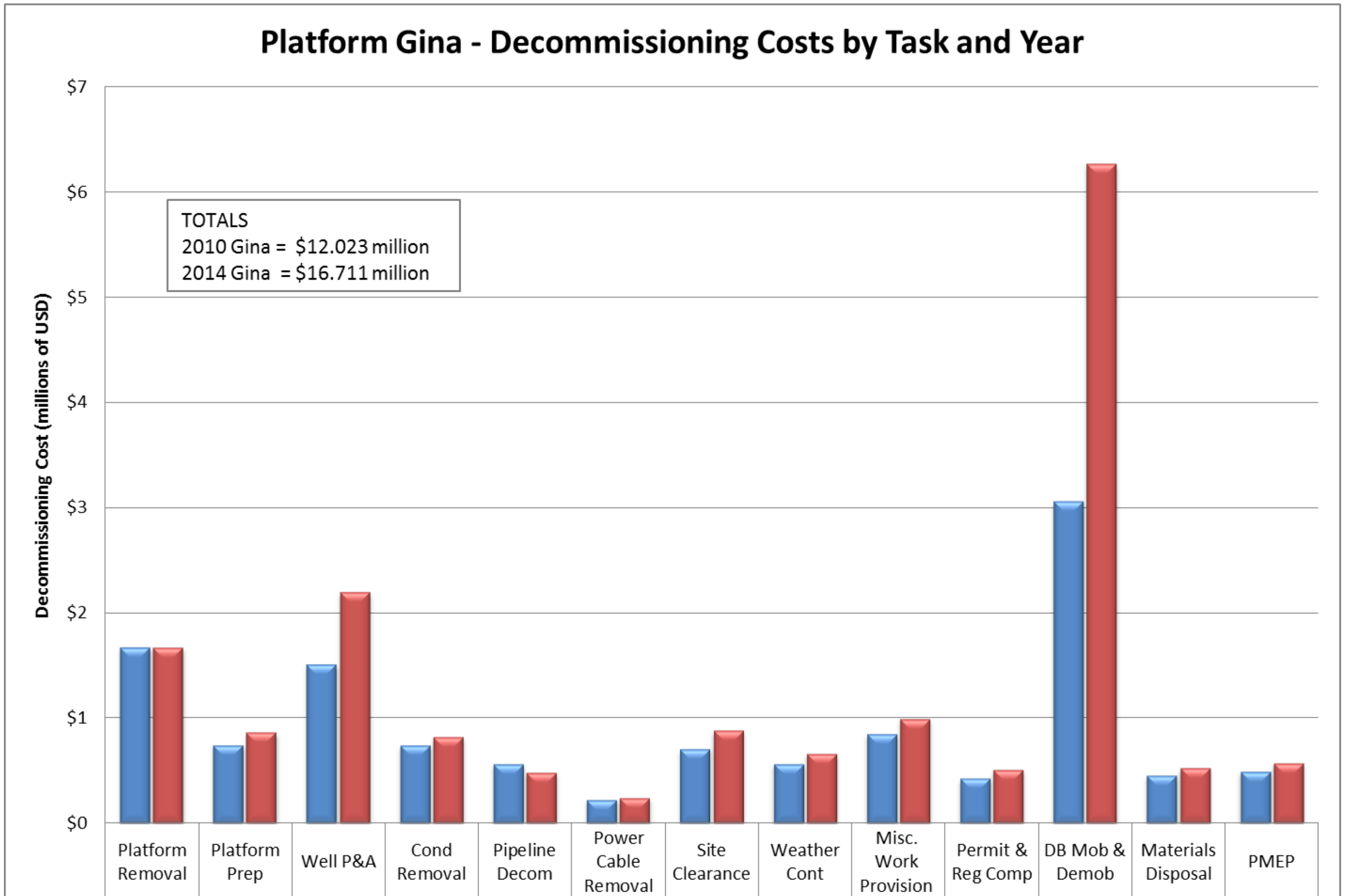
	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
2010	$34.281	$3.264	$3.437	$4.863	$4.175	$0.000	$1.282	$4.739	$7.109	$0.511	$9.072	$12.002	$4.104
2014	$44.377	$3.670	$5.487	$6.567	$3.441	$0.000	$1.472	$5.858	$8.786	$1.191	$3.135	$14.651	$5.201

Figure A.7-15 Platform Gail Decommissioning Costs by Task and Year



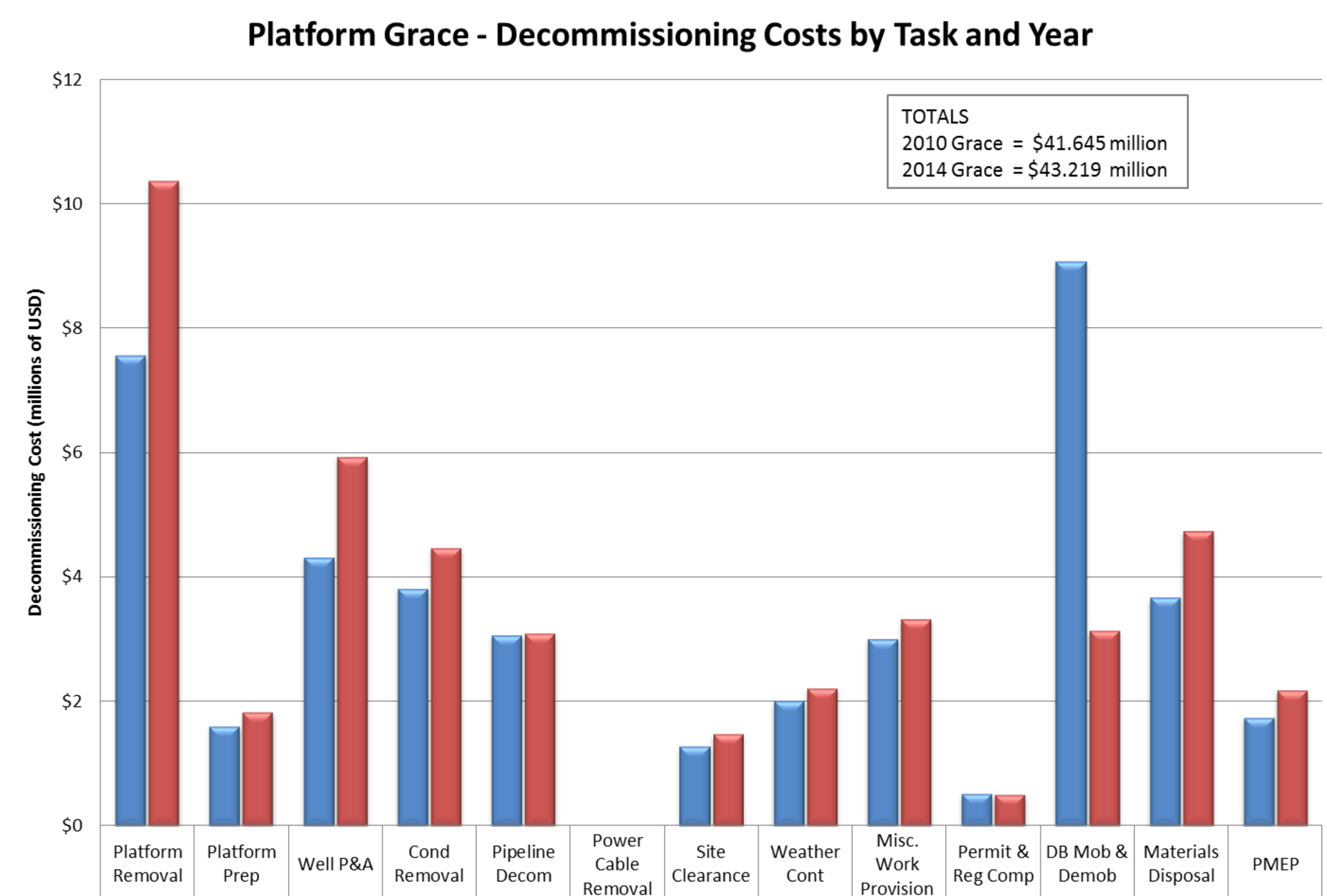
	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
2010	$5.545	$1.840	$7.880	$5.063	$2.067	$1.181	$0.709	$2.295	$3.443	$0.852	$6.120	$3.851	$1.943
2014	$5.794	$2.096	$11.271	$5.338	$9.095	$1.268	$0.884	$2.896	$4.343	$2.566	$6.270	$4.489	$2.860

Figure A.7-16 Platform Gilda Decommissioning Costs by Task and Year



	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
2010	$1.675	$0.746	$1.510	$0.739	$0.565	$0.228	$0.709	$0.567	$0.851	$0.426	$3.060	$0.453	$0.494
2014	$1.674	$0.864	$2.196	$0.819	$0.485	$0.244	$0.884	$0.665	$0.998	$0.510	$6.270	$0.528	$0.573

Figure A.7-17 Platform Gina Decommissioning Costs by Task and Year



	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
2010	$7.561	$1.606	$4.314	$3.812	$3.071	$0.000	$1.282	$2.005	$3.007	$0.511	$9.072	$3.672	$1.732
2014	$10.363	$1.827	$5.935	$4.466	$3.090	$0.000	$1.472	$2.212	$3.318	$0.494	$3.135	$4.734	$2.172

Figure A.7-18 Platform Grace Decommissioning Costs by Task and Year

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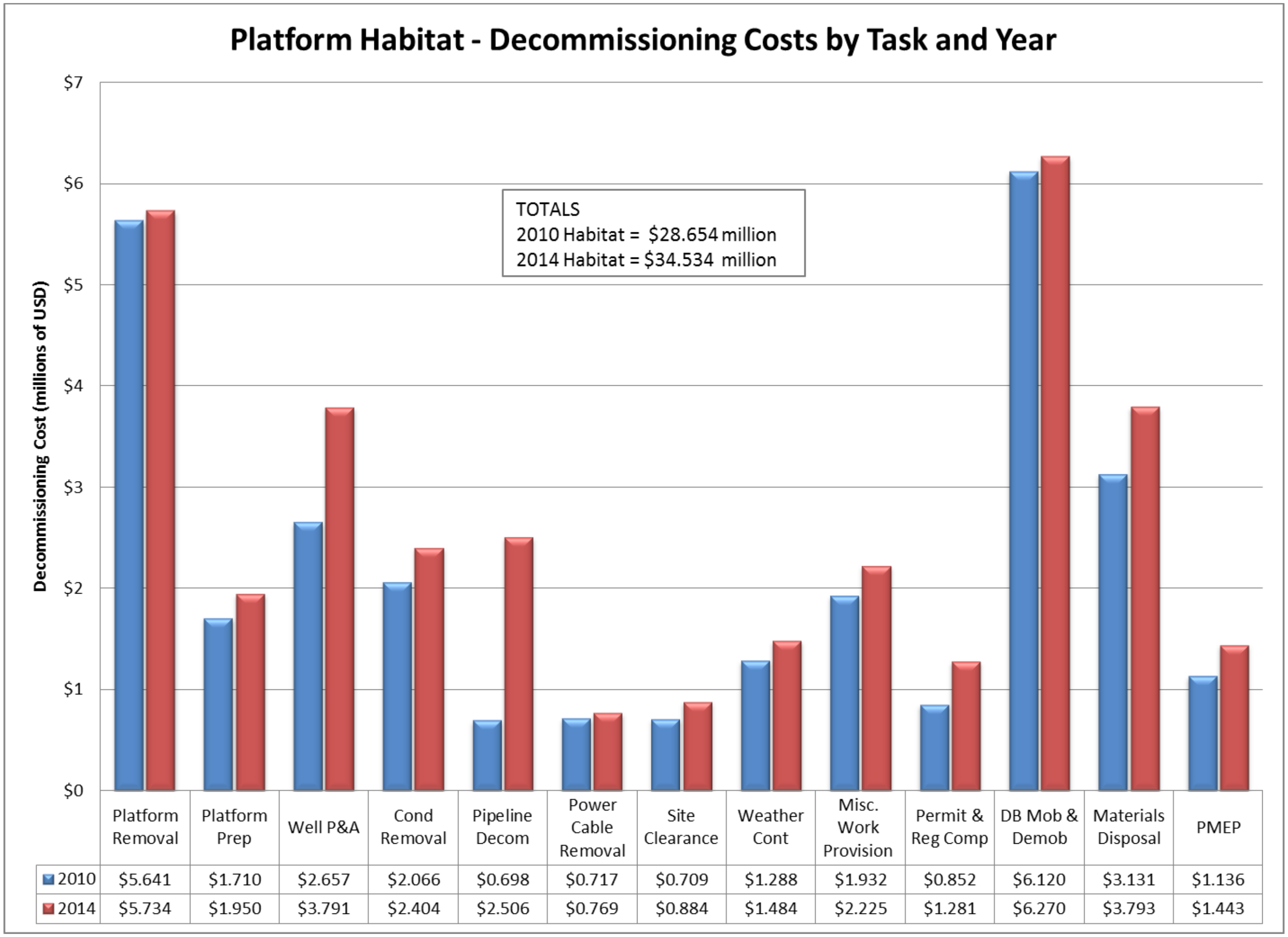
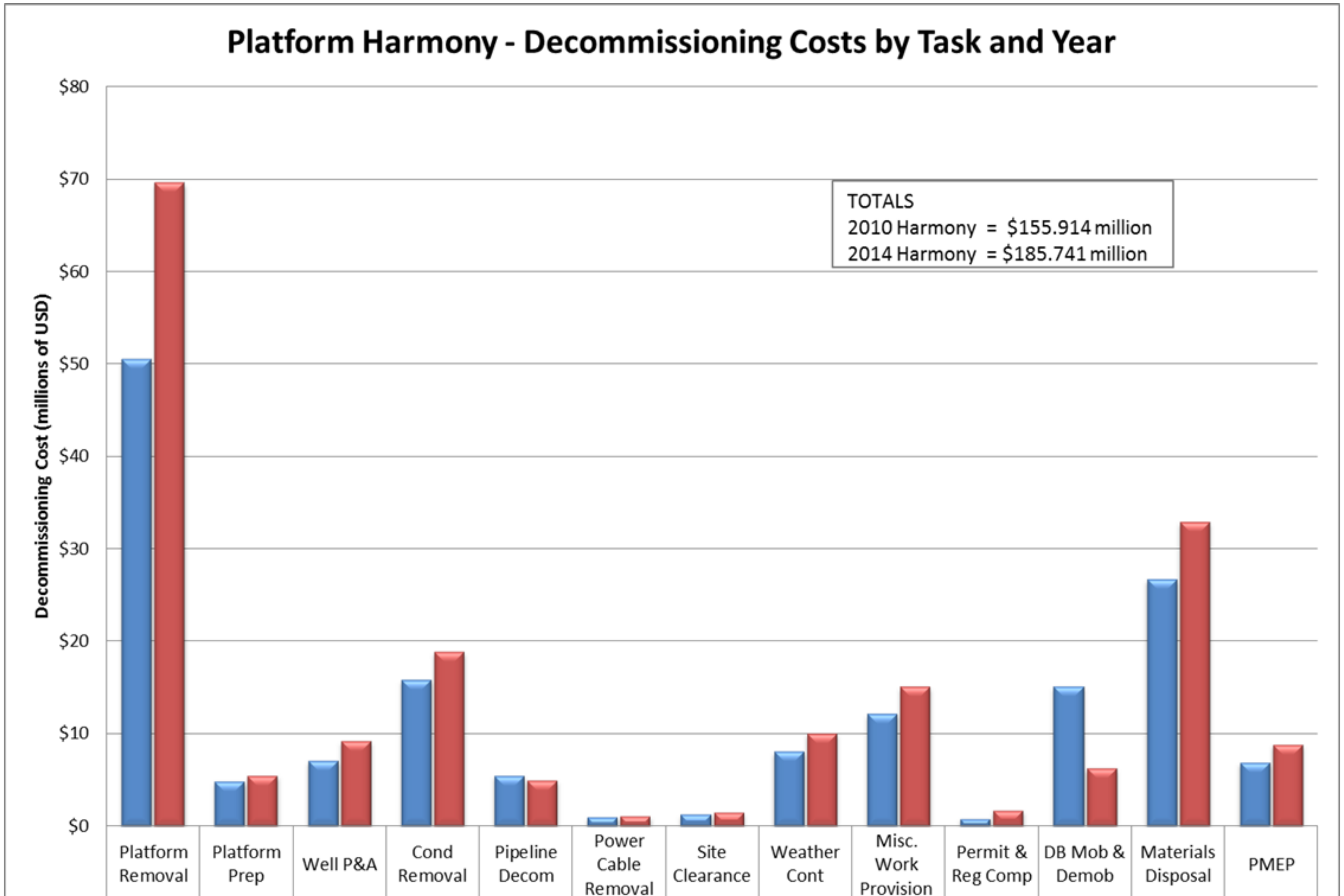


