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BUSINESS

America's Power Grid Is Increasingly Unreliable

By Katherine Blunt Follow

Feb. 18, 2022 10:06 am ET

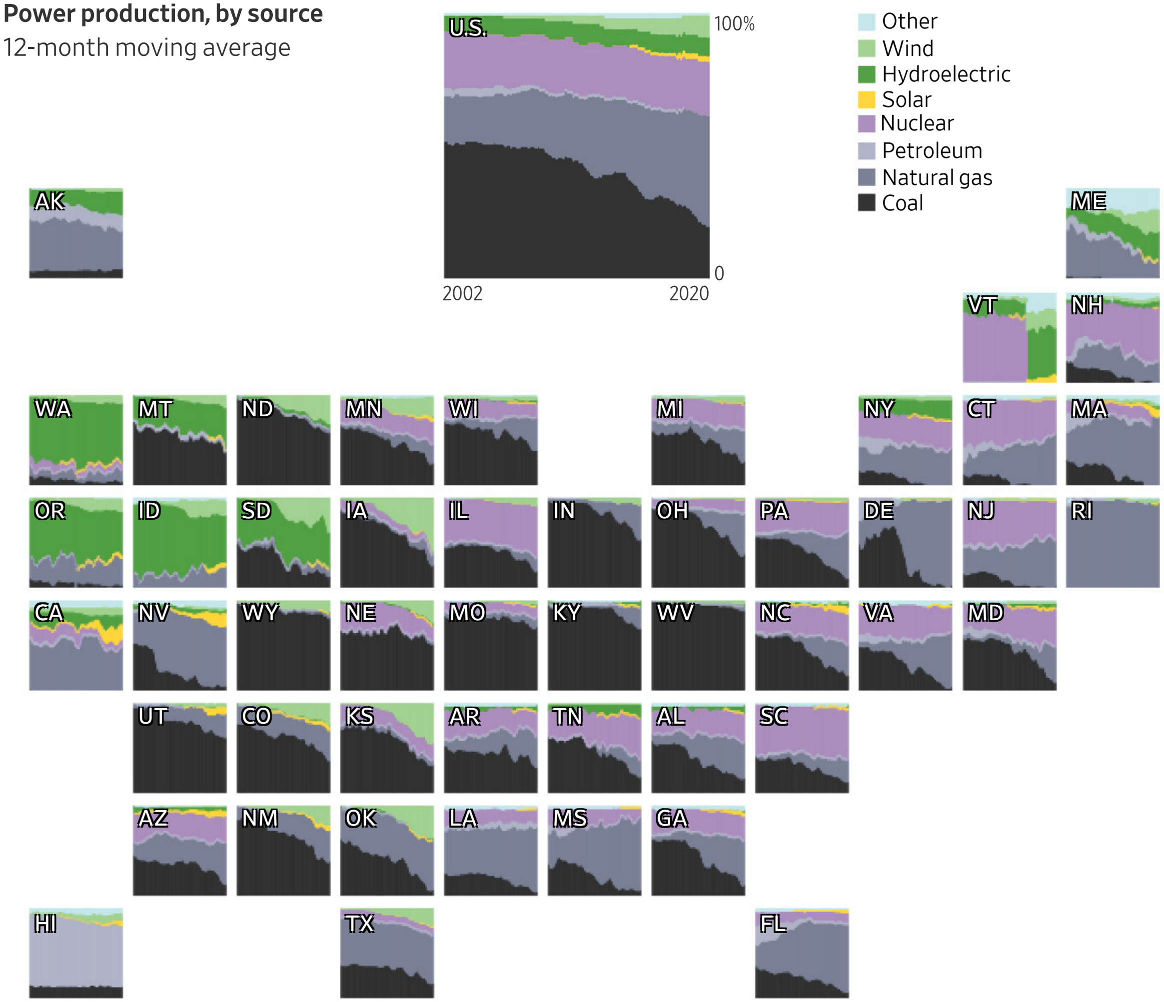
The U.S. electrical system is becoming less dependable. The problem is likely to get worse before it gets better.

Large, sustained outages have occurred with increasing frequency in the U.S. over the past two decades, according to a Wall Street Journal review of federal data. In 2000, there were fewer than two dozen major disruptions, the data shows. In 2020, the number surpassed 180.

Utility customers on average experienced just over eight hours of power interruptions in 2020, more than double the amount in 2013, when the government began tracking outage lengths. The data doesn't include 2021, but those numbers are certain to follow the trend after a freak freeze in Texas, a major hurricane in New Orleans, wildfires in California and a heat wave in the Pacific Northwest left millions in the dark for days.

Power production, by source

12-month moving average



Source: Environmental Protection Agency
James Benedict/THE WALL STREET JOURNAL

The U.S. power system is faltering just as millions of Americans are becoming more dependent on it—not just to light their homes, but increasingly to work remotely, charge their phones and cars, and cook their food—as more modern conveniences become electrified.

At the same time, the grid is undergoing the largest transformation in its history. In many parts of the U.S., utilities are no longer the dominant producers of electricity following the creation of a patchwork of regional wholesale markets in which suppliers compete to build power plants and sell their output at the lowest price. Within the past decade, natural gas-fired plants began displacing pricier coal-fired and nuclear generators as fracking unlocked cheap gas supplies. Since then, wind and solar technologies have become increasingly cost-competitive and now rival coal, nuclear and, in some places, gas-fired plants.

Regulators in many parts of the country are attempting to further speed the build-out of renewable energy in response to concerns about climate change. A number of states have enacted mandates to eliminate carbon emissions from the grid in the coming decades, and the Biden administration has set a goal to do so by 2035.

The pace of change, hastened by market forces and long-term efforts to reduce carbon emissions, has raised concerns that power plants will retire more quickly than they can be replaced, creating new strain on the grid at a time when other factors are converging to weaken it.

One big factor is age. Much of the transmission system, which carries high-voltage electricity over long distances, was constructed just after World War II, with some lines built well before that. The distribution system, the network of smaller wires that takes electricity to homes and businesses, is also decades old, and accounts for the majority of outages.

Severe storms like Hurricane Ida, last year, have contributed to the growing number of large power outages in the U.S.
PHOTOS: LUKE SHARRETT/BLOOMBERG NEWS

A report last year by the American Society of Civil Engineers found that 70% of transmission and distribution lines are well into the second half of their expected 50-year lifespans. Utilities across the country are ramping up spending on line maintenance and upgrades. Still, the ASCE report anticipates that by 2029, the U.S. will face a gap of about $200 billion in funding to strengthen the grid and meet renewable energy goals.

Another factor is the changing climate. Historically unusual weather patterns are placing great stress on the electric system in many parts of the U.S., leading to outages.

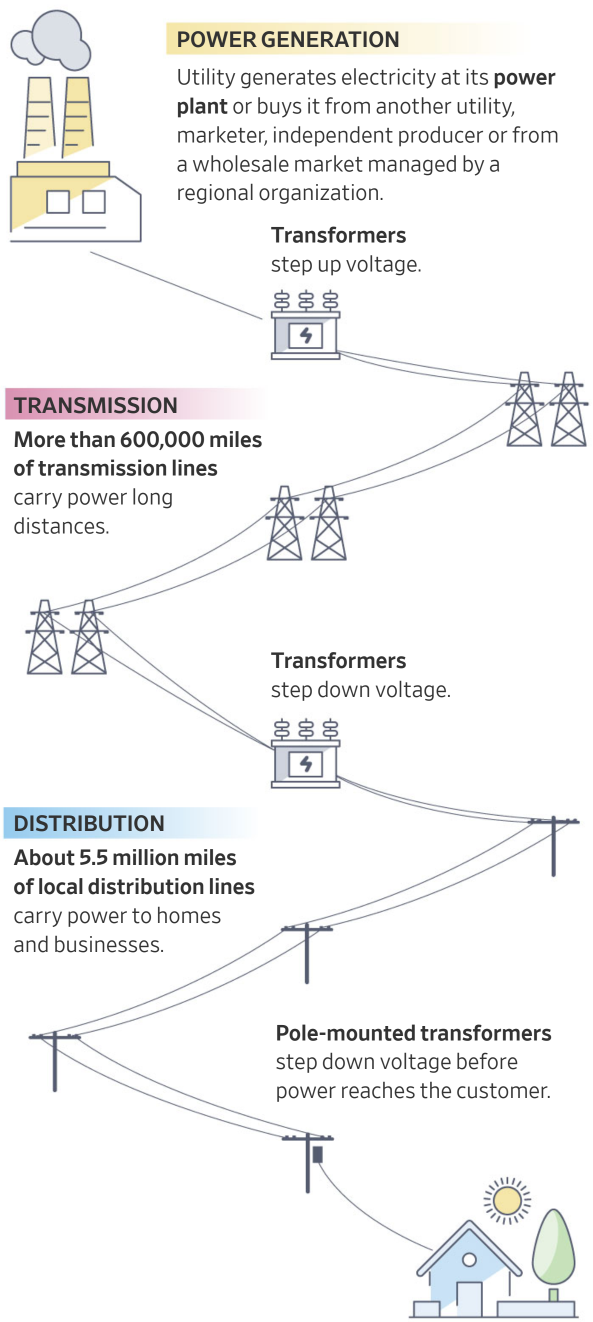
Weather-related problems have driven much of the increase in large outages shown in federal data, topping 100 in 2020 for the first time since 2011. Scientists have tied some of the weather patterns, such as California’s prolonged drought and wildfires and the severity of floods and storms throughout the country, to climate change. They project that such events will likely increase in years to come. Unlike electric systems in Europe, distribution and transmission lines in the U.S. were typically built overhead instead of buried underground, which makes them more vulnerable to high winds and other weather.

Those weather extremes are raising the costs of power network upgrades for utilities all over the country. That in turn is set to raise power bills for homeowners and businesses.

Public Service Enterprise Group Inc., which serves 2.3 million electric customers in New Jersey, plans to invest as much as $16 billion in transmission and distribution improvements over the next five years to replace aging equipment and make the grid more resilient to extreme weather events, such as a highly unusual spate of tornadoes that swept the state last year.

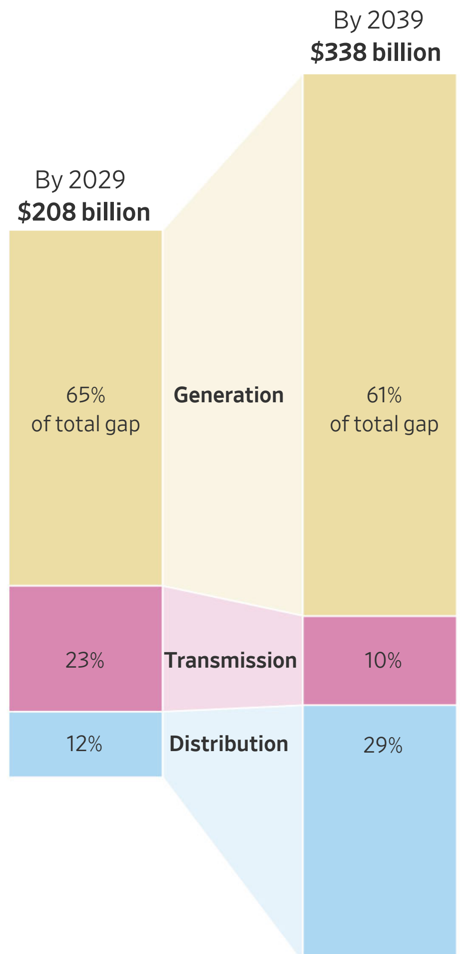
Ralph Izzo, PSEG's chief executive, said the plan is critical to ensuring reliability, especially as customers become more dependent on the grid to charge electric vehicles and replace traditional furnaces and gas appliances with electric alternatives. The movement toward electrification is in part driven by consumers, amid mounting concerns about climate change, as well as initiatives among cities and towns to enact mandates aimed at phasing out natural gas for cooking and heating.

Main components of the U.S. power grid



The shortfall in investment needed to upgrade the aging grid is projected to grow to a cumulative **$208 billion** by 2029 and **$338 billion** by 2039.

Cumulative projected investment gap, by grid component



Note: The investment gap is the difference between projected investment and needs. Needs are based on demand, the age of current infrastructure, evolving technologies, as well as state and federal policies.

Sources: Energy Information Administration (grid); American Society of Civil Engineers (investment gap)

Peter Santilli/THE WALL STREET JOURNAL

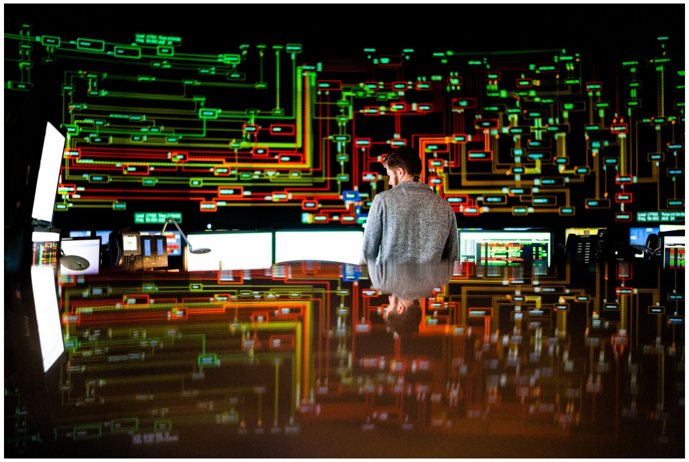
“That resiliency needs to be further enhanced, because the solutions to climate change are going to put more challenges on the grid,” Mr. Izzo said. “Those are the kinds of things that really keep you awake at night.”

The historic shift to new sources of energy has created another challenge. A decade ago, coal, nuclear and gas-fired power plants—which can produce power around the clock or fire up when needed—supplied the bulk of the nation’s electricity. Since then, renewable energy sources, including wind and solar farms whose output depends on weather and time of day, have become some of the most substantial sources of power in the U.S., second only to natural gas.

Grid operators around the country have recently raised concerns that the intermittence of some electricity sources is making it harder for them to balance supply and demand, and could result in more shortages. When demand threatens to exceed supply, as it has during severe hot and cold spells in Texas and California in recent years, grid operators may call on utilities to initiate rolling blackouts, or brief intentional outages over a region to spread the pain among everyone and prevent the wider grid from a total failure.

Companies around the country are rapidly adding large-scale batteries to store more intermittent power so it can be discharged during peak periods after the sun falls and wind dies. But because such storage technology is somewhat new, and was, until recently, relatively expensive, it remains a small fraction of the electricity market, and grid operators agree much more will be needed to keep the system stable as more conventional power plants retire.

The problem could soon threaten New York City. The New York Independent System Operator, or NYISO, which oversees the state’s power grid, last month warned of possible supply shortages in the coming years as several gas-fired power plants close or operate less frequently in light of stricter state air quality rules. New York, which has set a goal to eliminate emissions from its electricity supplies by 2040 and no longer has any coal-fired power plants, also recently shut down a nuclear plant some 30 miles north of Manhattan after critics for years called it a safety hazard.



A control room at the New York Independent System Operator, which recently warned of possible electricity shortages in the coming years as gas-fired power plants close or scale back operations.. PHOTO: CHRISTOPHER CAPOZZIELLO FOR THE WALL STREET JOURNAL

NYISO said its reserve margins—how much electricity it has available beyond expected demand—are shrinking, increasing the risk of outages. A 98-degree, sustained heat wave could result in shortfalls within New York City as soon as next year, a circumstance that would likely force NYISO to call for rolling blackouts for the first time ever.

"We already foresee razor-thin margins," said Zach Smith, NYISO's vice president of system and resource planning. "The risk is compounded when we take into consideration unforeseen events."

New York is adding substantial amounts of new wind and solar generation, as well as battery storage, and NYISO has said that it is critical that the projects remain on track to improve the stability of the system in the coming years. Already, wind and solar developers across the country are facing headwinds related to supply-chain issues, inflation and the amount of time it often takes to get approval to connect to the grid.

The North American Electric Reliability Corp., a nonprofit overseen by the Federal Energy Regulatory Commission that develops standards for utilities and power producers, warned in a report last month that the Midwest and West also face risks of supply shortages in the coming years as more conventional power plants retire.

Within the footprint of the Midcontinent Independent System Operator, or MISO, which oversees a large regional grid spanning from Louisiana to Manitoba, Canada, coal- and gas-fired power plants supplying more than 13 gigawatts of power are expected to close by 2024 as a result of economic pressures, as well as efforts by some utilities to shift more quickly to renewables to address climate change. Meanwhile, only 8 gigawatts of replacement supplies are under development in the area. Unless more is done to close the gap, MISO could see a capacity shortfall, NERC said. MISO said it is aware of this potential discrepancy but declined to comment on the reasons for it.

Curt Morgan, CEO of Vistra Corp., which operates the nation’s largest fleet of competitive power plants selling wholesale electricity, said he is worried about reliability risks in New York, New England and other markets as state and federal policy makers pursue ambitious goals to quickly phase out fossil fuel-fired power plants. His concern is that the plants will retire before replacements such as wind, solar and battery storage come online, he said, given the cost and challenge of quickly building enough batteries to have meaningful supply reserves.

Last year’s freak freeze in Texas put a spotlight on the power grid’s vulnerabilities to extreme weather events. PHOTOS: BRETT COOMER/HOUSTON CHRONICLE/ASSOCIATED PRESS; SHELBY TAUBER/REUTERS

“Everything is tied to having electricity, and yet we’re not focusing on the reliability of the grid. That’s absurd, and that’s frightening,” he said. “There’s such an emotional drive to get where we want to get on climate change, which I understand, but we can’t throw out the idea of having a reliable grid.”

Serious electricity supply constraints have historically been rare. Most recently, the Texas grid operator called for sweeping outages during an unusually strong winter storm last February that caused power plants and natural gas facilities of all kinds to fail in subfreezing temperatures. Millions of people were in the dark for days, and more than 200 died.

California, which experienced outages during a West-wide heat wave in the summer of 2020, also called on residents to conserve power several times last summer amid a historic drought that constrained hydroelectric power generation across the region. The state is now racing to secure large amounts of renewable energy and batteries in the coming years to account for the closure of several conventional power plants, as well as potential constraints on power imported from other states when temperatures rise.

California state Sen. Bill Dodd, Democrat from Napa, recently introduced legislation that would require the state’s electricity providers to offer programs that compensate large industrial power users for quickly reducing electricity use when supplies are tight, helping to ease strain on the grid.

"We just can't go down the road of having rolling blackouts again," Mr. Dodd said. "People expect their government to keep the lights on, and our reliability situation in California still isn't where it needs to be."

California's prolonged drought has fueled wildfires that in turn knock out critical electrical infrastructure. PHOTO: PATRICK T. FALLON/AGENCE FRANCE-PRESSE/GETTY IMAGES

Similar challenges have emerged elsewhere in the West. PNM Resources Inc., a utility that provides electricity for more than 525,000 customers in New Mexico, has warned that it would likely have to resort to rolling blackouts this coming summer, following the June retirement of a large coal-fired power plant. It has recently proposed keeping one of the generating units online for an extra three months to help meet demand during the hottest months of the year.

Tom Fallgren, PNM's vice president of generation, said the company faced significant delays in getting regulatory approval for several solar projects to replace the coal plant's output, as well as construction delays tied to supply-chain issues. A spokeswoman for the New Mexico Public Regulation Commission said the agency does its best to address all utility proposals in a fair and timely manner.

Mr. Fallgren said he anticipates even steeper challenges in the coming years as the company works to replace output from a nuclear plant with a combination of renewable energy and battery storage.

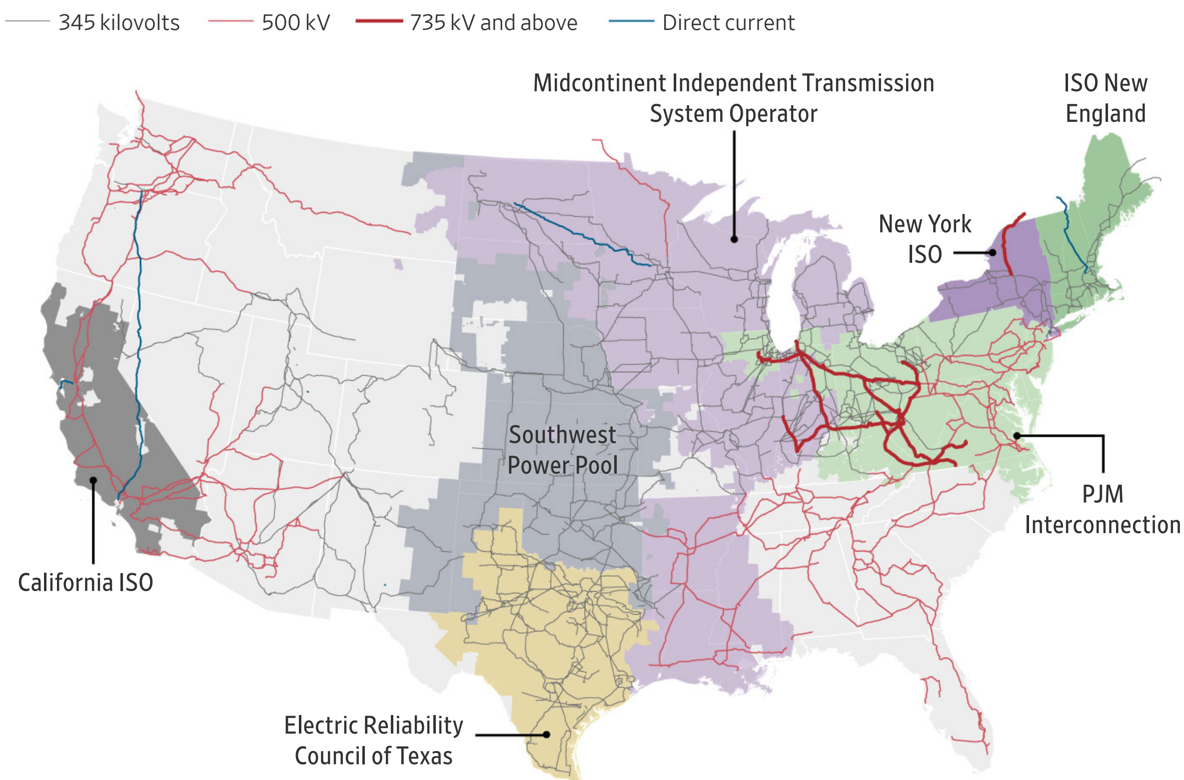
"We used to do resource planning on a spreadsheet. It used to be very simple," he said. "The math is just astronomically more complicated today."

One of the biggest challenges facing grid operators and utility companies is the need for better technology that can store large amounts of electricity and discharge it over days, to account for longer weather events that affect wind and solar output. Most large-scale batteries currently use lithium-ion technology, and can discharge for about four hours at most.

A Fractured Grid

Power delivery in the U.S. relies on an aging patchwork of hundreds of thousands of miles of high-voltage transmission lines that carry electricity to local distribution networks. More than half of the power supply is managed by independent regional organizations.

Regional organizations and transmission lines



Note: Lines with smaller capacity are omitted for clarity. ISO stands for Independent System Operator.
Source: Homeland Infrastructure Foundation Level Database
Emma Brown/THE WALL STREET JOURNAL

Form Energy Inc., a company that is working to develop iron-air batteries as a multiday alternative to lithium-ion, recently announced plans to work with Georgia Power, a utility owned by Southern Co., to develop a battery capable of supplying as many as 15 megawatts of electricity for 100 hours. It would be a significant demonstration of the technology, which the company is aiming to broadly commercialize by 2025.

Form Energy CEO Mateo Jaramillo said the U.S. has ample capability to produce power, but increasingly finds itself short on electricity during periods of high demand and low production as the generation mix changes.

“That’s sort of a feature of this new grid that we find ourselves with today,” he said.

Other outage risks are mounting as extreme weather events test the strength of the grid itself. A spate of strong storms in Michigan last summer left hundreds of thousands of residents in the dark for days as utility companies rushed to make repairs. DTE Energy Co., a utility with 2.2 million electricity customers in southeastern Michigan, had more than 100,000 customers lose power.

CEO Jerry Norcia called the storm barrage unprecedented, and said the company needed to invest more heavily in reliability. DTE now plans to spend an additional $90 million to keep trees away from power lines and is working to hire more people to help maintain its system. But it may take time for such utility improvements to fully materialize, and meanwhile, consumers may suffer further inconveniences.

Michael Fuhlhage, a professor at Wayne State University who lives just outside of Detroit, hadn’t thought much about the power grid until a few years ago, when he began noticing an uptick in the number of times severe weather caused his lights to go out. He has since started measuring outage length by the number of trash bags it takes to clean out his fridge.

In August, a storm caused a dayslong outage while he was visiting family, and he returned home to find a mess of spoiled food.

“That was probably a three-garbage bag storm,” he said. “We worry every time there’s some kind of weather coming in now, and that’s not an anxiety we had to deal with before.”

Write to Katherine Blunt at Katherine.Blunt@wsj.com

Corrections & Amplifications
Renewable energy generated from wind and solar farms, hydroelectric facilities and other technologies has recently emerged as the second-most prevalent source of power generation in the U.S. An earlier version of this article incorrectly said that wind and solar farms have become the second-most prevalent sources of power generation. (Corrected on Feb. 23.)

Appeared in the February 19, 2022, print edition as 'The Power Struggle'.

CALIFORNIA DEPARTMENT OF FORESTRY AND FIRE PROTECTION
SAN LUIS OBISPO UNIT
635 North Santa Rosa Street
San Luis Obispo, CA 93405
VENTURA COUNTY FIRE DEPARTMENT
165 Durley Avenue
Camarillo, CA 93010

INVESTIGATION REPORT

CASE NUMBER: 17CAVNC103156

CASE NAME: THOMAS

DATE: December 4, 2017

INCIDENT TYPE: Wildland Fire

INCIDENT INVESTIGATORS: Christine SAQUI, Fire Investigator – VCFD

Aimin ALTON, Firefighter (PM) - VCFD
Dennis BYRNES, Fire Captain – CAL FIRE
Gregg DELAROSA, Senior Deputy – VCSO
Jace CHAPIN, Battalion Chief – CAL FIRE
Ryan MILLER, Firefighter – VCFD
Steven DEAN, Fire Investigator – USFS
Tom CRASS, Fire Captain-Specialist – CAL FIRE
Patrick KELLEY, Fire Captain – VCFD

Alex LOMVARDIAS, Special Agent – USFS
Brian KINSLEY, Firefighter – VCFD
Jay SNODGRASS, Fire Captain Investigator - SBCOFD
Jon BERGH, Fire Investigator – VCFD
Ken RUSSELL, Fire Captain-Specialist – CAL FIRE
Marshall HATCH, Fire Investigator – VCFD
Shannan HARRIS, Fire Captain-Specialist – CAL FIRE

1 – VIOLATIONS:

Penal Code § 192

Manslaughter is the unlawful killing of a human being without malice. It is of three kinds:

(b) Involuntary—in the commission of an unlawful act, not amounting to a felony; or in the commission of a lawful act which might produce death, in an unlawful manner, or without due caution and circumspection. This subdivision shall not apply to acts committed in the driving of a vehicle.

Penal Code § 452

A person is guilty of unlawfully causing a fire when he recklessly sets fire to or burns or causes to be burned, any structure, forest land or property.

(a) Unlawfully causing a fire that causes great bodily injury is a felony punishable by imprisonment in the state prison for two, four or six years, or by imprisonment in the county jail for not more than one year, or by a fine, or by both such imprisonment and fine.

(b) Unlawfully causing a fire that causes an inhabited structure or inhabited property to burn is a felony punishable by imprisonment in the state prison for two, three or four years, or by imprisonment in the county jail for not more than one year, or by a fine, or by both such imprisonment and fine.

(c) Unlawfully causing a fire of a structure or forest land is a felony punishable by imprisonment in the state prison for 16 months, two or three years, or by imprisonment in the county jail for not more than six months, or by a fine, or by both such imprisonment and fine.

(d) Unlawfully causing a fire of property is a misdemeanor. For purposes of this paragraph, unlawfully causing a fire of property does not include one burning or causing to be burned his own personal property unless there is injury to another person or to another person's structure, forest land or property.

Health & Safety Code § 13001

Every person is guilty of a misdemeanor who, through careless or negligent action, throws or places any lighted cigarette, cigar, ashes, or other flaming or glowing substance, or any substance or thing which may cause a fire, in any place where it may directly or indirectly start a fire, or who uses or operates a welding torch, tar pot or any other device which may cause a fire, who does not clear the inflammable material surrounding the operation or take such other reasonable precautions necessary to insure against the starting and spreading of fire.

Public Resources Code § 4421

A person shall not set fire or cause fire to be set to any forest, brush, or other flammable material which is on any land that is not his own, or under his legal control, without the permission of the owner, lessee, or agent of the owner or lessee of the land.

General Order 95, 31.1: Design, Construction and Maintenance

Electrical supply and communication systems shall be of suitable design and construction for their intended use, regard being given to the conditions under which they are to be operated, and shall be maintained in a condition which will enable the furnishing of safe, proper and adequate service.

2 – SUMMARY:

On Monday, December 4, 2017, at approximately 6:23 PM, a phone report of a wildland fire was called into the Ventura County Fire Department (VCFD) Fire Station 20. Fire Captain Tony SALAS took the phone call. While on the phone, Station 20 was toned out for a wildland fire in the area of 1681 Dickenson Drive. While enroute in VCFD Engine 20 (E20) SALAS and crew observed a wildland fire in Anlauf Canyon. This is in the same geographical area as the phone-in report received at VCFD Station 20 regarding a wildland fire near Thomas Aquinas College. E20 arrived on scene, confirmed the wildland fire, reported to dispatch the fire was approximately 50 acres and requested a second alarm. The fire was located in a canyon above Steckel Park. SALAS observed strong winds in the area and the fire racing down canyon toward Highway 150. E20 was unable to engage in fire suppression due to extreme fire conditions. SALAS assumed command of the fire and directed incoming resources into the fire. At approximately 7:30 PM, VCFD dispatched a reported wildland fire in the area of Koenigstein Road and Highway 150, this fire was determined by investigators to be a separate fire *(identified as the KOENIGSTEIN fire)* not associated with the THOMAS fire.

The THOMAS fire continued to burn out of control. On Tuesday, December 5, 2017, at approximately 1:00 AM, the THOMAS and KOENIGSTEIN fires merged into one and both fires were referred to as the THOMAS fire. Collectively, the THOMAS fire and the KOENIGSTEIN fire consumed 281,893 acres of mixed wildland and 1343 structures destroyed/damaged. One civilian fatality and one fire fighter fatality occurred as a result of these two fires. The fire was fully controlled on Wednesday, January 10, 2018.

The assigned fire investigation team *(IT)* determined the THOMAS fire occurred when energized power lines came into contact (phase to phase) with each other between two power poles, emitting molten aluminum particles onto the surrounding dry vegetation. The IT documented, photographed and collected sections and parts associated with the involved power lines. The power lines and equipment responsible for the THOMAS fire where owned and operated by Southern California Edison (SCE).

3 – SUSPECT:

S-1 Southern California Edison (SCE)
Corporate Headquarters
9200 Oakdale Avenue, 9th Floor
Los Angeles, CA 91311
Phone: (888) 848-4754

Process Service Agent - SCE
Cristina LIMON
[redacted]

4 – VICTIMS & WITNESSES:

VICTIMS:

V-1 Virginia PASOLA
Civilian
[redacted]
For further information pertaining to PASOLA contact Ventura County Medical Examiner's Office at (805) 641-4400 (reference report #1501-17).

V-2 Cory IVERSON
Fire Apparatus Engineer – CAL FIRE
[redacted]
For further information pertaining to IVERSON contact Ventura County Medical Examiner's Office at (805) 641-4400 (reference report #1539-17).

Other Victims:

For a complete list of properties which sustained damage or burned structures during the THOMAS and/or KOENINGSTEIN fires *(see attachment #4)*. This list may or may not include damaged land and other miscellaneous burned properties.

WITNESSES:

W-1 David DOLLAR

[redacted]

Fire originated on his property, can testify to seeing fire surrounding his property, and sustained damage to vegetation, barn and other property. DOLLAR recalled the power was interrupted approximately 15 minutes prior to receiving a phone call from his son Chris DOLLAR, notifying him of the fire. DOLLAR was on his property with two employees from Carbon California approximately two hours prior to the fire. Also DOLLAR'S vehicle was inspected by the investigation team (see attachment #5).

W-2 Chris DOLLAR

[redacted]

C. DOLLAR can testify to receiving a phone call from Juan GAMEZ Jr. and telling C. DOLLAR there was a fire behind his parents' house, Chris was also present when DOLLAR was interviewed (see attachment #5).

W-3 Matt DOLLAR

[redacted]

M. DOLLAR is the son of DOLLAR and can testify to being present when DOLLAR was interviewed (see attachment #5).

W-4 Dori Thompson CLARKE
Owner of THOMPCO
[redacted]
Can testify to sending three of her employees up to the Timber Oil Lease (Carbon California) the day the THOMAS fire occurred. CLARKE provided documentation of what her employees did and time they arrived and left on the oil lease (see attachment #6).

W-5 Alberto NUNEZ
THOMPCO Employee
[redacted]
NUNEZ can testify to working for THOMPCO and was with Jesus VALENZUELA and John TAIT working at the Timber Oil Lease (Carbon California) the day of the fire and arrived at the lease at approximately 7:30 AM, and left at approximately 3:00 PM (see attachment #6).

W-6 John TAIT
THOMPCO Employee
[redacted]
TAIT can testify to working for THOMPCO and was with Jesus VALENZUELA and NUNEZ working at the Timber Oil Lease (Carbon California) the day of the fire and arrived at the lease at approximately 7:30 AM, and left at approximately 3:00 PM (see attachment #6).

W- 7 Jesus VALENZUELA

THOMPCO Employee

[redacted]

VALENZUELA was working for THOMPCO and was with NUNEZ and TAIT working at the Timber Oil Lease (Carbon California) the day of the fire. VALENZUELA arrived at the lease at approximately 7:30 AM, and left at approximately 3:00 PM. The THOMPCO vehicle VALENZUELA was utilizing the day of the THOMAS fire, was inspected by the investigation team (see attachment #6).

W-8 Richard RUDMAN

[redacted]

Can testify to maintaining the radio towers in Anlauf Canyon. RUDMAN was on the property the afternoon prior to the fire starting. RUDMAN experienced strong winds at the radio tower prior to the start of the THOMAS fire. RUDMAN provided the DATA logs of power outages the day of the THOMAS fire to the IT (see attachment #7).

W-9 Peter RIOUX

[redacted]

Can testify to being the Operation Supervisor at Saint Thomas Aquinas College, and placed the fire within DOLLAR'S property in a canyon above his house before 6:30 PM. RIOUX called VCFD Fire Station 20 prior to them being dispatched by Ventura County Fire Communication Center and advised them of the fire. RIOUX took pictures of the fire and provided them to the IT (see attachment #8).

W-10 Brian DICKENSON

[redacted]

Can testify to calling 911 reporting the THOMAS fire. DICKENSON lives in Santa Paula and saw the fire in the area of Anlauf Canyon. DICKENSON is one of the first 911 reporting parties for the THOMAS fire (see attachment #49).

W-11 Tony SALAS

[redacted]

SALAS can testify to receiving a phone call from Peter RIOUX reporting the fire in the area of Anlauf Canyon. SALAS was the Fire Captain on the first arriving VCFD Fire Engine 20, SALAS was the first Incident Commander and saw the fire coming from DOLLAR'S property (see attachment #9).

W-12 Steve SWINDLE

[redacted]

SWINDLE can testify to being the Fire Apparatus Engineer on the first arriving VCFD Engine 20 (see attachment #9).

W-13 Steve BUCKLES

[redacted]

BUCKLES can testify to being the Firefighter on first arriving VCFD Engine 20 (see attachment #9).

W-14 Juan GAMEZ Sr.

[redacted]

Can testify to seeing the fire in Anlauf Canyon and taking pictures of the fire. GAMEZ sent a multimedia message service image to his son Juan GAMEZ Jr. (see attachment #10).

W-15 Juan GAMEZ Jr.

[redacted]

GAMEZ Jr. can testify to receiving a phone text message picture from his father GAMEZ of a fire near DOLLAR'S house. GAMEZ Jr. called C. DOLLAR and advised him there was a fire near his parents' house (see attachment #10).

W-16 Robert FROST

[redacted]

Can testify to leasing the property from DOLLAR for his cattle. FROST received a phone call from GAMEZ stating there was a fire on DOLLAR'S property (see attachment #11).

W-17 Mel LOVO

Fire Captain VCFD

[redacted]

LOVO can testify to being on Copter 8, and being the first arriving helicopter. LOVO took video upon arrival (see attachment #12).

W-18 Ken WILLIAMS

Ventura County Sheriff's Department

[redacted]

WILLIAMS can testify to being the Pilot on Copter 8 with Fire Captain LOVO (see attachment #12).

W-19 Randy GILBERT

Firefighter, VCFD

[redacted]

GILBERT can testify to being on the second arriving helicopter (Copter 7).

W-20 Leila THAYER

[redacted]

Can testify to calling 911 and seeing the fire from Highway 150 near Steckel Park (see attachment #13).

W-21 Tammy GARCIA

[redacted]

Can testify to driving on Highway 150 at approximately 6:30 PM, on Monday, December 4, 2017. GARCIA saw the fire on the east side of Highway 150 and took photos and videos (see attachment #13).

W-22 Lindsey MOORE

[redacted]

Can testify to driving on Highway 150 with her mother GARCIA *at approximately 6:30 PM, on Monday, December 4, 2017. MOORE saw the fire on the east side of Highway 150 (see attachment #13).*

W-23 Martin HAGGARD

[redacted]

Can testify to calling 911 and seeing the fire from Thomas Aquinas College (see attachment #13).

W-24 Rose LEMON

[redacted]

Can testify to calling 911, smelling smoke and seeing the fire from Steckel Park (see attachment #13).

W-25 Jeanette RICHARD

[redacted]

Can testify to calling 911 and seeing a red glow from Thomas Aquinas College (see attachment #13).

W-26 Bill ALLEN

[redacted]

Can testify to calling 911 and seeing the fire from Highway 126 (see attachment #13).

W-27 Jorge MONZADA

[redacted]

Can testify to receiving seven photos and forwarding the photos to the THOMAS IT (see attachment #14).

W-28 Alexandra PRICE

[redacted]

Can testify to receiving a phone call from her friend Susan at approximately 6:30 PM, who told her about the THOMAS fire. Susan was aware of the fire from a phone fire alert app. PRICE and her husband drove to an advantage point and described the fire to be on DOLLAR'S property (see attachment #15).

W-29 Ray PRICE

[redacted]

Can testify to being with his wife, A. PRICE, during the start of the THOMAS fire on DOLLAR'S property (see attachment #15).

W-30 Tiarzha TAYLOR

[redacted]

Can testify to seeing and taking photographs of the THOMAS fire (see attachment #16).

W-31 Earl BROCK

[redacted]

Can testify to observing the THOMAS fire to the south and taking photos of the fire (see attachment #17).

W-32 Michael MCLEAN

[redacted]

Can testify to being the President of Saint Thomas Aquinas College, resides on the property and was there at the time of the fire. MCLEAN received text messages from Robert GOYETTE and RIOUX stating there was a fire one-half mile south and east of the college (see attachment #18).

W-33 Clark TULBERG

[redacted]

Can testify to being the Facilities Manager for Saint Thomas Aquinas College, and was on the property at the time of the fire. RIOUX called TULBERG and told him about the fire. TULBERG showed the investigation team the photos he received from RIOUX of the THOMAS fire (see attachment #19).

W-34 John GOYETTE

[redacted]

Can testify to being employed at Saint Thomas Aquinas College and was at the property at the time of the fire. His son Robert GOYETTE notified him of the fire at 6:27 PM (see attachment #20).

W-35 Maria GOYETTE

[redacted]

Can testify to driving south on Highway 150 and seeing a large glow in the Mountains above Steckel Park (see attachment #20).

W-36 Robert GOYETTE

[redacted]

Can testify to being a student at Saint Thomas Aquinas College and was standing near his dormitory, looked south and saw the fire at approximately 6:27 PM, GOYOTTE alerted his father, J. GOYETTE about the fire (see attachment #20).

W-37 Stephen SMITH

[redacted]

Can testify to seeing smoke and then fire coming over ridge from the direction of Anlauf Canyon (see attachment #21).

W-38 Patricia MOREHART

[redacted]

Can testify to receiving a phone call from her neighbor notifying her of the fire. MOREHART observed the fire coming towards her house from Anlauf Canyon area, called M. MOREHART telling him to return home because of the fire (see attachment #22).

W-39 Martin MOREHART

[redacted]

Can testify to leaving his house at approximately 6:20 PM, and receiving a phone call from P. MOREHART at approximately 6:40 PM, telling him to return because of a large fire (see attachment #22).

W-40 Paul HERNANDEZ

[redacted]

HERNANDEZ can testify to seeing the fire in the hills above Steckel Park. HERNANDEZ believed the fire was near the DOLLAR'S house and observed no fire in the direction of flare stack (see attachment #23).

W-41 Noel HERNANDEZ

[redacted]

Can testify to receiving a phone call from his son P. HERNANDEZ, notifying him of the fire, and seeing the fire near DOLLAR'S house (see attachment #23).

W-42 Nicholas BROUWER

[redacted]

BROUWER can testify to standing by his son Jason BROUWER'S gate at [redacted] Santa Paula. BROUWER left his sons house on Monday, December 4, 2017, at approximately 5:15 PM, and did not see any fire (see attachment #24).

W-43 Jason BROUWER

[redacted]

J. BROUWER and N. BROUWER were standing at his gate on Monday, December 4, 2017, at approximately 5:15 PM, and did not see any fire (see attachment #24).

W-44 Troy HENDERSON

[redacted]

Can testify to seeing smoke and then fire from his deck with friend Char WARINNER, and can remember the flare stack was not lit at the time of the fire. HENDERSON is the first 911 reporting party for the THOMAS fire (see attachments #25 and #49).

W-45 Christine LAW

[redacted]

LAW'S home is located at the west entrance of DOLLAR'S property. LAW can testify to initially observing the fire coming out of the canyon above DOLLAR'S house and over the ridge towards her home (see attachment #26).

W-46 Charles LAW

[redacted]

LAW'S residence is located at the west entrance of DOLLAR'S property. Mr. LAW can testify to his wife seeing the fire from their kitchen. Initially Mr. LAW observed the fire coming out of the area around DOLLAR'S house and over the ridge towards his home (see attachment #26).

W-47 Frank SCHREINER

[redacted]

SCHREINER is the General Manager of the Ventura Ranch KOA, east of Steckel Park. SCHREINER can testify he was not at the KOA at the time of the fire (see attachment #27).

W-48 RAMANDA (This is his full legal name)

[redacted]

RAMANDA can testify to observing the fire when it approached the KOA Campground. RAMANDA was told about the fire from an unknown party who knocked on his RV door, RAMANDA was at Birch space #33 (see attachment #27).

W-49 Terry BELL

[redacted]

BELL is an off-duty Santa Paula Fire Apparatus Engineer, BELL can testify he was home with his family at the time of the fire. BELL was alerted about the fire from a phone app. (Pulse Point), then saw the fire from his kitchen door (see attachment #28).

W-50 Tanner CARPENTER

[redacted]

CARPENTER resides on the DOLLAR'S property. CARPENTER was not home at the time of the fire. CARPENTER was driving westbound on Highway 126, observed the fire in Mud Creek Canyon from Highway 126/ Hallock Road at approximately 6:53 PM (see attachment #29).

W-51 Mike RIEDER

[redacted]

Can testify to seeing smoke in a canyon below the flare stack (see attachment #30).

W-52 Mark ALVERADO

[redacted]

Can testify to seeing the glow from the THOMAS fire from Highway 126 and Highway 150 (see attachment #31).

W-53 Todd HABILSTON

[redacted]

HABILSTON can testify to being a partner in the company (Carbon California) and is unaware there was a missing plastic 55-gallon barrel containing methanol. HABILSTON called several people within Carbon and all were unaware of where the missing barrel was (see attachment #32).

W-54 Matthew ZEIER

Oil Lease Operator (Technician), CARBON California

[redacted]

Can testify to being at the Timber oil lease at approximately 1:45 PM, the day of the fire, and leaving at approximately 3:45 PM. On ZEIER'S way down the hill, he saw DOLLAR, PRICE and FERNANDEZ also on their way down the hill. ZEIER can testify to the activities at the Carbon California Timber Oil Lease in Anlauf Canyon on Monday, December 4, 2017 (see attachment #32).

W-55 Michael DEAN Jr.

Field Operations Supervisor, Carbon California

[redacted]

Can testify to Carbon California activities at the Timber Oil Lease/Anlauf Canyon on Monday, December 4, 2017, and operation of Carbon flare stack (see attachment #32).

W-56 Scott PRICE

[redacted]

Can testify to being on DOLLAR'S property the day of the fire and leaving the property at approximately 5:00 PM. PRICE can also testify to the condition of the oil well units and equipment at the Timber Oil Lease Carbon California (see attachment #32).

W-57 Curtis FERNANDEZ

[redacted]

Can testify to being with DOLLAR and PRICE on DOLLAR'S ranch one and a half hours prior to the THOMAS fire (see attachment #32).

W-58 Kelly BROWN
Well Site Manager, Carbon California
[redacted]
Can testify to sending three workers from THOMPCO to work on pipe within the Timber Oil lease (Carbon California) property (see attachment #32).

W-59 James BRADEY
Owner of Coastline Technologies
Coastline Technologies
[redacted]
Can testify to not seeing the missing barrel of methanol since Monday, November 27, 2017 (see attachment #33).

W-60 Daniel CLARKE
[redacted]
Can testify to the examination of the Carbon California Oil Facility (see attachment #34).

W-61 Nathan PAPE
[redacted]
PAPE can testify to the examination of the Carbon California Oil Facility and how the facility operates (see attachment #34).

W-62 Mark STEINHILBER

Department of Conservation Division of Oil, Gas and Geothermal Resources

Facilities Program Manager

[redacted]

Can testify to conducting a visual inspecting on the Timber Oil Lease (Carbon California), (see attachment #35).

W-63 Bruce WEIHS

Department of Conservation Division of Oil, Gas and Geothermal Resources

Facilities Program Manager

[redacted]

Can testify to speaking with SAQUI.

W-64 Eric WEATHERBEE

Ventura County APCD

[redacted]

Can testify to providing documents pertaining to public records regarding Carbon California Facility (see attachment #36).

W-65 Kirby ZOLULA

Ventura County APCD

[redacted]

Can testify to providing documents pertaining to public records regarding Carbon California Facility (see attachment #36).

W-66 Dan FERCY

Ventura County APCD

[redacted]

Can testify to providing documents pertaining to public records regarding Carbon California Facility (see attachment #36).

W-67 Michael F. EVANS

Owner, RIDGEWAY, Inc.

[redacted]

Can testify to Ridgeway contractors had not been to the Timber Canyon Oil Lease since mid-November (see attachment #37).

W-68 Tom HUNTER

COMSAT Teleport

[redacted]

HUNTER can testify to being employed by COMSAT, and providing electronic copies of teleports that recorded two separate power events. The data was provided to the IT (see attachment #38).

W-69 Guy WHITE

Director, Teleport Engineering & Operation

[redacted]

Can testify to overall COMSAT operations and engineering including commercial power supply. WHITE showed the IT and explained the power event that was recorded on Monday, December 4, 2017, at approximately 6:17 PM (see attachment #38).

W-70 Dean BERN

COMSAT Senior Electronics Technician

[redacted]

Can testify to power loss, logging the event, providing detailed reports to USFS Alex LOMVARDIAS and seeing fire approaching COMSAT Teleport (see attachment #38).

W-71 Howard WISNIEWSKI

COMSAT Station Engineer

[redacted]

Can testify how COMSAT logging systems works related to COMSAT. The Power interruption and power loss electronic documentation was provided to the IT (see attachment #38).

W-72 Paul PIMENTEL

Southern California Edison Representative

[redacted]

PIMENTEL was in the GOA when the first span of power lines was taken down by Southern California Edison (SCE) employees.

W- 73 Julie OLIN

Southern California Edison Representative

[redacted]

OLIN was in the GOA when spans of power lines were taken down by SCE employees (see attachment #39).

W-74 Joshua Edward HUNTER

Southern California Edison Employee

[redacted]

W-75 Rick MCCOLLUM

Southern California Edison Representative

[redacted]

MCCOLLUM was in the GOA when the second spans of power lines were taken down by SCE employees (see attachment #40).

W-76 Koko TOMASSIAN

Utilities Engineer

California Public Utilities Commission

[redacted]

Can testify to inspecting SCE power equipment.

W-77 Ryan ISHIKAWA

Utilities Engineer

California Public Utilities Commission

[redacted]

Can testify to inspecting SCE power equipment.

W-78 Christine SAQUI

Fire Investigator – VCFD

[redacted]

Can testify to being the lead fire investigator.

W-79 Aimin ALTON

Firefighter – VCFD

[redacted]

Can testify to assisting with the fire investigation, data collection and analysis.

W-80 Gregg DELAROSA

Deputy – VCSO

[redacted]

Can testify to assisting with the fire investigation.

W-81 Jace CHAPIN

Battalion Chief – CAL FIRE

[redacted]

Can testify to assisting with the fire investigation.

W-82 Ryan MILLER

Fire Investigator – VCFD

[redacted]

Can testify to assisting with the fire investigation.

W-83 Steven DEAN

Fire Investigator – US Forest Service

[redacted]

Can testify to assisting with the fire investigation.

W-84 Tom CRASS

Fire Captain-Specialist – CAL FIRE

[redacted]

Can testify to assisting with the fire investigation.

W-85 Alex LOMVARDIAS

Fire Investigator – US Forest Service

[redacted]

Can testify to assisting with the fire investigation.

W-86 Brian KINSLEY

Fire Fighter – VCFD

[redacted]

Can testify to assisting with the fire investigation.

W-87 Jay SNODGRASS

Fire Captain Investigator – SBCOFD

[redacted]

Can testify to assisting with the fire investigation and coordinated the origin and cause investigation. SNODGRASS wrote the origin and cause (O&C) report (see attachment #2).

W-88 Jon BERGH

Fire Investigator – VCFD

[redacted]

Can testify to assisting with the fire investigation.

W-89 Kenneth RUSSELL

Fire Captain-Specialist – CAL FIRE

[redacted]

Can testify to assisting with the fire investigation.

W-90 Marshall HATCH

Fire Investigator – VCFD

[redacted]

Can testify to assisting with the fire investigation.

W-91 Shannan HARRIS

Fire Captain-Specialist – CAL FIRE

[redacted]

Can testify to assisting with the fire investigation.

W-92 Patrick KELLY

Fire Captain – VCFD

[redacted]

Can testify to assisting with the fire investigation.

W-93 Eric WATKINS

Assistant Chief – CAL FIRE

[redacted]

Can testify to transporting evidence from the THOMAS fire to Fresno, and being the liaison between the investigation team and Southern California Edison.

W-94 Dennis BYRNES

Fire Captain – CAL FIRE

[redacted]

Can testify to assisting with the fire investigation and scene security (see attachment #51).

W-95 Patrick WALKER

Fire Fighter – CAL FIRE

[redacted]

Can testify to providing scene security (see attachment #51).

W-96 Sal KUTKUT

KT Security Service

[redacted]

Can testify to providing 24 hour scene security (see attachment #51).

W-97 James "Jed" DEGRAFF
Technical Services Section
Senior Land Surveyor – CAL FIRE
[redacted]

Can testify to using LiDAR in the area identified by the IT. The LiDAR team can explain how LiDAR functions and interpret the data collected (see attachment #59).

W-98 Dave KAROLY
Technical Services Section
Survey Party Chief – CAL FIRE
[redacted]

Can testify to using LiDAR in the area identified by the IT. The LiDAR team can explain how LiDAR functions and interpret the data collected (see attachment #59).

W-99 Garrett JACKSON
Technical Services Section
Transportation Surveyor – CAL FIRE
[redacted]

Can testify to using LiDAR in the area identified by the IT. The LiDAR team can explain how LiDAR functions and interpret the data collected (see attachment #59).

W-100 Jim NOLT

Electrical Engineer

[redacted]

NOLT assisted with the visual inspection of the Edison Power equipment within the THOMAS fire (see attachment #63).

5 – EVIDENCE:

Evidence collection at the THOMAS fire began on Thursday, December 28, 2017, by Kenneth RUSSELL. Eight pieces of evidence *(E-1 thru E-8)* were collected on Thursday, December 28, 2017. A property receipt and chain of custody log was completed by the IT and SCE (Julie OLIN) for evidence *(see attachment #39)*.

On Friday, January 5, 2018, the IT arrived at an upper area above the fire origin area to continue the investigation and collected evidence *(E-9 thru E-13)*. A property receipt and chain of custody log was completed by the IT and SCE (Rick MCCOLLUM) for evidence *(see attachment #40)*.

The evidence collected on Thursday, December 28, 2017, and on Friday, January 5, 2018, was tagged by both SCE and the IT with independent tracking tags and tracking numbers. All evidence *(E-1 thru E-13)* was secured and transported in a locked/unmarked CAL FIRE vehicle by Eric WATKINS. A chain of custody was completed by the IT team and WATKINS. All evidence collected on the THOMAS fire was transferred to the CAL FIRE evidence locker at Southern Region Headquarters, 1234 East Shaw Avenue, Fresno, California 93710. Evidence *(E-1 thru E-8)* was placed in the evidence locker on Tuesday, January 2, 2018, *(see attachment #41)*. Evidence *(E-9 thru E-13)* was placed into the evidence locker on Saturday, January 6, 2018, *(see attachment #42)*.

PHYSICAL EVIDENCE

Item #1 – (E-1) Section of #4 ACSR powerline spanning from Pole #1025341E, #1202085E, #3002114E, by rectifier. Section was not in contact with the ground in the Specific Origin Area (SOA). Section was from the center phase and marked with WHITE tape and tracking tags. Wire was collected by RUSSELL, logged, and property receipt given to SCE OLIN.

Item #2 – (E-2) Section of #4 ACSR powerline spanning from Pole #1025341E, #1202085E, #3002114E, by rectifier. Section was not in contact with the ground in the SOA. Section was from the west phase and marked with RED tape. Wire was collected by RUSSELL, logged, and property receipt given to SCE OLIN.

Item #3 – (E-3) Section of #4 ACSR powerline spanning from Pole #1025341E, #1202085E, #3002114E, by rectifier. Section was not in contact with the ground in the SOA. Section was from the east phase and marked with BLUE tape. Wire was collected by RUSSELL, logged, and property receipt given to SCE OLIN.

Item #4 – (E-4) Section of #4 ACSR powerline spanning from Pole #1025341E, #1023542E. Section was not in contact with the ground. Section was from the center phase and marked with WHITE tape and tracking tags. Wire was collected by RUSSELL, logged, and property receipt given to SCE OLIN.

Item #5 – (E-5) Section of #4 ACSR powerline spanning from Pole #1025341E, #1023542E. Section was not in contact with the ground. Section was from the east phase and marked with BLUE tape and tracking tags. Wire was collected by RUSSELL, logged, and property receipt given to SCE OLIN.

Item #6 – (E-6) Section of #4 ACSR powerline spanning from Pole #1025340E, #1023541E. Section was not in contact with the ground. Section was from the west phase and marked with RED tape and tracking tags. Wire was collected by RUSSELL, logged, and property receipt given to SCE OLIN.

Item #7 – (E-7) End of jumper wire from with Item #4 associated with Pole #1025341E. Collected by RUSSELL, logged, and a property receipt given to SCE OLIN.

