Baker & O'Brien

CITY OF LOS ANGELES

OIL AND GAS DRILLING ORDINANCE

STUDY 21: AMORTIZATION OF CAPITAL INVESTMENT STUDY FOR THE MISSION-VISCO DRILL SITE

PREPARED FOR:

The City of Los Angeles

Board of Public Works

Office of Petroleum and Natural Gas Administration and Safety

DATE:

December 23, 2024

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1. LEGAL NOTICE

1. The City of Los Angeles (the "City"), through its Board of Public Works' Office of Petroleum and Natural Gas Administration and Safety ("OPNGAS"), has retained Baker & O'Brien, Inc. ("Baker & O'Brien") to conduct this Amortization of Capital Investment Study under Contract Number C-142695.

2. This *Amortization of Capital Investment Study for the Mission-Visco Drill Site* (the "Study") presents the basis and conclusions for the time required to amortize capital investment for this group of oil wells and surface facilities. The Effective Date for this Study is December 31, 2022 (the "Study Effective Date").

3. Baker & O'Brien prepared this Study for the sole benefit of the City. Baker & O'Brien makes no warranty, either express or implied, and assumes no liability with respect to the use of any information or methods disclosed herein. Any use, reproduction, or distribution of this information by others requires Baker & O'Brien's prior written consent. Baker & O'Brien expressly disclaims all liability for the use, reproduction, distribution, or disclosure of this information to or by any third party.

4. The analysis, opinions, and findings presented in this Study are based on the experience, expertise, and skills of Baker & O'Brien consultants, as well as their research, analysis, discussions, and related work in preparing this Study. In preparing this Study, Baker & O'Brien has relied upon public and proprietary information available for use in this assignment. All conclusions, forecasts, and projections presented in this Study represent Baker & O'Brien's best judgment based upon information available as of the Study Effective Date. Forecasts, backcasts, and projections prepared for this Study are inherently uncertain due to the potential impact of factors or events that are unknowable, unforeseeable, or beyond Baker & O'Brien's control. Baker & O'Brien reserves the right to supplement or amend this Study if additional information should subsequently become available that is material to the conclusions presented herein.

2. EXECUTIVE SUMMARY

5. *Location*: The Mission-Visco Drill Site (the "Site") is located at 14737 N. San Fernando Road in the Granada Hills - Knollwood neighborhood of Los Angeles.[1] The wells and production facilities are all in one location. The wells on this Site are located south of the Sunshine Canyon Landfill and on top of a hill overlooking a neighborhood just west of Balboa Boulevard next to the Metropolitan Water District ("MWD") Jensen Water Treatment Plant.

6. *Zoning*: The Site is located within Council District 12 and the Granada Hills - Knollwood Community Plan area. The Site is zoned as A1-1-O, Agriculture with height limitations in an Oil Drilling District.[2]

7. *History*: Teater-Wadley Company ("TW") drilled the first well in 1954 and followed it up with a second well in 1955. Macson Oil Company ("Macson") took over the two wells from TW in 1956 and drilled an additional three wells that same year. In 1961, Macson transferred ownership of the Site to McCulloch Oil Corporation of California ("McCulloch"). McCulloch drilled a well in 1962. In 1970, McCulloch converted a well to an injector and initiated a waterflood at the Site. McCulloch drilled six additional wells before transferring the Site to Patriot Resources ("Patriot") in 1995. Patriot added six additional wells from 2001 to 2003 before transferring the Site to Castle Peak Resources LLC ("Castle Peak") in 2003. Castle Peak added three additional wells in 2004. The Site was transferred to the current owners, DCOR, LLC ("DCOR"), in 2006, and one additional well was drilled in 2014.

8. *Site Status*: The Site includes 23 oil and gas wells. In 2022, the Site had 19 active production wells, two active injection wells, an idle production well, and an idle injection well. Surface facilities at the Site include lease equipment and various improvements.

9. *Capital Investment*: The original cost to drill and complete wells and install lease facilities at the Site amounted to about $7.64 million. In addition to the original capital investment, sustaining capital investment in well equipment and lease equipment

[1] ZIMAS, https://zimas.lacity.org/

[2] City zone definitions are found at https://planning.lacity.gov/odocument/eadcb225-a16b-4ce6-bc94-c915408c2b04/Zoning_Code_Summary.pdf

amounted to more than $4.08 million. The cumulative estimated capital investment in the Site was about $11.72 million as of December 31, 2022.

10. *Site Income*: The Site generated revenue from the sale of crude oil and natural gas. Crude oil production from the Site peaked in 2004 at about 424,000 barrels annually, or 1,159 barrels per day. Natural gas production peaked in 2005 at more than 83,000 barrels of oil equivalent annually, or just over 226 barrels per day. Production of crude oil and natural gas declined from 2004 until 2022 when the Site produced about 72,000 barrels of oil (196 barrels per day) and about 22,000 barrels of oil equivalent (less than 59 barrels per day) of natural gas. Crude oil produced at the Site is medium-sweet crude with a market value comparable to Alaskan North Slope crude oil. After deductions for payments of royalties, operating costs, income taxes, and sustaining capital investment, the Site generated a cumulative net cash flow of about $136.7 million between 1954 and 2022.

11. *Base Case Conclusion*: In the Base Case, the capital investment in wells and lease facilities at the Site was amortized by 1957, within three years of the original capital investment. The cumulative internal rate of return for the Site in 2022 is higher than the market rate of return of 8%.

12. *Sensitivity Case Conclusions*: Sensitivity cases were prepared to consider reasonable ranges in alternative assumptions in the income analysis, including a higher market rate of return, a lower value received for crude oil, and a higher capital investment. A market rate of return of 12% resulted in no change in the time to amortize the capital investment. Deducting $0.50 per barrel of crude oil resulted in no change in the time to amortize capital investment. Increasing the capital investment to drill and complete new wells by 50% did not lengthen the time required to amortize capital investment. Over a reasonable range of assumptions, these factors do not significantly change the time required to amortize capital investment at the Site.

3. INTRODUCTION

13. The production of oil and gas has played a major role in the history and development of the City of Los Angeles (the "City"). The legacy of more than 100 years of oil and gas production can be counted in 26 oil and gas fields and more than 5,000 oil and gas wells that are located throughout the City.

14. The Los Angeles City Council passed Oil and Gas Drilling Ordinance 187709[3] (the "Ordinance") that prohibits new oil and gas extraction facilities and makes existing extraction activities in the City a nonconforming land use, with an Ordinance Effective Date of January 18, 2023.

15. The City, through its Board of Public Works' Office of Petroleum and Natural Gas Administration and Safety ("OPNGAS"), retained Baker & O'Brien, Inc. ("Baker & O'Brien") to determine the time required for amortization of capital investment in oil and gas production facilities located within the City under Contract Number C-142695. This *Amortization of Capital Investment Study for the Mission-Visco Drill Site* (the "Study") presents the basis and conclusions for Baker & O'Brien's determination of the time required to amortize capital investment for the group of oil wells and surface facilities located at the Mission-Visco Drill Site (the "Site"), which is located at 14737 N. San Fernando Road in the Granada Hills – Knollwood area of Los Angeles.

16. This Study is incorporated into a larger amortization study that addresses all of the active and idle wells in the City, which is presented in Baker & O'Brien's *Summary Report on the Amortization of Capital Investment Study* (the "Summary Report"). The Summary Report presents Baker & O'Brien's scope of work and qualifications, the methodology used in the amortization analysis, and other reference information that is generally common to the analysis of the various drill sites.

17. This Study presents a detailed economic analysis for the Site that considers capital investment in existing wells and surface facilities, revenues produced from sales of oil and gas, operating costs associated with the production of oil and gas, and determination of year-to-year financial returns for the Site. Financial returns for the Site are compared to market returns on the invested capital achieved by oil and gas production companies to

[3] Los Angeles City Ordinance No. 187709; https://clkrep.lacity.org/onlinedocs/2017/17-0447-S2_ord_187709_1-18-23.pdf

determine the time required for amortization of capital investment. A Base Case determines the time required to amortize capital investment at the Site, based on historical data and reasonable estimates of capital investment, revenues, and operating costs. The sensitivity cases consider the extent to which alternative assumptions that may be used in the income analysis, including a higher market rate of return, a lower oil price, and larger capital investment, might change the Base Case amortization period.

18. This Study refers to various abbreviations and terms that are used in the oil and gas industry. These abbreviations, terms, and a brief definition for each item are listed for convenience in **Exhibit 1** of the Summary Report.

19. The Study Effective Date for this Study is December 31, 2022. The Study Effective Date represents the cut-off date for historical information that was considered to represent historical capital investment, production volumes, and operating costs used in this Study. In preparing this Study, Baker & O'Brien has relied upon public and proprietary information about the Site that was available at the Study Effective Date. Reference materials that have been considered in preparing this Study are listed in **Exhibit A**.

