Baker & O'Brien

CITY OF LOS ANGELES
OIL AND GAS DRILLING ORDINANCE

STUDY 11:
AMORTIZATION OF CAPITAL INVESTMENT STUDY FOR THE TORRANCE O'DONNELL OIL LEASES

PREPARED FOR:

The City of Los Angeles

Board of Public Works

Office of Petroleum and Natural Gas Administration and Safety

DATE:

November 5, 2024

Baker & O'Brien, Inc.

12001 N. Central Expressway

Suite 1200

Dallas, TX 75423

CONFIDENTIAL

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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 Torrance O'Donnell Oil Leases* (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*: O'Donnell Oil, LLC ("O'Donnell") operates oil and gas production facilities at four different locations (the "Sites") in the Wilmington – Harbor City area of Los Angeles. The Sites extract oil and gas from the Torrance oil field under four leases, which include:

   i. Capital Lease: 25209 S. Vermont Ave.

   ii. Ferrell Lease: 1226 W. Lowen St.

   iii. Kettler Lease: 23200 S. Western Ave.

   iv. Spring Lease: 1700 N. Figueroa St.

6. *Zoning*: The Sites are located within Council District 15 and the Wilmington – Harbor City Community Plan area. The parcels are zoned as [Q]MR1-1VL-O (Restricted Industrial with height limitations in an Oil Drilling District), [Q]RD1.5-1XL-O (Qualified Restricted Density Multiple Dwelling with height limitation in an Oil Drilling District), PF-1XL-O-CUGU (Public Facilities with height restrictions in an Oil Drilling District and a Clean Up, Green Up Supplemental Use District), R1-1XL-CUGU (One-Family Residential with height restrictions in a Clean-up, Green Up Supplemental Use District), and [Q]R3-1VL-O (Qualified Multiple Dwelling with height limitations in an Oil Drilling District).[1]

7. *History*: Drilling at the Sites began in 1938 by Richfield Oil Corp and D. & B. Oil Company. Most wells were drilled by 1944 when the O'Donnell family began to take control of several wells. The last well was drilled in 1963 by Lebrow Harbor Oil Company. By 2006, all of the wells were formally transferred to the O'Donnell entity that currently controls the Sites.

8. *Sites Status*: A total of 10 wells were drilled at the Sites between 1938 and 1963. Of these, nine operated during 2022 and one well was idle. Surface facilities at the Sites include lease equipment and various improvements.

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

9. *Capital Investment*: The original cost to drill and complete wells and install lease facilities at the Sites amounted to about $0.6 million. In addition to the original capital investment, sustaining capital investment in well equipment and lease equipment amounted to more than $2.1 million. The cumulative estimated capital investment in the Sites was about $2.7 million as of December 31, 2022.

10. *Sites Income*: The Sites generated revenue from the sale of crude oil and natural gas. Production of crude oil from the Sites peaked in 1939 at about 194,000 barrels annually, or 531 barrels per day. Natural gas production peaked in 1982 at about 2,000 barrels of oil equivalent annually, or 5 barrels per day. Production of crude oil and natural gas declined from 1939 until 2022, when the Sites produced about 25,000 barrels of oil (68 barrels per day) with no reportable amounts of natural gas. Crude oil produced at the Sites is heavy-sour crude with a market value comparable to Kern River crude oil. After deductions for payments of royalties, operating costs, income taxes, and sustaining capital investment, the Sites generated a cumulative net cash flow of more than $34.2 million between 1938 and 2022.

11. *Base Case Conclusion*: In the Base Case, the capital investment in wells and lease facilities at the Sites were amortized by 1939, within one year of the original capital investment. The cumulative internal rate of return for the Sites in 2022 is significantly 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 required to amortize the capital investment. Deducting $0.50 per barrel of crude oil resulted in no change in the time required to amortize capital investment. Increasing the capital investment to drill and complete new wells by 50% lengthened the time required to amortize capital investment by one year. Over a reasonable range of assumptions, these factors do not significantly change the time required to amortize capital investment at the Sites.

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[2] (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 Torrance O'Donnell Oil Leases* (the "Study") presents the basis and conclusions for Baker & O'Brien's determination of the time required to amortize capital investment for the consolidated operations at four sites where small-scale oil and gas operations are conducted (the "Sites") in the Wilmington-Harbor City area of Los Angeles.

16. This Study is incorporated into a larger amortization study that addresses all 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 Sites 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 Sites. Financial returns for the Sites are compared to market returns on the invested capital achieved by oil and gas production

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

companies to determine the time required for amortization of capital investment. A Base Case determines the time required to amortize capital investment at the Sites, 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 a 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 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 Sites 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 SITES

4.1 LOCATION

20. The O'Donnell entity operates oil and gas production facilities at four different locations in the Wilmington – Harbor City area of Los Angeles (the "Sites"). The Sites extract oil and gas from the Torrance oil field under four leases, which include:

    i. Capital Lease: 25209 S. Vermont Ave.

    ii. Ferrell Lease: 1226 W. Lowen St.

    iii. Kettler Lease: 23200 S. Western Ave.

    iv. Spring Lease: 1700 N. Figueroa St.

21. Three of the Sites are located just north of the interchange of the Harbor Freeway and the Pacific Coast Highway. The Ferrell and Spring Leases are to the east of the Harbor Freeway and the Capital Lease is to the west. The Kettler Lease is located just to the southeast of the intersection of Sepulveda Blvd. and S. Western Ave. Aerial photographs of the Sites are presented in **Exhibit B**.[3] Additional location-specific details are provided in **Exhibit 5** of the Summary Report.

4.2 HISTORY

22. Drilling for the Sites began in 1938 when D. & B. Oil Company and Richfield Oil Corp drilled the first two wells. Five additional wells were drilled by 1944, with three of them being drilled by Pongratz Petroleum Company ("Pongratz"). The O'Donnell family began acquiring the wells in 1944. They acquired the Pongratz wells in 1950 and drilled additional wells in 1951 and 1963

23. By 1963, the O'Donnell's owned 8 out of the Sites' 10 wells. Another well transferred to their control in 1985. The last well was transferred to the O'Donnell family between

[3] Google Earth.

1988 and 2006. By 2006, all 10 wells formally fell under the control of the O'Donnell entity that currently controls the Sites.[4]

4.3 LEASES

24. The four Sites operate wells that produce oil and gas from four leases, which includes: the Capital Lease, Ferrell Lease, Kettler Lease, and Spring Lease. Three leases appear to have storage facilities, although the Kettler Lease production facilities could not be observed from aerial maps.

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

- *Capital Lease*: This lease includes three wells, which are used for the production of oil and gas. During 2022, all three production wells were active.
- *Ferrell Lease*: This lease includes one well, which is utilized for the production of oil and gas. During 2022, the production well was still active.
- *Kettler Lease*: This lease includes two wells, which are used for the production of oil and gas. During 2022, both production wells were active.
- *Spring Lease*: This lease includes four wells, which are used for the production of oil and gas. During 2022, three of the four production wells were active and one well was idle.

4.4 SURFACE FACILITIES

26. Surface facilities at the Sites include tanks, pumps, and pipelines used for the collection and processing of well fluids (the "lease equipment"), as well as various site improvements. The surface facilities can be seen in **Exhibit B** and **Exhibit D**.[5]

[4] See CalGEM records for each of the wells at the Sites, which are listed in **Exhibit A**.
[5] The assessment of surface facilities in this Study is based upon aerial photos since physical access to the Sites was not authorized.

27. The wellheads at the Sites are generally located at grade and pump-jacks lift oil from the wells. No records are available to document the methods or costs associated with disposal of produced water.[6]

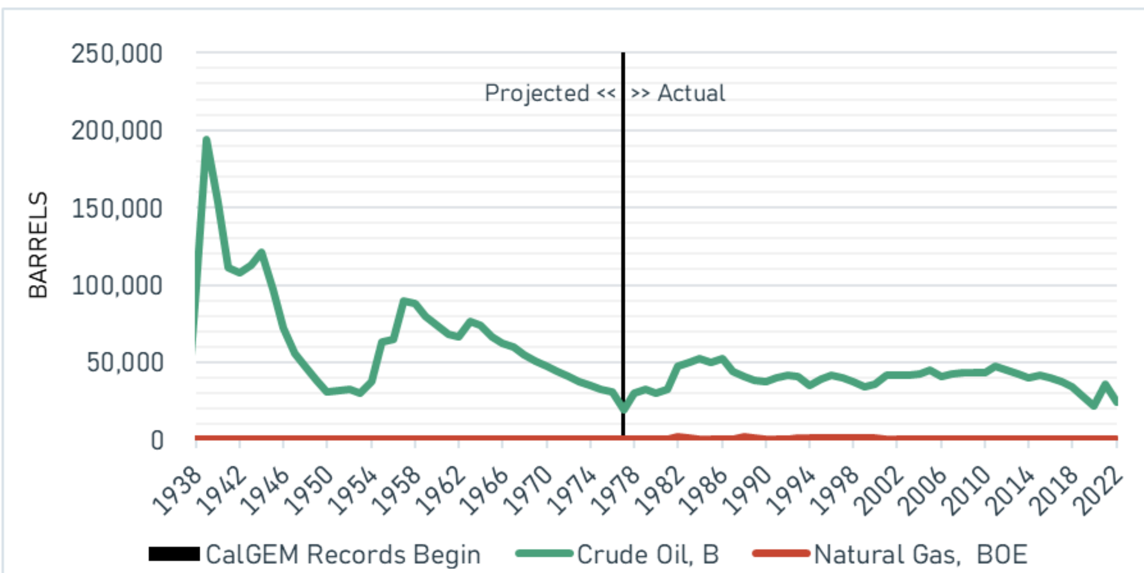
28. For these leases, some lease equipment (mainly storage tanks) is visible in **Exhibit B**.[7] While the equipment shown in the aerial photographs appears to be typical, it is not possible to determine the condition of the equipment, nor which equipment remains in operation or has been abandoned in place. No records are available that document the size, capacity, or cost of lease equipment when it was originally installed.

