APPENDIX D1

Throughput Projection and Vessel Mix Methodology

D1

THROUGHPUT PROJECTION AND VESSEL MIX METHODOLOGY

D1.0 INTRODUCTION

This appendix documents the data and methods used to derive throughput and vessel mix numbers for the analysis in the Supplemental Environmental Impact Statement/Subsequent Environmental Impact Report (SEIS/SEIR). The information presented supplements the overall supply and demand description found in Chapters 1 and 2 of the SEIS/SEIR (particularly Section 1.1.3 and Section 2.3). The appendix addresses the following elements:

- a comparison of projections for crude oil demand in southern California, and evaluation of the reasonableness of the Baker & O'Brien (2007a) forecast
- consideration of what types of vessels are likely to deliver crude oil to southern California
- the capacity of existing marine terminals in southern California to receive additional crude oil imports
- the data and methods used to estimate throughput and tanker vessel calls for the proposed Project, Reduced Project Alternative, and No Federal Action/No Project Alternative.

D1.1 Crude Oil Demand

D1.1.1 Baker & O'Brien Projected Demand for Crude Oil Imports

Plains All American Pipeline, L.P. (Plains) retained Baker & O'Brien, Inc. (Baker & O'Brien), an independent consulting engineering firm serving the oil, gas, and related industries, to prepare a crude oil forecast for strategic planning purposes (Baker & O'Brien 2007a; Baker & O'Brien 2008). Baker & O'Brien examined publicly available data on the current sources of crude oil refined by Southern California refineries from 1996 to 2006 and predicted how those sources would change between

2007 and 2040, the projected end of the 30-year lease in the Port of Los Angeles (Port) for which Plains has applied. In addition, Baker & O'Brien projected the regional demand for crude oil in southern California through 2040 based on an analysis of current refinery capacity and estimates of likely future increases in refinery capacity. The analysis considered the effects of "refinery capacity creep" and short-term capacity additions. Baker & O'Brien based their analysis on refinery demand for crude oil rather than consumer demand for refined products (Baker & O'Brien 2008); note that this is consistent with information from the California Energy Commission (CEC), which notes that due to the limited refining capacity in California, the state must import ten percent of its refined blending components and finished gasoline and diesel to meet the growing demand (CEC 2007b). With this assumption, Baker & O'Brien project that future refinery demand for crude oil (beyond 2006) would increase at the same rate as refinery capacity (Baker & O'Brien 2008).

In addition to available data from public sources, Baker & O'Brien applied its knowledge of oil industry practices, foreign and domestic sources of crude oil, oil production operations, transportation logistics, and the operations of southern California refineries (refinery capabilities, throughput capacities, crude slates, and likely improvements that would increase capacity) in order to project future trends in the production and distribution of domestic crude oil and the likely sources of imported crude oil that will be needed to replace declining domestic production (Baker & O'Brien 2008).

As noted in Chapter 1 of the SEIS/SEIR, crude oil refined in southern California comes from three primary sources: California crude oil production; Alaska North Slope (ANS) crude oil; and imported oil (Middle East, Latin America, and West Africa, with small volumes from the Pacific Rim and Canada). Supplies of California crude oil are declining rapidly, which will lead to significant increases in imports. (Supplies of ANS crude oil are also declining rapidly, as documented by both Baker & O'Brien (2007a, 2008) and CEC (2007b, 2007c). However, ANS crude oil arrives by marine vessel, so for the purpose of assessing the need for marine import infrastructure, the more important consideration is the decline in California production, which primarily arrives in southern California by pipeline.)

Baker & O'Brien assumed that production of California crude oil would decline at 3.5% per year through 2040. This projected decline is based on recent historical production: during the three-year period between 2003 and 2006, production declined at 3.7% per year; during the five-year period between 2001 and 2006, it declined at 3.3% per year (Baker & O'Brien 2008). Baker & O'Brien also notes that these production declines occurred during a period when crude oil prices were increasing dramatically (Baker & O'Brien 2008). Although Baker & O'Brien assumed that crude production from the Los Angeles Basin and Ventura areas would continue to be directed to southern California refineries, it also assumed that crude production closer to Bakersfield and Santa Maria would be preferentially supplied to refineries in those areas first, as these areas do not have access to imports (Baker & O'Brien 2008).

Baker & O'Brien considered the potential domestic supply from the Alaska National Wildlife Reserve (ANWR). However, Baker & O'Brien note that production has not been authorized in the ANWR, would not begin for at least 10 years after approval, and would not likely affect southern California (Baker & O’Brien 2008). (In addition, like ANS production, any deliveries from ANWR production to southern California would likely be delivered by marine vessel.)

Baker & O’Brien projected refinery runs from 2007 to 2040 starting with estimates of 2006 refinery runs for each refinery, based on public sources including company annual reports, throughput capacity information, and non-proprietary industry knowledge. Baker & O’Brien estimated future refinery runs from refinery capacity creep (i.e., increase of distillation capacity due to various improvements that increase efficiency and remove bottlenecks at existing refineries, provided those improvements meet environmental and permitting requirements, and can be justified as having a sufficient economic return) (CEC 2007b; Baker & O’Brien 2008).

Baker & O’Brien developed two scenarios with different refinery capacity creep assumptions. Since consumer demand for transportation fuels is currently greater than the output of southern California refineries, and the difference is met by the importation of transportation fuels (CEC 2007b; Baker & O’Brien 2008), Baker & O’Brien assumed for their analysis that consumer demand would continue to be greater than refinery output. Therefore, in their analysis, refinery output was assumed to be the limiting factor on crude oil imports, rather than consumer demand (Baker & O’Brien 2008).

The two capacity creep scenarios include a Base Case and an Alternative Case. For both cases, Baker & O’Brien assumed an annual refinery capacity creep of 1.25% from 2007 to 2021. After 2021, the Base Case uses a lower refinery capacity creep compared to the Alternative Case (Table 1). Baker & O’Brien note that the deviation between the two scenarios is based on “the difficulty in making predictions beyond 20 years due to a variety of issues including, among other things, uncertain regulatory requirements, changing fuel economy standards, the potential impact of measures to address climate change, and political issues that could affect the availability of crude oil from certain areas of the world” (Baker & O’Brien 2008). Baker & O’Brien note further that “it is our opinion that the Base Case would be the more appropriate one to use for forecasting the period between 2022 and 2040. During this period, use of the more conservative Base Case is justified when considering the unknowable longer-term impacts of factors such as alternative fuels and conservation on refinery product requirements” (Baker & O’Brien 2008). Alternative fuels and conservation would decrease consumer demand for refined petroleum products, which would in turn decrease the potential economic returns from projects to expand refinery capacity and, therefore, the amount of refinery capacity creep.

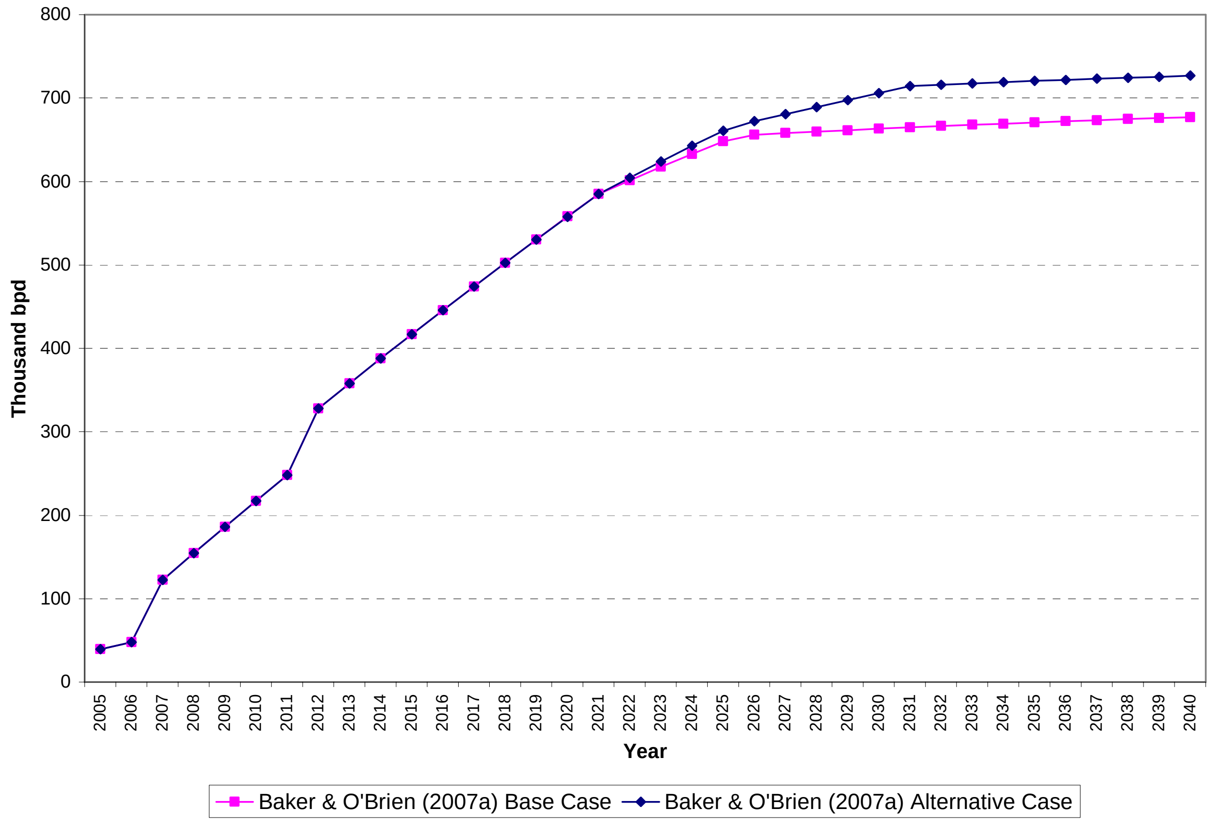
Table 1. Rates of Refinery Capacity Creep Used in Baker & O’Brien (2007a) Scenarios

Scenario	*2007-2021*	*2022-2026*	*2027-2031*	*2032-2040*
Base Case	1.25%	0.50%	0.00%	0.00%
Alternative Case	1.25%	0.75%	0.50%	0.00%
Source: Baker & O’Brien (2007a, 2008).				

On top of refinery capacity creep, Baker & O’Brien also assumed refineries would increase their distillation capacity by an additional 50,000 barrels per day (bpd), beginning in 2012, via expansion of existing refineries (over and above the capacity expansions expected from refinery capacity creep). Baker & O’Brien explain that this figure is based upon industry speculation that such a level of expansion was likely; this assumption is supported by the fact that in early 2007, two southern California refineries announced plans for capacity expansions totaling 21,000 bpd (Baker & O'Brien 2008).