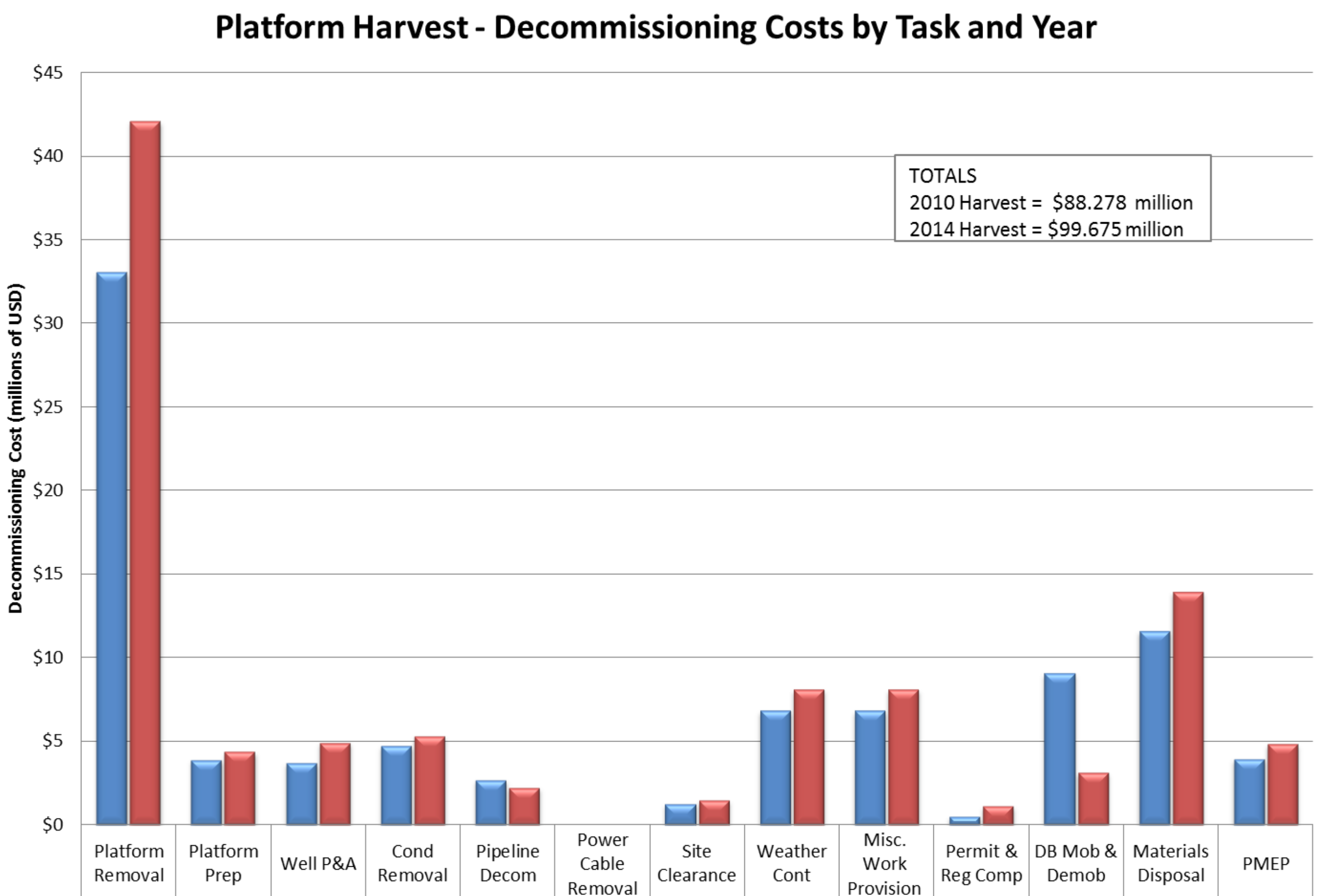
	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
2010	$5.641	$1.710	$2.657	$2.066	$0.698	$0.717	$0.709	$1.288	$1.932	$0.852	$6.120	$3.131	$1.136
2014	$5.734	$1.950	$3.791	$2.404	$2.506	$0.769	$0.884	$1.484	$2.225	$1.281	$6.270	$3.793	$1.443

Figure A.7-19 Platform Habitat Decommissioning Costs by Task and Year



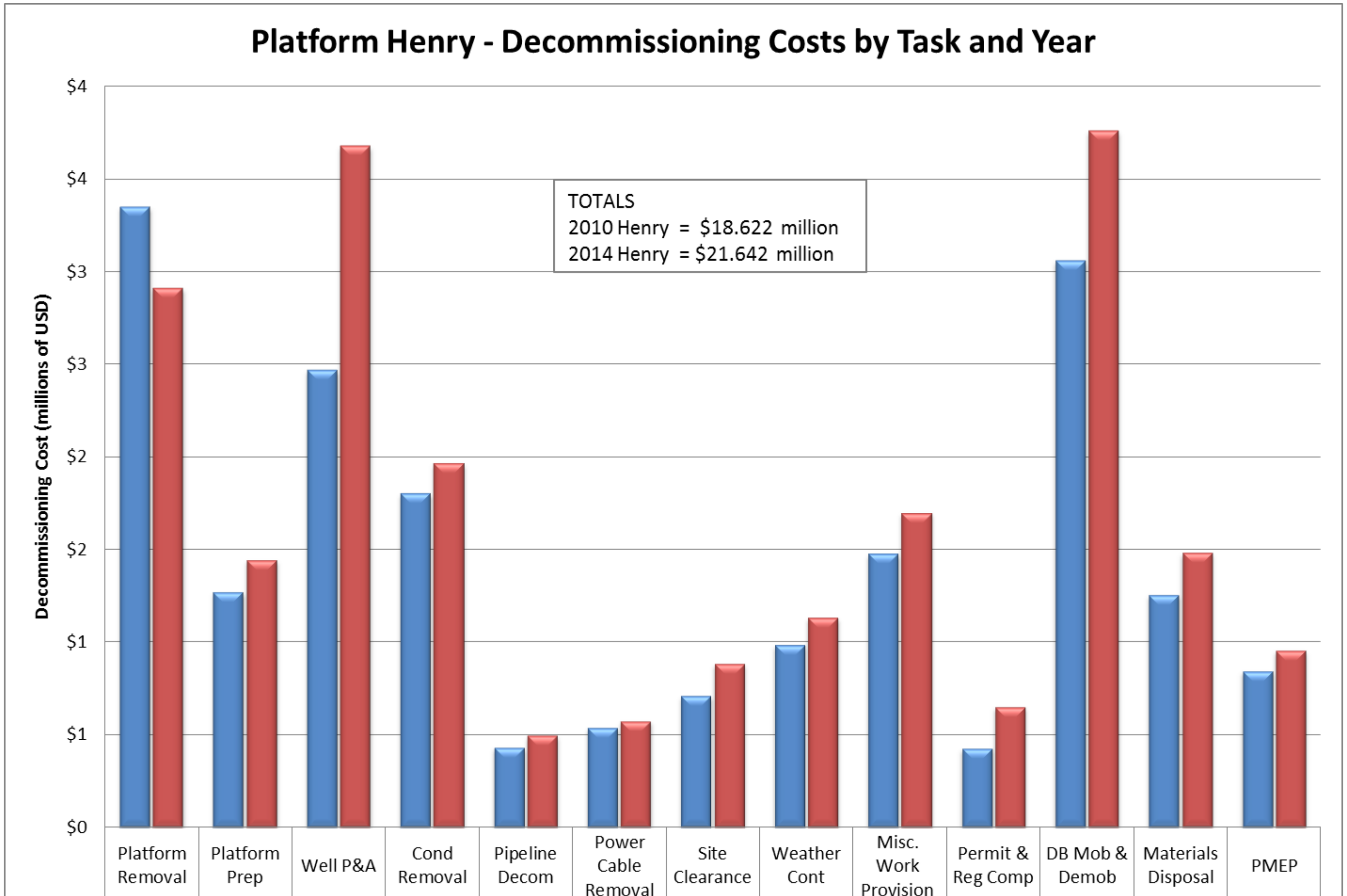
	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
2010	$50.482	$4.866	$7.069	$15.846	$5.515	$1.021	$1.282	$8.096	$12.144	$0.852	$15.120	$26.735	$6.886
2014	$69.600	$5.517	$9.234	$18.875	$4.994	$1.096	$1.472	$10.060	$15.089	$1.721	$6.270	$32.950	$8.863

Figure A.7-20 Platform Harmony Decommissioning Costs by Task and Year



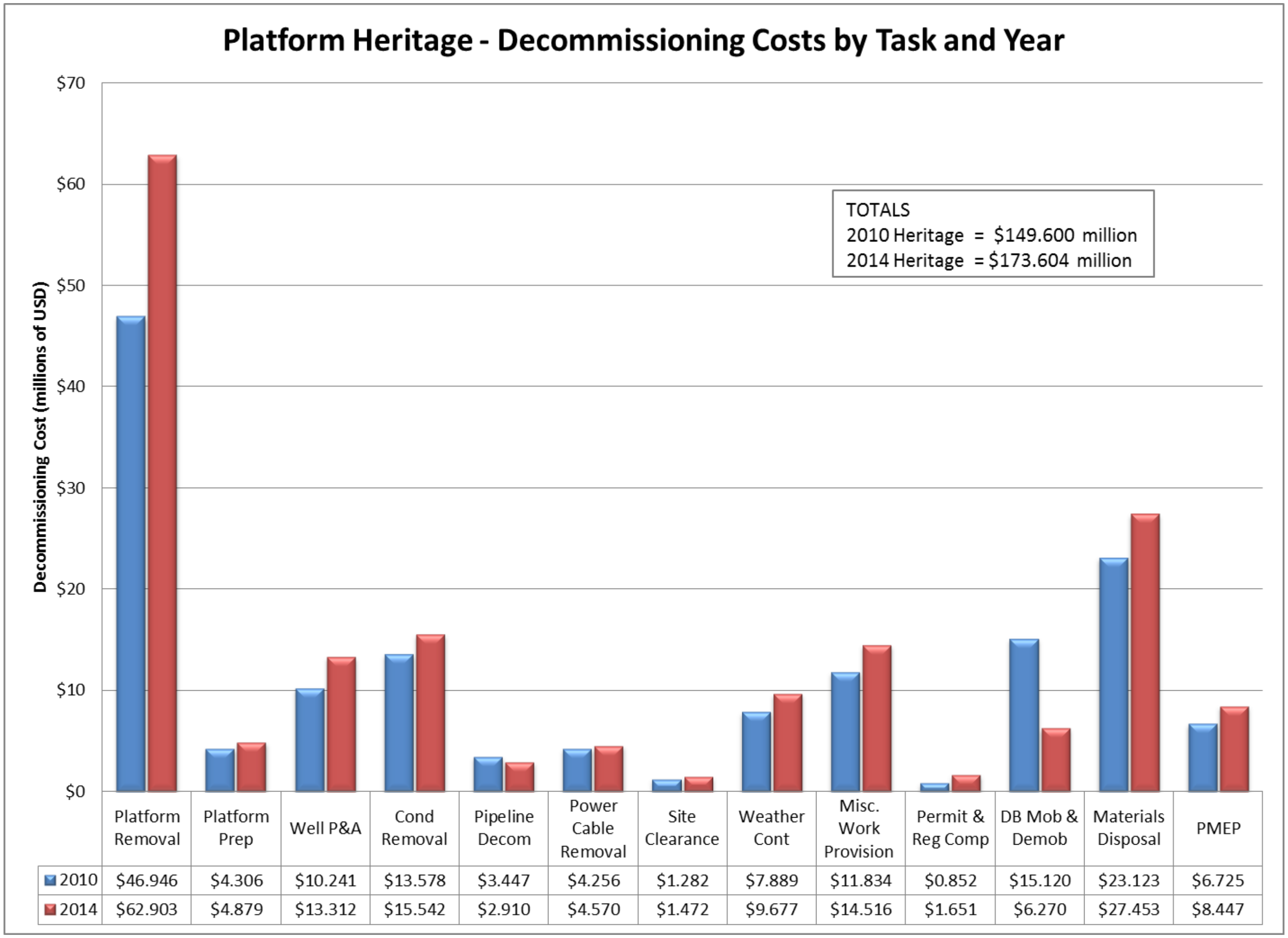
	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
2010	$33.076	$3.900	$3.729	$4.752	$2.708	$0.000	$1.282	$6.838	$6.838	$0.511	$9.072	$11.617	$3.956
2014	$42.101	$4.373	$4.933	$5.319	$2.241	$0.000	$1.472	$8.091	$8.091	$1.115	$3.135	$13.968	$4.835