29. No production related buildings are visible in the aerial photos at any of the Sites. All of the Sites are surrounded by chain-link fencing with gates to control access.

4.5 HISTORICAL OIL AND GAS PRODUCTION

30. Oil and gas production from the Sites are shown below in **Figure 1**.[8]

Figure 1 – Sites Oil and Gas Production



31. Production rates at the Sites peaked in 1939, shortly after the first wells were drilled but then generally declined until the 1950s. In the 1950s, a few additional wells were

[6] See waste disposal definition in Exhibit 1 of the Summary Report.
[7] **Exhibit D.**
[8] CalGEM Production Records.

brought on, and workovers were performed on existing wells, leading to a secondary peak in production in 1957, after which, production declined again until the 1980s. Production rates from 1938 to 1977 were projected based on a type-curve that was prepared from documented production rates following new production wells and well modifications. Production rates were also documented prior to well modifications. Between 1938 and 1976, production averaged 188 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 Sites.

32. Since 1977, the Sites averaged 108 B/D of oil and 1 barrel of oil equivalent per day ("BOE/D") of natural gas.

4.6 OIL AND GAS QUALITY

33. Crude oil produced at the Sites is heavy-sour crude, averaging 18.8 degrees API ("°API") since 1977.[9] While the sulfur content of crude oil produced at the Sites is not documented, crude oil produced from the Torrance oil field is reported to have a sulfur content of approximately 1.62%.[10] The quality of crude oil produced at the Sites is comparable to Kern River ("Kern") crude oil, which has market specifications of 13.3°API and a sulfur content of 1.10%.

34. Natural gas produced at the Sites is assumed to have been treated to meet pipeline quality specifications and injected into the Southern California Gas Company ("SoCalGas") system at the Sites' boundaries.

4.7 LOGISTICS

35. No record is available to confirm how crude oil was delivered from the Sites to local refineries or costs actually 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.[11] The Sites are near major Los Angeles refineries

[9] CalGEM Production Records.
[10] *Sulfur Content of Crude Oils*, Bureau of Mines Information Circular 8676, 1975. https://dggs.alaska.gov/webpubs/usbm/ic/text/ic8676.pdf.
[11] Los Angeles Municipal Code Section 13.01.F.2 and 54.

and terminals in Long Beach. This Study estimates that transportation costs to deliver crude oil from the Sites to nearby refineries were $0.50 per barrel ("/B") in 2022.

36. Since small amounts of natural gas were produced at the Sites, it is assumed that the Sites are connected to a pipeline for delivery of 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 Sites' boundary.

5. CAPITAL INVESTMENT

37. The capital investment to be amortized at the Sites is the total investment in plant, property, and equipment used to produce income from the Sites. 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.[12]

5.1 ORIGINAL CAPITAL INVESTMENT

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

39. 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

40. Original capital investment for production wells at the Sites was estimated based on drilling and completion costs reported by California operators. Costs that are relevant to drill and complete new wells at the Sites 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 both primary and waterflood operations similar to wells found in the City. 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.[13] The average of the normalized costs in 2022 is $1,397,866 per well. This Study uses an average cost of $1.4

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

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.

41. The California Department of Conservation's California Geologic Energy Management Division's ("CalGEM") records identify completion dates for wells at the Sites. 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 prior to 2022 was estimated by adjusting costs in 2022 for historical changes in drilling costs to the year when a well was completed.[14] Original capital investment for wells at the Sites amounted to about $533,000.

5.1.2 LEASE EQUIPMENT

42. 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.

43. The U.S. Department of Energy's Energy Information Administration ("EIA") published annual estimates of capital investment for lease equipment between 1976 and 2009.[15] These estimates included representative costs for lease equipment used in primary 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 Sites by applying a standard cost-

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

capacity relationship.[16] The original capital investment in lease facilities was allocated in the cash flow analysis to years when new wells were completed between 1938 and 1963. The original capital investment for lease equipment at the Sites amounted to about $43,000.

5.1.3 SITE IMPROVEMENTS

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

45. For this Study, the original investment in site improvements was estimated as 5% of the cost for lease facilities.[17] The original site improvements are assumed to have occurred at various times and are allocated to the years in which new wells were completed. Overall, the original capital investment for site improvements amounted to about $2,000.

5.2 SUSTAINING CAPITAL INVESTMENT

46. 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 Sites includes well modifications and replacement of well equipment and lease equipment that reaches end of life. Routine maintenance, testing expenses, and maintenance of site improvements are considered as operating costs and are not included in sustaining capital investment.[18]

47. 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 amortization of 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.

[16] 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).
[17] See Section 5.2.3 of the Summary Report.
[18] Operating costs are discussed below in Section 6.3.

5.2.1 WELL MODIFICATIONS

48. Modifications to wells generally include redrill, rework, recompletion, and casing alterations, and other work that is 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.

49. CalGEM records present a history of well modifications for each of the wells at the Sites from 1938 to the present.[19] These records may include the nature of the work, the time when the work was done, and changes in production rates and crude oil quality.

50. California operators have reported the costs for well modifications and those relevant to the Sites are listed below in **Table 2**. CRC reported the costs for three types of well modifications,[20] while Sentinel Peak Resources California, LLC, ("SPR") reported an average cost for these activities.[21] 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.

[19] See CalGEM records for each of the wells at the Sites, which are listed in **Exhibit C**.
[20] California Resources Corp. 2017 Analyst Day Presentation, p. 67; https://www.sec.gov/Archives/edgar/data/1609253/000160925317000055/crc2017analystday032017.htm.
[21] 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

51. CalGEM records identify the completion dates for modifications to wells.[22] Sustaining capital investment in well modifications is recorded in the cash flow analysis during the year in which the modification is completed. The total sustaining capital investment for well modifications amounted to $368,000.

5.2.2 WELL EQUIPMENT

52. 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 is well equipment that is subject to capital replacement. The remainder of drilling and completion costs are drill rig and casing costs. Well equipment has an average mechanical life of 30 years with proper maintenance.

53. The Study allows for 3.33% of the replacement cost of well equipment as sustaining capital investment each year.[23] This sustaining capital investment is based on the cost to drill and complete wells, which is adjusted annually for changes in the costs of these activities.[24] The total sustaining capital investment for well equipment amounted to $1.05 million between 1938 and 2022.

5.2.3 LEASE EQUIPMENT

54. 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.

55. The Study allows for 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.[25] The total sustaining capital investment for lease equipment amounted to about $704,000 between 1938 and 2022.

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[22] See CalGEM records for each of the wells at the Sites, which are listed in **Exhibit A**.
[23] 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.
[24] See Section 5.2.4 of the Summary Report.
[25] See Section 5.2.4 of the Summary Report.

5.3 SUMMARY OF CAPITAL INVESTMENT

56. The total capital investment at the Sites to be amortized is $2.70 million, as summarized below in **Table 3**. This amount includes about $0.6 million of original capital investment that occurred between 1938 and 1963, and $2.13 million of sustaining capital investment that occurred between 1938 and 2022. These dollar amounts represent the capital investment incurred by operators from 1938 to 2022.

Table 3 – Summary of Sites Capital Investment

Summary of Site Capital Investment		
	Investment	**Time**
Original Capital Investment		
New Wells	$532,746	1938-1963
Lease Equipment	$43,025	1938-1963
Site Improvements	$2,151	1938-1963
Subtotal	**$577,922**	
Sustaining Capital Investment		
Well Modifications	$368,286	1944-1992
Well Equipment	$1,053,775	1938-2022
Lease Equipment	$703,886	1938-2022
Subtotal	**$2,125,947**	
Capital Investment to be Amortized	**$2,703,868**	

6. INCOME ANALYSIS

57. Capital investment is amortized by the net cash flow generated from sales of oil and gas. This Study prepared an income analysis that calculates the annual net cash flow beginning with the start of drilling operations at the Sites. In the income analysis, gross revenues are realized from the sale 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.

58. 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

59. 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 Sites 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 Sites receives for these sales, which are referred to as "netback" prices.