4. ABOUT THE SITE

4.1 LOCATION

20. The Site is located at 14737 N. San Fernando Road in the Granada Hills - Knollwood neighborhood of Los Angeles. The wells and production facilities are all in one location. The wells on this Site are located south of the Sunshine Canyon Landfill and on top of a hill overlooking a neighborhood just west of Balboa Boulevard next to the MWD Jensen Water Treatment Plant. The Site extracts oil and gas under four leases from the Cascade Oil Field. An aerial photograph of the Site is shown in **Exhibit B**.[4] Additional location-specific details are provided in **Exhibit 5** of the Summary Report.

4.2 HISTORY

21. TW drilled the first well in 1954 and followed it up with a second well in 1955. Macson took over the two wells from TW in 1956 and drilled an additional three wells that same year. In 1961, Macson transferred ownership of the Site to McCulloch.[5] McCulloch drilled a well in 1962. In 1970, McCulloch converted a well to an injector and initiated a waterflood at the Site. McCulloch drilled seven additional wells before transferring the Site to Patriot in 1995. Patriot added six additional wells from 2001 to 2003 before transferring the Site to Castle Peak in 2003. Castle Peak added three additional wells in 2004. The Site was transferred to the current owners, DCOR, in 2006, and one additional well was drilled in 2014.[6]

4.3 LEASES

22. The Site operates wells that produce oil and gas from four leases, which include: the Mission-S.V. De. P. Lease, Mission-Visco Lease, O'Melveny Park Lease, and the Cascade Unit Lease.

[4] Google Earth.
[5] McCulloch controlled the Site under several names during their time as operator of the Site.
[6] See CalGEM records for each of the wells at the Site, which are listed in **Exhibit C**.

23. The status of the wells operating in each of the four leases in 2022 is listed in **Exhibit C** and summarized as follows:

- *Mission-S.V. De. P. Lease*: This lease includes one well. During 2022, the production well was active.
- *Mission-Visco Lease*: This lease includes eight wells. During 2022, five production wells were active, two injection wells were active, and one injection well was idle.
- *O'Melveny Park Lease*: This lease includes seven wells. During 2022, six production wells were active, and one production well was idle.
- *Cascade Unit Lease*: This lease includes seven wells. During 2022, all seven production wells were active.

4.4 SURFACE FACILITIES

24. Site surface facilities include tanks, pumps, and pipelines for collecting and processing well fluids (the "lease equipment") and various site improvements.

25. The wellheads at the Site are generally located at grade, and pump jacks lift oil from the wells.[7] No records are available to document the methods or costs associated with the disposal of produced water. Still, it is generally believed that produced water has been handled onsite and injected back into the ground since 1970.

26. For the Site, some lease equipment (mainly storage tanks) is visible in **Exhibit B**. While the equipment shown in the aerial photograph appears typical, it is impossible to determine its condition, or which equipment remains in operation or has been abandoned in place. No records document the size, capacity, or cost of lease equipment when installed.

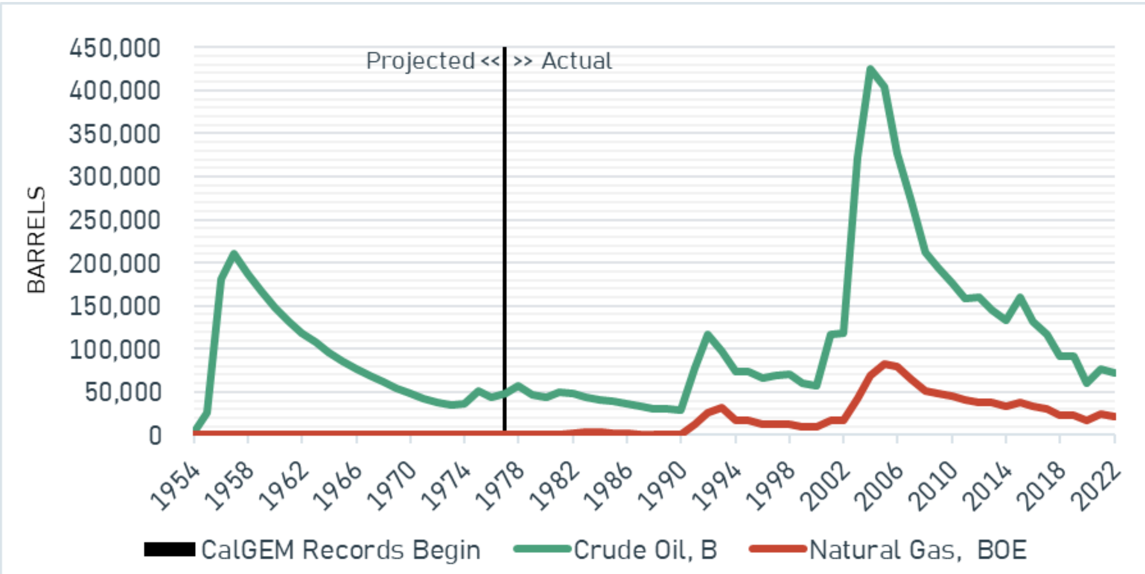
27. One building is visible in the aerial photo at the Site.[8] The Site is surrounded by chain-link fencing with gates to control access.

[7] See waste disposal definition in Exhibit 1 of the Summary Report.
[8] **Exhibit B** and **Exhibit D**.

4.5 HISTORICAL OIL AND GAS PRODUCTION

28. Oil and gas production from the Site is shown below in **Figure 1**.[9]

Figure 1 – Site Oil and Gas Production



29. Production rates at the Site peaked in 1957 and generally declined until 1973. Between 1954 and 1976, production averaged 240 barrels per day ("B/D") of oil. This Study assumes that natural gas production before 1977 was negligible and contributed no material income to the Site.

30. Production was mostly flat until 1991, when production began to rise again. Production at the Site peaked again in 2004. Since 1977, the Site has averaged 316 B/D of oil and 63 barrels of oil equivalent per day ("BOE/D") of natural gas.

4.6 OIL AND GAS QUALITY

31. The Site produced medium-sweet crude oil averaging 24.3 degrees API ("°API") since 1977.[10] The sulfur content of crude oil was not documented. However, a nearby oil field

[9] CalGEM Production Records.
[10] CalGEM Production Records.

is reported to have a sulfur content of approximately 0.92%.[11] The Site's crude oil quality compares to Alaskan North Slope ("ANS") crude oil, which has market specifications of 31.9°API and a sulfur content of 0.93%.

32. Natural gas produced at the Site is assumed to have been treated to meet pipeline quality specifications and injected into the Southern California Gas Company ("SoCalGas") system at the Site's boundary. Natural gas must be treated to pipeline quality before being injected into a local distribution system.

4.7 LOGISTICS

33. No record is available to confirm how crude oil was delivered from the Site to local refineries or costs paid to third parties for the delivery of crude oil. The Los Angeles Municipal Code requires that all oil produced from wells in the City will be transported by underground pipeline.[12] This Study assumes that crude oil is injected into a common carrier pipeline for customer delivery through a custody transfer meter at the Site's boundary. This Study estimates that transportation costs to deliver crude oil from the Site to Long Beach by a common carrier pipeline were $1.50 per barrel ("/B") in 2022.

34. Since small amounts of natural gas were produced at the Site, it is assumed that the Site is connected to a pipeline to deliver natural gas into the SoCalGas system (or another local distribution company). A producer generally injects natural gas into a local distribution company pipeline through a custody transfer meter at the Site's boundary.

[11] No sulfur content was found for Cascade Oil Field, but nearby oilfields were in the 0.5% to 1.0% range, using nearby field Aliso Canyon sulfur content as a reasonable proxy. *Sulfur Content of Crude Oils*, Bureau of Mines Information Circular 8676, 1975. https://dggs.alaska.gov/webpubs/usbm/ic/text/ic8676.pdf

[12] Los Angeles Municipal Code Section 13.01.F.2 and 54.

5. CAPITAL INVESTMENT

35. The capital investment to be amortized at the Site is the total investment in the plant, property, and equipment used to produce income from the Site. For this Study, the total capital investment to be amortized includes the original capital investment, sustaining capital investment in well equipment, and sustaining capital investment in lease equipment.[13]

5.1 ORIGINAL CAPITAL INVESTMENT

36. Original capital investment is an operator's investment to acquire lease rights, drill new wells, construct new surface facilities, and start producing oil and gas. Capital investment that adds production capacity to an existing facility (such as drilling and completion of a new production well) is also considered an original investment. Records of capital investment at the Site are not available, and this Study estimates original capital investment for wells, lease equipment, and site improvements.

37. The original capital investment is included in the income analysis in the appropriate year of the cash flow analysis, corresponding to when new facilities were completed.