Figure 1 provides a summary of Baker & O'Brien's projected demand, measured as incremental demand over the 2004 baseline, and including all marine deliveries (i.e., ANS as well as foreign crude). The figure shows both the Base Case and the Alternative Case. Throughout the remainder of this appendix, for simplicity, references to the Baker & O'Brien (2007a) projection imply the Base Case unless otherwise noted.

Figure 1. Baker & O'Brien Projected Demand for Crude Oil Marine Imports to Southern California (Incremental Over 2004)



Source: Baker & O'Brien (2007a).

D1.1.2 CEC Projected Demand for Transportation Fuels

The California Energy Commission (CEC) is California's primary energy policy and planning agency. Created by the state legislature in 1974, the CEC's responsibilities include forecasting future energy needs, keeping historical energy data, promoting energy efficiency, developing energy technologies and supporting renewable energy, and planning for and directing state response to energy emergencies. Senate Bill (SB)

1389 (Bowen and Sher, Chapter 568, Statutes of 2002) requires the CEC to "conduct assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices," and to "use these assessments and forecasts to develop energy policies that conserve resources, protect the environment, ensure energy reliability, enhance the state's economy, and protect public health and safety" (Public Resources Code § 25301[a]).

To fulfill this charge, the CEC produces and adopts an Integrated Energy Policy Report (IEPR) every two years and an update every other year. The most recent IEPR (CEC 2007a) was adopted in December 2007, and is supported by a suite of documents including the IEPR Committee Final Report (CEC 2007b), which includes more technical detail, and the Transportation Energy Forecasts for the 2007 IEPR (CEC 2007c), which provides detailed documentation of CEC's analysis for energy needs in the transportation sector.

This section provides an overview of the major conclusions of the 2007 IEPR as they relate to the CEC's forecast for transportation fuel demand. Section D1.1.3 provides an overview of the CEC's forecast for crude oil demand, which the LAHD and the USACE used to evaluate the reasonableness of the Baker & O'Brien forecast.

As noted in Chapter 1 of the SEIS/SEIR, crude oil in California is used predominantly to make transportation fuels for consumers and businesses; no electricity in the state is generated using petroleum (CEC 2007a). Thus, the demand for crude oil in southern California is mainly a function of demand for transportation fuels: gasoline, diesel, and jet fuel. About 79 percent of California's refinery output in 2006 consisted of these fuels (CEC 2007c). Demand for transportation fuels is, in turn, a function of several factors, including population, income, vehicle purchasing and driving habits, fuel prices, rates of adoption of new technologies and alternative fuels, and greenhouse gas (GHG) reduction rules and standards. In addition to supplying southern California's transportation fuel needs, the refineries operating in southern California also supply virtually 100 percent of transportation fuels for Nevada and 60 percent for Arizona (CEC 2007b).

The California Department of Finance (DOF) predicts California's population will grow by about 30 percent between 2005 and 2030 (an average of 1.05 percent per year), and real income will grow by about 31 percent (an average of 1.08 percent per year) (CEC 2007c). From 2001 to 2005 the number of vehicles registered on California roads increased by about 3.1 percent per year. While growth in registered vehicles was fastest for hybrid vehicles (nearly doubling every year), as of 2005 hybrids were still a small proportion, just 0.3 percent, of on-road registered vehicles (CEC 2007c).

CEC's projections for fuel demand for light-duty vehicles (passenger cars, light trucks, minivans, and sport utility vehicles) take into account the following major regulations affecting fuel economy:

- AB 1493 (Pavley, Chapter 200, Statutes of 2002). As a result of this regulation, the California Air Resources Board (ARB) adopted a GHG standard for light-duty vehicles in 2004. According to the CEC (2007c), the standard requires a gradual reduction of GHG equivalent emissions beginning in 2009, which by 2016 results in approximately a 30 percent reduction in emissions per mile for the average new vehicle as compared to today's new vehicles (CEC 2007c).

- Current state mandates (amended September 2006) regarding Low Emission Vehicles (LEVs) and Zero Emission Vehicles (ZEVs) (CEC 2007c).

CEC (2007c) constructed alternative forecasts of future demand for transportation fuel, corresponding to different assumptions about the implementation of GHG standards for light-duty vehicles and the ZEV mandate. In addition, the CEC report documents alternative forecasts corresponding to different assumptions about fuel prices. CEC developed these fuel price forecasts based on the U.S. Energy Information Administration (EIA) *2007 Annual Energy Outlook High, Reference, and Low Case* oil price forecasts. For comparison, the CEC's Base Case starts at $2.92 per gallon for retail regular-grade gasoline in 2007, dips to $2.56 in 2014, and then rises to $2.76 by 2030, expressed as annual average inflation-adjusted 2007 dollars. The 2030 price for gasoline in the High Case is $3.96 per gallon, and in the Low Case is $2.09. In nominal dollars, or actual prices customers would see at the pump, the 2030 price for gasoline would be $6.13 per gallon in the High Case, $4.28 in the Base Case, and $3.23 in the Low Case (CEC 2007c).

Under all six alternative forecasts (Low, Base, and High Cases for fuel prices, and with or without GHG regulations under AB 1493), the CEC's transportation fuel demand model projects that vehicle miles traveled (VMT) will continue to increase through 2030, by annual average rates between 1.5% and 1.9%. The model also predicts increased numbers of on-road registered vehicles in California, by annual average rates between 1.4% and 1.5%. However, CEC predicts demand for on-road gasoline could increase or decrease, depending on fuel prices and implementation of GHG standards. Between 2005 and 2030, CEC predicts demand for on-road gasoline could increase by as much as 0.6% per year (low fuel price and no GHG standards) or decrease by as much as 0.5% per year (high fuel price and GHG standards) (CEC 2007c).

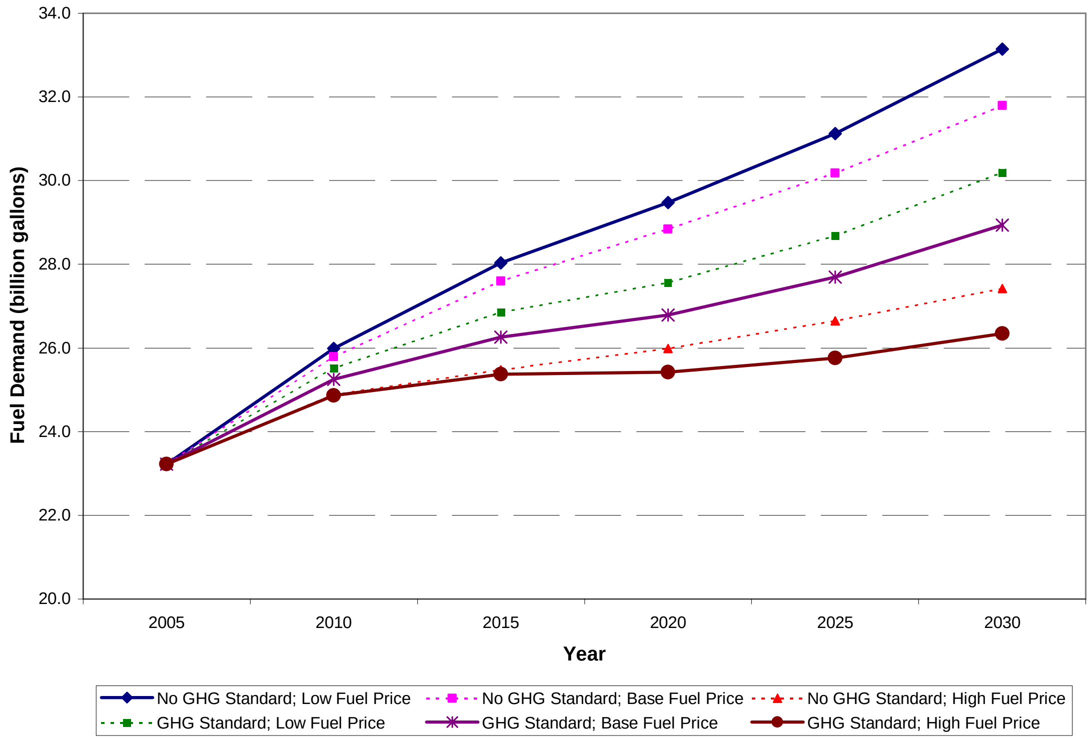
However, CEC predicts that the demand for diesel fuel will increase due to several factors, including increasing consumer purchase of light-duty diesel vehicles and truck and rail movement of imported containers from ports. The CEC's demand for diesel fuel also includes its use in off-road vehicles (mainly for construction and agriculture) as well as vehicles used for mass transit (assuming that the current proportion of mass transit vehicles using diesel fuel remains unchanged). CEC (2007c) predicts average growth in demand for diesel fuel will range between 2.1% per year (high fuel price, GHG standards) and 3.0% per year (low fuel price, no GHG standards).

CEC also predicts increasing demand for jet fuel even under alternative scenarios for fuel prices. CEC notes that the implementation of statewide GHG regulations will not affect demand for jet fuel since jet fuel is formulated to national and international, rather than state, standards. CEC predicts demand for commercial jet fuel will increase by between 2.2% per year (high fuel price) and 2.6% per year (low fuel price) (CEC 2007c).

Combining the demand for regular gasoline, diesel, and jet fuel, CEC (2007c) predicts a net increase in overall demand for transportation fuels within California, ranging from 0.5% per year to 1.4%. Table 2 shows the same info in tabular form.

Figure 2 shows the change in demand from 2005-2030 for each of the six alternative cases in the CEC prediction. Table 2 shows the same info in tabular form.

Figure 2. CEC Forecast of California Transportation Fuel Demand, 2005-2030



Source: CEC (2007c), Tables 8, 9, and 10.

Table 2. CEC Forecast of California Transportation Fuel Demand (billion gallons)

	No GHG Standard			*GHG Standard*		
Year	*Low Fuel Price*	*Base Fuel Price*	*High Fuel Price*	*Low Fuel Price*	*Base Fuel Price*	*High Fuel Price*
2005	23.2	23.2	23.2	23.2	23.2	23.2
2010	26.0	25.8	24.9	25.5	25.2	24.9
2015	28.0	27.6	25.5	26.9	26.3	25.4
2020	29.5	28.8	26.0	27.6	26.8	25.4
2025	31.1	30.2	26.7	28.7	27.7	25.8
2030	33.1	31.8	27.4	30.2	28.9	26.3

Source: CEC (2007c), Tables 8, 9, and 10.
Note: Includes gasoline, diesel, and jet fuel. Does not include transportation fuels sold to wholesalers or retailers in other states after being refined or received within California.