6.1.1 PRODUCTION VOLUMES

60. Operators in California are required to report production volumes of crude oil and natural gas to CalGEM, which maintains records of production rates for individual wells from 1977 to the present. This information is available for the wells at the Sites.[26]

61. All of the wells at the Sites were completed and in operation prior to 1977. This Study estimates annual production rates prior to 1977 by backcasting production rates of well fluids utilizing type-curves derived from available production data. Type-curves are

[26] CalGEM Production Records.

developed using standard engineering calculations applied in oil and gas reservoir management, using historical data from operating wells.[27] This standard approach assumes that characteristics of the reservoir dictate production rates evident in the type-curves.[28]

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

6.1.2 NETBACK PRICES FOR CRUDE OIL

63. Netback prices for crude oil represent the market price that the operator receives for sales of crude oil produced at the Sites, 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, the quality of crude oil, and transportation costs to deliver crude oil to a Los Angeles area refinery.

64. No records are available that document netback prices received for Torrance crude oil.[29] However, Torrance crude oil is typically 18.8°API with a sulfur content of about 1.62%. Torrance crude oil quality is comparable to Kern crude oil with 13.3°API and 1.10% sulfur.

65. This Study estimated netback prices for Torrance crude oil based on market prices for Kern crude oil delivered to Long Beach.[30] Historical price assessments for Kern crude were used as a benchmark for the value of Torrance crude from 1988 to the present. Since Kern price assessments are not available before 1988. Thus, Torrance crude prices were estimated by applying a market differential to Brent crude oil between 1979 and 1987, and by applying a market differential to West Texas Intermediate ("WTI") crude oil between 1947 and 1978.[31]

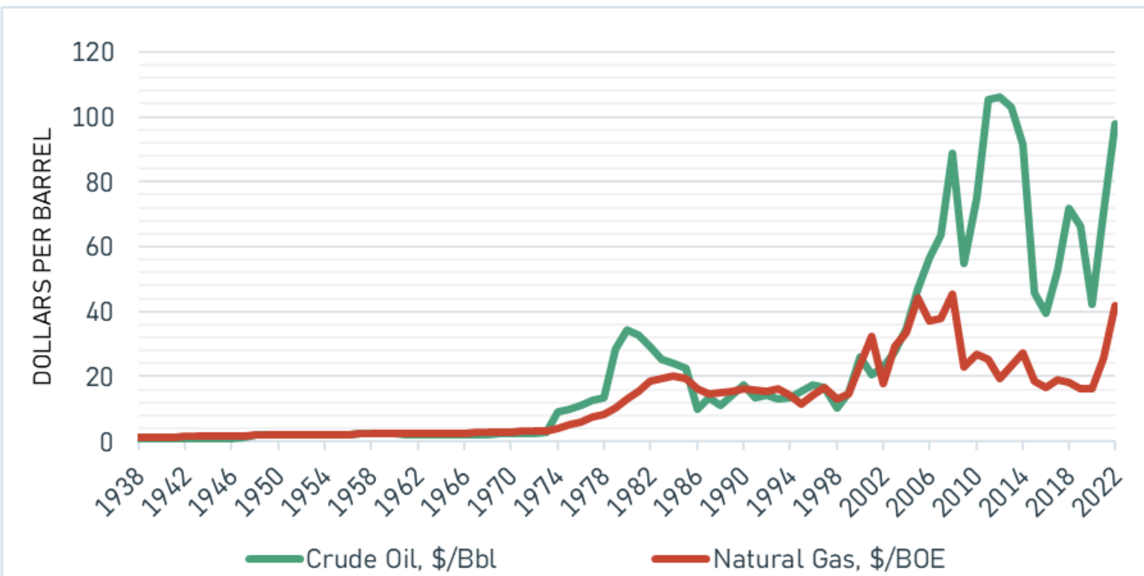
[27] A type-curve is also referred to as a "decline curve.'
[28] See Section 6.2 of the Summary Report.
[29] "Torrance" crude oil is used in this Study to refer to crude oil produced from the Site.
[30] Kern crude is delivered by pipeline to Long Beach.
[31] See Section 6.3 of the Summary Report.

66. A quality adjustment to the benchmark price assessment reflects the difference in refining value between Torrance crude oil and the benchmark.[32] As noted above, Torrance crude oil is higher in API Gravity than Kern crude and would be more valuable to a refiner. Based on reasonable industry adjustments for API Gravity, a quality premium of $1.93/B reflects the higher market value of Torrance crude oil.

67. Crude oil from the Sites is assumed to be delivered to nearby refineries by pipeline. The Sites are located near refineries in Wilmington and terminals in Long Beach. Due to this proximity, transportation costs to deliver crude oil from the Sites to Long Beach are estimated as $0.50/B in 2022.

68. Annual average netback prices for Torrance 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

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

[32] See Section 6.3 of the Summary Report.

company that serves the Los Angeles area. Natural gas must meet pipeline quality specifications before it can be injected into a local distribution system.[33]

70. This Study estimated netback prices for natural gas based upon 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. Since City Gate price assessments are not available prior to 1989, 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.[34] No discount for transportation costs was applied on these sales, which would be delivered into a pipeline.

71. Annual average netback prices for Torrance natural gas are shown above in **Figure 2**.[35]

6.2 ROYALTIES

72. Owners of mineral rights earn a royalty on commercial volumes of oil and gas produced from their property.[36] 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 Sites.

73. 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.[37]

6.3 OPERATING COSTS

74. Lease operating costs generally include labor, utilities, operating materials, maintenance materials, spare parts, general and administrative expenses, insurance, and permits. Direct operating costs include the costs to separate the oil, gas, and produced water; treat

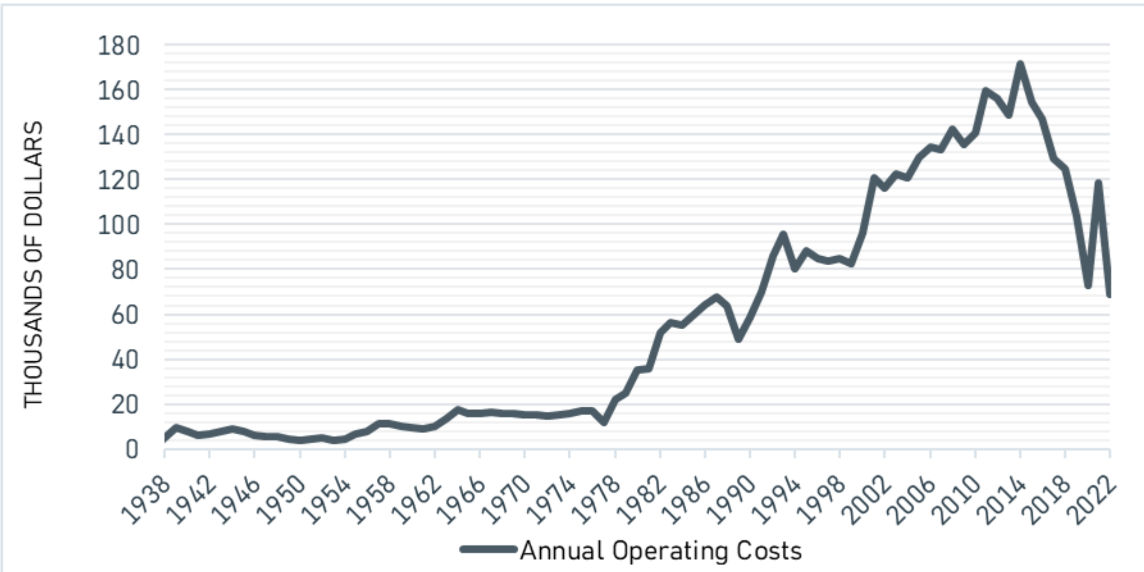
[33] https://www.socalgas.com/documents/news-room/fact-sheets/PipelineBasics.pdf
[34] See Section 6.4 and Exhibit 1 of the Summary Report.
[35] "Torrance" natural gas is used in this Study to refer to natural gas produced from the Sites.
[36] Owners of mineral rights and landowners may or may not be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

crude oil and natural gas to market specifications and treat produced water for reinjection or disposal.

75. The EIA published annual estimates of oil lease operating costs between 1976 and 2009.[38] Operating costs for the Sites were estimated by normalizing EIA operating costs for its design production rate of well fluids and applying these costs to the reported production of well fluids from the Sites. Prior to 1976 and after 2009, the EIA operating costs were adjusted for historical changes in operating costs.[39]

76. Annual operating costs for the Sites are summarized below in **Figure 3**.

Figure 3 – Sites Operating Costs



6.4 INCOME TAXES

77. 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.

[38] See Section 6.6 of the Summary Report.
[39] See Section 5.2.4 of the Summary Report.