Item #8 – (E-8) Eight parallel groove connectors possibly associated with Item #6. Parts relating to E-8 were recovered by the IT from SCE employees after realizing the items had been removed without authorization from the IT, in violation of the MOU *(see attachment #54)*. Collected by RUSSELL, logged, and a property receipt given to SCE OLIN.

Item #9 – (E-9) Section of #4 ACSR powerline spanning from Pole #1041915E, #1041913E. Section was in contact with the ground. Section was from the south phase and marked with RED tape and tracking tags. E-9 was approximately 300 feet long. Wire was collected by BYRNES, logged, and property receipt given to SCE MCCOLLUM.

Item #10 – (E-10) Section of #4 ACSR powerline spanning from Pole #1041915E, #1041913E. Section was not in contact with the ground. Section was from the south phase and marked with RED tape and tracking tags. E-10 was approximately 10 feet long. Wire was collected by BYRNES, logged, and property receipt given to SCE MCCOLLUM.

Item #11 – (E-11) Section of #4 ACSR powerline spanning from Pole #1041915E, #1041913E. Section was in contact with the ground. Section was from the center phase and marked with WHITE tape and tracking tags. E-11 was approximately 290 feet long. Wire was collected by BYRNES, logged, and property receipt given to SCE MCCOLLUM.

Item #12 – (E-12) Section of #4 ACSR powerline spanning from Pole #1041915E, #1041913E. Section was not in contact with the ground. Section was from the center phase and marked with WHITE tape and tracking tags. E-10 was approximately 10 feet long. Wire was collected by BYRNES, logged, and property receipt given to SCE MCCOLLUM.

Item #13 – (E-13) Section of #4 ACSR powerline spanning from Pole #1041915E, #1041913E. Section was not in contact with the ground. Section was from the north phase and marked with BLUE tape and tracking tags. E-13 was approximately 300 feet long. Wire was collected by BYRNES, logged, and property receipt given to SCE MCCOLLUM.

PHOTOGRAPHS and VIDEOS *(Civilians and Fire Emergency Personnel)*

Chris DOLLAR Video *(see attachment #5)*
Peter RIOUX Photos *(see attachment #6)*
Richard RUDMAN Photos *(see attachment #7)*
Juan GAMEZ Sr. Photos *(see attachment #10)*
Mel LOVO Photos and Videos *(see attachment #12)*
Tammy GARCIA Photos and Videos *(see attachment #13)*
Jorge MONZADA Photos *(see attachment #14)*
Tiarzha TAYLOR Photos *(see attachment #16)*
Earl BROCK Photos *(see attachment #17)*
Troy HERNDERSON Photos *(see attachment #25)*

All audio recordings associated with the THOMAS fire investigation *(see attachment #89)*.

WRITTEN WITNESS STATMENT *(Civilians)*

Earl BROCK *(see attachment #17)*
Matthew ZEIER *(see attachment #32)*

PHOTOGRAPHS and VIDEOS *(Investigation Team)*

HATCH Photos and Video's *(see attachment #32 and #90)*
DELAROSA Photos and Video's *(see attachment #91)*
KINSLEY Photos *(see attachment 92)*
KELLY Photos and Video's *(see attachment #32 and #93)*
SAQUI Photos and Video's *(see attachment #35 and #94)*
ALTON Photos and Video's *(see attachment #95)*
CHAPIN Photos *(see attachment #96)*
BERGH Photos *(see attachment #97)*
RUSSELL Photos *(see attachment #98)*
HARRIS Photos *(see attachment #99)*
SNODGRASS Photos and Videos *(see attachment #100)*

6 – CONDITIONS:

The origin of the THOMAS fire was near the address of 16840 Anlauf Canyon Road, Santa Paula, California 93060. The origin was approximately one half mile back in the canyon on a cattle ranch. The origin was on a southwest slope Lat/Long: (N 34 25.516/W 119 03.289, elevation 1,766 feet). The origin was near the top of a small ridge top. The mouth of the canyon ends at Highway 150. The vegetation at the origin was a mixture of grass and brush. The forecasted weather for Ventura County on Monday, December 4, 2017, predicted extreme fire danger and potentially the strongest, longest duration Santa Ana wind event of the season. A red flag warning was in effect with anticipated wind gusts of up to 80 miles per hour.

Weather information for Monday, December 4, 2017, was obtained from three different remote automated weather station (RAWS) located near the communities of Piru, El Rio and Ojai in the County of Ventura, California. The Piru RAWS is approximately 14 miles east of the THOMAS fire origin at an elevation of 636 feet. The El Rio RAWS is approximately 12 miles south of the THOMAS fire origin at an elevation of 131 feet. The Ojai RAWS is approximately 10 miles northeast of the THOMAS fire origin at an elevation of 774 feet.

All three RAWS record weather hourly. The start time of the THOMAS fire was at approximately 6:20 PM. Additionally, a lightning map was obtained with no recorded lightning activity from Friday, December 1, 2017, through the start of the THOMAS fire *(see attachment #43 through #45)*.

Piru RAWS

Date:	Monday, December 4, 2017
Time:	6:00 PM
Temperature:	59 degrees Fahrenheit
Dew Point:	8 degrees Fahrenheit
Relative Humidity:	13 percent
Wind Speed:	17 to 27 miles per hour
Wind Direction:	From the northeast
Elevation	636 feet
Latitude/Longitude	34.40426 / -118.80991

El Rio RAWS

Date:	Monday, December 4, 2017
Time:	6:00 PM
Temperature:	62 degrees Fahrenheit
Dew Point:	7 degrees Fahrenheit
Relative Humidity:	11 percent
Wind Speed:	17 to 30 miles per hour
Wind Direction:	From the northeast
Elevation	131 feet
Latitude/Longitude	34.25238 / -119.14318

Ojai RAWS

Date:	Monday, December 4, 2017
Time:	6:00 PM
Temperature:	59 degrees Fahrenheit
Dew Point:	3 degrees Fahrenheit
Relative Humidity:	10 percent
Wind Speed:	4 to 9 miles per hour
Wind Direction:	From the southeast
Elevation	774 feet
Latitude/Longitude	34.44804 / -119.23131

7 – EQUIPMENT:

The equipment associated with the cause of the THOMAS fire is owned and operated by Southern California Edison (SCE). The fire originated within the GOA established by the THOMAS fire IT. Power lines were determined to be the cause of the THOMAS fire. The power lines were inspected between several poles *(see attachment #46)*. Within the GOA, the IT observed several areas where SCE equipment failed. The power lines were inspected within the GOA and determined by the IT to have had phase to phase contact on several spans of power lines.

Data collected from COMSAT showed a power interruption associated with SCE equipment on Monday, December 4, 2017, at approximately 6:17 PM. COMSAT data was corroborated by several pieces of video imagery obtained by the IT throughout the course of the THOMAS fire investigation *(see attachment #3 and #38)*.

8 – PROPERTY:

The GOA of the THOMAS fire is located on property identified by Ventura County Assessor Parcel Numbers (APN). The GOA encompasses two different parcels, APN 400 090 025 and 400 060 065 *(see attachment #47)*.

The GOA is on private property located at [redacted] Santa Paula, California 93060. The area within the identified APN numbers has several easement rights on an unmaintained paved road running through DOLLAR'S property. There are three ways to access DOLLAR'S property, through Anlauf Canyon Road, SENECA properties and up through Timber Canyon Road. All areas identified to access DOLLAR'S property is controlled by locked gates and barbed wire fences.

The Ventura County Assessor's Office lists the properties as 240 acres and 133.77 acre parcels. The property is owned by David and Susan DOLLAR. The property owner's address is recorded as [redacted] Santa Paula, California 93060.

The THOMAS fire burned downslope in alignment with the wind threatening the cities of Santa Paula, Ventura and Ojai. The general area around the THOMAS fire is urban interface surrounded by mixed wildland.

9 – NARRATIVE:

On Monday, December 4, 2017, at approximately 6:25 PM, I was dispatched as a Wildland Fire Investigator by the Ventura County Fire Department (VCFD) Fire Communications Center (FCC) to a wildland fire *(later identified as the THOMAS fire)* located at [redacted] Santa Paula, CA, 93060. Multiple reports from witnesses identified the fire in the hills northeast of Santa Paula. VCFD Engine 20, located in Upper Ojai, informed FCC they received phone calls from locals of a brush fire near the college and attached themselves to the original dispatch.

FCC originally dispatched units to 1681 Dickenson Drive, Santa Paula, CA. This was the address of an initial reporting party. While responding to the incident, FCC dispatched units to [redacted] FCC advised responding units that occupants at the residence reported their home was threatened by flames, later this location was identified as David DOLLAR'S residence *(see attachment #48 through #50)*.

I arrived at the Incident Command Post (ICP) located at Mill Park, 736 Santa Paula Ojai Road, at approximately 7:24 PM. I observed the fire growing quickly and spotting across Santa Paula Ojai Road (Highway 150). The incident required multiple fire crews from neighboring cities and county fire departments. Ventura County Sheriff's Office (VCSO) deputies, Santa Paula Police officers, and California Highway Patrol officers were also in the area assigned to mandatory evacuations. No emergency personnel were able to access 16840 Anlauf Canyon Road due to fire conditions.

Numerous residences in Anlauf Canyon, Ojai Road, and Kampgrounds of America (KOA) at Steckel Park required rescue or assistance from emergency crews and were under mandatory evacuation. CHP closed Santa Paula Ojai Road/Highway 150 to any traffic except emergency personnel and evacuees exiting.

A separate fire was reported on Koenigstein Road at approximately 7:30 PM, located approximately 3.5 miles northwest of the THOMAS fire. Because of the prevailing wind direction, location, and reports from fire crews, it was determined this fire was unrelated to the THOMAS fire. This fire was later identified by investigators as the KOENIGSTEIN fire *(see report 17CAVNC103338)*.

I contacted FCC requesting the first reporting parties information, I obtained Brian DICKENSON'S contact information whom I contacted at approximately 8:15 PM. DICKENSON was among the first reporting parties to the THOMAS fire. DICKENSON told me the following in summary: DICKENSON was taking out the trash when he observed a glow in the direction of Ferndale Ranch and Saint Thomas Aquinas College. DICKENSON was concerned because he knew there were residences in that area and called 911 at approximately 6:23 PM. DICKENSON described the fire as small and a single glow.

The ICP was moved to Santa Paula Fire (SPFD) Station 82, located at 114 S. 10th Street, Santa Paula, at approximately 8:30 PM. While transitioning to the second ICP location, I contacted VCFD Fire Investigator Jon BERGH. BERGH and VCFD Firefighter Brian KINSLEY met me at SPFD Station 82. We attempted to access the KOENIGSTEIN fire because access to the THOMAS fire GOA presented several safety concerns which included extreme fire behavior, unfamiliar terrain and lack of visibility.

We observed extreme fire behavior along Highway 150. During our observations, the THOMAS fire and KOENIGSTEIN fire had not merged together. At approximately 11:45 PM, while parked off the shoulder of Highway 150, I watched a flank of the THOMAS fire burn back along a west facing slope just west of Anlauf Canyon. Several electrical power poles and tree limbs along Highway 150 broke and were blocking the road as the fire burned through the area.

We waited for the fire to burn through the KOENIGSTEIN neighborhood prior to entering. The fire increased in intensity and visibility was encumbered as a result of the smoke and flames. Because of this, it was not possible to enter the KOENIGSTEIN neighborhood. Since the power lines fell across the lower section of Highway 150, we drove westbound and through upper Ojai to exit. By this time, the fire had already burned through upper Ojai and crossed Highway 150.

On Tuesday, December 5, 2017, I arrived at the Ventura County Fairgrounds at approximately 7:00 AM. The fairground was the new location of the ICP. I met with BERGH and KINSLEY, we attended the morning briefing. I met with CAL FIRE Chief John MOODY, he informed me a fire investigation team from their department would be assigned to me. Soon after, I received a phone call from CAL FIRE Assistant Chief Eric WATKINS who informed me that two investigators, CAL FIRE Battalion Chief Jace CHAPIN and CAL FIRE Fire Captain-Specialist Shannan HARRIS would be arriving later in the day.

At approximately 8:30 AM, I met with Senior Deputy Gregg DELAROSA, VCSO. DELAROSA was assigned to assist me in the investigation.

On Tuesday, December 5, 2017, at approximately 9:00 AM, I spoke with James SNODGRASS, fire investigator for Santa Barbara County Fire Department (SBFD). I requested his assistance for the investigation. SNODGRASS informed me he would be enroute and arrive by late morning.

At approximately 12:30 PM, VCFD Fire Investigator Marshall HATCH, DELAROSA, and I met SNODGRASS along an east perimeter road at Saint Thomas Aquinas College. Saint Thomas Aquinas is located at 10000 Santa Paula Ojai Road. From the college, we entered through a fenced area to access Ferndale Ranch. Traveling through numerous unmarked dirt roads and locked ranch gates, we reached an access gate to Anlauf Canyon *(later determined to be part of David DOLLAR'S property)*.

We reached an area within the mountains southeast of the college that contained oil well equipment. Near one of the peaks, I observed compressor equipment and a flare stack off Anlauf Canyon Road. A sign near this pad read "Timber Canyon Lease, Carbon California Company, LLC, In case of emergency call: [redacted]" The fire had already burned through this area.

The flare stack was not burning off excess gases at the time. I observed a fire next to compressor equipment, approximately two feet wide by four feet high, it was contained to an area within the compressor site and burning continually. The fire was emanating directly from a ground level grate which appeared to be a type of catch basin. I did not observe any obvious smoke emanating from this area. The flames did not appear to be spreading or enlarging. I did not observe any fire damage, such as char or melting, to the surrounding equipment.

We continued past the compressor site and drove approximately 1500 yards east. We reached the location of a radio tower. I observed the east flank of the fire burning downhill below and east of the radio tower. The wind was blowing from the east at approximately 15 – 20 miles an hour. We drove in an easterly direction out of Anlauf Canyon Road, passed through a locked ranch gate, and through Timber Canyon Road until we reached Highway 126.

We returned to the ICP and met WATKINS, CHAPIN, and HARRIS. We briefed them to the particulars associated with the THOMAS fire's potential origin. We explained the terrain, surroundings, and the difficult access due to the locked ranch gates and closure at Highway 150.

It was decided to assign BERGH, CHAPIN, CAL FIRE Fire Captain-Specialist Kenneth RUSSELL, and VCFD Firefighter Ryan Miller to the KOENIGSTEIN fire investigation and assign HARRIS and CAL FIRE Fire Captain-Specialist Tom CRASS to the THOMAS fire investigation. I planned on meeting HARRIS, CRASS, and SNODGRASS at the 76 Gas Station located off Highway 126 and Hallock Road, in Santa Paula, the following morning at approximately 8:00 AM.

On Wednesday, December 6, 2017, I arrived at the ICP at approximately 7:00 AM. I spoke with Amy FANZO, a California Resources Corporation (CRC) representative and oil lease contact, to inquire about CARBON CA COMPANY (CCC) and a contact person. She gave me a contact name and phone number of Todd HABLISTON. DELAROSA met me at the ICP and followed me to the 76 gas station in Santa Paula to meet with HARRIS, CRASS, and SNODGRASS.

At approximately 8:00 AM, it was decided that SNODGRASS would be responsible for writing the origin and cause (O&C) report for the THOMAS fire *(see attachment #2)*.

At approximately 9:00 AM, we traveled back to Anlauf Canyon through Highway 126 and Timber Canyon Road. We observed the heel of the fire near the radio tower the evening prior had now burned back to the bottom of the hill. The fire was burning through the orchards of a ranch on the lower half of Timber Canyon Road.

Once we accessed the oil lease, we stopped at an open dirt lot, near the CLARK tank battery. I contacted HABLISTON, who explained he was located in Colorado and he would make notifications to someone local from the CCC office to meet us. HABLISTON was aware that Scott PRICE and David DOLLAR were in Anlauf Canyon the day of the fire. HABLISTON told me they were viewing existing gas pipe lines for potential purchase from DOLLAR.

At approximately 11:00 AM, PRICE met us at the CLARK tank battery. PRICE made access to the oil lease off Highway 150. A downed power pole across a lower oil lease access road caused PRICE to walk to our location. PRICE informed us he turned off valves at a nearby compressor site on his way to our location. The compressor site was later identified as the site where we observed fire actively burning under the grates on Tuesday, December 5, 2017.

While interviewing PRICE (*see attachment #32)*, HATCH and KINSLEY drove through the CCC site. They drove to a compressor site and observed active fire near the equipment and took video (*see attachment #90)*. This was the same compressor site that DELAROSA, SNODGRASS, and I observed on Tuesday, December 5, 2017.

I drove down Anlauf Canyon to a residence and met David DOLLAR and his two sons, Matt and Christopher DOLLAR. DOLLAR identified himself as the property owner and was tending to his cattle and residence. DOLLAR and his wife, Susan DOLLAR, were displaced the evening of the fire (*see attachment #5)*.

At approximately 2:45 PM, I met with VCFD Fire Captain Tony SALAS, Engineer Steve SWINDLE, and Firefighter Steve BUCKLES. We met on Highway 150/Ojai Road, near East Sulphur Mountain Road. We stood on the shoulder of the road while SALAS described what he observed that evening. SALAS pointed towards Anlauf Canyon and DOLLAR's residence and stated as they drove south on Highway 150, he initially observed flames within Anlauf Canyon. SALAS described the fire as "well established" (*see attachment #9)*.

HARRIS, SNODGRASS, CRASS, DELAROSA, and I established our Investigation Team (IT) for the THOMAS fire. United States Forest Service Fire Investigator (USFS) Steve DEAN, HATCH, KINSLEY, VCFD Fire Captain Patrick KELLEY and CAL FIRE Fire Captain Dennis BYRNES joined the IT.

Due to the totality and complexity of the THOMAS fire, the IT decided to focus our team member efforts in Origin and Cause (O&C) and Intelligence/Interview (INTEL). The IT debriefed daily information collected with regard to O&C and INTEL.

The THOMAS fire scene was secured by BYRNES, CAL FIRE Firefighter II Patrick WALKER and KT Security Services. They shared the responsibilities of scene security *(see attachment #51)*.

On Thursday, December 7, 2017, the IT began reviewing the list of Reporting Parties (RP) to 911 and initiated contact *(see attachment #52)*. The IT requested VCFD GIS and Mapping Services to produce aerial maps of the area of the THOMAS fire.

The IT interviewed multiple witnesses throughout the investigation. Some witnesses took photographs with their cell phones and were voluntarily escorted back to the area where they first saw fire. The maps were used to help witnesses identify the location where they witnessed the fire or took photographs/videos. The IT had them point to where they observed the fire, while the IT took daytime comparison photographs.

On Friday, December 8, 2017, I requested FCC produce a list of THOMAS fire RP's in order to organize and plainly see a list of RP's. FCC Supervisor Michael DICKERSON worked on preparing a spread sheet of the RP's. The IT obtained video footage via email from VCSO Office of Emergency Services (OES). The video footage is taken from a camera located at an OES facility on Torrey Peak *(see attachment #3)*.

The IT traveled to the KOA, located east of Steckel Park and southwest of Anlauf Canyon. We spoke to Frank SCHREINER, KOA General Manager, and RAMANDA, the onsite manager. SCHREINER was not at the KOA at the time of the fire, but

RAMANDA was. RAMANDA took us to space #33, where he was the evening of the fire *(see attachment #27)*.

We then met with Alexandra PRICE at the east end of KOENIGSTEIN Road *(see attachment #15)*.

Additional interviews conducted on this day also included Richard RUDMAN *(see attachment #7)*, Tanner CARPENTER *(see attachment #29)*, and John, Robert, and Maria GOYETTE *(see attachment #20)*.

On Friday, December 8, 2017, USFS Special Agent Alex LOMVARDIAS arrived to assist in the investigation. LOMVARDIAS was briefed on the previous week's findings and sequence of events. The IT interviewed COMSAT employees and collected any relevant information that their equipment recorded in relation to the THOMAS fire *(see attachment #38)*.

We received the RP list from JR TENBROOK, CAD Manager at FCC. The list contained the first 309 RP's to the THOMAS fire. The list of callers were in chronological order, with available contact information and location of their call. Because the fire became well established within the canyon relatively early, a decision was made to contact the first 20 callers on the list. That would capture the first 16 minutes of the fire being witnessed. The goal was to obtain pertinent information/data associated with these callers *(see attachment #52)*.

On Saturday, December 9, 2017, the IT traveled to Saint Thomas Aquinas College and met with Peter RIOUX, a faculty member of Saint Thomas Aquinas College. RIOUX was an RP to the THOMAS fire and had called VCFD Fire Station 20 prior to them receiving the initial dispatch from FCC *(see attachment #8)*. Later that day we met with VCFD Fire Captain Mel LOVO at the Santa Paula Airport. LOVO was Copter Manager on Copter 7 the evening of the THOMAS fire *(see attachment #25)*. At approximately 6:00 PM, I spoke with Fire Engineer Terry BELL at Santa Paula Fire Station 81. BELL lives on Mupu Road at the bottom of Anlauf Canyon Road *(see attachment #28)*.

On Monday, December 11, 2017, the IT established two private and secured classrooms at the VCFD Regional Training Center (RTC), Camarillo, as home base and offices. VCFD Firefighter Paramedic Aimin ALTON joined the investigation as a Technical Specialist to assist with office management, image and data analysis *(see attachment #3)*.

As requested by the IT, on Wednesday, December 13, 2017, the VCSO Unmanned Aircraft Systems (UAS) Team flew an area of interest in the THOMAS fire *(see attachment #91)*. Simultaneously, a CAL FIRE Light Imaging, Detection and Ranging (LiDAR) team was surveying the same area *(see attachments #2 and #59)*.

On Thursday, December 14, 2017, the IT analyzed the information from the VCSO OES video camera. The video captured bright flashes of light at Anlauf Canyon *(see attachment #3)*.

I contacted the Division of Oil, Gas, and Geothermal Resources (DOGGR) to inquire about CCC's facilities and asked that an engineer from their office meet with the IT to do a site review at the Timber Canyon facility. Engineering Geologist Eric HEATON, of DOGGR, met with the IT at the oil facility in Anlauf Canyon. HEATON advised the IT, his specialty was not related to the daily operations of oil well facilities, therefore he would request that a Senior Engineer with a background in oil field safe practices would be better suited and would contact us.

At approximately 3:00 PM, I received a phone call from Bruce WEIHS, a Senior Engineer and Supervisor with DOGGR. WEIHS informed me that their program does not oversee the flare stack system of the oil wells. WEIHS advised me to contact Air Pollution Control District (APCD).

On Friday, December 15, 2017, the IT did a reconnaissance flight in a helicopter to view the overall fire area in Anlauf Canyon, take photographs of the oil lease site around their GOA, and to look for a missing plastic drum. The drum was previously located at the compressor site and had contained methanol. Its location was unknown and thought to have blown down the canyon *(see attachment #100)*.

On Monday, December 18, 2017, the IT retrieved raw video footage from Patrick MAYNARD, OES.

On Tuesday, December 19, 2017, SCE sent their LiDAR team to the GOA to survey the area of interest and their equipment. The IT requested SCE to lower their power lines when they had completed their LiDAR survey.

At approximately 3:45 PM, the IT boarded a helicopter for a reconnaissance flight over Anlauf Canyon and the CCC oil lease *(see attachment #95)*.

On Wednesday, December 20, 2017, SCE lowered several spans of power lines. The IT walked the conductors for examination purposes *(see attachment #2)*.

On Thursday, December 21, 2017, I met Mark STEINHILBER, Facilities Program Manager at DOGGR, at VCFD fire station 50 at approximately 7:40 AM. The IT briefed STEINHILBER on our previous findings at the compressor site located at the CCC oil facilities in Anlauf Canyon. The IT took him to the compressor site and flare stack. STEINHILBER examined the site's compressors and flare stack. This interview and examination was video recorded by the IT *(see attachment #35)*. We departed the oil lease site at approximately 2:00 PM.

On Friday, December 22, 2017, I contacted the Ventura County Counsel. I forwarded them an example of a preservation letter for an electric company. I asked they draft a similar letter and address it to SCE *(see attachment #53)*.

On Saturday, December 23, 2017, the VCSO UAS team returned to the GOA to record another area of interest. A CAL FIRE LiDAR team was also on scene to survey *(see attachments #2 and #59)*.

On Tuesday, December 26, 2017, IT gave SCE permission to send their LiDAR team to the GOA to survey their equipment, while IT was present and continued to secure and preserve the scene.

On Wednesday, December 27, 2017, SCE LiDAR team concluded their examination. SCE lowered another section of power lines for the IT. The IT proceeded to examine the power lines and collect evidence *(see attachments #2 and #39)*.

At approximately 1:35 PM, I spoke to Dan FERCY, APCD. FERCY told me the following, in summary: The APCD does oil field inspections that relate to equipment that would have adverse effects to the air quality. Flare stacks at oil facilities are considered "control devices" as they burn excess gases. One flare is operational and permitted at CCC. Every year the flare stack and other equipment are inspected. Written violations can be imposed upon the company if not in compliance and minor violations were noted *(see attachment #36)*.

FERCY was not familiar with the chemical, methanol, being used at the facility. FERCY suggested I speak with Kerby ZOLULA, also with APCD, since ZOLULA has more technical information pertaining to oil field practices.

FERCY continued to tell me, the oil lease belonged to CRC before it was purchased by CCC. Prior to CRC, it was owned by VINTAGE PETROLEUM.

At approximately 3:00 PM, the IT allowed the California Public Utilities Commission (CPUC) to conduct their preliminary investigation within the GOA. At approximately 3:00 PM, I met with Southern California Edison (SCE) Rick MCCOLLUM and Julie OLIN, both SCE Claims Investigators near the GOA. MCCOLLUM confirmed the circuit identity in our GOA was named the "CASTRO circuit." MCCOLLUM further stated at 6:41 PM, their substation reported a remote automatic recloser alert to their system.

On Thursday, December 28, 2017, I spoke with Bruce WEIHS, Senior Engineer with DOGGR. WEIHS informed me I may make a public records request for inspection records for CCC. I placed an official request via email for notices of violations and inspection records *(see attachment #35)*.

At approximately 11:15 AM, I spoke to Eric WEATHERBEE, APCD. WEATHERBEE has been inspecting oil lease facilities in the area for the past 20 years. WEATHERBEE confirmed CCC recently purchased the lease from CRC. They acquired it less than one year ago. WEATHERBEE told me CCC is an east coast based company and were not very familiar with west coast standards. Therefore, they received a few minor violations initially *(see attachment #36)*. Since then, CCC has corrected the violations and have remained in good standing.

WEATHERBEE identified CCC as Permit #00939. CCC is permitted to operate two pieces of combustion equipment, one of which is the "glycol reboiler" and the other as the flare stack. The reboiler separates oil, gas, and water. In addition, there are two engines located at the site; a "Waukesha" engine, at the EP Clark facility, which acts as standby power for the vapor recovery and an Ingersoll Rand engine, which is for on-going operations.

WEATHERBEE confirmed I may request a public records request through their website. The request would include the transfer of ownership, last five years of application materials and permits, and enforcement reports. On Thursday, December 28, 2017, at approximately 2:00 PM, I sent an official request for the above items.

At 2:25 PM, I spoke to Kerby ZOLULA, APCD. ZOLULA told me the following, in summary: Methanol is typically injected into a natural gas line as an inhibitor. It acts as "freeze protection" because there is water present in natural gas. APCD does not need to permit the use of methanol, as CCC only uses a small amount of it *(see attachment #36)*.

I contacted HABLISTON, CCC Partner. I requested a representative meet us to download equipment data. HABLISTON scheduled a technician from PROCTEK to arrive Tuesday, January 2, 2018, at 9:00 AM.

On Friday, December 29, 2017, the IT went out to search for and collect surveillance video that would capture any activity within the GOA. A portion of the IT met with PRICE at 9:30 AM, and ZEIER at 11:45 AM, at the CCC compressor site for interviews and to review the equipment *(see attachment #32)*.

At approximately 10:00 AM, the IT made contact with personnel at 300 E. Esplanade Drive, Oxnard. The building is a high-rise building, known as the tower, near Highway 101.

At 300 E. Esplanade Drive, we met with Quentin SESSYL, Post Commander/Security for Allied Universal Security Services. Topa Management Company manages the building and uses Allied Universal as contracted security. We were told a surveillance camera is posted on the roof of the building, next to a helicopter pad, pointing towards the northeast.

IT reviewed the video from Monday, December 4, 2017, and time stamped at approximately 6:17 PM. We observed two separate flashes that are consistent with arc flashes. The flashes we observed on the video appear to be within the GOA that was established for the THOMAS fire. We collected the videos on a thumb drive *(see attachment #3)*.

At approximately 3:00 PM, the IT continued to the StorHouse Storage Center (SSC), located at 3201 West Fifth Street, Oxnard. This location is along the south perimeter of Oxnard Airport runway. We met with Marc HERMANN and Tony DUENAS, Operations Manager. Their storage facility has a high definition security system installed.

SSC retained video from the evening of the fire which captured similar footage the Esplanade tower had, but from a slightly different angle. The SSC video matched the flashes seen in the previous surveillance video. The video footage was collected on a thumb drive *(see attachment #3)*.

On Tuesday, January 2, 2018, at approximately 9:40 AM, the IT met with Renzo NAVARRETE, from ProcTek, and PRICE, of CCC. We traveled to the compressor site in Anlauf Canyon. NAVARRETE downloaded gas meter data from the equipment.

While at the compressor site, we re-examined the area where flames were observed after the THOMAS fire traveled through there. Closer examination of the enclosed grate and catch basin revealed a pipe was located under the metal mesh grate. After following the pipe's flow, it was determined natural gas was flowing from the compressor. After speaking to PRICE, PRICE confirmed he had closed a valve that controlled the natural gas that fed the fire emitting from the grate. PRICE recalled doing that on Wednesday, December 6, 2017, which was also the day of our first interview with him. Once the valve was closed, the fire went out. The valve that was closed came out of a "suction" intake at the first stage compressor.

We then went to CCC's office located at 12720 Ojai Santa Paula Road, Ojai. At this location, NAVARRETE downloaded additional data from their server. Data was downloaded on to a thumb drive, utilized by the IT, and printed for this report *(see attachment #32)*.

On Wednesday, January 3, 2018, after analyzing all collected video (TORREY, TOPA, STORHOUSE, R&R PIPELINE, CLARK GAS) and estimated triangulations, the IT determined there were two distinct separate flash locations (eastern and western) approximately one and a half miles apart. These flashes occurred nearly simultaneously and appeared to be on the same circuit. The IT determined these were areas of interest. IT inspected both areas of interest and observed physical evidence associated with the triangulated eastern flashes. The physical evidence observed (power lines) was consistent with phase to phase arcing. The video and physical evidence showed the THOMAS fire GOA was not in the location of the eastern flashes. Physical evidence at the triangulated western flashes had already been observed and collected by the IT during the O&C investigation on Thursday, December 28, 2017. The IT determined physical evidence on the power lines associated to the eastern flashes were connected to the same circuit as the power lines associated to the western flashes (CASTRO Circuit). Based on extensive analysis of video evidence, the IT determined the start of the THOMAS fire was a result of the western flashes. The IT collected the physical evidence relating to the eastern flashes on Friday, January 5, 2018.

On Wednesday, January 3, 2018, a preservation letter was drafted by the Ventura County Counsel to address SCE records and equipment. I signed the letter, addressed it to SCE with attention to MCCOLLUM, and had Kim BEECHAM, VCFD front receptionist, mail it via FedEx at approximately 9:40 AM. Pick up was scheduled for later that same day with tracking number 8028-9397-6654 *(see attachment #53)*.

Investigators were initially dispatched to the THOMAS fire on Monday, December 4, 2017. IT was unable to access what was later determined to be the Overall Fire Area (OFA) due to fire conditions. The OFA was secured on Wednesday, December 6, 2017, determined to be approximately 230 acres. Ultimately, the IT narrowed the GOA to approximately 22 acres. Throughout the course of the THOMAS fire investigation, the IT were able to independently corroborate the GOA through O&C and Intel. The THOMAS fire GOA was released on Friday, January 5, 2018 *(see attachments #2 and #3)*.

On Monday, January 29 and Tuesday, January 30, 2018, I returned to the THOMAS fire site to view SCE crews lower and remove power line equipment *(see attachment #55)*.

On Tuesday, May 29 through May 31, 2018, Investigators from CAL FIRE and VCFD met with Jim NOLT, Professional Engineer (PE). The IT utilized NOLT on several occasions throughout the course of the Thomas fire investigation to evaluate the electrical system within the OFA and GOA. We reviewed SCE data that was submitted to us on April 6, 2018, NOLT created a timeline of events that occurred associated with the Castro circuit on Monday, December 4, 2017.

On Wednesday, October 24, 2018, we received a report created by NOLT *(see attachment #63)*. The IT reviewed NOLT's report and concluded it further corroborated the IT's final hypothesis.

On Saturday, November 17, 2018, we added documents received per our request from SCE dated Friday, October 26, 2018. The response letter and documents from SCE are in regards to the Thomas fire investigation report are pertaining to meter No. 254000-004308 and 222-931684. We still have yet to receive the data requested in its entirety *(see attachment #64)*.

OPINIONS & CONCLUSIONS:

The following opinions and conclusions were based on supporting documentation, supplemental reports, statements made to investigators, audio/video recordings, CAD reports obtained from dispatch centers, and evidence found while conducting the origin and cause investigation.

Skies were clear with no thunderhead or cloud build-up observed. There was no evidence located within the GOA consistent with lightning strikes or fire resulting from a lightning strike. A lightning detection map was printed and confirmed there was no recent lightning activity in the area. Based upon the weather data, I eliminated a lightning caused fire *(see attachment #43)*.

There are no campgrounds in the area where the GOA is located. The area is not typically used for camping and did not have campfire rings, campsites, piled material typically associated with a campfire, or indications of any campfires near the GOA. The fire occurred on private property. DOLLAR told the IT he never has fires on his property of any type. Based upon the lack of the above items, I eliminated a campfire caused fire.

The IT did not observe or locate any cigarette butts or other smoking paraphernalia within the GOA. All people who had access to the DOLLAR ranch the day of the THOMAS fire were interviewed and stated they do not smoke. Based upon the above facts the IT eliminated smoking as a potential cause of the fire.

Ventura County APCD had a burn ban in effect which prohibited debris burning. There were no burn barrels, piles of trash, or signs of burn barrels being used to conduct debris burning located near the GOA. Additionally, the IT did not observe any of the previously mentioned items during a perimeter search of the area, eliminating debris burning as a potential cause of this fire.

There was no evidence of items typically associated with an intentionally set fire was observed/located within the GOA. The inaccessibility to the DOLLAR ranch, which is controlled by locked gates and fences is not consistent with that of a person who commits the crime of arson. Additionally, all persons who had access to the DOLLAR ranch the day of the THOMAS fire were vetted, and if needed, alibis were corroborated eliminating incendiary as a potential cause of the fire.

There was no indication of equipment use in the GOA prior to the IT arriving to the incident. During the investigation, the IT examined the GOA and observed no signs of motorized equipment recently used within the general vicinity. The IT did not observe any disturbed soils, or any area where equipment had been used. The GOA is not located along public roads. The nearest road is an unmaintained paved road that traverses through the DOLLAR property. The only people that have access to the DOLLAR property is the DOLLAR family, oil lease representatives, a cattle rancher (Robert FROST) who leases a portion of the DOLLAR ranch, and a radio station representative (Richard RUDMAN) who maintains an antenna on the

DOLLAR property. Vehicles operating on the DOLLAR ranch the day of the THOMAS fire were all evaluated/inspected by the IT. The IT obtained current registration and insurance information for all vehicles in question. The last vehicle on the DOLLAR ranch the day of the fire was owned and operated by RUDMAN who exited the lower gate toward Highway 150 approximately one hour prior to the fire. There was no mention by DOLLAR of any vehicles in and or around the property at the time the THOMAS fire started. Additionally, the IT saw no signs of Off Highway Vehicle (OHV) use in the area. No catalytic converter particulates were located within the GOA. Based upon the above facts, I eliminated equipment as a potential cause of the subject fire.

There are no railroads or railways within Anlauf Canyon, therefore I eliminated railroad equipment as a cause of the subject fire.

There were no toys, forts, or evidence of any activities associated with children playing with fire near the GOA. The only known juveniles in the area were at the KOA campground located approximately one and one half miles southwest of the GOA. The DOLLAR ranch is remote and has locked gates and fencing at all access points to the property. Based on the above facts playing with fire was eliminated as the cause of the fire.

The County of Ventura has a strict ordinance not allowing the use of fireworks within the County. No witnesses reported seeing, or hearing any indication of the use of fireworks. The area where the fire occurred is on private property and is not open to the public. Additionally, no persons who had access to the DOLLAR ranch the day of the THOMAS fire observed anyone lighting fireworks or heard sounds typically associated with use of fireworks. During the examination of the GOA, no remnants of fireworks were located. Based upon the above facts, fireworks were eliminated as a potential cause of the fire.

No signs of cutting, welding or grinding of metal was noted during the course of the investigation. Therefore, I eliminated this as a potential cause of the fire.

There were no reports of anyone engaging in recreational shooting activities prior to the fire. DOLLAR does have a shooting area established on his property, but

DOLLAR told the IT nobody has utilized the shooting area for two months. All people who had access to the DOLLAR ranch were interviewed and stated they did not hear or witness anyone engaged in recreational shooting. Therefore, I eliminated shooting as a potential cause of the fire.

During the examination of the GOA, the IT did not locate any broken glass or glass bottles. The fire occurred approximately one and a half hours after sundown. Based upon these facts glass refraction was eliminated a caused of the fire.

Spontaneous combustion was excluded as a potential cause. No evidence of mulch or organic material was located within the GOA that had the ability to spontaneously combust. There was no evidence of mulch or organic material piles hay or grass in the GOA. Spontaneous combustion was eliminated a cause of the fire.

The Timber Canyon Lease owned and operated by CCC was located along the east perimeter of the OFA. A flare stack was located within the Timber Canyon lease, approximately three quarters of mile from the perimeter of the GOA. The IT did not observe any indications of a malfunction in, on or immediately around the flare stack. The IT obtained security video footage revealing the flare stack was not actively burning at the time the THOMAS fire started *(see attachment #3)*. The IT did observe a fire burning within the CCC compressor site. Interviews with oil field professionals and observed burn patterns indicate this fire was secondary to the THOMAS fire and contained to the compressor site. The IT determined the cause of the compressor site fire was a result of ember cast from the THOMAS fire that ignited the natural gas. Based on the above facts, I was able to eliminate flare stacks or a fire originating within the oil facility as a potential cause of the THOMAS fire.

Due to portions of the DOLLAR ranch being utilized as cattle grazing land, the IT evaluated fencing in the OFA and GOA. The IT did not locate or observe any electrical fencing, and noted only barbed wire fencing on subject property. Therefore I eliminated electric fences as a potential cause of the fire.

My experience and knowledge of conducting fire investigations, includes instances where power lines producing heat/sparks in a receptive fuel bed, has the potential for igniting a low intensity, slow developing incipient fire dependent on wind. Weather conditions and low fuel moistures contributed to the ignition and rapid extension of the THOMAS fire. During the course of the investigation, the IT collected many pieces of evidence/data substantiating the determination of an electrical event. The IT utilized the collected data to triangulate the multiple arc flashes as well as the fire during its initial growth.

The facts and circumstances revealed during the course of the investigation indicate the fire was caused by a phase to phase contact within a receptive fuel bed. The IT's O&C, Intel, collection and evaluation of evidence concluded that the power lines owned and operated by SCE were the cause of the THOMAS fire *(see attachment #2 and #3)*.

Based on my training, knowledge, experience, observations at scene, consultation with other fire investigators, expert opinions, data analysis and the elimination of other causes through the scientific methodology, I determined the fire occurred when a phase to phase contact arced ejecting molten metal particles onto dry ground vegetation.

CSaqui 11/18/18

Signature Date

Christine SAQUI

Fire/Arson Investigator

Ventura County Fire Department

10 – ATTACHMENTS:

1 – NFIRS
2 – Origin and Cause
3 – Data Collection and Analysis
4 – DINS
5 – Witnesses 1 thru 3, D. DOLLAR, C. DOLLAR, M. DOLLAR
6 – Witnesses 4 thru 7, Dori CLARKE, A. NUNEZ, J. TAIT, J. VALENZUELA
7 – Witness 8, R. RUDMAN
8 – Witness 9, P. RIOUX
9 – Witnesses 11 thru 13, T. SALAS, S. SWINDLE, S. BUCKLES
10 – Witnesses 14 & 15, J. GAMEZ Sr., J. GAMEZ Jr.
11 – Witness 16, R. FROST
12 – Witnesses 17 & 18, M. LOVO, K WILLIAMS
13 – Witnesses 20 thru 26, L. THAYER, T. GARCIA, L. MOORE, M. HAGGARD, R. LEMON, J. RICHARD, B. ALLEN
14 – Witness 27, J. MONZADA
15 – Witnesses 28 & 29, A. PRICE, R. PRICE
16 – Witness 30, T. TAYLOR
17 – Witness 31, E. BROCK
18 – Witness 32, M. MCLEAN
19 – Witness 33, C. TULBERG
20 – Witnesses 34 thru 36, J. GOYETTE, M. GOYETTE, R. GOYETTE
21 – Witness 37, S. SMITH
22 – Witnesses 38 & 39, P. MOREHART, M. MOREHART
23 – Witnesses 40 & 41, P. HERNANDEZ, N. HERNANDEZ
24 – Witnesses 42 & 43, N. BROUWER, J. BROUWER
25 – Witness 44, T. HENDERSON
26 – Witnesses 45 & 46, Christine LAW, Charles LAW
27 – Witnesses 47 & 48, F. SCHREINER, RAMANDA

28 – Witness 49, T. BELL
29 – Witness 50, T. CARPENTER
30 – Witness 51, M. RIEDER
31 – Witness 52, M. ALVERADO
32 – Witnesses 53 thru 58, T. HABILSTON, M. ZEIER, M. DEAN Jr., S. PRICE, C. FERNANDEZ, K. BROWN
33 – Witness 59, J. BRADEY
34 – Witnesses 60 & 61, Daniel CLARKE, N. PAPE
35 – Witness 62, M. STEINHILBER
36 – Witness 64 – 66, E. WEATHERBEE, K. ZOLULA, D. FERCY
37 – Witness 67, M. EVANS
38 – Witnesses 68 thru 71, T. HUNTER, G. WHITE, D. BERN, H. WISNIEWSKI
39 – Witness 73, J. OLIN
40 – Witness 75, R. MCCOLLUM
41 – Chain of Custody, Thursday, December 28, 2017 (LE-76)
42 – Chain of Custody, Friday, January 5, 2018 (LE-76)
43 – Forecasted Weather (National Weather Service)
44 – Local Weather Report (RAWS)
45 – Lightning Detection Map
46 – SCE Map of Equipment in the GOA
47 – Ventura County Assessor Parcel Number
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49 – CHP CAD and 911 Audio
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Appliance Efficiency Proceedings - Title 20

Appliance efficiency standards must be technically feasible, be cost-effective, and save energy or water. In the pre-rulemaking stage, California Energy Commission staff and stakeholders develop a proposal. Public comment is gathered on the proposal during the rulemaking. Compliance of the standard is monitored after adoption.

Appliance Efficiency Rulemakings

The following appliance categories have open rulemakings. Stakeholders can review proposals, submit comments, or view workshops.

There are no open rulemakings. Please check back.

Appliance Efficiency Pre-Rulemaking

The following appliances categories are in the pre-rulemaking stage. Stakeholders can submit proposals, make comments, or view workshops.

- Dipper Wells (21-AAER-01)
- Federally Exempted Linear Fluorescent Lamps (18-AAER-08)
- Irrigation Controllers (17-AAER-10)
- Low-Power Mode (17-AAER-12)
- Power Factor (19-AAER-03)
- Set-Top Boxes (17-AAER-11)
- Solar Inverters (17-AAER-13)
- Tub Spout Diverters (17-AAER-09)
- Water Closets (22-AAER-05)

Adopted Standards

The Energy Commission has adopted standards for the following categories.

Repeal of Portable Luminaries (22-AAER-02)

- **Adopted February 28, 2023** / Effective date April 25, 2023

Air Filters (20-AAER-02)

- **Adopted January 25, 2023** / Effective date July 1, 2024

Commercial and Industrial Fans and Blowers (22-AAER-01)

- **Adopted November 16, 2022** / Effective date November 16, 2023

Portable Electric Spas (20-AAER-04)

- **Adopted July 15, 2021** / Effective date January 1, 2022

Amendments to Computers and Monitors (20-AAER-03)

- **Adopted December 9, 2020**/ Effective date December 9, 2021

2020 Amendments to the Title 20 Appliance Efficiency Regulations (20-AAER-01)

- **Adopted December 9, 2020** / Effective date March 16, 2021

Replacement Pool Pump Motors (19-AAER-02)

- **Adopted April 7, 2020** / Effective date July 19, 2021

General Service Lamps (19-AAER-04)

- **Adopted November 13, 2019** / Effective date January 1, 2020
- News Release
- Frequently Asked Questions
- Regulatory Advisory

Spray Sprinkler Bodies (19-AAER-01)

- **Adopted August 14, 2019** / Effective date October 1, 2020
- News Release

Commercial and Industrial Air Compressors (18-AAER-05)

- **Adopted January 9, 2019**/Effective date January 1, 2022

Portable Air Conditioners (18-AAER-04)

- **Adopted December 10, 2018** / Effective date February 1, 2020

Amendments to Title 20 Appliance Efficiency Regulations Rulemaking (18-AAER-10)

- **Adopted July 11, 2018** / Effective date October 1, 2018
- Clean-up and technical amendments to current standards and the Modernized Appliance Efficiency Database System (MAEDBS). There were no underlying energy and water efficiency standards.

Portable Electric Spas and Battery Charger Systems (18-AAER-02)

- **Adopted April 11, 2018** / Effective date June 1, 2019
- News Release

RELATED INFORMATION

Setting minimum efficiency levels for energy and water use in products produces significant savings without affecting the usefulness of the products.

Modernized Appliance Efficiency Database System Login

All appliances regulated under Title 20 must be certified to the Energy Commission using the database system.

Collapse All

Regulations

- California Code of Regulations - Title 20 (westlaw.com)

Outreach

- Fact Sheets and FAQs
- How to Participate in a Proceeding
- Program Bulletins
- Webinar Documents

Modernized Appliance Efficiency Database System (MAEDbS)

- Login
- Quick Search
- Advance Search
- Company Search (Third Party and Test Labs)
- Certification Packets
- Instructions for Submitting Appliance Data
- Enhancements and Updates

RELATED EVENTS

No events are available at this time.

RELATED NEWS

California Joins National Coalition of States and Local Governments Strengthening Building Performance Standards

SACRAMENTO – Today, California officials announced the state has joined the National B

State Leaders Launch New Program Encouraging Builders to Construct All-Electric Affordable Housing

Los Angeles – State leaders helped kick off a new program from the California Energy Commission (CEC) to su

State, Local Leaders to Announce $60 Million Program for New All-Electric Affordable Housing Projects

Media Contact
Lindsay Buckley
916-208-6545

See More News >

CONTACT

Appliance Compliance Assistance
appliances@energy.ca.gov
Toll-free in California: 888-838-1467
Outside California: 916-651-7100

RELATED LINKS

Appliance Efficiency Program: Outreach and Education

Appliance Efficiency Regulations – Title 20

Flexible Demand Appliances

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Appliance Efficiency Standards

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CATEGORIES

Topic

Efficiency

Division
Efficiency

Program
Appliance Efficiency Regulations

Liquefied Natural Gas

Liquefied Natural Gas

California gets about 10 percent of its liquefied natural gas (LNG) from in-state production and 90 percent from five interstate natural gas pipelines. California does not have a liquefied natural gas (LNG) terminal or any proposed LNG terminals along the coast.

What is LNG?

Liquefied natural gas, or LNG, is natural gas in a liquid form. When natural gas is cooled to minus 259 degrees Fahrenheit (minus 161 degrees Celsius), it becomes a clear, colorless, odorless liquid. LNG is neither corrosive nor toxic. This liquid form allows large volumes of natural gas to be transported to locations unreached by gas pipelines.

CONTACT

Natural Gas Office

916-654-4771

CATEGORIES

Topic

Fuels

Renewable Energy

Division

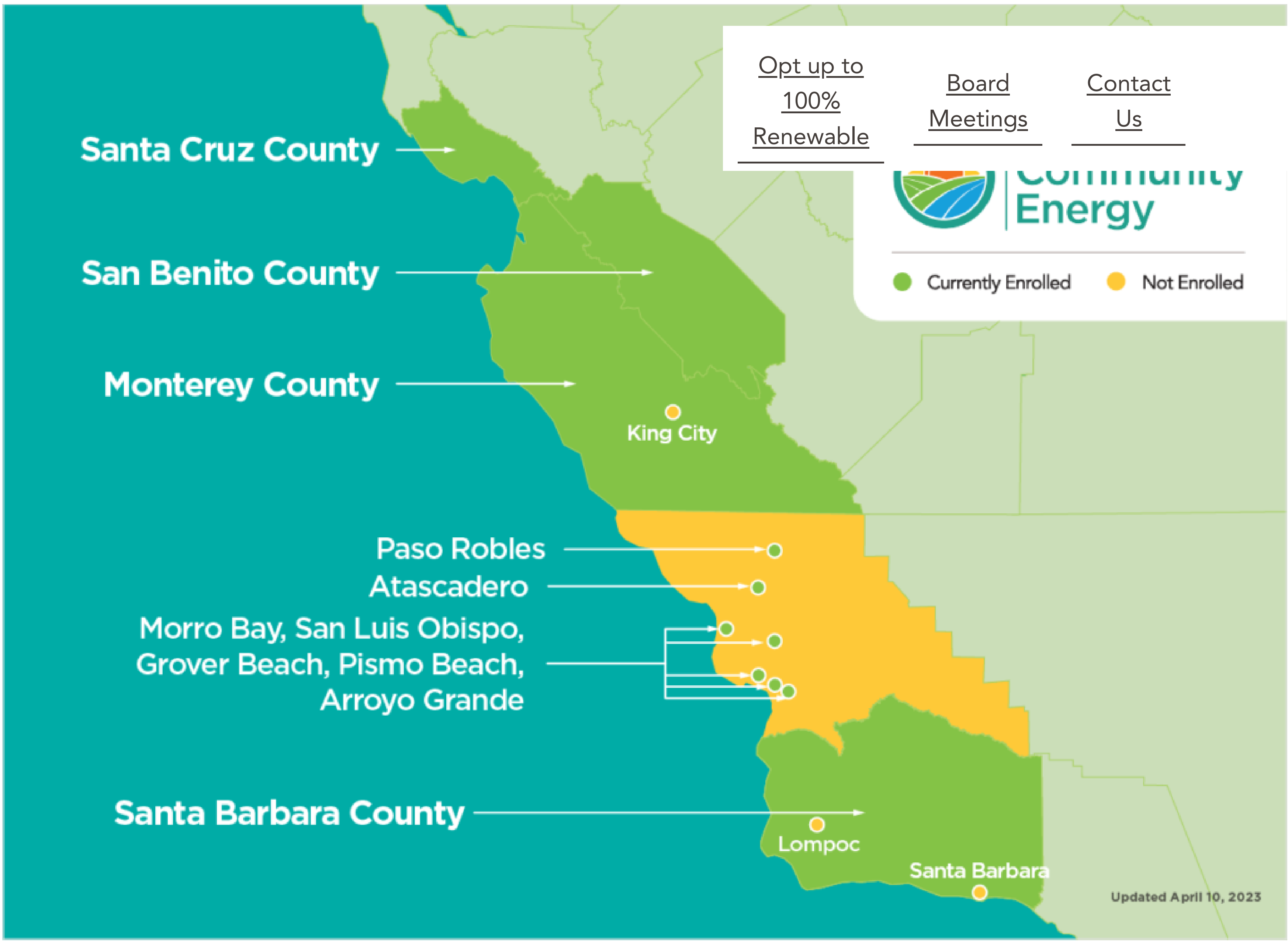
Energy Assessments

How 3CE Works

Powered By Community Choice

Central Coast Community Energy is the primary electricity provider for the following communities:

County of Monterey, County of San Benito, County of Santa Cruz, County of Santa Barbara, Arroyo Grande, Buellton, Capitola, Carmel, Carpinteria, Del Rey Oaks, Goleta, Gonzales, Greenfield, Grover Beach, Guadalupe, Hollister, Marina, Monterey, Morro Bay, Pacific Grove, Paso Robles, Pismo Beach, Salinas, Sand City, San Juan Bautista, San Luis Obispo, Santa Cruz, Santa Maria, Scotts Valley, Seaside, Soledad, Solvang, and Watsonville. Atascadero will begin service in January 2024.



Thirty-four communities joined Central Coast Community Energy (3CE) with the shared goal of gaining more control over their electricity needs: to reduce greenhouse gas emissions, support the growth of clean and renewable energy, and access additional economic and environmental benefits.

Are You A Central Coast Community Energy Customer?

3CE serves 95% of the population throughout Monterey, San Benito, Santa Cruz, San Luis Obispo, and Santa Barbara counties.

Many community members are 3CE customers without realizing it.

PG&E Customers: Customers receive a bill from PG&E, the 3CE service costs are integrated on this bill. Refer to page one of your electric bill, if there is a line on "Your Account Summary" reading "Central Coast Community Energy Electric Generation Charges," you are a 3CE customer.

SCE Customers: Customers receive a bill from SCE, the 3CE service costs are integrated on this bill. Refer to the "Supply/Generation" page of your electric bill. The top right of this page will indicate who supplies your energy. If the page reads "Central Coast Community Energy supplies your energy," you are a 3CE customer.

You can also give 3CE a call at 1-877-455-2223.

What is "community choice" energy?

3CE follows the **Community Choice Aggregator** or "CCA" model, a community-focused, not-for-profit model that allows for greater commitment to clean and renewable energy while supporting community reinvestment for affordable and fair rates and equitable access to clean-energy resources.

More than 11 million Californians are served by 24 community choice energy agencies, accounting for nearly a quarter of the state's electricity load. Collectively, CCAs are significantly contributing to a cleaner, more reliable grid.

How does 3CE work?

Here is a simple explanation:

Here is a more technical explanation:

Speak with a Local Customer Service Energy Advisor:

1-877-455-2223
info@3CE.org
(Please include whether you receive a PG&E or SCE Bill)

70 Garden Court, Suite 300
Monterey, CA 93940

71 Zaca Lane, #140
San Luis Obispo, CA 93401

2022 California Gas Report

Prepared in Compliance with California Public Utilities Commission Decision

D.95-01-039

2022 CALIFORNIA GAS REPORT

PREPARED BY THE CALIFORNIA GAS AND ELECTRIC UTILITIES

Southern California Gas Company
Pacific Gas and Electric Company
San Diego Gas & Electric Company
Southwest Gas Corporation
City of Long Beach Energy Resources Department
Southern California Edison Company

2022 CALIFORNIA GAS REPORT

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2022 CALIFORNIA GAS REPORT

FOREWORD

FOREWORD

The *2022 California Gas Report* (CGR) presents a comprehensive outlook for natural gas requirements and supplies for California through the year 2035. This report is prepared in even-numbered years, followed by a supplemental report in odd-numbered years, in compliance with California Public Utilities Commission (CPUC or Commission) Decision (D.) 95-01-039. The projections in the CGR are for long-term planning and do not necessarily reflect the day-to-day operational plans of the utilities.