In addition to supplying California consumers, refineries in California supply transportation fuels to other states. As CEC (2007c) states:

> *"Nevada and Arizona do not have any refineries that can produce transportation fuels. As a consequence, these states must import all of their transportation fuels from refineries located outside their borders. Refineries located in California export petroleum products via pipelines that are linked to distribution terminals located in Reno, Las Vegas, and Phoenix. This network of interstate pipelines is owned and operated by the Kinder Morgan Pipeline Company (KMP). Pipelines that originate in California provide nearly 100 percent of the transportation fuels consumed in Nevada. Approximately 60 percent of Arizona's demand also is met by products exported from California. The balance of transportation fuels consumed in Arizona is delivered in a petroleum product pipeline that originates in Western Texas on a section of the KMP system referred to as the East Line.*
>
> *"Over the near- and long-term forecast periods, transportation fuel demand growth in Nevada and Arizona, taking into account East Line expansion plans, will place additional pressure on California refineries and the California petroleum marine import infrastructure system to provide adequate supplies of transportation fuels for this regional market."*

Based on recent trends, CEC (2007c) forecasts demand for gasoline and diesel in Nevada and Arizona will increase linearly with population, but demand for jet fuel will increase faster than population because of tourist destinations in these states (especially Las Vegas). CEC (2007c) predicts that pipeline exports from California to Arizona of gasoline, diesel, and jet fuel will increase 2.5% per year on average between 2006 and 2025 (from 133.1 thousand bpd to 211.4 thousand bpd), under both high and low population growth scenarios. For Nevada, CEC (2007c) predicts that pipeline exports from California of transportation fuels (through refined product pipelines) will increase between 2.2% and 2.6% per year, with the variation attributable to alternative scenarios for population growth. In the lower case, this represents a growth from 156.0 thousand bpd in 2006 to 234.7 thousand bpd in 2025; in the higher case, the growth would be to 255.4 thousand bpd in 2025.

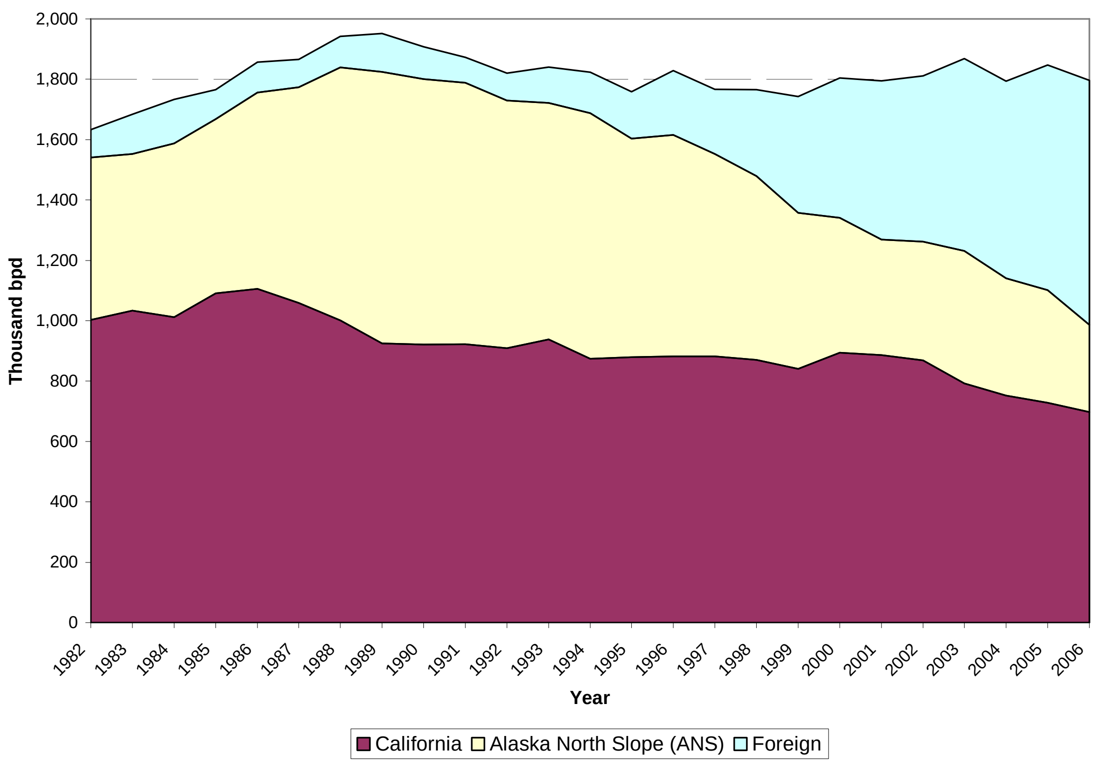
D1.1.3 CEC Projected Demand for Crude Oil Imports

Over the last several years, production of transportation fuels from California refineries has not kept pace with consumer demand for fuels in California and other states to which California supplies refined fuels. Due to the limited refining capacity in California, the state must import ten percent of its refined blending components and finished gasoline and diesel to meet the growing demand (CEC 2007b). Thus, the limiting factors on crude oil marine imports are production of California crude, refinery distillation capacity, and the capacity of infrastructure to receive ship-borne deliveries of crude oil. In 2005, California refineries produced about 532 million barrels (bbl), or 22.4 billion gallons, of gasoline, diesel, and jet fuel; as noted in Table 2, transportation fuel demand within California constituted about 23.2 billion gallons, or about 553 million bbl. In 2006 California exported about 156 thousand bpd (about 56.9 million bbl, or 2.4 billion gallons) of transportation fuels to Nevada, and about 133.1 thousand bpd (about 48.6 million bbl, or 2.0 billion gallons) to Arizona.

Twenty-one refineries operate in California, including ten in the Los Angeles basin. In 2005, these refineries processed 674 million bbl of crude oil, or 1.8 million bpd (CEC 2007c). Crude oil from foreign imports made up the largest share of that amount (40.4%); California sources supplied 39.5%, and ANS sources supplied 20.2% (CEC 2007c). The ten refineries operating within southern California processed 356 million bbl in 2005 (975 thousand bpd); 52% of this supply was from foreign imports, 34% was from California sources, and 14% was from ANS (Baker & O'Brien 2007a). It is important to note that ANS supply arrives in southern California on tankers, so marine imports include foreign imports as well as ANS. Most California production arrives in southern California by pipeline.

Crude oil production from California and Alaska (as well as the rest of the U.S.) is decreasing. California crude production peaked in 1985 and has declined by 39 percent since 1986, and Alaskan crude production has declined 60 percent since 1986 (Figure 3; CEC 2007d). (Note that Figure 3 uses the same data as Figure 1-3 in Chapter 1 of the SEIS/SEIR, but measures thousand bpd rather than million bbl.)

Figure 3. California Crude Oil Supply, Statewide, 1982-2006



Source: CEC (2007d).

CEC (2007c) uses two alternative forecasts for the decline in California production. From 1991 through 2006, the decline averaged 2.23 percent per year; more recently (2003 to 2006), the decline averaged 3.44 percent per year. These two averages constitute the bounding assumptions on the CEC's alternative predictions for declines in California crude oil production (rounded to one decimal place: 2.2 and 3.4 percent per year) (CEC 2007c).

Occasionally, a refiner may expand slightly the capacity of its crude oil distillation equipment if the expansion meets environmental guidelines and can be justified as having a sufficient economic return (CEC 2007c). Between 2001 and 2006, CEC notes, California refinery capacity creep increased by 0.98 percent per year. However, most of this growth occurred in 2001 and 2002; between 2003 and 2006, refinery capacity creep increased just 0.41 percent per year (CEC 2007c). Thus, CEC (2007c) presents three cases for refinery capacity creep: a Low Case of 0.41 percent per year, a High Case of 0.98 percent per year, and a Base Case of 0.70 percent per year (representing the average of the Low and High Cases).

Thus, CEC (2007c) provides six alternative scenarios for the demand for marine imports of crude oil (three scenarios for refinery capacity creep, times two scenarios for California crude oil production decline). CEC (2007c) provides scenarios separately for statewide and southern California.

As part of evaluating the reasonableness of the Baker & O'Brien (2007a) import scenario, the LAHD and the USACE compared the Baker & O'Brien (2007a) forecasts to those from the CEC (CEC 2007b). However, an adjustment was necessary to use the same starting year from which to measure incremental crude oil demand. The crude oil demand forecasts in CEC (2007c) use a 2005 baseline; that is, they measure the amount of incremental demand over 2005. To correspond to the 2004 date of the Notice of Preparation (NOP) of this SEIS/SEIR, which is also the date of the baseline used by Baker & O'Brien (2007a), the LAHD and the USACE rebaselined the CEC forecast to measure the amount of incremental demand over 2004. The adjustment was accomplished by adding the difference in marine imports of crude oil to southern California between 2004 and 2005 (shown in Table 3).

Table 3. Southern California Crude Oil Supply, 2004-2005 (thousand bpd)

Source	*2004*	*2005*
ANS	193	167
Foreign	399	465
California	377	343
Total	969	975

Source: Baker & O'Brien (2007a).
ANS = Alaska North Slope.

As Table 3 shows, southern California received 592 thousand bpd in 2004, and 632 thousand bpd in 2005, of crude oil from ANS and foreign sources (i.e., received through marine terminals). Thus, to rebaseline the CEC projections to 2004, the difference of 40 thousand bpd was added to the CEC projections. Table 4 shows the six alternative cases for southern California crude oil marine imports after implementing the rebaseline adjustment.