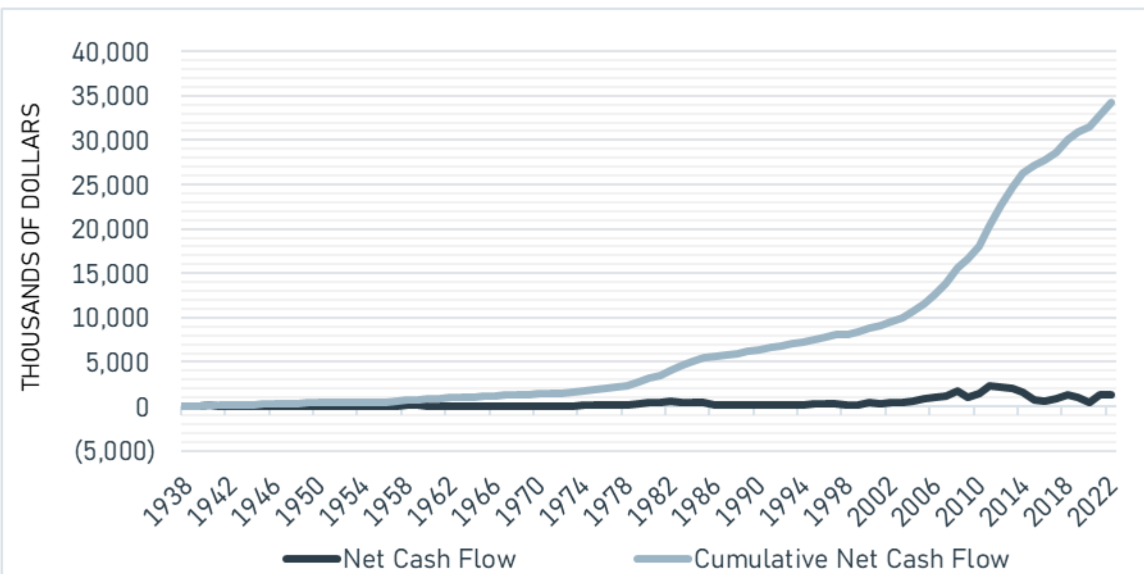
78. Federal and state income taxes on taxable income are calculated using the highest corporate tax brackets in effect each year. Federal income tax rates range from 21% to 46%, and California state income tax rates range from 8.8% to 9.6%.[40]

6.5 NET CASH FLOW FOR AMORTIZATION

79. 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 Sites averaged about $402,000, and the cumulative net cash flow between 1938 and 2022 amounted to more than $34.2 million. These nominal dollar amounts represent the cash flow generated from 1938 to 2022.

80. The annual and cumulative net cash flow from the Sites are shown below in **Figure 4**.

Figure 4 – Sites Net Cash Flow



[40] See Section 6.7 of the Summary Report.

7. MARKET RATE OF RETURN ON INVESTMENT

81. The tests for amortization of capital investment use a "market" rate of return on investment that is characteristic of oil and gas production companies.[41] The market rate of return on investment is a total rate of return that is realized by public companies in this industry sector.

82. This Study refers to an analysis of the Weighted Average Cost of Capital ("WACC") for public companies that has been published annually since 1998.[42] 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.

83. 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.

[41] See Section 4.3 of the Summary Report.
[42] See Section 7.1 of the Summary Report.

8. CONCLUSIONS

84. 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.

8.1 BASE CASE AMORTIZATION OF CAPITAL INVESTMENT

85. In the Base Case, capital investment in wells and lease facilities at the Sites were amortized by 1939, within one year of the original capital investment.

86. 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 1939 when the cumulative IRR exceeded the 8% market rate of return. The Net Present Value ("NPV") test for amortization was also achieved in 1939 when the cumulative net present value exceeded zero.

87. The total capital investment of $2.7 million was amortized by $34.2 million of net cash flow between 1938 and 2022. Original capital investment was amortized within one year of commencement of operations. The cumulative IRR increased to about 259% by 1942 and remained at that level through 2022.

8.2 SENSITIVITY CASE A: MARKET RETURN ON CAPITAL INVESTMENT

88. This sensitivity analysis demonstrates that the time required to achieve amortization of capital investment does not change over a reasonable range of assumptions in the market rate of return.

89. 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.[43]

90. The results of the Sensitivity Case A income analysis are summarized in **Exhibit F**. The IRR test for amortization was achieved in 1939 when the cumulative IRR exceeded the 12% rate of return. The NPV test for amortization was also achieved in 1939 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 Sites was amortized by 1939.

8.3 SENSITIVITY CASE B: COMMODITY PRICE

91. This sensitivity analysis demonstrates that the time required to achieve amortization of capital investment remained unchanged over a reasonable range of assumptions related to the price of crude oil.

92. In Sensitivity Case B, the Base Case quality premium of $1.93/B was changed to a premium of $1.43/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 Torrance crude oil.

93. The results of the Sensitivity Case B income analysis are summarized in **Exhibit G**. The IRR test for amortization was achieved in 1939 when the cumulative IRR exceeded the 8% market rate of return. The NPV test for amortization was also achieved in 1939 when the cumulative net present value exceeded zero. Even with lower netback prices for Torrance crude oil, the capital investment in wells and lease facilities at the Sites was amortized by 1939.

8.4 SENSITIVITY CASE C: ORIGINAL CAPITAL INVESTMENT

94. This sensitivity analysis demonstrates that the time required to achieve amortization of capital investment is within two years, even with a larger original capital investment.

95. 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 cost for an oil well exceeds the maximum

[43] See Exhibit 4 of the Summary Report.

cost for a new well reported by CRC by more than 19%.[44] The Case C scenario represents the upper limit for a reasonable range of original capital costs.

96. The results of the Sensitivity Case C income analysis are summarized in **Exhibit H**. The IRR test for amortization was achieved in 1940 when the cumulative IRR exceeded the 8% market rate of return. The NPV test for amortization was also achieved in 1940 when the cumulative net present value exceeded zero. Even with a larger capital investment in wells and lease facilities at the Sites, this capital investment was amortized by 1940.

8.5 INCOME ANALYSES SUMMARY

97. The Base Case and Sensitivity assumptions and results for this Study are summarized in **Table 4** below. 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.

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

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 ($/B)				
Crude Oil Transportation – Site to Long Beach	0.50	0.50	0.50	0.50
Crude Oil Quality Adjustment	1.93	1.93	1.43	1.93
Royalty and Lease Costs, % Revenue				
Royalty Rate	16.660%	16.660%	16.660%	16.660%
Site Operating Costs, 2022 ($/B)				
Basis: Total Produced Liquids	0.97	0.97	0.97	0.97
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, %	259.75%	259.75%	245.35%	81.27%
NPV, ($ Thousands)	679	311	663	573
Years to Amortization, IRR	1	1	1	2
Years to Amortization, NPV	1	1	1	2