The report is organized into three sections: Executive Summary, Northern California, and Southern California. The Executive Summary provides statewide highlights and consolidated tables on supply and demand. The Northern California section provides details on the requirements and supplies of natural gas for Pacific Gas and Electric Company (PG&E), the Sacramento Municipal Utility District (SMUD), Southwest Gas Corporation (SWG), Wild Goose Storage, LLC., Central Valley Gas Storage, LLC., Gill Ranch Storage, LLC., and Lodi Gas Storage LLC. The Southern California section shows similar detail for Southern California Gas Company (SoCalGas), the City of Long Beach Municipal Oil and Gas Department, Southwest Gas Corporation, and San Diego Gas & Electric Company (SDG&E).

Each participating utility has provided a narrative explaining its assumptions and outlook for natural gas requirements and supplies, including tables showing data on natural gas availability by source, with corresponding tables showing data on natural gas requirements by customer class. Separate sets of tables are presented for average and cold year temperature conditions. Any forecast, however, is subject to considerable uncertainty. Changes in the economy, energy and environmental policies, natural resource availability, and the continually evolving restructuring of the gas and electric industries can significantly affect the reliability of these forecasts. This report should not be used by readers as a substitute for a full, detailed analysis of their own specific energy requirements.

A working committee comprised of representatives from each utility was responsible for compiling the report. The membership of this committee is listed in the Respondents Section at the end of this report.

2022 CALIFORNIA GAS REPORT

EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

CALIFORNIA ENERGY MARKETS ARE EVOLVING

Serving the needs of customers and providing safe, reliable, and affordable services are top priorities among the participating investor owned utilities (IOUs). As we meet these needs, there is a growing realization that California energy markets are evolving. Though still undergoing transformation, the economic drivers, customer preferences, climate change, technological innovation, and policy will point out the road forward for our energy system.

The joint IOUs are committed to achieving our state's carbon goals and are taking steps to reduce the energy system carbon footprint, while continuing to serve the energy needs of our customers. More traditional solutions to reduce these emissions include, but are not limited to, conservation measures such as adjusting thermostats to lower baselines, where possible, and energy efficiency measures such as building and appliance improvements. Additional efforts are becoming increasingly important as well, such as efforts to diversify and decarbonize energy portfolios and sources by incorporating low-carbon and renewable fuels. Accelerating the adoption of these low-carbon and renewable energy sources will be critical to meeting carbon neutrality goals and will also be transformational for California's energy system.

Reducing reliance on traditional fuels (fossil fuels) comes with significant tradeoffs. From an economic standpoint it may be costly and is certainly not expected to be rapid or easy. Nonetheless, the push to find ways forward and to provide energy solutions to customers in a clean and affordable way is an imperative.

What is required is a concerted and sustained effort in addition to active participation across multiple sectors, alongside dialogue with all stakeholders with an interest in energy security. Clear communication between governments, industry, consumers and utility service providers is an essential focal point for successful implementation. Through open-minded dialogue, we can ensure a secure and sustainable energy future.

EXECUTIVE SUMMARY

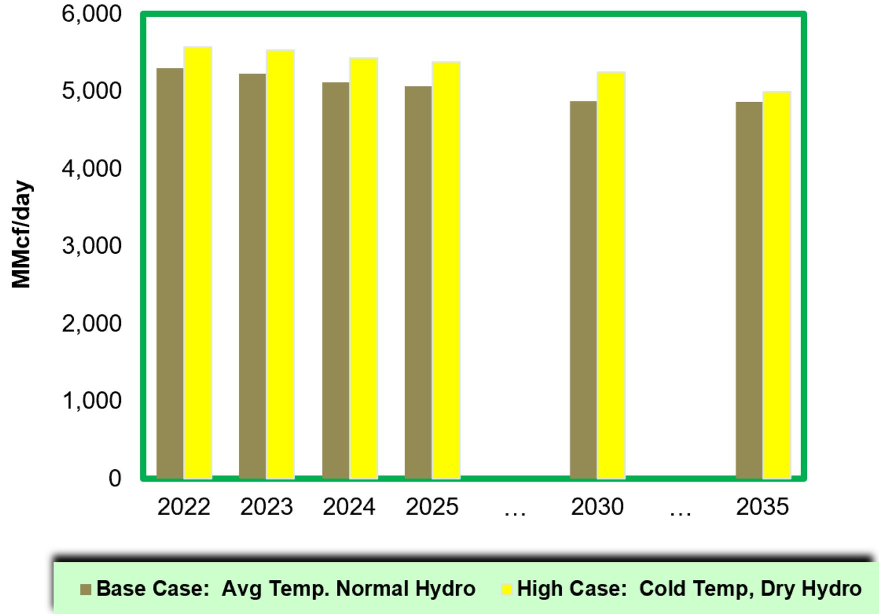
DEMAND OUTLOOK

Utility-served, statewide natural gas demand is projected to decrease at an annual average rate of 1.1 percent per year through 2035. The decline is 0.1 percent faster than what had been projected in the 2020 California Gas Report (CGR). More aggressive energy efficiency and fuel substitution have accelerated the decline in forecasted throughput for the 2022 CGR relative to the 2020 findings. In this Report, fuel substitution refers to the conversion of all or a portion of existing energy uses from one fuel type to another with the goal of reducing greenhouse gas emissions such as replacing a gas water heater with an electric water heater.

The projected decline comes from less gas demand in the major market segment areas of residential, electric generation (EG), commercial and wholesale markets. Total Statewide residential gas demand is projected to decrease at an annual average rate of 2.4 percent per year, a faster decline than the 1.7 percent annual rate of decline that had been forecasted in the 2020 Report. EG demand is projected to decrease at an annual rate of 1.1 percent per year, which is a slightly less rapid rate than the 1.5 percent annual decline that had been forecasted in 2020. The statewide commercial demand is projected to decrease at an annual average rate of 1.8 percent per year, which is slightly more accelerated than the 1.5 percent annual decline from the 2020 CGR. The aggregate statewide wholesale market segment is expected to decline at an annual average rate of 0.25 percent per year. The segments where growth in demand is expected are the natural gas vehicle (NGV) sector and the industrial market segments. The industrial market segment and the NGV sectors are expected to grow at an annual average rate of 0.16 percent and 2.3 percent per year over the forecast period.

There are several drivers of these declines across many of the key energy sectors. Aggressive energy efficiency programs and fuel substitution are expected to dampen gas demand in these sectors. Statewide efforts to minimize greenhouse gas (GHG) emissions are depressing EG demand through aggressive programs that pursue demand side reductions and the acquisition of preferred power generation resources that produce few or no carbon emissions. Nevertheless, for the foreseeable future, gas-fired generation and gas storage will continue to be important technologies that support long-term electric demand growth and growing integration of intermittent renewable resource generation.

FIGURE 1 – CALIFORNIA GAS DEMAND OUTLOOK: 2022-2035



The graph above summarizes statewide gas demand under the Average Demand case (base case) and the Cold Weather, Dry Hydroelectric Generation[1] case (high case). The base case refers to the expected gas demand for an average temperature year and normal hydroelectric generation (hydro) year, and the high case refers to expected gas demand for a cold temperature year and dry hydro conditions. Under the base case, gas demand for the entire state is projected to average 5,298 million cubic feet of gas per day (MMcf/d) in 2022 decreasing to 4,857 MMcf/d by 2035, a decline of 0.67 percent per year.

Compared to the Average Year forecast, the Northern California high demand scenario is 3.3 percent higher in year 2022 while the Southern California demand is 3.0 percent higher for the same year.

[1] Hydroelectric generation refers to generation within the Western Electricity Coordinating Council (WECC).

EXECUTIVE SUMMARY

FOCUS ON ENERGY EFFICIENCY AND ENVIRONMENTAL QUALITY

California utilities continue to focus on conservation and energy efficiency. The IOUs are committed to helping their customers make the best possible energy decisions and helping customers identify and implement ways to benefit environmentally and financially from energy efficiency investments. An important role of the energy efficiency programs includes services, administered by the respective utilities, to help customers evaluate their energy efficiency options and adopt recommended solutions, as well as equipment-retrofit improvements, such as rebates for new hot water heaters and space heaters.

Gas demand for electric power generation is expected to be dampened by statewide GHG reduction goals and electric energy efficiency programs and additional renewable power generation. Both demand forecasts assume that renewable power will meet the CPUC 2021 Integrated Resource Plan Preferred System Plan (IRP PSP).

Renewable power capacity additions are driven, in part, by Senate Bill (SB) 100. Passed in 2018, SB 100 increased and accelerated the Renewables Portfolio Standard (RPS) targets and established the policy goal that zero carbon energy resources supply 100 percent of electric retail sales to end-use customers by the year 2045. One major milestone will occur by 2030, when renewable power generation will generate at least 60 percent of retail electric sales. The currently approved IRP PSP helps the state move towards attainment of this goal.

Additional California legislation and policy direction[2] provides directives and incentives to increase energy efficiency. Some of these efforts require access to building performance data, encouraging pay-for-performance incentive-based programs, and the use of energy management technology for use in homes and businesses. Moreover, legislation requires energy utilities to develop a plan to educate residential customers and small and medium business customers about the incentive programs. The programs and targets must meet three requirements: (1) they must be cost-effective; (2) they must be feasible; and (3) they should not adversely impact the environment. In recent years, California has increasingly focused on the potential for fuel substitution to address GHG emission reduction goals. The Commission has developed a

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[2] For more information, see https://www.cpuc.ca.gov/energyefficiency/.

baseline for analyzing and evaluating energy efficiency and fuel substitution using a code baseline, industry standard practice and existing conditions. So far, the Commission standard requires that the fuel substitution measure must both save energy and not harm the environment as measured by GHG emissions.

EXECUTIVE SUMMARY

CALIFORNIA'S LONG-TERM CLIMATE GOALS AND THE ENERGY TRANSITION: FUTURE GAS SYSTEM IMPACTS

California is facing the ambitious goal of economy-wide carbon neutrality by 2045 or sooner and has adopted a suite of policies that begin to move the State towards this goal. Many of these policies are discussed more specifically elsewhere in this Report, but there are still many unknowns about the exact timing and path of the energy transition. The current policy landscape does suggest that there will be significant changes to the way Californians use energy. California natural gas utilities are actively participating in, studying and monitoring this evolution.

While much uncertainty remains about the exact path California will take, the gas utilities recognize it is probable that two segments of natural gas customers in particular may potentially face substantial change – natural gas-fired electric generation (EG) and core (mainly residential and commercial buildings), as discussed above. Today, California relies on gas-fired EG, hydroelectric generation, and growing battery resources to balance its electric grid – a role that will likely persist through the energy transition. This role will evolve, however, as fuel-based electric generation is displaced by increasing amounts of solar and wind to meet energy decarbonization goals. While this is likely to result in less natural gas being used by the EG segment, gas fired EG is forecasted to be an important resource for providing electricity when intermittent renewables or variable hydroelectric generation are not available. This means that peak EG load could persist or grow while usage pattern will become more volatile and less predictable. This could have a greater influence over peak natural gas system design conditions and, accordingly, costs.

At the same time, decarbonization goals will accelerate energy efficiency and support fuel substitution for natural gas end-uses in the core building segment. This is likely to result in declining core gas use over time. The core segment currently contributes the majority of the gas utilities' revenue requirements. These issues combined, among other trends and factors, create the impetus for an evolved approach to natural gas and clean fuels in California – from perspectives of system design, financial, and rate reform. These issues are highlighted in this Report and the subject of the Long-term Gas Reliability and Planning Proceeding (R.20-01-007) currently in Track 2 at the CPUC.

One element of the energy transition and attaining the State's decarbonization goals is building electrification also known as fuel substitution. The gas utilities' forecasts have incorporated these evolving forecasts, including collaborating with the CEC developed fuel substitution scenarios. The state is in the early stages of the energy transition. Forecasts around the timing and degree of these changes are highly uncertain. These forecasts will improve over time as trends are observed in the real world and as policy and market drivers mature. The gas utilities will be actively monitoring these trends and expect that each update of the biannual California Gas Report will further refine these factors and their impacts on resultant gas demand forecasts.

It is important to note that the California Gas Report is relied upon for system planning purposes to help benchmark investment and operating policies that impact natural gas system capacity and reliability. The gas utilities recognize the need to evolve with the government-mandated energy transition. The utilities also recognize the necessity of maintaining flexibility during the energy transition to ensure California gas customers have safe, clean, reliable, and affordable sources of energy.

Since electric utility system operators must balance electrical demand with generation sources on a real-time basis, most system operators rely on "dispatchable" resources that can respond quickly to changes in demand. One challenge with renewable resources is that while they provide energy, the amounts are not always predictable and are not always immediately dispatchable.

The increase in future renewable generation in the state will reduce the total amount of natural gas usage. It is also expected that the increasing and intermittency of renewable generation will add to the daily and hourly load forecast variance on the gas-fired EG fleet. In the long-term, balancing electric supply and demand may come through the higher expected integration of energy storage devices (e.g., batteries, fuel cells, and hydroelectric pumped storage).

Due to the expansion of intermittent renewable resources, there may be an increased need for rapid response, gas-fired generators to follow electric net load fluctuations. Since gas-fired generation is the marginal resource in most hours, the amount of gas consumed for integrating more renewables will fluctuate hourly. The gas system will therefore need to be both robust and flexible to handle such fluctuations and continue to support electric reliability.

The expected growth in electrification poses considerable uncertainty on when, where, and how large the impacts will be on gas demand. In the building sector, electrification could decrease gas use. Recently, some California local jurisdictions have forbidden the use of gas in new building construction. Moreover, there are some indications that jurisdictions may actively pursue appliance substitution away from natural gas and to the electric alternative(s). The expected growth in electrification of vehicles and buildings would result in increasing electric load that could create a need for additional use of gas-fired generators.

Further adding to gas demand variance is the impact of natural gas burner-tip prices. Burner-tip gas prices represent what gas utility customers pay at their premises. For EG, relative geographic burner-tip prices impact generation dispatch economics. If prices in one portion of the state are higher or lower than another portion, gas demand can vary accordingly.

GAS PRICE FORECAST

MARKET CONDITIONS

The natural gas industry has experienced multiple changes over the past two decades. Gas supply rapidly grew on the back of the shale gas revolution. More recently, gas supply growth has come from the rise of associated gas production from tight oil supply growth. Additionally, Liquefied Natural Gas (LNG) export demand has grown rapidly. Since the end of 2021, the European Union (EU) and United Kingdom (UK) imported record-high LNG volumes because of low natural gas inventories and interrupted gas pipeline supplies. As a result, the North American gas market has seen gas prices fluctuate. To exemplify this price variation, the U.S. EIA[3] reported the national benchmark price at Henry Hub was about $3/Million British thermal units (MMBtu) in early June 2021. One year later, the gas price was about $8.50/MMBtu.

Natural gas prices have risen, relative to the 2020 outlook, mainly because of five factors. First, the North American natural gas inventories have fallen below the five-year average. Second, there has been steady demand in U.S. LNG exports due to European natural gas shortages, which have been exacerbated by the war in Ukraine. Europe has become the main destination for U.S. LNG exports and accounted for 74 percent of total U.S. LNG exports during the first 4 months of 2022. Third, the current U.S. Administration is restricting licensing and drilling for traditional fuels including natural gas. Fourth, high demand for natural gas being driven by the growing needs of the electric power sector in the U.S. as a whole. Lastly, natural gas production investment has lagged behind the rapid growth of gas demand over the past year.

For the 2022 CGR, the gas price outlook[4] reflects market conditions in early 2022. The 2022 near term gas price average at the California city-gates[5] is a little above $5.00/MMBtu. During the mid-2020s, gas prices are projected to decline to approximately $4.00/MMBtu.

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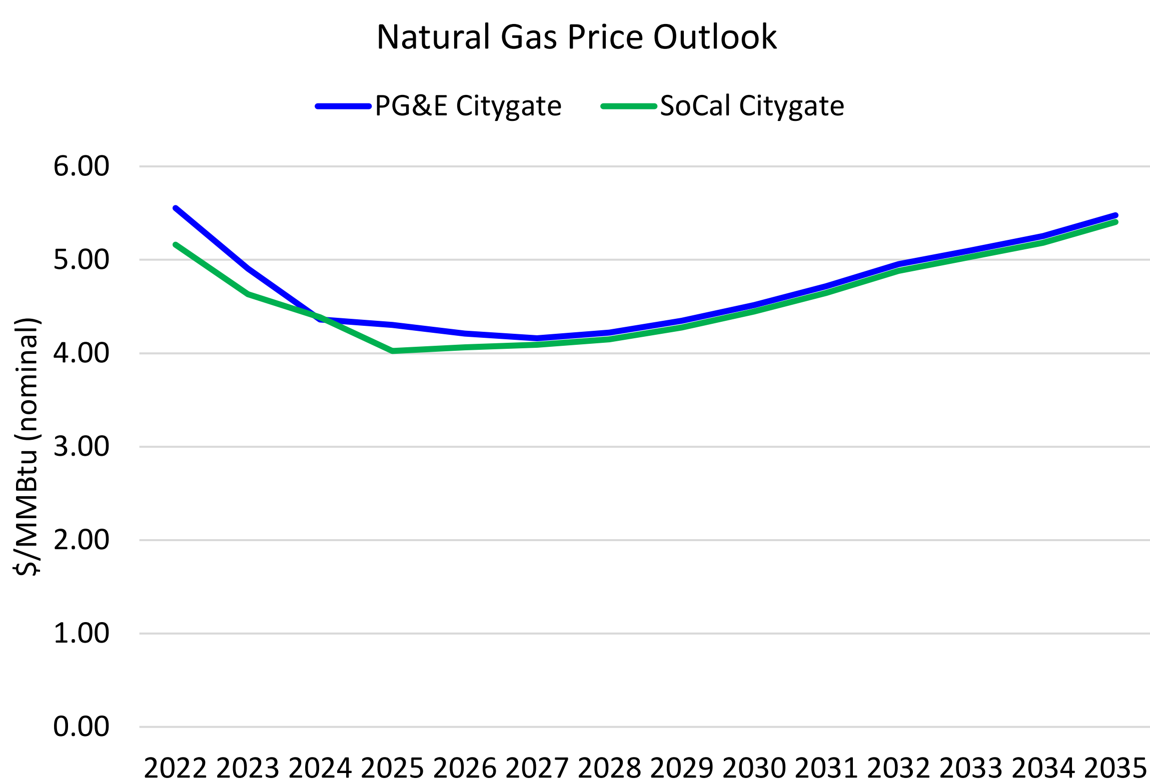
[3] U.S. Energy Information Administration https://www.eia.gov/dnav/ng/ng_pri_fut_s1_d.htm.
[4] Nominal dollars.
[5] The two Citygate price hubs are the Southern California Gas Company Citygate (SoCal Citygate) and the Pacific Gas and Electric Citygate (PG&E Citygate).

Industry experts forecast that gas prices will increase about $1.50/MMBtu thereafter to average approximately $5.50/MMBtu by year 2035.

DEVELOPMENT OF THE GAS PRICE FORECAST

The 2022 CGR gas price forecast was developed using a combination of market prices and fundamental long -term forecasts. For the 2022 through 2027 period, the gas prices represent a blend of contract futures prices from the Chicago Mercantile Exchange and S&P Global[6] basis differentials to Henry Hub. For 2030 and beyond, S&P Global fundamental price forecasts were used. The forecasts for 2028 and 2029 reflect a blending of futures prices and fundamental prices.

FIGURE 2 – FORECASTED NATURAL GAS PRICES



[6] S&P Global Commodity Insights North American Gas Regional Short-Term Forecast, March 22, 2022.

It is important to recognize that natural gas price forecasts are inherently uncertain. The price forecast used in the Report were developed in early 2022. The prices seen in much of the first half of 2022 have been materially higher than the prices in the forecast. Additionally, gas prices have seen significant volatility.

PG&E, SoCalGas, and the respondents of the 2022 CGR, separately and collectively, do not warrant the accuracy of the gas price projections. PG&E, SoCalGas, or the respondents of the 2022 CGR shall not be liable or responsible for the use of or reliance on this natural gas price forecast.

GAS SUPPLY

California's existing gas supply portfolio is regionally diverse and provides long -term supply availability. Gas production that California has access to includes California (onshore and offshore), Southwestern U.S. (the Permian, Anadarko, and San Juan basins), the Rocky Mountains, and Canada.

California natural gas utilities and customers gain access to this diverse supply portfolio using an extensive pipeline system. Interstate pipelines serving California include Ruby Pipeline LLC, El Paso Natural Gas Company, Kern River Transmission Company, Mojave Pipeline Company, Gas Transmission Northwest LLC (GTN), Transwestern Pipeline Company, Tuscarora Pipeline, and the Baja Norte/North Baja Pipeline. The map on the following page shows the locations of these supply sources and the natural gas pipelines serving California.

FIGURE 3 – WESTERN NORTH AMERICAN NATURAL GAS PIPELINES

1. West Coast Pipeline
2. Woodfibre LNG Terminal
3. Terasen Sumas Gas Pipeline
4. TransCanada Pipeline
5. Alliance Pipeline
6. Northern Border Pipeline
7. Gas Transmission Northwest (GTN Pipeline
8. Northwest Pipeline
9. Jordan Cove LNG (Proposed)
10. Pacific Connector (Proposed)
11. Tuscarora Gas Transmission
12. Paiute Pipeline
13. Ruby Pipeline
14. Questar Pipeline
15. Rockies Express Pipeline
16. Southern Star Pipeline
17. TransColorado Pipeline
18. Kern River Pipeline
19. Pacific Gas and Electric Company
20. Southern California Gas Company
21. San Diego Gas and Electric Company
22. North Baja Pipeline
23. El Paso Natural Gas
24. TransWestern Pipeline
25. Rosarito Pipeline
26. Trasnportadora de Gas Natural (TGN)
27. Costa Azul LNG

California benefits from substantial gas storage capacity in dedicated gas storage facilities across the state. These gas storage facilities supplement pipeline gas supply during high demand periods and also provide supply reliability. Additionally, storage allows gas customers to take advantage of low prices and store gas for use in periods with higher prices. Various regulations and standards[7] have been implemented to ensure safe and reliable operations of California gas storage facilities. The table below gives the current status of gas storage capacity in California.

Table 1: California Natural Gas Storage Capacities
Recorded Year 2021

	Inventory (Bcf)	Injection (MMcf/d)	Withdrawal (MMcf/d)	Cite
Northern California				
Independent Storage Providers				1
Lodi Gas Storage	31	552	750	
Wild Goose Storage	75	525	950	
Gill Ranch	15	165	162	
Central Valley	11	300	300	
Pacific Gas & Electric Company-Utility Storage***	35	315	1,144	2
Northern California Total	167	1,857	3,306	
Southern California				
Southern California Gas Company-Utility Storage	137	790	2,660	3
California Total	375	3,432	7,995	

Citations
1) Capacities derived from information provided by Independent Storage Providers
2) ***Firm maximum inventory level
3) Per the current active Triennial Cost Allocation Proceeding, D 20-02-045

[7] See Geologic Energy Management Division's Underground Natural Gas Storage for more details on regulations and standards at: https://www.conservation.ca.gov/calgem/Pages/UndergroundGasStorage.aspx.

EXECUTIVE SUMMARY

In addition to traditional sources of gas supply, multiple Renewable Natural Gas (RNG) interconnection projects in California have come online in recent years. As further detailed in this CGR, gas utilities see broad potential for RNG in California and are taking significant steps to make RNG interconnection easier and more transparent. As policies evolve and new programs are created, such as California's recently approved Renewable Gas Standard, we expect RNG to play a growing role in serving customers' energy needs beyond the transportation sector. Currently, incentive programs such as California's Low Carbon Fuel Standards (LCFS) and the federal Renewable Fuel Standard (RFS) are successfully supporting the use of RNG in the transportation sector.

As California continues towards achieving a decarbonized energy system, hydrogen (H_2) will become an important fuel source in achieving the State's emissions goals. There is growing potential for generating renewable H_2[8] and storing and delivering it using existing gas utility infrastructure to help meet California's dynamic energy needs. Hydrogen pathways can provide exceptional and important value, such as long-duration, high capacity and high energy storage capabilities relative to other clean energy storage technologies.

LIQUEFIED NATURAL GAS

In years past, the U.S. imported LNG to supplement North American supplies. Since the mid-2010s, LNG imports have primary been used to serve peak winter load. However, U.S. imports of LNG have been declining since 2008. Since this time, the development of low-cost domestic shale gas supplies largely eliminated the need for LNG imports. Since 2016, the U.S. has been exporting LNG.

LNG exports are expected to continue growing. Current economic conditions and the sanctions imposed on Russia in response to its invasion of Ukraine have exacerbated natural gas shortages, primarily in Europe. The outlook suggests that LNG will continue to expand and grow because world needs are expanding.

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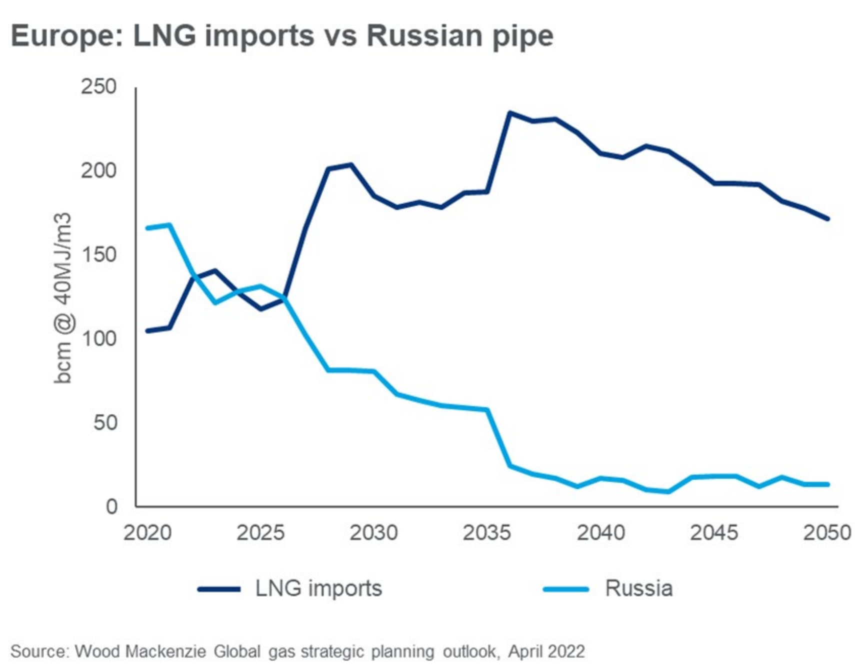
[8] Renewable hydrogen is hydrogen produced by renewable electricity, hydrogen derived from biomethane, or hydrogen derived from biomass using a thermal conversion process.

LNG is expected to help meet European heating load needs as well as its gas fired EG demand. Published studies have found that although the average CO_2 emissions have declined over the last decade, marginal emissions have not decreased, but rather increased slightly due primarily to countries' reliance on coal to satisfy marginal electricity use.[9] Flowing LNG supplies to Europe may mitigate the environmental impact of the forecasted energy shortage in Europe. The chart below illustrates the outlook that industry experts are projecting to sustain LNG demand growth in the European countries including the UK and Turkey for the next twelve years, with demand subsiding somewhat after 2034.

Worldwide LNG demand is expected to almost double from current levels by the year 2040. According to industry experts, the U.S. is expected to become the largest LNG exporter in 2022, leap-frogging Australia and Qatar. Industry surveys of global LNG developers have indicated plans to accelerate the expansion of operations to meet the growth in overseas demand over the long-term.

Figure 4 - LNG Outlook



9 "Why are Marginal CO_2 Emissions Not Decreasing for Electricity? Estimates and Implications for Climate Policy," by Stephen Hallard, Matthew Kotchen, Erin Mansur and Andrew Yates. Presented at the 2022 American Economic Association annual meetings.

EXECUTIVE SUMMARY

In the next few years, LNG export facilities will begin operations in Western Canada and Western Mexico. In the US, exports are expected to increase as global demand for LNG grows. The following maps illustrate (1) Existing U.S. LNG export terminals; (2) U.S. export terminals approved but not yet built; and (3) U.S. LNG export terminals proposed and being evaluated whose application status is in the process of being reviewed.

Figure 5

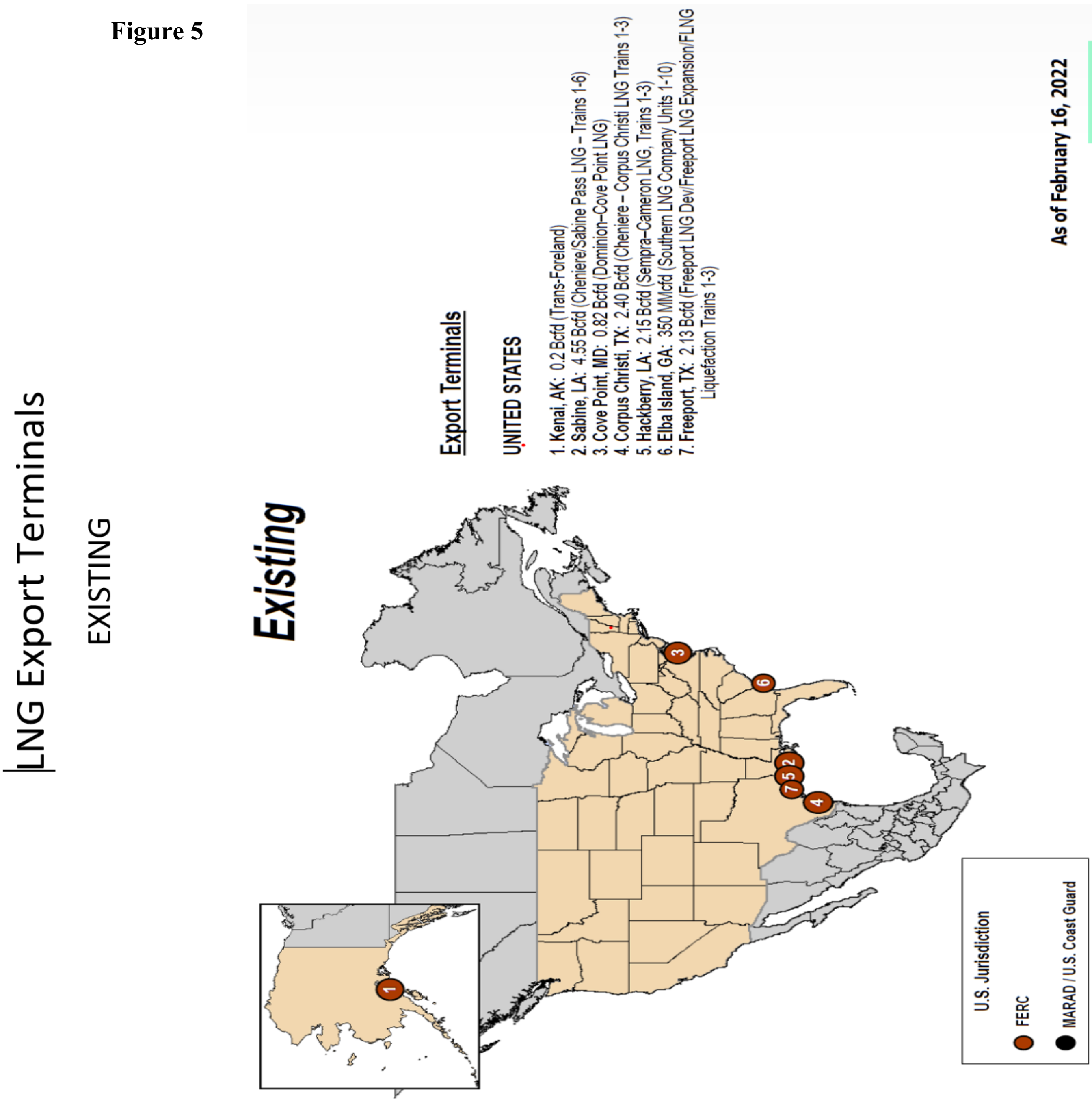
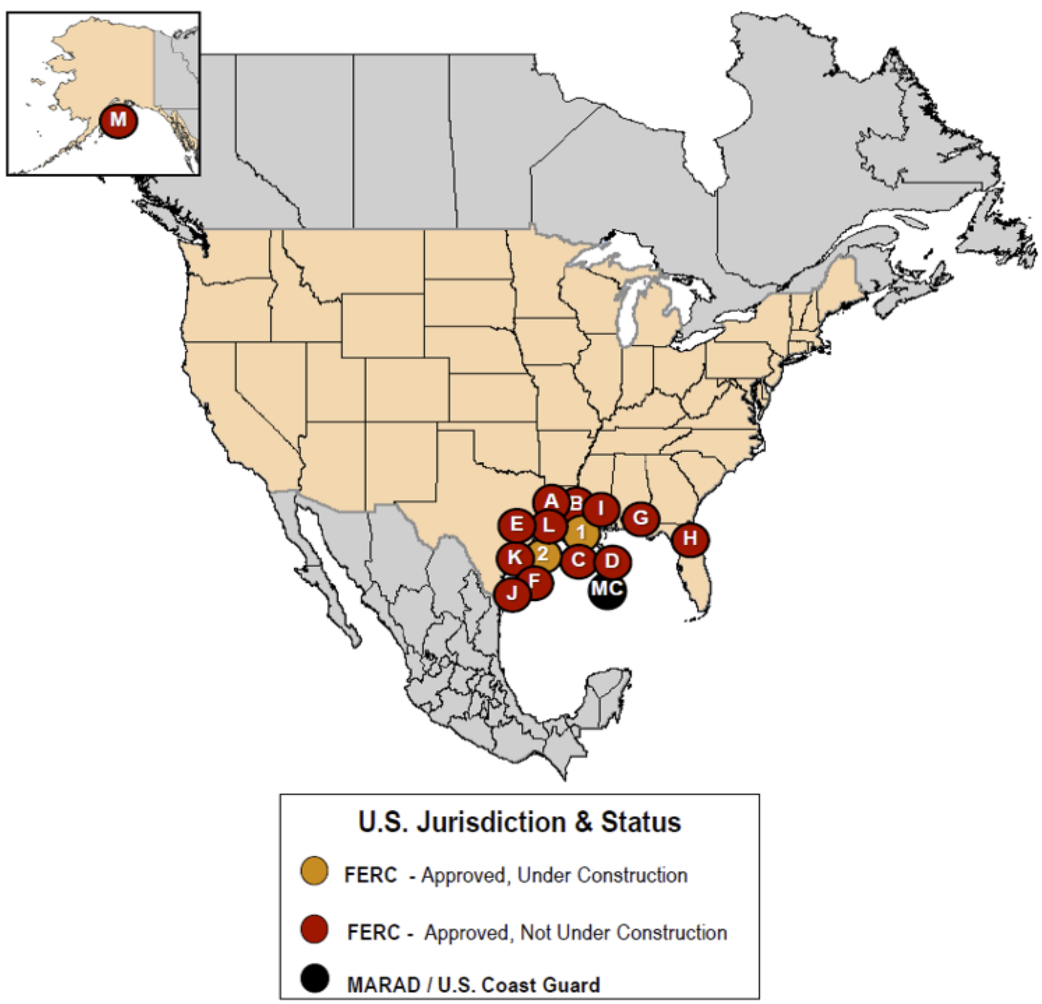

LNG Export Terminals
EXISTING
Existing
Export Terminals
UNITED STATES
1. Kenai, AK: 0.2 Bcfd (Trans-Foreland)
2. Sabine, LA: 4.55 Bcfd (Cheniere/Sabine Pass LNG – Trains 1-6)
3. Cove Point, MD: 0.82 Bcfd (Dominion–Cove Point LNG)
4. Corpus Christi, TX: 2.40 Bcfd (Cheniere – Corpus Christi LNG Trains 1-3)
5. Hackberry, LA: 2.15 Bcfd (Sempra–Cameron LNG, Trains 1-3)
6. Elba Island, GA: 350 MMcfd (Southern LNG Company Units 1-10)
7. Freeport, TX: 2.13 Bcfd (Freeport LNG Dev/Freeport LNG Expansion/FLNG Liquefaction Trains 1-3)
As of February 16, 2022
U.S. Jurisdiction
FERC
MARAD / U.S. Coast Guard

Figure 6

LNG Export Terminals Approved

(In Process: Not Yet Completed)



Export Terminals

UNITED STATES

FERC – APPROVED, UNDER CONSTRUCTION

1. **Cameron Parish, LA:** 1.41 Bcfd (Venture Global Calcasieu Pass) (CP15-550)
2. **Sabine Pass, TX:** 2.26 Bcfd (ExxonMobil – Golden Pass) (CP14-517, CP20-459)

FERC – APPROVED, NOT UNDER CONSTRUCTION

A. **Lake Charles, LA:** 2.2 Bcfd (Lake Charles LNG) (CP14-120)
B. **Lake Charles, LA:** 1.186 Bcfd (Magnolia LNG) (CP14-347)
C. **Hackberry, LA:** 1.41 Bcfd (Sempra - Cameron LNG Trains 4 & 5) (CP15-560)
D. **Calcasieu Parish, LA:** 4.0 Bcfd (Driftwood LNG) (CP17-117)
E. **Port Arthur, TX:** 1.86 Bcfd (Port Arthur LNG Trains 1 & 2) (CP17-20)
F. **Freeport, TX:** 0.72 Bcfd (Freeport LNG Dev Train 4) (CP17-470)
G. **Pascagoula, MS:** 1.5 Bcfd (Gulf LNG Liquefaction) (CP15-521)
H. **Jacksonville, FL:** 0.132 Bcf/d (Eagle LNG Partners) (CP17-41)
I. **Plaquemines Parish, LA:** 3.40 Bcfd (Venture Global Plaquemines) (CP17-66)
J. **Brownsville, TX:** 0.55 Bcfd (Texas LNG Brownsville) (CP16-116)
K. **Brownsville, TX:** 3.6 Bcfd (Rio Grande LNG – NextDecade) (CP16-454)
L. **Corpus Christi, TX:** 1.86 Bcfd (Cheniere Corpus Christi Stage III) (CP18-512)
M. **Nikiski, AK:** 2.63 Bcfd (Alaska Gasline) (CP17-178)

MARAD/USCG – APPROVED, NOT UNDER CONSTRUCTION

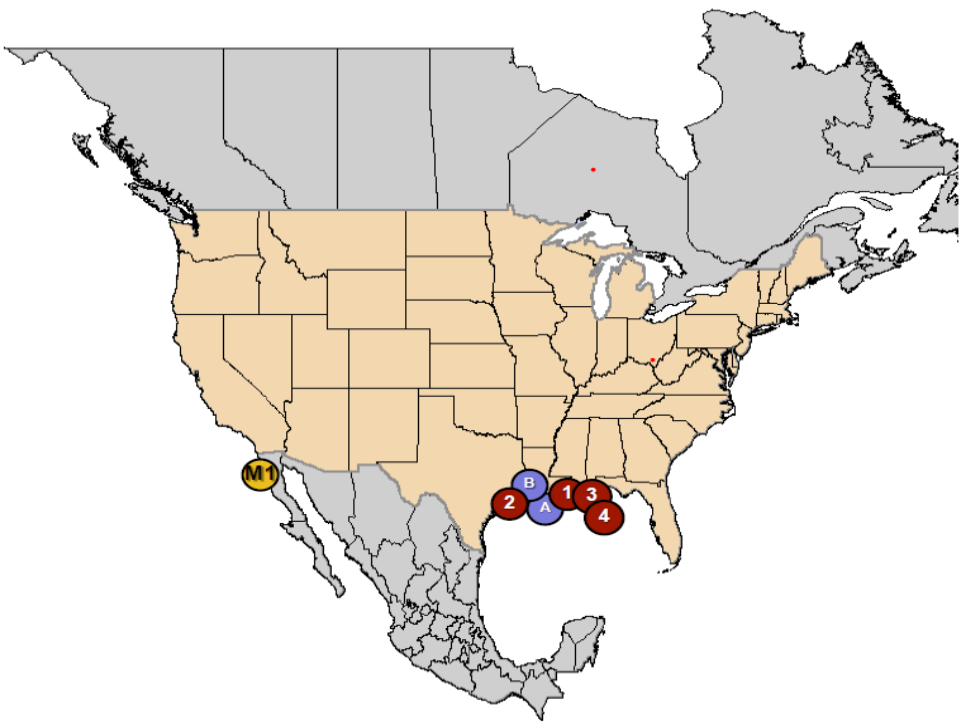
MC. **Gulf of Mexico:** 1.8 Bcfd (Delfin LNG)

CANADA - LNG IMPORT AND PROPOSED EXPORT FACILITIES
https://www.nrcan.gc.ca/energy/natural-gas/5683

As of February 16, 2022

Figure 7

LNG Export Terminals
PROPOSED & Under Evaluation



UNITED STATES

PROPOSED TO FERC
Pending Applications:
1. Cameron Parish, LA: 1.18 Bcfd (Commonwealth, LNG) (CP19-502)
2. Port Arthur, TX: 1.86 Bcfd (Sempra - Port Arthur LNG Trains 3 & 4) (CP20-55)
3. Cameron Parish, LA: 1.45 Bcfd (Venture Global CP2 Blocks 1-9) (CP22-21)
4. Cameron Parish, LA: .057 Bcfd (Venture Global Calcasieu Pass) (CP22-25)

Projects in Pre-filing:
A. LaFourche Parish, LA: 0.65 Bcfd (Port Fourchon LNG) (PF17-9)
B. Plaquemines Parish, LA: 2.76 Bcfd (Delta LNG - Venture Global) (PF19-4)

CANADA
For Canadian LNG Import and Proposed Export Facilities:

https://www.nrcan.gc.ca/energy/natural-gas/5683

MEXICO (Projects in advanced planning/development stages)
M1. Baja California, MX: 0.4 Bcfd (Sempra – Energía Costa Azul Phase 1)

As of February 16, 2022

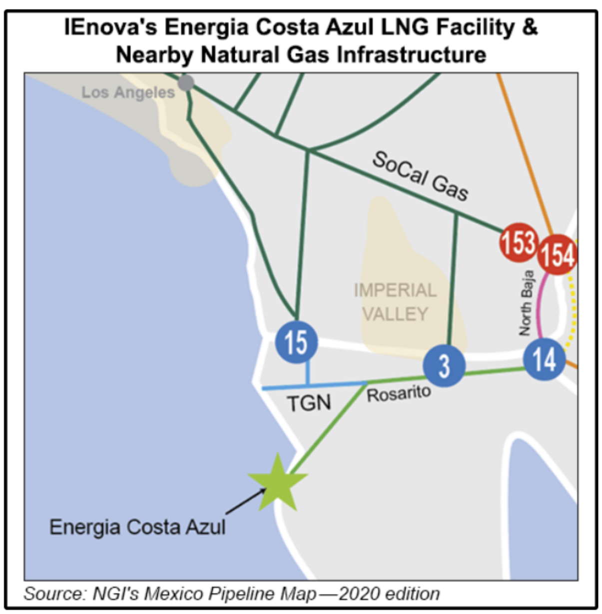
EXECUTIVE SUMMARY

Along the western North American coast, there are two LNG facilities. These include the LNG export terminal in Kenai Alaska owned and operated by Foreland and the LNG facility in Baja California/Mexico owned by Energia Costa Azul, a Sempra-owned subsidiary.

The Kenai plant in Nikiski, Alaska was once the only LNG export terminal in the U. S. but has not exported LNG since Fall 2015. In winter 2020, the FERC voted to approve Trans-Foreland's project to make modifications and reactivate portions of the plant. The project will bring the plant out of "warm idle status" and would enable the transfer of gas to an adjacent refinery.

Energia Costa Azul is a liquified natural gas joint venture between Sempra LNG and IEnova. It is the first and only LNG export project in Mexico. The project connects gas supplies from Texas and the northern U.S. directly to markets in Mexico and countries across the Pacific Basin.

Figure 8 LNG Infrastructure Map in Baja California and Mexico



More locally, in January 2022, under a grant agreement, Sysco Riverside developed a publicly accessible liquefied natural gas station to fuel their expanding fleet of natural gas-powered goods movement vehicles in Riverside, California. The new station established natural gas fueling infrastructure to support its fleet and others operating along one of the busiest stretches of highway in the nation. At the time of application, Sysco operated 35 trucks. This initial fleet is expected to grow to 125 liquefied natural gas trucks during the project life, thus creating a strong need for infrastructure to fuel its vehicles.

Sysco' s contractor, Fullmer Construction, was responsible for the construction of the liquefied natural gas fueling station. Sysco' s objective in constructing this station is to provide the additional necessary infrastructure needed to make alternative fuels like natural gas a commercially available and preferable fueling option. Natural gas contains less carbon than any other traditional fuel, and thus produces lower carbon dioxide and greenhouse gas emissions per year. In fact, natural gas vehicles produce up to 20-30 percent fewer greenhouse gas emissions than comparable diesel vehicles. Natural gas is also typically less expensive than diesel, costing less per unit of energy.

STATEWIDE CONSOLIDATED SUMMARY TABLES

The consolidated summary tables on the following pages show the statewide aggregations of projected gas supplies and gas requirements (demand) from 2022-2035 for Average Temperature and Normal Hydro years (base case) in addition to the Cold Temperature and Dry Hydro (high case).

Gas sales and transportation volumes are consolidated under the general category of system requirements. Details of gas transportation for individual utilities are given in the tabular data for Northern California and Southern California. The wholesale category includes the City of Long Beach Energy Resources Department, SDG&E, Southwest Gas (SWG), City of Vernon, Alpine Natural Gas, Island Energy, West Coast Gas, Inc., and the municipalities of Coalinga and Palo Alto.

Some columns may not sum precisely because of modeling accuracy and rounding differences and do not imply curtailments.

TABLE 2 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR
(MMcf/d)
2022-2026

	2022	2023	2024	2025	2026
California's Supply Sources					
Utility					
California Sources	117	117	117	117	117
Out-of-State	4,428	4,408	4,310	4,257	4,252
Utility Total	4,545	4,525	4,427	4,374	4,369
Non-Utility Served Load (1)	1,024	1,010	990	995	999
Statewide Supply Sources Total	**5,570**	**5,535**	**5,416**	**5,368**	**5,369**
California's Requirements					
Utility					
Residential	1,101	1,077	1,054	1,031	1,008
Commercial	463	462	455	449	442
Natural Gas Vehicles	52	53	54	56	57
Industrial	906	920	933	938	937
Electric Generation (2)	1,377	1,327	1,252	1,219	1,245
Enhanced Oil Recovery Steaming	27	27	27	27	27
Wholesale/International+Exchange	283	283	282	282	281
Company Use and Unaccounted-for	65	65	64	63	62
Utility Total	4,273	4,215	4,122	4,064	4,059
Non-Utility					
Enhanced Oil Recovery Steaming	640	637	638	634	631
EOR Cogeneration/Industrial	54	52	49	52	45
Electric Generation	330	321	303	309	323
Non-Utility Served Load (1)	1,024	1,010	990	995	999
Statewide Requirements Total (3)	**5,298**	**5,225**	**5,111**	**5,058**	**5,059**

Notes:
(1) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(2) Includes utility generation, wholesale generation, and cogeneration.
(3) The difference between California supply sources and California requirements is PG&E's forecast of off system deliveries.

TABLE 3 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR
(MMcf/d)
2027-2035

	2027	2028	2029	2030	2035
California's Supply Sources					
Utility					
California Sources	117	117	117	117	117
Out-of-State	3,909	3,844	3,802	3,731	3,594
Utility Total	4,026	3,961	3,919	3,848	3,711
Non-Utility Served Load (1)	995	979	1,006	1,025	1,147
Statewide Supply Sources Total	**5,021**	**4,940**	**4,926**	**4,874**	**4,857**
California's Requirements					
Utility					
Residential	988	964	944	921	804
Commercial	435	425	417	408	366
Natural Gas Vehicles	59	60	62	63	70
Industrial	937	936	935	933	925
Electric Generation (2)	1,240	1,210	1,198	1,162	1,193
Enhanced Oil Recovery Steaming	26	25	24	24	20
Wholesale/International+Exchange	281	280	279	278	274
Company Use and Unaccounted-for	61	61	60	59	58
Utility Total	4,026	3,961	3,919	3,848	3,711
Non-Utility					
Enhanced Oil Recovery Steaming	628	627	672	712	878
EOR Cogeneration/Industrial	40	39	19	14	0
Electric Generation	327	313	316	299	269
Non-Utility Served Load (1)	995	979	1,006	1,025	1,147
Statewide Requirements Total (3)	**5,021**	**4,940**	**4,926**	**4,874**	**4,857**

Notes:
(1) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant
Source: CEC staff-provided forecast results from their own model simulations.
(2) Includes utility generation, wholesale generation, and cogeneration.
(3) The difference between California supply sources and California requirements is PG&E's forecast of off system deliveries.

TABLE 4 – STATEWIDE TOTAL SUPPLY SOURCES-TAKEN
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR
(MMcf/d)
2022-2035

Utility	**2022**	**2023**	**2024**	**2025**	**2026**
Northern California					
California Sources (1)	56	56	56	56	56
Out-of-State	2,049	2,054	2,043	2,038	2,063
Northern California Total	2,105	2,110	2,099	2,094	2,119
Southern California					
California Sources (2)	61	61	61	61	61
Out-of-State	2,379	2,354	2,266	2,219	2,190
Southern California Total	2,440	2,415	2,327	2,280	2,251
Utility Total	4,545	4,525	4,427	4,374	4,369
Non-Utility Served Load (3)	1,024	1,010	990	995	999
Statewide Supply Sources Total	**5,570**	**5,535**	**5,416**	**5,368**	**5,369**

Utility	**2027**	**2028**	**2029**	**2030**	**2035**
Northern California					
California Sources (1)	56	56	56	56	56
Out-of-State	1,749	1,738	1,722	1,698	1,681
Northern California Total	1,805	1,794	1,778	1,754	1,737
Southern California					
California Sources (2)	61	61	61	61	61
Out-of-State	2,160	2,106	2,080	2,034	1,912
Southern California Total	2,221	2,167	2,141	2,095	1,973
Utility Total	4,026	3,961	3,919	3,848	3,711
Non-Utility Served Load (3)	995	979	1,006	1,025	1,147
Statewide Supply Sources Total	**5,021**	**4,940**	**4,926**	**4,874**	**4,857**

Notes:
(1) Includes utility purchases and exchange/transport gas.
(2) Includes utility purchases and exchange/transport gas and City of Long Beach "own-source" gas.
(3) Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.

Source: CEC staff-provided forecast results from their own model simulations.

TABLE 5 – STATEWIDE ANNUAL GAS REQUIREMENTS [1]
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR
(MMcf/d)
2022-2026

	2022	**2023**	**2024**	**2025**	**2026**
Utility					
Northern California					
Residential	491	473	460	445	432
Commercial - Core	208	214	213	210	208
Natural Gas Vehicles - Core	7	7	8	8	8
Natural Gas Vehicles - Noncore	4	4	4	4	4
Industrial - Noncore	462	477	492	497	498
Wholesale	9	9	9	9	9
SMUD Electric Generation	96	96	96	96	96
Electric Generation [2]	484	448	441	442	481
Exchange (California)	38	38	38	38	38
Company Use and Unaccounted-for	34	34	34	34	34
Northern California Total [3]	1,833	1,800	1,794	1,784	1,809
Southern California					
Residential	610	604	594	585	575
Commercial - Core	206	200	194	190	185
Commercial - Noncore	48	49	49	49	49
Natural Gas Vehicles - Core	41	42	43	44	45
Industrial - Core	54	54	53	52	51
Industrial - Noncore	389	390	389	389	388
Wholesale (excluding EG)	236	236	235	235	234
SDG&E, Vernon & Ecogas EG	127	117	104	97	97
Electric Generation (EG) [4]	670	667	612	584	571
Enhanced Oil Recovery Steaming	27	27	27	27	27
Company Use and Unaccounted-for	31	30	29	29	28
Southern California Total	2,440	2,415	2,327	2,280	2,251
Utility Total	4,273	4,215	4,122	4,064	4,059
Non-Utility Served Load [5]	1,024	1,010	990	995	999
Statewide Gas Requirements Total [6]	**5,298**	**5,225**	**5,111**	**5,058**	**5,059**

Notes:
(1) Includes transportation gas.
(2) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.
(3) Northern California Total excludes Off-System Deliveries to Southern California.
(4) Southern California Electric Generation includes commercial and industrial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.
(5) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(6) Does not include off-system deliveries.

TABLE 6 – STATEWIDE ANNUAL GAS REQUIREMENTS [1]
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR
(MMcf/d)
2027-2035

	2027	2028	2029	2030	2035
Utility					
Northern California					
Residential	423	412	402	391	338
Commercial - Core	205	200	195	189	163
Natural Gas Vehicles - Core	8	8	9	9	10
Natural Gas Vehicles - Noncore	4	5	5	5	5
Industrial - Noncore	499	499	499	498	496
Wholesale	9	9	9	9	9
SMUD Electric Generation	96	96	96	96	96
Electric Generation [2]	489	493	493	486	549
Exchange (California)	38	38	38	38	38
Company Use and Unaccounted-for	33	33	33	33	33
Northern California Total [3]	1,805	1,794	1,778	1,754	1,737
Southern California					
Residential	565	552	542	530	466
Commercial - Core	181	177	174	170	155
Commercial - Noncore	49	49	49	49	48
Natural Gas Vehicles - Core	46	47	48	50	54
Industrial - Core	50	49	48	47	44
Industrial - Noncore	388	388	388	387	385
Wholesale (excluding EG)	234	233	232	231	228
SDG&E, Vernon & Ecogas EG	96	92	92	88	87
Electric Generation (EG) [4]	558	529	516	493	461
Enhanced Oil Recovery Steaming	26	25	24	24	20
Company Use and Unaccounted-for	28	27	27	26	25
Southern California Total	2,221	2,167	2,141	2,095	1,973
Utility Total	4,026	3,961	3,919	3,848	3,711
Non-Utility Served Load [5]	995	979	1,006	1,025	1,147
Statewide Gas Requirements Total [6]	**5,021**	**4,940**	**4,926**	**4,874**	**4,857**

Notes:
(1) Includes transportation gas.
(2) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.
(3) Northern California Total excludes Off-System Deliveries to Southern California.
(4) Southern California Electric Generation includes commercial and industrial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.
(5) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR
Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(6) Does not include off-system deliveries.

TABLE 7 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS COLD TEMPERATURE (4) AND DRY HYDRO YEAR (MMcf/d) 2022-2026

	2022	2023	2024	2025	2026
California's Supply Sources					
Utility					
California Sources	117	117	117	117	117
Out-of-State	4,561	4,581	4,487	4,438	4,443
Utility Total	4,678	4,698	4,604	4,555	4,560
Non-Utility Served Load (1)	1,159	1,144	1,130	1,129	1,152
Statewide Supply Sources Total	**5,837**	**5,842**	**5,734**	**5,684**	**5,713**
California's Requirements					
Utility					
Residential	1,186	1,165	1,142	1,118	1,094
Commercial	488	481	473	467	460
Natural Gas Vehicles	52	53	54	55	57
Industrial	911	924	935	940	939
Electric Generation (2)	1,378	1,374	1,307	1,278	1,315
Enhanced Oil Recovery Steaming	27	27	27	27	27
Wholesale/International+Exchange	297	297	295	295	295
Company Use and Unaccounted-for	67	67	66	65	64
Utility Total	4,406	4,388	4,299	4,245	4,250
Non-Utility					
Enhanced Oil Recovery Steaming	639	635	638	629	628
EOR Cogeneration/Industrial	48	50	50	50	41
Electric Generation	472	460	442	450	484
Non-Utility Served Load (1)	1,159	1,144	1,130	1,129	1,152
Statewide Requirements Total (3)	**5,565**	**5,532**	**5,429**	**5,374**	**5,403**

Notes:

(1) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.