5.1.1 PRODUCTION AND INJECTION WELLS

38. Original capital investment for production wells at the Site was estimated based on drilling and completion costs reported by California operators. Costs that are relevant to drill and complete new wells at the Site are summarized below in **Table 1**. The developments listed in **Table 1** are representative of the wells drilled in the City from reservoirs found below 2,000 feet in depth. These wells are used for primary and waterflood operations, similar to wells found in the City. California Resources Corporation ("CRC") reported various drilling and completion costs for its developments in 2016 and 2022. These costs were normalized to 2022 using the United States ("U.S.") Bureau of Labor Statistics ("BLS") Producer Price Index Oil and Gas Drilling ("PPI-OGD") cost index.[14] The average of the normalized costs in 2022 is $1,397,866 per well.

[13] Capital investment does not include operating costs or termination costs. See Section 5.4 of the Summary Report.
[14] Cost indices are discussed in Section 5.2.4 of the Summary Report.

This Study uses an average cost of $1.4 million per well as the original capital investment to drill and complete a production or an injection well during 2022.

Table 1 – Drilling and Completion Costs

Original Cost to Drill and Complete a New Well							
		Reported			Normalized to 2022		
Operator	Location	Year	PPI-OGD [1]	Cost, $/Well	Year	PPI-OGD [1]	Cost, $/Well
CRC	Elk Hills [2]	2016	316.7	$500,000	2022	371.8	$586,980
CRC	Long Beach [2]	2016	316.7	$1,400,000	2022	371.8	$1,643,543
CRC	Wellbore/Stacked Reservoirs [3]	2016	316.7	$1,500,000	2022	371.8	$1,760,939
CRC	Los Angeles Basin [4]	2022	371.8	$1,600,000	2022	371.8	$1,600,000
	Average			**$1,250,000**	**2022**		**$1,397,866**
Cost Used In Model					**2022**		**$1,400,000**

Notes:

1. PPI OGD is BLS Series ID PCU213111213111. June index values are used to reflect mid-year costs.
2. California Resources Corp. 2017 Analyst Day Presentation, p. 36. Includes horizontal component.
3. California Resources Corp. 2017 Analyst Day Presentation, p. 67.
4. California Resources Corp. 2022 Analyst Day Presentation, p. 10. Includes horizontal component.

39. The California Department of Conservation's California Geologic Energy Management Division's ("CalGEM") records identify completion dates for wells at the Site. In the cash flow analysis, capital investment in a well is recorded during the year in which the well was completed. The original capital investment to drill and complete wells before 2022 was estimated by adjusting costs in 2022 for historical changes in drilling costs to the year when a well was completed.[15] Original capital investment for wells at the Site amounted to about $6.95 million.

5.1.2 LEASE EQUIPMENT

40. Lease equipment generally includes the flowlines, separators, pumps, and metering equipment used to separate the well fluids into oil, gas, and water; treat crude oil and natural gas for sale and treat water for reinjection or disposal.

41. The U.S. Department of Energy's Energy Information Administration ("EIA") published annual capital investment estimates for lease equipment between 1976 and 2009.[16] These estimates included representative costs for lease equipment used in waterflood operations. Lease equipment is typically sized to accommodate the anticipated production rates of well fluids. The EIA costs for lease equipment were adjusted to account for the peak well fluid rates produced at the Site by applying a standard cost-

[15] See Section 5.2.4 of the Summary Report.
[16] See Section 5.2.2 of the Summary Report.

capacity relationship.[17] The original capital investment in lease facilities was allocated in the cash flow analysis to years when new wells were completed between 1954 and 2014. The original capital investment for lease equipment at the Site amounted to about $656,000.

5.1.3 SITE IMPROVEMENTS

42. Site improvements include permanent buildings, perimeter fences, electrical distribution equipment, safety, and security facilities.

43. For this Study, the original investment in site improvements was estimated to be 5% of the cost for lease facilities.[18] The original site improvements are assumed to have occurred at various times and are allocated to the years when new wells were completed. The original capital investment for site improvements amounted to about $33,000.

5.2 SUSTAINING CAPITAL INVESTMENT

44. Sustaining capital is invested from time to time to maintain the productive capacity of an oil and gas development to produce income. Sustaining capital investment for the Site includes well modifications and replacement of well equipment and lease equipment that reaches the end of life. Routine maintenance, testing expenses, and maintenance of Site improvements are considered operating costs and are not included in sustaining capital investment.[19]

45. The income analysis considers sustaining capital investment in two ways. First, sustaining capital is deducted from income to calculate the net cash flow available for amortizing capital investment. Second, sustaining capital investment is added to the original capital investment to determine the total capital investment to be amortized. Sustaining capital investment is recorded in the cash flow analysis in the year that well modifications were completed and annually for capital replacement of well equipment and lease equipment.

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[17] This relationship, commonly referred to as the Rule of Six-Tenths, is an empirical relationship between the cost and the capacity of a manufacturing facility. The estimated cost = $((\text{capacity}) / (\text{base capacity}))^{0.6}$ x (base cost).

[18] See Section 5.2.3 of the Summary Report.

[19] Operating costs are discussed below in Section 6.3.

5.2.1 WELL MODIFICATIONS

46. Modifications to wells generally include redrill, rework, recompletion, and casing alterations, and other work intended to improve or extend the useful life of a well. These activities require a permit from a California regulator and are documented in CalGEM records. Well modifications often restore or increase production rates that characteristically decline over time by opening wells to different productive zones, converting wells from one use to another, or correcting mechanical issues.

47. CalGEM records present a history of well modifications for each well at the Site from 1954 to the present.[20] These records may include the nature of the work, the time it was done, and changes in production rates and crude oil quality.

48. California operators have reported the costs for well modifications, and those costs that are relevant to the Site are listed below in **Table 2**. CRC reported the costs for three types of well modifications,[21] while Sentinel Peak Resources California, LLC, ("SPR") reported an average cost for these activities.[22] Costs reported by CRC and SPR were normalized to 2022 and averaged $207,734 per activity. This Study uses an average cost for well modifications of $210,000 per activity in 2022.

Table 2 – Well Modification Costs

Capital Workover and Modification Costs for an Existing Well							
		Reported			Normalized to 2022		
Operator	Activity	Year	PPI-OGD [1]	Cost, $/Activity	Year	PPI-OGD [1]	Cost, $/Activity
CRC	Convert to Injection [2]	2016	316.7	$150,000	2022	371.8	$176,094
CRC	Addpay [2]	2016	316.7	$200,000	2022	371.8	$234,792
CRC	Deepening [2]	2016	316.7	$200,000	2022	371.8	$234,792
SPR	Recompletion [3]	2021	321.1	$160,000	2022	371.8	$185,260
	Average			**$177,500**	**2022**		**$207,734**
Cost Used In Model					**2022**		**$210,000**

Notes:

1. PPI OGD is BLS Series ID PCU213111213111. June index values are used to reflect mid-year costs.
2. California Resources Corp. 2017 Analyst Day Presentation, p. 67. Additional pay zone work is abbreviated "Addpay."
3. Sentinel Peak Resources, Report of Robert Lang, Alvarez & Marsal, June 17, 2021, Exhibit 1.

[20] See CalGEM records for each of the wells at the Site, which are listed in **Exhibit C**.

[21] California Resources Corp. 2017 Analyst Day Presentation, p. 67; https://www.sec.gov/Archives/edgar/data/1609253/000160925317000055/crc2017analystday032017.htm

[22] Sentinel Peak Resources, Report of Robert Lang, Alvarez & Marsal, June 17, 2021, Exhibit 1. https://www.culvercity.org/files/assets/public/v/1/documents/city-attorney/writtenpubliccomments_2021-6-17_citycouncil-p.pdf

49. CalGEM records identify the completion dates for modifications to wells.[23] Sustaining capital investment in well modifications is recorded in the cash flow analysis during the year the modification is completed. Between 1970 and 2010, the total sustaining capital investment for well modifications amounted to $954,000.

5.2.2 WELL EQUIPMENT

50. Sustaining capital investment is needed to replace well equipment, such as pumps and wellheads, when the original equipment reaches the end of its mechanical life. The Study estimates that 10% of the original capital investment to drill and complete production wells and 5% of the original capital investment to drill and complete injection wells are well equipment subject to capital replacement. The remainder of the drilling and completion costs are drill rig and casing costs. Well equipment has an average mechanical life of 30 years with proper maintenance.

51. The Study allows for 3.33% of the replacement cost of well equipment as sustaining capital investment each year.[24] This sustaining capital investment is based on the cost to drill and complete wells, adjusted annually for changes in these activities' costs.[25] The total sustaining capital investment for well equipment amounted to $1.79 million between 1954 and 2022.

5.2.3 LEASE EQUIPMENT

52. Sustaining capital investment is needed to replace original lease equipment that reaches the end of its mechanical life. In addition, the installation of mandated safety and environmental equipment is considered as sustaining capital investment. Lease equipment has an average mechanical life of 30 years with proper maintenance.

53. The Study allows for the replacement of an average of 3.33% of the original capital investment for lease equipment each year. This sustaining capital investment is adjusted for changes in lease equipment costs.[26] The total sustaining capital investment for lease equipment amounted to about $1.34 million between 1954 and 2022.