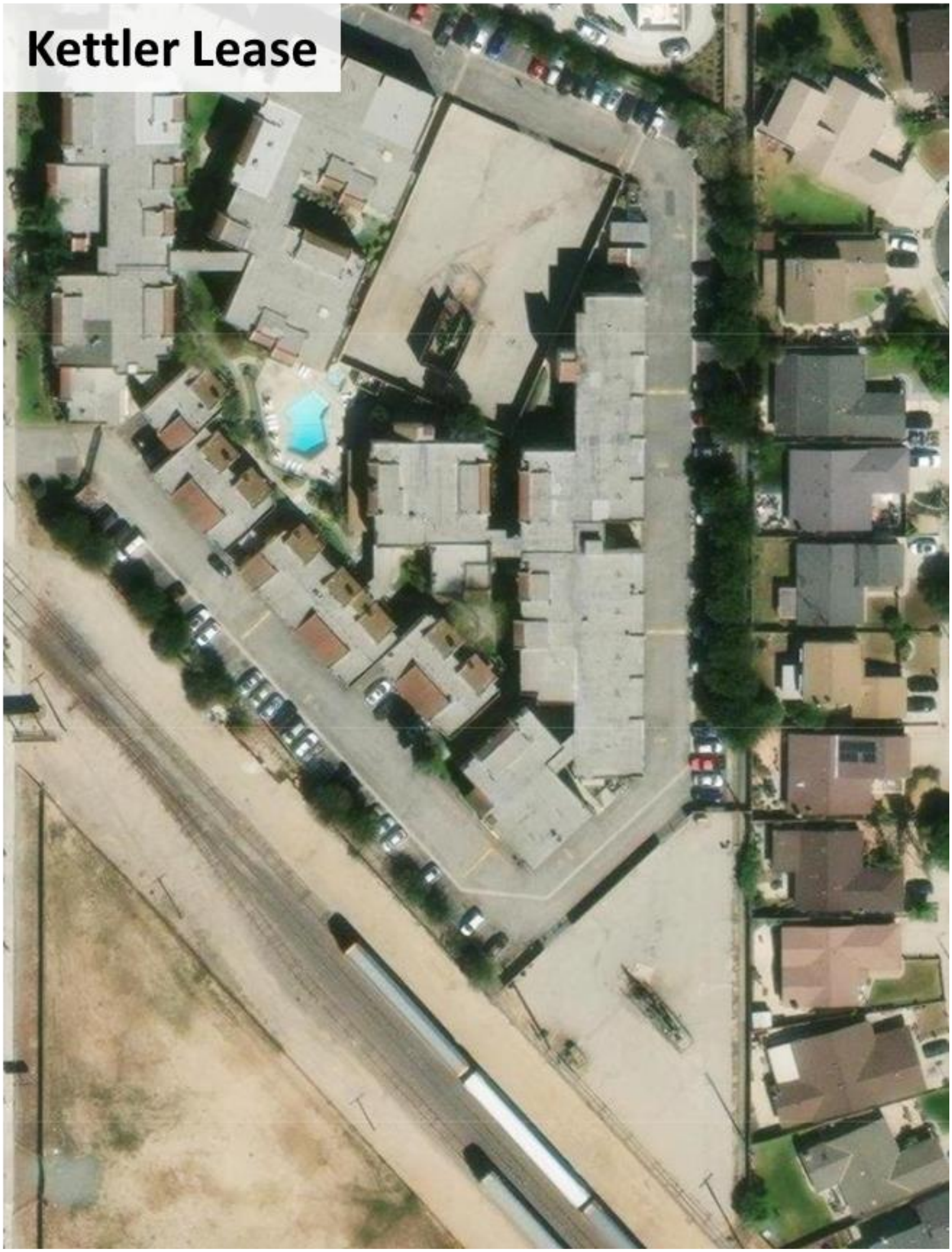
EXHIBIT A: LIST OF REFERENCE DOCUMENTS

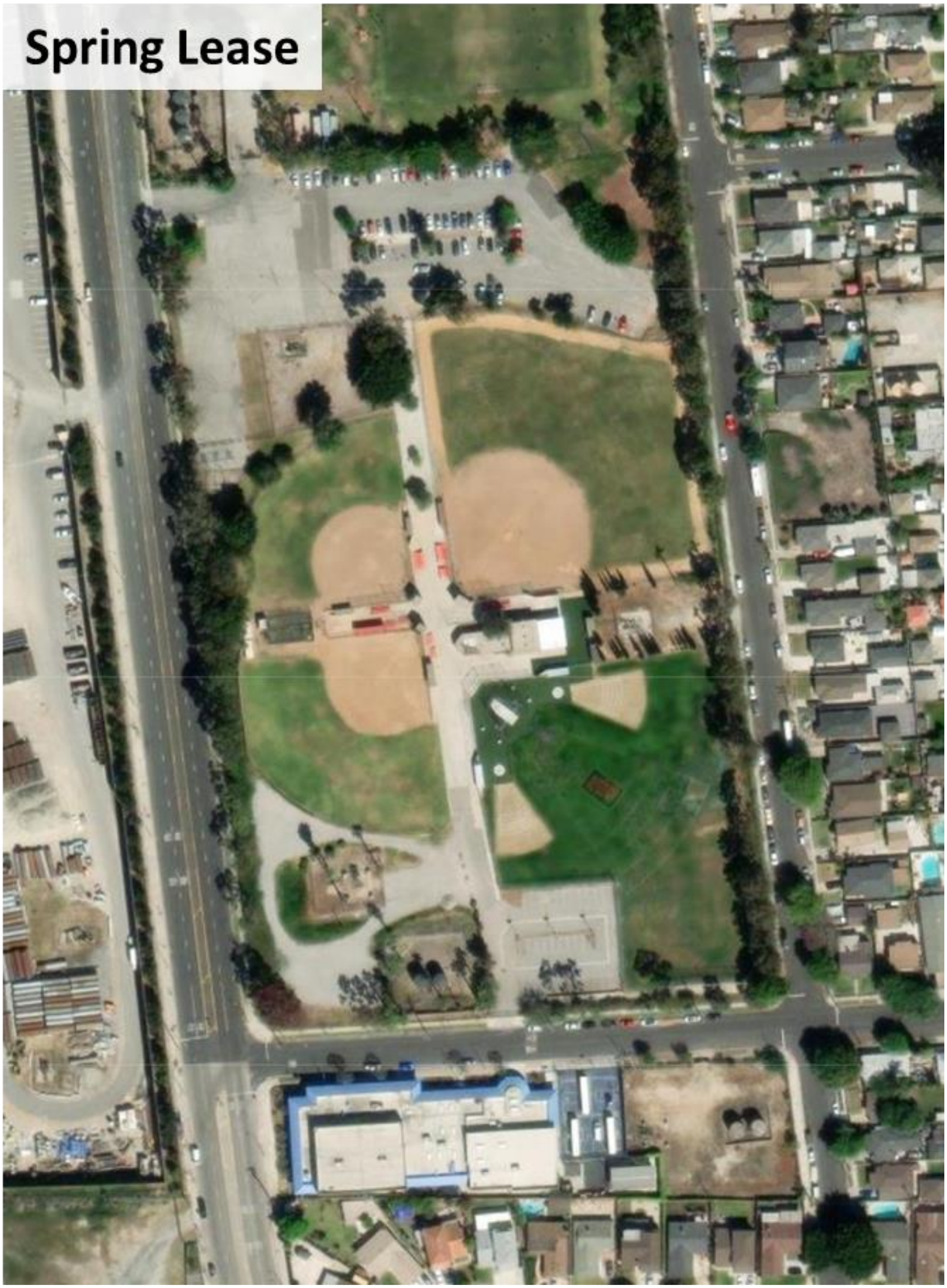
Title	Date
Bureau of Mines Information Circular 8676, Sulfur Content of Crude Oils	January 1, 1975
Costs and Indices for Domestic Oil and Gas Field Equipment and Operations , DOE/EIA-0185(95)	August 1, 1996
2010 EIA Lease Equip Cost Cost Study Data File	September 28, 2010
Oil and Gas Lease Equipment and Operating Costs 1994 through 2009 , DOE/EIA	September 28, 2010
California Resources Corporation 2017 Analyst Day Presentation	March 22, 2017
California Resources Corporation 2018 Corporate Presentation	November 1, 2018
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 403717250, File 03717250_DATA_11-6-2015	Various
CalGEM Records for API 403717349, File 03717349_2006-04-04_DATA	Various
CalGEM Records for API 403717475, File 03717475_2014-11-26_DATA	Various
CalGEM Records for API 403717529, File 03717529_2014-11-26_DATA	Various
CalGEM Records for API 403717532, File 03717532_2014-11-26_DATA	Various
CalGEM Records for API 403717533, File 03717533_2014-11-26_DATA	Various
CalGEM Records for API 403717538, File 03717538_2014-11-26_DATA	Various
CalGEM Records for API 403717539, File 03717539_2014-11-26_DATA	Various
CalGEM Records for API 403717541, File 03717541_2014-11-26_DATA	Various
CalGEM Records for API 403717542, File 03717542_2014-11-26_DATA	Various
CalGEM Production Records, File CALGEMs_Well_Data_Formatting_Torrance_ODO	Various

EXHIBIT B: AERIAL PHOTOGRAPHS OF THE SITES


Capital Lease


Ferrell Lease


Kettler Lease



Source: Google Earth.