Figure A.7-21 Platform Harvest Decommissioning Costs by Task and Year



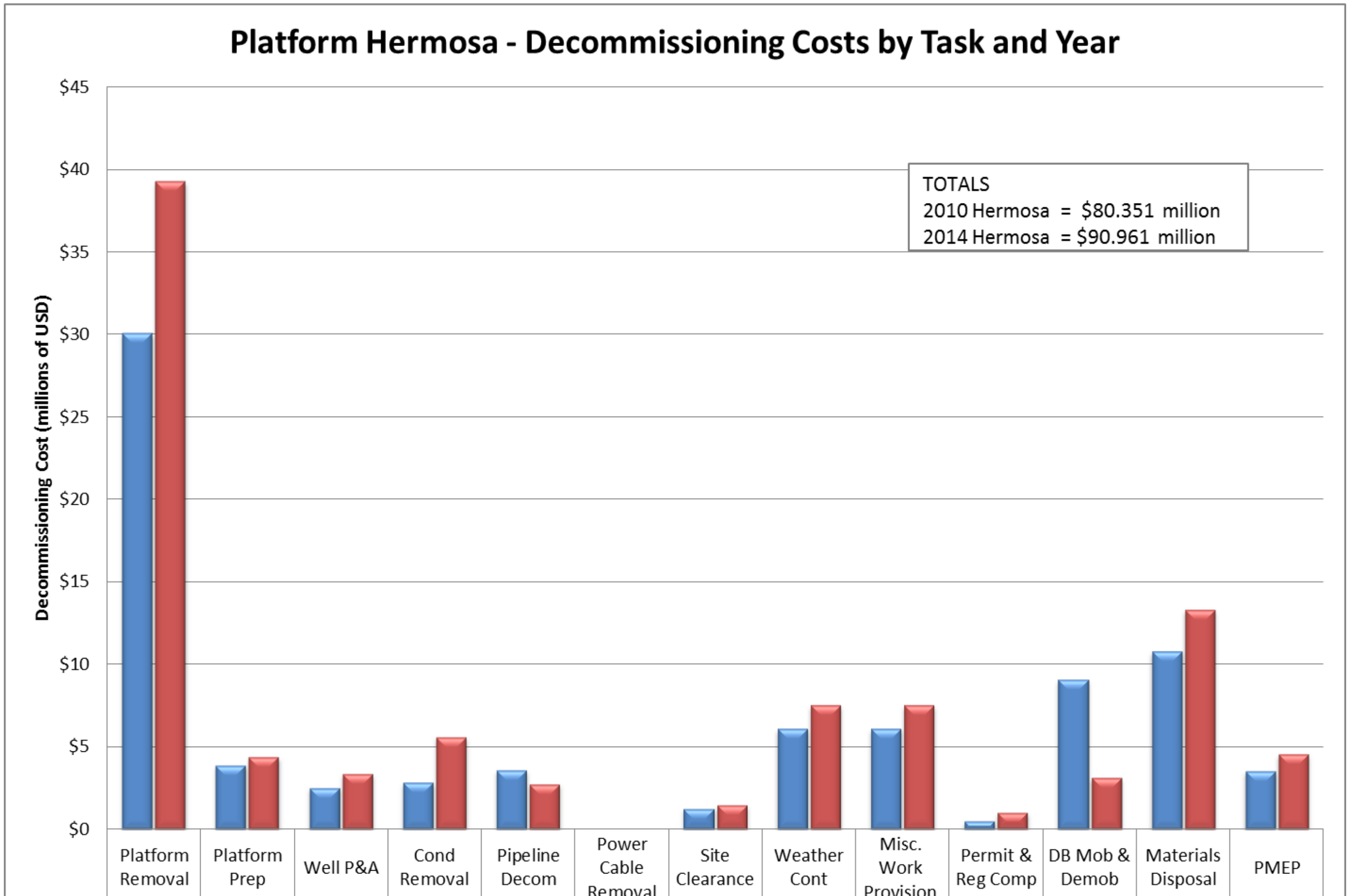
	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
2010	$3.352	$1.270	$2.470	$1.804	$0.432	$0.537	$0.709	$0.985	$1.477	$0.426	$3.060	$1.255	$0.846
2014	$2.913	$1.445	$3.678	$1.965	$0.496	$0.576	$0.884	$1.133	$1.699	$0.651	$3.762	$1.484	$0.957

Figure A.7-22 Platform Henry Decommissioning Costs by Task and Year



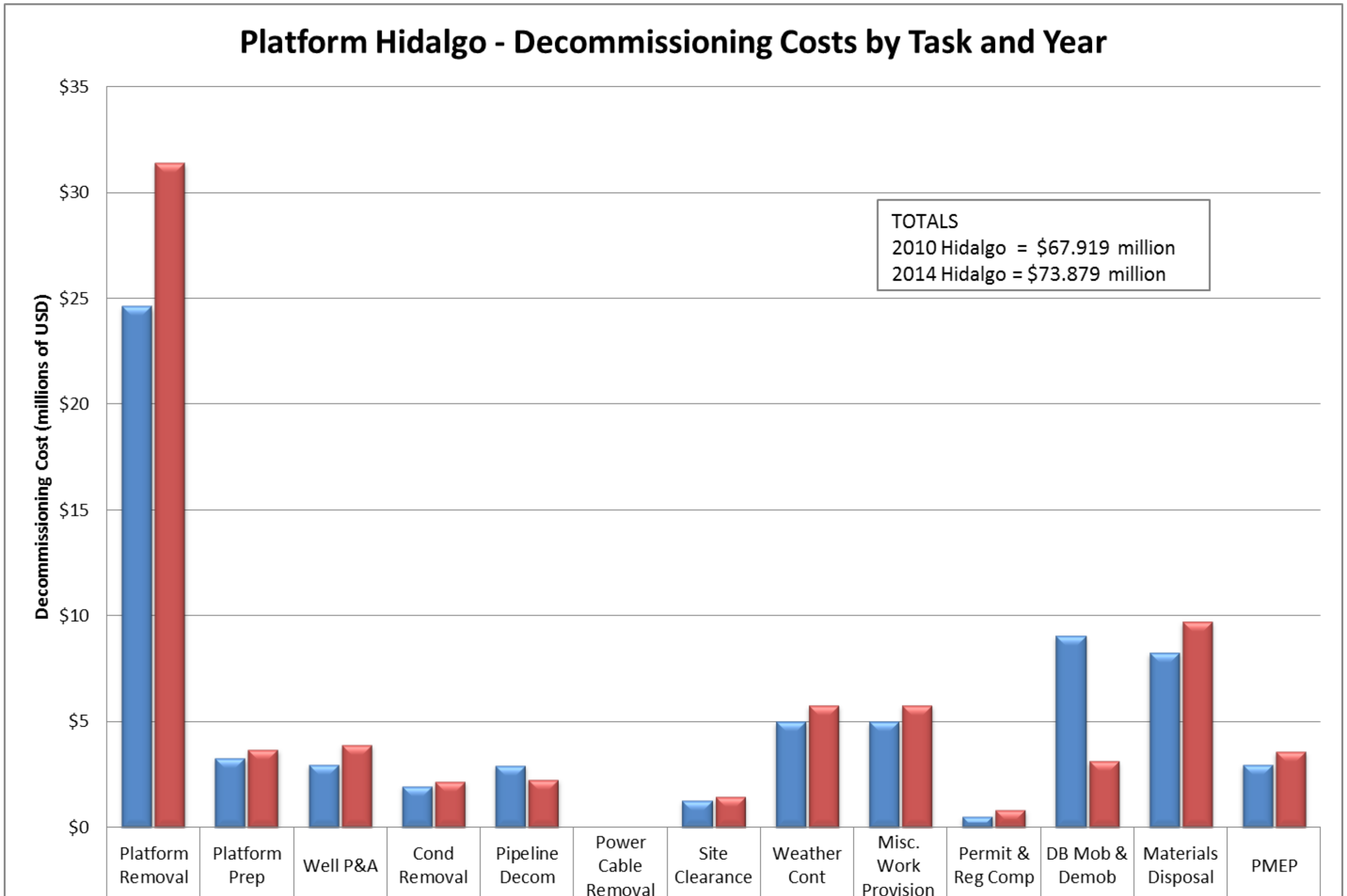
	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
2010	$46.946	$4.306	$10.241	$13.578	$3.447	$4.256	$1.282	$7.889	$11.834	$0.852	$15.120	$23.123	$6.725
2014	$62.903	$4.879	$13.312	$15.542	$2.910	$4.570	$1.472	$9.677	$14.516	$1.651	$6.270	$27.453	$8.447

Figure A.7-23 Platform Hertiage Decommissioning Costs by Task and Year



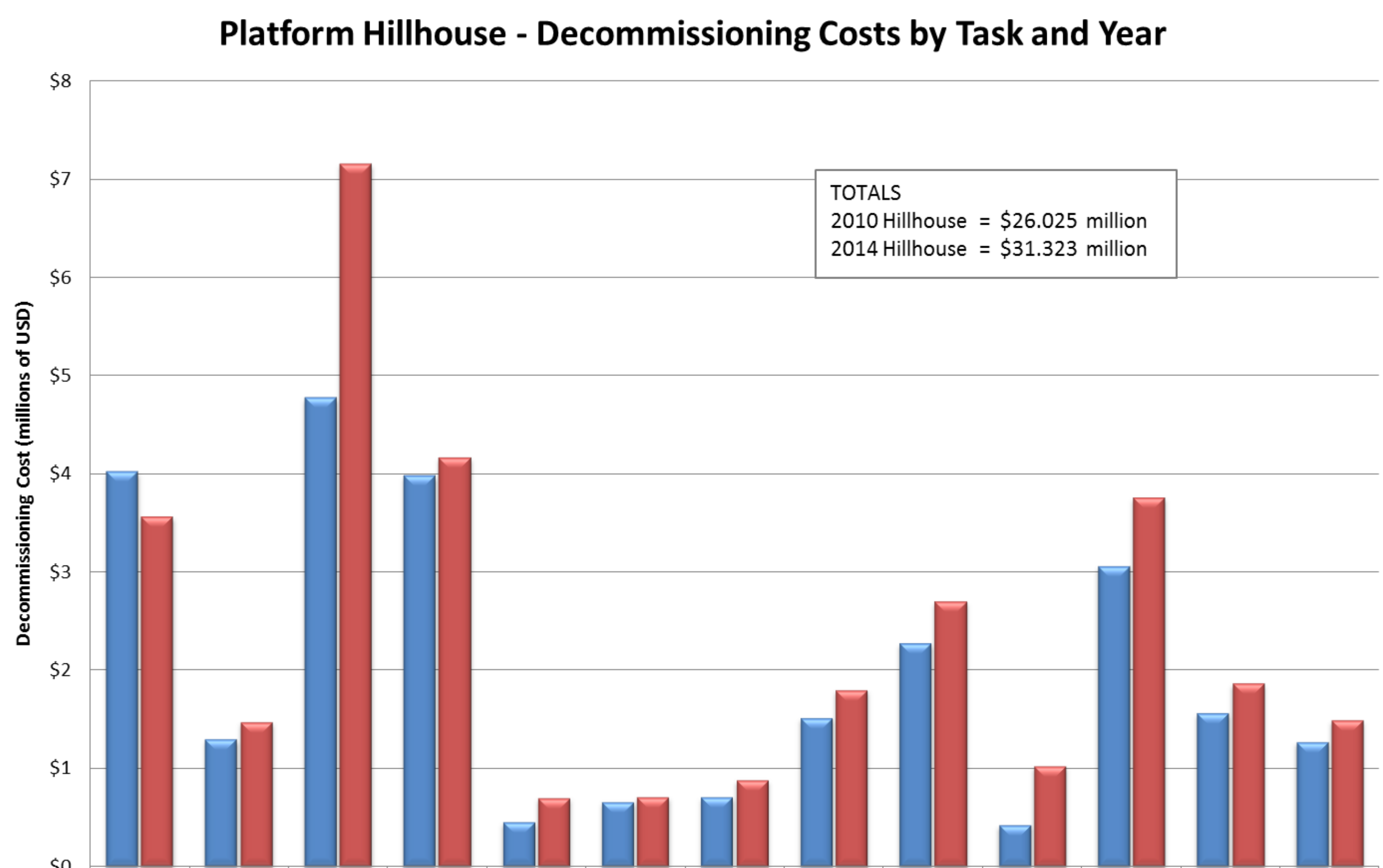
	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
2010	$30.083	$3.900	$2.540	$2.840	$3.597	$0.000	$1.282	$6.099	$6.099	$0.511	$9.072	$10.788	$3.539
2014	$39.297	$4.373	$3.379	$5.606	$2.763	$0.000	$1.472	$7.521	$7.521	$1.004	$3.135	$13.338	$4.551