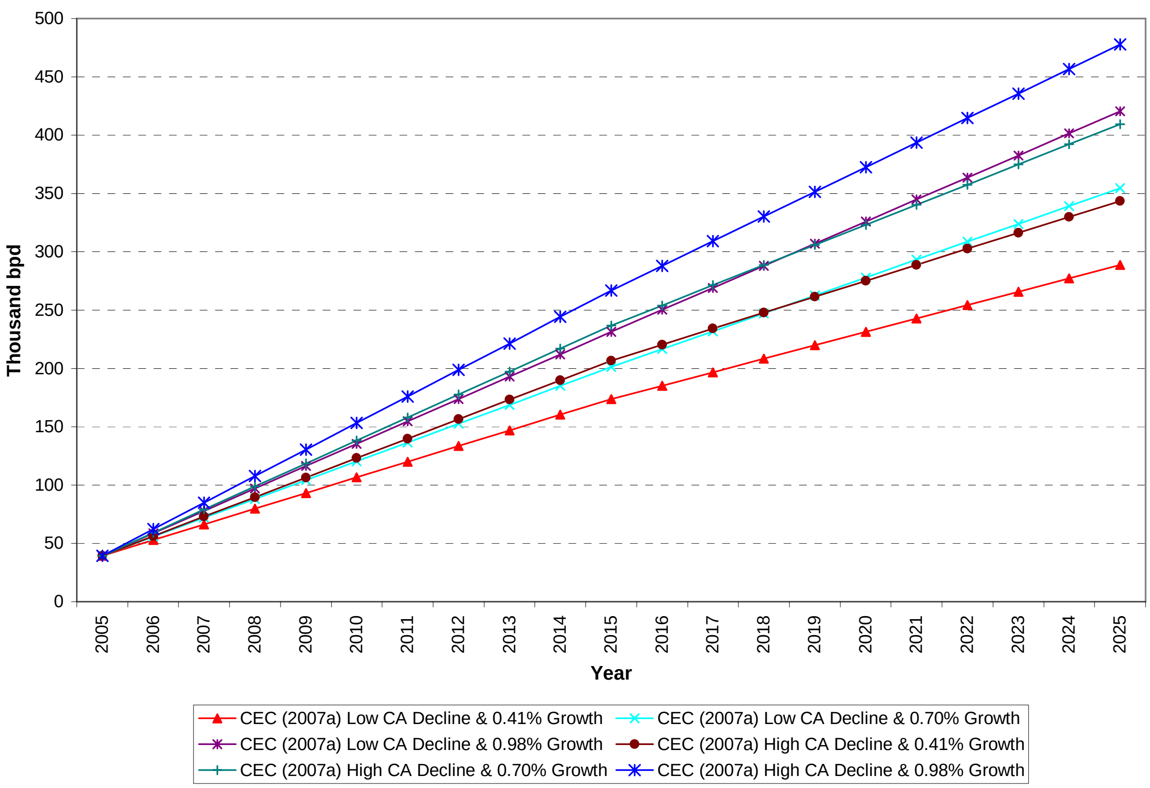
Table 4. CEC Forecast of Southern California Crude Oil Marine Imports, Incremental Over 2004 (thousand bpd)

Rate of Refinery Capacity Creep	*Low Rate of California Crude Oil Production Decline – 2.2%*		*High Rate of California Crude Oil Production Decline – 3.4%*	
	2015	*2025*	*2015*	*2025*
0.41 Percent	174	289	207	344
0.70 Percent	201	355	237	409
0.98 Percent	231	420	267	478

Source: CEC (2007c), Table 12; modified to use 2004 baseline (original document uses 2005 baseline), and converted from million bbl to thousand bpd.
Source for establishing 2004 baseline (i.e., incremental imports in 2005 over 2004): Baker & O'Brien (2007a).

Figure 4 provides the same information in graphical form.

Figure 4. CEC Projected Demand for Crude Oil Marine Imports to Southern California, 2005-2025

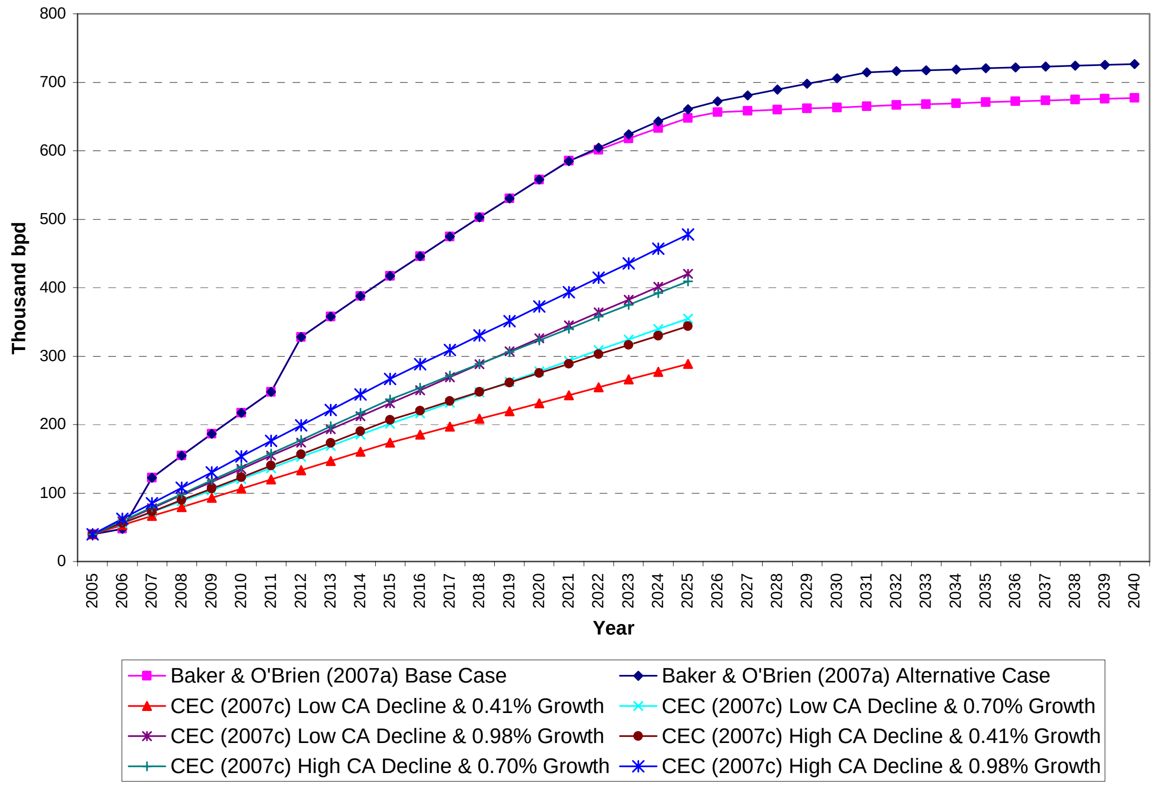


Source: Based on CEC (2007c), Table 12; modified to use 2004 baseline (original document uses 2005 baseline), and converted from million bbl to thousand bpd. Source for establishing 2004 baseline (i.e., incremental imports in 2005 over 2004): Baker & O'Brien (2007a).

D1.1.4 Comparison of Demand Scenarios

Figure 5 shows a comparison of the CEC and Baker & O'Brien demand projections in graphical form. Note that the CEC demand projections end in 2025, whereas the Baker & O'Brien projection goes through 2040.

Figure 5. Comparison of Demand Scenarios for Crude Oil Marine Imports to Southern California (Incremental Over 2004)



Source: Baker & O'Brien (2007a); CEC (2007c). CEC (2007c) figures are modified to use 2004 baseline (original document uses 2005 baseline), and converted from million bbl to thousand bpd. Source for establishing 2004 baseline (i.e., incremental imports in 2005 over 2004): Baker & O'Brien (2007a).

Table 5 shows the same data in tabular format.

As Figure 5 and Table 5 show, crude oil demand projected by Baker & O'Brien (2007a) exceeds that projected by all of the CEC (2007c) cases through 2025. This result arises from three factors: Baker & O'Brien (2007a) assumes faster decline in California crude oil production, faster refinery capacity creep, and the additional increase in refinery capacity (50,000 bpd by 2012), over and above refinery capacity creep, that is included in the Baker & O'Brien forecast but not that of the CEC.

Table 5. Comparison of Demand Scenarios for Crude Oil Marine Imports to Southern California (thousand bpd; Incremental Over 2004)

			California Energy Commission (CEC)					
			Low Rate of California Crude Production Decline – 2.2%			*High Rate of California Crude Production Decline – 3.4%*		
Year	*Baker & O'Brien (Base Case)*	*Baker & O'Brien (Alternative Case)*	*0.41% RCC (CEC Low Case)*	*0.70% RCC*	*0.98% RCC*	*0.41% RCC*	*0.70% RCC*	*0.98% RCC (CEC High Case)*
2005	40	40	40	40	40	40	40	40
2006	48	48	53	56	59	56	59	62
2007	122	122	66	72	78	73	79	85
2008	155	155	80	88	97	90	99	108
2009	186	186	93	104	116	106	118	131
2010	217	217	107	120	135	123	138	153
2011	248	248	120	137	155	140	158	176
2012	328	328	134	153	174	157	178	199
2013	358	358	147	169	193	173	197	221
2014	388	388	160	185	212	190	217	244
2015	417	417	174	201	231	207	237	267
2016	446	446	185	217	250	220	254	288
2017	474	474	197	232	269	234	271	309
2018	502	502	208	247	288	248	289	330
2019	530	530	220	263	307	261	306	351
2020	558	558	231	278	326	275	323	372
2021	585	585	243	293	345	289	340	394
2022	602	605	254	309	364	303	358	415
2023	617	624	266	324	383	316	375	436
2024	633	643	277	339	401	330	392	457
2025	648	661	289	355	420	344	409	478
2026	656	672	n/a	n/a	n/a	n/a	n/a	n/a
2027	658	681	n/a	n/a	n/a	n/a	n/a	n/a
2028	660	689	n/a	n/a	n/a	n/a	n/a	n/a
2029	661	698	n/a	n/a	n/a	n/a	n/a	n/a
2030	663	706	n/a	n/a	n/a	n/a	n/a	n/a
2031	665	714	n/a	n/a	n/a	n/a	n/a	n/a
2032	666	716	n/a	n/a	n/a	n/a	n/a	n/a
2033	668	717	n/a	n/a	n/a	n/a	n/a	n/a
2034	669	719	n/a	n/a	n/a	n/a	n/a	n/a
2035	671	720	n/a	n/a	n/a	n/a	n/a	n/a
2036	672	722	n/a	n/a	n/a	n/a	n/a	n/a
2037	673	723	n/a	n/a	n/a	n/a	n/a	n/a
2038	675	724	n/a	n/a	n/a	n/a	n/a	n/a
2039	676	726	n/a	n/a	n/a	n/a	n/a	n/a
2040	677	727	n/a	n/a	n/a	n/a	n/a	n/a

RCC = refinery capacity creep.

n/a = Not applicable.

Source: Baker & O'Brien (2007a); CEC (2007c) Table 12. CEC data are converted from million bbl to thousand bpd, and modified to use 2004 baseline; original document uses 2005 baseline; source for establishing 2004 baseline (i.e., incremental imports in 2005 over 2004) is Baker & O'Brien (2007a).

As noted in Section D1.1.1, the 3.5 percent decline in California crude oil production used by Baker & O'Brien is based on the three-year and five-year trends of California production; as noted in Section D1.1.3, the CEC's alternative assumptions are based on the fifteen-year and four-year trends.