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[23] See CalGEM records for each of the wells at the Site, which are listed in **Exhibit C**.
[24] Oil fields typically have longer economic lives than the original equipment. Theoretically, to maintain operations, 3.33% of the cost of the equipment will be replaced each year over a 30-year life. See Section 5.3.2 of the Summary Report.
[25] See Section 5.2.4 of the Summary Report.
[26] See Section 5.2.4 of the Summary Report.

5.3 SUMMARY OF CAPITAL INVESTMENT

54. The total capital investment at the Site to be amortized is $11.72 million, as summarized below in **Table 3**. This includes $7.64 million of original capital investment between 1954 and 2014 and $4.08 million sustaining capital between 1954 and 2022. These dollar amounts represent the capital investment incurred by operators from 1954 to 2022.

Table 3 – Summary of Site Capital Investment

Summary of Site Capital Investment		
	Investment	**Time**
Original Capital Investment		
New Wells	$6,951,252	1954-2014
Lease Equipment	$656,330	1954-2014
Site Improvements	$32,817	1954-2014
Subtotal	**$7,640,399**	
Sustaining Capital Investment		
Well Modifications	$953,982	1970-2010
Well Equipment	$1,787,460	1954-2022
Lease Equipment	$1,336,600	1954-2022
Subtotal	**$4,078,042**	
Capital Investment to be Amortized	**$11,718,440**	

6. INCOME ANALYSIS

55. Capital investment is amortized by the net cash flow generated from sales of oil and gas. This Study prepared a consolidated income analysis that calculates the annual net cash flow beginning with the start of drilling operations at the Site. In the income analysis, gross revenues are realized from sales of crude oil and natural gas. Net income is calculated by deducting royalties, operating costs, and income taxes from gross revenues. Finally, annual net cash flow is determined by deducting capital investment from net income.

56. The income analysis calculates net cash flow by considering revenues, operating costs, and capital investment each year in "nominal dollars." Nominal dollars (or "dollars of the day") represent the amount of money spent or earned in a particular year. This Study uses nominal dollar amounts in the income analysis to represent the amounts that an operator spent for capital investment and received as income during each year of the income analysis.

6.1 REVENUES

57. Revenues from oil and gas operations are realized as sales volumes of crude oil and natural gas that are valued at market prices. Sales volumes of crude oil and natural gas from the Site are the production volumes reported by CalGEM or estimated as discussed below. Market prices for crude oil and natural gas, net of quality adjustments and delivery costs, are the values that the operator of the Site receives for these sales, which are referred to as "netback" prices.

6.1.1 PRODUCTION VOLUMES

58. Operators in California are required to report production volumes of crude oil and natural gas to CalGEM, which maintains production records for individual wells beginning from 1977 to the present. This information is available for the wells at the Site.[27]

59. Some of the wells at the Site were completed and in operation before 1977. This Study estimates annual production rates prior to 1977 by backcasting production rates of well

[27] CalGEM Production Records.

fluids utilizing type-curves derived from available production data. Type-curves are developed using standard engineering calculations applied in oil and gas reservoir management and historical data from operating wells.[28] This standard approach assumes that characteristics of the reservoir dictate production rates evident in the type-curves.[29]

60. Annual crude oil and natural gas production volumes from individual wells are aggregated for the Site to determine income. Annual production volumes from the Site are summarized above in **Figure 1**, **Section 4.5**.

6.1.2 NETBACK PRICES FOR CRUDE OIL

61. Netback prices for crude oil represent the market price the operator receives for sales of crude oil produced at the Site, net of quality adjustments, and transportation costs. The netback price is generally determined as the market price for a benchmark crude, plus a quality adjustment, less delivery costs from the drill site to the consumer. Netback prices for crude oil depend upon market values for crude oil of similar quality available in southern California, its quality, and transportation costs to deliver the crude oil to a Los Angeles area refinery.

62. No records are available that document netback prices received for Mission-Visco crude oil.[30] However, Mission-Visco crude oil is typically 24.3°API with a sulfur content of about 0.92%. Mission-Visco crude oil quality is comparable to ANS crude oil, with 31.9°API and 0.93% sulfur.

63. This Study estimated netback prices for Mission-Visco crude oil based on market prices for ANS crude oil delivered to Long Beach.[31] Historical price assessments for ANS crude were used as a benchmark for the value of Mission-Visco crude from 1988 to the present. ANS price assessments are not available before 1988. Thus, Mission-Visco crude prices were estimated by applying a market differential to Brent crude oil between 1979 and 1987 and a market differential to West Texas Intermediate ("WTI") crude oil between 1947 and 1978.[32]

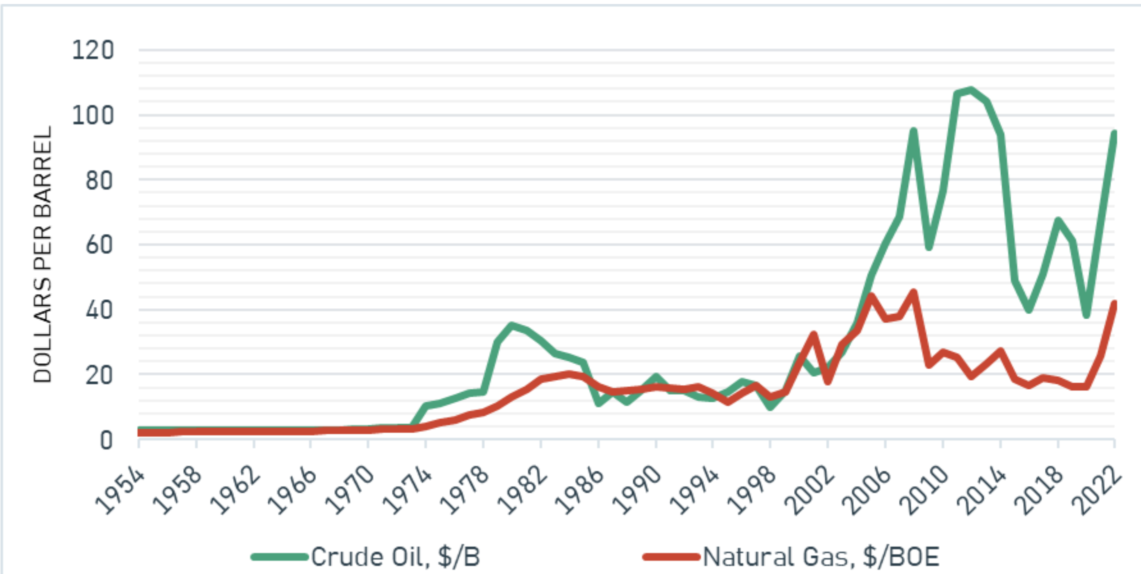
[28] A type-curve is also referred to as a "decline curve."
[29] See Section 6.2 of the Summary Report.
[30] "Mission-Visco" crude oil is used in this Study to refer to crude oil produced from the Site.
[31] ANS crude is delivered by marine tanker to Long Beach.
[32] See Section 6.3 of the Summary Report.

64. A quality adjustment to the benchmark price assessment reflects the difference in refining value between crude oil and the benchmark.[33] As noted above, Mission-Visco crude oil is lower in API Gravity than ANS crude and would be less valuable to a refiner. Based on reasonable industry adjustments for API Gravity, a quality discount of $2.66/B reflects the lower market value of Mission-Visco crude oil.

65. Crude oil from the Site is assumed to be delivered to nearby refineries by pipeline. Due to this proximity, transportation costs to deliver crude oil from the Site to Long Beach are estimated at $1.50/B in 2022, based on common carrier tariffs.[34]

66. Annual average netback prices for Mission-Visco crude oil are shown below in **Figure 2**.

Figure 2 – Netback Prices for Crude Oil and Natural Gas



6.1.3 NETBACK PRICES FOR NATURAL GAS

67. Netback prices for natural gas represent the market price that an operator receives for natural gas produced at the Site, less delivery costs. The Site is assumed to have a connection for delivering natural gas to the SoCalGas system or another local distribution

[33] See Section 6.3 of the Summary Report.

[34] Crimson California Pipeline L.P. trunkline tariff, August 1, 2022; Crimson California Pipeline L.P. gathering line tariff, August 1, 2022.

company serving the Los Angeles area. Natural gas must meet pipeline quality specifications before it can be injected into a local distribution system.[35]

68. This Study estimated netback prices for natural gas based on market prices for delivery to the SoCalGas "City Gate," which is a virtual Los Angeles-area trading location. Historical City Gate price assessments for natural gas were used as a benchmark from 1989 to the present. City Gate price assessments are not available before 1989. Thus, Los Angeles area natural gas prices were estimated by applying a historical market differential to Henry Hub natural gas price assessments between 1964 and 1988.[36] No discount for transportation costs was applied to these sales, which would be delivered into a pipeline.