Figure A.7-24 Platform Hermosa Decommissioning Costs by Task and Year



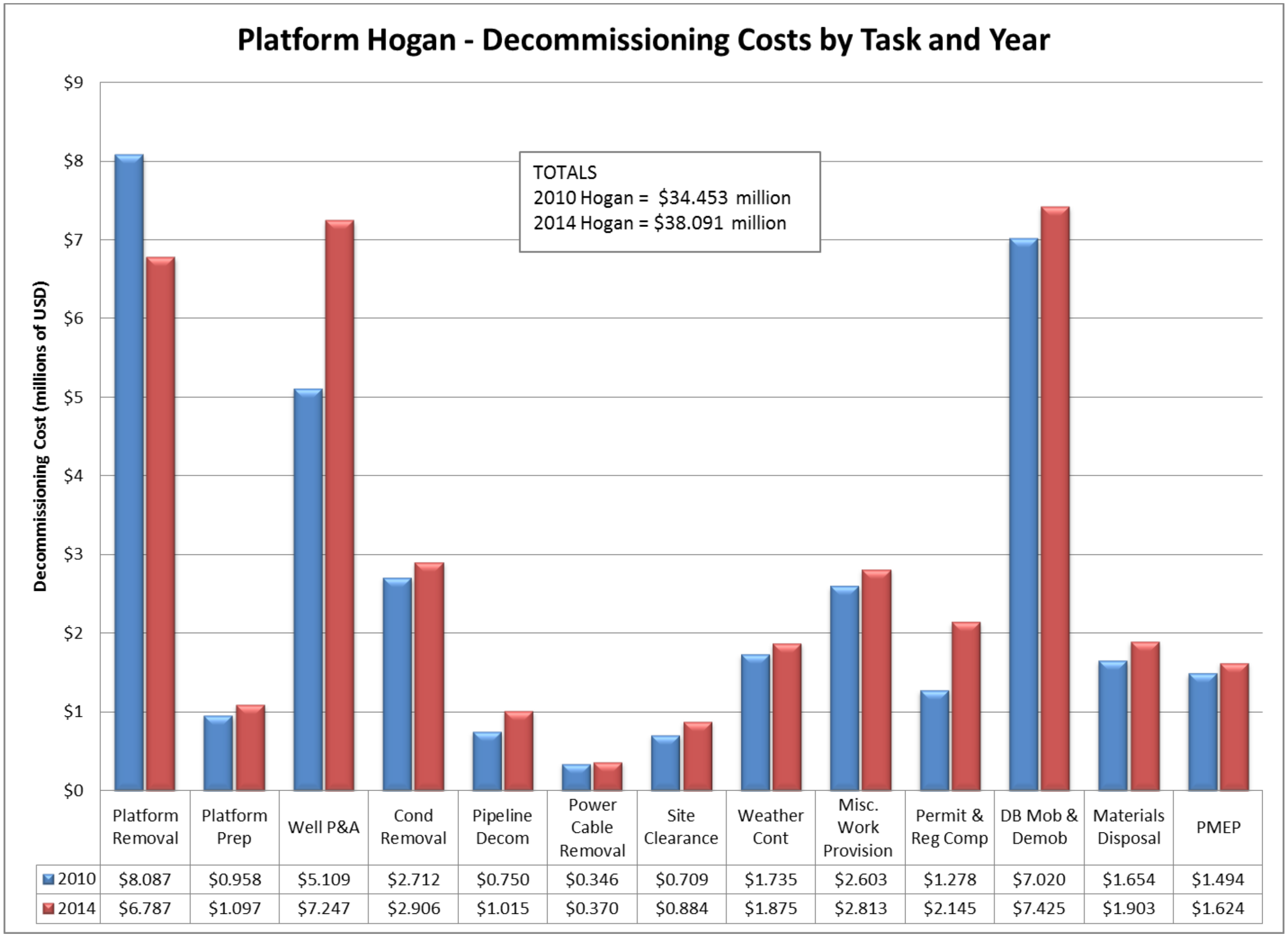
	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
2010	$24.622	$3.302	$2.983	$1.958	$2.954	$0.000	$1.282	$5.004	$5.004	$0.511	$9.072	$8.259	$2.968
2014	$31.410	$3.708	$3.917	$2.189	$2.286	$0.000	$1.472	$5.790	$5.790	$0.828	$3.135	$9.757	$3.599

Figure A.7-25 Platform Hidalgo Decommissioning Costs by Task and Year



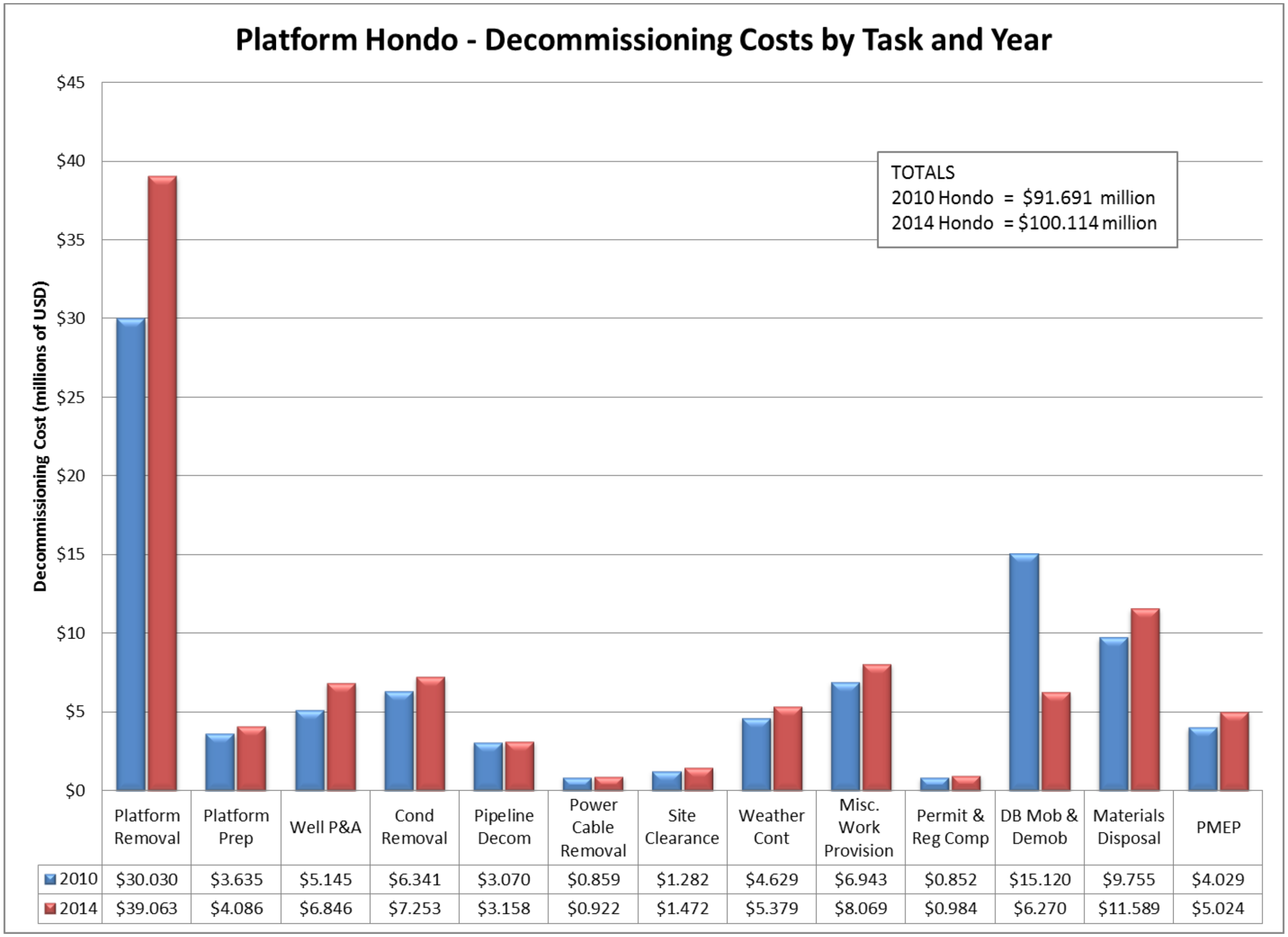
	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
2010	$4.021	$1.296	$4.779	$3.985	$0.456	$0.664	$0.709	$1.517	$2.276	$0.426	$3.060	$1.563	$1.273
2014	$3.566	$1.474	$7.160	$4.170	$0.705	$0.712	$0.884	$1.802	$2.703	$1.026	$3.762	$1.866	$1.494

Figure A.7-26 Platform Hillhouse Decommissioning Costs by Task and Year



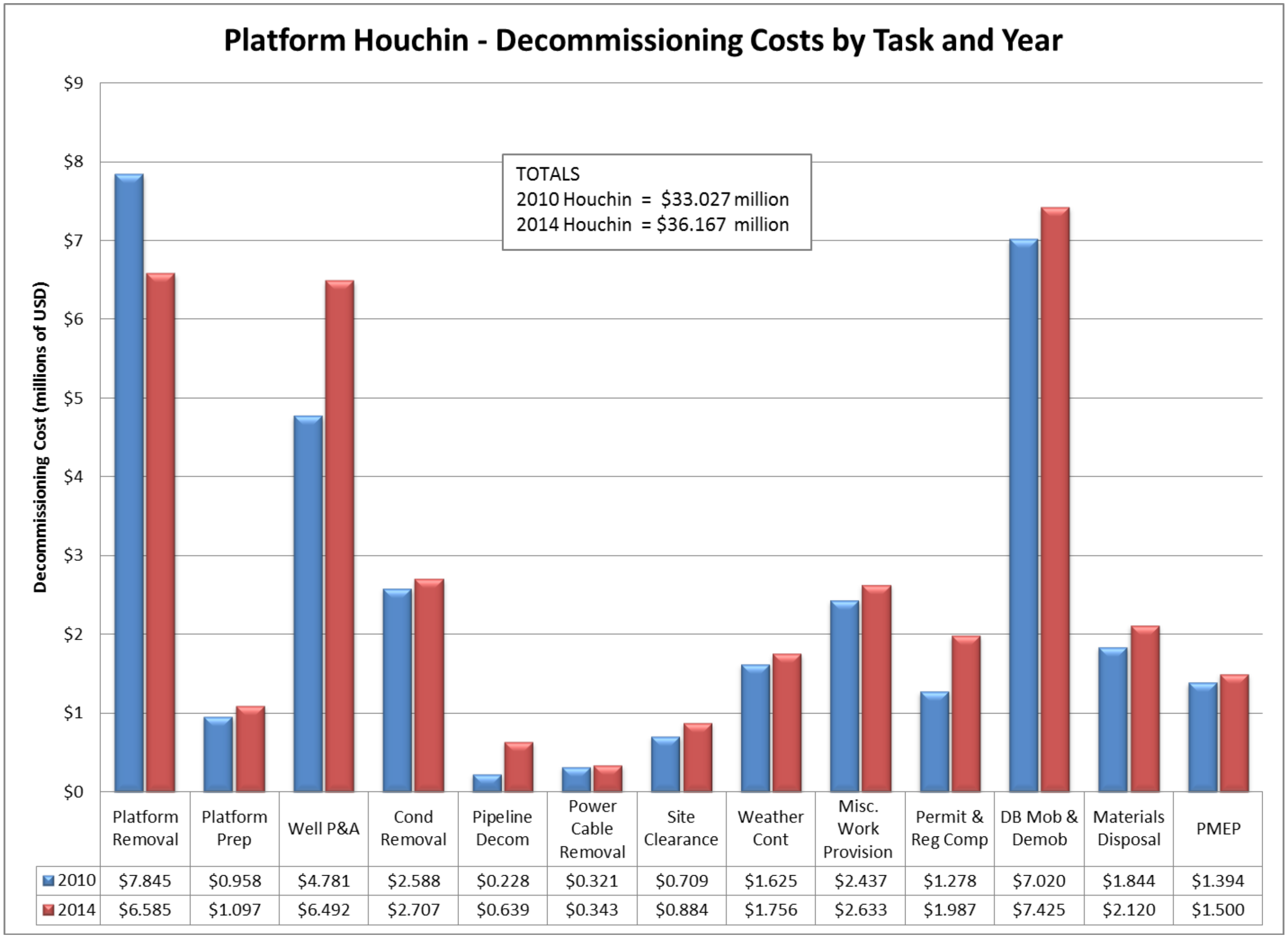
	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
2010	$8.087	$0.958	$5.109	$2.712	$0.750	$0.346	$0.709	$1.735	$2.603	$1.278	$7.020	$1.654	$1.494
2014	$6.787	$1.097	$7.247	$2.906	$1.015	$0.370	$0.884	$1.875	$2.813	$2.145	$7.425	$1.903	$1.624