The Port and the USACE find reasonable Baker & O'Brien's scenarios for future refinery capacity creep. As noted above, the CEC's three scenarios are based on arithmetic averages of the historical average annual refinery capacity creep from 2001-2006 (0.98 percent) and 2003-2006 (0.41 percent). Baker & O'Brien (2008) note that "while creep history is an interesting statistic, it is not a good indicator of future trends, as can be seen from the five-year and three-year history" (i.e., that the average over 2001-2002 was not a good predictor of the average over 2003-2006). Baker & O'Brien state that the 1.25 percent per year creep through 2021 that they assumed "is achievable and will be sought out by refiners to meet increasing product demand" (Baker & O'Brien 2008).

Furthermore, the Port and the USACE find reasonable Baker & O'Brien's prediction that refineries in southern California would likely add about 50,000 bpd of new capacity by 2012. This assessment is based in part on Baker & O'Brien's role as consultant to many firms in the oil and gas industry and the resulting extensive in-depth knowledge of operating parameters and potential future plans of firms operating in the industry. It is also based on the specificity of their focus in the referenced study, including their geographic focus on southern California as well as their topical focus on refineries' demand for crude oil (in contrast to CEC's more broadly defined mission). The Port and the USACE find additional support for this prediction from the fact that, as Baker & O'Brien note, in early 2007 two southern California refineries announced plans for capacity expansions totaling 21,000 bpd (Baker & O'Brien 2008).

Although the Baker & O'Brien Alternative Case scenario would result in a higher level of environmental impacts (due to higher refinery demand and thus potentially higher throughput), Baker & O'Brien (2008) advises that the Base Case is more reasonable given the anticipated reduction in consumer demand for refined petroleum fuels due to alternative fuels and conservation.

For the reasons described above, and also to provide a conservative analysis of reasonably foreseeable environmental impacts, the Port and the USACE used the Baker & O'Brien Base Case scenario as the basis for the projected throughput and vessel calls used in the environmental analysis.

The environmental analysis also uses the assumption that every new barrel of crude oil demanded by southern California refineries would be received at the new Berth 408. This may not occur in practice, as competition will continue among marine oil terminals to bring in oil imports and deliver them to area refineries. However, the assumption provides for a conservative analysis of reasonably foreseeable environmental impacts; it is reasonably foreseeable that due to the modern facility design, high offloading rates, and ability to accommodate Very Large Crude Carriers (VLCCs), the new Berth 408 could provide the lowest-cost receiving facility at the San Pedro Bay Ports.

D1.1.5 Applicant's Projections for Customer Demand

As part of its business plan, Pacific Los Angeles Marine Terminal LLC (PLAMT) has discussed the needs of various potential customers that may receive crude oil through the proposed Project terminal if it is built. PLAMT projects that the needs of its potential customers are as follows (PLAMT, 2007a):

- 350,000 bpd in 2010
- 500,000 bpd in 2015
- 565,000 bpd in 2020
- 590,000 bpd in 2025.

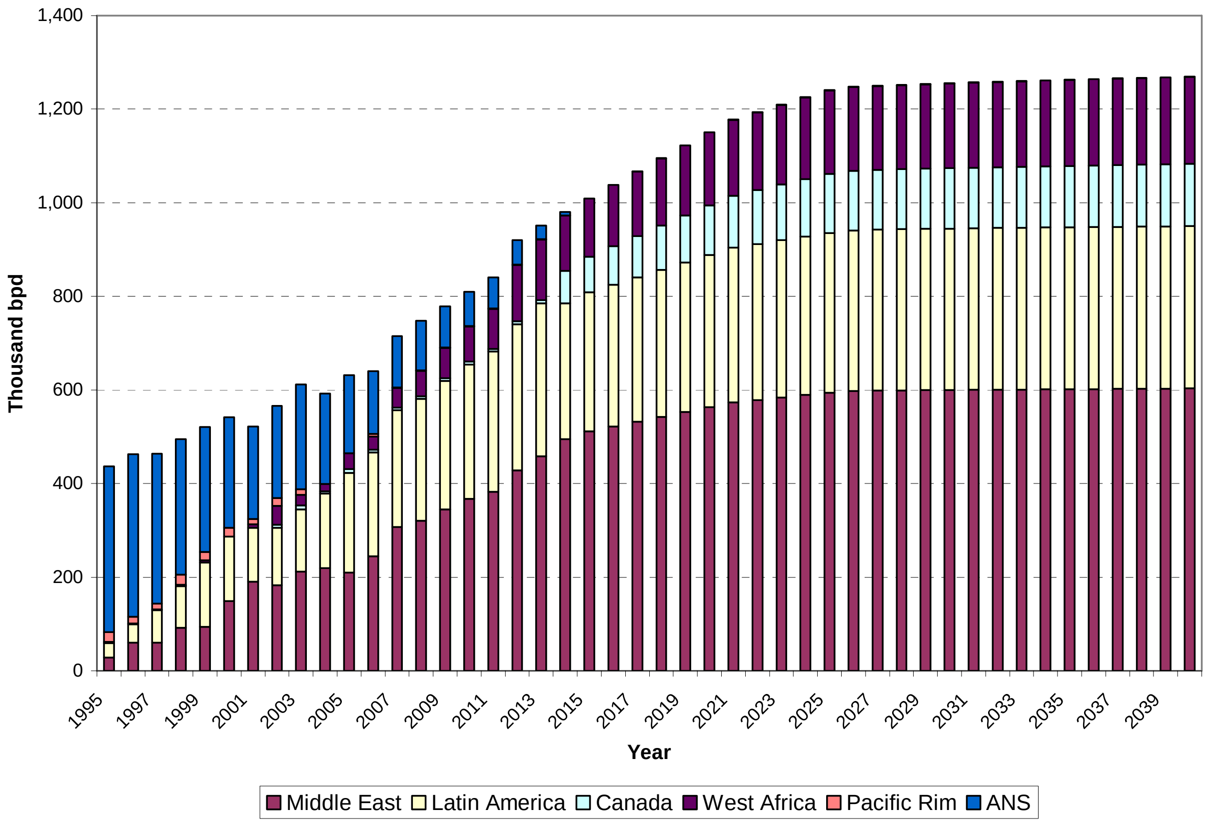
For 2010, 2015, and 2020, these needs are higher than the incremental demand for importation of crude oil projected by Baker & O'Brien (2007a) or the CEC (see Figure 5 and Table 5). This is consistent with the idea that the berth constructed as part of the proposed Project could accommodate some oil that is currently received at existing terminals (on smaller vessels at a higher cost per barrel, and generally more environmental impacts per barrel).

D1.2 Vessel Types

Many factors determine the sizes of vessels that are used to transport and deliver crude oil, such as conditions at the load port and destination port (type and amount of shore side tankage, draft, length, and beam allowance), physical characteristics of the oil (e.g., some heavy crudes require heating prior to being pumped and only certain vessels have heating units), market conditions, transport time, shoreside pipeline scheduling requirements, and transportation economics that vary by vessel type. Thus, predicting what types of vessels would call at Berth 408 or other berths under the proposed Project, Reduced Project Alternative, and No Federal Action/No Project Alternative is a difficult proposition. For analysis purposes, the LAHD and the USACE used conservative assumptions in order to predict a conservative, but reasonably foreseeable, vessel mix based on projected imports of crude oil to southern California by source (world region) and other factors.

Figure 6 shows historical and projected future marine imports of crude oil to southern California by source (Baker & O'Brien 2007a, 2008). As the figure shows, foreign imports are currently sourced from the Middle East, Latin America, and West Africa, with some small volumes coming from the Pacific Rim and Canada. Imports from the Middle East have increased steadily since 1995 and are projected to continue to increase; imports from Latin America also comprise a large share of projected future marine imports. Imports from West Africa and Canada also comprise a sizable share of projected future marine deliveries. ANS deliveries have historically represented a large share of marine deliveries, but have decreased over time, and Baker & O'Brien expect ANS deliveries to southern California to drop to zero by about 2015. Baker & O'Brien predict that the ANS crude will generally be replaced by Middle East crudes, because the common characteristics (weight and constituents) between Middle East and ANS crudes mean that refineries can substitute one for the other with relatively minor modifications to refinery equipment. Baker & O'Brien predict that California crude would be replaced by a combination of crudes from Latin America, West Africa, Canada, and the Middle East, for the same reason (most of the crude produced in California is heavy and sour, and most of the heavy sour crude that could replace it is produced in these regions) (Baker & O'Brien 2007a; Baker & O'Brien 2008).

Figure 6. Marine Imports of Crude Oil to Southern California Crude Oil, by Region of Origin



Source: Baker & O'Brien (2007a); reflects Baker & O'Brien Base Case.

Based on the current and future world fleet mix and other considerations, as outlined above, Baker & O'Brien (2007a, 2008) developed assumptions for the correspondence between location of crude oil load ports and vessel size for transport to southern California. Baker & O'Brien assume that Middle East crudes will be transported exclusively on VLCCs, because these large vessels reduce transportation costs on a per barrel basis. Baker & O'Brien assume that Latin American crude will be transported by Suezmax and Aframax tankers in equal measure from 2005-2016, but project that from 2017 to 2040, the mix would change to 75% Suezmax and 25% Aframax. Baker & O'Brien explain that since as import volumes from Latin America increase, it is likely that a larger proportion of volumes will come from farther located countries, such as Brazil, than those that currently provide a majority of the imports, such as Ecuador and Mexico. As voyage distances increase, transportation via the larger Suezmax vessels becomes economical (Baker & O'Brien 2008). Baker & O'Brien assume that West Africa crude would be transported exclusively on Suezmax tankers, and Canadian crude would be transported on a combination of Suezmax and Aframax tankers. Thus, their assumptions are as follows:

- Middle East: 100% transported on VLCCs
- Latin America (2004-2016): 50% transported on Suezmax and 50% on Aframax

- Latin America (2017-2040): 75% transported on Suezmax and 25% on Aframax
- Canada: 50% transported on Suezmax and 50% on Aframax
- West Africa: 100% transported on Suezmax.

ANS crude is usually transported on Suezmax vessels; nine vessels in the world fleet are specifically dedicated to the transport of ANS crude (due to specific requirements particular to operating in the necessary load ports), and all are Suezmax class.

Based on the data shown in Figure 6 and the assumptions shown above, incremental marine deliveries (compared to 2004) would be comprised of the vessel mix shown in Table 6.

Table 6. Potential Marine Deliveries to Southern California by Vessel Type (Incremental Over 2004)

Vessel Type	*2010*	*2015*	*2025*	*2040*
Aframax	34	54	34	37
Suezmax	1	7	75	81
VLCC	27	53	68	70
Source: Calculated from Baker & O'Brien (2007a) Base Case.				