69. Annual average netback prices for Mission-Visco natural gas are shown above in **Figure 2**.[37]

6.2 ROYALTIES

70. Owners of mineral rights earn a royalty on commercial volumes of oil and gas produced from their property.[38] These arrangements are set out in lease agreements between the mineral rights owner and the operator, which can vary from lease to lease. The operator pays royalties to the owner of the mineral rights out of revenues, and this cash is not available to amortize the operator's capital investment. No records are available to document royalty rates paid on leases at the Site.

71. The income analysis deducts royalties and other land lease costs equal to 16.660% of revenues. This is the same royalty rate applicable to leases for oil and gas extraction on California state lands.[39]

6.3 OPERATING COSTS

72. Lease operating costs generally include labor, utilities, operating materials, maintenance materials, spare parts, general and administrative expenses, insurance, and permits.

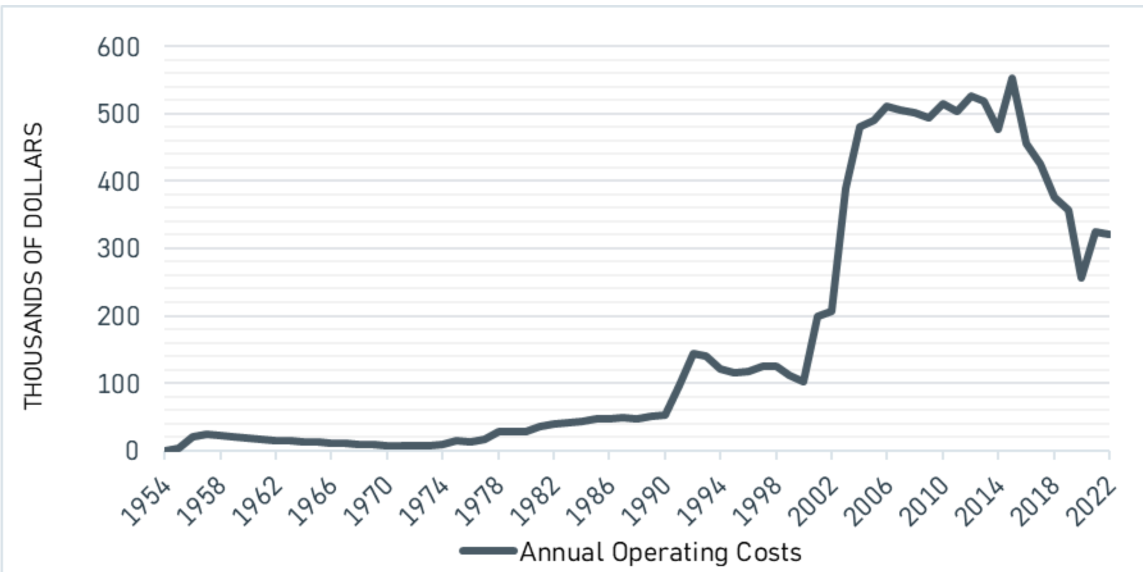
[35] https://www.socalgas.com/documents/news-room/fact-sheets/PipelineBasics.pdf
[36] See Section 6.4 and Exhibit 1 of the Summary Report.
[37] "Mission-Visco" natural gas is used in this Study to refer to natural gas produced from the Site.
[38] Owners of mineral rights and landowners may or may not be the same person/entity.
[39] *Report on the Federal Oil and Gas Leasing Program*, U.S. Department of the Interior, November 2021.

Direct operating costs include costs to separate the oil, gas, and produced water, treat crude oil and natural gas to market specifications, and treat produced water for reinjection or disposal.

73. The EIA published annual estimates of oil lease operating costs between 1976 and 2009.[40] Operating costs for the Site were estimated by normalizing EIA figures to the Site's design production rate of well fluids and applying these costs to the reported production of well fluids from the Site. Prior to 1976 and after 2009, the EIA operating costs were adjusted for historical changes in operating costs.[41]

74. Annual Site operating costs are summarized below in **Figure 3**.

Figure 3 – Site Operating Costs



6.4 INCOME TAXES

75. The income analysis deducts income taxes from revenues to determine the net cash flow available for the amortization of capital investment. Income before taxes is adjusted for depreciation of capital investment and for tax loss carry-forward (where applicable) to calculate taxable income.

[40] See Section 6.6 of the Summary Report.
[41] See Section 5.2.4 of the Summary Report.

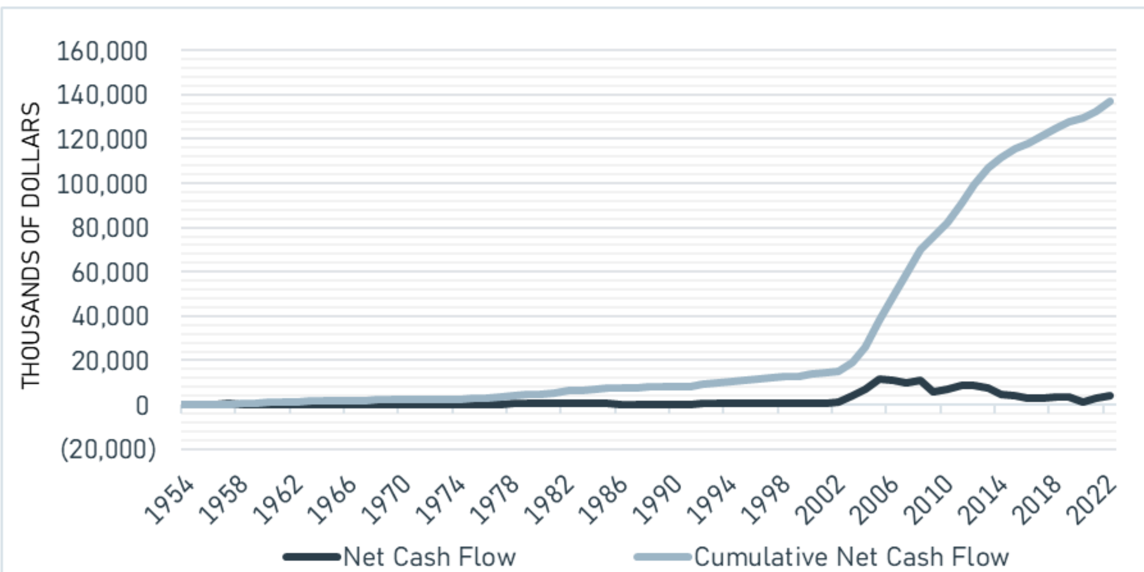
76. Federal and state income taxes on taxable income are calculated using the highest corporate tax brackets in effect each year. Federal income tax rates range from 21% to 46%, and California state income tax rates range from 8.8% to 9.6%.[42]

6.5 NET CASH FLOW FOR AMORTIZATION

77. Annual net income is calculated by deducting royalties, operating costs, and income taxes from revenues. Annual net cash flow is determined by deducting capital investment from net income. Annual net cash flow from the Site averaged about $1.98 million, and the cumulative net cash flow between 1954 and 2022 amounted to about $136.72 million. These nominal dollar amounts represent the cash flow generated from 1954 to 2022.

78. The annual and cumulative net cash flow from the Site is shown in **Figure 4**.

Figure 4 – Site Net Cash Flow



[42] See Section 6.7 of the Summary Report.

7. MARKET RATE OF RETURN ON INVESTMENT

79. The tests for amortization of capital investment use a “market” rate of return on investment characteristic of oil and gas production companies.[43] The market rate of return on investment is a total rate of return that is realized by public companies in this industry sector.

80. This Study refers to an analysis of the Weighted Average Cost of Capital (“WACC”) for public companies that has been published annually since 1998.[44] For each year, the cost of equity, cost of debt, capital structure, and WACC are reported for companies in the oil and gas industry sector that are mainly structured as corporations. The number of oil and gas production companies included in the annual report varied from 92 to 411 firms. For this group, the WACC has ranged between 6% and 10% since 1998, as shown in **Exhibit 4** of the Summary Report.

81. The income analysis for this Study assumes a market rate of return of 8%, which is near the median of companies engaged in oil and gas production from 1998 through 2022. This industry rate of return is characteristic of returns on capital investment to a corporation that pays income taxes on net operating income.

[43] See Section 4.3 of the Summary Report.
[44] See Section 7.1 of the Summary Report.

8. CONCLUSIONS

82. The income analysis was used in the amortization model to determine the time required to achieve amortization of capital investment using the Base Case assumptions discussed above. The income analysis was also used to test the impact of alternative assumptions on the time to achieve amortization.

83. The Base Case and Sensitivity assumptions and results for this Study are summarized below in **Table 4**. The alternative assumptions used in each of the sensitivity cases are highlighted.

8.1 BASE CASE AMORTIZATION OF CAPITAL INVESTMENT

84. In the Base Case, capital investment in wells and lease facilities at the Site was amortized by 1957, within three years of the original capital investment.

85. The results of the Base Case income analysis are summarized in **Exhibit E**. The Internal Rate of Return ("IRR") test for amortization was achieved in 1957 when the cumulative IRR exceeded the 8% market rate of return. The Net Present Value ("NPV") test for amortization was also achieved in 1957 when the cumulative net present value exceeded zero.