EXHIBIT C: WELLS AT THE SITES

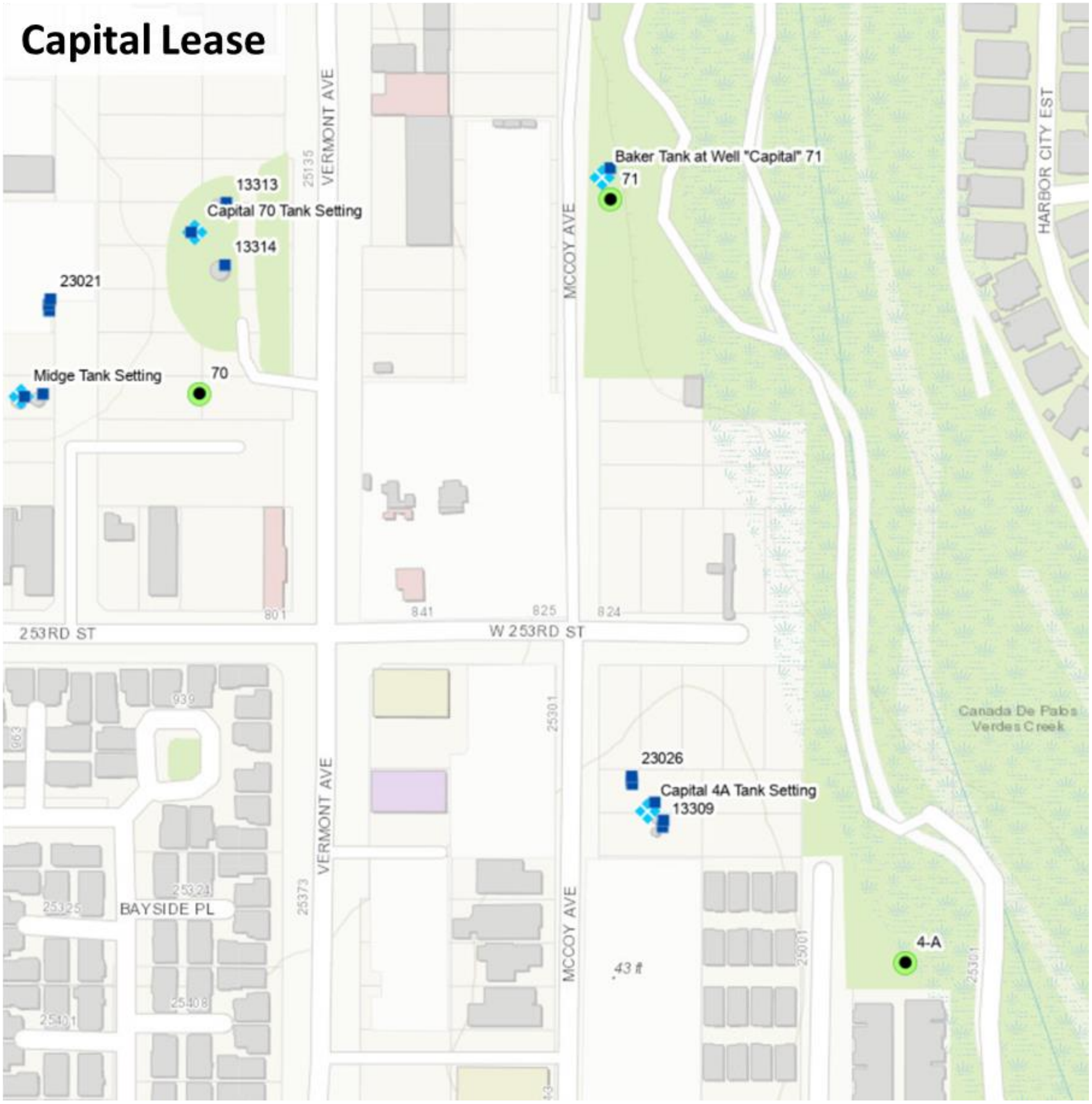
Well API No.	Lease Name	Well Designation	Spudded	Complete	Current Type	Current Status
403717250	Capital	4-A	10/17/1955	10/26/1955	Oil & Gas	Active
403717349	Spring	1	9/17/1938	10/11/1938	Oil & Gas	Idle
403717475	Kettler	20	4/12/1963	4/25/1963	Oil & Gas	Active
403717529	Kettler	29	7/29/1951	8/28/1951	Oil & Gas	Active
403717532	Capital	70	4/6/1938	5/22/1938	Oil & Gas	Active
403717533	Capital	71	3/14/1939	3/29/1939	Oil & Gas	Active
403717538	Spring	80	11/2/1941	11/28/1941	Oil & Gas	Active
403717539	Spring	81	12/7/1942	12/25/1942	Oil & Gas	Active
403717541	Spring	83	3/20/1944	4/6/1944	Oil & Gas	Active
403717542	Ferrell	84	1/8/1944	2/4/1944	Oil & Gas	Active

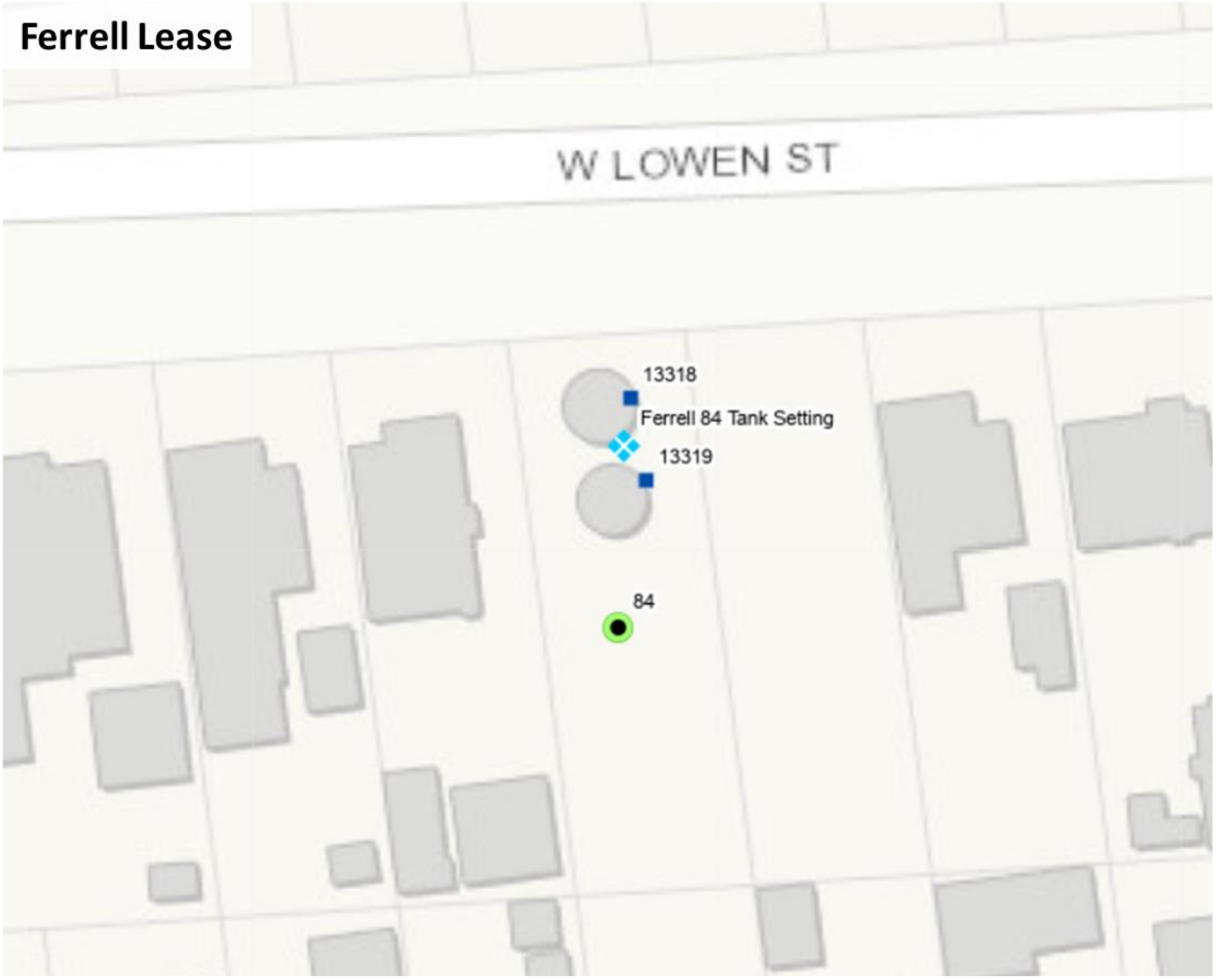
Source: CalGEM Well Finder and CalGEM Records.

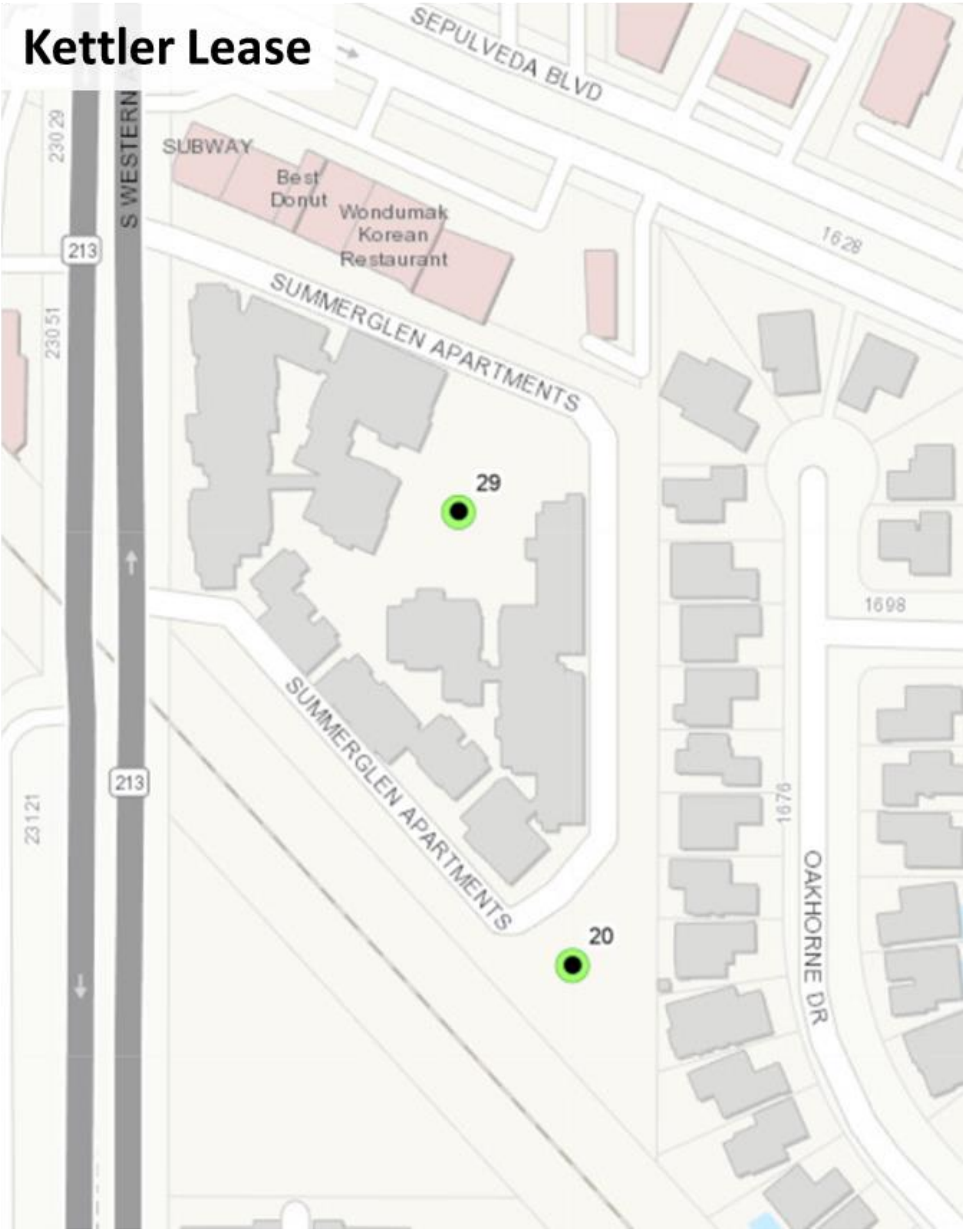
* No Record found, date is an approximation