Figure A.7-27 Platform Hogan Decommissioning Costs by Task and Year



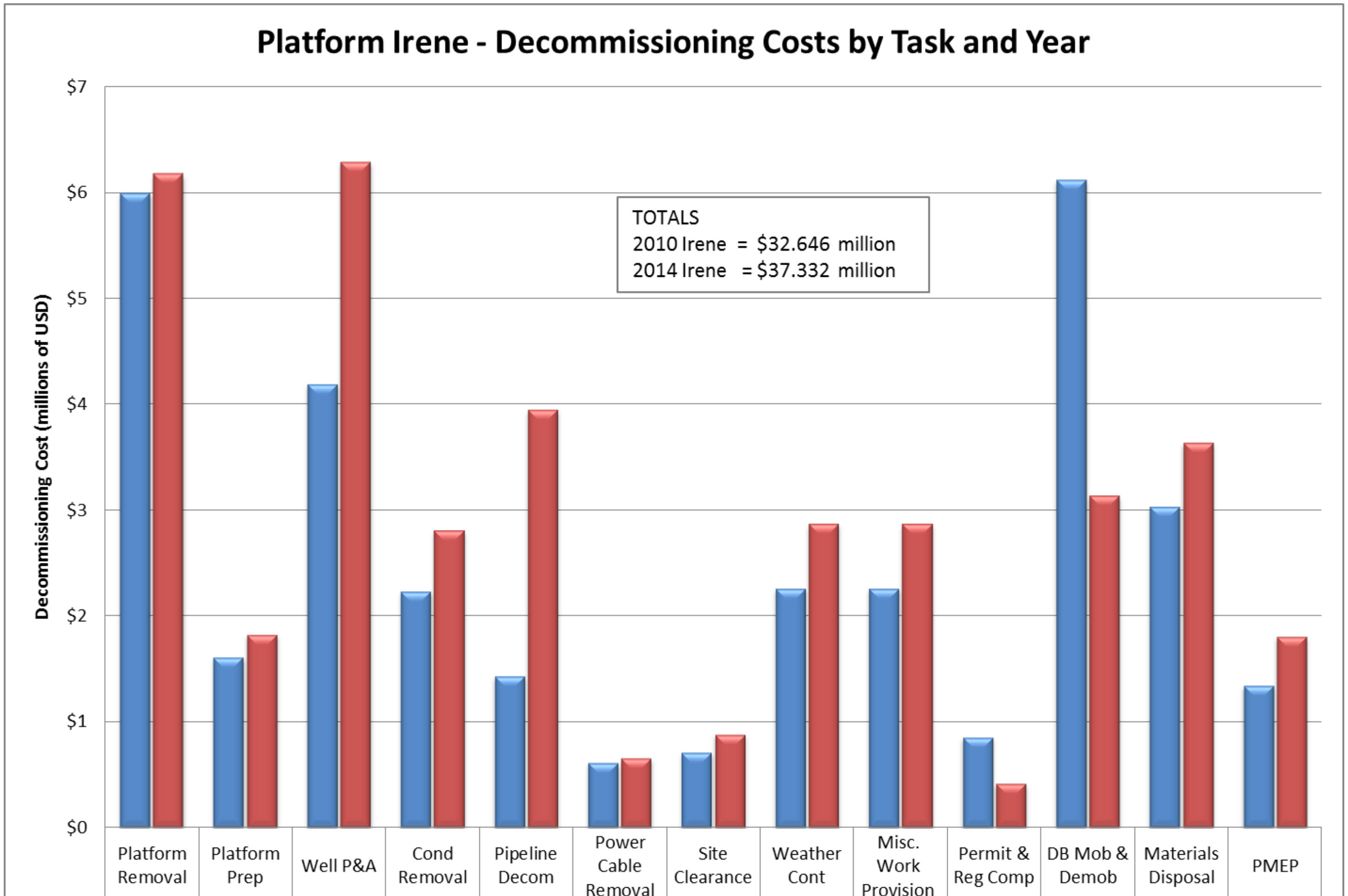
	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
2010	$30.030	$3.635	$5.145	$6.341	$3.070	$0.859	$1.282	$4.629	$6.943	$0.852	$15.120	$9.755	$4.029
2014	$39.063	$4.086	$6.846	$7.253	$3.158	$0.922	$1.472	$5.379	$8.069	$0.984	$6.270	$11.589	$5.024

Figure A.7-28 Platform Hondo Decommissioning Costs by Task and Year



	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
2010	$7.845	$0.958	$4.781	$2.588	$0.228	$0.321	$0.709	$1.625	$2.437	$1.278	$7.020	$1.844	$1.394
2014	$6.585	$1.097	$6.492	$2.707	$0.639	$0.343	$0.884	$1.756	$2.633	$1.987	$7.425	$2.120	$1.500

Figure A.7-29 Platform Houchin Decommissioning Costs by Task and Year



	Platform Removal	Platform Prep	Well P&A	Cond Removal	Pipeline Decom	Power Cable Removal	Site Clearance	Weather Cont	Misc. Work Provision	Permit & Reg Comp	DB Mob & Demob	Materials Disposal	PMEP
2010	$5.997	$1.606	$4.192	$2.234	$1.429	$0.612	$0.709	$2.260	$2.260	$0.852	$6.120	$3.034	$1.342
2014	$6.177	$1.827	$6.289	$2.807	$3.951	$0.656	$0.884	$2.872	$2.872	$0.414	$3.135	$3.640	$1.807