86. The total capital investment of $11.72 million was amortized by $136.72 million of net cash flow between 1954 and 2022. The original capital investment was amortized within three years of commencement of operations. The cumulative IRR increased to about 100% by 1961 and remained at that level through 2022.

8.2 SENSITIVITY CASE A: MARKET RETURN ON CAPITAL INVESTMENT

87. Case A sensitivity analysis demonstrates that the capital investment amortization time did not change over a reasonable range of the market rate of return assumptions.

88. In Sensitivity Case A, the Base Case market rate of return of 8% was replaced with a rate of return of 12%. This alternative assumption was selected as the highest cost of equity

for oil and gas companies reported since 1998 and is the upper limit of a reasonable range of market rates of return.[45]

89. The results of the Sensitivity Case A income analysis are summarized in **Exhibit F**. The IRR test for amortization was achieved in 1957 when the cumulative IRR exceeded the 12% rate of return. The NPV test for amortization was also achieved in 1957 when the cumulative net present value exceeded zero. Even with a higher market return on capital, the capital investment in wells and lease facilities at the Site was amortized by 1957.

8.3 SENSITIVITY CASE B: COMMODITY PRICE

90. This sensitivity analysis demonstrates that the time required to achieve amortization of capital investment did not change over a reasonable range of assumptions related to the price of crude oil.

91. In Sensitivity Case B, the Base Case quality discount of $2.66/B was changed to a discount of $3.16/B. This assumption reduces the netback price received by the operator by $0.50/B, which is a lower limit for a reasonable range of values for Mission-Visco crude oil.

92. The results of the Sensitivity Case B income analysis are summarized in **Exhibit G**. The IRR test for amortization was achieved in 1957 when the cumulative IRR exceeded the 8% market rate of return. The NPV test for amortization was also achieved in 1957 when the cumulative net present value exceeded zero. Even with lower crude oil netback prices, the capital investment in wells and lease facilities at the Site was amortized by 1957.

8.4 SENSITIVITY CASE C: ORIGINAL CAPITAL INVESTMENT

93. This sensitivity analysis demonstrates that the time required to achieve amortization of capital investment did not change, even with a larger original capital investment.

94. In Sensitivity Case C, the Base Case cost to drill and complete a well was increased by 50%, from $1.4 million to $2.1 million. This assumed investment for an oil well exceeds

[45] See Exhibit 4 of the Summary Report.

the maximum cost for a new well reported by CRC by more than 19%.[46] The Case C scenario represents the upper limit for a reasonable range of original capital costs.

95. The results of the Sensitivity Case C income analysis are summarized in **Exhibit H**. The IRR test for amortization was achieved in 1957 when the cumulative IRR exceeded the 8% market rate of return. The NPV test for amortization was also achieved in 1957 when the cumulative net present value exceeded zero. Even with a larger capital investment in wells and lease facilities at the Site, this capital investment was amortized by 1957.

8.5 INCOME ANALYSES SUMMARY

96. The Base Case and Sensitivity assumptions for this Study are summarized below in **Table 4**. The sensitivity cases are calculated to test the potential impact of alternative assumptions on the Base Case conclusion of the time required to achieve amortization of capital investment. As discussed in Section 8 of the Summary Report, the alternative assumptions include a 4% higher market return on capital investment, a $0.50/B lower price of crude oil, and an increase of 50% to the costs to drill and complete the wells. The alternative assumptions used in each of the sensitivity cases are highlighted.

Table 4 – Income Analyses Assumptions

Model Assumptions	Base Case	Case A	Case B	Case C
Market Return on Capital Investment, %				
Oil and Gas Production Companies	8.00%	12.00%	8.00%	8.00%
Commodity Price Factors, 2022 ($/B)				
Crude Oil Transportation - Site to Long Beach	1.50	1.50	1.50	1.50
Crude Oil Quality Adjustment	(2.66)	(2.66)	(3.16)	(2.66)
Royalty and Lease Costs, % Revenue				
Royalty Rate	16.660%	16.660%	16.660%	16.660%
Site Operating Costs, 2022 ($/B)				
Basis: Total Produced Liquids	1.53	1.53	1.53	1.53
Capital Expenditures, 2022 ($ Thousands)				
Drilling and Completion Cost per Well	1,400	1,400	1,400	2,100
Well Modification Cost per Event	210	210	210	210
Results, 2022				
IRR, %	100.25%	100.25%	98.98%	65.78%
NPV, ($ Thousands)	3,748	1,452	3,709	3,541
Years to Amortization, IRR	3	3	3	3
Years to Amortization, NPV	3	3	3	3

[46] See **Table 1** above.

EXHIBIT A: LIST OF REFERENCE DOCUMENTS

Title	Date
Bureau of Mines Information Circular 8676, Sulfur Content of Crude Oils	January 1, 1975
Costs and Indices for Domestic Oil and Gas Field Equipment and Operations , DOE/EIA-0185(95)	August 1, 1996
2010 EIA Lease Equip Cost Cost Study Data File	September 28, 2010
Oil and Gas Lease Equipment and Operating Costs 1994 through 2009 , DOE/EIA	September 28, 2010
California Resources Corporation 2017 Analyst Day Presentation	March 22, 2017
Report of R Lang, Alvarez & Marsal, for Sentinel Peak Resources	June 17, 2021
US. Department of the Interior, Report on the Federal Oil and Gas Leasing Program	November 1, 2021
California Resources Corporation Investor Presentation	June 1, 2022
Crimson California Pipeline L.P. Local Tariff for Gathering of Crude Petroleum	August 1, 2022
Crimson California Pipeline L.P. Local Tariff for Transportation of Crude Petroleum	August 1, 2022
https://crudemarketing.chevron.com/crude/north_american/california.aspx	September 14, 2023
Official City of Los Angeles Municipal Code	June 30, 2023
CalGEM Records for API 403701177, File 03701177_DATA_02-15-2008	Various
CalGEM Records for API 403701179, File 03701179_DATA_03-07-2008	Various
CalGEM Records for API 403701181, File 03701181_DATA_02-15-2008	Various
CalGEM Records for API 403701183, File 03701183_DATA_02-15-2008	Various
CalGEM Records for API 403701184, File 03701184_DATA_02-15-2008	Various
CalGEM Records for API 403701185, File 03701185_DATA_02-15-2008	Various
CalGEM Records for API 403721452, File 03721452_DATA_2-22-2008	Various
CalGEM Records for API 403721803, File 03721803_DATA_02-15-2008	Various
CalGEM Records for API 403722301, File 03722301_DATA_02-15-2008	Various
CalGEM Records for API 403724036, File 03724036_DATA_11-27-07	Various
CalGEM Records for API 403724071, File 03724071_DATA_11-27-07	Various
CalGEM Records for API 403724072, File 03724072_DATA_02-15-2008	Various
CalGEM Records for API 403724125, File 03724125_DATA_02-15-2008	Various
CalGEM Records for API 403724221, File 03724221_DATA_02-15-2008	Various
CalGEM Records for API 403724227, File 03724227_DATA_02-15-2008	Various
CalGEM Records for API 403724248, File 03724248_DATA_02-15-2008	Various
CalGEM Records for API 403724249, File 03724249_DATA_02-15-2008	Various
CalGEM Records for API 403724263, File 03724263_DATA_02-15-2008	Various
CalGEM Records for API 403724264, File 03724264_DATA_02-15-2008	Various
CalGEM Records for API 403724269, File 03724269_DATA_11-27-07	Various
CalGEM Records for API 403724270, File 03724270_DATA_02-15-2008	Various
CalGEM Records for API 403724272, File 03724272_DATA_02-15-2008	Various
CalGEM Records for API 403724363, File 03724363_DATA	Various
CalGEM Production Records, File CALGEMs_Well_Data_Formatting_Mission_Visco	Various

EXHIBIT B: AERIAL PHOTOGRAPH OF THE SITE

Source: Google Earth.