Although the Baker & O'Brien assumptions do not include the use of smaller Panamax vessels, Plains acknowledges that these vessels may call at Berth 408 as needed in order to accommodate specialized customer needs or supply crude oil on a quick turnaround to meet changing market needs (i.e., service the spot market). Thus, the analysis of the proposed Project and Reduced Project Alternative includes some use of Panamax vessels as well as the three classes shown above.

D1.3 Capacity of Existing Terminals

In order to develop the No Federal Action/No Project Alternative and the Reduced Project Alternative, the Port and the USACE evaluated the capacity of existing crude oil terminals in southern California to accommodate additional crude oil imports. However, the available capacity of existing terminals is difficult to assess due to the highly sensitive nature of such information, which is usually considered confidential business information.

Capacity of terminals to receive crude oil is a complex product of multiple factors, including physical considerations – size of vessels (depth, beam or width, and length overall (LOA)) that can be accommodated at berths, the capacity to receive vessels at multiple berths simultaneously, the rate at which pumps can offload crude oil from vessels, storage capacity, pipeline capacity, and the ability of refineries to receive crude oil immediately – as well as permitting considerations related to the South Coast Air Quality Management District (SQAQMD) and other agencies. This analysis of capacity assumes no change in infrastructure or operating permits. It is important to note that marine terminals generally cannot operate at their theoretical maximum capacity since it is difficult to precisely calculate a tanker's travel time and arrival (because of changing sea conditions) and unexpected delays in unloading cargo (e.g., the potential for lengthy inspections, processing delays in paperwork, and interruption of pumping operations during cargo discharge) (CEC 2007b). In addition, landside constraints such as storage tank capacity, pipeline scheduling constraints, and balancing the needs of refinery customers introduce additional constraints that prevent terminals to operate at their theoretical maximum capacity.

The Port and the USACE considered available public information from various sources including the California State Lands Commission (CSLC), the Marine Exchange of Southern California, and the SCAQMD, to assess the existing capacity of terminals presently operating in southern California. (Note that certain information from SCAQMD, including detailed operating data available in permit applications, is considered confidential and not available for public review.) Plains, through its normal course of business, also has knowledge of the operations of existing oil terminals, pipelines, and storage facilities in southern California. Based on this publicly available information and Plains' knowledge of the oil import and pipeline industry, as verified by the Port's own knowledge of the operations of existing terminals at both San Pedro Bay Ports, the Port and the USACE estimated the potential incremental capacity remaining at the existing marine terminals.

D1.3.1 El Segundo Mooring

Chevron's El Segundo mooring facility comprises two sea berths for offshore mooring just west of El Segundo, about nine miles (14.5 km) northwest of the Port. Berth 3 is about 7,200 feet offshore, and Berth 4 is about 8,100 feet offshore. The two berths can accommodate vessels simultaneously; each can accommodate a vessel up to 1,000 feet in length overall (LOA) and carrying approximately 150,000 deadweight tons (DWT). Berth 3 can accommodate a vessel drafting up to 51 feet, and Berth 4 a vessel drafting up to 56 feet. The facility receives about 16 to 18 vessels per month (CSLC 2007c). The facility received about 56 million bbl of crude oil (average of 153,000 bpd) in 2004; 70 million bbl (average of 191,000 bpd) in 2005; and 66 million bbl (average of 181,000 bpd) in 2006 (CSLC 2007a; CSLC 2007b). All crude oil received at the facility is processed by Chevron's El Segundo refinery.

The El Segundo refinery is the subject of several recent CEQA filings. The Heavy Crude Project EIR (SCAQMD, 2006), which was certified in August 2006, documented the impacts of modifying one of the two existing crude oil processing units (No. 4 Crude Unit), coker, and crude oil storage tanks to enable the refinery to process heavier crude oils, with the potential for additional crude oil imports. Although the No. 4 Crude Unit would be expanded from 195,000 bpd to 210,000 bpd of heavier crude, with the potential to process up to 230,000 bpd of a crude slate tailored to the modified unit (SCAQMD, 2006, Appendix F2), the document analyzes a smaller amount of incremental throughput in terms of the increased number of vessels (estimated at nine additional vessels per year carrying about 700,000 bbl per vessel). In addition to the Heavy Crude Project, the SCAQMD recently released a Notice of Preparation for a Product Reliability and Optimization Project which would involve physical changes and additions to various process units as well as operational and functional improvements within the refinery, but which would not result in an increase in crude throughput (SCAQMD, 2007).

The recent (2006) environmental clearance for additional throughput of approximately 6.3 million bbl (average of 18,000 bpd) at the El Segundo facility suggests that the facility now has additional capacity, in terms of both physical infrastructure and operating permits, to receive crude oil over and above the amount it received in 2004 (the baseline year for the SEIS/SEIR). It is reasonable to suppose that the additional throughput would be received at the El Segundo terminal regardless of the approval of the Project proposed in this SEIS/SEIR. Approval of the proposed Project at Berth 408 would not decrease throughput at the El Segundo mooring and refinery because the mooring is proprietary to Chevron, which is a large oil company with rights over many producing areas, and which can be expected to protect its investments in the mooring and refinery by continuing to import as much crude oil as the refinery can accommodate. Failure to approve the proposed Project at Berth 408 would not result in increased throughput at the Chevron El Segundo terminal, unless Chevron further expanded capacity of the refinery and potentially the mooring facility. Note that neither the EIR for the Heavy Crude Project nor other publicly available information about the project indicates the timeline for the additional throughput of crude oil as a result of that project.

D1.3.2 Port of Los Angeles Berths 238-240

LAHD Berths 238, 239, 240B, and 240C, operated by ExxonMobil, receive crude oil and refined products. In 2004 this facility received 36 vessels carrying about 4.5 million bbl of refined product (Knott 2007), but received no crude oil (CSLC 2007a, CSLC 2007b). The facility also received no crude oil in 2005; 780,000 bbl of crude oil in 2006; and 16,000 bbl (about 45 bpd) of crude oil in 2007 (CSLC 2007b; CSLC 2008). According to the CSLC, the facility now receives an average of 5 to 6 vessels per month (CSLC 2007d).

The terminal receives oil and products 24 hours a day (CSLC 2007d). The terminal property contains 19 storage tanks for crude oil and products with capacities ranging from 5,000 to 80,000 bbl; the total capacity is 968,000 bbl. The largest pipelines can receive oil at a maximum rate of 4,760 gallons per minute, or 6,800 bbl/hr (Knott 2007). The maximum vessel draft is 37 feet and maximum vessel length overall (LOA) is 1,000 ft (Knott 2007). Based on the physical constraints of the terminal, the Port believes that if this terminal were to import crude oil on a regular basis, it would most likely arrive on Panamax-size vessels carrying about 300,000 bbl each.

Plains's knowledge of pipeline capacity suggests this terminal could theoretically accommodate 120,000 bpd of crude oil. This figure does not take into account conflicts between accommodation of crude oil and refined products, nor does it take into account certain other considerations (e.g., conflicts for the use of storage tanks for crude oil versus refined products, or the influence of long-term contracts and the competitive strategies of firms). If the terminal were to accommodate 120,000 bpd of crude oil in Panamax tankers carrying about 300,000 bbl each, this would represent about 146 such tanker vessels.

D1.3.3 Port of Long Beach Berth 121

Port of Long Beach Berth 121, operated by BP, receives crude oil from one tanker at a time at its single berth. The wharf is dredged to 76 feet below mean lower low water (MLLW). The facility can receive a vessel with up to 1,225 feet LOA and a beam (width) of up to 230 feet (CSLC 2007e) and is designed to accommodate vessels carrying from 50,000 deadweight tons (DWT) to 265,000 DWT (Port of Long Beach 2007).

The terminal receives ANS as well as other crude oil, and also loads bunker fuel onto vessels. The terminal has no storage tanks of its own; crude oil discharged at the terminal is pumped directly to BP's Carson Refinery (T-2). According to CSLC (2007e), this terminal receives about 20 tanker calls per month on average.

The terminal received about 124 million bbl (339,000 bpd) in 2004, 126 million bbl (average of 344,000 bpd) in 2005, and 121 million bbl (average of 331,000 bpd) in 2006 (CSLC 2007b). The decline in the quantity of crude oil offloaded at Berth LB 121 in 2006 compared to 2005 is attributable to two events: a two-month shutdown of several processing units at BP's Los Angeles Refinery, and a pipeline incident that resulted in a temporary reduction of ANS crude production from the Prudhoe Bay field (Baker & O'Brien 2007b). In 2007, the terminal received about 118 million bbl (average of 324,000 bpd) (CSLC 2008).

The LAHD's research suggests this terminal is operating at its capacity to receive crude oil and would not be able to accommodate additional crude oil without a change in its physical infrastructure or operating permits. This is supported by the fact that this terminal did not increase its throughput between 2004 and 2006 despite the apparent potential to make additional profits from importing and refining additional crude oil (as reflected in the continued profitability of oil transport and refining).

D1.3.4 Port of Long Beach Berths 76-78

Port of Long Beach Berths 76, 77, and 78, operated by BP, receive crude oil, refined products, and chemicals. This terminal received about 9.8 million bbl of crude oil in 2004 (27,000 bpd), 8.6 million bbl of crude oil in 2005 (24,000 bpd) and 5.5 million bbl in 2006 (15,000 bpd) (CSLC 2007b). In 2007, the terminal received about 7.5 million bbl, or 21,000 bpd on average (CSLC 2008). According to the CSLC, the facility receives an average of 20-25 vessels per month (CSLC 2007f).

Each of the three berths has slightly different capacity in terms of maximum vessel size; however, the longest vessel that can be accommodated is 900 ft (with 106 ft beam). Berth 78, the deepest, is dredged to 41 feet MLLW (CSLC 2007f). The terminal can receive barges as well as vessels carrying up to 150,000 DWT. Based on the physical constraints of the terminal, the Port believes that if this terminal were to import crude oil on a regular basis, it would most likely arrive on light-loaded Aframax-size vessels carrying about 400,000 bbl each.

Plains's knowledge of pipeline capacity suggests this terminal could theoretically accommodate 43,000 bpd of crude oil in addition to its receipts in 2007. This figure does not take into account conflicts between accommodation of crude oil and refined products, nor does it take into account certain other considerations (e.g., conflicts for the use of storage tanks for crude oil versus refined products, or the influence of long-term contracts and the competitive strategies of firms). Since the terminal received about 6,000 bpd less in 2007 than in 2004, to be consistent with the 2004 baseline used as the basis for the crude oil demand projection, the LAHD and the USACE estimated that the additional capacity at this terminal that was available in 2004 was about 37,000 bpd. If the terminal were to accommodate 37,000 bpd of crude oil on Aframax tankers carrying about 400,000 bbl each, this would represent about 34 such tanker vessels.