(2) Includes utility generation, wholesale generation, and cogeneration.

(3) The difference between California supply sources and California requirements is PG&E's forecast of off-system deliveries.

(4) 1-in-35 cold year temperature for SoCalGas; 1-in-10 cold year temperature for PG&E.

TABLE 8 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
COLD TEMPERATURE (4) AND DRY HYDRO YEAR
(MMcf/d)
2027-2035

	2027	2028	2029	2030	2035
California's Supply Sources					
Utility					
California Sources	117	117	117	117	117
Out-of-State	4,116	4,043	4,000	3,925	3,792
Utility Total	4,233	4,160	4,117	4,042	3,909
Non-Utility Served Load (1)	1,143	1,147	1,209	1,204	1,077
Statewide Supply Sources Total	**5,376**	**5,307**	**5,326**	**5,246**	**4,987**
California's Requirements					
Utility					
Residential	1,073	1,049	1,028	1,004	884
Commercial	453	443	434	425	382
Natural Gas Vehicles	58	60	61	63	70
Industrial	939	938	937	935	927
Electric Generation (2)	1,326	1,290	1,277	1,239	1,279
Enhanced Oil Recovery Steaming	26	25	24	24	20
Wholesale/International+Exchange	294	293	293	292	288
Company Use and Unaccounted-for	64	63	62	62	60
Utility Total	4,233	4,160	4,117	4,042	3,909
Non-Utility					
Enhanced Oil Recovery Steaming	625	627	719	756	906
EOR Cogeneration/Industrial	37	37	21	17	6
Electric Generation	481	483	470	431	165
Non-Utility Served Load (1)	1,143	1,147	1,209	1,204	1,077
Statewide Requirements Total (3)	**5,376**	**5,307**	**5,326**	**5,246**	**4,987**

Notes:
(1) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR
Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(2) Includes utility generation, wholesale generation, and cogeneration.
(3) The difference between California supply sources and California requirements is PG&E's forecast of
off-system deliveries.
(4) 1-in-35 cold year temperature for SoCalGas; 1-in-10 cold year temperature for PG&E.

TABLE 9 – STATEWIDE TOTAL SUPPLY SOURCES-TAKEN
COLD TEMPERATURE (4) and DRY HYDRO YEAR
(MMcf/d)
2022-2026

Utility	**2022**	**2023**	**2024**	**2025**	**2026**
Northern California					
California Sources (1)	56	56	56	56	56
Out-of-State	2,109	2,149	2,144	2,141	2,177
Northern California Total	2,165	2,205	2,200	2,197	2,233
Southern California					
California Sources (2)	61	61	61	61	61
Out-of-State	2,452	2,432	2,343	2,298	2,267
Southern California Total	2,513	2,493	2,404	2,359	2,328
Utility Total	4,678	4,698	4,604	4,555	4,560
Non-Utility Served Load (3)	1,159	1,144	1,130	1,129	1,152
Statewide Supply Sources Total	**5,837**	**5,842**	**5,734**	**5,684**	**5,713**

Utility	**2027**	**2028**	**2029**	**2030**	**2035**
Northern California					
California Sources (1)	56	56	56	56	56
Out-of-State	1,876	1,863	1,844	1,821	1,800
Northern California Total	1,932	1,919	1,900	1,877	1,856
Southern California					
California Sources (2)	61	61	61	61	61
Out-of-State	2,239	2,180	2,156	2,104	1,992
Southern California Total	2,300	2,241	2,217	2,165	2,053
Utility Total	4,233	4,160	4,117	4,042	3,909
Non-Utility Served Load (3)	1,143	1,147	1,209	1,204	1,077
Statewide Supply Sources Total	**5,376**	**5,307**	**5,326**	**5,246**	**4,987**

Notes:
(1) Includes utility purchases and exchange/transport gas.
(2) Includes utility purchases and exchange/transport gas and City of Long Beach "own-source" gas.
(3) Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant. Source: CEC staff-provided forecast results from their own model simulations.
(4) 1-in-35 cold year temperature for SoCalGas; 1-in-10 cold year temperature for PG&E.

TABLE 10 – STATEWIDE ANNUAL GAS REQUIREMENTS [1]
COLD TEMPERATURE [7] and DRY HYDRO YEAR
(MMcf/d)
2022-2026

	2022	2023	2024	2025	2026
Utility					
Northern California					
Residential	527	512	500	485	472
Commercial - Core	224	224	222	220	217
Natural Gas Vehicles - Core	7	7	8	8	8
Natural Gas Vehicles - Noncore	3	4	4	4	4
Industrial - Noncore	467	480	493	499	499
Wholesale	10	10	10	10	10
SMUD Electric Generation	96	96	96	96	96
Electric Generation (2)	485	490	490	493	543
Exchange (California)	38	38	38	38	38
Company Use and Unaccounted-for	36	35	35	35	35
Northern California Total (3)	1,893	1,895	1,895	1,887	1,923
Southern California					
Residential	660	653	642	632	622
Commercial - Core	214	208	202	197	193
Commercial - Noncore	49	49	49	50	50
Natural Gas Vehicles - Core	41	42	43	44	45
Industrial - Core	55	55	53	52	51
Industrial - Noncore	389	390	389	389	388
Wholesale (excluding EG)	249	249	248	248	247
SDG&E, Vernon & Ecogas EG	127	118	105	98	98
Electric Generation (EG) (4)	670	671	616	591	578
Enhanced Oil Recovery Steaming	27	27	27	27	27
Company Use and Unaccounted-for	32	31	30	30	29
Southern California Total	2,513	2,493	2,404	2,359	2,328
Utility Total	4,406	4,388	4,299	4,245	4,250
Non-Utility Served Load (5)	1,159	1,144	1,130	1,129	1,152
Statewide Gas Requirements Total (6)	**5,565**	**5,532**	**5,429**	**5,374**	**5,403**

(1) Includes transportation gas.
(2) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.
(3) Northern California Total excludes Off-System Deliveries to Southern California.
(4) Southern California Electric Generation includes commercial and industrial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.
(5) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(6) Does not include off-system deliveries.
(7) 1-in-35 cold year temperature for SoCalGas; 1-in-10 cold year temperature for PG&E.

TABLE 11 – STATEWIDE ANNUAL GAS REQUIREMENTS (1)
COLD TEMPERATURE (7) AND DRY HYDRO YEAR
(MMcf/d)
2025-2035

	2027	2028	2029	2030	2035
Utility					
Northern California					
Residential	463	452	441	431	378
Commercial - Core	214	209	204	199	172
Natural Gas Vehicles - Core	8	8	9	9	10
Natural Gas Vehicles - Noncore	4	4	4	4	5
Industrial - Noncore	500	500	500	500	497
Wholesale	10	9	9	9	9
SMUD Electric Generation	96	96	96	96	96
Electric Generation (2)	565	567	564	557	616
Exchange (California)	38	38	38	38	38
Company Use and Unaccounted-for	35	35	34	34	35
Northern California Total (3)	1,932	1,919	1,900	1,877	1,856
Southern California					
Residential	610	597	586	573	506
Commercial - Core	189	184	181	177	161
Commercial - Noncore	50	49	49	49	49
Natural Gas Vehicles - Core	46	47	48	50	54
Industrial - Core	51	50	49	48	45
Industrial - Noncore	388	388	388	387	385
Wholesale (excluding EG)	247	246	245	244	241
SDG&E, Vernon & Ecogas EG	98	93	94	89	92
Electric Generation (EG) (4)	567	534	524	496	474
Enhanced Oil Recovery Steaming	26	25	24	24	20
Company Use and Unaccounted-for	29	28	28	27	26
Southern California Total	2,300	2,241	2,217	2,165	2,053
Utility Total	4,233	4,160	4,117	4,042	3,909
Non-Utility Served Load (5)	1,143	1,147	1,209	1,204	1,077
Statewide Gas Requirements Total (6)	**5,376**	**5,307**	**5,326**	**5,246**	**4,987**

(1) Includes transportation gas.
(2) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.
(3) Northern California Total excludes Off-System Deliveries to Southern California.
(4) Southern California Electric Generation includes commercial and industrial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.
(5) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(6) Does not include off-system deliveries.
(7) 1-in-35 cold year temperature for SoCalGas; 1-in-10 cold year temperature for PG&E.

EXECUTIVE SUMMARY

STATEWIDE RECORDED SOURCES AND DISPOSITION

The Statewide Sources and Disposition Summary complements the existing 5-year recorded data tables included in the tabular data sections for each utility.

The information displayed in the following tables shows the composition of supplies from both out-of-state sources, as well as California sources. The data are based on the utilities' accounting records and available gas nomination and preliminary gas transaction information obtained daily from customers or their appointed agents and representatives. It should be noted that data on daily gas nominations are frequently subject to reconciliation adjustments. In addition, some of the data are based on allocations and assignments that, by necessity, rely on estimated information. These tables have been updated to reflect the most current information.

Some columns may not sum exactly because of factored allocation and rounding differences and do not imply curtailments.

TABLE 12– RECORDED 2017 STATEWIDE SOURCES AND DISPOSITION SUMMARY (MMcf/d)

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave	Other (1)	Ruby	Total
Southern California Gas Company									
Core + UAF (2)	100	443	127	54	208	0	(27)	0	905
Noncore Commercial/Industrial	(4)	97	80	39	158	52	24	0	446
EG (3)	(4)	156	128	63	252	82	39	0	715
EOR	(0)	9	7	3	14	5	2	0	39
Wholesale/Resale/International (4)	(7)	88	72	35	142	46	22	0	398
Total	84	792	414	195	773	185	60	0	2,503
Pacific Gas and Electric Company (5)									
Core	0	18	65	319	(1)	0	0	179	580
Noncore Industrial/Wholesale/EG (6)	29	208	99	840	34	0	12	420	1,642
Total	29	226	164	1,159	33	0	12	599	2,222
Other Northern California									
Core (7)	22	0	0	0	0	0	12	0	34
Non-Utilities Served Load (8,9)									
Direct Sales/Bypass	698	28	0	0	698	44	0	0	1,468
TOTAL SUPPLIER	833	1,046	578	1,354	1,504	229	84	599	6,227
San Diego Gas & Electric Company									
Core	14	61	17	7	28	0	(4)	0	124
Noncore Commercial/Industrial	(2)	38	31	15	62	20	10	0	175
Total	12	99	49	23	90	20	6	0	299
Southwest Gas Corporation									
Core	22	0	0	0	0	0	12	0	34
Noncore Commercial/Industrial	2	0	0	0	0	0	0	0	2
Total	24	0	0	0	0	0	12	0	36

Notes:

(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.
(2) Includes NGV volumes
(3) EG includes UEG, COGEN, and EOR Cogen.
(4) Includes transportation to City of Long Beach, Southwest Gas, City of Vernon, DGN, and SDG&E, as shown.
(5) Kern River supplies include net volume flowing over Kern River High Desert interconnect.
(6) Includes UEG, COGEN, industrial and deliveries to PG&E's wholesale customers.
(7) Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(8) Deliveries to end-users by non-CPUC jurisdictional pipelines.
(9) California production is preliminary.

TABLE 13 – RECORDED 2018 STATEWIDE SOURCES AND DISPOSITION SUMMARY
(MMcf/d)

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave	Other (1)	Ruby	Total
Southern California Gas Company									
Core + UAF (2)	158	439	103	37	173	0	(2)	0	908
Noncore Commercial/Industrial	(17)	99	35	57	207	61	7	0	448
EG (3)	(23)	136	48	78	283	83	10	0	615
EOR	(1)	8	3	5	18	5	1	0	38
Wholesale/Resale/International (4)	(13)	74	26	42	153	45	6	0	333
Total	104	756	214	218	834	194	22	0	2,342
Pacific Gas and Electric Company (5)									
Core	0	3	55	303	(4)	0	0	165	522
Noncore Industrial/Wholesale/EG (6)	28	212	221	966	16	0	0	355	1,798
Total	28	215	276	1,269	12	0	0	520	2,320
Other Northern California									
Core (7)	22	0	0	0	0	0	12	0	34
Non-Utilities Served Load (8,9)									
Direct Sales/Bypass	401	49	0	0	686	42	0	0	1,178
TOTAL SUPPLIER	555	1,020	490	1,487	1,532	236	34	520	5,874
San Diego Gas & Electric Company									
Core	22	61	14	5	24	0	(0)	0	127
Noncore Commercial/Industrial	(4)	25	9	14	52	15	2	0	112
Total	18	86	23	19	76	15	2	0	239
Southwest Gas Corporation									
Core	22	0	0	0	0	0	12	0	34
Noncore Commercial/Industrial	2	0	0	0	0	0	0	0	2
Total	24	0	0	0	0	0	12	0	36

Notes:

(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.
(2) Includes NGV volumes
(3) EG includes UEG, COGEN, and EOR Cogen.
(4) Includes transportation to City of Long Beach, Southwest Gas, City of Vernon, DGN, and SDG&E, as shown.
(5) Kern River supplies include net volume flowing over Kern River High Desert interconnect.
(6) Includes UEG, COGEN, industrial and deliveries to PG&E's wholesale customers.
(7) Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(8) Deliveries to end-users by non-CPUC jurisdictional pipelines.
(9) California production is preliminary.

TABLE 14 – RECORDED 2019 STATEWIDE SOURCES AND DISPOSITION SUMMARY (MMcf/d)

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave	Other (1)	Ruby	Total
Southern California Gas Company (2)									
Core + UAF (3)	162	476	111	30	223	0	10	0	1,012
Wholesale/Resale/International (5)	(65)	368	47	118	674	213	19	0	1,374
Total	97	844	158	148	897	213	29	0	2,386
Pacific Gas and Electric Company (4)									
Core	0	0	58	286	(2)	0	0	172	514
Noncore Industrial/Wholesale/EG (5)	24	380	223	896	9	0	0	481	2,014
Total	24	380	281	1,182	7	0	0	653	2,528
Other Northern California									
Core (6)	22	0	0	0	0	0	12	0	34
Non-Utilities Served Load (7, 8)									
Direct Sales/Bypass	388	29	0	0	664	71	0	0	1,152
TOTAL SUPPLIER	531	1,253	439	1,330	1,568	284	41	653	6,100
San Diego Gas & Electric Company									
Core	21	61	14	4	28	0	1	0	129
Noncore Commercial/Industrial	(4)	22	3	7	40	12	1	0	81
Total	17	83	17	11	68	12	2	0	210
Southwest Gas Corporation									
Core	25	0	0	0	0	0	0	0	25
Noncore Commercial/Industrial	3	0	0	0	0	0	0	0	3
Total	28	0	0	0	0	0	0	0	28

Notes:

(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.
(2) SoCalGas core volumes are accrued volumes.
(3) Includes NGV volumes
(4) Kern River supplies include net volume flowing over Kern River High Desert interconnect.
(5) Includes UEG, COGEN, industrial and deliveries to PG&E's wholesale customers.
(6) Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(7) Deliveries to end-users by non-CPUC jurisdictional pipelines.
(8) California production is preliminary.

TABLE 15 – RECORDED 2020 STATEWIDE SOURCES AND DISPOSITION SUMMARY (MMcf/d)

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave	Other (1)	Ruby	Total
Southern California Gas Company (2)									
Core + UAF (3)	132	406	151	9	245	0	0	0	943
Noncore	(45)	532	64	169	613	139	38	0	1,510
Total	87	938	215	178	858	139	38	0	2,453
Pacific Gas and Electric Company (4)									
Core	0	8	33	379	(7)	0	0	165	578
Noncore Industrial/Wholesale/EG (5)	26	294	214	936	9	0	0	411	1,890
Total	26	302	247	1,315	2	0	0	576	2,468
Other Northern California									
Core (6)	14	0	0	0	0	0	0	0	14
Non-Utilities Served Load (7,8)									
Direct Sales/Bypass	334	37	0	0	621	60	0	0	1,052
TOTAL SUPPLIER	461	1,277	462	1,493	1,481	199	38	576	5,987
San Diego Gas & Electric Company									
Core	18	56	21	1	34	0	0	0	131
Noncore Commercial/Industrial	(4)	49	6	15	56	13	3	0	138
Total	14	105	27	16	90	13	3	0	269
Southwest Gas Corporation - Southern California Division									
Core	25.4	0	0	0	0	0	0	0	25
Noncore Commercial/Industrial	2.0	0	0	0	0	0	0	0	2
Total	27.4	0	0	0	0	0	0	0	27

Notes:

(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.
(2) SoCalGas core volumes are accrued volumes.
(3) Includes NGV volumes
(4) Kern River supplies include net volume flowing over Kern River High Desert interconnect.
(5) Includes UEG, COGEN, industrial and deliveries to PG&E's wholesale customers.
(6) Includes Southwest Gas Coproration and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(7) Deliveries to end-users by non-CPUC jurisdictional pipelines.
(8) California production is preliminary.

TABLE 16 – RECORDED 2021 STATEWIDE SOURCES AND DISPOSITION SUMMARY (MMcf/d)

	California Sources	El Paso	Trans western	PG&E/GTN	Kern River	Mojave	Other (1)	Ruby	Total
Southern California Gas Company									
Core + UAF (2)	132	406	151	9	245	0	0	0	943
Noncore Commercial/Industrial/EG/EOR/Wholesale/Resale/International	-46	432	206	217	583	85	3	0	1,480
Total	86	838	357	226	828	85	3	0	2,423
Pacific Gas and Electric Company (5)									
Core	0	29	0	410	-2	0	0	159	597
Noncore Industrial/Wholesale/EG (6)	23	356	186	942	6	0	0	32	1,840
Total	23	386	186	1,352	4	0	0	485	2,437
Other Northern California									
Core (7)	13	0	0	0	0	0	0	0	13
Non-Utilities Served Load (8,9)									
Direct Sales/Bypass	295	49	0	0	631	42	0	0	1,017
TOTAL SUPPLIER	417	1,273	543	1,578	1,463	127	3	485	5,890

Notes:
(1) Includes storage activities, volumes delivered on North Baja and Questar Southern Trails for SoCalGas and PG&E.
(2) Includes NGV volumes
(3) EG includes UEG, COGEN, and EOR Cogen.
(4) Includes transportation to City of Long Beach, Southwest Gas, City of Vernon, DGN, & SDG&E, as shown.

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave	Other (1)	Ruby	Total
San Diego Gas & Electric Company									
Core	19	59	22	1	36	0	0	0	137
Noncore Commercial/Industrial	-4	37	18	19	50	7	0	0	128
Total	15	91	40	20	86	7	0	0	265
SouthWest Gas									
Core	24	0	0	0	0	0	13.00	0.000	37.00
Noncore Commercial/Industrial	2	0	0	0	0	0	0.17	0.000	2.17
Total	26	0	0	0	0	0	13.17	0.000	39.17

Notes

(1) **Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.**
(2) **SoCalGas core volumes are accrued volumes.**
(3) **Includes NGV volumes.**
(4) **Kern River supplies include net volume flowing over Kern River High Desert interconnect.**
(5) Includes UEG, Cogen, industrial load and deliveries to PG&E's wholesale customers.
(6) Includes Great Basin Gas Transmission Company and Tuscarora Deliveries in the Lake Tahoe and Susanville areas.
(7) Deliveries to end-users by non-CPUC jurisdictional pipelines.
(8) California production is preliminary.

STATEWIDE RECORDED HIGHEST SENDOUT

The tables below summarize the highest sendout days by the state in the summer and winter periods from the last 5 years. Daily sendout from SoCalGas, PG&E, and from customers not served by these utilities were used to construct the following tables.

Table 17: Estimated California Highest *SUMMER* Sendout (MMcf/d)

Year	Date	PG&E (1)	SoCal Gas (2)	Utility Total (4)	Non-Utility (3)	State Total
2017	08/28/2017	2,602	3,484	6,086	1,416	7,502
2018	07/24/2018	2,925	2,926	5,851	1,410	7,261
2019	09/04/2019	2,606	2,907	5,7513	1,310	6,823
2020	08/18/2020	2,792	3,143	5,935	1,270	7,205
2021	09/09/2021	2,909	2,827	5,736	1,080	6,816

Table 18: Estimated California Highest *WINTER* Sendout (MMcf/d)

Year	Date	PG&E (1)	SoCal Gas (2)	Utility Total (4)	Non-Utility (3)	State Total
2017	12/21/2017	3,665	3,456	7,121	1,259	8,380
2018	02/20/2018	3,527	3,621	7,148	1,378	8,526
2019	02/05/2019	3,751	3,913	7,664	1,097	8,761
2020	02/04/2020	3,230	3,881	7,111	1,261	8,372
2021	12/14/2021	3,470	3,837	7,307	935	8,242

Notes:
(1) PG&E Pipe Ranger.
(2) SoCalGas Envoy.
(3) Source: Provided by the CEC. Data are from DOGGR, Monthly Oil and Gas Production and Injection Report. Nonutility Demand equals Kern-Mojave and California monthly average total flows less PG&E and SoCal Gas peak day supply from Kern-Mojave and California in-state production.

(4) PG&E and SoCalGas sendout(s) are reported for the day on which the *combined* two utilities' total sendout is maximum for the respective seasons each year. For each calendar year, Winter months are Jan, Feb, Mar, Nov and Dec; while Summer months are Apr, May, Jun, Jul, Aug, Sep and Oct.

2022 CALIFORNIA GAS REPORT

NORTHERN CALIFORNIA

INTRODUCTION

PG&E owns and operates an integrated natural gas transmission, underground storage, and distribution system across most of Northern and Central California. As of December 31, 2021, PG&E's natural gas system consists of approximately 42,000 miles of distribution pipelines, over 6,400 miles of backbone and local transmission pipelines, and three fully owned underground storage facilities and a 25 percent interest in Gill Ranch Storage. PG&E uses its backbone transmission system, composed primarily of Lines 300A, 300B, 400, and 401, to transport gas from its interconnection with interstate pipelines, other local distribution companies, and California gas fields to PG&E's local transmission and distribution systems.

PG&E provides natural gas procurement, transportation, and storage services to approximately 4.3 million residential customers and over 200,000 commercial and industrial customers. PG&E also provides gas transportation and storage services to a variety of gas-fired Electric Generation (EG) plants in its service area and serves multiple Natural Gas Vehicle (NGV) fleets, including utility owned facilities, with its publicly-accessible fueling stations throughout California. Other wholesale distribution systems, which receive gas transportation service from PG&E, serve a small portion of the gas customers in the region. PG&E's customers are located in 37 counties from southeast of Bakersfield to north of Redding, with high concentrations in the San Francisco Bay Area and the Sacramento and San Joaquin valleys. In addition, some customers, including other regulated utilities, also utilize the PG&E system to meet their gas needs in Southern California.

The Northern California section of this report includes PG&E's gas demand forecast and discussions on gas supply, pipeline capacity, storage, and related policies, as well as the natural gas regulatory environment, including legislative developments and regulatory proceedings. Finally, the report includes PG&E's forecast of supply and demand for an Abnormal Peak Day (APD) and demand for a 1-in-10 Peak Day during the winter and summer. What follows is a summary of key takeaways from the Northern California sections of this report.

PG&E Forecasts a Gradual Decline in Future Gas Demand: PG&E's average year demand is forecasted to decline at an annual average rate of 0.5 percent between 2022 and 2035. The decline in forecasted gas demand is in response to the state's decarbonization policies and reflects reduced demand due to energy efficiency, building electrification resulting from fuel switching from natural gas appliances to electric, and climate change.

The Forecasted Demand is Subject to Significant Uncertainties: Forecast uncertainties are significant including the impacts from Northern and Southern California gas price differentials, impact of climate change on forecasted gas and electric load and hydroelectric generation, planned electric generation buildout, and the level of building electrification.

PG&E is Taking Actions to Evolve the Natural Gas System to be an Affordable Energy Delivery Platform Consistent with Decarbonization Goals. PG&E's work is guided by the following four pillars:

1. Reduce the carbon footprint of the gas system by greening the gas supply, leveraging electrification, facility conversion from dirtier fuel sources, efficiency, and methane abatement.

2. Decrease costs by limiting system expansion, strategically reducing capital and operational expenses, strategically pruning the gas system, and focusing on targeted and zonal electrification.

3. Identify alternative revenue sources through opportunities to 1) convert dirtier fuel sources to cleaner natural gas through investment in compressed natural gas, 2) switch facilities (including backup generation) from dirtier fuel sources, and 3) invest in the rail and marine sectors.

4. Leverage innovative financial mechanisms such as changes to depreciation, rate design, and external funding to help close the gap between costs and revenues.

Policy and Regulatory Solutions and a Managed Transition Plan Are Needed to Keep Customers' Bills Affordable. PG&E is committed to working with regulators and other stakeholders to support statewide GHG reduction policies and develop options to minimize customer bill impacts. PG&E is doing this by safely reducing costs and maximizing utilization of existing infrastructure. In order to successfully implement the State's environmental goals, issues such as obligation to serve, treatment of capital versus expense dollars, and non-traditional funding need to be addressed and resolved.

Regulatory bodies and investor-owned utilities (IOU) should work together to ensure that Californians continue to have access to clean, reliable, and affordable energy. In support of these important goals, PG&E is actively participating in the Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning (Gas System Planning OIR) (R.20-01-007), which addresses crucial topics that will impact the future of the California gas system.

PG&E is accelerating its work on the use of Renewable Natural Gas (RNG) to contribute towards access to clean, reliable, and affordable energy. The current investment and incentives for Renewable Natural Gas (RNG) principally favor the transportation sector resulting in little RNG available to comply with the recently enacted Renewable Gas Standard (RGS). If this is to change, California will have to balance the funding mechanisms between the transportation sector and the RGS so that RNG project developers have opportunities to supply RNG towards the RGS or the transportation sector.

GAS DEMAND

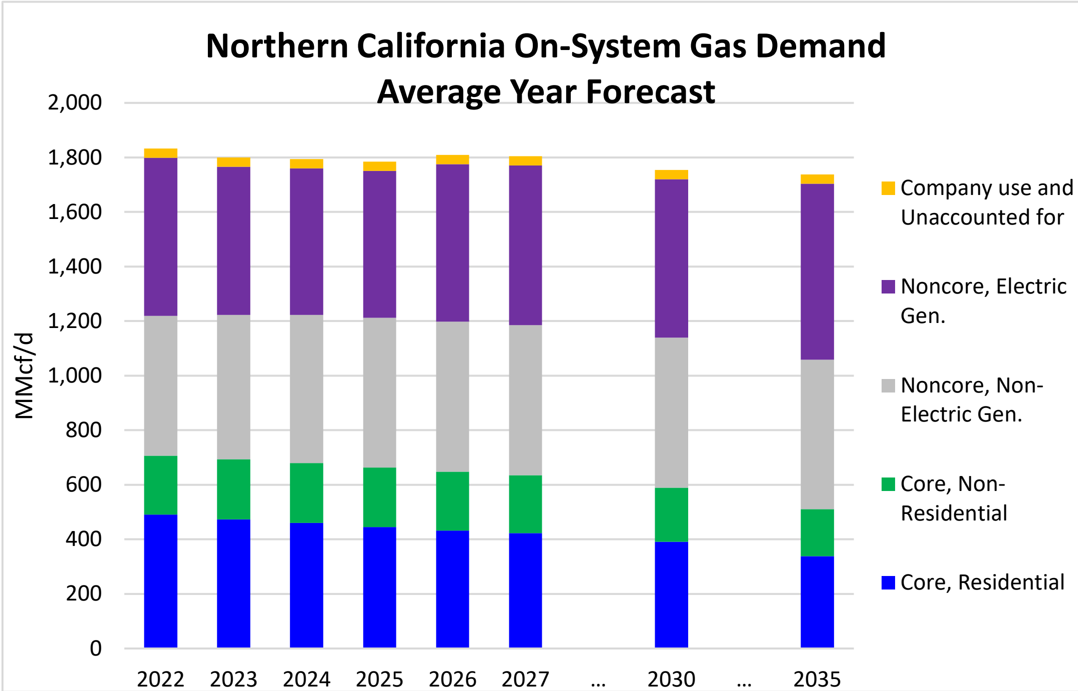
OVERVIEW

PG&E's 2022 CGR Average Year (also known as Average Temperature and Normal Hydro Year) demand forecast projects total on-system demand to decline at an annual average rate of 0.5 percent between 2022 and 2035. The core sectors are forecasted to decline at an average annual rate of 2.5 percent. The noncore sectors increase at a rate of 0.6 percent annually, driven in part by an increase in throughput for electric generation.

This projected decline in total demand could result in gas system operating and maintenance costs allocated over lower usage, causing customer gas rates to increase. Consequently, PG&E and statewide utility stakeholders will need to continue their work to mitigate customer rate increases. In future, additional gas throughput could come from the substitution of higher carbon intensive fuels, such as high sulfur marine shipping fuels, to help allocate transmission costs over a larger customer base.

This chapter includes PG&E's gas demand forecast and begins with a description of the forecast method, including a discussion of important assumptions. After the methodology discussion, the report presents information on the average demand forecast by customer sector. To provide more information about gas throughput under stressed conditions, the Cold Temperature and Dry Hydro Year forecast presents demand under cold temperature and dry hydroelectric conditions. This is followed by a discussion of gas demand policies, trends, and impacts. The chapter concludes with a presentation of abnormal peak day demand.

FIGURE 9



Changes in the major components of on-system gas demand are illustrated in Figure 9 above. Core demand declines, driven by increasing energy efficiency, increasing building electrification, and a warming climate. Noncore, non-EG demand is forecasted to remain largely flat over the forecast horizon, as potential demand growth is partly limited by energy efficiency and increasing gas prices. The Noncore EG demand forecast increases from 2022 to 2035.

The EG demand forecast is largely a function of electric energy demand, the future CAISO generation portfolio, transmission constraints, and gas prices. PG&E's forecast incorporates the higher levels of renewable generation and electric storage from the 2021 California Public Utilities Commission Integrated Resource Plan[10] and reflects higher burner-tip gas prices for Northern California electric generators relative to Southern California. The forecast for gas demand by electric generators[11] and co-generators in Northern California[12] increases at 0.9

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[10] https://www.cpuc.ca.gov/irp/.

[11] This gas demand forecast excludes gas delivered by non-utility pipelines to electric generators and cogenerators in PG&E's service area, such as deliveries by the Kern/Mojave pipelines to the La Paloma and Sunrise plants in Central California.

[12] Northern California electric generation gas demand consists of the generation fleet north of Path 26.

percent per year from 2022 through 2035[13]. The increase is driven in part by Northern California electric reliability needs due to transmission constraints in some hours.

FORECAST METHOD AND ASSUMPTIONS

PG&E's gas demand forecasts for the residential, commercial, and industrial sectors are developed using econometric models as the foundation. These models are then modified to incorporate assumptions around future policy formation and technology adoption. Forecasts for NGVs and wholesale customers are developed based on market information and historical trends over the past five years. To address the impact of COVID, PG&E developed a simplified approach. The first order COVID impacts are assumed to occur between March 2020 and ramping down after the introduction of vaccines to mid-2023, after which COVID effects are considered to be subsumed into economic and population variables. This general profile is consistent with estimates and discussion from our economic forecasting data source, Moody's. This dummy variable[14] approach models the increases in residential load and the decreases in commercial load which are then ramped down to zero in mid-2023. Effects beyond that time period are limited to those explicitly produced by economic and population variables or reflected in the historical time series apart from a simple dummy variable. Such a simplified approach is necessitated by the very limited amount of historical data from the COVID time period as well as the idiosyncratic nature of the COVID response over location and time. The simplified approach could introduce uncertainty on the duration and scale of impacts from COVID.

Forecasts of gas demand by power plants are developed by modeling the electricity market in the Western Electricity Coordinating Council (WECC) using PLEXOS software. PLEXOS is a production cost modeling tool that estimates the consumption of all fuels used for power generation on an economic basis. The tool determines the least cost dispatch of generating resources to meet a given power demand.

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[13] EG demand forecast uses common modeling assumptions developed jointly by the IOUs. Since the forecast is dependent on several factors including gas price differential between northern and southern California, future resource additions and retirements, and hydro-electric generation, actual EG demand in future may vary from the forecast.

[14] A dummy variable is a variable that takes on the values 1 and 0; 1 means something is true. https://www.stata.com/support/faqs/data-management/creating-dummy-variables/.

While variation in short-term gas use depends mainly on prevailing weather conditions and gas prices, longer term projections in gas demand are driven primarily by changes in:

- Customer usage patterns influenced by underlying economic, demographic, and technological changes, such as growth in population and employment;
- Forecasted prices;
- Growth in electricity demand;
- Growth of renewable generation;
- Efficiency profiles of residential and commercial buildings and the appliances within them; and
- Impacts from climate change.

TEMPERATURE ASSUMPTIONS

Space heating accounts for a high percentage of use. Therefore, gas requirements for PG&E's residential and commercial customers are sensitive to prevailing temperature conditions. PG&E's Average Year demand forecast assumes that temperatures in the forecast period will be equivalent to the average of observed temperatures during the past 19 years, with the addition of a temperature adjustment for climate change. Adding the climate change adjustment has little impact to the temperature assumptions in the early years of the forecast; however, the later years begin to show the effects of a warming climate. For example, by 2035 the total December/January heating degree days (HDD) are projected to be 16 percent lower than the 19-year average, reducing core throughput by approximately 6 percent.

Actual temperatures in the forecast period will be higher or lower than the assumption including climate change. Temperature variation impacts gas use. PG&E's Cold, Dry Hydro demand forecast assumes that winter temperatures in the forecast horizon will have a 1-in-10 likelihood of occurrence.

PG&E's EG gas throughput forecast uses an average temperature approach. The forecast does not capture peak day temperatures. Each summer typically contains a few heat waves with temperatures 10 to 15 degrees F above normal. This leads to peak electricity demands and drives up power plant gas demand. This forecast captures the seasonal variations on a monthly basis.

HYDROELECTRIC CONDITIONS ASSUMPTIONS

In contrast to temperature deviations, annual water runoff for hydroelectric plants has varied by 50 percent above and below the long-term annual average. PG&E uses a vintage approach to WECC hydroelectric generation by assuming average generation for the most recent 15 historical years, 2005-2019, in the Average Year demand forecast. PG&E uses the Cold, Dry Hydro forecast to illustrate the impacts from extreme conditions impacting both core space heating demand and EG. PG&E uses the hydroelectric generation conditions for the calendar years 2014 and 2015 to represent the dry hydroelectric condition.

GAS PRICE AND RATE ASSUMPTIONS

Inputs for gas prices and transportation rate assumptions are important for forecasting gas demand. This is especially true for market sectors that are particularly price sensitive, such as the industrial or EG sectors. PG&E used the gas commodity price forecast described in detail in the Executive Summary. It combines transportation rates with the gas commodity price forecast. PG&E's forecast assumes that changes to throughput do not directly impact rates. As a reminder, natural gas price forecasts are inherently uncertain and impact market sectors sensitive to price.

GAS LOAD ASSUMPTIONS

As described above, PG&E's base forecast is developed from econometric regression models. This forecast is modified by forecasts of policy and technology adoption. The major modifiers are building electrification (BE) and energy efficiency (EE). The EG forecast is based on the mid case electricity demand forecast from the CEC 2021 Integrated Energy Policy Report (IEPR). This demand forecast includes the Additional Achievable Fuel Substitution (AAFS 2) scenario building electrification information as described under "Electric Load Assumptions" and the forecast building electrification quantities have accompanying consistent gas reduction quantities. These gas reductions are included in the forecast as a modifier to the base models.

PG&E also includes the impact of EE in its gas forecast. PG&E's model requires the inputs of two categories of energy efficiency, "Additional Achievable Energy Efficiency" (AAEE) savings and "Committed" savings. AAEE represents savings from programs that had not yet been funded and new codes and standards (C&S). Committed represents savings from measures resulting from codes & standards already on the books but implemented during the forecast period. The AAEE forecast used by PG&E is the CEC's 2019 IEPR Mid AAEE case[15]. PG&E also utilizes the Committed savings forecast from the CEC 2019 IEPR to avoid double-counting. Committed savings are provided separately by the CEC since they are embedded in the IEPR baseline. Since committed savings for the 2021 IEPR were not available in time for use in this forecast, PG&E opted to use the previous vintage (2019 IEPR) to avoid introducing overlap between the two categories.

Finally, there is a smaller adjustment that tends to increase gas sales. There is a group of customers who intend to use natural gas as a cleaner alternative to current fuels. A few of these customers have already signed agreements and the remainder are assumed to sign at a 30% conversion rate. These customers are classified as industrial because they are predominately industrial gas users.

ELECTRIC LOAD ASSUMPTIONS

PG&E's forecast relies on the mid case electricity demand forecast from the CEC 2021 Integrated Energy Policy Report (IEPR). The IEPR captures the increasing electric load as electric vehicles become more commonplace as projected. The electric demand forecast also includes building electrification from the CEC IEPR AAFS 2 forecast[16 & 17]. The AAFS 2 scenario is the CEC's mid-low scenario for electrification.

Finally, the electric load forecast incorporates the CEC IEPR Additional Achievable Energy Efficiency (AAEE) 3 forecast, the mid case[18]. IOU savings are informed by the CPUC's recent 2021 Potential & Goals Study (P&G). Savings for publicly owned utility (POU) utilize the

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15 California Energy Commission, Adopted 2019 Integrated Energy Policy Report https://efiling.energy.ca.gov/getdocument.aspx?tn=232922.

16 The "AAFS" here stands for Additional Achievable Fuel Substitution, so the scenarios include reductions for gas consumption that are "substituted out" through electrification.

17 California Energy Commission https://www.energy.ca.gov/media/6102.

18 California Energy Commission, ADOPTED Final 2021 Integrated Energy Policy Report Volume IV California Energy Demand Forecast https://efiling.energy.ca.gov/GetDocument.aspx?tn=241581.

California Municipal Utilities Association's (CMUA) 2020 Energy Efficiency Potential Forecast for POU program savings. Additionally, the CEC conducts additional studies to assess the impact of codes & standards as well as savings "Beyond Utility" contributions not accounted for in other categories.

ELECTRIC GENERATION AND ELECTRIC TRANSMISSION ASSUMPTIONS

With increasing electric load and more stringent environmental requirements, California's portfolio of EG resources is expected to change significantly over the forecast horizon to 2035. Generation resource addition and retirement assumptions are from the 2021 CPUC Integrated Resource Plan (IRP) Preferred System Plan (PSP). The PSP proposes a target resource mix that includes new renewable and energy storage resources. Gas-fired plants that employ once-through cooling are assumed to retire by the compliance dates set by the California State Water Resources Control Board (SWRCB) in conjunction with the CPUC direction[19] with some re-powered by new gas-fired units. Lastly, modeled CAISO import capability also aligns with the PSP.

For cogeneration gas demand, the forecast for all years reflects recent past cogeneration usage. Most cogeneration plants are not strongly affected by prices in the wholesale electricity market. The electricity generated comes from some other industrial process, usually steam, and generation does not follow wholesale electric prices. Consequently, the cogeneration gas demand projection exhibits no variation throughout the forecast horizon.

All of these assumptions are subject to uncertainty and puts the forecasted demand at significant uncertainty. The forecasted gradual decline in future gas demand is in response to the state's decarbonization policies and reflects reduced demand due to energy efficiency, building electrification resulting from fuel switching from natural gas appliances to electric, and climate change. Furthermore, the trajectory of gas prices may change dramatically as well. The following four factors have the most impact to the forecasted demand.

[19] California State Water Resources Control Board policy effective December 23, 2021 https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/policy.html.

- **Gas Prices**: Gas prices impact retail customer usage and the extent to which thermal resources are used to meet electric demand. Over the past year, California and the world have been experiencing high and volatile gas prices. Moreover, the relative north-to-south gas burner-tip price differential has a significant impact on which thermal generation resources will dispatch. This forecast assumes a nominal Southern California price advantage.

- **Climate Change:** Changes in climate impacts both core and electric generation gas demand. It also significantly impacts hydroelectric generation which affects the need for gas generation. Although this forecast attempts to use methodologies that best reflects climate change (e.g., use of a 15-year hydroelectric generation average), the impacts and pace of change are not fully understood and will be different than the assumptions used in this forecast.

- **Generation Resource Policy and Buildout:** PG&E's forecasts assume California will invest in generation resources in accordance with the California Public Utilities Commission's 2021 Integrated Resource Plan Preferred System Plan. The Plan is ambitious with over 26,000 megawatts of added resources[20]. Deviation from the plan in either resource mix or timing will impact the gas demand forecast.

- **Building Electrification Policy:** PG&E's Average Year and Cold, Dry Hydro Year demand forecasts reflect the impact of existing building decarbonization policies as reflected in the California Energy Commission's 2021 Integrated Energy Policy Report. The CEC has developed multiple forecasts for building electrification growth, reflecting the uncertainty.

[20] Nameplate capacity.

NORTHERN CALIFORNIA

MARKET SECTOR FORECASTS

RESIDENTIAL

Northern California residential demand is forecasted to decrease from 491 MMcf/d in 2022 to 338 MMcf/d in 2035. Residential households in the PG&E service area are forecasted to be flat to slightly declining from 2022 to 2035. This is the result of continued mild growth until about 2029, after which households with gas service use begins to decline. More importantly, gas use per household has been dropping in recent years due to improvements in appliance and building shell efficiencies. PG&E expects continued efficiency improvements, coupled with the following emerging trends, to decrease long-term residential gas demand.

1. As of June 16, 2022, 57[21] jurisdictions in the state of California have adopted ordinances that require or give preference to all-electric new construction. Around 40 of these jurisdictions used Reach Codes (beyond Title 24, Part 6, of the Energy Code) as a policy tool; these are local ordinances which must be approved by the California Energy Commission (CEC). The remaining jurisdictions adopted local ordinances which do not require further approvals[22]. Not all construction types are covered by these ordinances and there is regional variation (residential versus non-residential). While the number of households are forecasted to grow at 0.9 percent annually, the CEC building electrification outlook indicates that many of these households will install electric-only appliances as new planning cycles comply with these new ordinances.

2. In addition to new construction building electrification, this forecast anticipates that existing households will begin to convert appliances from gas to electric driven by the formation of state or local policies, customer cost savings, or other mechanisms.

3. The warming climate will reduce winter heating needs gradually decreasing residential gas sales.

[21] Sierra Club https://www.sierraclub.org/articles/2021/07/californias-cities-lead-way-pollution-free-homes-and-buildings.

[22] Some jurisdictions adopt both an energy Reach Code and an ordinance.

Total annual residential demand is projected to continue declining, driven by efficiency gains, building and appliance electrification, and warming temperatures. By 2035, annual residential gas throughput is projected to be 33 percent lower than forecasted 2022 throughput, with most of this decrease occurring in the later years of the forecast.

COMMERCIAL

Northern California commercial demand, not including natural gas vehicles, is forecasted to decrease from 208 MMcf/d in 2022 to 163 MMcf/d in 2035. The number of commercial customers in the PG&E service area is projected to grow on average by 0.23 percent per year from 2022-2035. Similar to the residential customer class, PG&E expects new construction and retrofit building electrification, coupled with continuing existing trends of energy efficiency and climate change, to lead to a long-term decline in commercial throughput. As a result, total commercial gas demand is projected to decline at 1.9 percent per year over the next 13 years, with the decline increasing in later years because total commercial accounts flatten out in those years. Core natural gas vehicles (NGV) remain a minor component but continue to grow at about 3 percent per year.

INDUSTRIAL

Northern California industrial demand is forecasted to increase nominally from 462 MMcf/d in 2022 to 496 MMcf/d in 2035. Gas requirements for PG&E's industrial sector are affected by the level and type of industrial activity in the service area and changes in industrial processes. Gas demand from this sector can fluctuate due to a combination of gas prices, noncore to core migration, capacity at local refineries, and manufacturing demand tied to market dynamics. While the industrial sector has the potential for high year-to-year variability, over the long-term, industrial gas consumption is expected to increase slowly, with energy efficiency and higher gas prices offsetting some growth.[23] As with the commercial category of NGV, industrial category NGV sees moderate growth from a small base, with some as yet unquantified possibilities for additional growth as described in "Future Opportunities" below.

[23] PG&E's industrial forecast includes impacts from California's Cap-and-Trade policies. Future GHG policies may impact industrial demand, adding uncertainty to the forecast.

NORTHERN CALIFORNIA

Given the state's GHG reduction targets, PG&E has been working with many of our industrial customers to begin converting them to natural gas from more polluting fuels, with an eye towards RNG and potentially renewable hydrogen in the future. With these conversions in the planning stage, natural gas demand from the industrial sector is expected to grow by 0.5 annually over the next 13 years.

ELECTRIC GENERATION

Gas demand from EG includes gas-fired cogeneration and power plants connected to PG&E's gas system. PG&E forecasts a relatively steady gas demand for electric generation through the 2020s, ranging between 441 and 493 MMcf/d. This reflects a continuing need in the mid-term for thermal plants to provide electric system reliability. In 2035, EG gas demand is forecasted at 549 MMcf/d.

Through the 2020s to 2035, the CPUC Integrated Resource Plan (IRP) Preferred System Plan (PSP) plans for additional renewables and storage[24] [25]. The IRP PSP forecasts most new renewable resource installation in Southern California, particularly solar. Additionally, transmission capacity constraints sometimes limit the ability to transport Southern California solar generation from south-to-north during daytime hours when solar is generating[26]. Additionally, increases in electric load, driven by electric vehicles and building electrification, need additional generation to meet load. The combination of the increasing level of planned Southern California renewable resources and south-to-north electric transmission congestion drives the EG gas demand higher.

As discussed above, the forecast has significant uncertainty due to factors, including:

- Future burner-tip gas prices;[27]
- Impact of electrification of vehicles and building appliances on electric load;

[24] Total CAISO renewable and storage capacity planned from 2021 to 2026 is about 26,000 megawatts.
[25] By 2035, capacity increases 50,000 MW compared to 2021.
[26] Estimated at about 80 percent.
[27] Burnertip gas prices are the combination of the commodity price and transportation rate.

- Timing, location, and type of new generation, particularly renewable energy facilities;
- Variable precipitation affecting hydroelectric generation; and
- Impacts of GHG policies and regulations on generation.

The burner-tip gas price forecast and the relative difference between Northern and Southern California prices impacts the EG demand forecast. The price forecast used in this Report has the price of gas ranging from $4 to $6 per MMBtu, with a small price advantage for Southern California for most of the forecast period. This places the Northern California gas-fired EG plants at a competitive disadvantage compared to plants farther south.

Gas prices have recently shown significant volatility. For example, the forecasted PG&E Citygate price for June 2022 is about $5.30/MMBtu. Actual June 2022 daily gas prices show a range of about $7.50/MMBtu to $10.30/MMBtu. This type of volatility and the relative price volatility between prices in Northern and Southern California can drive significant uncertainty in the forecast.

As stated above, the IRP PSP indicates renewable generation and storage capacity buildout mostly built-in Southern California. Additionally, electric transmission capacity from south-to-north is assumed at about 3,000 MW. Differences in the amount or location of the actual California renewable buildout or transmission constraints will impact EG gas throughput.

Finally, variability in hydroelectric generation can significantly impact EG gas demand. In 2017 the average gas demand was 698 MMcf/d in 2017 and in 2021 it was 964 MMcf/d. One of the major drivers of this difference is hydroelectric generation. 2017 was a wet year with ample hydroelectric generation and 2021 was a dry year with lower hydroelectric generation. The wide year-to-year hydroelectric generation fluctuations further illustrate the inherent uncertainty in EG gas demand.

NORTHERN CALIFORNIA

SACRAMENTO MUNICIPAL UTILITY DISTRICT ELECTRIC GENERATION

Sacramental Municipal Utility District (SMUD) is the sixth largest community owned municipal utility in the U.S. and provides electric service to over 575,000 customers within the greater Sacramento area. SMUD operates three cogeneration plants, a gas-fired combined-cycle plant, and a peaking turbine with a total capacity of approximately 1,000 MW. The peak gas load of these units is approximately 171 MMcf/d, and the average load is about 96 MMcf/d. This forecast assumes the average load of 96 MMcf/d, which is embedded in this forecast.

SMUD owns and operates a pipeline connecting the Cosumnes combined-cycle plant and the three cogeneration plants to PG&E's backbone system near Winters, California. SMUD owns an equity interest of approximately 3.8 percent in PG&E's Line 300 and approximately 4.2 percent in Line 401 for about 86 MMcf/d of capacity.

FORECAST SCENARIOS

The Average Year gas demand forecast presented above is a reasonable projection for an uncertain future. However, a point forecast presented in the Average Year forecast cannot capture the uncertainty in the major determinants of gas demand (e.g., weather, economic activity, decarbonization policies, appliance saturation, and efficiencies). Therefore, to capture some of the uncertainties in gas demand, PG&E developed a high gas demand situation for cold temperature conditions and dry hydroelectric (hydro) conditions.

HIGH DEMAND SCENARIO: COLD/DRY HYDRO

For the High Demand scenario, PG&E forecasts gas demand under cold temperature and dry hydro conditions. This forecast assumes that winter temperatures over the time horizon will have a 1-in-10 likelihood of occurrence. The cold weather assumption increases electric load for space heating needs and EG gas demand. To represent dry hydroelectric conditions throughout the WECC, this forecast assumes the same dry hydroelectric generation conditions as those that prevailed during 2014 and 2015. The dry hydroelectric conditions increase EG gas demand.

Total gas demand for this forecast averages 6 percent higher than the Average Year demand forecast. The cold weather impact drives gas throughput higher due to higher space heating.

Winter monthly core throughput is projected to increase on average by 8 percent, ranging from 7 to 10 percent. The noncore industrial segment demonstrates little correlation to temperature leading to an insignificant demand increase over the Average Year demand forecast.

This forecast projects that EG gas demand increases by 10 percent on average over the Average Year demand outlook. In this forecast, the generation from Northern California hydroelectric resources is about half of the 15-year average assumed in the Average Year demand outlook. This lower generation increases EG gas demand. Hydroelectric conditions can vary widely throughout the WECC and illustrates another degree of uncertainty in EG gas demand forecasting.

POLICIES IMPACTING GAS DEMAND

During the forecast horizon covered by this CGR, there are many policies that may significantly impact the future trajectory of natural gas demand. Executive Order (EO) S-3-05 set a goal to reduce annual GHG emissions to 1990 levels by 2020 and to 80 percent below 1990 levels by 2050. EO B-55-18 set a goal to achieve carbon neutrality by 2045. The Global Warming Solutions Act of 2006 (Assembly Bill (AB) 32) established the 2020 GHG emission reduction goal into law. Senate Bill (SB) 32 went further, calling for a 40 percent reduction in GHG emissions below 1990 levels by 2030. Additionally, the California Air Resources Board (CARB) Cap-and-Trade Program complements these policies.

GHG POLICIES

The gas demand forecast includes a Cap-and-Trade GHG allowance price projection.[28] The forecast also incorporates complementary policies that aim to achieve California GHG emissions reductions goals. See below for further discussion of these policies. Finally, any trends embedded in historical demand patterns due to GHG goals and/or the compliance entities' participation in the Cap-and-Trade market translates to the forecast.

Given that the utilization of fossil natural gas emits GHGs, PG&E believes that renewable gases (renewable natural gas or hydrogen) must be part of the solution to reach California's

[28] CEC Integrated Energy Policy Report mid-case forecast to 2030. Extrapolated to 2035 using the real adder to the floor price (5 percent rate).

GHG reduction goals. PG&E will continue to minimize GHG emissions by pursuing both demand-side reductions and acquisition of preferred resources, which produce little or no carbon emissions.

Renewable Electric Generation

PG&E expects renewable EG to grow due to procurement orders by the CPUC in the IRP Proceeding[29]. While this increase in renewable generation will put downward pressure on the demand for generation from natural gas-fueled resources, the intermittent nature of the largest renewable generation supplies (i.e., wind and solar) should cause the electric system to continue to utilize natural gas-fired EG for reliability through the forecast horizon. Offsetting the impact on the EG demand forecast will be both short-term and long-term electric storage.

Energy Efficiency Programs

PG&E engages in many Energy Efficiency and Conservation (EE) programs designed to help customers identify and implement ways to benefit environmentally and financially from EE investments. Programs administered by PG&E include services that help customers evaluate their EE options and adopt recommended solutions, as well as simple equipment retrofit improvements, such as rebates for new hot water heaters.

PG&E's forecast of cumulative natural gas savings is dominated by the residential sector. Additionally, most of the forecasted savings are due to codes and standards, such as federal and state appliance standards and state building codes. State building codes (Title 24) make up most of these savings.

[29] https://www.cpuc.ca.gov/irp/.

IMPACT OF SB 350 ON ENERGY EFFICIENCY

SB 350, which was enacted in fall 2015, requires the CEC, in coordination with the CPUC and the local public utilities, to set EE targets that double the CEC's AAEE mid-case forecast, subject to what is cost-effective and feasible.[30] The CEC issued its final report doubling targets in October 2017,[31] and the CPUC incorporated higher levels of EE savings in their EE goals for 2018 and beyond,[32] which was partially due to the adoption of an interim GHG adder in the Integrated Distributed Energy Resources proceeding.[33] The CEC's final report suggests the State is on a path to meet or exceed the natural gas SB 350 doubling goal after accounting for IOU programs, POU programs, and codes and standards.[34]

IMPACT OF REACH CODES, APPLIANCE ORDINANCES, AND ELECTRIFICATION

In California, cities and counties have enacted ordinances or "reach" building codes that require or give preference to electric new construction. As of June 16, 2022, 57 local jurisdictions have adopted reach codes[35]. Electrification policies continue to evolve at both the local and state level. The California Air Resources Board (CARB) and Bay Area Air Quality Management District (BAAQMD) have introduced proposals aimed at the electrification of

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[30] The bill text states:

"On or before November 1, 2017, the commission, in collaboration with the Public Utilities Commission and local publicly owned electric utilities, in a public process that allows input from other stakeholders, shall establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of statewide energy efficiency savings in electricity and natural gas final end uses of retail customers by January 1, 2030. The commission shall base the targets on a doubling of the mid case estimate of additional achievable energy efficiency savings, as contained in the California Energy Demand Updated Forecast, 2015-2025, adopted by the commission, extended to 2030 using an average annual growth rate, and the targets adopted by local publicly owned electric utilities pursuant to Section 9505 of the Public Utilities Code, extended to 2030 using an average annual growth rate, to the extent doing so is cost effective, feasible, and will not adversely impact public health and safety."

[31] Jones, Melissa, Michael Jaske, Michael Kenney, Brian Samuelson, Cynthia Rogers, Elena Giyenko, and Manjit Ahuja. 2017. SB 350: Doubling Energy Efficiency Savings by 2030. CEC. Publication Number: CEC-400-2017-010-CMF.

[32] D.17-09-025: Decision Adopting Energy Efficiency Goals for 2018-2030, CPUC, September 28, 2017.

[33] D.17-08-022: Decision Adopting Interim GHG Adder, CPUC, August 24, 2017.

[34] See Figure 2 from the CEC report cited above.

[35] Sierra Club, https://www.sierraclub.org/articles/2021/07/californias-cities-lead-way-pollution-free-homes-and-buildings.

existing buildings—namely space and water heating. BAAQMD's proposal to amend Rules 9-4 and 9-6 would put in place a point-of-sale ban on gas water heaters beginning in 2027 and gas furnaces in 2029.[36] Similarly, CARB's 2022 State Implementation Plan (SIP) calls for all furnaces and water heaters sold within California to comply with a 0 ng/joule NOx limit beginning in 2030. If implemented, this would effectively eliminate the sale of gas water heaters and furnaces in California. Electrification, consequently, appears to be adding electric load in the long-term while removing sources of growth in gas demand. How these policies become implemented, at an unknown scale and timeframe all introduce uncertainty to the gas demand forecasts.