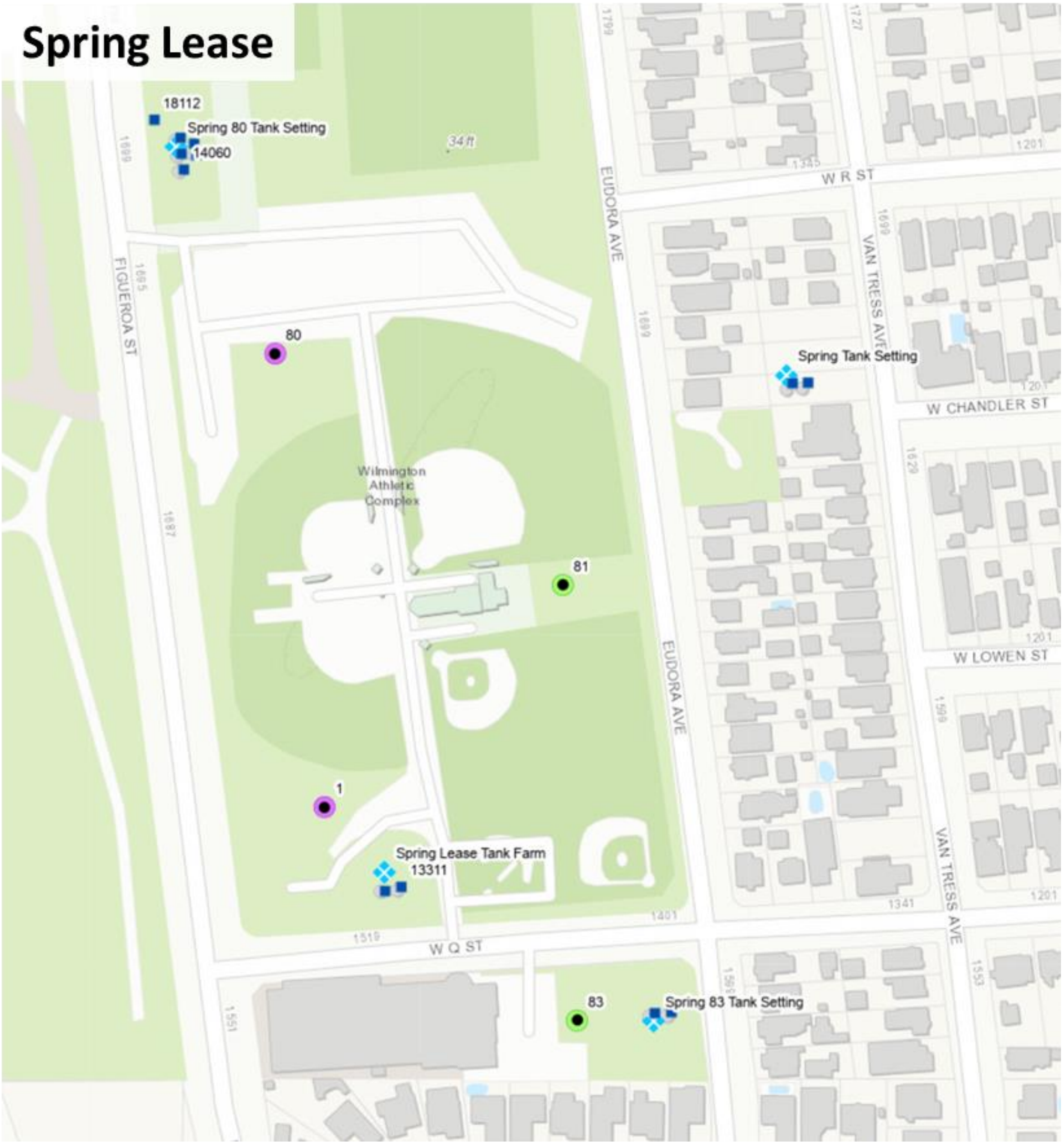
Note: "Spudded" refers to the start of drilling operations. "Complete" refers to completion of drilling operations such that the well is ready to be placed into production.

EXHIBIT D: LOCATION OF WELLS AT THE SITES




Ferrell Lease
W LOWEN ST
13318
Ferrell 84 Tank Setting
13319
84


Kettler Lease
SEPULVEDA BLVD
S WESTERN
213
SUBWAY
Best Donut
Wondumak Korean Restaurant
SUMMERGLEN APARTMENTS
29
20
SUMMERGLEN APARTMENTS
213
OAKHORNE DR
1628
1698
1676
23029
23051
23121



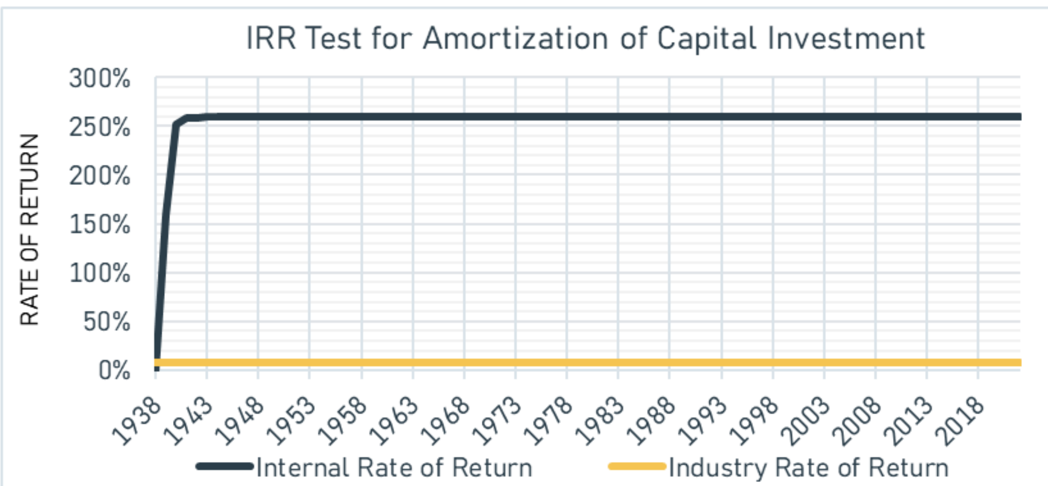
Source: CalGEM Well Finder website

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; and
- Injection wells are indicated with an arrow.