D1.3.5 Port of Long Beach Berths 84-87

The terminal at Port of Long Beach Berths 84-87, recently purchased by Tesoro from Shell, receives crude oil and products. Of the six berths at the terminal (84, 84a, 85, 85a, 86, and 87), only two (Berths 84a and 86) are operational. Both Berth 84a (located at the east end of the dock) and berth 86 (located at the west end of the dock) are dredged to 45 feet MLLW and can accommodate vessels with LOA up to 1,000 feet and beam up to 146 feet; vessels carrying up to 130,000 DWT can dock (Tesoro 2005). The two berths can accommodate vessels simultaneously, although they cannot both accommodate large Aframax tankers at the same time (Tesoro 2007a). Based on the physical constraints of the terminal, the Port believes that this terminal is capable of receiving light-loaded Aframax-size vessels carrying about 400,000 bbl each.

This terminal received about 20 million bbl (54,000 bpd) of crude oil in 2004, 28 million bbl (77,000 bpd) in 2005, 30 million bbl (83,000 bpd) in 2006, and 33 million bbl (90,000 bpd) in 2007 (CSLC 2007b; CSLC 2008). The terminal experienced 68 tanker calls in 2004, 80 in 2005, and 88 in 2006 (Tesoro 2007a); no data were available for 2007.

Plains's knowledge of pipeline capacity suggests this terminal could theoretically accommodate 59,000 bpd of crude oil over and above its receipts in 2007. This figure does not take into account conflicts between accommodation of crude oil and refined products, nor does it take into account certain other considerations (e.g., conflicts for the use of storage tanks for crude oil versus refined products, or the influence of long-term contracts and the competitive strategies of firms). Since the terminal received about 36,000 bpd more crude oil in 2007 than in 2004, to be consistent with the 2004 baseline used as the basis for the crude oil demand projection, the LAHD and the USACE estimated that the additional capacity at this terminal that was available in 2004 was about 95,000 bpd. If the terminal were to accommodate 95,000 bpd of crude oil on Aframax tankers carrying about 400,000 bbl each, this would represent about 87 such tanker vessels.

D1.3.6 Additional Berths at Port of Los Angeles and Port of Long Beach

Although the terminals described above are the primary terminals at the San Pedro Bay Ports that receive crude oil, other terminals occasionally receive small amounts of crude oil.

Table 7 shows crude oil receipts at these additional terminals in 2004-2007.

Table 7. Additional Berths at the San Pedro Bay Ports: Crude Oil Receipts

Berth	Crude Oil Receipts (bbl)			
	2004	2005	2006	2007
LA 143	164,000	0	0	52,000
LA 164 (Valero)	0	213,000	0	0
LA 167 (Shell)	0	0	150,000	390,000
LA Vopak	32,300	18,000	0	424,000
Source: CSLC (2007b) and CSLC (2008).				

However, the operators at these terminals typically focus on receipt of refined petroleum products and chemicals rather than crude oil. Thus, the LAHD and the USACE did not incorporate increased crude oil throughput at these terminals into the analysis of the No Federal Action/No Project Alternative.

D1.4 Assumptions for Analysis

As noted above (Section D1.1.4), the LAHD and the USACE used the Baker & O'Brien (2007a) Base Case as the basis for crude oil demand for the proposed Project, No Federal Action/No Project Alternative, and Reduced Project Alternative. In addition, the LAHD and the USACE based assumptions for throughput at Berth 408 on the applicant's projections of its customers' needs, and, for the Reduced Project Alternative only, the lease cap that would be imposed as a condition of that alternative. For the No Federal Action/No Project Alternative and Reduced Project Alternative, assumptions for throughput at existing terminals are based on crude oil demand projections and the capacity of existing crude oil terminals.

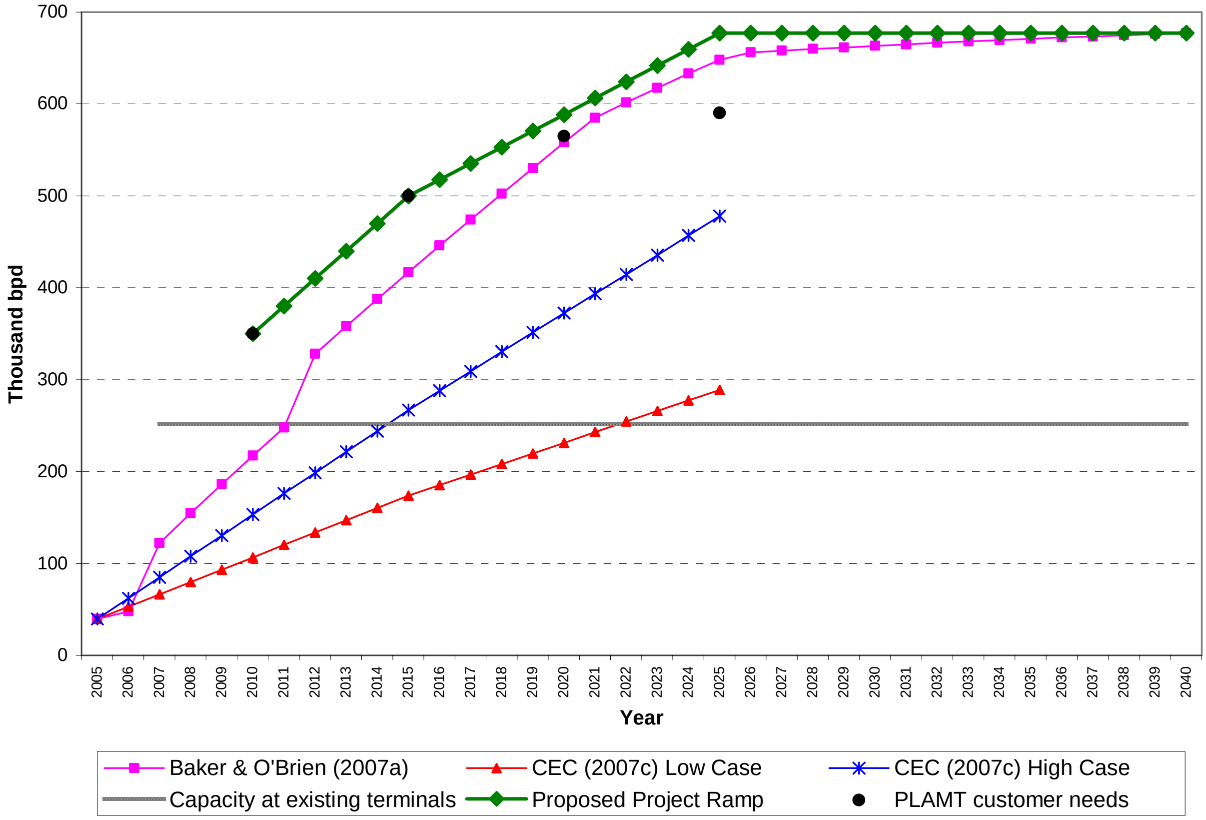
D1.4.1 Throughput and Vessel Calls Under the Proposed Project

Based on the information presented above, and to provide a conservative analysis of reasonably foreseeable environmental impacts so as to disclose all reasonably foreseeable impacts of the proposed Project, the LAHD and the USACE used a level of throughput for each year that is at least as high as the Baker & O'Brien (2007a) Base Case incremental demand projection, as well as PLAMT's estimates of its customers' needs. These considerations resulted in the following assumptions for throughput at Berth 408:

- 350,000 bpd in 2010
- 500,000 bpd in 2015
- 677,000 bpd in 2025-2040.

Figure 7 shows these assumptions with linear interpolation for intermediate years. As noted previously (Section D1.1.4), the actual use of Berth 408 will depend on a variety of factors including market conditions. The use of these assumptions for analysis does not mean that Berth 408 would necessarily receive the full amount of crude oil for the years indicated, but it does allow disclosure of all reasonably foreseeable impacts of the proposed Project.

Figure 7. Throughput Assumptions for the Proposed Project



To project the amount of vessel calls that would be associated with throughput, the LAHD and the USACE considered projections about likely sources of imported crude oil and assumptions used by Baker & O'Brien in their projections of southern California marine deliveries (Section D1.2). Like the throughput scenario, to allow disclosure of all reasonably foreseeable impacts of the proposed Project, the LAHD and the USACE used a vessel mix for the proposed Project that represents a conservative, but reasonably foreseeable, case, due to the use of a greater number of smaller vessels. Table 8 shows the vessel mix used for analysis.

Table 8. Vessel Mix Analyzed for the Proposed Project

Vessel Type	*2010*	*2015*	*2025*	*2040*
Panamax	26	12	18	18
Aframax	32	24	36	36
Suezmax	45	60	78	78
VLCC	26	51	69	69

D1.4.2 Throughput and Vessel Calls Under the No Federal Action/No Project Alternative

As noted above, a conservative analysis of the No Federal Action/No Project Alternative requires that throughput be estimated at the highest reasonably foreseeable level. Section D1.3 documents available information from which the available capacity of existing crude oil terminals in southern California can be estimated. Based on the information presented in Section D1.3, the LAHD and the USACE concluded that Port of Long Beach Berth 121 probably has no excess capacity beyond its current throughput. The LAHD and the USACE did not include the additional approximately 18,000 bpd throughput associated with the El Segundo Marine Terminal in the analysis because, as stated above, it is reasonable to suppose that this additional throughput would be received at the El Segundo terminal regardless of the approval of the Project proposed in this SEIS/SEIR. However, available information about LAHD Berths 238-240 and Port of Long Beach Berths 76-78 and 84-87 suggests that there is excess capacity at these terminals. As documented in Section D1.3, the LAHD and the USACE estimate the total remaining capacity (over 2004 throughput) at 252,000 bpd, including 120,000 bpd at LAHD Berths 238-240, 37,000 bpd at Port of Long Beach Berths 76-78, and 95,000 bpd at Port of Long Beach Berths 84-87.

In the No Federal Action/No Project Alternative, the level of throughput is equal to the lesser of existing capacity (i.e., 252,000 bpd) or incremental demand according to Baker & O'Brien (2007a). Figure 8 shows a summary of throughput used for analysis of the No Federal Action/No Project Alternative.