As the Average Year forecast projects an increase in industrial and EG sectors, the effort to achieve the GHG emissions goal could come by differing gas supply options. The natural gas supply sources could be a cleaner version in the form of renewable natural gas (RNG) or renewable hydrogen (RH_2). The next chapter on natural gas supply will elaborate on these potential gas supplies.

FUTURE GAS DEMAND TRENDS AND POLICY

PG&E's gas demand forecast projects lower throughput over the long-term (due to GHG policies, such as electrification and procurement of renewable generation resources) which would show a decline in revenues at current rates. At the same time, policies on safe utility operations have put upward pressure on costs. Investments into long lived assets, such as gas pipelines, are typically recovered over the assets' useful lives, which extend beyond this forecast. The combination of lower throughput and remaining investment in need of being recovered will put upward pressure on gas transportation rates.

In addition, the transition from fossil fuel (traditional fuels) to other forms of energy usage needs to be carefully planned and managed. PG&E is committed to working with regulators and other stakeholders to support the statewide GHG reduction policies and develop options to minimize rate increase for the remaining gas customers.

[36] Building Appliances (baaqmd.gov.)

To minimize the rate impacts on gas customers, PG&E is following a three-pronged approach while keeping safety as its top priority: (1) reduce cost, (2) identify alternative revenue sources and (3) leverage innovative financial mechanisms. To reduce cost, PG&E is pursuing opportunities to systematically retire infrastructure and reduce capital and operating expenses through PG&E's Integrated Investment Planning. Since 2018 this program has reached agreements with 84 customers which avoided 80 high pressure regulator rebuilds, retired 4.2 miles of distribution main, and retired 22 miles of transmission line. To increase utilization of existing infrastructure where electrification is not feasible or cost effective, PG&E is actively planning for and implementing programs to decarbonize existing gas throughput, exploring new opportunities to support RNG adoption across new industries, increase load on the natural gas system in areas that would replace less favorable hydrocarbon (e.g., marine, rail and transportation sectors) and seek opportunities to utilize the gas system as a long-term and large scale storage mechanism. Innovative financial mechanisms - such as accelerated depreciation, rate reform, and the capital treatment for cost-effective zonal electrification projects will help - but non-traditional funding sources may also be critical as we evolve to an affordable, decarbonized gas system.

FUTURE OPPORTUNITIES

One recent development that could increase throughput comes from the June 2020 California Air Resources Board (CARB) approval of the Advance Clean Truck (ACT) Regulation. This regulation requires increasing percentages of all new medium- and heavy-duty trucks sales in California to be zero-emission vehicles (ZEV)[37]. The regulation begins in 2024 with sales percentages ranging between 5 percent and 9 percent depending on truck or chassis type. By 2035, the percentages increase to a range of 40 percent to 75 percent.

Truck manufactures may choose hydrogen fuel cells as they decide how to meet this requirement. The fuel required for this could be transported via utility gas pipelines (under appropriate safety protocols) which could mitigate the potential for increasing customer costs.

In addition, companies such as Amazon have internal goals for decarbonizing fleets. Chevron has announced that they are building natural gas fueling stations, including about 15 in Northern California, and truck engine producer Cummins has announced a new 15-liter NGV truck engine. While adoption of such NGV technology is determined by market response, and the carbon status of this fuel choice depends on uncertain RNG implementation and markets, this is a potential path to higher NGV adoption than is reflected in the forecast numbers.

RAIL

Another high horsepower sector to consider for increasing gas throughput is rail transportation. Based on a study by the California Air Resource Board (CARB) from 2016, annual statewide locomotive diesel fuel consumption totals about 260 million gallons. Union Pacific Railroad (UP) and BNSF Railway Company (BNSF) combined interstate and intrastate locomotives account for 93 percent of this fuel usage, California's passenger locomotives are 6%, and the remaining 1percent is from military industrial locomotives[38].

[37] ZEVs are defined as either battery electric or hydrogen fuel cell vehicles.
[38] CARB. (2016). *Technology Assessment: Freight Locomotives.* Sacramento: California Air Resource Board.

CNG and LNG as a fuel source has been considered by the rail industry, but thus far has been mostly limited to pilot studies. Based on conversations with representatives from UP, BNSF, and CARB, some of the key obstacles to CNG and LNG locomotive adoption include: few, if any, new locomotives are planned to be purchased in the near future; the high cost of converting the fueling infrastructure from diesel to CNG or LNG; and current emission standards don't adequately promote fuels cleaner than low sulfur diesel. Additionally, because LNG has an energy density of approximately 60 percent that of diesel, its use for long interstate routes would require increased fuel storage volume. This comes in the form of an LNG tender, which is an additional railcar that includes an insulated cryogenic tank and other equipment to convert LNG back to CNG. The added tender increases cost and complexity to the fuel transition[39].

One possible path to greater CNG or LNG locomotive adoption is more stringent emissions standards. Locomotive emissions are governed by the U.S. EPA. Currently, their strictest emission level is Tier 4 and applies to locomotives manufactured in 2015 or later. In g/bhp-hr it limits nitrogen oxide (NO_x), particulate matter (PM), and hydrocarbon (HC) emissions to 1.3, 0.03, and 0.14 respectively[40]. In 2017, CARB petitioned to the U.S. EPA to consider adopting a new, stricter, Tier 5 standard with a proposed effective date of 2025. The Tier 5 standard would limit NO_{x-}, PM, and HC emissions to 0.2, <0.01, and 0.02.[41]

MARINE

Another potential growth area for gas throughput is the marine transportation sector which is increasingly looking at reducing its SOx and GHG emissions. This is orchestrated by the International Maritime Organization (IMO) which regulates global shipping emissions under Annex VI.[42] The IMO updated Annex VI on January 1, 2020 to target reductions in nitrogen

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[39] *Ibid.*

[40] CFR 1033.101 (https://www.ecfr.gov/cgi-bin/text-idx?SID=159ba6f126272ea1995c71a43b7af309&mc=true&node=pt40.36.1033&rgn=div5#se40.36.1033_1101).

[41] https://www2.arb.ca.gov/sites/default/files/2020-07/final_locomotive_petition_and_cover_letter_4_3_17.pdf.

[42] http://www.imo.org/en/OurWork/Environment/PollutionPrevention/AirPollution/Pages/Air-Pollution.aspx.

oxides (NOx) and sulfur oxides (SOx). To reduce SOx, the sulphur limit for all marine fuels were reduced from 3.50 percent m/m (mass by mass) to 0.50 percent m/m.

The consensus in the marine fuel industry is that the 0.50 percent sulphur limit is only a stop on the way to a global 0.10 percent sulphur limit, which currently exists in several Emissions Control Areas (ECA)[43] around the globe. Moving to 0.10% would necessitate using road grade diesel fuel as bunker fuel, therefore increasing fuel cost. Refining companies would need to further invest in hydrodesulfurization, which is costly to build and operate.

The push towards lowering SOx is driven by environmental groups, government regulations, and the shipping industry itself. Large European container companies are driving it as part of their corporate carbon strategies.[44]

LNG is widely recognized as the best path forward to reduce SOx and GHG for marine purposes but has not seen much growth in the previous decade. The updated IMO Annex VI are changing that, spurring investments in bunkering equipment[45] and vessels[46]. LNG also allows for decarbonizing of the shipping industry as the fuel can be made from RNG and, eventually, renewable hydrogen.

California marine fuel markets can be divided into ocean and coastal. The ocean market is the largest due to the fuel volumes vessels consume. California, with its large container ports in Oakland, Los Angeles, and Long Beach, may see demand for LNG in the future and would require large investments. Some of the investments needed to meet this demand include storage terminals, bunker loading vessels, or liquefaction terminals.

This demand may come sooner rather than later as modern ship engines are flex-fuel capable in that they can run on either fuel oil or natural gas, thus optimizing fuel costs and environmental

43 http://www.imo.org/en/OurWork/Environment/SpecialAreasUnderMARPOL/Pages/Default.aspx.
44 https://www.maersk.com/news/articles/2019/06/26/towards-a-zero-carbon-future .
45 https://sea-lng.org/why-lng/bunkering/; https://www.ship-technology.com/news/west-coasts-lng-bunker-abs/.
46 https://www.cma-cgm.com/news/2749/world-premiere-launching-of-the-world-s-largest-lng-powered-containership-and-future-cma-cgm-group-flagship .

compliance.[47] To give an idea of the potential size of this market, in 2020 vessel bunkering residual fuel oil use in California totaled about 12 million barrels or 62 Bcf.[48]

Coastal market consists mostly of smaller vessels such as passenger ferries, tugs, fishing vessels, etc. These smaller vessels already use an Ultra Low Sulphur Diesel under CARB regulations and these vessels, could see a cost reduction by switching to LNG powered fleets.[49] Small on-demand liquefaction terminals can bunker vessels at berth and have already been installed in Europe[50] successfully. They can be connected directly to the natural gas grid producing fuel on-demand.

NORTH AMERICAN GAS DEMAND

Liquefied Natural Gas Imports/Exports

In years past, the U.S. imported LNG to supplement North American supplies to meet demand. Since the mid-2010s, LNG imports have primarily been used to serve peak winter load[51]. The development of low-cost domestic shale gas supplies since the mid-2000s has largely eliminated the need for LNG imports and positioned the U.S. as a net exporter of LNG.

Recent global events have increased the expectations for more LNG exports from North America. As Europe embarks on measures to increase its energy security and diversify its energy sources, LNG export developers in North America are seeking development opportunities. The gas industry anticipates further growth in LNG exports from North America.

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47 https://www.wartsila.com/twentyfour7/energy/taking-dual-fuel-marine-engines-to-the-next-level.

48 U.S. Energy Information AdministrationSales of Residual Fuel Oil by End Use https://www.eia.gov/dnav/pet/pet_cons_821rsd_a_EPPR_VVB_Mgal_a.htm

49 https://www.mckinsey.com/industries/oil-and-gas/our-insights/imo-2020-and-the-outlook-for-marine-fuels# .

50 https://ec.europa.eu/energy/intelligent/projects/sites/iee-projects/files/projects/documents/magalog_lng_supply_chain.pdf .

51 U.S. Energy Information Administration (US EIA) U.S. Liquefied Natural Gas Imports https://www.eia.gov/dnav/ng/hist/n9103us2m.htm .

NORTHERN CALIFORNIA

The U.S. began exporting LNG in 2016. For projects proposing to export LNG, the U.S. Department of Energy (DOE) evaluates the impact of exports to countries without a Free Trade Agreement (FTA) with the U.S. The DOE grants approval if the project is deemed in the public interest. The U.S. Federal Energy Regulatory Commission (FERC) evaluates the environmental impacts of proposed LNG projects and authorizes the siting and construction of LNG facilities.

Currently, there are more than a dozen proposed projects to export LNG to world markets.[52] Many of the projects are "brownfield," using existing U.S. import terminals to export LNG. Some are "greenfield" projects where LNG infrastructure has not been developed in the past. Two greenfield projects on North America's West Coast are in British Columbia. The larger project is LNG Canada located in Kitimat.[53]

A brownfield project on North America's West Coast is the Energia Costal Azul (ECA) LNG export facility in Baja California, Mexico. ECA has received authorization from the DOE to liquify and re-export up to 1.7 billion cubic feet per day (Bcf/d) of U.S. produced natural gas.[54] This facility will have a nameplate capacity of 3.25 million metric tons (mmt) per annum of liquification capacity. Construction of the project is underway with an online date of 2024.[55]

The ECA LNG export project, which would be the second on the North America's West Coast, is positioned to source gas off the El Paso Mainline System. Thus, it could divert gas supplies currently available to Northern California. ECA diversion of gas supplies from California is currently under consideration at the CPUC in the R.20-01-007 Proceeding.[56] This proceeding will investigate whether the demand from ECA could impact supply reliability to California, especially the southern portion, and put upward pressure on gas prices.

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[52] U.S. EIA https://www.eia.gov/naturalgas/U.S.liquefactioncapacity.xlsx .

[53] LNG Canada https://www.lngcanada.ca/media-kit/ .

[54] https://ecalng.com/ .

[55] Mexico ECA LNG Development Advancing to 2024 Start Date, Natural Gas Intelligence, https://www.naturalgasintel.com/mexico-eca-lng-development-advancing-to-2024-start-date/#:~:text=The%20facility%20is%20adjacent%20to,the%20facility%20online%20in%202024.

[56] OIR to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning.

U.S. NATURAL GAS PIPELINE EXPORTS TO MEXICO

With low domestic natural gas prices compared to world markets, the U.S. remained a net exporter of natural gas in 2021.[57] The U.S. natural gas exports to Mexico have grown in recent years from 0.9 Bcf/d in 2010 to 5.9 Bcf/d in 2021,[58] and pipeline exports are projected to reach 7.4 Bcf/d by 2035.[59]

Most of the exports to Mexico are supplied through Texas from the Permian and Western Gulf of Mexico basins. Production growth in the Permian Basin, combined with new pipeline capacity, will enable growing exports to Mexico.

57 Energy Information Administration (EIA), The U.S. exported more natural gas than it imported in 2017: https://www.eia.gove/todayinenergy/detail.php?id=35392.

58 EIA, U.S. Natural Gas Pipeline Exports to Mexico: https://www.eia.gov/dnav/ng/ng_move_poe2_dcu_NUS-NMX_a.htm.

59 EIA, Annual Energy Outlook 2022 – Table 60. Natural Gas Imports and Exports Case: AEO2022 Reference case: https://www.eia.gov/outlooks/aeo/data/browser/#/?id=76-AEO2022&cases=ref2022&sourcekey=0 .

GAS SUPPLY, CAPACITY, AND STORAGE

OVERVIEW

The Gas Supply, Capacity, and Storage section provides information about PG&E's current gas supply, natural gas pipelines, gas storage, and policies affecting these topics. The Gas Supply section includes information about current and anticipated developments regarding Renewable Natural Gas (RNG), as well as gas supply from sources throughout North America. The Pipeline section includes information about "upstream" interstate pipelines, as well as intrastate pipelines. The Storage section gives an overview of PG&E's gas storage capacity and its gas storage facilities. The Policies section looks at a range of current policy developments and their impacts on PG&E's gas supply, including integration challenges for alternative fuel types, such as hydrogen (H_2).

Competition for gas supply, market share, and transportation access has increased significantly since the late 1990s. Implementation of PG&E's Gas Accord in March 1998 and the addition of interstate pipeline capacity and storage capacity have provided all customers with direct access to gas supplies, intra- and inter-state transportation, and related services.

Since gas demand in California is greater than the limited amount of native California production available, most of the gas supplies that serve PG&E customers are sourced from out of state.

PG&E anticipates that sufficient supplies will be available from a variety of sources at market competitive prices to meet existing and projected market demands in its service area. Supply can be delivered through a variety of sources, including any new and expanded interstate pipeline facilities and of PG&E's existing transmission facilities, or other storage facilities.

GAS SUPPLY

RENEWABLE NATURAL GAS

PG&E has several RNG projects in various phases. Four projects are already connected and flowing clean, renewable gas onto our system. Two projects are in development and should be online by the end of 2022. These six projects are expected to inject roughly 11,500 Mcf/d (thousand cubic feet per day) into PG&E's pipeline system by year end. In addition, there are over a dozen other projects that are in early-stage development that PG&E anticipates will be online over the next two to three years.

Two of the projects are a result of the SB 1383 Dairy Pilot Program, highlighted below, and the other five are identified in the Biomethane Project Incentive Reservation Queue located on the CPUC website.[60]

SB 1383 DAIRY PILOT PROJECTS

On December 3, 2018, the CPUC, CARB, and the California Department of Food and Agriculture (CDFA) issued a joint press release announcing the selection of six dairy pilot projects in compliance with CPUC D.17-02-004 and SB 1383. Two of the pilot projects were awarded in PG&E's service territory (see the Figure below): (1) the Merced Pipeline project sited at the Vander Woude Dairy in Merced (6 miles south of Merced); and (2) the J.G. Weststeyn Dairy project in Willows (5 miles west of Logandale).

On January 7, 2022, the Vander Woude Dairy project became operational, and the maximum RNG volumetric flow rate was met in February 2022, qualifying the project's entire authorized costs under the SB 1383 Dairy Pilot Program to be reimbursed.

As of May 2022, the J.G. Weststeyn Dairy project is completing its project design with an anticipated construction start date beginning in 2023.

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[60] https://www.cpuc.ca.gov/renewable_natural_gas/.

NORTHERN CALIFORNIA

FIGURE 10 – PG&E SERVICE AREA: RNG PILOT PROJECTS LOCATION

FUTURE CALIFORNIA RNG SUPPLY

A 2016 CARB-sponsored study by University of California (UC), Davis, "The Feasibility of Renewable Natural Gas as a Large Scale, Low Carbon Substitute" (the "STEPS study"), anticipated that as much as 82 Bcf per year of RNG supply could become available in California with appropriate policy development and investment.[61] The STEPS study identified that the largest opportunity for increasing the supply of RNG would come from landfill sites, followed by dairy, municipal solid waste, and waste-water facilities.

A more recent assessment of in-state RNG supply for transportation, conducted by GNA[62], projects that there will be roughly 16 Bcf annually of RNG interconnected into gas pipelines in California by January 2024. Additionally, the CPUC has required the utilities to file an application in the Summer of 2023 to advance pilot projects that would convert woody biomass into RNG, further expanding the potential long-term supply of RNG in the state.

Given the STEPS study results, the gas flowing from RNG sources by January 2024 is just the first wave of RNG expected to be eventually injected into the gas system. Therefore, going forward, PG&E expects to see more RNG projects as developers realize the near- and mid-term potential of this supply source.

Gas Absorption Capacity

To encourage effective development of RNG, PG&E created the Gas Supply Absorption Capacity Map.[63] This map is a high-level snapshot of PG&E's gas system that is designed to help contractors and developers find potential project sites by showing the relative ability (high to low) to accept new gas supply on PG&E transmission pipelines. Suppliers are encouraged to contact PG&E to discuss opportunities to bring on RNG supplies. Currently this map is being revised to provide better information to potential developers.

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[61] STEPS Program Study, The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute, prepared by Amy Myers Jaffe, available at: https://steps.ucdavis.edu/the-feasibility-of-renewable-natural-gas-as-a-large-scale-low-carbon-substitute/.

[62] https://www.gladstein.org/gna_whitepapers/an-assessment-californias-in-state-rng-supply-for-transportation-2020-2024/ .

[63] Available at: https://www.pge.com/en_US/for-our-business-partners/interconnection-renewables/interconnections-renewables/biomethane-map-overview.page .

NORTHERN CALIFORNIA

NORTH AMERICAN SUPPLY DEVELOPMENT

North America has an abundance of natural gas resources. In the United States, the Potential Gas Committee estimates resources of 3,368 trillion cubic feet (Tcf).[64] Natural gas resource development has improved over the past two decades as horizontal drilling and hydraulic fracturing has matured. Furthermore, advancements in drilling know-how and improved efficiencies have improved resource development, typically at lower costs. The U.S. produced almost 94 Bcf/d on average in 2021.[65] Three producing regions contributed about 60 percent of this production: the Haynesville region mainly in Louisiana and Texas, the Permian region in Texas and New Mexico, and the Appalachia region mostly located in Pennsylvania, Ohio, and West Virginia.[66] The resources that contribute to these production regions include both shale gas resources and associated gas from oil production.[67] Most industry forecasts continue to predict that gas production will meet most demand outlooks in the future.

The growth of associated gas production in the Permian Basin and eastern shale plays - the Haynesville and Appalachia) continue to push gas volumes from Canada, the Rocky Mountain area, and the Southwest towards California. These production regions interconnect with California via pipelines as highlighted below.

CALIFORNIA SOURCED GAS

Northern California sourced gas supplies come primarily from gas fields in the Sacramento Valley. In 2021, PG&E's customers obtained on average 23 MMcf/d of California sourced gas. PG&E anticipates that California sourced gas may increase from this level. The primary driver to this growth is RNG production.

[64] http://potentialgas.org/press-release. This estimate represents the total mean technically recoverable resource base as of year-end 2020. Technically recoverable resources means gas can be produced using currently available technology and industry practices.

[65] U.S. Energy Information Administration Natural Gas Dry Production (eia.gov) .

[66] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis .

[67] Production - Amid uncertainty, the United States continues to be an important global supplier of crude oil and natural gas - U.S. Energy Information Administration (EIA) .

U.S. SOUTHWEST GAS

PG&E's customers have access to three major U.S. Southwest gas producing basins—Permian, San Juan, and Anadarko—via the El Paso and Transwestern pipeline systems.

PG&E's customers can purchase gas in the producing basins and transport it to California via interstate pipelines. They can also purchase gas at the California Arizona border or at the PG&E Citygate from marketers who hold inter or intrastate pipeline capacity.

CANADIAN GAS

PG&E's customers can purchase gas from various suppliers in Western Canada (British Columbia and Alberta) and transport it to California, primarily through the Gas Transmission Northwest (GTN) pipeline. Likewise, they can also purchase these supplies at the California-Oregon border or at the PG&E Citygate from marketers who hold interstate or intrastate pipeline capacity.

ROCKY MOUNTAIN GAS

PG&E's customers have access to gas supplies from the Rocky Mountain area via the Kern River Gas Transmission Pipeline, the Ruby Pipeline and via the GTN Pipeline interconnect at Stanfield, Oregon.

GAS PIPELINE CAPACITY

INTERSTATE PIPELINE CAPACITY

California utilities and end-use customers benefit from access to multiple supply basins, enhanced by produced gas-on-gas and pipeline-on-pipeline competition. Interstate pipelines serving northern and central California include El Paso Natural Gas, Mojave, Transwestern, GTN, Paiute Pipeline Company, Ruby, and Kern River Gas Transmission pipelines. These pipelines provide northern and central California with access to gas producing regions in the U.S. Southwest, Rocky Mountains, and in Western Canada.

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U.S. SOUTHWEST AND ROCKY MOUNTAINS

PG&E's Baja Path (Line 300) is connected to U.S. Southwest and Rocky Mountain pipeline systems (Transwestern, El Paso, and Kern River) at and west of Topock, Arizona. The Baja Path has a firm capacity of 935 MMcf/d.

CANADA AND ROCKY MOUNTAINS

PG&E's Redwood Path (Lines 400/401) is connected to GTN and Ruby at Malin, Oregon. The Redwood Path has a firm capacity of 2,060 MMcf/d.

IN-STATE PIPELINES

PG&E continues to accelerate the analysis of the existing pipeline system for opportunities to minimize rate increases for our customers by reducing our expenses, look for new opportunities for load growth and to decarbonize by increasing throughput of RNG. PG&E is actively pursuing a variety of initiatives including electrification opportunities on radial feeds where several miles of pipe are in place to serve a small handful of customers, pruning the system of pipe that is underutilized or no longer serving customers, downrating lines, and elimination or streamlining projects. Electrifying these customers and decommissioning the pipeline will achieve greater cost savings in the long term. These opportunities will also help inform PG&E's longer-term efforts, in partnership with cities, to strategize where to reduce our spending and predict long-term gas needs more accurately.

GAS STORAGE

Northern California is served by several gas storage facilities in addition to the longstanding PG&E fields at McDonald Island, Los Medanos, and a 25 percent ownership in Gill Ranch Storage.[68] These facilities combine for a total inventory of 167 Bcf, with 35 Bcf under PG&E management.

[68] PG&E also has operated the Pleasant Creek storage field. The Decision (D.) 19-09-025 for the 2019 Gas Transmission and Storage rate case, Ordering Paragraph 42, adopted PG&E's proposal to sell or decommission the Pleasant Creek storage field.

Other Northern California storage providers consist of Gill Ranch Storage, LLC (a 20 Bcf facility that was co-developed with PG&E), Wild Goose Storage, LLC, Lodi Gas Storage, LLC, and Central Valley Storage, LLC. The abundant storage capacity in Northern California has the effect of creating ample liquidity in the market both in Northern California and in other parts of the West.

Within the past ten years, Northern California natural gas storage facilities have experienced regulatory changes. In response to the Southern California Gas Company's Aliso Canyon Storage natural gas leak in October 2015, the California Department of Conservation, Geologic Energy Management Division (CalGEM), previously known as the Division of Oil Gas and Geothermal Resources (DOGGR), adopted new natural gas storage well safety regulations across California. Key elements of these new rules included requiring all operators to submit risk and integrity management plans, well casing inspection and pressure testing plans, and a schedule to convert or retrofit wells to tubing and packer.[69] Packers seal off the annulus space in the casing and limit the gas flow to the smaller diameter inner tubing only, which is forecasted to reduce traditional storage well performance on average by 40 percent.[70] Partly in response to the new regulations, PG&E proposed a Natural Gas Storage Strategy (NGSS) in its 2019 Gas Transmission and Storage (GT&S) Rate Case. Specifically, PG&E proposed to exit the commercial storage market and focus on reliability services. As a part of the NGSS, PG&E proposed to sell or decommission its Los Medanos and Pleasant Creek storage facilities. The CPUC approved the NGSS in Decision (D.) 19-09-025.

On December 1, 2020, PG&E announced the sale of the Pleasant Creek natural gas storage field, located in Yolo County, California. The Pleasant Creek field is the smallest of four underground natural gas storage fields owned wholly or partly by PG&E.

In PG&E's 2023 General Rate Case application, filed at the CPUC on June 30, 2021, PG&E proposed updates to the NGSS in response to evolving CalGEM regulations. These updates include a proposal to retain the Los Medanos storage facility while still decommissioning or

[69] Geologic Energy Management Division Statutes & Regulations January 2022 (ca.gov) https://www.conservation.ca.gov/index/Documents/CALGEM-SR-1%20Web%20Copy.pdf

[70] Workpaper Table 7-37. Pacific Gas and Electric Company 2023 General Rate Case Workpapers.

selling the Pleasant Creek storage facility. The proposal to retain Los Medanos is in lieu of drilling additional new wells at the McDonald Island facility to meet the utility's firm withdrawal obligations. PG&E's proposed NGSS updates are pending before the CPUC as of mid-2022.

Last, in March 2019, PG&E submitted an underground storage risk and integrity management plan and accompanying field specific well risk evaluation and construction standard implementation plan (2019 Implementation Plan) to CalGEM consistent with CalGEM's regulations. After input and feedback from CalGEM, PG&E submitted a revised implementation plan in January 2021 (2021 Revised Implementation Plan), which details our well testing, conversion, and risk management plans. In June 2021, CalGEM approved the 2021 Revised Implementation Plan with some additional requirements. Consistent with the 2021 Revised Implementation Plan, PG&E expects all new wells to be drilled and existing wells converted to tubing and packers by 2026.

OTHER CALIFORNIA STORAGE FACILITIES

In addition to storage services offered by PG&E, there are four other storage providers in Northern California: Wild Goose Storage, LLC; Gill Ranch Storage, LLC; Central Valley Gas Storage, LLC; and Lodi Gas Storage, LLC. These facilities have an estimated total working gas capacity of roughly 132 Bcf[71].

POLICIES IMPACTING FUTURE GAS SUPPLY AND ASSETS OVERVIEW

California's policies to reduce GHGs are expected to impact gas supply and assets. PG&E is responding to these policies and actively planning for and implementing programs to decarbonize existing gas throughput, supporting RNG adoption, supplying hard to electrify industries, and planning to utilize the gas system as a long-term energy storage mechanism.

[71] Capacities derived from information provided by Independent Storage Providers.

RENEWABLE NATURAL GAS

As a result of various policy and regulatory changes to decarbonize gas throughput, PG&E is seeing an influx of requests to interconnect RNG to utility pipelines in Northern California. RNG producers are leveraging available grants and incentives to encourage the production of RNG to reduce GHG emissions from these biogas-sources and for use as an alternative fuel source for transportation and other end use customers. PG&E is engaged in the following efforts regarding RNG:

- Procuring RNG for all PG&E-owned Compressed Natural Gas (CNG) fueling stations;
- Actively working with RNG developers to interconnect their projects through the biomethane program;
- Working to file an application to advance woody biomass pilot projects under CPUC D. 22-02-025;
- Planning for implementation of biomethane (RNG) procurement for core customers under CPUC Decision 22-02-025; and
- Participation in various Research and Development (R&D) efforts to further understand and develop new methods and technologies to produce RNG that reduce the carbon intensity of the gas in the pipeline.

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MONETARY INCENTIVE PROGRAM

D.15-06-029 established a biomethane monetary incentive program that included $40 million to encourage biomethane producers to design, construct, and safely operate projects that interconnect and inject biomethane into California's natural gas utilities' pipeline systems.

D.19-12-009 implements an Incentive Reservation System for the biomethane monetary incentive program established in D.15-06-029. The Incentive Reservation System opened to applications on February 3, 2020, and the queue is published on the CPUC's RNG website.[72]

D.20-12-031 authorized an additional $40 million of RNG project incentive funding sourced from Cap-and-Trade allowance auction proceeds subject to projects meeting applicable CARB program regulations.

Based on information provided on the CPUC's RNG website, seven projects have received a total of approximately $29.5 million of funding under the incentive program, leaving $50.5 million remaining in the program.

RESEARCH AND DEVELOPMENT

PG&E's R&D RNG roadmap[73] further outlines PG&E's goals for incorporating RNG into the supply portfolio.

HYDROGEN

Hydrogen, H_2, is seen as a game changer in decarbonizing the gas supply and sectors that will be difficult to electrify. To achieve the goals set forth in SB 100, discussed below, California will likely need to incorporate H_2 into the portfolio of green fuels for various sectors. Many other countries have already embraced H_2 and fuel cell technology to reduce their carbon footprint.

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[72] https://www.cpuc.ca.gov/renewable_natural_gas/ .

[73] https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/interconnection-renewables/interconnections-renewables/RNG_Roadmap_2020.pdf.

Given the momentum, California, through the Governor's Office of Business and Economic Development, is in the process of unifying Northern and Southern California efforts into a single application for the upcoming DOE (U.S. Department of Energy) RFP (Request For Proposals) for hydrogen infrastructure investment. This will be an important step in taking advantage of the geographic diversity in the northern and southern portions of the state.

Additionally, the California IOUs are working together on an action plan for incorporating H_2 into the pipelines through pilot and demonstration projects to help inform an eventual hydrogen injection standard.

HYDROGEN STORAGE (CONVENTIONAL AND NEW TECHNOLOGY)

H_2 has many potential applications. One such application is to produce H_2 through electrolysis from excess renewable energy and store it in the pipeline system (or dedicated underground storage facilities) for later use. Such uses may include H_2 as fuel for electric generation to backup intermittent renewable generation. H_2 storage has great potential for longer-term storage that current electric battery storage technology is unable to serve. Moreover, H_2 storage can provide clean fuel for electric generation at larger volumes as renewable generation experiences seasonal intermittency. Battery storage technology currently cannot provide the scale needed to backup seasonal intermittency.

NORTHERN CALIFORNIA

CNG AS RAIL AND LNG AS MARINE FUEL

As mentioned above in the Gas Demand section, there is tremendous opportunity for growth in the rail and marine markets. The gas supply needed for this demand will need to come from cleaner sources of fuel such as RNG and H_2. Additionally, LNG infrastructure would need to be developed at the appropriate scale to meet marine demand for LNG.

REGULATORY ENVIRONMENT

OVERVIEW

This section provides an overview of the existing and near-term regulatory policies and their effect on the Northern California gas system and its users.

Given the anticipated state and federal regulatory policies surrounding storage, transportation, inspection, and capacity requirements, the cost to safely and reliably operate PG&E's gas system will continue to rise. At the same time, a decline in throughput—which PG&E anticipates is a result of California's GHG reduction goals and cities taking action to establish new electric codes and ordinances—will mean those costs will be spread over fewer therms and possibly fewer customers. Unless the evolution of the gas system is well managed, rising costs combined with reduced throughput would impact the affordability of gas for customers.

Furthermore, despite readily available domestic gas supply and operational innovation, the complex regulatory environment and evolving policies are likely to create price uncertainty in the medium to long term.

FEDERAL AND CANADIAN REGULATORY MATTERS

PG&E actively participates in FERC ratemaking proceedings for interstate pipelines connected to PG&E's system since these proceedings can impact the cost of gas delivered, the reliability of gas supply, and the services provided to the PG&E's gas customers. PG&E also participates in FERC proceedings of general interest to the extent they affect PG&E's operations and policies or natural gas market policies generally.

GTN AND RUBY PIPELINES

Gas Transmission Northwest (GTN) and their shippers settled during pre-rate case negotiations with no rate increase for two years beginning on January 1, 2022. GTN has also filed a certification application in October 2021 for its Xpress Project that PG&E has intervened in and are monitoring for impacts on PG&E's customers. The proposed project will create 150

MDth/d of incremental mainline capacity on GTN's system. The in-service date is November 1, 2023.

On March 31, 2022, Ruby Pipeline, LLC (Ruby) filed to reorganize under Chapter 11 of the United States Bankruptcy Code in response to an upcoming debt repayment obligation.[74] PG&E will follow this event to limit the impacts to PG&E's operations and policies or natural gas market policies.

El Paso Natural Gas Company

On April 21, 2022, FERC issued an order initiating an investigation to determine whether the rates currently charged by El Paso Natural Gas Company, L.L.C. ("El Paso") are just and reasonable and setting the matter for hearing. PG&E is monitoring the proceeding.

Other Pipelines

There are currently no significant regulatory issues regarding Kern River Gas Transmission (Kern River); or Transwestern Pipeline Company, LLC (Transwestern) pipelines.

CANADIAN REGULATORY MATTERS

PG&E continually monitors Canadian regulatory matters that can impact PG&E's customers. Currently, no regulatory issues are currently present.

FERC AND CAISO GAS--ELECTRIC COORDINATION ACTIONS

While there are no general inquiries or proceedings at FERC addressing gas-electric coordination, the California Independent System Operator (CAISO), which is FERC-jurisdictional, has ongoing policy initiatives that may impact gas demand, supply, and prices. These initiatives include:

- Day-Ahead Market Enhancements; and
- Extended Day-Ahead Market

[74] https://cases.ra.kroll.com/rubypipeline/Administration.

These policy initiatives will need FERC approval before the proposed changes can be implemented.

STATE REGULATORY MATTERS

CALIFORNIA STATE SB 100 AND CARBON NEUTRALITY EXECUTIVE ORDER

On September 10, 2018, Governor Brown signed into law SB 100, which further increases the Renewable Portfolio Standard (RPS) targets and includes the following key requirements:

- Accelerates the RPS to 50 percent by 2026 and increases the RPS to 60 percent by 2030;
- Creates a separate state policy that requires 100 percent of all retail sales of electricity to serve end-use customers and 100 percent of electricity procured to serve state agencies to come from RPS-eligible or zero -carbon resources by 2045; and
- Requires the CPUC, in consultation with the CAISO and other balancing authorities, to issue a joint report to the Legislature by January 1, 2021, and every four years thereafter, that evaluates the anticipated costs and benefits of the 100 percent clean policy to electric, gas, and water utilities, including customer rate impacts and benefits.

Additionally, Governor Brown signed an EO on September 10, 2018, establishing a new statewide goal to achieve carbon neutrality by 2045 across all sectors of the California economy and to achieve and maintain net negative GHG emissions thereafter. Implementation of the order will require California to undertake additional decarbonization and carbon removal efforts. CARB is developing California's plan for achieving carbon neutrality in its Climate Change Scoping Plan Update, due to be completed by the end of 2022.[75]

[75] CARB Scoping Plan, available at: https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan.

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PIPELINE SAFETY

Since 2011, the CPUC and the California State Legislature have adopted a series of regulations and bills that reinforce the setting of public and employee safety as the top priority for the state's gas utilities. In particular, Senate Bill (SB) 705 mandated that gas operators develop and implement safety plans that are consistent with the best practices in the gas industry.

On March 15, 2022, PG&E filed its 2022 Gas Safety Plan with the CPUC, which explains how PG&E puts the safety of the public, customers, employees, and contractors first, and details gas safety work performed in 2021. The Gas Safety Plan is reviewed and updated annually in accordance with General Order 112-F Section 123.2(k), and Public Utilities Code Sections 961 and 963.1.

Additionally, PG&E submits the following reports to the CPUC: (1) semi-annual Gas Transmission & Storage Compliance Report; (2) annual Gas Distribution Pipeline Safety Report; (3) annual Risk Spending Accountability Report; and (4) annual Safety Performance Metrics Report. These reports are designed to provide the CPUC and other interested stakeholders with insight into the amount of safety, reliability, and maintenance -related work PG&E has completed over the course of the reporting period and/or performance in key safety areas.

Below are selected highlights from PG&E's 2021 reports and the Gas Safety Plan which further demonstrate PG&E's commitment to pipeline safety:

- **Asset Management System:** PG&E maintains an asset management system to help drive the business toward achieving its commitment to the safe, reliable, and affordable management and operation of PG&E's gas assets. Using the Publicly Available Specification (PAS) 55: 2008 and International Organization for Standardization (ISO) 55001: PG&E's asset management system focuses on: (1) knowing the condition of the assets; (2) understanding the risks to those assets; (3) implementing asset risk reduction strategies; (4) maintaining asset condition and performance; and (5) balancing asset cost, risk, and performance in pursuit of the asset management strategic objectives.

- **Process Safety:** Guided by the elements set by the Center for Chemical Process Safety, PG&E's commitment to implement process safety aligns with American Petroleum

Institute (API) Recommended Practice (RP) 754 Process Safety Performance Indicators for the Refining and Petrochemical Industries. A risk-sorting criterion to track and trend process safety leading and lagging indicators is used to identify emerging issues before incidents occur. The Process Safety team continued to review changes to existing procedures and standards and new procedures and standards in order to help Gas Operations operate and maintain safe facilities and consistently implement process safety practices.

- **In-Line Inspection (ILI):** PG&E's current goal is to upgrade the gas transmission pipeline system to be capable of ILI for over 4,500 transmission pipeline miles by the end of 2036, which is approximately 69 percent of PG&E's GT pipeline miles. As of December 31, 2021, PG&E has successfully upgraded 46 percent of the GT pipeline system, resulting in approximately 2,956 miles of piggable transmission lines.

- **Third-Party Dig-Ins:** In 2021, PG&E experienced 0.91 third-party dig-ins per 1,000 Underground Service Alert (USA) tickets, outperforming its 2021 target of 1.07 third-party dig-ins per 1,000 tickets.

- **Community Pipeline Safety Initiative (CPSI)**: A multi-year program designed to enhance safety by improving access to pipeline rights-of-way. To date, the program has cleared more than 99 percent of the work scope, including approximately 1,544 vegetation miles and 359.9 structure miles. Pending outstanding municipality and customer agreements, and receipt of long-lead time permits, the remaining 8.38 miles of vegetation and 0.02 miles of structure clearing has been extended to at least December 2022. For areas with completed CPSI work, PG&E remains committed to keeping the area above and around the pipeline clear through our ongoing Gas Transmission Vegetation Management Program.

NORTHERN CALIFORNIA

STORAGE SAFETY

In response to the Southern California Aliso Canyon Storage natural gas leak in October 2015, the California Department of Conservation, Geologic Energy Management Division (CalGEM) adopted new safety regulations concerning natural gas storage wells across California. Key elements of these new rules included requiring all operators to submit risk and integrity management plans, well casing inspection and pressure testing plans, and a schedule to convert or retrofit wells to tubing and packer. The elimination of the annulus flow could reduce traditional well performance on average by 40 percent.

Partly in response to the new regulations, PG&E proposed a Natural Gas Storage Strategy (NGSS) in its 2019 Gas Transmission and Storage (GT&S) Rate Case. Specifically, PG&E proposed to exit the commercial storage market and focus on reliability services. As a part of the NGSS, PG&E proposed to sell or decommission its Los Medanos and Pleasant Creek storage facilities. The CPUC approved the NGSS in Decision (D.) 19-09-025.

In its 2023 General Rate Case application, filed at the CPUC on June 30, 2021, PG&E proposed updates to the NGSS in response to evolving CalGEM regulations. These updates include a proposal to retain the Los Medanos storage facility while still decommissioning or selling the Pleasant Creek storage facility. The proposal to retain Los Medanos is in lieu of drilling additional new wells at the McDonald Island facility to meet our firm withdrawal obligations. PG&E's proposed NGSS updates are still pending before the CPUC.

In March 2019, PG&E submitted an underground storage risk and integrity management plan (R&IMP) and accompanying field specific well risk evaluation and construction standard implementation plan (2019 Implementation Plan) to CalGEM consistent with CalGEM's regulations. After input and feedback from CalGEM, PG&E submitted a revised implementation plan in January 2021 (2021 Revised Implementation Plan), which details our well testing, conversion, and risk management plans. In June 2021, CalGEM approved the 2021 Revised Implementation Plan with some additional requirements. Consistent with the 2021 Revised Implementation Plan, PG&E expects all new wells to be drilled and existing wells converted to tubing and packers by of 2026.

Cities, Regulators, and Air Districts Pursue Electrification

Local governments continue to take steps towards electrification at the city and county level with new electric "reach" building codes that require or give preference to electric new construction.[76] The California Public Utilities Commission has also proposed a removal of gas line extension allowances, discounts, and refunds within the Building Decarbonization OIR (R.19-01-011). PG&E's position was to not oppose a removal of residential gas line extension allowances, but to request that allowances remain for non-residential customers that provide a financial or environmental benefit to ratepayers.

The spread of all-electric new construction and the consideration of point-of-sale bans on gas furnaces and water heaters suggests a future flattening of demand for gas in buildings.

Known Regulatory Hurdles

Federal regulation along with state and local climate action goals are set to create an evolving and time challenging environment for gas utilities and customers. To succeed in achieving operational safety and climate action goals, the following hurdles need to be addressed:

- As regulations continue to be revised and updated, the cost of providing a safe and reliable gas system will continue to rise. This increase in cost, paired with state and local GHG goals, are expected to drive down gas throughput. Lower gas throughput will likely result in a higher cost per-therm for customers if the evolution is not well-managed.

- While there is significant potential for renewable gas (RG) to replace some portion of natural gas supply, the current investments and incentives for RG end-use principally favor the transportation sector. With the clear financial advantage towards transportation, there is comparatively little RG available to establish a consistent RG supply to meet PG&E's customer or third-party needs now that an RG standard has been established. If this is to change, California will have to balance the funding mechanisms between the

[76] "California's Cities Lead the Way on Pollution-Free Homes and Buildings." Sierra Club, June 16, 2022: https://www.sierraclub.org/articles/2021/07/californias-cities-lead-way-pollution-free-homes-and-buildings.

transportation sector and other sectors so that RG project developers have opportunities to supply RG towards an RG standard or the transportation sector.

California's gas system is going through unprecedented changes. As it evolves, it is important that regulatory bodies and the utilities work together to ensure that Californians continue to have access to clean, reliable, and affordable energy.

OTHER REGULATORY MATTERS

OVERVIEW

This section includes PG&E's GHG and Cap-and-Trade reporting and discusses other regulatory matters that may impact Northern California's gas system.

PG&E is participating in several OIRs, which address crucial topics that will impact the California gas system. For example, the:

- Biomethane OIR (R.13-02-008) helped the utilities make RNG interconnections more efficient and affordable across California as well as established an RNG procurement program for core customers.

Gas System Planning OIR (R.20-01-007) which will allow the utilities to: (1) develop updated reliability standards that are in line with current and future operational challenges of gas system operators, (2) improve coordination between gas utilities and gas -fired generators, and (3) develop and implement a long -term strategy to work towards California's decarbonization goals.

GHG REPORTING AND CAP-AND-TRADE OBLIGATIONS

In March 2022, PG&E Gas Operations reported to the U.S. Environmental Protection Agency (EPA) GHG emissions in accordance with 40 Code of Federal Regulations Part 98 in four primary categories: GHG emissions in reporting year 2021 resulting from combustion at seven compressor stations, where the annual emissions exceed 25,000 metric tons of CO2 equivalent (mtCO2e); the GHG emissions resulting from combustion of all customers except customers consuming more than 460 MMscf; certain vented and fugitive emissions from the seven compressor stations and natural gas distribution system; and GHG emissions from transmission pipeline blowdowns.

In April 2022, PG&E reported to CARB GHG emissions approximately 42.5 million mtCO2e (metric tons carbon dioxide equivalent) in these primary categories for reporting year 2021: GHG emissions resulting from combustion at seven compressor stations and one underground gas storage facility, where the annual emissions exceed 10,000 mtCO2e; the GHG emissions resulting from combustion of delivered gas to all customers; and vented and fugitive emissions from seven compressor stations and one underground gas storage facility.

Both the seven compressor stations obligation and PG&E's natural gas supplier obligation subject to the CARB mandatory reporting are subject to the CARB Cap-and-Trade Program. In 2021, CARB estimated that PG&E's responsibility for compliance obligations of GHG emissions as a natural gas supplier was approximately 17.9 million mtCO2e for reporting year 2020. CARB will issue the final 2020 PG&E's compliance obligations of GHG emissions as a natural gas supplier in October 2022.

In June 2021, PG&E filed the 2020 Annual Natural Gas Leakage Abatement Report and reported 3 billion standard cubic feet (Bscf) of methane emissions from intentional and unintentional releases. The annual report is a partial fulfillment of Rulemaking (R.) 15-01-008 to adopt rules and best practices aiming to reduce methane emissions from the Natural Gas System in application of SB 1371.

In addition, PG&E filed its two-year Leak Abatement Compliance Plan in March 2022. This plan addresses the 26 best practices outlined in the Leak Abatement OIR D.17-06-015. It emphasizes minimizing methane emissions through changes to policies and procedures, personnel training, leak detection, leak repair and leak prevention. PG&E's plan includes transitioning from the three-year gas distribution leak survey cycle to optimized leak surveys, potential reduction of the Super Emitter threshold, extending blowdown reduction strategies to compressor station and storage facilities, lowering the pipeline pressure to near zero for scheduled transmission projects and applying degassing technologies for In-Line Inspection (ILI) and lower volume transmission projects.

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Finally, PG&E is an active member and founding partner in the voluntary EPA Natural Gas STAR and Methane Challenge Programs, respectively, where annual reports are submitted to the EPA showcasing PG&E's efforts and best practices to reduce methane emissions. Each year, on a mandatory basis, PG&E reports its methane emissions to the California Public Utilities Commission and, on a voluntary basis, also reports—and obtains third-party verification for—a more comprehensive corporate greenhouse gas emissions inventory, including PG&E's methane emissions. Each year, PG&E also completes and publishes the Edison Electric Institute (EEI) and American Gas Association (AGA) voluntary Environmental, Social, Governance (ESG) and Sustainability reporting templates for investors, which includes methane emissions. PG&E believes it's essential that investors, customers, policymakers, and other stakeholders have access to information on PG&E's emissions profile. In addition, PG&E is committed through its 1-million-ton challenge to reduce GHG emissions from company operations through 2022. PG&E's strategy to meet this goal includes increased leak survey and repair, removing high-bleed pneumatic devices, replacing vintage distribution main, and reducing transmission pipeline blowdowns.

BIOMETHANE OIR R.13-02-008 PHASE 3

On July 5, 2018, the CPUC reopened R.13-02-008 Phase 3 and ordered the joint California utilities to propose a joint RNG interconnection tariff and interconnection agreements.

On October 28, 2020, the CPUC approved the joint utilities' Standard Renewable Gas Interconnection Tariff pursuant to D. 20-08-035 which established standards and requirements to permit the safe injection of RNG into a jurisdictional common carrier pipeline.

The CPUC also instituted a Reservation System in D.19-12-009 that became effective as of February 3, 2020, for the biomethane incentive program implemented by D.15-06-029.

BIOMETHANE OIR R.13-02-008 PHASE 4

On November 21, 2019, the CPUC issued a Ruling to establish Phase 4 of the proceeding that will address injection of renewable H2 into gas pipelines and implementation of SB 1440 (RNG procurement).

On February 24, 2022, the CPUC approved D.22-02-025 implementing Senate Bill 1440 establishing a framework of a mandatory Biomethane Procurement Program. This Biomethane Procurement Program will assist the state in meeting short-lived climate pollutant emissions reduction goals by requiring the Joint Utilities to procure biomethane (RNG) produced from organic waste for their core customers.

On April 5, and 6, 2022, the Joint Utilities hosted public workshops to discuss the Standard Biomethane Procurement Methodology (SBPM) that included panelists from each stakeholder group. The Joint Utilities are directed to file a joint Tier 2 Advice Letter with a report of the workshop and feedback received. On April 22, 2022, the Joint Utilities hosted a separate public workshop to discuss the Renewable Gas Procurement Plan (RGPP) that also included panelists from each stakeholder group. The Joint Utilities are directed to file a Tier 1 Advice Letter to establish a template RGPP. The joint utilities plan to file a new application outlining three distinct H_2 projects to further understand capabilities of H_2 and inform a statewide injection standard.

GAS SYSTEM PLANNING OIR R.20-01-007

The CPUC has an in-progress Rulemaking - Order Instituting Rulemaking to "Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning." This proceeding will be conducted in two tracks and will: (1) develop and adopt as necessary updated reliability standards that reflect current and future operational challenges to gas system operators, (2) determine the regulatory changes to improve coordination between gas utilities and gas-fired generators, and (3) implement a long-term planning strategy to manage the transition away from natural gas-fueled technologies to meet California's decarbonization goals. This proceeding is currently in track two.

ABNORMAL PEAK DAY DEMAND AND SUPPLY

APD DEMAND FORECAST

The Abnormal Peak Day (APD) forecast is a projection of demand under extreme weather conditions. PG&E defines an APD as a 1-in-90 year cold temperature event. The 1-in-90 temperature corresponds to a 28.3 degree Fahrenheit system weighted mean temperature across the PG&E system. The PG&E core demand forecast corresponding to a 28.3 degree Fahrenheit temperature is estimated to be approximately 3.0 Bcf/d. The PG&E load forecast shown here excludes all noncore demand and excludes all electric generation (EG) demand. Under an APD design scenario PG&E is only required to ensure that it can supply enough gas to core customers on the system.

The APD core forecast in the table below is developed using the observed relationship between historical daily weather and core usage data. This relationship is then used to forecast the core load under APD conditions.

APD SUPPLY REQUIREMENT FORECAST

For APD planning purposes, supplies will flow under core Procurement's firm capacity, any as-available capacity, and capacity made available pursuant to supply diversion arrangements. Supplies could also be purchased from noncore suppliers. Flowing supplies may come from Canada, the U.S. Southwest, the Rocky Mountain region, SoCalGas, and California production. Also, a significant part of the APD demand will be met by storage withdrawals from PG&E's and independent storage providers' underground storage facilities located within Northern and Central California.

PG&E's Core Gas Supply Department is responsible for procuring adequate flowing supplies to serve approximately 80 percent of PG&E's core gas usage. Core aggregators provide procurement services for the remaining balance of PG&E's core customers and have the same obligation as PG&E Core Gas Supply to make and pay for all necessary arrangements to deliver gas to PG&E to match the use of their customers.

In previous extreme cold weather events, PG&E has observed a drop in flowing pipeline supplies. Supply from Canada is affected as cold weather drops south from Canada with a two- to three-day lag before hitting PG&E's service territory. There is also impact on supply from the Southwest. While prices can influence the availability of supply to PG&E's system, cold weather can affect producing wells in the basins, which in turn can affect the total supply to the PG&E system and others.

If core supplies are insufficient to meet core demand, PG&E can divert gas from noncore customers, including EG customers, to meet demand. PG&E's tariffs contain diversion and Emergency Flow Order non-compliance charges that are designed to cause the noncore market to either reduce or cease its use of gas, if required. Since little, if any, alternate fuel-burn capability exists today, supply diversions from the noncore would necessitate those noncore customers to curtail operations. Under supply-shortfall conditions—such as an APD—a significant portion of EG customers could be shut down potentially impacting electric system reliability.

TABLE 19 – FORECAST OF CORE GAS DEMAND AND SUPPLY ON AN ABNORMAL PEAK DAY (APD)

(MMcf/d)

Line No.		2022-23	2023-24	2024-25
1	APD Core Demand (1)	3,057	3,062	3,070
2	Independent Storage Provider Withdrawal (2)	2,162	2,162	2,162
3	Firm Flowing Supply (3)	3,051	3,051	3,051
4	Projected Resources to Meet Demands (4)	4,232	4,193	4,108

Notes:

(1) Includes PG&E's Gas Procurement Department's and other Core Aggregator's core customer demands. APD core demand forecast is calculated for 28.3 degrees F system composite temperature, corresponding to 1-in-90-year cold temperature event. PG&E uses a system composite temperature based on six weather sites.

(2) The Independent Storage Provider Withdrawal is based on information provided by the Independent Storage Providers to PG&E and internal analysis by PG&E.

(3) The Firm Flowing Supply includes firm Redwood and Baja capacities and nominal amounts of California gas production. These values are those currently approved for use within PG&E.

(4) Projected Resources to Meet Demands (Line No. 4) are less than the sum of Independent Storage Provider Withdrawal (Line No. 2) and Firm Flowing Supply (Line No. 3) because PG&E's system cannot simultaneously accommodate all flowing supplies and all storage withdrawals. This number is designed for a 1-in-10 design scenario while an APD is a 1-in-90 design scenario, meaning this number may not be representative of what the actual supply on a 1-in-90 day will be, but is sufficient to meet all APD Core demand.

The tables below provide peak day demand projections on PG&E's system for both winter month (December) and summer month (August) periods under PG&E's high Peak Day Demand Cases.

TABLE 20– WINTER PEAK DAY DEMAND (MMcf/d)

Year	Core Unadjusted for Building Electrification	Building Electrification Modifier	Core With Building Electrification	Noncore Non-EG	EG, Including SMUD	Total Demand
2022-2023	2,574	-2	2,572	458	897	3,927
2023-2024	2,579	-4	2,575	460	908	3,942
2024-2025	2,585	-6	2,579	475	929	3,984
2025-2026	2,591	-8	2,582	488	983	4,054
2026-2027	2,600	-11	2,589	489	1,006	4,085
2027-2028	2,609	-17	2,592	490	1,021	4,104

The core demand in the Winter Peak Day Demand table is developed using the observed relationship between historical daily weather and core gas usage. This relationship is then used to forecast the core load under a 1-in-10 temperature scenario. The building electrification modifier represents the California Energy Commission's 2021 Integrated Energy Policy Report Additional Achievable Fuel Substitution (Low Case, AAFS 2)[77]. The projection in the AAFS 2 represents the building electrification, moving from natural gas use to electric use. The noncore Non-EG forecast is the average daily December demand under 1-in-10 Cold and Dry conditions. Last, the EG, including SMUD projection is the 90th percentile for the months of December through February under 1-in-10 Cold, Dry Hydro Demand conditions.

[77] https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report .

TABLE 21 – SUMMER PEAK DAY DEMAND
(MMcf/d)

Year	Core Unadjusted for Building Electrification	Building Electrification Modifier	Core With Building Electrification	Noncore Non-EG	EG, Including SMUD	Total Demand
2022	353	-3	351	585	979	1,914
2023	340	-5	335	598	929	1,892
2024	330	-7	323	610	927	1,860
2025	319	-10	309	615	853	1,777
2026	309	-13	296	616	978	1,890
2027	304	-17	287	616	1,025	1,929

The core and noncore Non-EG demands in the Summer Peak Day Demand table represent the average August daily summer demand under 1-in-10 cold and dry conditions. The building electrification modifier represents the California Energy Commission's 2021 Integrated Energy Policy Report Additional Achievable Fuel Substitution (Low Case, AAFS 2). Last, the EG including SMUD demand forecast is the 90th percentile for the months of July through September under 1-in-10 cold and dry conditions.