Figure A.7-30 Platform Irene Decommissioning Costs by Task and Year

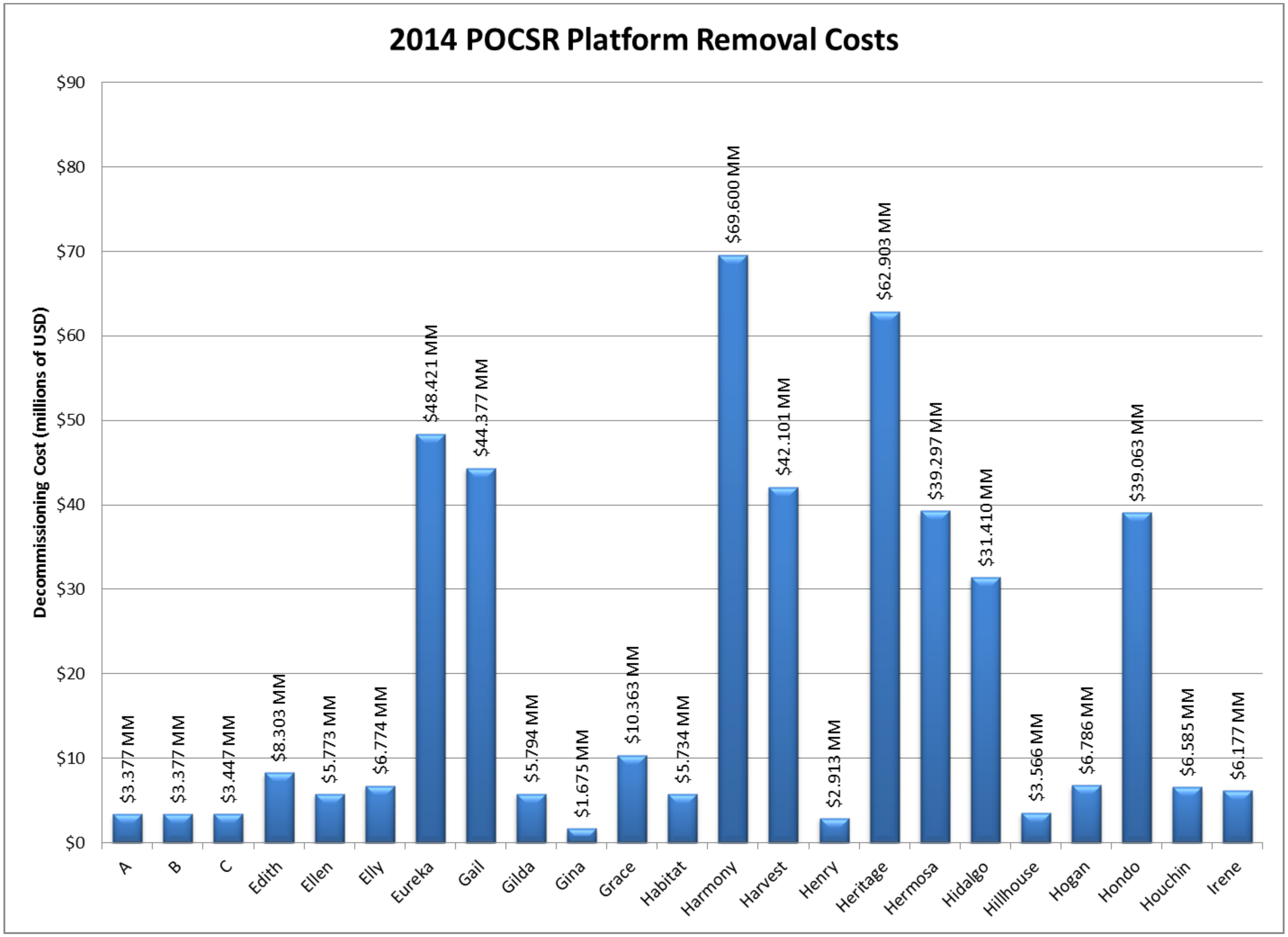


Figure A.7-31 2014 POCSR Platform Removal Costs

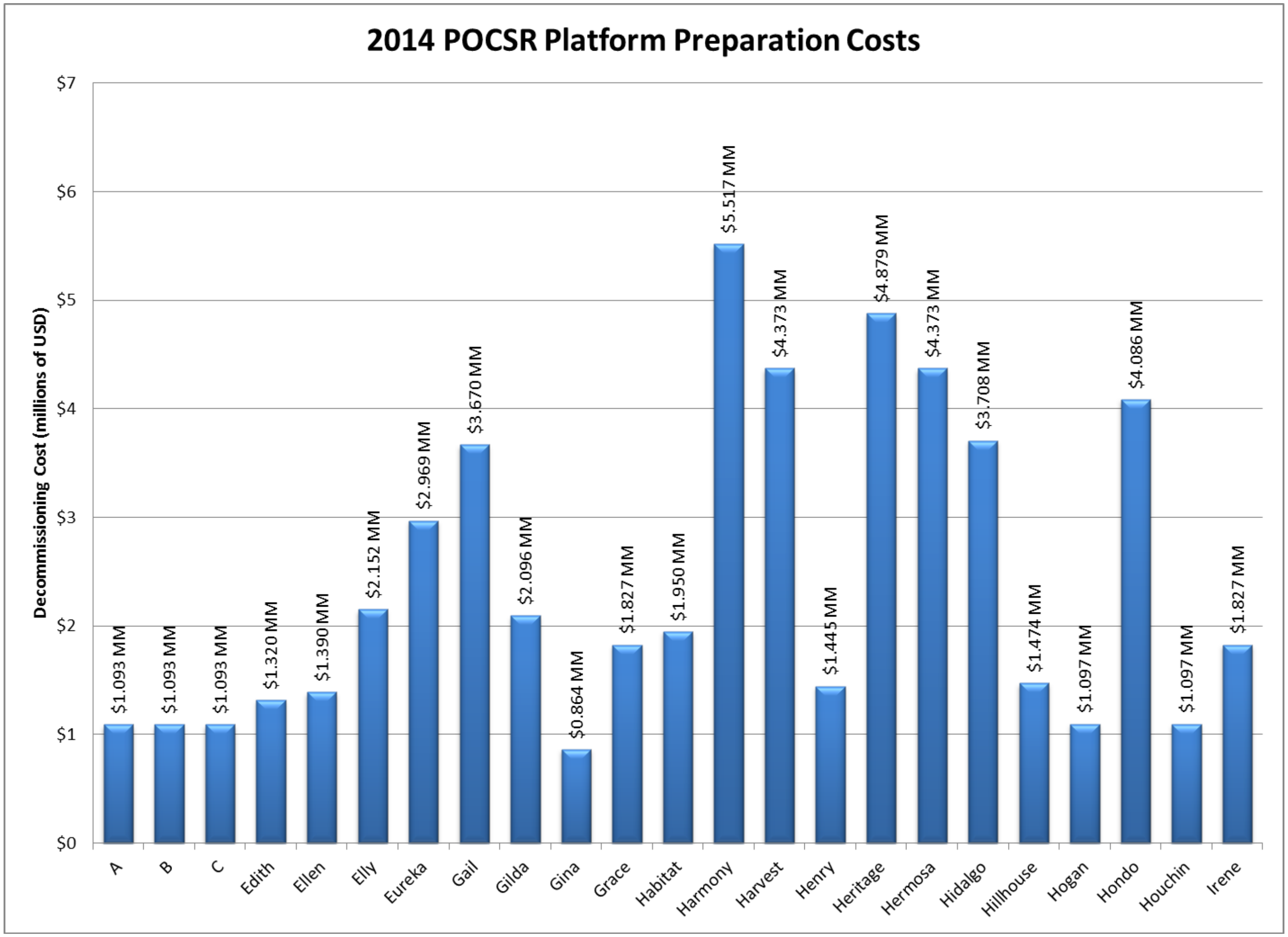


Figure A.7-32 2014 POCSR Platform Preparation Costs

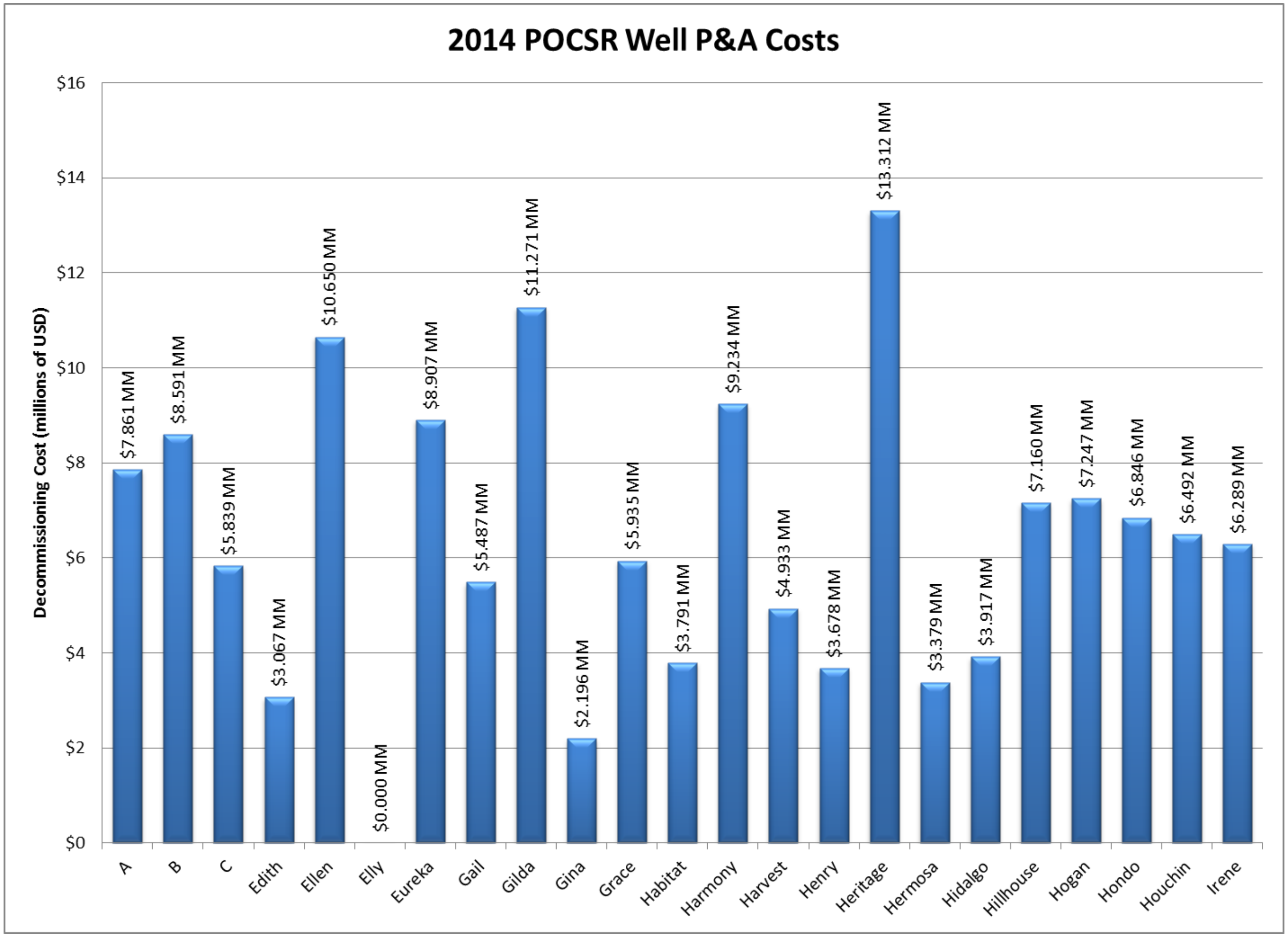


Figure A.7-33 2014 POCSR Well P & A Costs

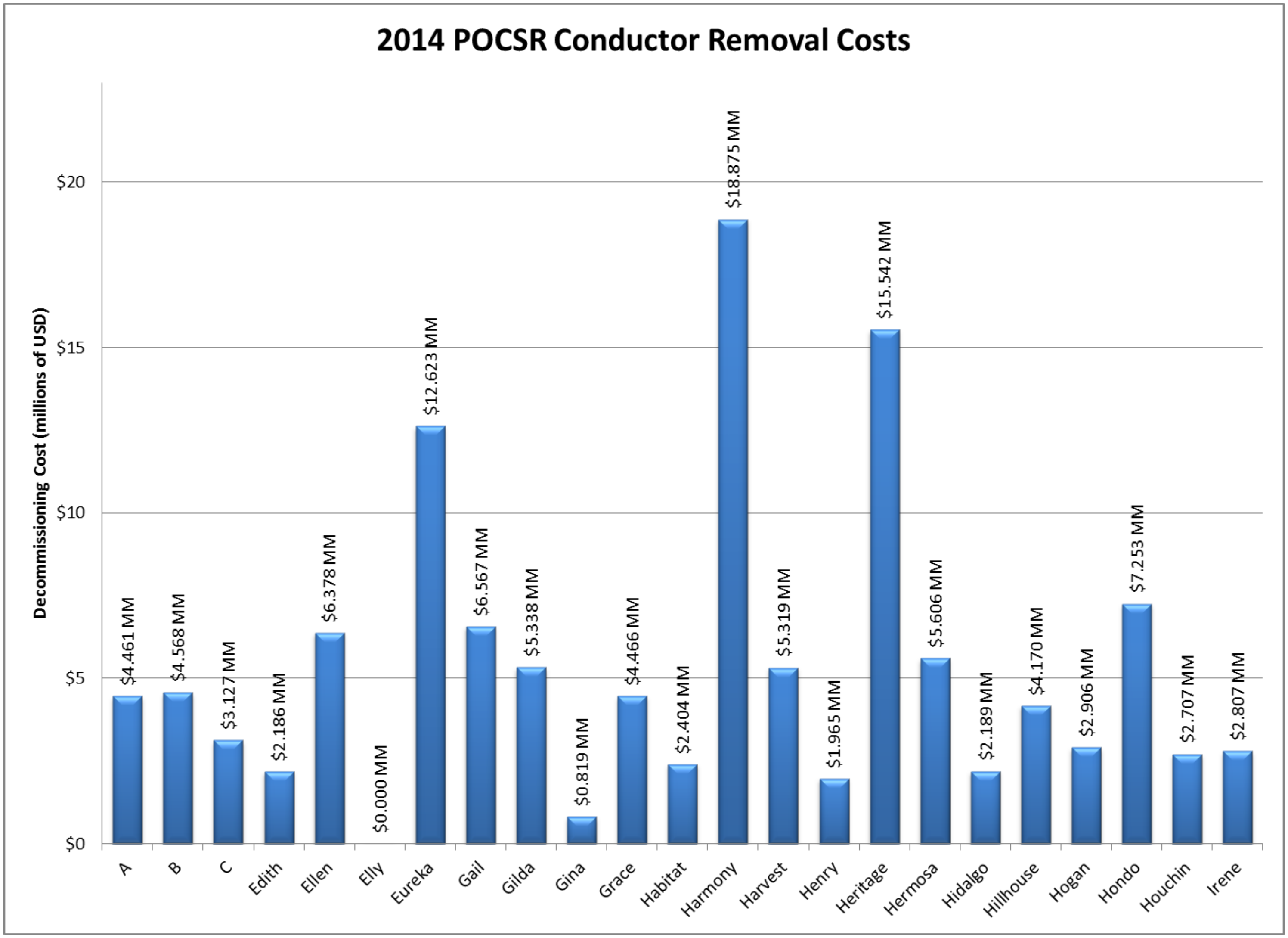


Figure A.7-34 2014 POCSR Conductor Removal Costs

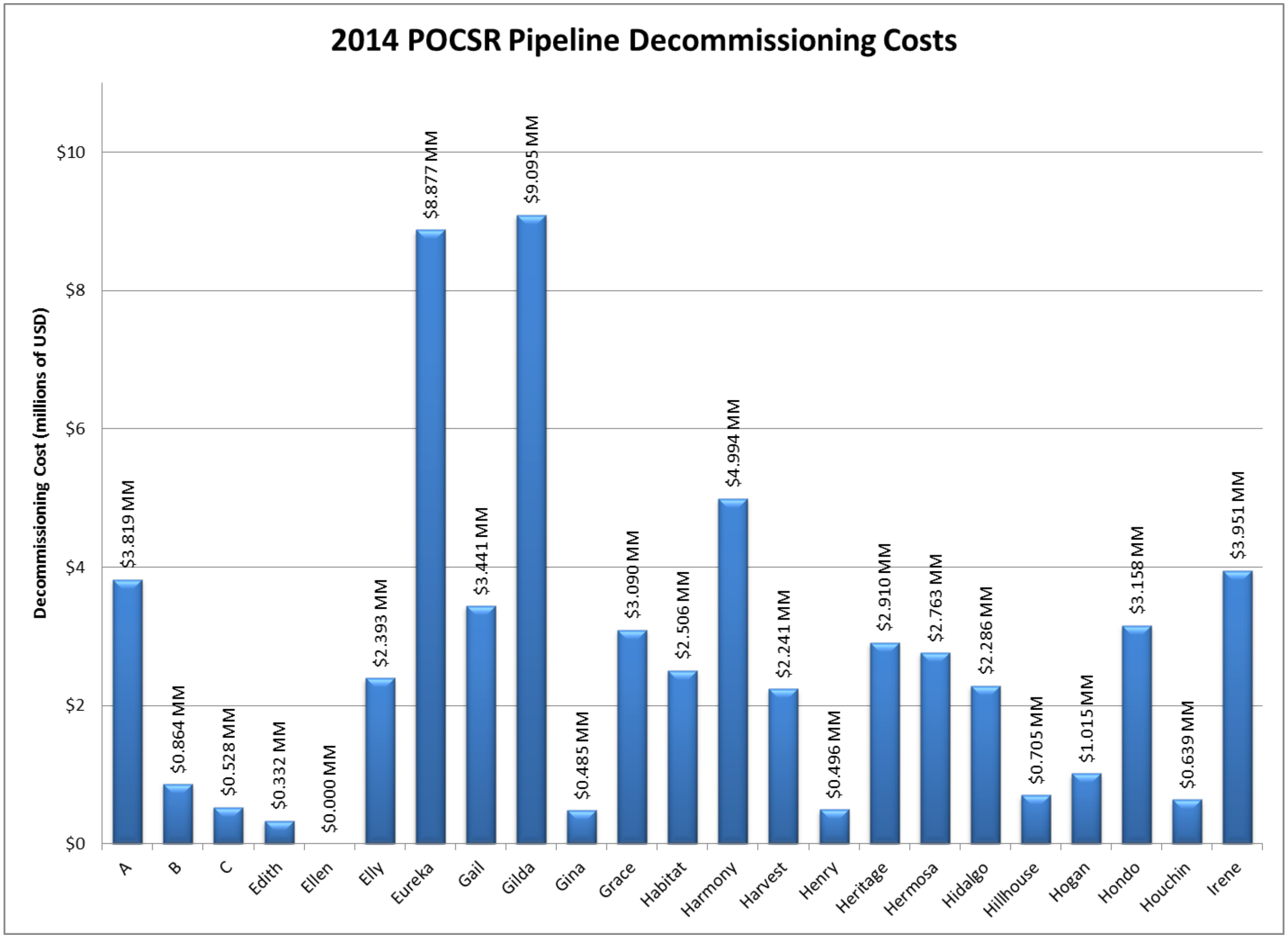