EXHIBIT C: WELLS AT THE SITE

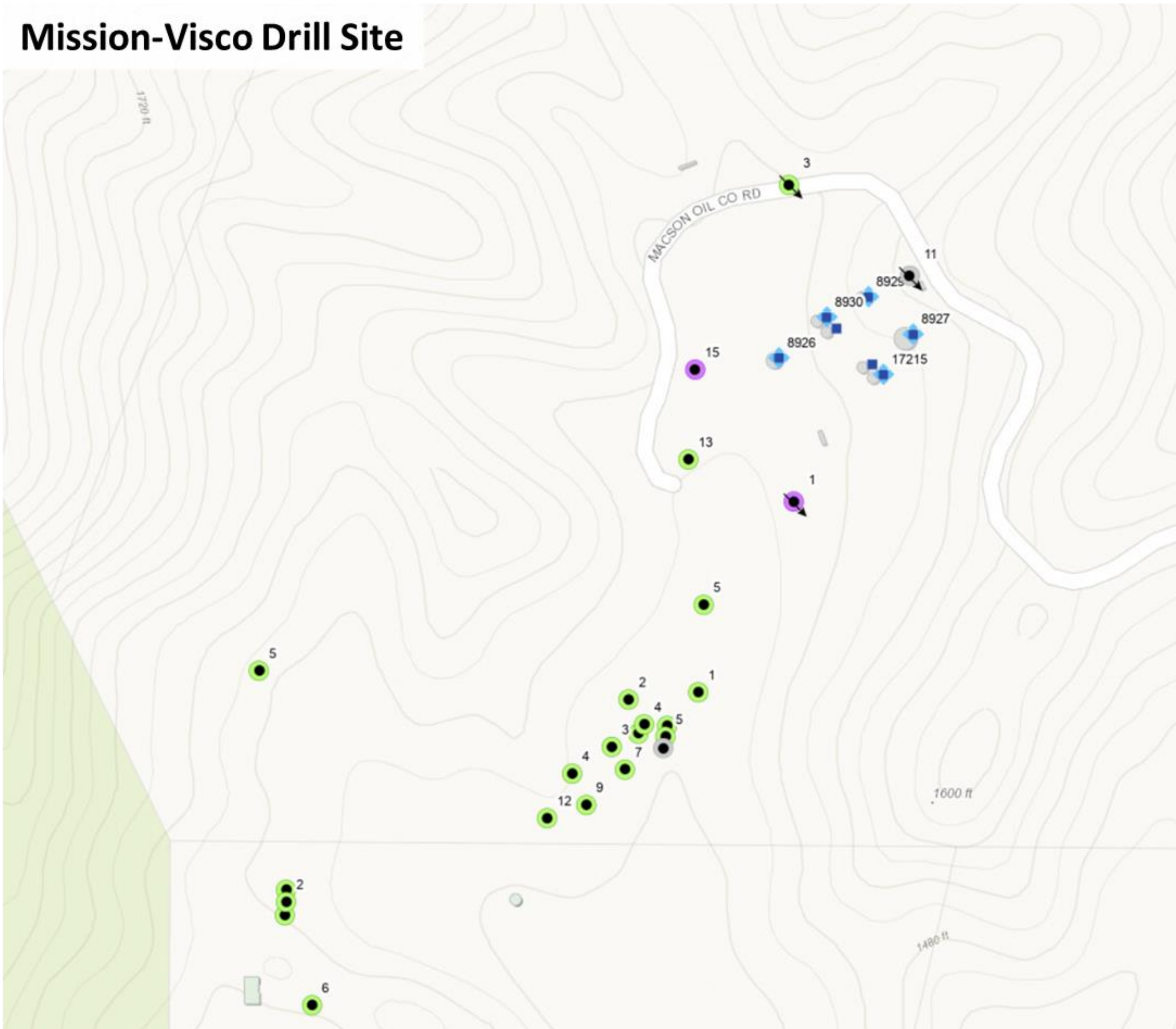
Well API No.	Lease Name	Well Designation	Spudded	Complete	Current Type	Current Status
403701177	Mission-S.V. De P.	6	3/1/1956	3/14/1956	Oil & Gas	Active
403701179	Mission-Visco	1	9/20/1954	11/7/1954	Waterflood	Active
403701181	Mission-Visco	3	4/1/1955	6/26/1955	Waterflood	Active
403701183	Mission-Visco	5	2/8/1956	2/24/1956	Oil & Gas	Active
403701184	Mission-Visco	9	7/10/1956	7/23/1956	Oil & Gas	Active
403701185	Mission-Visco	11	8/15/1962	9/13/1962	Waterflood	Idle
403721452	Mission-Visco	12	Mar. 1974*	Aug. 1974*	Oil & Gas	Active
403721803	Mission-Visco	13	7/15/1977	8/7/1977	Oil & Gas	Active
403722301	Mission-Visco	15	11/3/1980	11/22/1980	Oil & Gas	Active
403724036	O'Melveny Park	1	10/25/1990	12/3/1990	Oil & Gas	Active
403724071	O'Melveny Park	2	7/3/1991	8/25/1991	Oil & Gas	Active
403724072	O'Melveny Park	3	8/26/1991	1/11/1992	Oil & Gas	Active
403724125	O'Melveny Park	5	10/29/1991	11/19/1991	Oil & Gas	Active
403724221	Cascade Unit	1	2/19/2001	3/18/2001	Oil & Gas	Active
403724227	Cascade Unit	2	8/12/2001	9/29/2001	Oil & Gas	Active
403724248	Cascade Unit	3	12/8/2002	1/7/2003	Oil & Gas	Active
403724249	O'Melveny Park	4	11/9/2002	12/5/2002	Oil & Gas	Active
403724263	O'Melveny Park	6	8/6/2003	9/1/2003	Oil & Gas	Active
403724264	Cascade Unit	4	9/4/2003	9/24/2003	Oil & Gas	Active
403724269	O'Melveny Park	7	8/29/2004	9/20/2004	Oil & Gas	Idle
403724270	Cascade Unit	5	9/22/2004	10/14/2004	Oil & Gas	Active
403724272	Cascade Unit	6	10/23/2004	11/18/2004	Oil & Gas	Active
403724363	Cascade Unit	7	10/25/2014	11/26/2014	Oil & Gas	Active

Source: CalGEM Well Finder and CalGEM Records.

* No Record found, date is an approximation

Note: "Spudded" refers to the start of drilling operations. "Complete" refers to completion of drilling operations such that the well is ready to be placed into production.

EXHIBIT D: LOCATION OF WELLS AT THE SITE



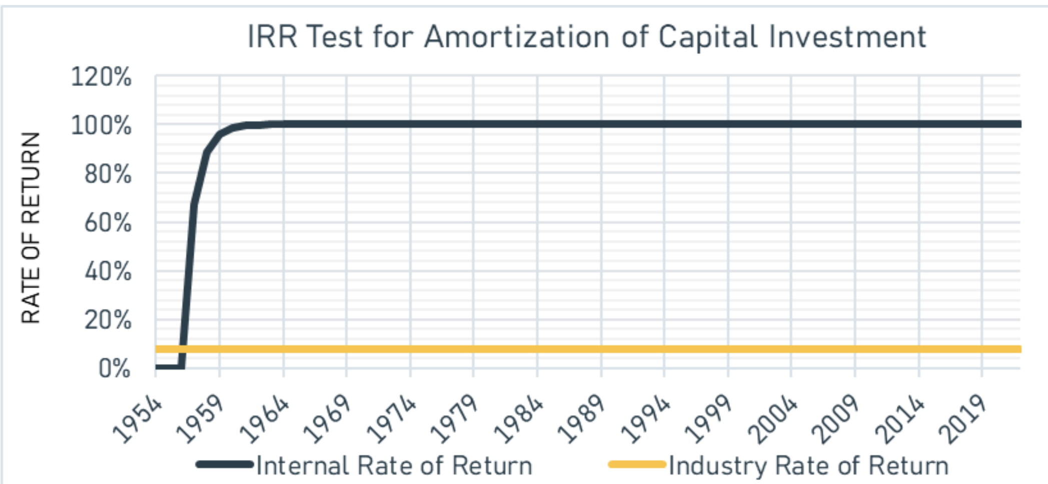
Source: CalGEM Well Finder website

The CalGEM website indicates the well status as follows:

- Wells indicated in green are active
- Wells indicated in purple are idle
- Wells indicated in grey are plugged
- Injection wells are indicated with an arrow

EXHIBIT E: BASE CASE AMORTIZATION OF CAPITAL INVESTMENT

Model Output Summary	
Start Year	1954
Amortization Year (IRR)	1957
Amortization Year (NPV)	1957
Years for Amortization of Capital Investment	3
Capital Investment, $thousands	11,718
Gross Revenues, $thousands	300,249
EBITDA, $thousands	238,799
Net Cash Flow, $thousands	136,719
Cumulative IRR at 2022	100.25%