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TABLE 22

ANNUAL GAS SUPPLY AND REQUIREMENTS
RECORDED YEARS 2017-2021
MMCF/DAY

LINE		2017	2018	2019	2020	2021
GAS SUPPLY TAKEN						
	CALIFORNIA SOURCE GAS					
1	Core Purchases	0	0	0	0	0
2	Customer Gas Transport & Exchange	42	49	62	63	60
3	Total California Source Gas	42	49	62	63	60
	OUT-OF-STATE GAS					
	Core Net Purchases					
6	Rocky Mountain Gas	178	161	170	158	158
7	U.S. Southwest Gas	84	58	58	41	29
8	Canadian Gas	319	303	286	379	410
	Customer Gas Transport					
10	Rocky Mountain Gas	461	367	486	416	329
11	U.S. Southwest Gas	304	430	599	505	539
12	Canadian Gas	832	957	888	927	933
13	Total Out-of-State Gas	2,178	2,276	2,487	2,425	2,397
14	STORAGE WITHDRAWAL(2)	328	397	350	252	344
15	Total Gas Supply Taken	2,548	2,722	2,898	2,740	2,801
GAS SENDOUT						
	CORE					
19	Residential	483	489	503	495	488
20	Commercial	220	225	226	196	209
21	NGV	7	7	7	7	7
22	Total Throughput-Core	710	721	736	698	704
	NONCORE					
24	Industrial	543	562	534	467	453
25	Electric Generation (1)	698	855	865	895	964
26	NGV	2	3	4	3	4
27	Total Throughput-Noncore	1,244	1,421	1,403	1,365	1,421
28	WHOLESALE	9	9	9	8	8
29	Total Throughput	1,963	2,151	2,148	2,072	2,133
30	OFF-SYSTEM DELIVERIES	233	264	224	241	284
31	CALIFORNIA EXCHANGE GAS	14	22	38	37	38
32	STORAGE INJECTION (2)	294	244	441	343	292
33	SHRINKAGE Company Use / Unaccounted for	44	41	47	47	55
34	Total Gas Send Out	2,548	2,722	2,898	2,740	2,801
	TRANSPORTATION & EXCHANGE					
38	CORE ALL END USES	139	139	138	115	111
39	NONCORE INDUSTRIAL	543	562	534	467	453
40	ELECTRIC GENERATION	698	855	865	895	964
41	SUBTOTAL/RETAIL	1,380	1,557	1,538	1,477	1,529
43	WHOLESALE/INTERNATIONAL	9	9	9	8	8
45	TOTAL TRANSPORTATION AND EXCHANGE	1,389	1,566	1,547	1,485	1,537
	CURTAILMENT/ALTERNATIVE FUEL BURNS					
48	Residential, Commercial, Industrial	0	0	0	0	0
49	Utility Electric Generation	0	0	0	0	0
50	TOTAL CURTAILMENT (3)	0	0	0	0	0

NOTES:

(1) Electric generation includes SMUD, cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by other pipelines.

(2) Includes both PG&E and third party storage

(3) UEG curtailments include voluntary oil burns due to economic, operational, and inventory reduction reasons as well as involuntary curtailments due to supply shortages and capacity constraints.

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TABLE 23

ANNUAL GAS SUPPLY FORECAST
MMCF/DAY
AVERAGE DEMAND YEAR

LINE		2022	2023	2024	2025	2026	LINE
FIRM CAPACITY AVAILABLE							
1	**California Source Gas**	56	56	56	56	56	1
	Out of State Gas						
2	Baja Path (1)	960	960	960	960	960	2
3	Redwood Path (2)	2,060	2,060	2,060	1,915	1,915	3
3.a	SW Gas Corp. from Great Basin Gas Transmission Company	39	39	39	39	39	3.a
4	**Supplemental (3)**	0	0	0	0	0	4
5	**Total Supplies Available**	3,115	3,115	3,115	2,970	2,970	5
GAS SUPPLY TAKEN							
6	**California Source Gas**	56	56	56	56	56	6
7	**Out of State Gas (via existing facilities)**	2,049	2,054	2,043	2,038	2,063	7
8	**Supplemental**	0	0	0	0	0	8
9	**Total Supply Taken**	2,105	2,110	2,099	2,094	2,119	9
10	**Net Underground Storage Withdrawal**	0	0	0	0	0	10
11	**Total Throughput**	2,105	2,110	2,099	2,094	2,119	11
REQUIREMENTS FORECAST BY END USE							
	Core						
12	Residential (4)	491	473	460	445	432	12
13	Commercial	208	214	213	210	208	13
14	NGV	7	7	8	8	8	14
15	**Total Core**	706	694	680	664	648	15
	Noncore						
16	Industrial	462	477	492	497	498	16
17	SMUD Electric Generation (5)	96	96	96	96	96	17
18	PG&E Electric Generation (6)	484	448	441	442	481	18
19	NGV	4	4	4	4	4	19
20	Wholesale	9	9	9	9	9	20
21	California Exchange Gas	38	38	38	38	38	21
22	**Total Noncore**	1,093	1,072	1,080	1,087	1,127	22
23	**Off-System Deliveries (7)**	272	310	305	310	310	23
	Shrinkage						
24	Company use and Unaccounted for	34	34	34	34	34	24
25	**TOTAL END USE**	2,105	2,110	2,099	2,094	2,119	25
	TRANSPORTATION & EXCHANGE						
26	CORE — ALL END USES	117	117	116	113	111	26
27	NONCORE — COMMERCIAL/INDUSTRIAL	504	519	534	539	540	27
28	ELECTRIC GENERATION	580	544	537	538	577	28
29	SUBTOTAL/RETAIL	1,201	1,180	1,186	1,191	1,229	29
30	WHOLESALE/INTERNATIONAL	9	9	9	9	9	30
31	TOTAL TRANSPORTATION AND EXCHANGE	1,210	1,189	1,195	1,200	1,238	31
32	System Curtailment	0	0	0	0	0	32

NOTES:
(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, and El Paso pipelines.
(2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via TransCanada Gas Transmission Northwest pipeline and Ruby pipeline.
(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.
(4) Includes Southwest Gas direct service to its northern California service area.
(5) Forecast by SMUD.
(6) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.
(7) Deliveries to southern California.

ANNUAL GAS SUPPLY FORECAST
MMCF/DAY
AVERAGE DEMAND YEAR

TABLE 24

LINE			2027	2028	2029	2030	2035	LINE
FIRM CAPACITY AVAILABLE								
1	**California Source Gas**		56	56	56	56	56	1
	Out of State Gas							
2	Baja Path [1]		960	960	960	960	960	2
3	Redwood Path [2]		1,915	1,915	1,915	1,915	1,915	3
3.a	SW Gas Corp. from Great Basin Gas Transmission Company		39	39	39	39	39	3.a
4	**Supplemental** [3]		0	0	0	0	0	4
5	**Total Supplies Available**		2,970	2,970	2,970	2,970	2,970	5
GAS SUPPLY TAKEN								
6	**California Source Gas**		56	56	56	56	56	6
7	**Out of State Gas (via existing facilities)**		1,749	1,738	1,722	1,698	1,681	7
8	**Supplemental**		0	0	0	0	0	8
9	**Total Supply Taken**		1,805	1,794	1,778	1,754	1,737	9
10	**Net Underground Storage Withdrawal**		0	0	0	0	0	10
11	**Total Throughput**		1,805	1,794	1,778	1,754	1,737	11
REQUIREMENTS FORECAST BY END USE								
	Core							
12	Residential [4]		423	412	402	391	338	12
13	Commercial		205	200	195	189	163	13
14	NGV		8	8	9	9	10	14
15	**Total Core**		636	620	605	589	511	15
	Noncore							
16	Industrial		499	499	499	498	496	16
17	SMUD Electric Generation [5]		96	96	96	96	96	17
18	PG&E Electric Generation [6]		489	493	493	486	549	18
19	NGV		4	5	5	5	5	19
20	Wholesale		9	9	9	9	9	20
21	California Exchange Gas		38	38	38	38	38	21
22	**Total Noncore**		1,135	1,140	1,139	1,132	1,193	22
23	**Off-System Deliveries** [7]		0	0	0	0	0	23
	Shrinkage							
24	Company use and Unaccounted for		33	33	33	33	33	24
25	**TOTAL END USE**		1,805	1,794	1,778	1,754	1,737	25
	TRANSPORTATION & EXCHANGE							
26	CORE	ALL END USES	109	106	104	101	86	26
27	NONCORE	COMMERCIAL/INDUSTRIAL	541	542	541	541	539	27
28		ELECTRIC GENERATION	585	589	589	582	645	28
29		SUBTOTAL/RETAIL	1,236	1,238	1,234	1,223	1,270	29
30		WHOLESALE/INTERNATIONAL	9	9	9	9	9	30
31		TOTAL TRANSPORTATION AND EXCHANGE	1,245	1,246	1,243	1,232	1,279	31
32	System Curtailment		0	0	0	0	0	32

NOTES:
(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, and El Paso pipelines.
(2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via TransCanada Gas Transmission Northwest pipeline and Ruby pipeline.
(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.
(4) Includes Southwest Gas direct service to its northern California service area.
(5) Forecast by SMUD.
(6) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.
(7) Deliveries to southern California.

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TABLE 25

ANNUAL GAS SUPPLY FORECAST
MMCF/DAY
HIGH DEMAND YEAR

LINE		2022	2023	2024	2025	2026	LINE
FIRM CAPACITY AVAILABLE							
1	**California Source Gas**	56	56	56	56	56	1
	Out of State Gas						
2	Baja Path [(1)]	960	960	960	960	960	2
3	Redwood Path [(2)]	2,060	2,060	2,060	1,915	1,915	3
3.a	SW Gas Corp. from Great Basin Gas Transmission Company	39	39	39	39	39	3.a
4	**Supplemental [(3)]**	0	0	0	0	0	4
5	**Total Supplies Available**	3,115	3,115	3,115	2,970	2,970	5
GAS SUPPLY TAKEN							
6	**California Source Gas**	56	56	56	56	56	6
7	**Out of State Gas (via existing facilities)**	2,109	2,149	2,144	2,141	2,177	7
8	**Supplemental**	0	0	0	0	0	8
9	**Total Supply Taken**	2,165	2,205	2,200	2,197	2,233	9
10	**Net Underground Storage Withdrawal**	0	0	0	0	0	10
11	**Total Throughput**	2,165	2,205	2,200	2,197	2,233	11
REQUIREMENTS FORECAST BY END USE							
	Core						
12	Residential [(4)]	527	512	500	485	472	12
13	Commercial	224	224	222	220	217	13
14	NGV	7	7	8	8	8	14
15	**Total Core**	758	744	729	713	698	15
	Noncore						
16	Industrial	467	480	493	499	499	16
17	SMUD Electric Generation [(5)]	96	96	96	96	96	17
18	PG&E Electric Generation [(6)]	485	490	490	493	543	18
19	NGV	3	4	4	4	4	19
20	Wholesale	10	10	10	10	10	20
21	California Exchange Gas	38	38	38	38	38	21
22	**Total Noncore**	1,099	1,116	1,131	1,139	1,190	22
23	**Off-System Deliveries [(7)]**	272	310	305	310	310	23
	Shrinkage						
24	Company use and Unaccounted for	36	35	35	35	35	24
25	**TOTAL END USE**	2,165	2,205	2,200	2,197	2,233	25
	TRANSPORTATION & EXCHANGE						
26	CORE — ALL END USES	126	124	122	120	118	26
27	NONCORE — COMMERCIAL/INDUSTRIAL	508	521	535	540	541	27
28	ELECTRIC GENERATION	581	586	586	589	639	28
29	SUBTOTAL/RETAIL	1,215	1,231	1,244	1,249	1,299	29
30	WHOLESALE/INTERNATIONAL	10	10	10	10	10	30
31	TOTAL TRANSPORTATION AND EXCHANGE	1,225	1,241	1,253	1,259	1,308	31
32	System Curtailment	0	0	0	0	0	32

NOTES:
(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, and El Paso pipelines.
(2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via TransCanada Gas Transmission Northwest pipeline and Ruby pipeline.
(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.
(4) Includes Southwest Gas direct service to its northern California service area.
(5) Forecast by SMUD.
(6) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.
(7) Deliveries to southern California.

ANNUAL GAS SUPPLY FORECAST
MMCF/DAY
HIGH DEMAND YEAR

TABLE 26

LINE		2027	2028	2029	2030	2035	LINE
	FIRM CAPACITY AVAILABLE						
1	**California Source Gas**	56	56	56	56	56	1
	Out of State Gas						
2	Baja Path [1]	960	960	960	960	960	2
3	Redwood Path [2]	1,915	1,915	1,915	1,915	1,915	3
3.a	SW Gas Corp. from Paiute Pipeline Comp.	39	39	39	39	39	3.a
4	**Supplemental [3]**	0	0	0	0	0	4
5	**Total Supplies Available**	2,970	2,970	2,970	2,970	2,970	5
	GAS SUPPLY TAKEN						
6	**California Source Gas**	56	56	56	56	56	6
7	**Out of State Gas (via existing facilities)**	1,876	1,863	1,844	1,821	1,800	7
8	**Supplemental**	0	0	0	0	0	8
9	**Total Supply Taken**	1,932	1,919	1,900	1,877	1,856	9
10	**Net Underground Storage Withdrawal**	0	0	0	0	0	10
11	**Total Throughput**	1,932	1,919	1,900	1,877	1,856	11
	REQUIREMENTS FORECAST BY END USE						
	Core						
12	Residential [4]	463	452	441	431	378	12
13	Commercial	214	209	204	199	172	13
14	NGV	8	8	9	9	10	14
15	**Total Core**	685	670	654	638	560	15
	Noncore						
16	Industrial	500	500	500	500	497	16
17	SMUD Electric Generation [5]	96	96	96	96	96	17
18	PG&E Electric Generation [6]	565	567	564	557	616	18
19	NGV	4	4	4	4	5	19
20	Wholesale	10	9	9	9	9	20
21	California Exchange Gas	38	38	38	38	38	21
22	**Total Noncore**	1,213	1,215	1,212	1,205	1,261	22
23	**Off-System Deliveries [7]**	0	0	0	0	0	23
	Shrinkage						
24	Company use and Unaccounted for	35	35	34	34	35	24
25	**TOTAL END USE**	1,932	1,919	1,900	1,877	1,856	25
	TRANSPORTATION & EXCHANGE						
26	CORE — ALL END USES	116	113	110	108	93	26
27	NONCORE — COMMERCIAL/INDUSTRIAL	542	543	542	542	540	27
28	ELECTRIC GENERATION	661	663	660	653	712	28
29	SUBTOTAL/RETAIL	1,319	1,319	1,313	1,303	1,345	29
30	WHOLESALE/INTERNATIONAL	10	9	9	9	9	30
31	TOTAL TRANSPORTATION AND EXCHANGE	1,329	1,328	1,322	1,312	1,355	31
32	System Curtailment	0	0	0	0	0	32

NOTES:
(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, and El Paso pipelines.
(2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via TransCanada Gas Transmission Northwest pipeline and Ruby pipeline.
(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.
(4) Includes Southwest Gas direct service to its northern California service area.
(5) Forecast by SMUD.
(6) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.
(7) Deliveries to southern California.

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2022 CALIFORNIA GAS REPORT

SOUTHERN CALIFORNIA GAS COMPANY

INTRODUCTION

SoCalGas is the principal distributor of natural gas in Southern California and provides retail and wholesale customers with transportation, exchange, storage services and also procurement services to most retail core customers. SoCalGas' distribution network is composed of approximately 51,070 miles of gas mains across an approximate 20,000 square mile service territory. Together with its intricate distribution network and transmission pipelines and four interconnected storage fields, SoCalGas delivered natural gas to over 5.874 million customers in 2021.

SoCalGas' vast system extends from the Colorado River on the eastern end to the Pacific Ocean on the western end and extending as far north as Tulare County and reaches the U.S./Mexico Border in the south (excluding San Diego County).

Figure 11: SoCalGas' Service Territory Map

Southern California

SoCalGas is a gas-only utility and, in addition to serving the residential, commercial, and industrial markets, provides gas for enhanced oil recovery (EOR) and electric generation (EG) customers in Southern California. SDG&E, SWG, the City of Long Beach Energy Resources Department, and the City of Vernon are SoCalGas' four wholesale utility customers. SoCalGas provides gas transportation services across its service territory to a border crossing point at the California-Mexico border at Mexicali to ECOGAS Mexico S. de R.L. de C.V which is a wholesale international customer located in Mexico.

This report covers a 14-year demand and forecast period, from 2022 through 2035; only the consecutive years 2022 through 2030 and the point year 2035 are shown in the tabular data in the next sections. All forecasts are subject to uncertainty, but represent best estimates for the future, based upon the most current information available.

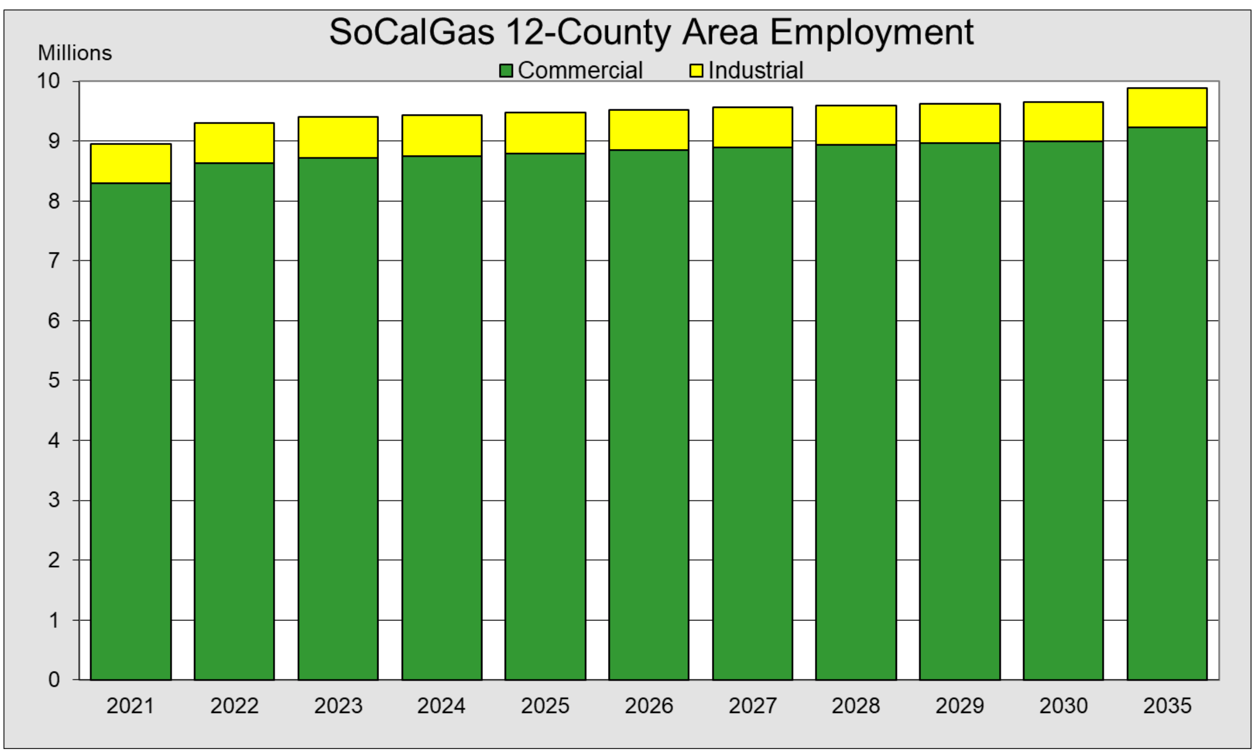
The Southern California section of the 2022 CGR begins with a discussion of the economic conditions and regulatory issues facing the utilities, followed by a discussion of the factors affecting natural gas demand in various market sectors. The outlook on natural gas supply availability, which continues to be favorable, is also presented. The regulatory environment and GHG issues are also discussed, followed by a review of the peak day demand forecast. Summary tables and figures underlying the forecast are also provided.

THE SOUTHERN CALIFORNIA ENVIRONMENT

ECONOMICS AND DEMOGRAPHICS

The gas demand projections are in large part determined by the long-term economic outlook for the SoCalGas service territory. After 2020's severe slowdown from the Covid-19 pandemic and related government restrictions, southern California's economy has nearly fully recovered. Total SoCalGas area jobs are expected to grow an average of 1.4% per year from 2021 through 2025. Local manufacturing and mining industrial employment is projected to average just 0.5% annual growth in the same period, with commercial jobs increasing about 1.5% annually. Jobs in accommodation, personal, and professional and business services should grow faster in the near term, as they recover from their pandemic plunge.

FIGURE 12 – SoCalGas 12-COUNTY AREA EMPLOYMENT



Southern California

Longer term, SoCalGas service-area employment is expected to increase slowly as population growth slows due to population aging and to more residents leaving for lower-cost locations primarily within the United States. From 2021 through 2035, total area job growth should average 0.7 percent per year. Area industrial jobs are forecasted to shrink an average of 0.1 percent per year through 2035; we expect the industrial share of total employment to fall from 7.4 percent in 2021 to 6.6 percent by 2035. Commercial jobs are expected to grow an average of 0.8 percent annually from 2021 through 2035.

Home building and meter hookups are expected to increase significantly in the next few years after the recent pandemic slowdown. Longer term growth should be sustained by pent-up demand and efforts to lessen southern California's longtime housing shortage. Net active meter growth --driven mainly by new home construction-- is projected to recover from a low pandemic-pressured 27,400 (+0.47 percent) in 2021, to 42,700 (+0.73 percent) in 2022 and 42,300 (+0.72 percent) in 2023--about the same percentage growth as last seen in 2017. Longer term, SoCalGas expects active meters to average about 0.6 percent annual growth from 2021 through 2035.

GAS DEMAND (REQUIREMENTS)

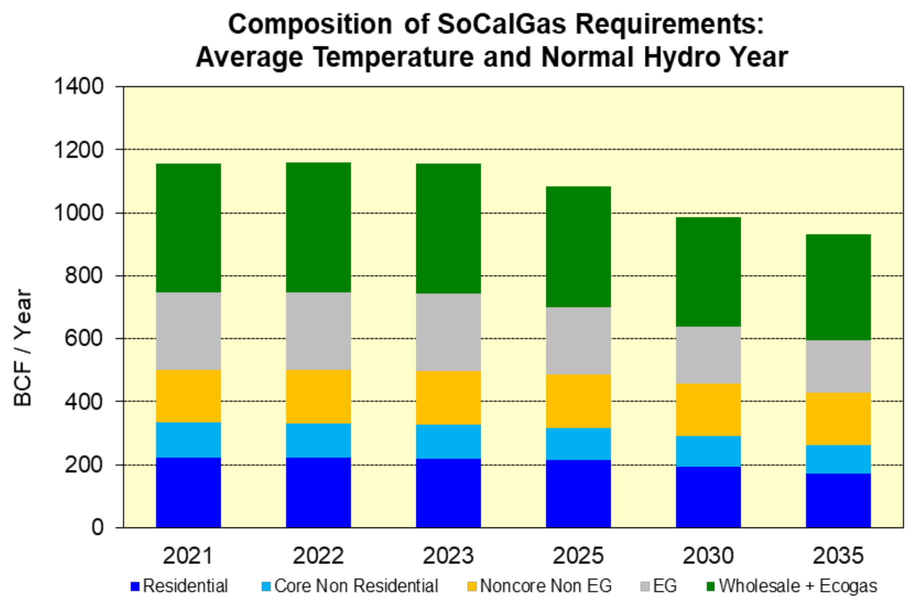
OVERVIEW

SoCalGas projects total gas demand to decline at an annual rate of 1.5 percent from 2022 to 2035. By comparison, the total gas demand had been projected to decline at an annual rate of 1.1 percent in the 2020 CGR. The forecasted, accelerated decline in throughput demand is being driven by modest economic growth and the forecasted energy efficiency and fuel substitution. Other factors that contribute to the downward trend are tighter standards created by revised Title 24 Codes and Standards, and renewable energy goals that impact gas-fired electricity.

The core, non-residential markets (comprised of core commercial, core industrial and natural gas vehicles (NGV)) are expected to decline at an average annual rate of 1.4 percent or from 224 Bcf in 2021 to 170 Bcf by 2035. However, the NGV market is expected to grow 2.1 percent over the forecast horizon. The NGV market is expected to grow due to government (federal, state and local) incentives and regulations encouraging the purchase and operation of alternate fuel vehicles as well as the increased use of RNG that provides significant GHG emission reduction benefits. The noncore, non EG- markets are expected to decline 0.1 percent from 167 Bcf in 2021 to 165 Bcf by 2035. That decline is being driven by very aggressive energy efficiency goals and associated programs. Total EG load, including large cogeneration and non-cogeneration- EG for a normal hydro year, is expected to decline from 243 Bcf in 2021 to 168 Bcf in 2035, a decrease of 2.6 percent per year.

The chart shows the composition of SoCalGas' throughput for the recorded year 2021 (with weather-sensitive market segments adjusted to average year HDD assumptions) and forecasts for the 2022 to 2035 forecast period.

FIGURE 13 – COMPOSITION OF SOCALGAS REQUIREMENTS AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR (2021-2035)



Notes:
(1) Core non-residential includes core commercial, core industrial, gas air-conditioning, gas engine, NGVs
(2) Non-core non-EG includes non-core commercial, non-core industrial, industrial refinery, and EOR-steaming
(3) Retail EG includes industrial and commercial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration EG.
(4) Wholesale includes sales to the City of Long Beach, City of Vernon, SDG&E, SWG, and Ecogas in Mexico.

MARKET SENSITIVITY

Temperature

Core demand forecasts are prepared for two design temperature conditions—average year and cold year—to quantify changes in space heating demand due to weather. Temperature variations can cause significant changes in winter gas demand due to space heating in the residential, core commercial and core industrial markets. The largest core demand variations due to temperature are likely to occur in the month of December. Heating degree day (HDD) differences between the two temperature conditions are developed from a six-zone temperature monitoring procedure within SoCalGas' service territory. One HDD is defined as when the average temperature for the day drops 1 degree below 65 degrees F. The cold design temperature conditions are based on a statistical likelihood of occurrence of 1-in-35 on an annual basis.

In our 2022 CGR, SoCalGas and SDG&E have included a climate-change warming trend that gradually reduces HDD's over the forecast period. First, average temperature year values were computed as the simple average of annual HDD's for the calendar years 2002 through 2021: 1,248 HDD's for SoCalGas and 1,158 HDD's for SDG&E. Corresponding 1-in-35 cold year HDD's were 1,476 for SoCalGas and 1,368 for SDG&E. For the forecast period, projected annual HDD's were reduced each year by 6 HDD's for both SoCalGas and SDG&E. For SoCalGas, projected average year and cold year HDD's both drop by 6 HDD annually: from 1,242 and 1,470 in year 2022, to 1,164 and 1,392 in year 2035. For SDG&E, projected average year and cold year HDD's drop by 6 HDD annually: from 1,152 and 1,362 in year 2022, to 1,074 and 1,284 in year 2035. The annual reductions are based on the latest 20-year trend in 20-year-averaged HDDs. That is, they are based on the observed trend in changes starting with average HDD's for years 1983-2002, then 1984-2003, 1985-2004...and ending with the average HDD's for years 2002-2021.

Southern California

Hydro Conditions

The EG forecasts are prepared for two hydro conditions—average year and dry hydro. The dry hydro case refers to gas demand in a 1-in-10 dry hydro year.

MARKET SECTORS

Residential

SoCalGas served approximately 5.67 million residential customers consisting of 3.79 million single-family households, 1.84 million multi-family households and 38,610 master meters in 2021. Residential usage varies for each of the market segments. Conditional demand estimates based on the 2019 Residential Appliance Saturation Survey (R.A.S.S.) indicate customer needs. This updated information formed part of the basis for the 2022 CGR residential market forecast.

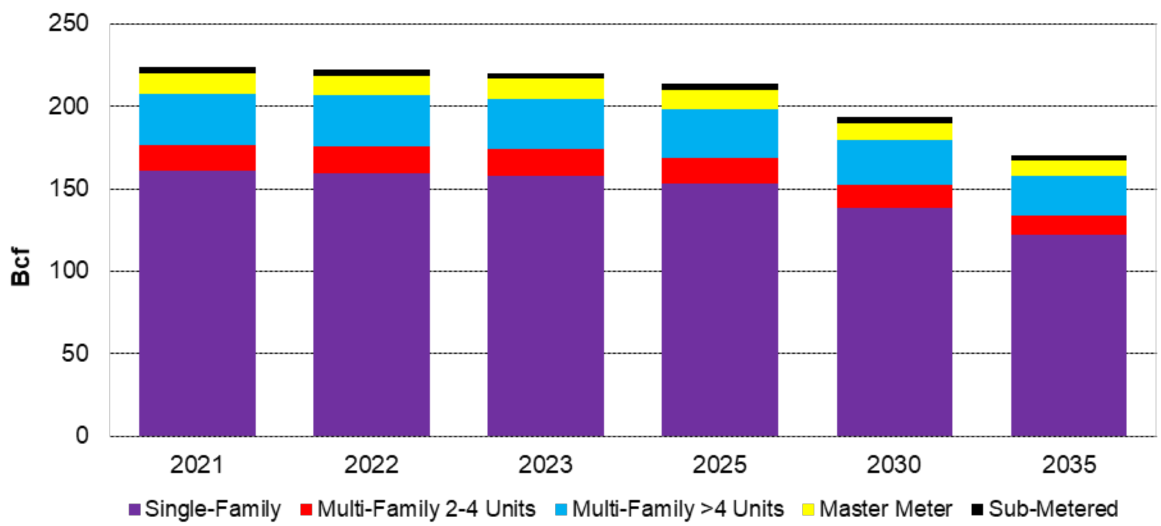
The table below shows the weather-normalized home usage by customer type and the saturations by end use for SoCalGas based upon the conditional demand study update.

Table 27: SoCalGas Residential Appliance Saturation Survey Results, 2019 Update

		2019 Residential Appliance Saturation Survey								
		Conditional Demand Study								
SoCalGas		Single Family Unit Energy Consumption (UEC)	Single Family Saturation (%)	Single Family Intensity	Single Family Use Proportion		Multi Family Unit Energy Consumption	Multi Family Saturation	Multi Family Intensity	Multi Family Use Proportion
	Space Heat	227	98.62%	224	51.75%		107	89.98%	96	46.67%
	Water Heat	141	95.98%	135	31.28%		94	81.33%	76	37.05%
	Cooking	30	82.37%	25	5.71%		28	77.80%	22	10.56%
	Clothes Drying	33	69.36%	23	5.29%		29	35.19%	10	4.95%
	Pool Heat	151	8.37%	13	2.92%		N/A			
	Spa Heat	102	9.68%	10	2.28%		47	1.19%	1	0.27%
	Gas Fireplace	11	7.33%	1	0.19%		7	4.58%	0	0.16%
	Gas Barbecue	16	15.56%	2	0.58%		14	5.17%	1	0.35%
	Total Household SF			433 Therms/Year	100%				206 Therms/Year	100%

The conditional demand estimates based on the 2019 R.A.S.S. show that the average use per meter is 433 therms for single-family households and 206 therms for multi-family households. The use-per-customer data is constructive in forming the forecast. For the residential market, the change in the baseline forecast from one year to the next is based on the confluence of two immediate economic drivers. In any given year, the residential load will grow due to the new customer hookups that occur. New customers generate a growth in demand. Second, the residential load will change due to existing customers' (vintage customers') changing needs. When gas appliances reach the end of their useful life, customers make a choice about equipment replacement. The choice consists of either replacing the older appliance with a more energy efficient gas appliance or substituting their gas appliance with one using another fuel, namely electricity. Customer choices can be influenced by economic factors, such as capital and operating costs, among other things, and are a key component of the baseline forecast. The usage calculator that generates the forecast is called the end use model.

Figure 14: Composition of SoCalGas' Residential Demand Forecast, 2021-2035



Residential gas demand is forecasted to decline from 224 Bcf in 2021 to 170 Bcf by 2035, or at an average annual rate of 1.9 percent. The decline is due to declining use per meter—primarily driven by very aggressive energy efficiency goals, anticipated fuel substitution, tightening Title 24 Codes and Standards, all of which affect the forecast by offsetting the new meter growth forecasted over the planning period.

As described above, SoCalGas' residential base forecast is developed from an end use model. The model results are modified by anticipated impacts of climate change as well as forecasts of policy adoptions that impact gas use. After the base forecast is developed, the forecast is modified by three out-of-model adjustments. The energy savings adjustments made to the forecast include (1) allowing for less heating degree days in the average weather design each year of the forecast period to account for climate change; (2) gas demand destruction due to greater energy efficiency savings forecast over the planning period; and (3) incremental energy savings created from assumed fuel substitution. All of the energy savings incorporated into the forecast reflect market potential and became load modifiers to create a final forecast of demand.

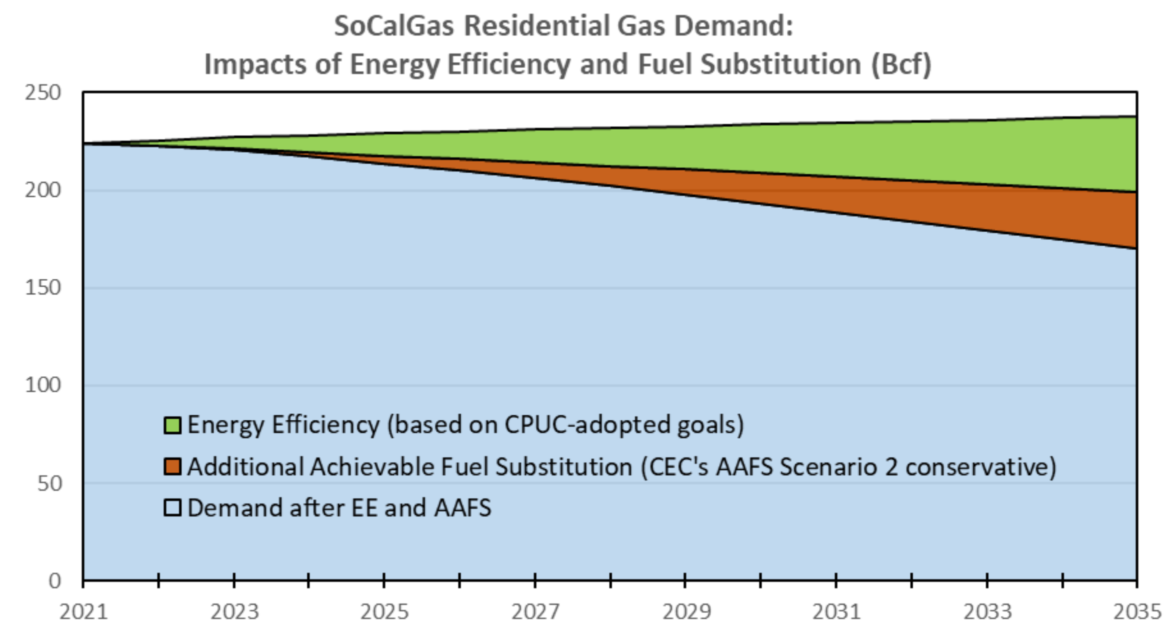
The major modifiers to the forecast are energy efficiency and building electrification. The energy efficiency forecast includes the confluence of two types of gas energy savings. Codes and Standards savings, which include current and expected modifications to Title 24, and the energy savings stemming from customer programs authorized by the CPUC's D.21-09-037. The baseline forecast was adjusted downward to account for these incremental energy saving influences that are expected to occur over the forecast period.

The final forecast also includes a load modifier for fuel substitution. For purposes of constructing a long-term reasonable forecast for the 2022 CGR, SoCalGas participated in an electrification working group committee together with PG&E, SDG&E and Southern California Edison (SCE) to evaluate different approaches and assumptions to modeling the effects of fuel substitution. After several meetings and discussions, SoCalGas aligned around the relatively conservative fuel substitution scenario forecast developed by the California Energy Commission. Fuel substitution was estimated and introduced separately from energy efficiency savings by the CEC in its 2021 IEPR as additional achievable fuel substitution (AAFS). Of the five possible fuel substitution scenarios developed by the CEC, the AAFS-2 Scenario, which is the CEC's mid-low scenario for electrification, was chosen by SoCalGas to prepare the final residential forecast. Scenario 2 quantifies the assumed fuel substitution that would take place with potential future updates in the Title 24 building standards and the presumed additional building electrification encouraged by future ratcheting driven by tighter goals, rate enhancements and higher uptake rates at future points in time. All of the above-mentioned gas reductions were included in the residential forecast as a modifier to the base forecast.

As can be seen from the following graph, the effects of both energy efficiency and fuel substitution have an impact on the residential market. By year 2035, the *assumed* additional energy efficiency removes 16 percent of residential gas demand. Evaluated separately, *assumed* additional fuel substitution removes another 12 percent of residential gas demand by 2035.

Southern California

Figure 15: SoCalGas: Residential Impacts of EE and AAFS



The final published forecast in this report is a product of the economic drivers in addition to policy drivers articulated and accounted for at the particular time the forecast was developed. As discussed elsewhere in this Report, much uncertainty remains in the timing, pace, extent, and overall evolution of residential natural gas demand in California.

Commercial

The core commercial market demand is expected to decline over the forecast period. On a temperature-adjusted basis, the 2021 core commercial market demand totaled 77 Bcf. By the year 2035, the load is anticipated to drop to approximately 56.5 Bcf. The average annual rate of decline from 2021-2035 is forecasted at 2.2 percent. The decline in gas usage is mainly the result of the impact of CPUC-authorized portfolio of energy efficiency programs and Title 24 codes building standards as well as some forecasted fuel substitution in this market.

In 2021, the noncore commercial temperature-adjusted usage was 17.4 Bcf. From 2021 through 2035, demand in this market is expected to be largely stable, reaching to about 17.7 Bcf in 2035. The noncore commercial market will be expected to grow at an average annual rate of 0.1 percent per year. Key factors of the trend are increasing commercial employment, commercial customers that move from core to noncore, and the CPUC-authorized energy efficiency programs.

FIGURE 16 – ANNUAL COMMERCIAL DEMAND FORECAST 2021-2035
BILLION CUBIC FEET PER YEAR (Bcf/y), AVERAGE YEAR WEATHER DESIGN

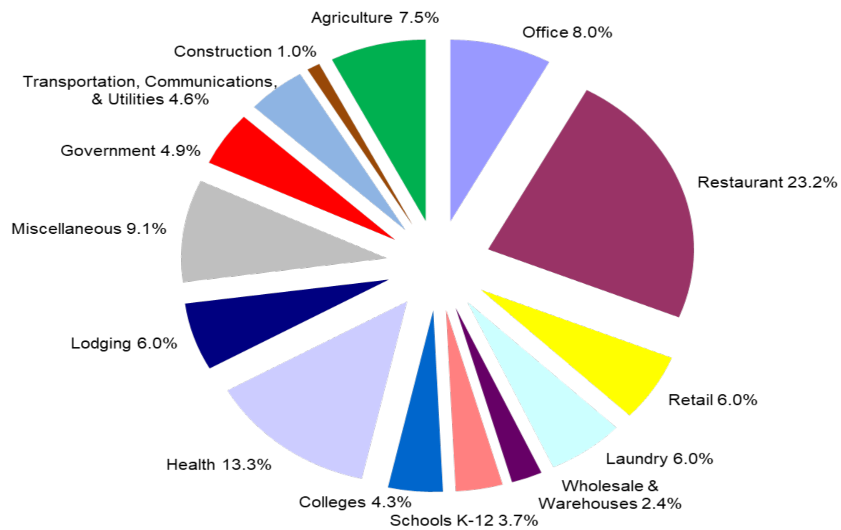
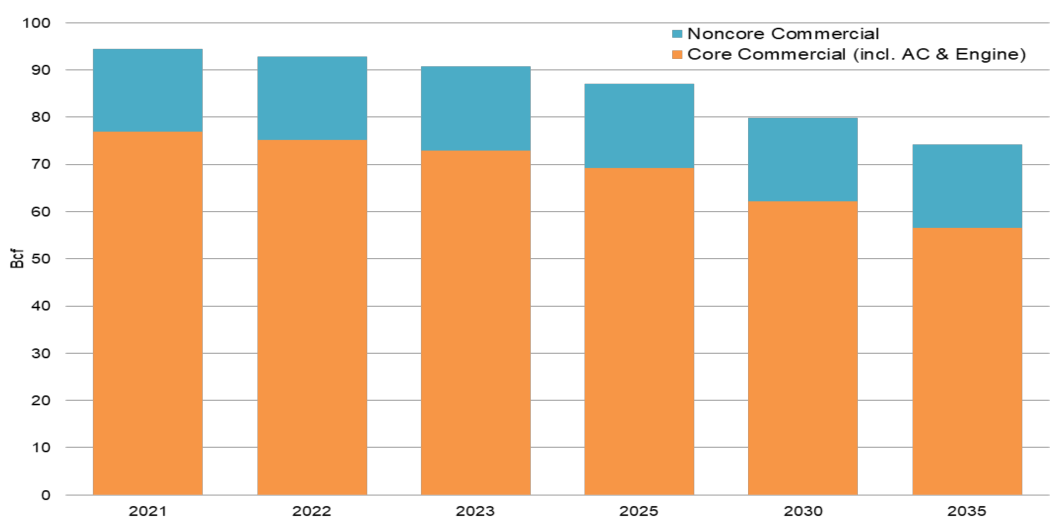


FIGURE 17 – COMMERCIAL GAS DEMAND BY BUSINESS TYPE
COMPOSITION OF INDUSTRY
(2021)



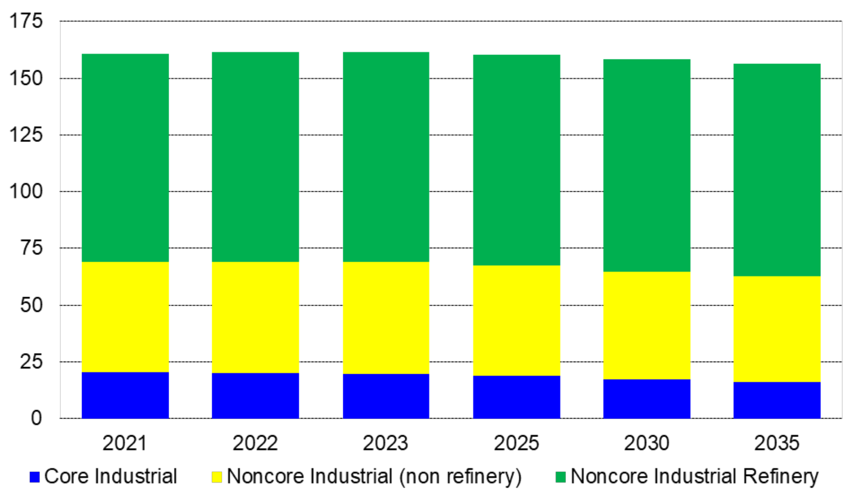
The commercial market consists of 14 business types identified by the customers' North American Industry Classification System codes. It represents includes both core and noncore usage. The restaurant business dominates this market with 23 percent of commercial usage in 2021, followed by the health services industry with a 13 percent share.

Industrial

Non-Refinery Industrial Demand

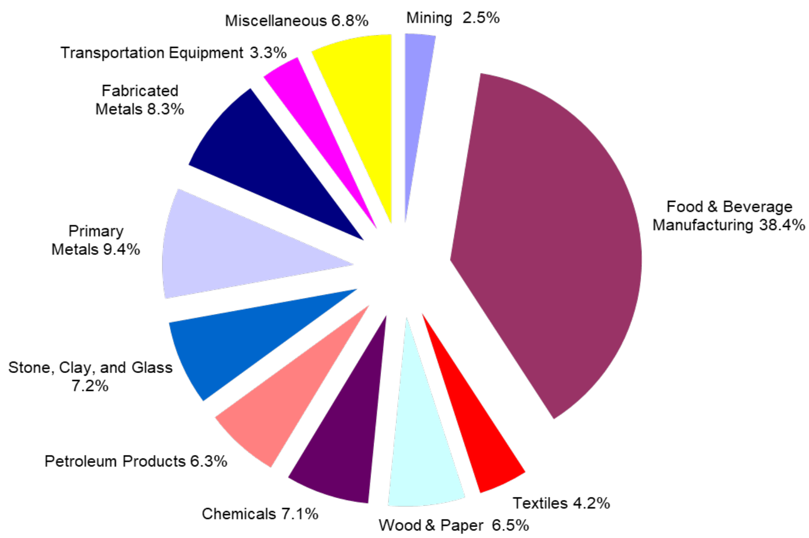
In 2021, temperature-adjusted core industrial demand was 20.4 Bcf. Core industrial market demand is projected to drop by 1.7 percent per year from 20.4 Bcf in 2021 to 16.1 Bcf in 2035. This decrease results from a combination of factors: a minor decrease in employment growth, an increase in marginal gas rates and CPUC-authorized energy efficiency programs.

FIGURE 18– ANNUAL INDUSTRIAL DEMAND FORECAST (Bcf)
(2021-2035)



The 2021 non-refinery industrial gas demand served by SoCalGas is shown below. Food and beverage manufacturing, with 38.4 percent of the total share, dominates this market. The graph below summarizes the composition of the core and noncore industrial market by business type.

FIGURE 19 INDUSTRIAL GAS DEMAND BY BUSINESS TYPE COMPOSITION OF INDUSTRY (2021)–



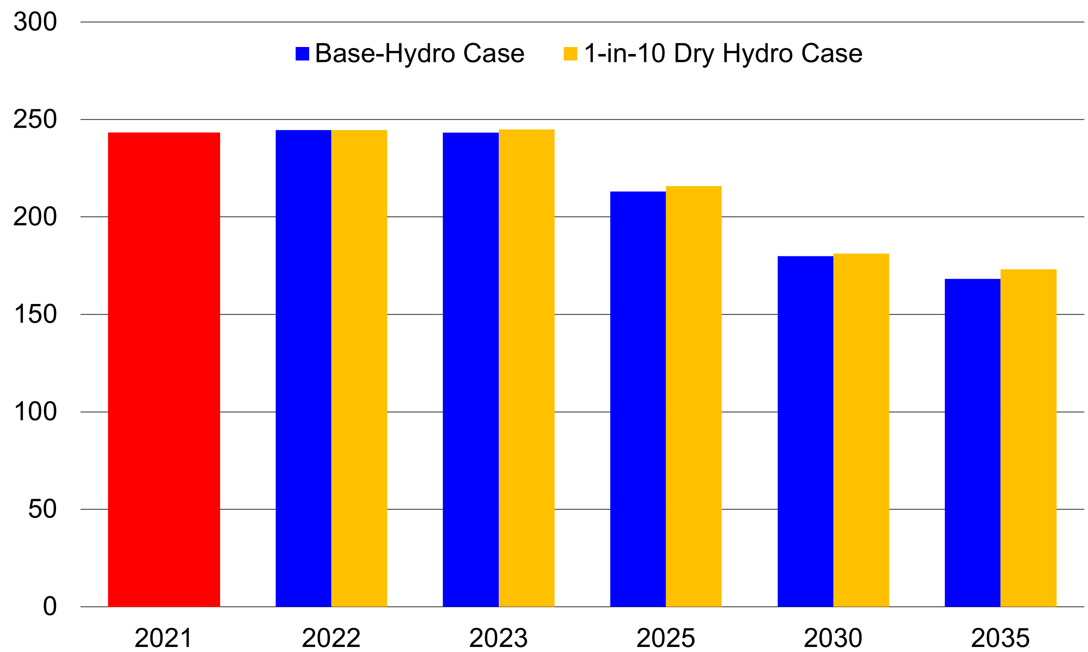
Gas demand for the retail noncore industrial (non-refinery) market is expected to decline at an annual rate of 0.3 percent from 48.6 Bcf in 2021 to 46.8 Bcf by 2035. The reduced demand is primarily due to the CPUC-authorized energy efficiency programs, decreasing industrial employment, and the departure of customers within the City of Vernon to wholesale service by the City of Vernon.

Refinery Industrial Demand

Refinery industrial demand is comprised of gas consumption by petroleum refining customers, H2 producers and refined petroleum product transporters. Gas demand in the refinery industrial market sector is forecasted to be largely stable over the 2022 - 2035 forecast period, from 91.7 Bcf in 2021 to 93.3 Bcf in 2035.

Electric Generation

FIGURE 20 – SoCalGas SERVICE AREA TOTAL EG
(Bcf)



The EG sector includes all commercial/industrial cogeneration, EOR-related cogeneration, and non-cogeneration electric generation. The EG load forecast is subject to a high degree of uncertainty. The forecast uncertainty is, in large part, due to load sensitivity to weather conditions, regional fuel price differences, the construction and retirement of power generating facilities (including thermal, renewable, and energy storage resources), the amount of California's import/export energy, and the state's overall long-term electricity demand growth. The EG gas throughput forecast can be higher or lower than the base case forecast, depending on the factors mentioned above. California's forecasted electricity demand is a major influence of southern California gas-demand EG. If the electricity demand forecast is higher, the EG gas throughput forecast would also tend to be higher. Please refer to the California Energy Commission's (CEC) 2021 Integrated Energy Policy Report for high, mid, and low electricity demand scenarios. On the supply side, lower SoCalGas Citygate gas prices relative to other regions, less energy imported into California, and dry hydro conditions are also factors that would increase the EG gas throughput forecast.

Additionally, many once through cooling (OTC) plants in California are scheduled to either retire or repower during the forecasted period. These are thermal plants, located near the coast, that use ocean water for cooling. A total of 5,370 MW of local gas-fired power plants and a 2,240 MW nuclear plant in northern California will retire by the end of 2029.

The gas-driven EG forecast uses a power market simulation for the period of 2022-2035. The simulation reflects the anticipated dispatch of all EG resources in the SoCalGas service territory using a base electricity demand scenario under both average and low hydroelectric availability market conditions. The base case assumes the CPUC adopted 2021 Preferred System Plan, which also assumes compliance with the Mid-Term Reliability (MTR).[78] Also assumed in the forecast is compliance with the GHG planning target of 38 million by year 2030. This plan includes an aggressive amount of energy storage resources along with significant renewables resources throughout the study period. While California load-serving entities (LSEs) are working to meet their GHG goals, there are uncertainties as to how much renewable power and energy storage resources will be added specifically during the study period.

The EG demand forecast for the State of California, used in the simulation, is sourced from the CEC's California Energy Demand Forecast, 2021 – 2035, adopted January 2022. This energy demand forecast was developed as part of the CEC's Integrated Energy Policy Report process. The mid energy demand forecast with Additional Achievable Energy Efficiency (AAEE) Scenario 3 and Additional Achievable Fuel Substitution (AAFS) Scenario 2 was selected as the energy demand forecast.

Industrial/Commercial/Cogeneration <20 MW

A segment of EG demand is the commercial/industrial cogeneration (including self-generation) market. This segment is comprised by customers with generating capacity of less

[78] Decision D.21-06-035.

than 20 megawatts (MW) of electric power. Most of the cogeneration units in this segment are installed primarily to generate electricity for internal customer consumption rather than for the sale of power to electric utilities. Customers in this market segment install their own electric generation equipment for both economic reasons (gas powered systems produce electricity cheaper than purchasing it from a local electric utility) and reliability reasons (lower purchased power prices are realized only for interruptible service). The gas demand in the small cogeneration market was 25.4 Bcf in 2021 and is expected to modestly increase to 27.6 Bcf by the year 2035, or at an average growth rate of 0.6 percent per year. The increase in demand is primarily due to the increasing electric price compared with natural gas.

Refinery-Related Cogeneration

Refinery cogeneration units are installed primarily to generate electricity for internal use. This market is forecasted to be stable over the 2022 - 2035 forecast period, changing from 23 Bcf in 2021 to 23.6 Bcf in 2035.

Enhanced Oil Recovery--Related Cogeneration

In 2021, recorded gas deliveries to the EOR -related cogeneration were 4.1 Bcf. EOR demand is forecasted to increase slightly and stabilize in the immediate future before gradually decreasing to 3.9 Bcf by 2035. Crude oil futures prices appear to be elevated and volatile for the immediate future which is expected to result in California EOR operations increasing slightly in the earlier part of the forecast before the gradual decrease, as volatility subsides.

Southern California

Electric Generation, Including Large Cogen

EG customers are comprised of utility electric generation (UEG) customers, various Exempt Wholesale Generator (EWG) customers and large cogeneration customers where usage exceeds 20 MW. For the base case (average hydro condition), gas demand is forecasted to decrease from 191 Bcf in 2021 to 113 Bcf in 2035. The main factors for the decline are aggressive energy storage resource additions, paired with significant renewable resource additions and the retirement of older gas-fired plants.

Wholesale

SoCalGas provides wholesale transportation service to SDG&E, the City of Long Beach Energy Resources Department (Long Beach), SWG, and the City of Vernon (Vernon), and Ecogas Mexico, L. de R.L. de C.V. The wholesale load excluding SDG&E is expected to increase from 38.6 Bcf in 2021 to 43.0 Bcf in 2035. The change reflects a 0.77 percent average annual increase.

SDG&E

Under average year temperature and normal hydro conditions, SDG&E gas demand is expected to decrease at an average rate of 1.9 percent per year from 94 Bcf in 2021 to 72 Bcf in 2035. Additional information regarding the composition of SDG&E's gas demand is provided in the SDG&E section of this report.

City of Long Beach

The wholesale load forecast is based on forecast information provided by the City of Long Beach Energy Resources Department. Long Beach's gas use is expected to increase slightly, from 8.8 Bcf in 2021 to 9.3 Bcf by 2035. Additional information regarding the City of Long Beach Energy Resources Department's gas demand is provided in the City of Long Beach Energy Resources Department section of this report.

Southwest Gas Corporation

SoCalGas used the forecast prepared by Southwest Gas for this report. In 2021, SoCalGas delivered 9.2 Bcf to Southwest Gas and the total load is expected to rise slightly to 10.3 Bcf by 2035. Refer to Southwest Gas for additional information regarding their gas demand.

City of Vernon

The City of Vernon initiated municipal gas service to its electric power plant within the city's jurisdiction in June 2005. Since 2005, there has also been a gradual increase of commercial/industrial gas demand as customers within the city boundaries have left the SoCalGas retail system and interconnected with Vernon's municipal gas system. The forecasted throughput starts at 8.5 Bcf in 2021 and increases to 9.3 Bcf by 2035. The forecasted throughput includes core and noncore customers and includes Malburg Power Plant throughput. Vernon's commercial and industrial load is based on recorded historical usage for commercial and industrial customers already served by Vernon plus the customers that are expected to request retail service from Vernon.

Ecogas Mexico, S. de R.L. de C.V. (Ecogas)

SoCalGas used the forecast prepared by Ecogas for this report. Ecogas' use is expected to increase, from 12 Bcf in 2021 to 14 Bcf by 2035. Refer to Ecogas or IENova, Ecogas' parent company, for more information.

Enhanced Oil Recovery Steam

In 2021, recorded gas deliveries to the EOR market were 8.5 Bcf. EOR demand is forecasted to increase slightly and stabilize in the immediate future before gradually decreasing to 7.4 Bcf by 2035. Crude oil futures prices appear to be elevated and volatile for the immediate future which is expected to result in California EOR operations slightly increasing in the earlier part of the forecast before the gradual decrease, as volatility subsides.