Figure A.7-35 2014 POCSR Pipeline Decommissioning Costs

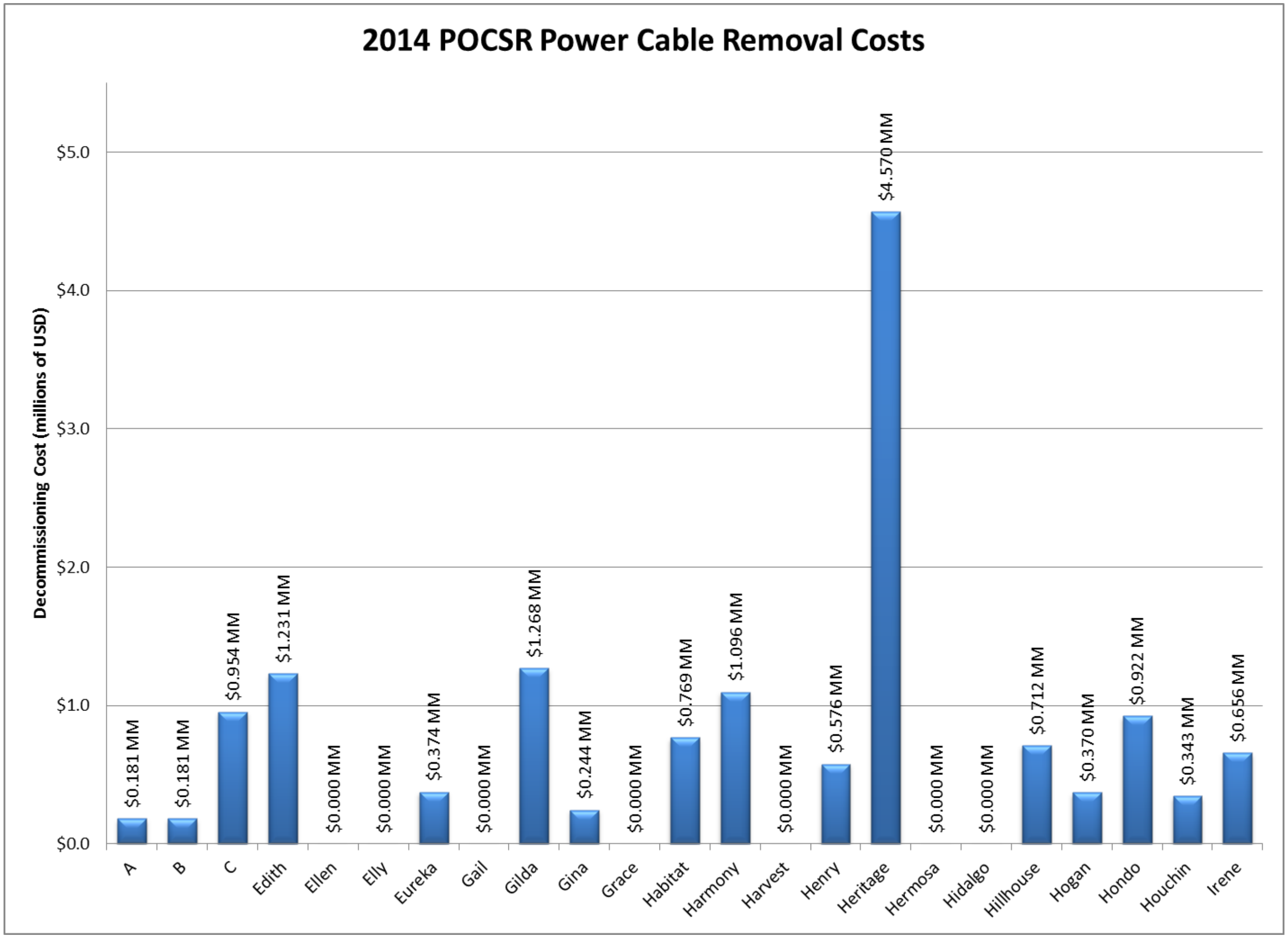


Figure A.7-36 2014 POCSR Power Cable Removal Costs

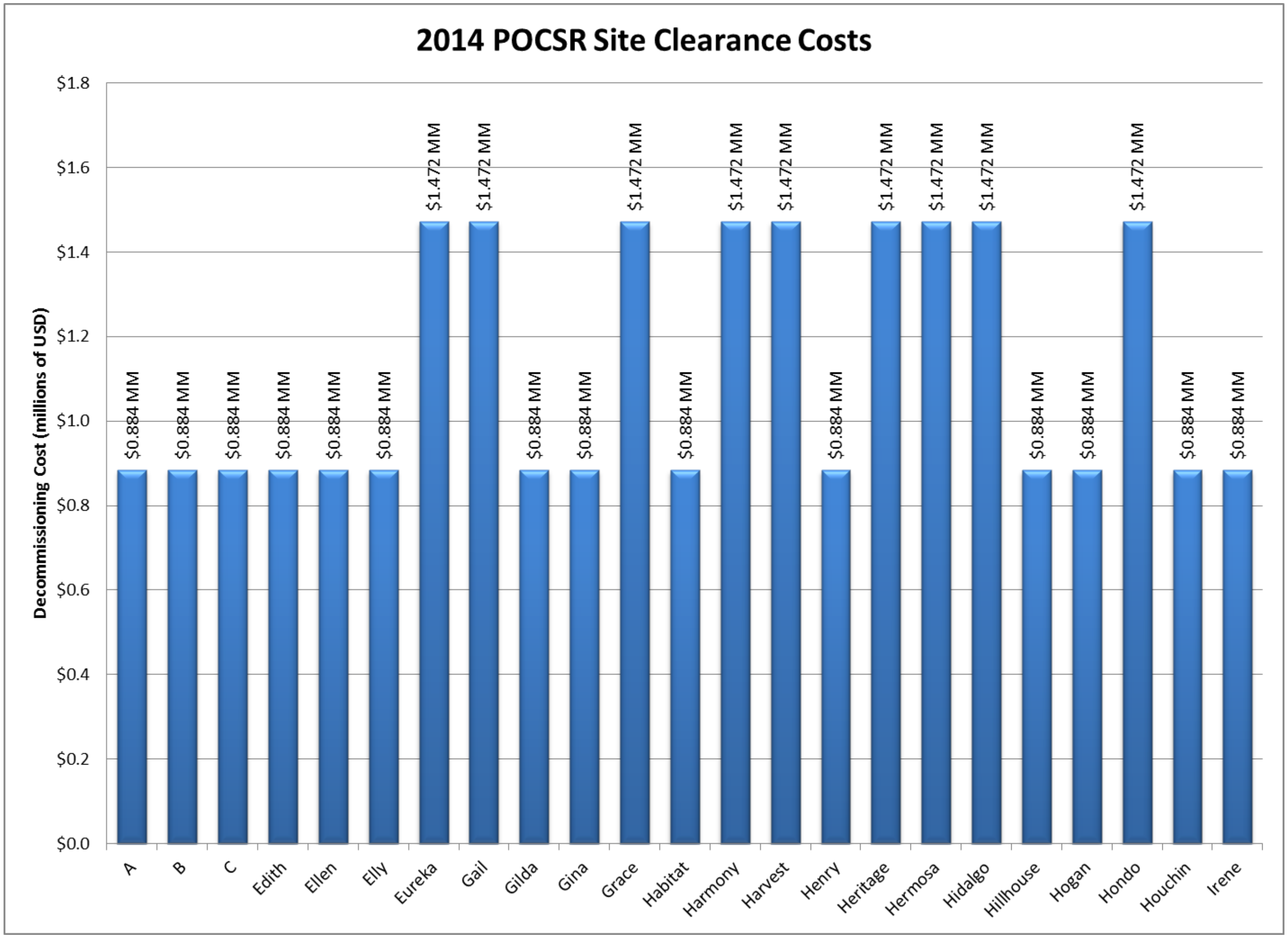


Figure A.7-37 2014 POCSR Site Clearance Costs

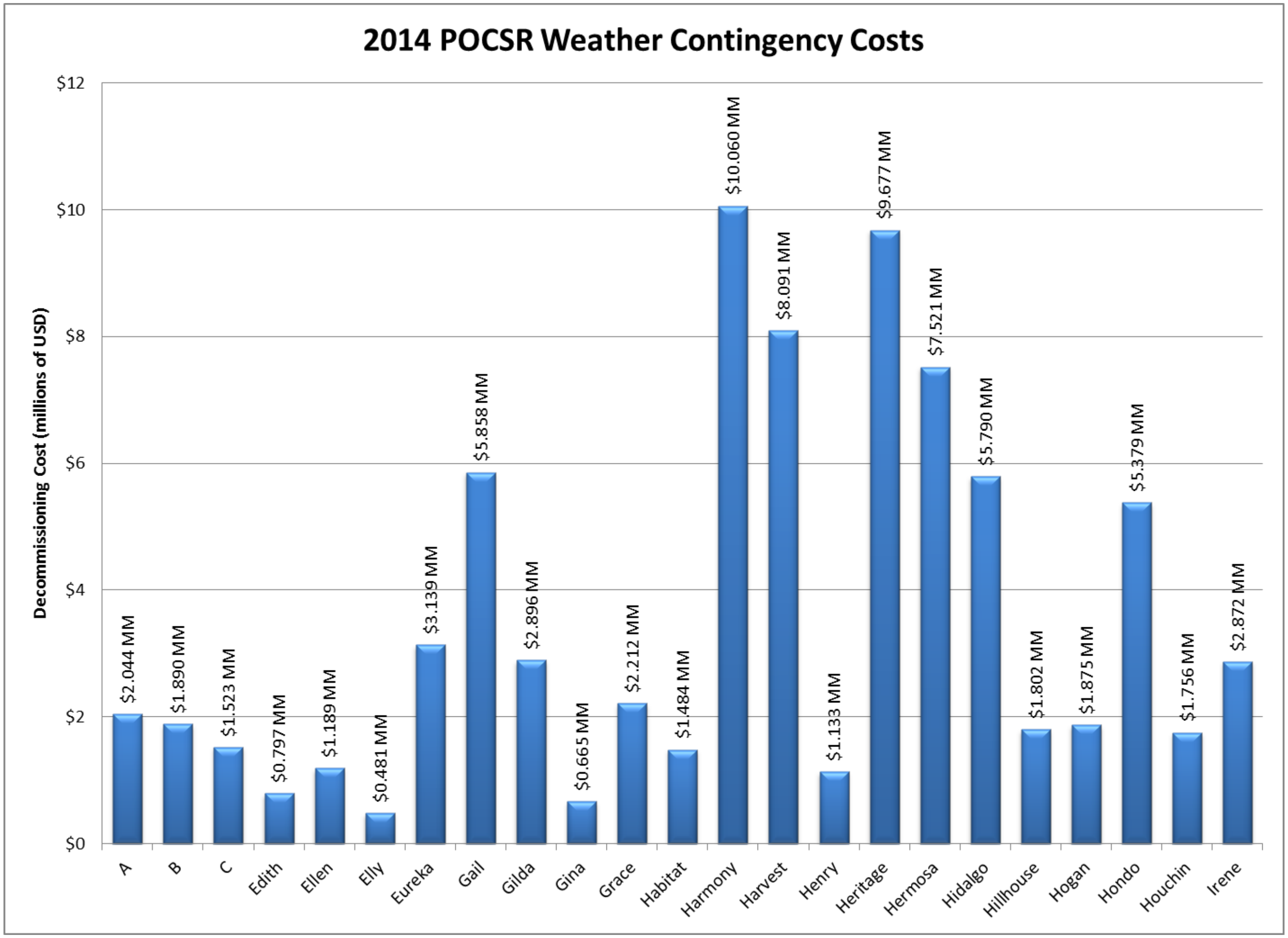


Figure A.7-38 2014 POCSR Weather Contingency Costs

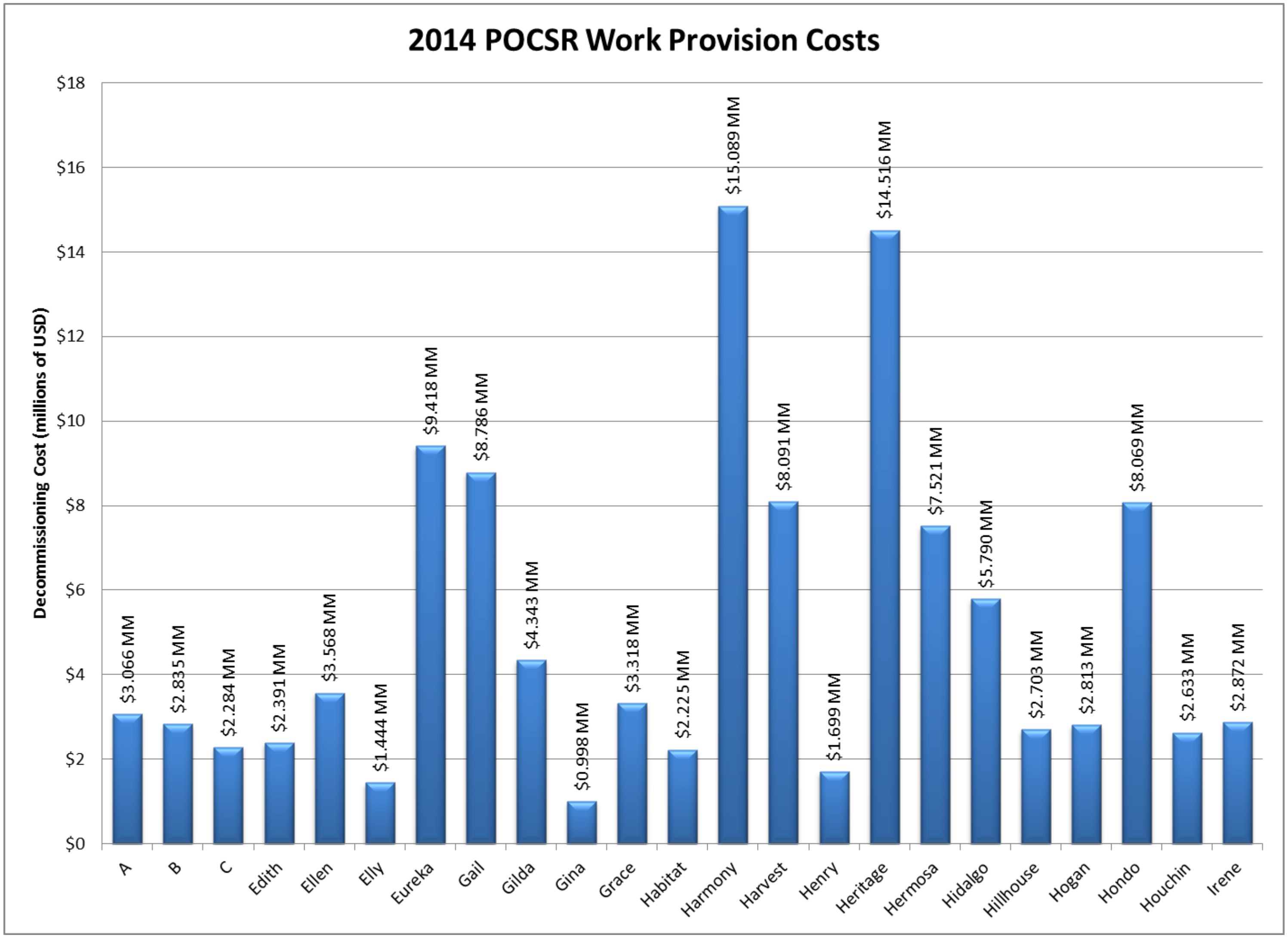


Figure A.7-39 2014 POCSR Work Provision Costs

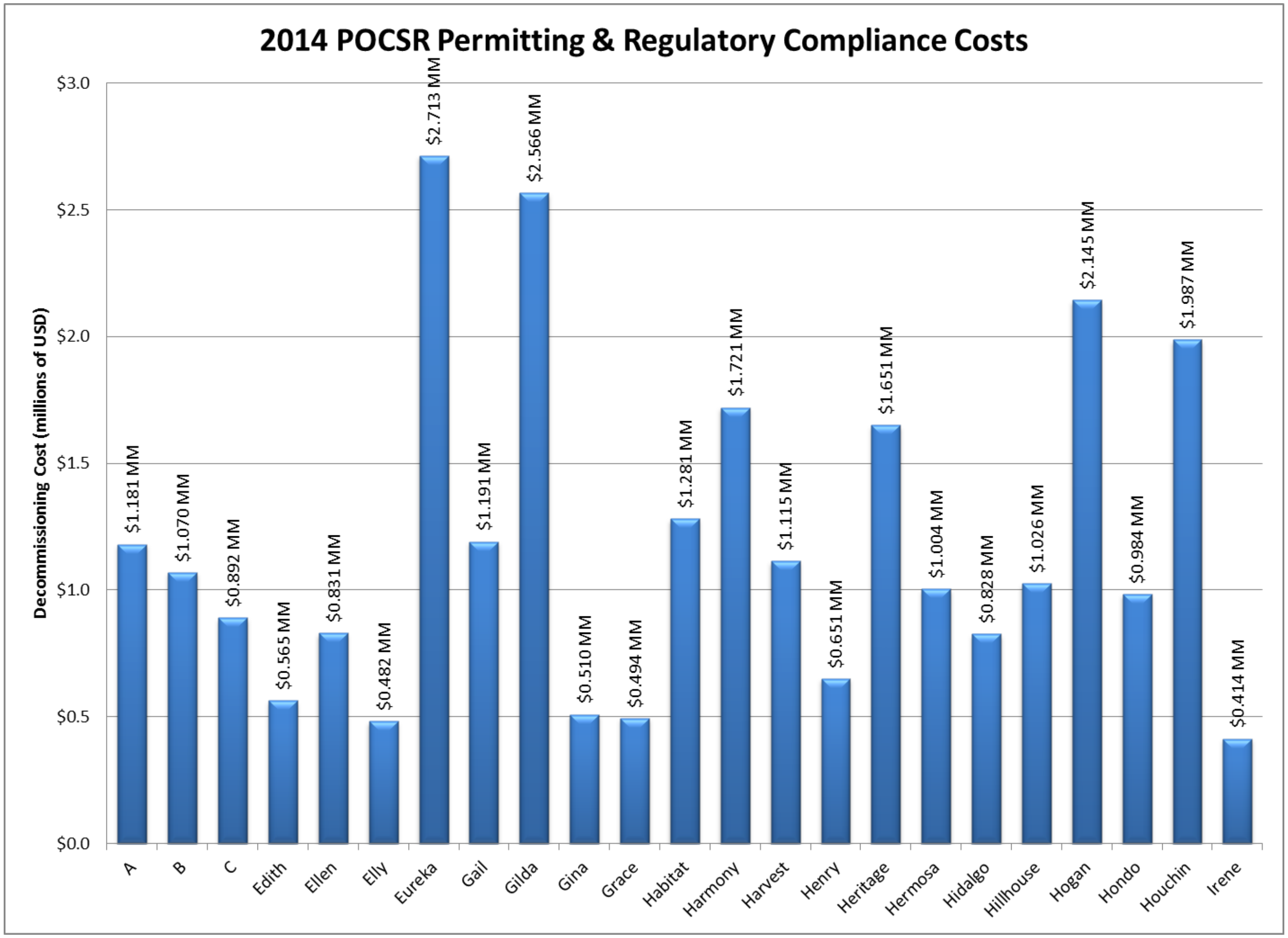


Figure A.7-40 2014 POCSR Permitting & Regulatory Costs