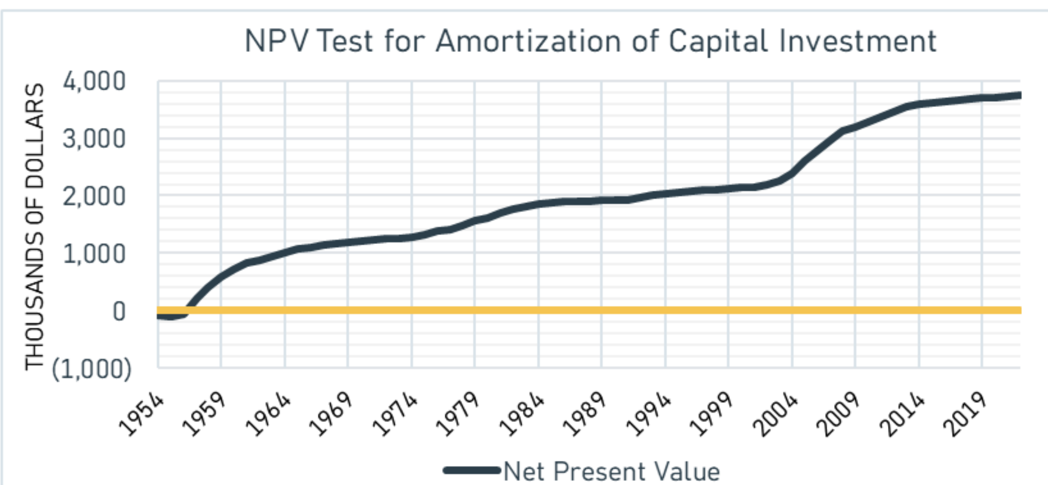
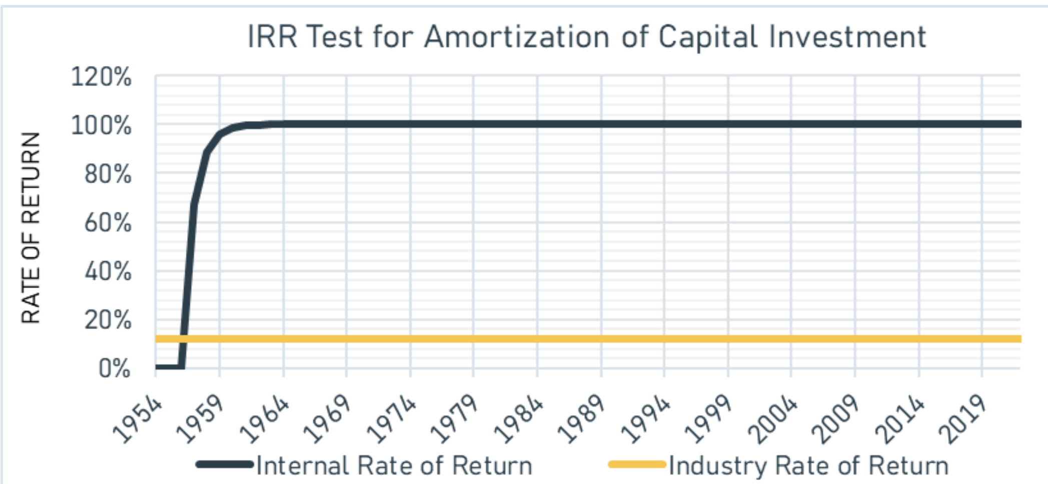


EXHIBIT F: SENSITIVITY CASE A—MARKET RETURN ON CAPITAL INVESTMENT

Model Output Summary	
Start Year	1954
Amortization Year (IRR)	1957
Amortization Year (NPV)	1957
Years for Amortization of Capital Investment	3
Capital Investment, $thousands	11,718
Gross Revenues, $thousands	300,249
EBITDA, $thousands	238,799
Net Cash Flow, $thousands	136,719
Cumulative IRR at 2022	100.25%



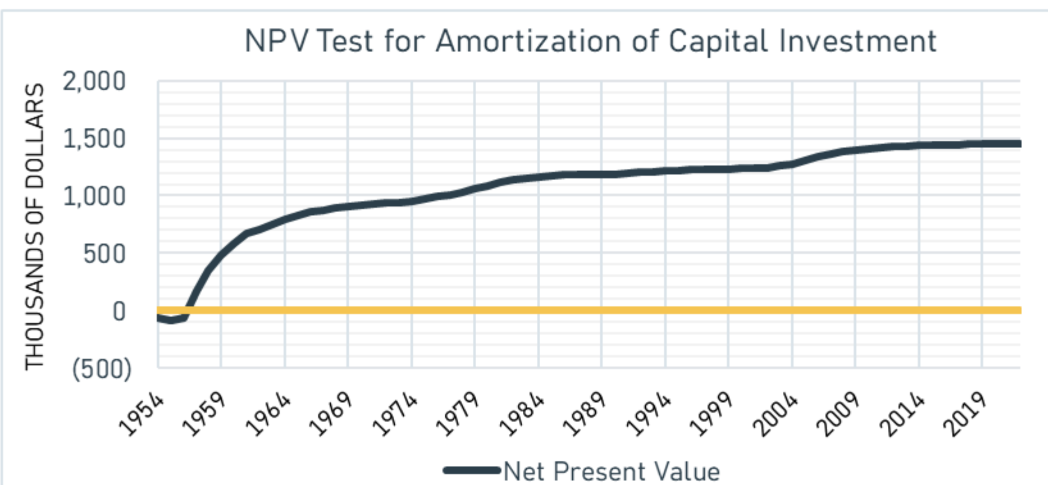
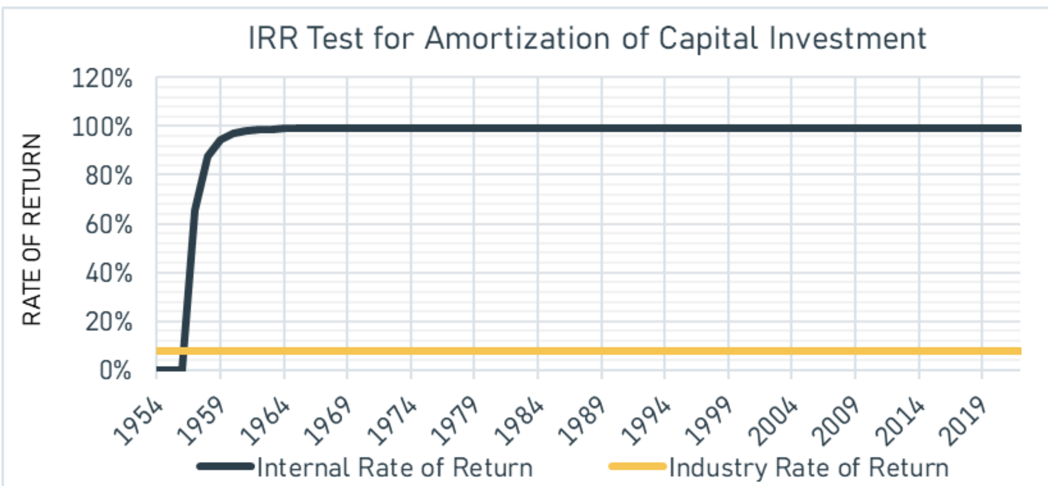


EXHIBIT G: SENSITIVITY CASE B—COMMODITY PRICE

Model Output Summary	
Start Year	1954
Amortization Year (IRR)	1957
Amortization Year (NPV)	1957
Years for Amortization of Capital Investment	3
Capital Investment, $thousands	11,718
Gross Revenues, $thousands	298,344
EBITDA, $thousands	237,211
Net Cash Flow, $thousands	135,761
Cumulative IRR at 2022	98.98%



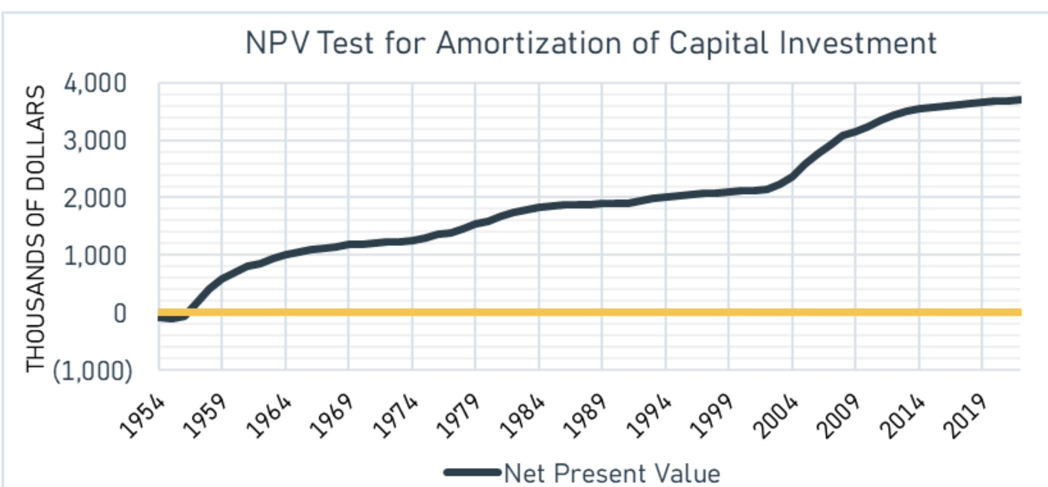


EXHIBIT H: SENSITIVITY CASE C—ORIGINAL CAPITAL INVESTMENT

Model Output Summary	
Start Year	1954
Amortization Year (IRR)	1957
Amortization Year (NPV)	1957
Years for Amortization of Capital Investment	3
Capital Investment, $thousands	16,088
Gross Revenues, $thousands	300,249
EBITDA, $thousands	238,799
Net Cash Flow, $thousands	134,048
Cumulative IRR at 2022	65.78%