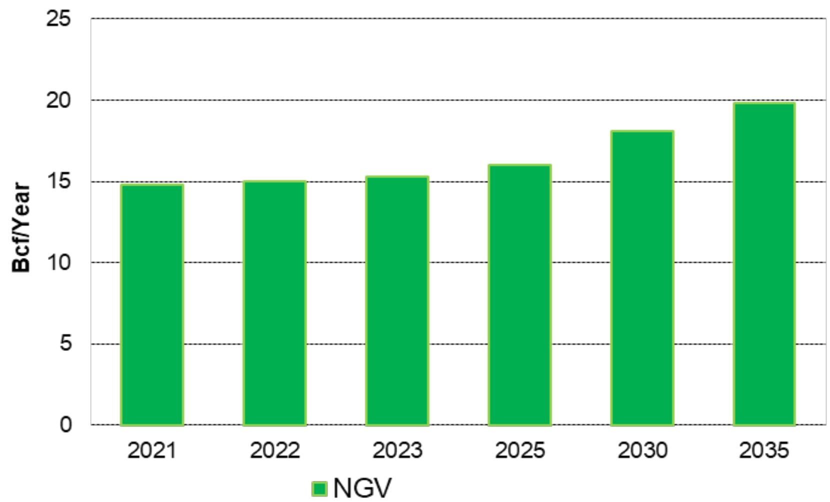
Southern California

Natural Gas Vehicles

The NGV market is expected to continue to grow, albeit at a slower rate than in the past. State regulations encourage the adoption of zero emission alternative fuels. Growth will continue for the next several years until zero emission alternative fuels become cost competitive with gasoline and diesel. NGV growth is also supported by the increased use and availability of RNG that provides significant GHG emission reduction and cost reduction benefits.

At the end of 2021, there were 352 CNG fueling stations delivering approximately15.4 Bcf of natural gas during the year. The NGV market is expected to grow 1.8 percent per year, on average. At the end of 2035, it is expected there will be 414 CNG fueling stations delivering approximately 20.8 Bcf of natural gas during the year.

FIGURE 21 – NGV DEMAND FORECAST
(2021-2035)



ENERGY EFFICIENCY PROGRAMS

SoCalGas engages in several energy efficiency (EE) and conservation programs designed to help customers identify and implement ways to benefit environmentally and financially from energy efficiency investments. Programs administered by SoCalGas include services that help customers evaluate their energy efficiency options and adopt recommended solutions, as well as simple equipment retrofit improvements, such as rebates for new hot water heaters.

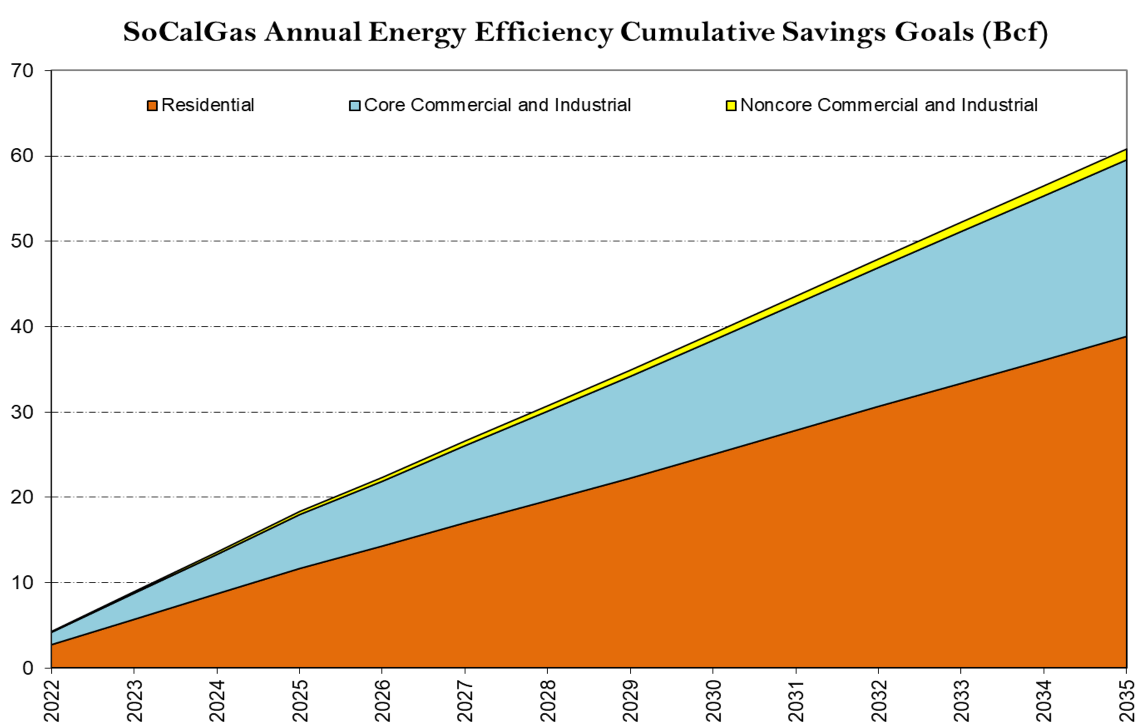
The forecast of cumulative natural gas savings due to SoCalGas' energy efficiency programs is provided in the figure below. The forecasts capture savings from programs developed in support of several goals and standards. Efforts were made to exclude the forecasted fuel substitution from the EE forecast. The forecast for fuel substitution is accounted in the separately in the AAFS Scenario 2, published in the CEC's 2021 Integrated Energy Policy Report. The savings shown below represent the net load impact for the energy efficiency portfolio that includes program savings and the codes and standards savings that SoCalGas anticipates will occur through year 2035.

SoCalGas' EE forecast is based upon inputs from the 2022-23 energy efficiency bi-annual budget advice letter (AL5898-A), utilizing program level energy savings values forecasted for the 2022 program year. Savings estimates from SoCalGas' 2022 EE programs are grouped by the classifications identified in the 2022 CGR (Residential, Commercial, Industrial, Industrial Refinery). These savings estimates are further split between the core and noncore classifications based on the estimated historical core and non-core savings achievements in 2017-2021. The EE program savings for 2017-2021 have been updated for this report.

Forecasted savings for the 2023-2035 period are based on the 2020 EE forecast scaled to the goals approved in the recent EE proceeding goals decision, D.21-09-037, which set EE goals through 2032. Forecasted savings beyond 2032 are held constant based on 2032 forecasted values. Cumulative savings reflect the lifecycle EE program achievements from forecasted program savings starting in 2022 and does not include lifecycle savings from prior program years. SoCalGas currently uses a 15-year lifecycle for cumulative savings calculations.

Combined EE Portfolio of EE Programs and Codes and Standards

FIGURE 22



GAS SUPPLY, CAPACITY, AND STORAGE

GAS SUPPLY SOURCES

SoCalGas and SDG&E receive gas supplies from several sedimentary basins in the Western U.S. and Canada including supply basins located in New Mexico (San Juan Basin), West Texas (Permian Basin), Rocky Mountains, Western Canada, and local California supplies. Recorded 2017 through 2021 receipts from gas supply sources can be found in the Sources and Disposition tables in the Executive Summary.

CALIFORNIA GAS

Gas supply available to SoCalGas and SDG&E from California sources averaged 69 MMcf/d in 2021.

SOUTH-WESTERN U.S. GAS

Traditional southwestern U.S. sources of natural gas will continue to supply most of Southern California's natural gas demand. This gas is primarily delivered via the El Paso Natural Gas pipeline with some volumes also on Transwestern pipeline. The San Juan Basin's gas supplies peaked in 1999 and have been declining at an annual rate of roughly 2 percent. The Permian Basin has experienced a major increase in gas production as a byproduct of the tremendous amount of oil development in the area. Permian gas production increased by over 130 percent during the period 2017-2021. This increase positioned the Permian Basin as a preferred gas supply source of economical gas.

Mexican demand for southwestern U.S. gas along with east of California demand continue to steadily increase and compete for southwestern supplies. This increasing demand will likely continue to compete with southern California for southwest supplies.

Southern California

ROCKY MOUNTAIN GAS

Rocky Mountain supply supplements traditional southwestern U.S. gas sources for southern California. This gas is delivered to southern California primarily on the Kern River Gas Transmission Company's pipeline, although there is also access to Rockies gas through pipelines interconnected to the San Juan Basin. Many pipelines that supply other markets connect to Rocky Mountain region, which allows Rockies gas to be redirected from lower to higher value markets as conditions change.

CANADIAN GAS

Canadian gas only provides a small share of southern California gas supplies due to the relatively high cost of transport.

LIQUEFIED NATURAL GAS

US liquified natural gas (LNG) exports grew in 2021 as additional capacity came online in 2020, however, global LNG demand increased sharply in 2021. Russia supplies to Europe decreased during 2021 which increased the demand for replacement gas in the form of LNG and caused international prices to spike while domestic prices saw less volatility. The global demand increase in 2021 created a supply/demand imbalance in Europe causing prices to spike to record highs. Current LNG supply is insufficient to replace Russian gas previously delivered into Europe which indicates international prices may remain high for several years.

RENEWABLE NATURAL GAS (RNG)

In February 2022, the CPUC adopted Decision (D.) 22-02-025 that implemented SB 1440 (Hueso) and established RNG procurement targets for years 2025 and 2030 to be met by the California natural gas utilities, "Joint Utilities", specifically Pacific Gas & Electric, San Diego Gas & Electric, Southern California Gas Company and Southwest Gas. This CPUC Decision established the nation's first Renewable Gas Standard (RGS) and provided additional support to meet the bill's short-lived pollution reduction goals. In particular, SB 1383 requires California to reduce emissions of methane by 40 percent below 2013 levels by 2030 and also develop landfill-diverted organic waste-to-RNG projects.

The RGS includes short and medium term biomethane procurement targets. The 2025 short-term target for biomethane procurement is 17.6 billion cubic feet (Bcf) annually, produced from eight million tons of organic waste, including wood waste, diverted annually from landfills. Joint Utilities, each, are responsible for procuring a percentage of the 17.6 Bcf according to each of their respective Cap-and-Trade allowance shares: Southern California Gas Company 49.26 percent, Pacific Gas and Electric Company 42.34 percent, San Diego Gas & Electric Company 6.77 percent, and Southwest Gas Corporation 1.63 percent.[79] The medium-term target is by year 2030, where the Joint Utilities, shall procure, on an annual basis, an amount of biomethane equivalent to 12.2 percent of its own share of 2020 annual bundled core customer natural gas demand, excluding Compressed Natural Gas Vehicle demand as noted in the California Gas Report (or approximately 72.8 Bcf).[80]

There is a growing recognition that clean fuels like hydrogen and renewable natural gas (RNG) will play an essential role in diversifying energy supplies while also helping California decarbonize and transform into a carbon neutral economy over the next twenty years.[81] RNG is methane produced from anaerobic digestion (AD) or by a non-combustion gasification process of organic feedstock material that can replace traditional natural gas. RNG produced from AD is typically derived from organic waste streams such as dairy manure, landfilled gas, and municipal organic waste (i.e., food scraps, lawn clippings, and animal or plant-based material). Non-combustion gasification pathways typically process agricultural waste, forest debris, and wastewater treatment by-products, among other feedstocks. Under baseline conditions, these organic waste streams typically release methane into the atmosphere as they decompose. Directing these feedstocks toward RNG production can help to capture and prevent the release of methane into the atmosphere.[82]

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[79] D. 22-02-025, op. 14-16.
[80] D. 22-02-025, op. 18.
[81] Final 2021 Integrated Energy Policy Report, Volume III.
[82] U.S. EPA's Landfill Methane Outreach Program (LMOP) at https://www.epa.gov/lmop/renewable-natural-gas .

RNG interconnected to a gas utility's pipeline[83] replaces traditional natural gas and can similarly be nominated to a variety of end users, providing decarbonized energy for hard-to-electrify sectors of the economy like heavy-duty transportation, industrial activities and dispatchable electric generation. RNG is a drop-in fuel replacing traditional natural gas and does not typically require equipment adjustments, upgrades, replacements or other modifications.

Unlike traditional natural gas, RNG feedstocks are composed of material containing biogenic carbon that has been absorbed from the atmosphere. Carbon emissions from fossil fuels such as traditional natural gas are drawn from geological sources such as deep wells or rocks and contain carbon that has accumulated over a geological timescale. In contrast, biogenic carbon, such as that in RNG, was sourced from the atmosphere on a much shorter biological timescale. This biogenic carbon is cycled from the atmosphere to plants over the course of only a few years or decades.[84] This means that carbon emissions released from the use of RNG are already part of a sustainable natural cycle, which is why GHG reporting protocols treat CO_2 emissions from RNG as carbon neutral.[85] RNG can even be a carbon negative fuel, reducing additional GHG emissions beyond the carbon emissions associated with its combustion, depending on the feedstock and production system used.

[83] SoCalGas Tariff Rule 30 (https://www2.socalgas.com/regulatory/tariffs/tm2/pdf/30.pdf) must be met in order to qualify for pipeline injection into SoCalGas' gas pipeline system.

[84] https://clear.ucdavis.edu/explainers/biogenic-carbon-cycle-and-cattle.

[85] https://www.ipccnggip.iges.or.jp/public/2019rf/pdf/2_volume2/19R_V2_2_Ch02_Stationary_Compbustion.pdf; 2.3-2.4 Treatment of Biomass .

Recent reports estimating RNG supply potential published by Livermore Laboratory Foundation, [86] the CEC, [87] E3 and the University of California Irvine,[88] and ICF,[89] illustrate there is a significant amount of feedstock available within California for the production of biogas and RNG to help replace traditional natural gas and help decarbonize the gas grid. These studies estimate between 70 and 170 Bcf of annual RNG production potential available solely from AD with potential for an additional 50 to 257 Bcf of annual RNG available from non-combustion gasification. Studies that sum both AD and gasification estimates provide an estimate between 148 and 387 Bcf of annual RNG potential within California.[90] RNG potential at the higher end of these summed estimates would be sufficient to meet either approximately 75 percent of the 2020 residential natural gas demand in California or approximately 150 percent of the commercial demand, or approximately 45 percent of industrial demand.[91]

[86] "Getting to Neutral: Options for Negative Carbon Emissions in California," Livermore Laboratory Foundation & Climateworks Foundation, August 2020. Available at https://wwwhttps://www-gs.llnl.gov/content/assets/docs/energy/Getting_to_Neutral.pdfgs.llnl.gov/content/assets/docs/energy/Getting_to_Neutral.pdf.

[87] "Final 2017 Integrated Energy Policy Report," CEC, February 2018. Available at https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2017-integrated-energy-policyhttps://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2017-integrated-energy-policy-reportreport.

[88] "The Challenge of Retail Gas in California's Low Carbon Future, Appendix A," E3 and University of California, Irvine, 2020. Available at https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-APhttps://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-AP-G.pdfG.pdf.

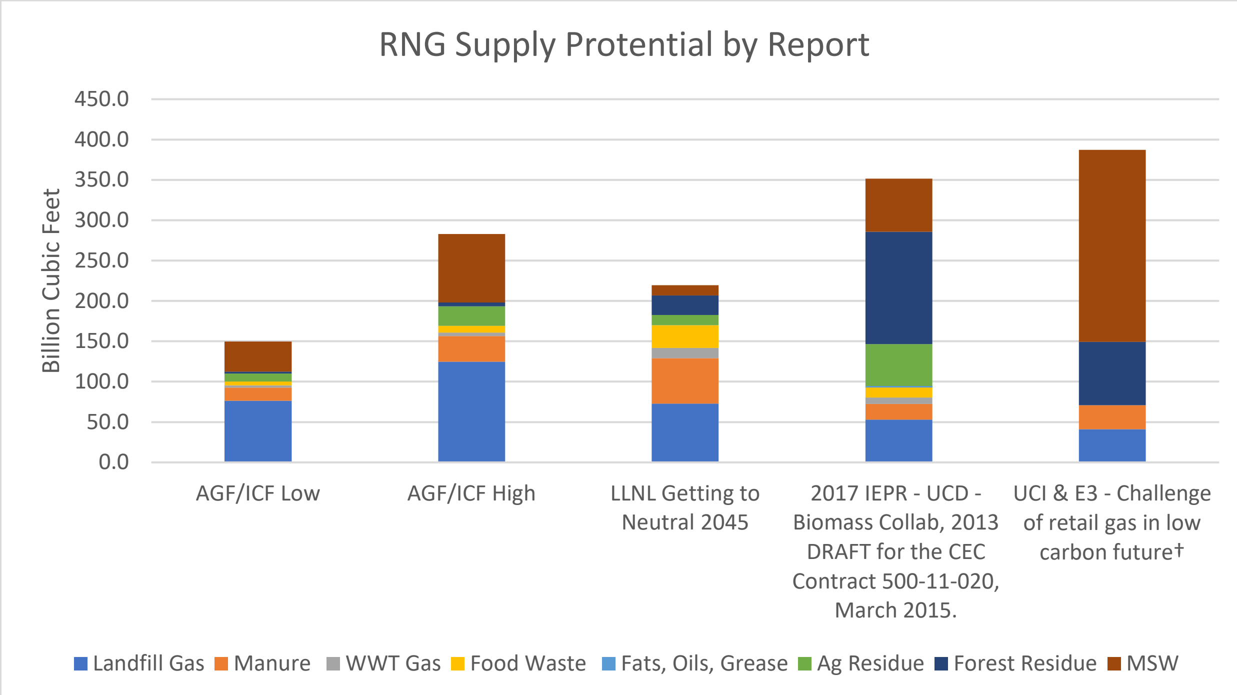
[89] "ICF 2019 Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment," American Gas Foundation, 2019. Available at https://www.gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNGhttps://www.gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdfStudy-Full-Report-FINAL-12-18-19.pdf.

[90] Using the top or 'high' estimate when a range is documented, but not the 'technical resource potential,' which does not consider accessibility or economic constraints.

[91] https://www.eia.gov/dnav/ng/NG_CONS_SUM_DCU_SCA_A.htm

Southern California

Figure 23 – RNG In-State Supply Potential



INTERSTATE PIPELINE CAPACITY

California utilities and end users benefit from access to supply basins and enhanced gas and pipeline competition. Interstate, international, and intrastate pipelines serving Southern and central California include the El Paso Natural Gas, Mojave, Transwestern, Kern River, TGN, North Baja, and PG&E pipelines. These pipelines provide southern and central California with access to gas producing regions in the southwest U.S. and Rocky Mountain areas, western Canada, California production and Mexico LNG. Indicated firm capacities for each SoCalGas receipt zone for receiving these supplies are specified in the SoCalGas GBTS Rate Schedule.

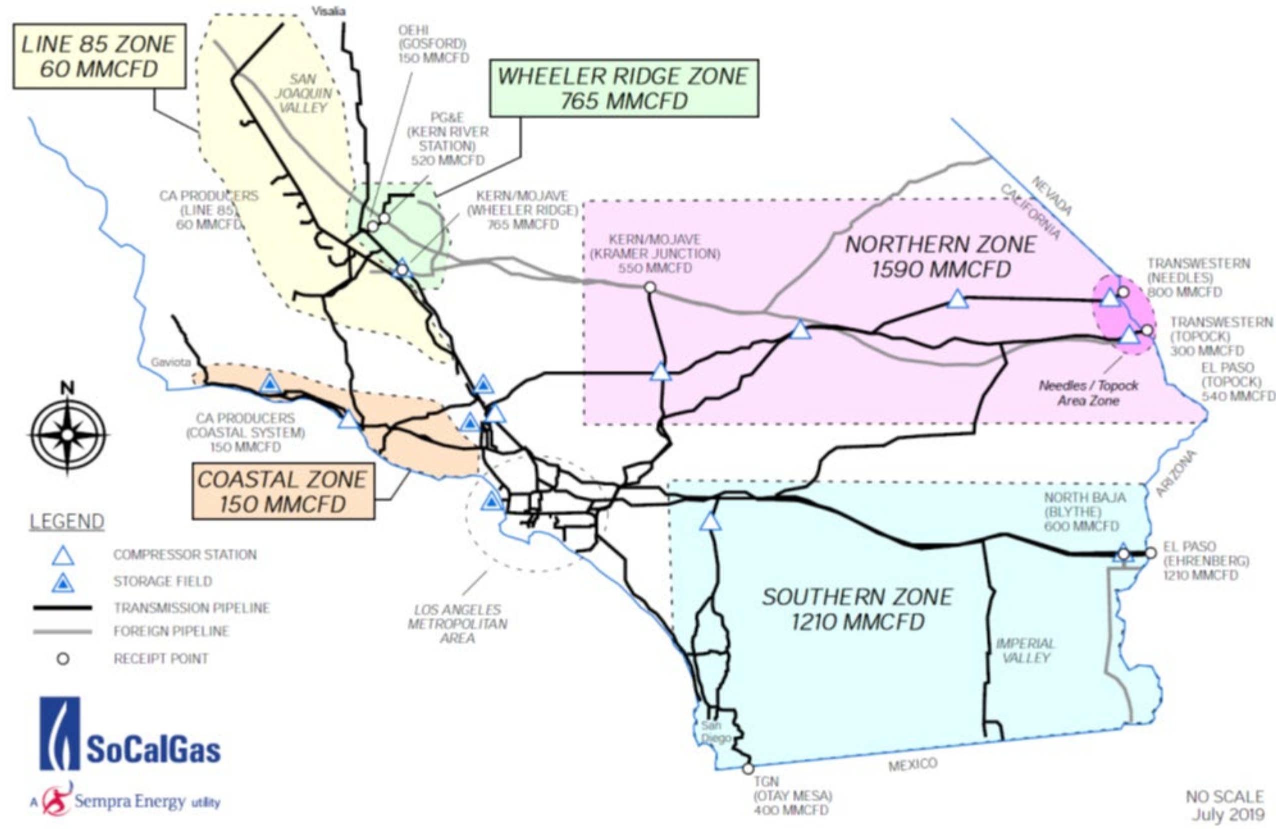
SoCalGas' Southern Zone is connected to U.S. Southwest and Mexico pipeline systems at Ehrenberg, Blythe, and Otay Mesa (to El Paso, North Baja, and TGN) respectively. The Southern Zone has a firm receipt capability of 1,210 MMcf/d.

SoCalGas' Northern Zone is connected to southwestern U.S. Southwest and Rocky Mountain pipeline systems (Transwestern, El Paso, Kern River, and Mojave) at Needles, west of

Topock AZ, and Kramer Junction. The Northern Zone has a nominal firm receipt capacity of 1,590 MMcf/d. Effective October 1, 2021, Line 4000 returned to service at a higher operating pressure. As a result, the amount of firm BTS capacity available in the Northern Zone and the Needles/Topock Area Zone increased to 1,250 MMcf/d and 800 MMcf/d respectively.

SoCalGas' Wheeler Ridge Zone is connected to Kern River/Mojave, OEHI Gosford, and PG&E and receives supplies from the U.S. Southwest, Rocky Mountain, and Western Canada production areas and California production from Elk Hills. The Wheeler Ridge Zone's firm receipt capacity is 765 MMcf/d.

FIGURE 24– RECEIPT POINT AND TRANSMISSION ZONE FIRM CAPACITIES



STORAGE

Underground storage of natural gas plays a vital role in balancing the region's energy supply and demand, and for systemwide reliability.[92] Natural gas storage is also used to meet peak daily and seasonal gas demand and to hedge against price volatility in natural gas commodity markets. In addition, natural gas storage has played a role in addressing emergency situations, including extreme weather and wildfires.[93] SoCalGas owns and operates four natural gas

[92] California Council on Science and Technology (CCST), January 2018, Long-Term Viability of Underground Natural Gas Storage in California, An Independent Review of Scientific and Technical Information, Conclusion, 2.4 at pp 504 at: Full-Technical-Report-v2_max.pdf (ccst.us) .

[93] *Id.,* Conclusion 2.5 at pp 506.

storage facilities within southern California: Aliso Canyon, Honor Rancho, La Goleta, and Playa Del Rey.

Southern California

In Southern California, natural gas storage fields are in areas with specific underground geologic characteristics, and in proximity to local gas consumers and transmission and distribution pipelines. Storage natural gas is withdrawn and delivered to customers through SoCalGas' transmission and distribution systems when customer demand exceeds flowing natural gas supplies and for system balancing.

SoCalGas' natural gas storage fields have a combined theoretical storage working inventory capacity of more than 130 Bcf.[94] However, the combined working inventory for SoCalGas is reduced due to current working inventory regulatory restrictions imposed at Aliso Canyon.

Prior to 2016 the Aliso Canyon working inventory was 86 Bcf.[95] Since October 2015,[96] the CPUC and CalGEM[97] have maintained restrictions on SoCalGas' use of Aliso Canyon. In November 2020, the CPUC set the Aliso Canyon storage inventory level at 34 BCF based on the prior Energy Division reports assessing whether monthly 1-in-10 peak day demand could be met with forecasted storage inventory levels.[98] In November 2021, the CPUC issued an order increasing the inventory limit for the Aliso Canyon Storage Field from 34 to 41.16 Bcf.[99] The CPUC and CalGEM may authorize a different maximum inventory in the future.

In July 2019, to improve short-term reliability and price stability in the southern California region, the CPUC deemed that Aliso Canyon be made available for withdrawals if certain conditions are met.[100] Aliso Canyon may be used for withdrawals only if any of the following four conditions are met: 1) Preliminary low Operational Flow Order (OFO) calculations for any

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[94] SoCalGas 2019 General Rate Case (GRC) Filing, Exhibit SCG-10-R, p. NPN-3 and NPN-4.
[95] As of July 19, 2017, CalGEM authorized Aliso Canyon to operate with a working inventory of equivalently 68.6 Bcf.
[96] Aliso Canyon experienced a natural gas leak in Well SS25 on October 23, 2015. The leak was stopped on February 11, 2016, and SS25 was permanently sealed on February 18, 2016.
[97] Formerly DOGGR.
[98] CPUC Decision (D.)20-11-044.
[99] CPUC Decision (D.)21-11-008 issued on November 4, 2021.
[100] https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2020/WithdrawalProtocol-revised-April112020clean.pdf

cycle result in a Stage 2 low OFO or higher for the applicable gas day. 2) Aliso Canyon is above 70% of its maximum allowable inventory between February 1 and March 31. 3) Honor Rancho and/or Goleta fields decline to 110% of their month-end minimum inventory requirements during the winter season and 4) There is an imminent and identifiable risk of gas curtailments created by an emergency condition that would impact public health and safety or result in curtailments of electric load that could be mitigated by withdrawals from Aliso Canyon.

STORAGE REGULATIONS

Since 2015, the CPUC, CalGEM, and Pipeline and Hazardous Materials Safety Administration (PHMSA) have proposed and adopted various regulations addressing natural gas storage requirements and standards including safety and reliability. SoCalGas is committed to working with various regulating bodies and policy makers to promote safe and reliable energy and natural gas storage services.

Most recently, PHMSA issued their Final Rule for Underground Storage regulations, CFR Part 192.12, amending its minimum safety standards for underground natural gas storage facilities, effective March 13, 2020. The PHMSA Final Rule adopts API RP 1171, Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs, as published, modifies compliance timelines, formalizes integrity management practices, and clarifies the state's regulatory role.

CalGEM established fourteen California Code of Regulations §1726 California Underground Gas Storage regulations effective October 1, 2018, which includes mechanical testing mandates that require each well to be taken out of service for inspection every 24 months, unless an alternative frequency is approved by CalGEM, and semiannual field shut in tests for inventory certification.

REGULATORY ENVIRONMENT

STATE REGULATORY MATTERS

GENERAL RATE CASE

On September 26, 2019, the CPUC unanimously approved a final 2019 GRC decision that adopted a TY 2019 revenue requirement of $2.770 billion for SoCalGas which is $166 million lower than the $2.937 billion that SoCalGas had requested in its updated testimony. The adopted revenue requirement represents an increase of $314 million or a 12.8 percent increase over 2018. The final decision adopted post-test year (PTY) revenue requirement adjustments for SoCalGas are $220 million for 2020 (7.9 percent increase) and $150 million for 2021 (5.0 percent increase).

In January 2020, the CPUC revised the rate case plans and implemented a 4-year GRC cycle for California IOUs. SoCalGas was directed to file a Petition for Modification (PFM) to revise its 2019 GRC decision to add two additional attrition years including adjustment amounts, resulting in a transitional 5-year GRC period (2019-2023).

In April 2020, SoCalGas filed a PFM of its 2019 GRC decision requesting attrition year increases of $155 million (+4.95 percent) for 2022 and $137 million (+4.15 percent) for 2023. In May 2021, the CPUC issued a decision authorizing SoCalGas to apply its PTY mechanism adopted in the 2019 GRC decision to 2022 and 2023 but updated the calculations based on the 2020 4th Quarter Global Insight forecast to more fully capture the impact of Covid-19 to the economy. This decision resulted in revenue requirements of $3.3 and $3.4 billion for SoCalGas for 2022 and 2023 respectively, which were slightly less than the original requests made in SoCalGas' PFM.

In May 2022, SoCalGas filed its 2024 General Rate Case seeking to revise its authorized revenue requirements, effective on January 1, 2024, to recover the reasonable costs of gas operations, facilities, infrastructure, and other functions necessary to provide utility services to customers. SoCalGas requests a $4.426 billion revenue requirement for 2024, which, if approved, would be an increase of $767 million over the expected 2023 revenue requirement, or a 20.9% increase. SoCalGas' 2024-2027 rate request includes investments in four key areas: maintaining and enhancing reliability and safety, supporting sustainability, and promoting innovation and technology to meet operational and customer needs and workforce development. SoCalGas also includes a post-test year revenue requirement and a regulatory account-related proposal. The general rate request process is scheduled to take between 18 months and two years and is expected to conclude in late 2023.

GAS RELIABILITY AND PLANNING OIR

The CPUC initiated a rulemaking (R.20-01-007) to update gas reliability standards, determine the regulatory changes necessary to improve coordination between gas utilities and gas-fired electric generators, and implement a long-term planning strategy to manage the state's transition away from natural gas-fueled technologies to meet California's decarbonization goals.

The rulemaking has two tracks. Track 1 is intended to establish baseline standards and address issues of more immediate concern. These Track 1 issues include: determining whether changes to the reliability standards are needed and, if so, how any additional costs will be recovered and allocated; considering a change to the Operational Flow Order (OFO) penalty structure, which provides a financial incentive for gas customers, including electric generators, to deliver sufficient gas supply; and evaluating whether gas and electric interdependency requires the establishment of new reliability and cost containment protocols. A Proposed Decision (PD) on the OFO penalty structure was issued on March 18, 2022, and voted out at the April 21, 2022, CPUC Business Meeting. A final decision on the remaining Track 1 issues was adopted in July 2022, and includes no changes to design standards, a citation program for failure to meet minimum design standards and new reporting requirements for the California Gas Report starting in 2024.

Track 2 of the Gas Reliability OIR focuses on long-term system planning. Track 2A focuses on gas infrastructure. Its goal is to create new criteria for the CPUC to use when evaluating utility requests for spending on infrastructure as well as for proactively identifying distribution pipelines that can be decommissioned. In this track, the CPUC seeks to find a balance in which California has sufficient transmission and storage infrastructure to avoid creating reliability issues and scarcity that drive up gas commodity prices while at the same time avoiding unneeded investments that could lead to stranded assets and reducing distribution pipeline miles to decrease revenue requirement over time. The CPUC held two workshops in January and issued a workshop report in March 2022. A PD is expected in November 2022.

Track 2B focuses on equity, rates, safety, and workforce issues. The equity portion focuses on barriers that low-income customers would face in advancing state electrification goals and what the CPUC can do to mitigate those barriers. The rates portion will look at ratemaking strategies and develop ways to mitigate the impact of the gas transition on customer rates both now and in the future. The safety portion will look at ways to streamline safety spending where possible, given that most safety spending is required by state or federal agencies.

Track 2C will focus on data and process, considering a long-term strategy for managing gas planning going forward. It is expected to begin in 2023.

ALISO CANYON ORDER INSTITUTING INVESTIGATION

On February 9, 2017, the CPUC opened the Aliso Canyon proceeding, Investigation I.17-02-002, as directed by SB 380 (Pavley, 2016). SB 380 required the CPUC to "determine the feasibility of minimizing or eliminating the use of the SoCalGas Aliso Canyon Natural Gas Storage Facility (Aliso Canyon) while still maintaining energy and electric reliability for the region." This facility is the largest of four gas storage facilities serving southern California. The CPUC has modeled the current gas system, finding that the Aliso Canyon facility is currently necessary for winter reliability and cost containment.

A third-party consultant modeled the costs and benefits of adding new infrastructure that would allow Aliso Canyon to be closed by 2027 or 2035. The consultant modeled several different infrastructure portfolios, including gas infrastructure upgrades, new electricity transmission, increased energy efficiency and building electrification, and additional electric generation and storage. This analysis concluded that any of these portfolios could successfully replace the services provided by Aliso Canyon. The consultant found that any of the portfolios modeled, except for new gas infrastructure, would result in a net decrease in energy system costs, when factoring in the costs of compliance with the Cap-and-Trade Program and Renewable Portfolio Standard, because the benefits of using the new resources would outweigh the investment costs. However, on balance the savings would accrue to gas ratepayers, while electricity ratepayer costs would increase. This analysis did not address costs or usage of the Aliso Canyon site itself. The proceeding remains open, with the CPUC yet to determine whether to order that Aliso Canyon be closed and, if so, what infrastructure will be procured to allow that closure and what the timeline and other parameters will be. The CPUC anticipates a ruling in this proceeding before 2023.

The CPUC is also using this proceeding to determine the Aliso Canyon facility's maximum allowable gas storage inventory. The allowed inventory level impacts customers rates because higher storage inventory allows for lower gas costs to ratepayers by enabling the utility to buy and store gas when prices are low and use its stored gas when prices are high. The CPUC increased the maximum inventory level for the facility in November 2021 which will remain in place until the Commission issues a new decision in the proceeding.

BUILDING DECARBONIZATION POLICY

In September 2018, former Governor Brown signed two bills into law related to reducing GHG emissions from buildings, SB 1477 and AB 3232. SB 1477 calls on the CPUC to develop, in consultation with the CEC, two programs (BUILD and TECH) aimed at reducing GHG emissions associated with buildings. AB 3232 calls on the CEC, by 2021, to develop plans and projections to reduce GHG emissions of California's residential and commercial buildings to 40 percent below 1990 levels by 2030, working in consultation with the CPUC and other state agencies.

In January 2019, the CPUC issued an OIR on building decarbonization (R.19-01-011). The proposed scope of the rulemaking includes: (1) implementing SB 1477; (2) potential pilot programs to address new construction in areas damaged by wildfires; (3) coordinating CPUC policies with Title 24 Building Energy Efficiency Standards and Title 20 Appliance Efficiency Standards developed at the CEC; and (4) establishing a building decarbonization policy framework. A final decision D.20-03-027 was issued on April 6, 2020, which establishes a framework for CPUC oversight of two building decarbonization pilot programs—the Building Initiative for Low-Emissions Development (BUILD Program) program and the Technology and Equipment for Clean Heating (TECH Initiative) initiative. These two pilot programs are designed to develop valuable market experience for the purpose of decarbonizing California's residential buildings in order to achieve California's zero-emissions goals. SB 1477 makes available \$50 million annually for four years, for a total of \$200 million, derived from the revenue generated from GHG emission allowances directly allocated to gas corporations and consigned to auction as part of the Air Resources Board's (ARB) Cap-and-Trade Program. Incentive eligibility for the BUILD Program shall be limited strictly to newly constructed all-electric building projects, without any hookup to the gas distribution grid.

Phase II issued a Final Decision on November 4, 2021, which adopted the Wildfire and Natural Disaster Resilience Rebuild (WNDRR) Program to support all-electric rebuilding of residential properties that were destroyed or red-tagged due to a natural or man-made disaster on or after January 1, 2017. WNDRR will be offered for a ten-year period (2022-2032) across the service territories of the electric IOUs. Further, the decision directs the electric IOUs to study the total electric and gas bill impacts resulting from a customer switching from a natural gas water heater to an electric heat pump water heater (HPWH). Based on this analysis, each electric IOU must propose a HPWH rate adjustment in its next General Rate Case (Phase II) or Rate Design Window applications. In an effort to allow the CPUC and stakeholders to better understand propane use, the decision directs the electric IOUs to ask all new customers whether or not they use: (i) electric space heating equipment; (ii) electric water heating equipment; and (iii) propane to power any appliance other than an outdoor grill. The electric IOUs must report these responses to ED annually beginning on February 1, 2023, along with the number of total customers receiving the all-electric baseline allowance, as well as total customers receiving the new HPWH baseline allowance. Lastly, the decision adopts detailed non-binding guiding principles for how to determine program costs and benefits when programs overlap. These principles apply to the programs adopted under this proceeding (BUILD, TECH, and WNDRR), as well as programs authorized to incentivize clean heating technologies, specifically under Energy Efficiency (EE) (incl. the new statewide Heating, Ventilation, and Air Conditioning and Plug Load Appliance Programs administered by SDG&E), and the Self-Generation Incentive Program (SGIP) (HPWH sub-program).

In Phase III of R.19-01-011, the CPUC is considering changing the rules regarding allowances, refunds, and discounts paid to builders to help facilitate the connection of buildings to the gas distribution system. In November 2021, CPUC's Energy Division staff released a report recommending the complete elimination of these payments for all customer classes effective July 1, 2023. According to the staff report, gas ratepayers subsidize gas line extensions at a cost exceeding $100 million annually. According to the staff report, "By eliminating all gas line extension allowances, builders would be forced to shoulder greater expense if they choose to construct a building that uses gas...the added up-front gas burden would send a signal to builders that building new gas infrastructure is more expensive, and thus make dual-fuel construction less desirable and financially riskier. As such, the builder community would be more likely to gravitate towards all-electric new construction." The CPUC is expected to issue a Proposed Decision in the third quarter of 2022.

AFFORDABILITY OIR

On July 12, 2018, the Commission instituted the OIR (R.18-07-006) to develop a common understanding, methods and processes to assess, the impacts on affordability of individual Commission proceedings and utility rate requests. This OIR includes gas, electric, water and communications utilities. On July 16, 2020, the Commission issued its Phase 1 decision (D.20-07-032), which defines affordability as the degree to which a representative household is able to pay for an essential utility service, given its socioeconomic status. This decision also adopts three metrics and supporting methodologies to be used by the Commission for assessing the affordability of essential utility services, including: hours at minimum wage required to pay for essential utility services; Socioeconomic vulnerability index (SEVI) of various communities; and ratio of essential utility service charges to non-disposable household income—known as the affordability ratio. The decision does not adopt an absolute definition of what constitutes affordable essential utility services; rather, the decision adopts metrics and methodologies for assessing affordability across utilities over time.

In Phase II of the Affordability Proceeding, a Proposed Decision was issued on June 10, 2021, providing further direction on implementation of the three metrics adopted in Phase I the CPUC will use to assess the affordability of utility service. The PD establishes how the affordability framework will be applied in CPUC proceedings and further develops the tools and methodologies used to calculate the three metrics. Gas and electric utilities must include certain Affordability Ratio and Hours-at-Minimum Wage data in any filing that would result in a revenue increase estimated to exceed one percent of currently authorized systemwide revenues. They must also include various estimated bill impacts by climate zone. The affordability metrics must also be updated at the time of a PD in General Rate Case (GRC) proceedings. SDG&E is directed to introduce the required affordability analysis in its next GRC Phase 2 application. Electric, gas and water utilities will also now all be required to submit quarterly rate trackers to the CPUC, aggregating the rate impacts of their various revenue requirements, pending rate requests, and authorizations.

The CPUC held an Affordability Proceeding 2022 En Banc on February 28 and March 1 of 2022 as part of Phase 3 of Affordability Rulemaking A.18-07-006, which examined proposals to contain costs and mitigate rate increases. Stakeholder proposals focusing on gas ratepayers included the following:

- Authorize utilities to deploy capital and recover cost for building decarbonization upgrades via tariffed on-bill structures that enable participation regardless of income, credit score, or renter status.

- Implement rate or infrastructure planning mechanisms to avoid excessive gas infrastructure costs falling disproportionately on residential customers who cannot electrify.

- Determine if electrification warrants securitization and/or accelerated depreciation of natural gas assets.

- Implement a Renewable Balancing Services tariff that would charge different rates to different customer classes, especially during peak hours, based on amount of natural gas use.

- Evaluate natural gas rates and affordability in coordination with the Long-Term Gas Planning Rulemaking.

- Determine how to efficiently prune the natural gas system while providing safety.

- Legislative action to ensure long-term budget availability and use state revenue to recover costs for programs, such as CARE.

The next step in Phase 3 of the proceeding is to build on the En Banc discussions. There will be Statewide listening sessions and a workshop held by the CPUC to solicit recommendations and strategies from parties to mitigate rate increases. A proposed decision is scheduled for Q2-Q3 2023.

PIPELINE SAFETY

In 2011, the CPUC issued an OIR, R.11-02-019, to develop and adopt new regulations on pipeline safety, requiring that the utilities file implementation plans to test or replace natural gas transmission pipelines that do not have sufficient record of a pressure test.

SoCalGas and SDG&E jointly filed their comprehensive Pipeline Safety Enhancement Plan (PSEP) on August 26, 2011, pursuant to D.11-06-017. The comprehensive plan covered all of the utilities' approximately 4,000 miles of transmission lines and would be implemented in two phases. Phase 1 focuses on populated areas and Phase 2 covers less populated areas of SoCalGas' and SDG&E's service territories.

In June 2014, the CPUC issued D.14-06-007 approving the utilities' plan for implementing PSEP, subject to after-the-fact reasonableness review, established criteria to determine the costs that may be recovered from ratepayers, and authorized the establishment of balancing accounts to facilitate the recovery of costs for implementing Phase 1.

Subsequently, in D.16-12-063 the Commission approved SoCalGas' and SDG&E's joint application, (Application (A.) 14-12-016, requesting review and recovery of $33.2 million, which is a portion of the tracked PSEP costs incurred prior to June 12, 2014. Additionally, D.16-08-003, approved SoCalGas' and SDG&E's application (A.15-06-013) to establish Phase 2 memorandum accounts. The decision also authorized 50 percent interim cost recovery for Phase 1 actual revenue requirements booked to the regulatory accounts subject to refund, and a long-term procedural schedule for PSEP going forward. D.16-08-003 ordered SoCalGas and SDG&E to transition PSEP to the GRC starting with Test Year 2019 and that future GRC applications could include PSEP costs until implementation of the Plan is complete.

From 2011 through March 2022, SoCalGas and SDG&E have invested approximately $2.4 billion and $790 million, respectively, in PSEP, with additional expenditures planned, involving the remediation of more than 450 pipeline miles for SoCalGas and 60 miles for SDG&E.

In D,19-02-004, the Commission approved SoCalGas' and SDG&E's second PSEP Reasonableness Review application (A.16-09-005), which presented costs totaling $195 million (including certain costs for which the utilities are not seeking recovery) of pipeline safety projects completed by June 30, 2015. The Commission approved cost recovery of approximately $187 million ($172 million for SoCalGas and $15 million for SDG&E).

In D.19-03-025, the Commission also approved SoCalGas' and SDG&E's PSEP forecast application (A.17-03-021), finding $254.5 million associated with twelve SoCalGas Phase 1B and 2A pipeline projects reasonable and eligible for cost recovery. The decision directs SoCalGas and SDG&E to record costs to a one-way balancing account on an aggregate basis and balance to the authorized revenue requirements.

In December 2018, SoCalGas and SDG&E filed a third joint PSEP reasonableness review application (A.18-11-010) requesting cost review and rate recovery for 83 completed Phase 1 projects. The total costs submitted for review are approximately $941 million ($811 million for SoCalGas and $130 million for SDG&E). In D.20-08-034, the Commission approved a settlement agreement which addressed the reasonableness review of approximately $940 million in costs incurred executing 44 pipeline projects and 39 valve pipeline safety enhancement plan projects by granting cost recovery in total of $934,607,000.

SoCalGas most recently requested additional PSEP funding in its 2024 GRC application (A.22-05-015) that will enable SoCalGas to continue the implementation and prudent execution of PSEP as mandated in Decision (D.) 14-06-007 and in furtherance of the CPUC's order to complete the Plan "as soon as practicable," while balancing other pipeline safety compliance regulations and the obligation to provide customers with safe and reliable service. Since its inception, the four objectives of PSEP have been and continue to be: (1) enhance public safety; (2) comply with Commission directives; (3) minimize customer impacts; and (4) maximize the cost effectiveness of safety investments.

ANGELES LINK APPLICATION

On February 17, 2022, SoCalGas filed A.22-02-007 requesting authorization to establish the Angeles Link Memorandum Account, which would track the incremental costs associated with stakeholder engagement, engineering, design, and environmental work for a proposed pipeline delivering "renewable green hydrogen" into the Los Angeles Basin. The application does not specify a cost recovery mechanism for expenses recorded in the memorandum account, but the company could request cost recovery from ratepayers in a future proceeding if the memorandum account is approved. It states that the project must be approved prior to SoCalGas's next GRC due to the urgent climate benefits that the project would bring. The anticipated costs for the proposed memorandum account do not include construction or capital costs. The application references the use of underground hydrogen transportation infrastructure and "new in-state dedicated hydrogen pipelines," suggesting much of the pipeline will be new infrastructure built underground.

The application says that the project is designed to facilitate the closure of the Aliso Canyon methane storage facility and preserve energy reliability, as well as address overall climate change concerns. The application does not name specific end users of the renewable hydrogen, but it describes an intent to serve future hydrogen end users, including "hard-to-electrify" industries, electric generators, and the heavy-duty transportation sector. The application says that the foundation of the system would be one or more transmission pipelines that would run from generation sources in areas such as the Central Valley, Mojave Desert/Needles, or the Blythe area. The application does not specify how the hydrogen would be produced other than that it would come from electrolysis powered by renewable electricity.

The application describes three phases for the project. Phase 1 would last from 12 to 18 months and cost an estimated $26 million. It would support a pre-Front End Engineering and Design analysis assessing hydrogen demand, identifying end users, and conducting energy studies, in addition to engaging stakeholders. Phase 2 would last from 18 to 24 months and cost $92 million. It would identify a preferred option through design, engineering, and environmental studies and complete refined engineering and implementation plans. Phase 3 would last from 18 to 30 months and cost "several hundreds of millions of dollars." This phase would prepare permit applications, including an application to the CPUC for a Certificate of Public Convenience and Necessity and other long-lead permit applications.

FEDERAL REGULATORY MATTERS

SoCalGas and SDG&E participate in Federal Energy Regulatory Commission (FERC) proceedings involving interstate natural gas pipelines serving California that can affect the deliveries of gas to their customers. SoCalGas holds contracts for interstate transportation capacity on the El Paso, Kern River, Transwestern, and GTN and Canadian pipelines. SoCalGas and SDG&E also participate in FERC and Canadian regulatory proceedings involving the natural gas industry generally as those proceedings may impact their operations and policies.

EL PASO

On August 15, 2021, El Paso Natural Gas's (EPNG) Line 2000 ruptured near Coolidge, Arizona. The National Transportation Safety Board (NTSB) opened Investigation PLD21FR003 into the incident. On April 19, 2022, EPNG reported that "the pipeline failure remains under a PHMSA order, and the entire Line 2000 system is under a reduced operating pressure. The reduced operating pressure in effect removes the Line 2000 system from service from Black River compressor station to the California border."

On April 21, 2022, FERC issued against EPNG an Order on Cost and Revenue Study, Instituting Investigation and Setting Matter for Hearing Procedures Pursuant to Section 5 of the Natural Gas Act. In that section 5 proceeding, FERC alleged that EPNG may be substantially over-recovering its cost of service, causing El Paso's existing rates to be unjust and unreasonable. The section 5 proceeding is anticipated to be resolved by mid-2023.

GTN AND CANADIAN PIPELINES

SoCalGas acquires its Canadian natural gas supplies from the NGTL pipeline located in Alberta, Canada and transports these supplies through the NGTL pipeline in Alberta, to the Foothills Pipelines Limited Company pipeline (Foothills) in British Columbia, and finally to GTN at the Canadian/U.S. international border.

On November 18, 2021, FERC issued a letter order approving GTN's settlement agreement in lieu of GTN filing a NGA section 4 general rate case filing. That settlement agreement, among other things, maintained existing tariff recourse rates, established a moratorium on rate changes through December 31, 2023, and obligated GTN to file a NGA section 4 rate case in early 2024.

NORTH BAJA XPRESS PROJECT

On April 21, 2022, FERC issued a certificate of public convenience and necessity (CPCN) to North Baja Pipeline Company to construct and operate the North Baja Xpress project. The project will enable North Baja to provide 495,000 Dth/day of firm transportation service to Sempra LNG from the EPNG system at Ehrenberg for export to Mexico. The CPCN is conditioned on (1) making the facilities available within 3 years of the order date; (2) compliance with environmental conditions stated in the order; and (3) the execution of a firm service agreement before commencing construction.

GREENHOUSE GAS ISSUES

NATIONAL POLICY

Fundamental elements of the nation's greenhouse gas(es) (GHG) program were established by the Clean Power Plan, which was adopted by the U.S. EPA in August 2015 pursuant to their authority under the federal Clean Air Act. The intent of the Clean Power Plan was to reduce carbon emissions from power plants while maintaining energy reliability and affordability. The Clean Power Plan established customized goals for each state. It was projected to reduce carbon emissions from the power sector 32 percent from 2005 levels by 2030. Individual state targets were based on national uniform "emission performance rate" standards (pounds of carbon dioxide (CO_2) per MWh) and each state's unique generation mix.

On February 9, 2016, the U.S. Supreme Court issued a stay of the EPA's Clean Power Plan, freezing carbon pollution standards for existing power plants while the rule was under review at the U.S. Court of Appeals for the District of Columbia Circuit. In March 2017, President Trump signed an Executive Order directing the EPA Administrator to review the Clean Power Plan and if appropriate, suspend, revise, or rescind the rule. On October 10, 2017, the EPA released a proposed rule to repeal the Clean Power Plan. On June 30, 2022, the U.S. Supreme Court determined that the EPA lacks authority under the Clean Air Act to set GHG standards that require power producers to significantly change the generation mix. The Court held that such consequential rules must be based on explicit congressional authorization.

Former President Trump announced the United States' withdrawal from the Paris Agreement[101] (the international treaty on climate change) in 2017, but a number of U.S. states including California formed the United States Climate Alliance to maintain the objectives of the Clean Power Plan within their state borders separately from the federal government. President

[101] The Paris Agreement | UNFCCC

Biden signed an executive order on January 20, 2021, to re-admit the United States into the Paris Agreement. Readmission became effective 30 days later.

MOTOR VEHICLE EMISSIONS REDUCTIONS

National GHG policymakers realize that motor vehicles are one of the largest sources of GHG emissions, and one of the potential solutions is the substitution of natural gas and electricity for the current diesel and gasoline energy sources. This transition to cleaner fuels will also increase the demand for both natural gas and natural gas-generated electricity. Under the EPA's Mandatory Reporting of GHGs rule, all vehicle and engine manufacturers outside of the light-duty sector must report emission rates of CO_2, nitrous oxide, and methane from their products.

ASSEMBLY BILL 32

The Global Warming Solutions Act of 2006 (AB 32) requires California to reduce GHG emissions to the adopted statewide 1990 level by 2020. AB 32 directs the Air Resources Board (ARB) to adopt rules and regulations in an open public process to achieve the "maximum technologically feasible and cost-effective GHG emission reductions".[102] AB 32 also required the ARB to prepare and approve a scoping plan that provides a roadmap to reach the 2020 emissions reduction target. The first scoping plan was approved by the ARB in 2008 and the ARB is required to update the plan at least once every 5 years. The most recent update, as of this writing, was adopted in December 2017. For each scoping plan, the ARB is required to use a collaborative consultation process through engagement with State agencies including the CPUC and CEC, and a diverse set of stakeholders with public input facilitated through workshops and other meetings. The result is a policy framework that comprises a broad portfolio of recommended GHG reduction strategies and regulations, including a market-based compliance mechanism that are cost effective and minimizes administrative burden and GHG emission leakage.

[102] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200520060AB32.

SENATE BILL 32

SB 32 (Pavley) was enacted on September 8, 2016 and went into effect on January 1, 2017. The law extended the goals of AB 32 by requiring the ARB to ensure statewide GHG emissions are 40 percent below the 1990 levels by 2030. The continuation of the Global Warming Solutions Act keeps California on track with the emission reduction goals of the Paris Agreement. The 2017 Scoping Plan Update incorporated the 2030 target and constructed California's climate policy portfolio that includes doubling building efficiency, increasing renewable power by 50 percent cleaner zero and near-zero emission vehicles, reducing short-lived climate pollutants such as black carbon and limiting industry emissions through a Cap-and-Trade program. The companion bill to SB 32, AB 197, provides increased legislative oversight of the ARB through a Joint Legislative Committee on Climate Change Policies and directed it to take certain actions to improve local air quality. These actions include internet posting of emissions of GHG, criteria pollutants, and toxic air contaminants from stationary and mobile sources, prioritization of specified emission reduction rules and regulations to protect disadvantaged communities, and consideration of the social cost of carbon when preparing plans to meet GHG reduction targets and goals.

On May 10, 2022, the ARB released the Draft 2022 Scoping Plan Update. The draft of the 2022 Update reflects direction from major climate legislation and four Governor's Executive Orders issued since the adoption of the 2017 Scoping Plan Update. One of the executive orders, B-55-18 (signed September 2018) establishes a statewide goal to achieve carbon neutrality (i.e., the point at which removal of carbon pollution from the atmosphere meets or exceeds emissions) as soon as possible, and no later than 2045, and to achieve and maintain net negative GHG emissions thereafter. It also calls for the ARB to ensure future scoping plans identify and recommend measures to achieve this carbon neutrality goal and to develop a framework for implementation and accounting that tracks progress toward the goal. Further, in July 2021, Governor Newsom wrote to the ARB Chair requesting that the ARB evaluate how to achieve carbon neutrality no later than 2035 including analysis of how to reduce or eliminate demand for fossil fuel and end oil extraction in California. Additionally, the Governor asked for the pathway to carbon neutrality to prioritize strategies that reduce emissions of GHG as well as provide public health co-benefits, include an evaluation of cost effectiveness, and protect against leakage of GHG emissions to other states as mandated by law (AB 32). The Draft 2022 Scoping Plan Update recommends an alternative that achieves carbon neutrality in 2045 and found that the two 2035 alternatives evaluated have much higher direct costs, job losses, rate of slowing economic growth and degree of uncertainty.

SENATE BILL 350

The Clean Energy and Pollution Reduction Act, or SB 350, was signed into law on October 7, 2015, and sets ambitious goals that will help the State achieve the emissions reduction targets of SB 32. SB 350 increased and extended the RPS target to 50 percent by 2030, which later was amended by SB 100. Additionally, the law requires the state to double statewide energy efficiency savings in both the electric and natural gas sectors by 2030. The GHG reduction targets associated with these requirements are to be incorporated into IRPs, which detail how each required utility will reduce GHGs, deploy clean energy resources and otherwise meet the resources needs of their customers. The Energy Commission is coordinating with other state agencies—including the: CPUC, ARB, and CAISO—to implement the bill. SoCalGas has been engaged with these agencies throughout the process and has provided input.