The incremental demand (over 2004) is less than 252,000 bpd only in 2010 and 2011 (also see Table 5); in 2012 and after, incremental demand exceeds the existing capacity of terminals in southern California. Additional imports of crude oil may come in by truck, rail, or barge (no pipelines transport crude oil into California, neither from neighboring states nor from Mexico). If refineries are unable to receive sufficient crude oil, their production of transportation fuels for consumers and businesses will decline so that they meet even less of the consumer demand than presently, which would increase pressure to import refined petroleum products. These additional refined products may come in by vessel, barge, truck, or rail. However, rather than speculate about the specific method by which more crude oil or refined products would enter the area, for analysis purposes the impact assessment for the No Federal Action/No Project Alternative in this SEIS/SEIR assumes no discretionary actions by the LAHD, the Port of Long Beach, or other agencies, and is based on marine imports up to the available capacity of existing crude oil berths. Appendix D3 contains additional information about the potential for other means of importing crude oil, as well as the potential for alternative energy sources and conservation to make up the difference. Appendix D2 documents potential economic impacts should supply not be available to meet demand.

Table 9 shows the number of vessel calls used for analysis of the No Federal Action/No Project Alternative. For years 2015, 2025, and 2040, when crude oil demand exceeds the estimated capacity of existing terminals, the analysis assumes full use of existing terminals up to their capacity. For the year 2010, the analysis

Figure 8. Throughput Assumptions for the No Federal Action/No Project Alternative

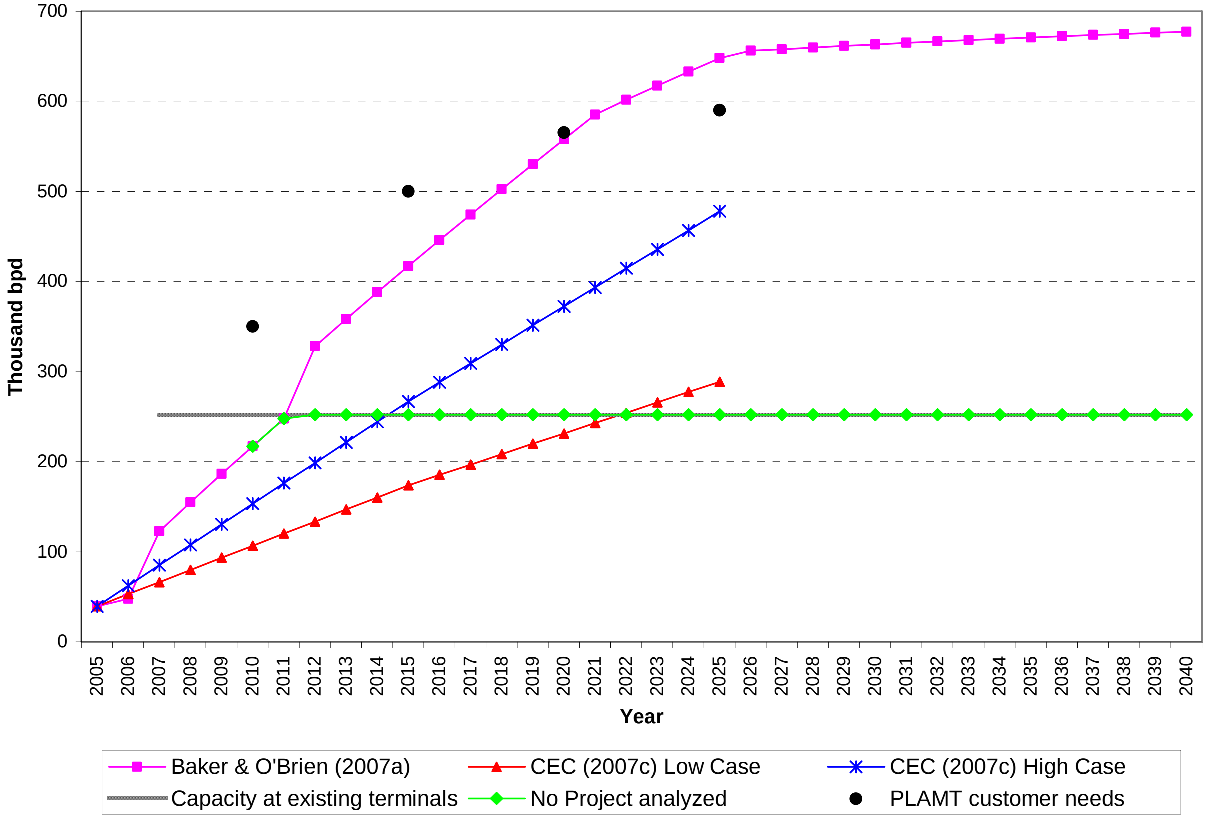


Table 9. Vessel Mix Analyzed for the No Federal Action/No Project Alternative

Vessel Type	2010	2015	2025	2040
Panamax (light loaded – 300,000 bbl) to LAHD Berths 238-240	125	146	146	146
Aframax (light loaded – 400,000 bbl) to Port of Long Beach Berths 76-78	29	34	34	34
Aframax (light loaded – 400,000 bbl) to Port of Long Beach Berths 84-87	75	87	87	87
Suezmax	0	0	0	0
VLCC	0	0	0	0
Total vessel calls	229	267	267	267

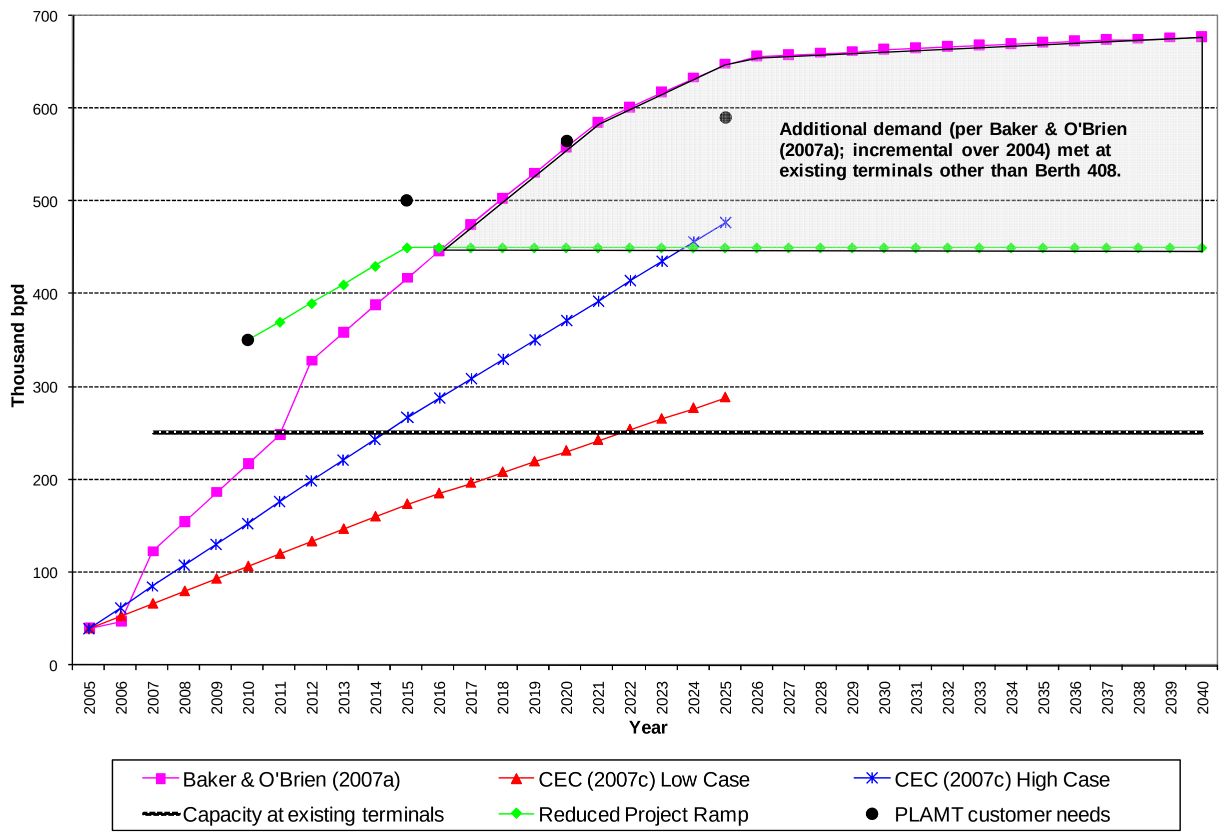
applies linear factors equivalent to incremental demand divided by excess capacity to prorate vessel calls at each berth. For instance, in 2010 incremental demand is 217,000 bpd, which is about 86% of the estimated excess capacity; therefore, the analysis uses a number of Panamax calls at LAHD Berths 238-240 equal to 86% of the estimated capacity of that terminal to receive vessels (i.e., 125 vessel calls rather than 146).

D1.4.3 Throughput and Vessel Calls Under the Reduced Project Alternative

Since the Reduced Project Alternative is identical to the proposed Project except for the imposition of a lease cap that limits throughput, impact assessment is based on throughput up to the level of the lease cap. Like the proposed Project, this provides for a conservative, but reasonably foreseeable, scenario, since crude oil throughput may be lower than the level of the lease cap, but will not be higher.

Figure 9 shows throughput assumptions for the Reduced Project Alternative.

Figure 9. Throughput Assumptions for the Reduced Project Alternative



The analysis of the Reduced Project Alternative also assumes that the level of crude oil demand projected by Baker & O'Brien (2007a) will ultimately be met. Therefore, the analysis assumes crude oil demanded would come to existing terminals at the San Pedro Bay Ports (up to their capacity). The assumption that demand would be met is based on the following factors:

- The demand for refined transportation fuels in southern California and the markets it supplies exceeds the ability of southern California refineries to produced refined fuels (Section D1.1)

- It is reasonable to assume that refinery owners would protect their assets by continuing to purchase crude oil; with continued demand for refinery outputs, it is reasonable to assume there would be continued demand for refinery inputs
- The LAHD has no authority over how much crude oil refineries may purchase from terminals other than Berth 408 (except that, in theory, the LAHD could impose a lease cap at Berths 238-240 during the lease renewal process on that terminal, which would happen in approximately 2025).

Thus, in the absence of speculating about additional projects or permit changes, it is reasonable to assume that existing terminals would continue to receive crude oil up to their capacity and up to the demand for crude oil from southern California refineries.

Vessel calls analyzed at Berth 408 were estimated using the same factors as described in Section D1.4.1 above, but were prorated for throughput at Berth 408 under the lease cap. Vessel calls at existing berths were also prorated for estimated throughput at existing berths using the same methodology as documented in Section D1.4.2.

D1.5 References

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