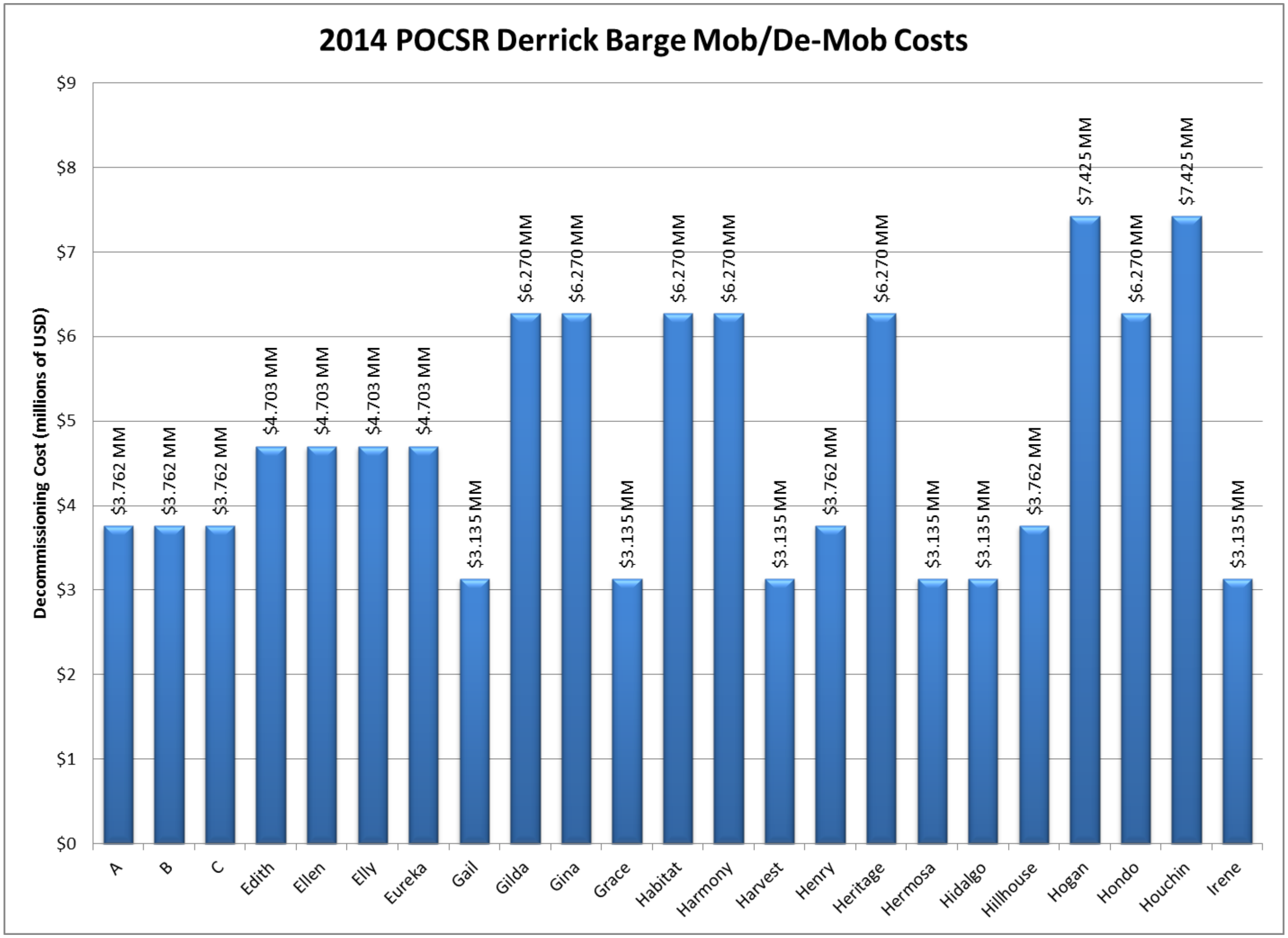


Figure A.7-41 2014 POCSR Derrick Barge Mob/Demob Costs

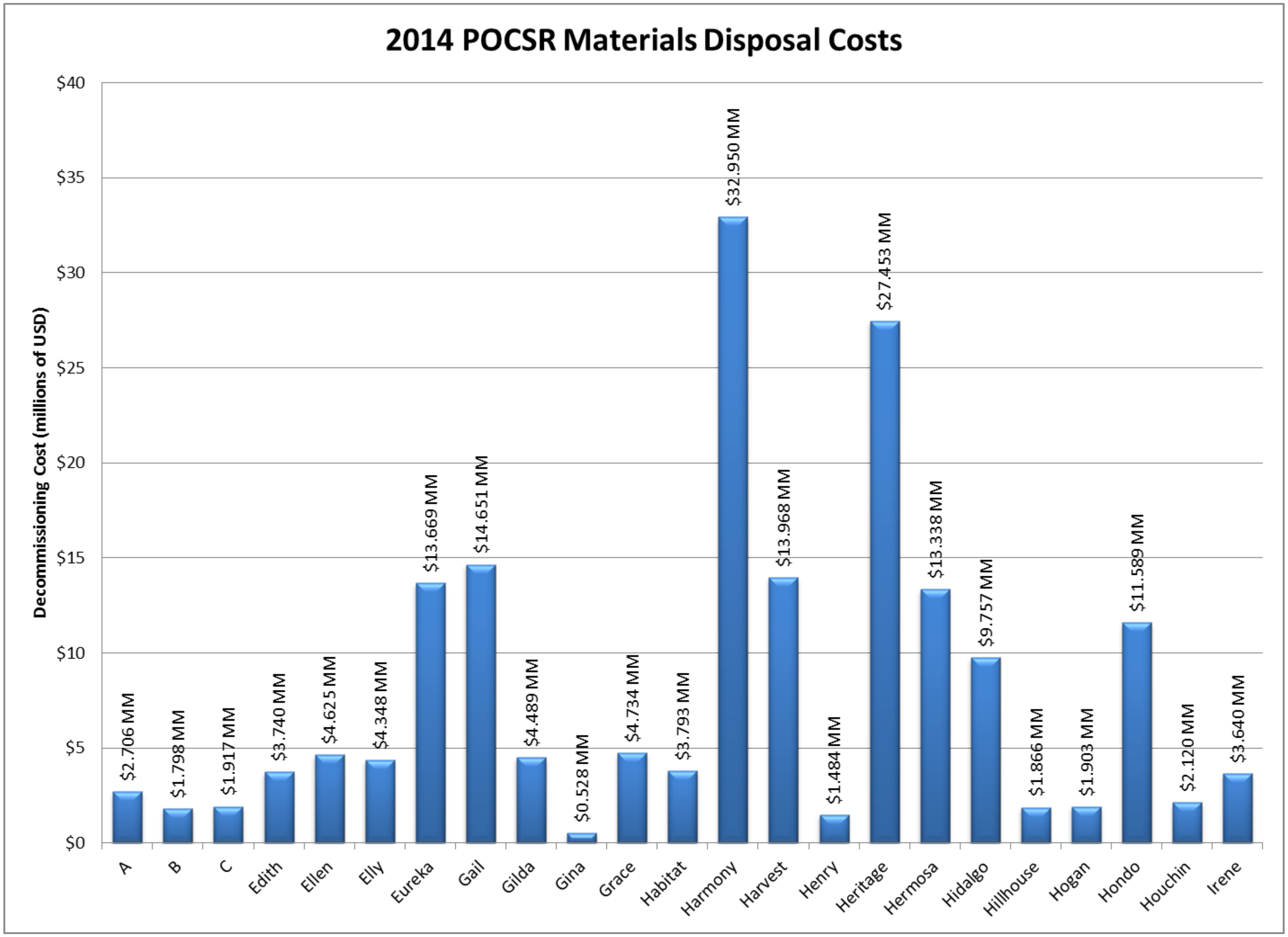


Figure A.7-42 2014 POCSR Material Disposal Costs

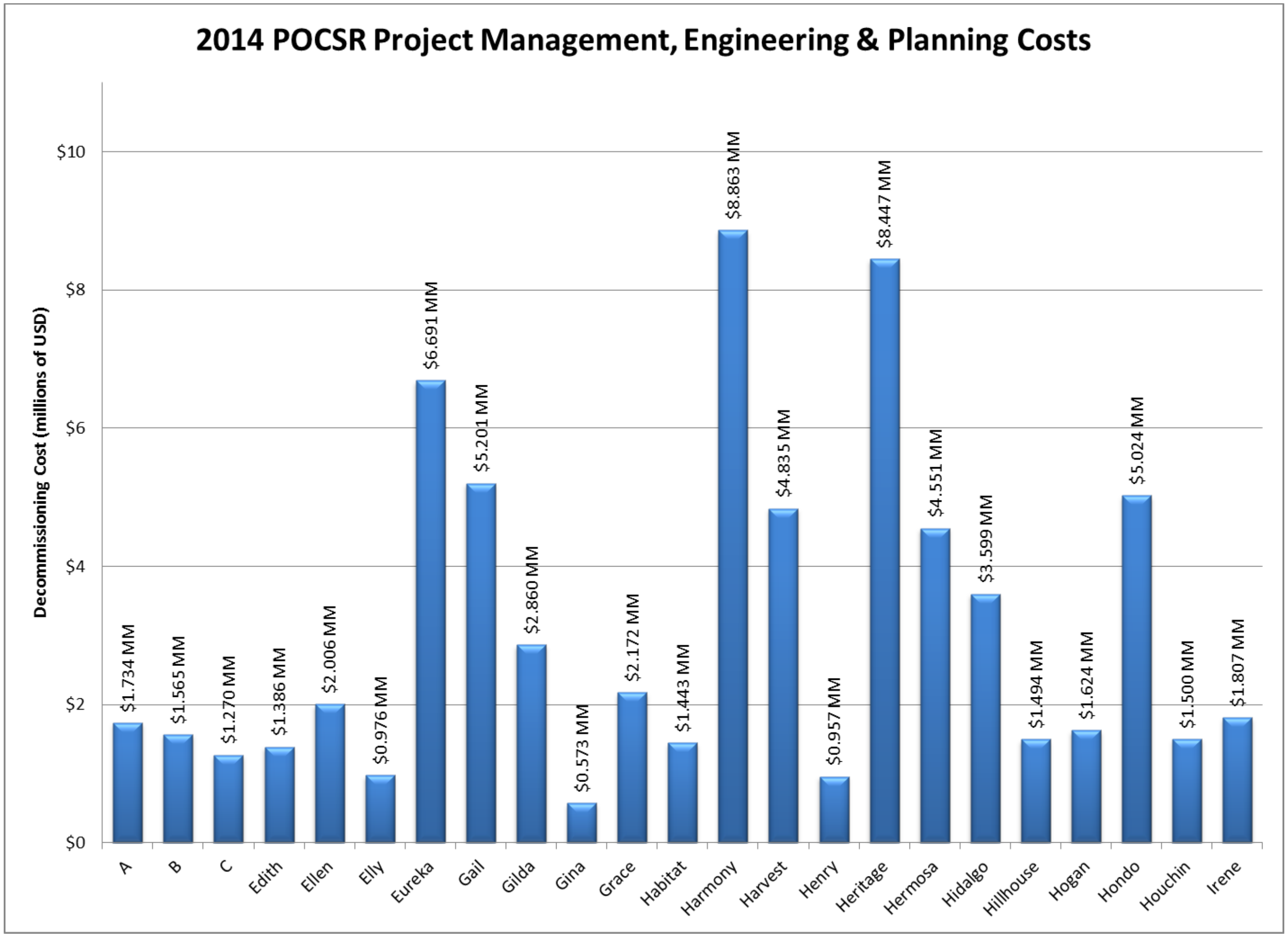


Figure A.7-43 2014 POCSR Project Management, Engineering & Planning Costs

Appendix 8: Presentation – Decommissioning Cost Update for Pacific OCS Region Facilities - 2014

See - https://www.bsee.gov/tap-technical-assessment-program/tap-735ac