EXHIBIT E: BASE CASE AMORTIZATION OF CAPITAL INVESTMENT

Model Output Summary	
Start Year	1938
Amortization Year (IRR)	1939
Amortization Year (NPV)	1939
Years for Amortization of Capital Investment	1
Capital Investment, $thousands	2,704
Gross Revenues, $thousands	77,511
EBITDA, $thousands	59,837
Net Cash Flow, $thousands	34,179
Cumulative IRR at 2022	259.75%



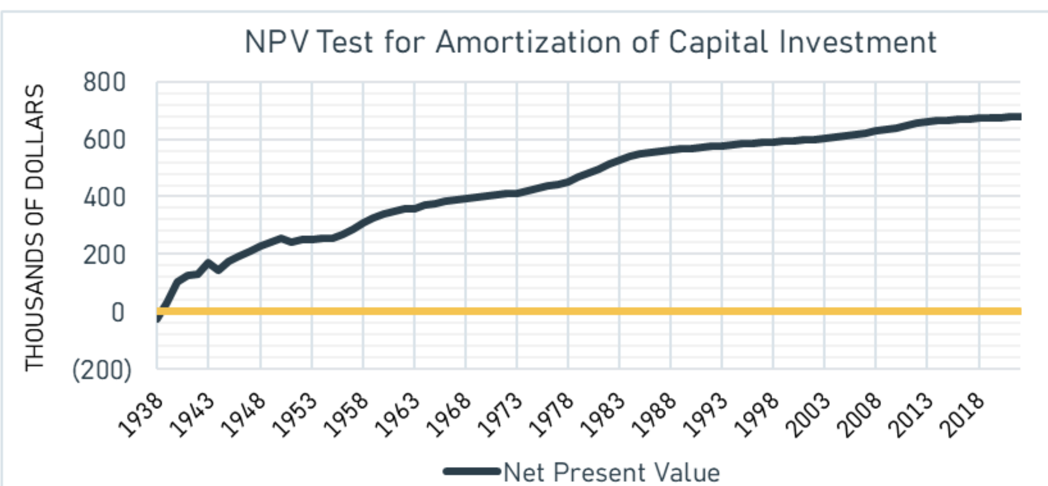
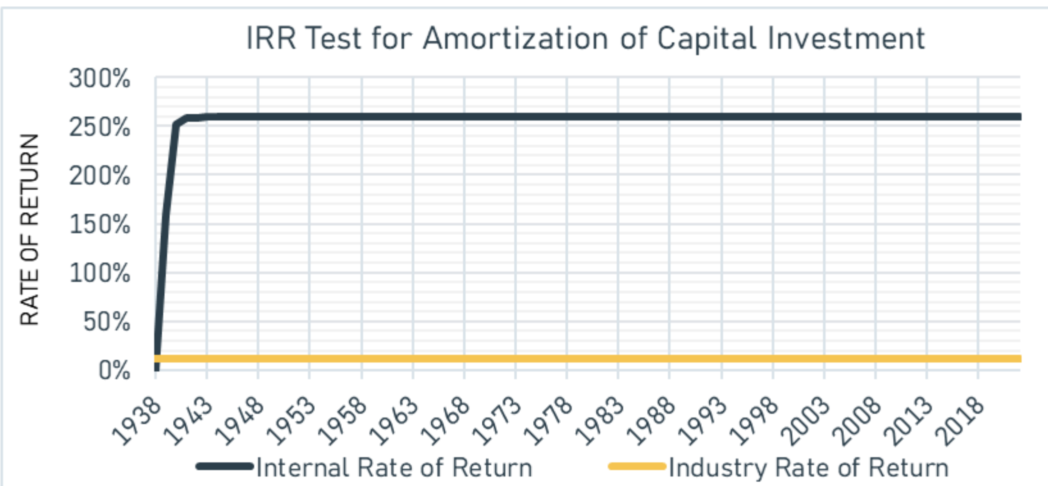


EXHIBIT F: SENSITIVITY CASE A—MARKET RETURN ON CAPITAL INVESTMENT

Model Output Summary	
Start Year	1938
Amortization Year (IRR)	1939
Amortization Year (NPV)	1939
Years for Amortization of Capital Investment	1
Capital Investment, $thousands	2,704
Gross Revenues, $thousands	77,511
EBITDA, $thousands	59,837
Net Cash Flow, $thousands	34,179
Cumulative IRR at 2022	259.75%



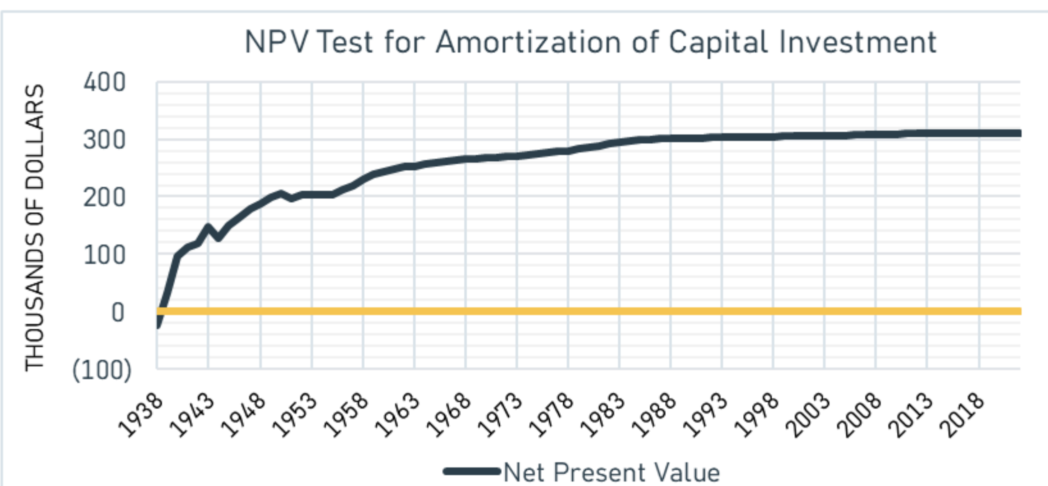
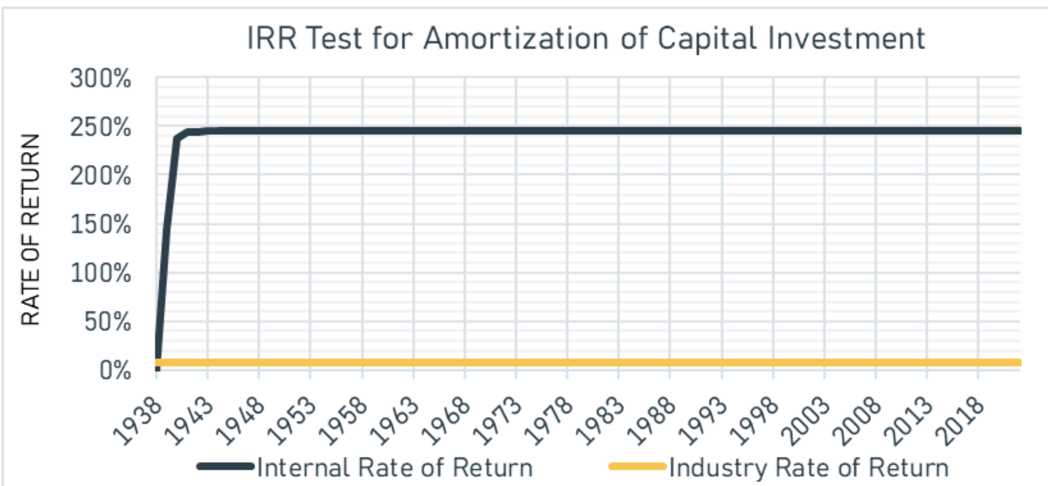


EXHIBIT G: SENSITIVITY CASE B—COMMODITY PRICE

Model Output Summary	
Start Year	1938
Amortization Year (IRR)	1939
Amortization Year (NPV)	1939
Years for Amortization of Capital Investment	1
Capital Investment, $thousands	2,704
Gross Revenues, $thousands	76,874
EBITDA, $thousands	59,306
Net Cash Flow, $thousands	33,862
Cumulative IRR at 2022	245.35%



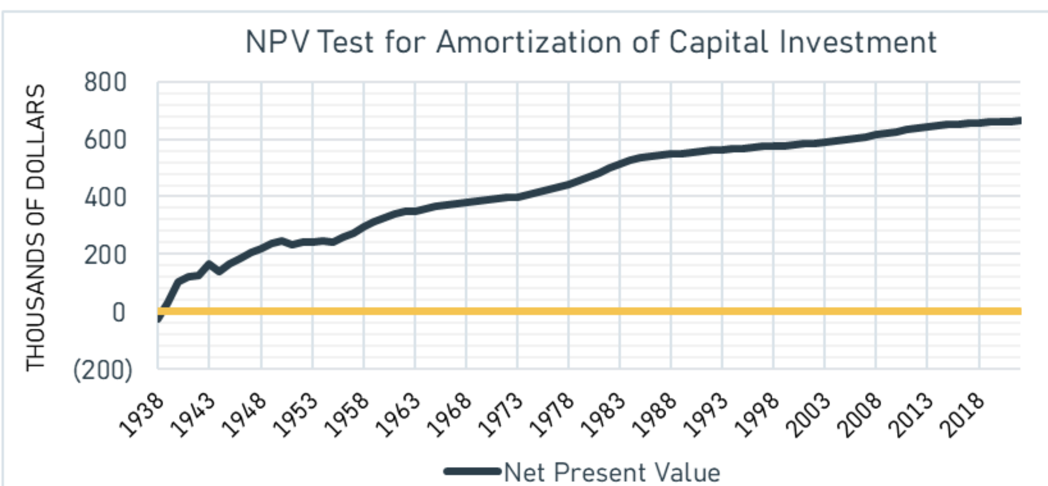


EXHIBIT H: SENSITIVITY CASE C—ORIGINAL CAPITAL INVESTMENT

Model Output Summary	
Start Year	1938
Amortization Year (IRR)	1940
Amortization Year (NPV)	1940
Years for Amortization of Capital Investment	2
Capital Investment, $thousands	3,497
Gross Revenues, $thousands	77,511
EBITDA, $thousands	59,837
Net Cash Flow, $thousands	33,655
Cumulative IRR at 2022	81.27%