SENATE BILL 1383

SB 1383 was signed into law on September 19, 2016, establishing methane emissions reduction targets in a statewide effort to reduce emissions of Short-Lived Climate Pollutants (SLCP) in various sectors of California's economy.[103] SB 1383 requires a 40 percent reduction in methane, a 40 percent reduction on hydrofluorocarbon gases and a 50 percent reduction in anthropogenic black carbon by 2030, relative to 2013 baseline levels and requires the ARB, the CPUC, and the CEC to undertake various actions related to reducing SLCPs in the state.
SB 1383 also establishes targets to achieve a 50 percent reduction in the level of the statewide disposal of organic waste from the 2014 level by 2020 and a 75 percent reduction by 2025. The law grants CalRecycle the regulatory authority required to achieve the organic waste disposal reduction targets and establishes an additional target that not less than 20 percent of currently disposed edible food is recovered for human consumption by 2025. The bill mandates the ARB,

[103] http://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160SB1383.

in consultation with the Department of Food and Agriculture, to adopt regulations to reduce methane emissions from livestock and dairy manure operations. SB 1383 also requires state agencies to consider and, as appropriate, adopt policies and incentives to significantly increase the sustainable production and use of RNG.

Pursuant to SB 1383, the ARB formed a Dairy and Livestock GHG Reduction working group in 2017 to help understand ways to reduce dairy and livestock methane emissions by 40 percent from 2013 levels by 2030. The working group's assignment was to identify and address technical, market, regulatory, and other barriers to development of methane reduction projects. SoCalGas actively participated in the working group and its three sub-groups including SoCalGas staff serving as co-chair of the Fostering Markets for Digester Projects sub-group whose task was to establish a roadmap, attentive to the SB 1383 statute dates of July 1, 2020 and January 1, 2024, to significantly expand the number of livestock digester projects in California that support the state's climate and air quality goals.

SoCalGas has participated in the CDFA Dairy Digester Research and Development Program (DDRDP), which provides financial assistance for the installation of dairy digesters in California, which will result in reduced GHG emissions. SoCalGas staff attended and presented at CDFA DDRDP workshops, webinars and listening sessions held in environmental justice (also known as disadvantaged communities) areas near dairies. SoCalGas also provided education and assisted customers who showed interest in the CDFA Program, as well as on other topics related to RNG, such as alternative fuel vehicles. A specific example is our promotion of RNG in our marketing materials especially those developed and displayed at the International Ag Expo held every year in Tulare, California. CDFA also includes a link on their DDRDP website to SoCalGas' RNG website.

SENATE BILL 100 AND EXECUTIVE ORDER B-55-18

The 100 Percent Clean Energy Act of 2019, or SB 100, was signed into law on September 10, 2018. SB 100 sets a state policy that eligible renewable energy and zero-carbon resources supply 100 percent of all retail sales of electricity in California by 2045. The bill also accelerates California's RPS, which, pursuant to a 2016 bill by the same author (SB 350), already mandates that load-serving entities procure at least 50 percent of retail sales from eligible renewable energy resources by 2030; under SB 100, the 2030 target will be increased to 60 percent, and the 50 percent target will be advanced to 2026, in recognition that California retail sellers are well on their way to achieving the target in advance of the existing deadlines. EO B-55-18 establishes a new statewide goal to achieve economy-wide carbon neutrality no later than 2045. In March 2021, the Joint Agencies (California Energy Commission, California Public Utilities Commission, and California Air Resources Board), published the 2021 *SB 100 Joint Agency Report: Achieving 100 Percent Clean Electricity in California: An Initial Assessment*. The report includes a review of the policy to provide 100 percent of electricity retail sales and state loads from renewable and zero-carbon resources in California by 2045. The report assesses various pathways to achieve the target and an initial assessment of costs and benefits. It also includes results from capacity expansion modeling and makes recommendations for further analysis and actions by the joint agencies. The Joint Agencies followed up with a workshop in October 2021 to analyze the non-energy benefits, social costs and reliability. Then the CEC conducted a workshop in collaboration with the CPUC and CAISO in February 2022, to discuss approaches for examining the environmental and land use implications of potential resource portfolios to meet SB 100 targets.

ASSEMBLY BILL 3232

The zero emissions buildings and sources of heat energy bill requires the CEC to assess the potential for the state to reduce the emissions of GHGs from the state's residential and commercial building stock by at least 40 percent below 1990 levels by January 1, 2030. AB 3232 also requires consideration of the impact of emission reduction strategies on grid reliability and as directed by AB 3232, the CEC will conduct additional analyses on strategies and update progress on reducing GHG emissions from residential and commercial buildings in the 2021 and future IEPRs. On August 11, 2021, the California Energy Commission (CEC) voted to adopt the AB 3232 California Building Decarbonization Assessment Final Staff Report (AB 3232 Final Report) during their regular Business Meeting. The Final Commissioner Report was published on August 13, 2021. In addition, a workbook containing updated assumptions being used in the Fuel Substitution Scenario Analysis Tool (FSSAT) was published to the 19-DECARB-01 Docket on February 28, 2022.

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AB 3232 suggests two baseline approaches from which California can track building decarbonization: systemwide and direct emissions. According to the Final Commissioner Report, the bulk of building GHG emissions in 2030 are from today's existing buildings and California has approximately 14 million existing single-family homes and multifamily units. The report defined and analyzed seven GHG emission strategies within seven high-level categories and the analysis concluded that as of 2018, systemwide GHG emissions in residential and commercial buildings are 26 percent below 1990 levels and current policies and activities are on a trajectory to reach 36 percent below 1990 levels by 2030. SoCalGas engaged with the CEC Commissioners and Staff on the Draft Version of the Building Decarbonization Assessment mandated by AB 3232 through attending six public workshops from December 2019 to May 2021 to discuss and share feedback on the findings presented in the AB 3232 Final Report; the CEC received many comments submitted to the public docket 19-DECARB-01.

GHG RULEMAKING

Beginning on January 1, 2015, the ARB's Cap-and-Trade Program expanded to include emissions from all SoCalGas customers. SoCalGas is required to purchase carbon allowances or offsets on behalf of our end-use customers for the emissions generated from the full combustion of the natural gas we deliver. Large end-use customers who emit at least 25,000 mtCO_2e equivalent per year have a direct obligation to the ARB for their own emissions; therefore, SoCalGas' obligation does not include these customers and they will not be responsible for compliance costs related to end-users from SoCalGas.

The CPUC completed a rulemaking proceeding in late 2015 to determine how the costs related to compliance with the Cap-and-Trade program will be included in end-use customers' rates.[104] The rulemaking had also addressed how revenues generated from the sale of directly allocated allowances will be returned to ratepayers. The rulemaking had initially determined that all Cap-and-Trade compliance costs will be included on a forecasted basis in customers' transportation rates beginning April 1, 2016. Customers with a direct obligation to the ARB for their emissions are exempt from SoCalGas' end-users' compliance obligation and will receive a volumetric credit called the "Cap-and-Trade Cost Exemption" for the amount of their

[104] CPUC D.15-10-032.

transportation rates that contribute to these costs. All customers' rates will also include compliance costs related to SoCalGas' covered facilities, as well as for Lost and Unaccounted For (LUAF) gas.

In the same CPUC decision, it was determined that revenues generated from the sale of directly allocated allowances would be returned as a fixed, once-annual, California Climate Credit to all residential households on their April bills. Nonresidential customers were not to receive a California Climate Credit. An Application for Rehearing on the use of the revenues generated from the sale of directly allocated allowances was granted in April 2016. As such, the introduction of Cap-and-Trade costs into rates and the distribution of the gas California Climate Credit was delayed. In March 2018, the CPUC issued its Final Decision (D.18-02-017), which directed IOUs to recover Cap-and-Trade costs and distribute the California Climate Credit. It found that: (1) only residential customers are eligible for the California Climate Credit, with the initial Climate Credit to be distributed in October 2018 and in April ever year thereafter; (2) GHG compliance costs can be incorporated in transportation rates beginning July 1, 2018, with 2018 costs amortized over 18 months; and (3) the accumulated 2015-2017 GHG costs and revenues are to be netted, with the remaining balance either distributed in the 2018 Climate Credit or amortized in transportation rates.

REPORTING AND CAP-AND-TRADE OBLIGATIONS

The ARB publishes total, covered and non-covered emissions because total emissions are used to calculate California's GHG emissions inventory and covered emissions are used to determine a facility's Cap-and-Trade obligation. At the time of the writing of the 2020 CGR, the 2019 GHG numbers have not been verified by the independent third party. The 2018 numbers were the most recent verified numbers for the reporting category. As of 2018, SoCalGas reported to the ARB *verified* GHG emissions of approximately 41.4 mmtCO_2E in three primary categories: (1) combustion emissions at five compressor stations and two storage fields, where annual emissions exceed 10,000 mtCO_2E; (2) vented and fugitive emissions from three compressor stations, two storage fields and the natural gas distribution system; and (3) the GHG emissions resulting from combustion of natural gas delivered to all customers.

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In 2018, GHG emissions for gas delivered to all customers was 39.9 mmtCO_2e, but 20.7 mmtCO_2e for gas delivered to non-covered customers. Non-covered customers consist of smaller customers with emissions of less than 25,000 mtCO_2E. For Cap-and-Trade obligation, 20.7 mmtCO_2e is the appropriate Cap-and-Trade value. Large, covered customers pay their own Cap-and-Trade bill.

Four of the five facilities subject to the EPA's mandatory reporting regulation are also subject to ARB's Cap-and-Trade Program. On January 1, 2015, natural gas suppliers became subject to the Cap-and-Trade Program and now have a compliance obligation for GHG emissions from the natural gas use of their small customers (i.e., those customers who are not covered directly under ARB's Cap-and-Trade Program). More recently, SoCalGas estimated that its GHG emissions compliance obligation as a natural gas supplier to be approximately 22.0 mtCO_2E for 2019. ARB will issue final 2019 GHG emissions compliance obligations for natural gas suppliers in November 2020.

The adoption of rules and procedures to minimize natural gas leakage from Commission-regulated natural gas pipelines consistent with Pub. Util. Code Section 961 (d), § 192.703 (c) of Subpart M of Title 49 of the CFR, and the Commission's General Order 112-F are covered under R.15-01-008. As part of this rulemaking, natural gas utilities are required to annually report their methane emissions from intentional and unintentional releases as well as their leak management practices. In 2020, SoCalGas reported 2.2 Bcf of methane emissions from intentional and unintentional releases for the year 2019. These emissions were reported in the SB 1371 report. Only some intentional emissions are subject to the ARB Cap-and-Trade Program.

PROGRAMMATIC EMISSIONS REDUCTION: CALIFORNIA GHG REDUCTION STRATEGIES

The ARB has the responsibility to develop the broad strategies to achieve California's GHG emissions reduction targets. The 2017 Scoping Plan Update identified several strategies to achieve the 2030 target to reduce emissions by 40 percent from 1990 levels: double building efficiency; 50 percent renewable power; cleaner transportation; and reduce SLCPs and Cap emissions from various sectors. The SLCP includes targets to reduce methane emissions from organic sources of methane and methane leakage from the oil and gas industry.

The CPUC has an on-going Rulemaking, R.15-01-008, to implement SB 1371, which requires the adoption of rules and procedures to minimize natural gas leakage from Commission -regulated natural gas pipeline facilities. In D.17-06-015, utilities were ordered to implement a Natural Gas Leak Abatement Program consistent with 26 Best Practices for emission mitigation. This proceeding is led by the CPUC in consultation with the ARB. The first phase will develop the overall policies and guidelines for a natural gas leak abatement program consistent with SB 1371. The second phase will develop ratemaking and performance-based financial incentives associated with the natural gas leak abatement program determined through Phase 1 of the proceeding. Energy efficiency and renewables are considered fundamental to GHG emission reduction in the electric sector. As a result, integration of additional renewables will require quick-start peaking capacity for firming and shaping of intermittent power, which in the foreseeable future will be gas-fired combustion turbines.

RENEWABLE NATURAL GAS

STATE AND FEDERAL POLICIES FOR RNG

STATE POLICIES ON RNG

AB 1900 (2012, Gatto) required that the Commission open a rulemaking to ensure that each gas corporation provide non-discriminatory open access to its gas pipeline system to any party for the purposes of physically interconnecting with the gas pipeline system and effectuating the safe delivery of gas. On February 13, 2013, the Commission opened the order instituting rulemaking (OIR) R.13-02-008, (or ‘Biomethane OIR’) to adopt a biomethane standard and requirement, pipeline open access rules, and related enforcement provisions. In collaboration with and the Office of Environmental Health Hazard Assessment, the Commission determined that biomethane could be safely injected into the natural gas pipeline system and Decision D.14-01-034 (January 16, 2014) adopted pipeline injection standards for 17 constituents of concern potentially found in biomethane. The establishment of these biomethane injection standards was Phase 1 of the Biomethane OIR.

Phase 2 of the Biomethane OIR resulted in Decision D.15-06-029, which adopted a biomethane interconnector monetary incentive program to encourage the development of biomethane projects interconnecting to the utilities gas pipeline systems. The incentive program authorized a total of $40 million for incentives, providing up to $1.5 million per project that successfully interconnect and operate by June 11, 2020. Pub. Util. Code § 399.19 later increased the incentive amounts to $3 million for non-dairy clusters and $5 million for dairy clusters and extended the incentive program to December 31, 2021.

On October 2, 2019, Governor Newsom signed into law SB 457, which extended the biomethane incentive program again until December 31, 2026, or until all available program funds were expended. Decision D.19-12-009 implemented the SB 457 extension which also implemented a reservation system for the biomethane monetary incentive program that allowed project developers to reserve incentive funds during the development of a project and receive the incentive funds once the project is operating. The Incentive Reservation System is publicly available online to promote the transparency of the use of funds and all $40 million earmarked for incentives was reserved by 11 biomethane projects, with an additional 8 projects placed on a waiting list for possible incentive funding later.

Phase 3 of the Biomethane OIR addressed the need for a statewide standard renewable gas interconnection tariff (SRGIT) and interconnection agreement (SRGIA) between the California natural gas utilities and RNG developers. On August 27, 2020, the Commission issued decision D.20-08-035, which adopted the SRGIT filed by SoCalGas, SDG&E, Southwest Gas, and PG&E (IUOs). Decision D.20-08-035 also allocated an additional $40 million for biomethane interconnection incentives to assist those RNG interconnection projects on the incentive waiting list.

Phase 4 of the Biomethane OIR was opened November 21, 2019, to address two issues: (1) standards for injection of renewable H2 into gas pipelines; and (2) implementation of SB 1440 that was signed into law on September 23, 2018 and required the Commission to consider adopting biomethane procurement targets (or goals) for each natural gas corporation in the state.

SB 1440 AND RNG

On February 24, 2022, the Commission issued Decision D.22-02-025 to implement SB 1440 and defined two biomethane procurement targets for the IOUs. A short-term 2025 biomethane procurement target was set at 17.6 billion cubic feet (BCF) of biomethane, which corresponds to 8 million tons of organic waste diverted statewide annually from landfills. This target was set to support the organic waste diversion targets established previously in SB 1383. With this target, each utility will be responsible for procuring only RNG produced from organic waste, including wood waste, at a level in accordance with its proportionate share of statewide Cap-and-Trade allowances.

The medium-term 2030 target for annual biomethane procurement was established at 72.8 BCF to assist the state achieve its goal to reduce methane emissions 40 percent by 2030[105] and is referred to as a "Renewable Gas Standard" (RGS) for California.[106] With this target, each utility will be responsible for procuring a percentage of the total in accordance with its proportionate share of 2020 annual bundled core customer natural gas demand, excluding NGV demand, as noted in the 2020 California Gas Report. Each utility may procure RNG produced from other feedstocks besides organic waste, including landfill, WWTP, Syngas or dairy.[107]

SB 1383 AND RNG

Another significant driver for RNG development in California is SB 1383. Signed into law on September 19, 2016, SB 1383 required the state board to implement a comprehensive strategy to reduce emissions of SLCPs so as to achieve a reduction in methane by 40%, hydrofluorocarbon gases by 40%, and anthropogenic black carbon by 50% below 2013 levels by 2030. The bill established specified targets for reducing organic waste in landfill and required state agencies to consider and, as appropriate, adopt policies and incentives to significantly increase the sustainable production and use of renewable gas.

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[105] SB-32 California Global Warming Solutions Act of 2006.

[106] D.22-02-025, p. 32.

[107] Dairy purchases are limited to 4% of the total utility proportionate share of the target volume.

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SB 1383 requires that beginning in 2022, all cities and counties provide organic waste collection services to all residents and businesses and also recycle these organic materials at recycling facilities such as anaerobic digestion facilities that create biofuel and electricity or composting facilities that make soil amendments. City and county governments are also required to procure prescribed amounts of products from in-state recycled organic material depending on their population. Allowed recycled products are, compost, mulch that meets SB 1383 regulations, renewable gas used as fuel for transportation, electricity, or heating applications and electricity generated from biomass conversion of municipal-solid-waste.

SB 1383 also required that the CPUC implement at least 5 dairy biomethane pilot projects to demonstrate interconnection to the common carrier pipeline system. For these pilot projects the gas corporations were allowed to fund and recover in rates the cost of pipeline infrastructure, including biogas collection lines and costs to interconnect with existing pipelines, removing many upfront costs developers would otherwise have to incur. On December 3, 2018, a selection committee consisting of staff members and attorneys from the CPUC, the ARB, and the CDFA, selected six dairy biomethane pilot projects. Four pilot projects are in SoCalGas service territory: CalBioGas Buttonwillow LLC; CalBioGas North Visalia LLC; CalBioGas South Tulare LLC; and Lakeside Pipeline LLC. (The other two projects are in PG&E service territory: Maas Energy Works in Merced; and Weststeyn Dairy in Willows.)

A.19-02-005[108] AND RNG

On February 28, 2019, SoCalGas and SDG&E filed a joint application A.19-02-005 for a voluntary RNG Tariff offering that would give the option to residential and small industrial and commercial customers to identify an amount of their monthly natural gas bill for the purchase of RNG in lieu of traditional natural gas. On December 17, 2020, Decision D.20-12-022, approved the voluntary renewable natural gas tariff authorizing a three-year voluntary Renewable Natural Gas (RNG) Tariff pilot program with two additional years for program wind-down. On March 14, 2022 SoCalGas filed an Advice Letter affirming their intention to implement the program

[108] On June 21, 2021, the Commission granted the Utilities' request for an extension of time to comply with D.20-12-022 as the Commission had provided guidance in OP 1(a) of D.20-12-022 that the Utilities should wait to consider sourcing long-term contracts for the voluntary RNG pilot program in conjunction with any RNG procurement authorized in the implementation of SB 1440.

within one year and review contract opportunities now that D.22-02-025 has implemented SB 1440.

FUEL STANDARDS AND RNG

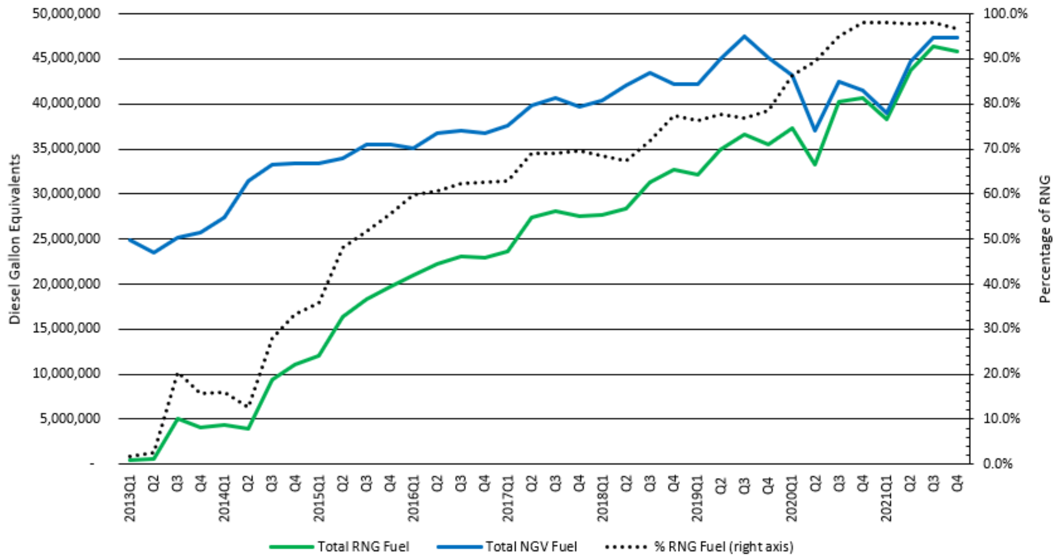
Fuel standards are evolving and becoming more stringent in California. Established by Executive Order and signed into law by then Governor Schwarzenegger in 2007, the fuel standard required a 10 percent carbon intensity reduction in the transportation sector by 2020. Those regulations were amended in 2018 to require a 20 percent reduction by 2030. The fuel standard(s) require fuel providers to ensure that the mix of fuel they sell into the California market meets, on average, provides a declining standard for GHG emissions measured in CO_2 equivalent grams per unit of fuel energy sold.

There is a significant amount of RNG used in California NGVs. The most recent data from the Low Carbon Fuel Standard (LCFS) Program[109] shows that approximately 98 percent of fuel delivered to NGVs in 2021 was RNG. The chart below shows how RNG usage in this important program has grown over time. Since 2013, RNG use by NGV's has displaced more than 886 million gallons of diesel fuel and has been responsible for reducing more than 8.4 MMT of carbon emissions.[110]

[109] https://ww2.arb.ca.gov/sites/default/files/2022-05/quarterlysummary_043022.xlsx.
[110] *Id.*

Southern California

Figure 25 - LCFS Program NGV Statistics for Years 2013 - 2021



The California NGV market continues to represent an important growth opportunity for RNG due to the economic incentives available from the LCFS Program and the Federal Renewable Fuel Standard, which help to offset the price premium between RNG and traditional fuels such as natural gas or diesel.

SoCalGas opted into the LCFS program in 2013 and began generating credits from fossil natural gas dispensed at utility owned CNG refueling stations that serve both company vehicles and the general public. In 2018, the CPUC approved a SoCalGas Advice Letter to initiate a Voluntary RNG Procurement Pilot program to procure and dispense RNG at its utility owned CNG stations. As RNG is an eligible alternative fuel under LCFS program and EPA's Renewable Fuel Standard (RFS), it generates Renewable Identification Number credits from the RFS Program in addition to the LCFS credits. The value from the credits generated is returned to CNG customers by reducing the price at the pump. Also, RNG has as lower carbon intensity than traditional CNG and will generate more credits per unit of energy under the LCFS program. On April 1, 2019, SoCalGas began procuring 100 percent RNG at all utility owned CNG stations. SoCalGas anticipates the Pilot will result in more value returned to its CNG customers while supporting the development of the RNG market.

CAP-AND-TRADE

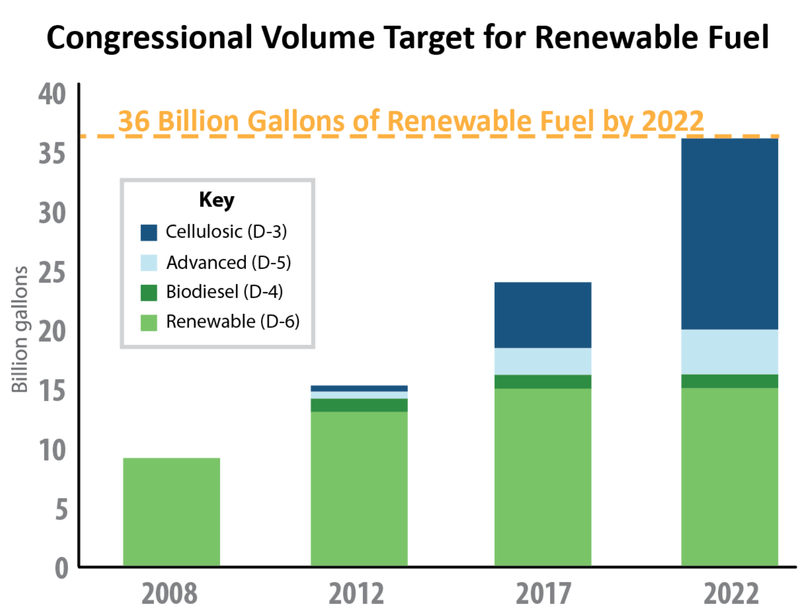
The Cap-and-Trade Regulation establishes a declining limit on major sources of GHG emissions throughout California. The Program applies to certain GHG emission sources and certain fuel suppliers, including natural gas utilities. CARB creates allowances equal to the total amount of permissible emissions and each year reduces the number of allowances created as the annual cap declines. An increasing auction reserve price for allowances and the reduction in annual allowances provides a carbon price signal intended to promote GHG emissions reductions. Many entities covered under the regulation must purchase allowances at quarterly auctions, however, qualifying RNG is exempt from compliance obligations under the program.

FEDERAL POLICIES ON RNG

RENEWABLE FUEL STANDARD (RFS)

The Renewable Fuel Standard (RFS) is a federal program that requires transportation fuel sold in the United States to contain a minimum volume of renewable fuels to expand the use of renewable fuels and reduce reliance on imported oil. RFS originated with the Energy Policy Act of 2005 and was expanded and extended by Congress in the Energy Independence and Security Act of 2007 (EISA). The RFS program provides a market-based monetary value for renewable fuels, including RNG that can be combined with LCFS incentives to increase the incentive amounts available to RNG developers, suppliers, or marketers. The RFS requires renewable fuel to be blended into transportation fuel in increasing amounts each year, escalating to 36 billion gallons by 2022.[111] For a fuel to qualify as a renewable fuel under the RFS program, EPA must determine that the fuel qualifies under the statute and regulations and the fuel must achieve a reduction in greenhouse gas (GHG) emissions as compared to a 2005 petroleum baseline.[112]

Figure 26 – Federal Renewable Fuel Targets



[111] https://www.epa.gov/renewable-fuel-standard-program/overview-renewable-fuel-standard
[112] *Id.*

HYDROGEN

Hydrogen is the simplest and most abundant element, making up approximately 75 percent of the observable universe. Hydrogen can be utilized as a fuel to generate energy. With its abundance and simple chemical structure, hydrogen can be manufactured from feedstock such as methane, or water and electricity, using scalable, sustainable, and renewable methods. Hydrogen has favorable emissions characteristics because it does not contain carbon or produce GHG when it is consumed. For this reason, hydrogen can play an important role in the transition to a clean, low-carbon energy system in California.[113]

As part of the State of California's climate strategy, hydrogen can provide important GHG emissions reductions, and can also play a key role in enabling the use of zero-emissions fuel cell electric vehicles, which can reduce criteria emissions from on-road diesel, the largest and hardest to electrify contributors to the State's black carbon and nitrogen oxides (NOx) inventories.[114] California has also been at the forefront of developing hydrogen fueling stations to demonstrate the feasibility of hydrogen-fueled transportation and the potential that such a network creates for deployment of light duty fuel-cell electric vehicles (FCEVs).

Hydrogen fuel for transportation was adopted in California through the policy framework by Assembly Bill (AB) 8, which provided certainty for hydrogen fueling station deployment.[115] In addition, new programs and policies have been developed and initiated to ensure that some of the most ambitious public-private goals are met as projected. The Low Carbon Fuel Standard's (LCFS) Hydrogen Refueling Infrastructure (HRI) credit provisions took effect, predicated on the goal of reaching 200 hydrogen stations by 2025 as described by Governor Brown's Executive Order B-48-18 (EO B-48-18).[116]

Globally, hydrogen is widely seen as a pivotal component of the future clean energy economy. The two primary technological processes used today to produce hydrogen are electrolysis and

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113 http://hydrogencouncil.com .
114 https://www.arb.ca.gov/cc/inventory/slcp/slcp.htm .
115 https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB8 .
116 https://www.ca.gov/archive/gov39/2018/01/26/governor-brown-takes-action-to-increase-zero-emission-vehicles-fund-new-climate-investments/index.html.

reformation, including steam methane reformation (SMR) and autothermal reformation (ATR). Hydrogen is also produced when organic mass is gasified, but this "syngas," consisting of mainly carbon monoxide (CO) and hydrogen, is typically an intermediate product often used to generate methane or electricity. Reforming is a mature technology and is the most economical way to produce hydrogen, supplying 95% or more of the hydrogen used in the United States today.[117] The electrolysis process uses renewable electricity to split water (H_2O) into hydrogen (H_2) and oxygen (O_2).

As a gaseous fuel, hydrogen can help decarbonize the gas grid and be used in a variety of end use applications, beyond transportation. The hydrogen can either be stored directly, or methanated and injected into the natural gas grid to be stored and delivered to a variety of end uses, supplementing or displacing traditional natural gas. Storing hydrogen from electrolysis is a scalable and versatile energy storage pathway.

In 2022, SoCalGas proposed the development of what would be the nation's largest green hydrogen energy infrastructure system, the Angeles Link, to deliver clean, reliable energy to the Los Angeles region. As proposed, the Angeles Link would support the integration of more renewable electricity resources like solar and wind and would significantly reduce greenhouse gas emissions from electric generation, industrial processes, heavy-duty trucks, and other hard-to-electrify sectors of the Southern California economy. The proposed Angeles Link would also significantly decrease demand for natural gas, diesel and other fossil fuels in the LA Basin, helping accelerate California's and the region's climate and clean air goals.

Electrolytic green hydrogen is produced entirely from renewable electricity, and it expands our renewable energy storage capabilities, allowing us to utilize more renewable electricity and avoid curtailment while reducing emissions in hard-to-electrify sectors. As contemplated, the Angeles Link would deliver green hydrogen in an amount equivalent to almost 25 percent of the natural gas SoCalGas delivers today. Building the system to provide a clean alternative fuel could, over time and combined with other future clean energy projects, reduce

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[117] The Potential to Build Current Natural Gas Infrastructure to Accommodate the Future Conversion to Near-Zero Transportation Technology, Institute of Transportation Studies, UC Davis (March 2017), available at https://steps.ucdavis.edu/wp-content/uploads/2017/05/2017-UCD-ITS- RR-17-04-1.pdf

natural gas demand served by the Aliso Canyon natural gas storage facility, facilitating its ultimate retirement while continuing to provide reliable and affordable energy to the region.

PEAK DAY DEMAND

Beginning in April 2008, gas supplies to serve both SoCalGas' and SDG&E's bundled core gas demand are procured as a combined portfolio. SoCalGas and SDG&E plan and design their systems to provide continuous service to their core customers under an extreme peak day event. On the extreme peak day event, service to all noncore customers is assumed to be fully interrupted. The criteria for extreme peak day design is defined as a 1-in-35 likelihood event foreach utility's service area. This criteria correlates to a system average temperature of 40.5 degrees Fahrenheit for SoCalGas' service area and 43.3 degrees Fahrenheit for SDG&E's service area.

TABLE 28 – CORE 1-IN-35 YEAR EXTREME PEAK DAY DEMAND (MMcf/d)

Year	SoCalGas Core Demand 1/	SDG&E Core Demand 2/	Other Core Demand 3/	Total Demand	*Estimated AAFS Impact on Core Peak Day Demand* 5/
2022	2,869	404	170	**3,443**	-2
2023	2,827	403	170	**3,401**	-9
2024	2,782	402	171	**3,355**	-25
2025	2,735	400	173	**3,308**	-44
2026	2,691	398	174	**3,263**	-65
2027	2,647	397	175	**3,218**	-88
2028	2,601	395	176	**3,173**	-113

Notes:

(1) 1-in-35 peak temperature cold day SoCalGas core sales and transportation. Forecast embodies the baseline forecast with load modifiers that include changing weather design to account for climate change, assumed EE savings and assumed fuel substitution under AAFS 2.

(2) 1-in-35 peak temperature cold day SDG&E core sales and transportation.

(3) 1-in-35 peak temperature cold day core demand of Southwest Gas Corporation, City of Long Beach, City of Vernon, and Ecogas.

(4) The criteria for extreme peak day design are defined as a 1-in-35 likelihood event for each utility's service area. These criteria correlate to a system average temperature of 40.5 degrees Fahrenheit for SoCalGas' service area and 43.3 degrees Fahrenheit for SDG&E's service area.

(5) Estimated impact shown represents SoCalGas and SDG&E's combined AAFS impacts. SoCalGas and SDG&E's AAFS Impacts are included in the forecast of Peak day demand of "SoCalGas Core Demand", "SDG&E Core Demand", and "Total Demand".

Southern California

Demand on an extreme peak day is met through a combination of withdrawals from underground storage facilities and flowing pipeline supplies. The following table provides forecasted core extreme peak day demand.

SoCalGas aligned around the fuel substitution scenario developed by the California Energy Commission (CEC). SoCalGas emphasizes that we are still in the early stages of this energy transition and forecasts around the timing and degree of these changes are highly uncertain. These forecasts will improve over time as trends are observed in the real world and policy and market drivers mature. SoCalGas will be actively monitoring these trends and expects that each update of the CGR will incorporate greater definition of these factors and their impact(s) on the resultant gas demand segment forecasts.

It is also important to note that the CGR is relied upon for system planning purposes to inform important infrastructure investment and operating decisions that impact the natural gas system capacity and reliability. For these reasons, it is important to recognize that while we need to evolve with the energy transition, we also consider a measured view around prospective load reductions to avoid premature design standard reductions that may not serve California well if less load reductions materialize than are anticipated. We have an obligation to our customers to make sure they have safe, clean, reliable and affordable sources of energy and compromising these outcomes based on prospective and uncertain projections will not serve the public interest so ambition must be appropriately balanced with reality.

The CPUC has also mandated that SoCalGas and SDG&E design its system to provide service to both core and noncore customers under a winter temperature condition with an expected recurrence interval of 10 years. The demand forecast for this 1-in-10-year cold day condition is shown in the table below.

TABLE 29 – WINTER 1-IN-10 YEAR COLD DAY DEMAND CONDITION (MMcf/d)

Year	SoCalGas Core (1)	SDG&E Core (2)	Other Core (3)	Noncore NonEG (4)	Electric Generation (5)	Total Demand	*Estimated AAFS Impact on Core Peak Day Demand* (7)
2022	2,709	380	150	621	812	4,672	-2
2023	2,670	380	150	621	792	4,612	-9
2024	2,628	378	151	622	749	4,528	-23
2025	2,584	376	152	622	725	4,459	-41
2026	2,542	375	153	621	710	4,402	-61
2027	2,500	373	154	621	735	4,383	-83
2028	2,458	372	155	620	669	4,274	-107

Notes:
(1) 1-in-10 peak temperature cold day SoCalGas core sales and transportation.
(2) 1-in-10 peak temperature cold day SDG&E core sales and transportation.
(3) 1-in-10 peak temperature cold day core demand of Southwest Gas Corporation, City of Long Beach, City of Vernon, and Ecogas.
(4) Noncore-Non-EG includes noncore non-EG end-use customers of SoCalGas, SDG&E, Southwest Gas Corporation, City of Long Beach, City of Vernon, and Ecogas. Average daily December Noncore-Non-EG demand for all market segments except Refinery and SoCalGas noncore Commercial; SoCalGas noncore Commercial is at 1-in-10 peak temperature cold day demand and Refinery is at connected load.
(5) Electric Generation includes UEG/EWG Base Hydro, large cogeneration, industrial and commercial cogeneration (<20MW), refinery-related cogeneration, and EOR-related cogeneration.
(6) The criteria for 1-in-10 peak day design are defined as a 1-in-10 likelihood event for each utility's service area. These criteria correlate to a system average temperature of 42.2 degrees Fahrenheit for SoCalGas' service area and 44.8 degrees Fahrenheit for SDG&E's service area.
(7) Estimated impact shown represents SoCalGas and SDG&E's combined AAFS impacts. SoCalGas and SDG&E's AAFS Impacts are included in the forecast of Peak day demand of "SoCalGas Core Demand", "SDG&E Core Demand", and "Total Demand".

The SoCalGas and SDG&E system is a winter peaking system; peak demand is expected to occur during the winter operating season of November through March. For this reason, the CPUC has not mandated a summer design standard. For informational purposes only, the table below presents a forecast of summer demand on the SoCalGas and SDG&E system.

TABLE 30 – SUMMER HIGH SENDOUT DAY DEMAND
(MMcf/d)

Year	High Demand Month (1)	SoCalGas Core (2)	SDG&E Core (3)	Other Core (4)	Noncore NonEG (5)	Electric Generation (6)	Total Demand
2022	Sep	607	87	57	587	1,241	2,579
2023	Sep	599	87	57	589	1,180	2,513
2024	Sep	591	87	57	590	981	2,306
2025	Sep	582	86	58	590	1,031	2,347
2026	Sep	575	86	58	589	1,080	2,387
2027	Sep	567	85	58	589	1,104	2,403
2028	Sep	558	84	59	588	1,022	2,312

Notes:
(1) Month of High Sendout gas demand during summer (July, August or September).
(2) Average daily summer SoCalGas core sales and transportation.
(3) Average daily summer SDG&E core sales and transportation.
(4) Average daily summer core demand of Southwest Gas Corporation, City of Long Beach, City of Vernon, and Ecogas.
(5) Noncore-Non-EG includes noncore non-EG end-use customers of SoCalGas, SDG&E, Southwest Gas Corporation, City of Long Beach, City of Vernon, and Ecogas. Average daily September Noncore-Non-EG demand for all noncore market segments except Refinery; Refinery is at connected load.
(6) Highest demand during the high demand month under 1-in-10 dry hydro conditions except year 2022, when the Electric Generation highest demand is based on 2022 hydro condition.

2022 CALIFORNIA GAS REPORT

SOUTHERN CALIFORNIA GAS COMPANY – TABULAR DATA

Table 31

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND SENDOUT - MMCF/DAY
RECORDED YEARS 2017 TO 2021

Line	CAPACITY AVAILABLE		2017	2018	2019	2020	2021
1	California Source Gas						
	Out-of-State Gas						
2	California Offshore -POPCO / PIOC						
3	El Paso Natural Gas Co.						
4	Transwestern Pipeline Co.						
5	Kern / Mojave						
6	PGT / PG&E						
7	Other						
8	Total Out-of-State Gas						
9	TOTAL CAPACITY AVAILABLE						
	GAS SUPPLY TAKEN						
10	California Source Gas		84	104	97	87	86
	Out-of-State Gas						
11	Other Out-of-State		2,434	2,246	2,305	2,366	2,377
12	Total Out-of-State Gas		2,434	2,246	2,305	2,366	2,377
13	TOTAL SUPPLY TAKEN		2,518	2,350	2,402	2,453	2,463
14	Net Underground Storage Withdrawal		(14)	(8)	7	(19)	(20)
15	TOTAL THROUGHPUT (1)(2)		2,504	2,342	2,409	2,435	2,443
	DELIVERIES BY END-USE						
16	Core	Residential	565	569	645	635	621
17		Commercial	214	217	226	196	211
18		Industrial	55	57	61	53	55
19		NGV	38	40	41	37	40
20		Subtotal	872	883	973	920	927
21	Noncore	Commercial	56	59	58	57	57
22		Industrial	389	389	**357**	369	376
23		EOR Steaming	39	38	51	51	34
24		Electric Generation	713	615	589	641	654
25		Subtotal	1,198	1,101	1,055	1,118	1,121
26	Wholesale/International		401	333	342	374	372
27	Co. Use & LUAF		33	25	39	23	23
28	SYSTEM TOTAL-THROUGHPUT (1)(2)		2,504	2,342	2,409	2,435	2,443
	TRANSPORTATION AND EXCHANGE						
29	Core	All End Uses	62	71	74	63	64
30	Noncore	Commercial/Industrial	446	448	415	426	433
31		EOR Steaming	39	38	51	51	34
32		Electric Generation	713	623	589	641	654
33		Subtotal-Retail	1,260	1,181	1,129	1,181	1,185
34	Wholesale/International		401	333	342	374	372
35	TOTAL TRANSPORTATION & EXCHANGE		1,660	1,514	1,471	1,554	1,557
36	CURTAILMENT (3)						
37	REFUSAL						
38		Total BTU Factor (Dth/Mcf)	1.0343	1.0319	1.0336	1.0293	1.0322

NOTES:

(1) The wholesale volumes only reflect natural gas supplied by SoCalGas; and, do not include supplies from other sources.
Refer to the supply source data provided in each utility's report for a complete accounting of their supply sources.

(2) Deliveries by end-use includes sales, transportation, and exchange volumes and data includes effect of prior period adjustments.

(3) The table does not explicitly show any curtailment numbers for the recorded years because, during some curtailment events.
the estimate of the curtailed volume is not available. This table does not explicitly show any curtailment data for the recorded years, the noncore customer usage data implicitly captures the effects of any curtailment events.

TABLE 1-SCG

Table 32

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2022 THRU 2026

AVERAGE TEMPERATURE YEAR

LINE			2022	2023	2024	2025	2026	LINE
	CAPACITY AVAILABLE							
1	California Line 85 Zone (California Producers)		60	60	60	60	60	1
2	California Coastal Zone (California Producers)		150	150	150	150	150	2
	Out-of-State Gas							
3	Wheeler Ridge Zone (KR, MP, PG&E, OEHI) 1/		765	765	765	765	765	3
4	Southern Zone (EPN,TGN,NBP) 2/		1,210	1,210	1,210	1,210	1,210	4
5	Northern Zone (TW,EPN,QST, KR) 3/		1,250	1,250	1,250	1,250	1,250	5
6	Total Out-of-State Gas		3,225	3,225	3,225	3,225	3,225	6
7	TOTAL CAPACITY AVAILABLE 4/		3,435	3,435	3,435	3,435	3,435	7
	GAS SUPPLY TAKEN							
8	California Source Gas 5/		61	61	61	61	61	8
9	Out-of-State		2,379	2,354	2,266	2,219	2,190	9
10	TOTAL SUPPLY TAKEN		2,440	2,415	2,327	2,280	2,251	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 6/		2,440	2,415	2,327	2,280	2,251	12
	REQUIREMENTS FORECAST BY END-USE 7/							
13	CORE 8/	Residential	610	604	594	585	575	13
14		Commercial	206	200	194	190	185	14
15		Industrial	54	54	53	52	51	15
16		NGV	41	42	43	44	45	16
17		Subtotal-CORE	912	900	883	870	856	17
18	NONCORE	Commercial	48	49	49	49	49	18
19		Industrial	389	390	389	389	388	19
20		EOR Steaming	27	27	27	27	27	20
21		Electric Generation (EG)	670	667	612	584	571	21
22		Subtotal-NONCORE	1,135	1,132	1,076	1,049	1,035	22
23	WHOLESALE &	Core	208	208	207	207	206	23
24	INTERNATIONAL	Noncore Excl. EG	28	27	27	28	28	24
25		Electric Generation (EG)	127	117	104	97	97	25
26		Subtotal-WHOLESALE & INTL.	363	352	339	332	331	26
27		Co. Use & LUAF	31	30	29	29	28	27
28	SYSTEM TOTAL THROUGHPUT 6/		2,440	2,415	2,327	2,280	2,251	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	64	64	63	63	62	29
30	NONCORE	Commercial/Industrial	437	438	437	438	437	30
31		EOR Steaming	27	27	27	27	27	31
32		Electric Generation (EG)	670	667	612	584	571	32
33		Subtotal-RETAIL	1,199	1,196	1,139	1,112	1,097	33
34	WHOLESALE & INTERNATIONAL	All End Uses	363	352	339	332	331	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,562	1,548	1,478	1,443	1,428	35
	CURTAILMENT (RETAIL & WHOLESALE)							
36		Core	0	0	0	0	0	36
37		Noncore	0	0	0	0	0	37
38		TOTAL - Curtailment	0	0	0	0	0	38

NOTES:
1/ Wheeler Ridge Zone: KR & MP at Wheeler Ridge, PG&E at Kern Stn., OEHI at Gosford)
2/ Southern Zone (EPN at Ehrenberg, TGN at Otay Mesa, NBP at Blythe); ability to receive 1,210 MMcfd dependent on local area demand
3/ Northern Zone (TW at No. Needles, EPN at Topok, QST at No. Needles, KR at Kramer Jct.); projected capacity may vary from that shown over the span of the CGR timeframe pending 2024 General Rate Case decision
4/ Represents the outlook for firm receipt capacities at the time of publication; subject to change over the span of the CGR timeframe.
5/ Average 2021 recorded California Source Gas; production less than capacity due to reservoir performance and economics.
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach: 1.3 (2022), 1.3 (2023), 1.3 (2024), 1.2 (2025), 1.2 (2026)
7/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.
8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d: 875 (2022), 863 (2023), 847 (2024), 834 (2025), 820 (2026)

Table 33

TABLE 2-SCG

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2027 THRU 2035

AVERAGE TEMPERATURE YEAR

LINE			2027	2028	2029	2030	2035	LINE
	CAPACITY AVAILABLE							
1	California Line 85 Zone (California Producers)		60	60	60	60	60	1
2	California Coastal Zone (California Producers)		150	150	150	150	150	2
	Out-of-State Gas							
3	Wheeler Ridge Zone (KR, MP, PG&E, OEHI) 1/		765	765	765	765	765	3
4	Southern Zone (EPN,TGN,NBP) 2/		1,210	1,210	1,210	1,210	1,210	4
5	Northern Zone (TW,EPN,QST, KR) 3/		1,250	1,250	1,590	1,590	1,590	5
6	Total Out-of-State Gas		3,225	3,225	3,565	3,565	3,565	6
7	TOTAL CAPACITY AVAILABLE 4/		3,435	3,435	3,775	3,775	3,775	7
	GAS SUPPLY TAKEN							
8	California Source Gas 5/		61	61	61	61	61	8
9	Out-of-State		2,160	2,106	2,080	2,034	1,912	9
10	TOTAL SUPPLY TAKEN		2,221	2,167	2,141	2,095	1,973	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 6/		2,221	2,167	2,141	2,095	1,973	12
	REQUIREMENTS FORECAST BY END-USE 7/							
13	CORE 8/	Residential	565	552	542	530	466	13
14		Commercial	181	177	174	170	155	14
15		Industrial	50	49	48	47	44	15
16		NGV	46	47	48	50	54	16
17		Subtotal-CORE	842	825	813	797	719	17
18	NONCORE	Commercial	49	49	49	49	48	18
19		Industrial	388	388	388	387	385	19
20		EOR Steaming	26	25	24	24	20	20
21		Electric Generation (EG)	558	529	516	493	461	21
22		Subtotal-NONCORE	1,021	991	977	952	914	22
23	WHOLESALE &	Core	206	205	204	203	199	23
24	INTERNATIONAL	Noncore Excl. EG	28	28	28	28	29	24
25		Electric Generation (EG)	96	92	92	88	87	25
26		Subtotal-WHOLESALE & INTL.	330	324	325	319	315	26
27		Co. Use & LUAF	28	27	27	26	25	27
28	SYSTEM TOTAL THROUGHPUT 6/		2,221	2,167	2,141	2,095	1,973	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	62	62	62	61	61	29
30	NONCORE	Commercial/Industrial	437	437	436	436	433	30
31		EOR Steaming	26	25	24	24	20	31
32		Electric Generation (EG)	558	529	516	493	461	32
33		Subtotal-RETAIL	1,083	1,052	1,039	1,013	975	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	330	324	325	319	315	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,413	1,376	1,363	1,333	1,290	35
	CURTAILMENT (RETAIL & WHOLESALE)							
36		Core	0	0	0	0	0	36
37		Noncore	0	0	0	0	0	37
38		TOTAL - Curtailment	0	0	0	0	0	

NOTES:

1/ Wheeler Ridge Zone: KR & MP at Wheeler Ridge, PG&E at Kern Stn., OEHI at Gosford)

2/ Southern Zone (EPN at Ehrenberg, TGN at Otay Mesa, NBP at Blythe); ability to receive 1,210 MMcfd dependent on local area demand

3/ Northern Zone (TW at No. Needles, EPN at Topok, QST at No. Needles, KR at Kramer Jct.); projected capacity may vary from that shown over the span of the CGR timeframe pending 2024 General Rate Case decision

4/ Represents the outlook for firm receipt capacities at the time of publication; subject to change over the span of the CGR timeframe.

5/ Average 2021 recorded California Source Gas; production less than capacity due to reservoir performance and economics.

	2027	2028	2029	2030	2035
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach	1.2	1.2	1.2	1.2	1.1

7/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.

	2027	2028	2029	2030	2035
8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	805	788	775	759	680

TABLE 3-SCG

Table 34

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2022 THRU 2026

COLD TEMPERATURE YEAR (1 IN 35 COLD YEAR EVENT) & DRY HYDRO YEAR

LINE			2022	2023	2024	2025	2026	LINE
	CAPACITY AVAILABLE							
1	California Line 85 Zone (California Producers)		60	60	60	60	60	1
2	California Coastal Zone (California Producers)		150	150	150	150	150	2
	Out-of-State Gas							
3	Wheeler Ridge Zone (KR, MP, PG&E, OEHI) 1/		765	765	765	765	765	3
4	Southern Zone (EPN,TGN,NBP) 2/		1,210	1,210	1,210	1,210	1,210	4
5	Northern Zone (TW,EPN,QST, KR) 3/		1,250	1,250	1,250	1,250	1,250	5
6	Total Out-of-State Gas		3,225	3,225	3,225	3,225	3,225	6
7	TOTAL CAPACITY AVAILABLE 4/		3,435	3,435	3,435	3,435	3,435	7
	GAS SUPPLY TAKEN							
8	California Source Gas 5/		61	61	61	61	61	8
9	Out-of-State		2,452	2,432	2,343	2,298	2,267	9
10	TOTAL SUPPLY TAKEN		2,513	2,493	2,404	2,359	2,328	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 6/		2,513	2,493	2,404	2,359	2,328	12
	REQUIREMENTS FORECAST BY END-USE 7/							
13	CORE 8/	Residential	660	653	642	632	622	13
14		Commercial	214	208	202	197	193	14
15		Industrial	55	55	53	52	51	15
16		NGV	41	42	43	44	45	16
17		Subtotal-CORE	970	957	940	926	911	17
18	NONCORE	Commercial	49	49	49	50	50	18
19		Industrial	389	390	389	389	388	19
20		EOR Steaming	27	27	27	27	27	20
21		Electric Generation (EG)	670	671	616	591	578	21
22		Subtotal-NONCORE	1,136	1,138	1,081	1,057	1,042	22
23	WHOLESALE &	Core	221	221	220	220	219	23
24	INTERNATIONAL	Noncore Excl. EG	28	28	28	28	28	24
25		Electric Generation (EG)	127	118	105	98	98	25
26		Subtotal-WHOLESALE & INTL.	376	366	353	346	345	26
27		Co. Use & LUAF	32	31	30	30	29	27
28	SYSTEM TOTAL THROUGHPUT 6/		2,513	2,493	2,404	2,359	2,328	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	66	65	64	64	64	29
30	NONCORE	Commercial/Industrial	438	439	438	439	438	30
31		EOR Steaming	27	27	27	27	27	31
32		Electric Generation (EG)	670	671	616	591	578	32
33		Subtotal-RETAIL	1,201	1,203	1,146	1,121	1,106	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	376	366	353	346	345	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,577	1,569	1,498	1,467	1,451	35
	CURTAILMENT (RETAIL & WHOLESALE)							
36		Core	0	0	0	0	0	36
37		Noncore	0	0	0	0	0	37
38		TOTAL - Curtailment	0	0	0	0	0	

NOTES:
1/ Wheeler Ridge Zone: KR & MP at Wheeler Ridge, PG&E at Kern Stn., OEHI at Gosford)
2/ Southern Zone (EPN at Ehrenberg, TGN at Otay Mesa, NBP at Blythe); ability to receive 1,210 MMcfd dependent on local area demand
3/ Northern Zone (TW at No. Needles, EPN at Topok, QST at No. Needles, KR at Kramer Jct.); projected capacity may vary from that shown over the span of the CGR timeframe pending 2024 General Rate Case decision
4/ Represents the outlook for firm receipt capacities at the time of publication; subject to change over the span of the CGR timeframe.
5/ Average 2021 recorded California Source Gas; production less than capacity due to reservoir performance and economics.
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach: 1.3 (2022), 1.3 (2023), 1.3 (2024), 1.3 (2025), 1.3 (2026)
7/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.
8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d: 934 (2022), 921 (2023), 903 (2024), 889 (2025), 874 (2026)

Southern California

Table 35

TABLE 4-SCG

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2027 THRU 2035

COLD TEMPERATURE YEAR (1 IN 35 COLD YEAR EVENT) & DRY HYDRO YEAR

LINE			2027	2028	2029	2030	2035	LINE
	CAPACITY AVAILABLE							
1	California Line 85 Zone (California Producers)		60	60	60	60	60	1
2	California Coastal Zone (California Producers)		150	150	150	150	150	2
	Out-of-State Gas							
3	Wheeler Ridge Zone (KR, MP, PG&E, OEHI) 1/		765	765	765	765	765	3
4	Southern Zone (EPN,TGN,NBP) 2/		1,210	1,210	1,210	1,210	1,210	4
5	Northern Zone (TW,EPN,QST, KR) 3/		1,250	1,250	1,590	1,590	1,590	5
6	Total Out-of-State Gas		3,225	3,225	3,565	3,565	3,565	6
7	TOTAL CAPACITY AVAILABLE 4/		3,435	3,435	3,775	3,775	3,775	7
	GAS SUPPLY TAKEN							
8	California Source Gas 5/		61	61	61	61	61	8
9	Out-of-State		2,239	2,180	2,156	2,104	1,992	9
10	TOTAL SUPPLY TAKEN		2,300	2,241	2,217	2,165	2,053	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 6/		2,300	2,241	2,217	2,165	2,053	12
	REQUIREMENTS FORECAST BY END-USE 7/							
13	CORE 8/	Residential	610	597	586	573	506	13
14		Commercial	189	184	181	177	161	14
15		Industrial	51	50	49	48	45	15
16		NGV	46	47	48	50	54	16
17		Subtotal-CORE	896	878	864	848	766	17
18	NONCORE	Commercial	50	49	49	49	49	18
19		Industrial	388	388	388	387	385	19
20		EOR Steaming	26	25	24	24	20	20
21		Electric Generation (EG)	567	534	524	496	474	21
22		Subtotal-NONCORE	1,031	996	985	956	928	22
23	WHOLESALE &	Core	219	217	217	216	212	23
24	INTERNATIONAL	Noncore Excl. EG	28	28	28	28	29	24
25		Electric Generation (EG)	98	93	94	89	92	25
26		Subtotal-WHOLESALE & INTL.	344	339	339	334	333	26
27		Co. Use & LUAF	29	28	28	27	26	27
28	SYSTEM TOTAL THROUGHPUT 6/		2,300	2,241	2,217	2,165	2,053	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	64	63	63	63	62	29
30	NONCORE	Commercial/Industrial	438	437	437	436	434	30
31		EOR Steaming	26	25	24	24	20	31
32		Electric Generation (EG)	567	534	524	496	474	32
33		Subtotal-RETAIL	1,095	1,059	1,048	1,019	990	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	344	339	339	334	333	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,439	1,398	1,387	1,353	1,324	35
	CURTAILMENT (RETAIL & WHOLESALE)							
36		Core	0	0	0	0	0	36
37		Noncore	0	0	0	0	0	37
38		TOTAL - Curtailment	0	0	0	0	0	

NOTES:

1/ Wheeler Ridge Zone: KR & MP at Wheeler Ridge, PG&E at Kern Stn., OEHI at Gosford)
2/ Southern Zone (EPN at Ehrenberg, TGN at Otay Mesa, NBP at Blythe); ability to receive 1,210 MMcfd dependent on local area demand
3/ Northern Zone (TW at No. Needles, EPN at Topok, QST at No. Needles, KR at Kramer Jct.); projected capacity may vary from that shown over the span of the CGR timeframe pending 2024 General Rate Case decision
4/ Represents the outlook for firm receipt capacities at the time of publication; subject to change over the span of the CGR timeframe.
5/ Average 2021 recorded California Source Gas; production less than capacity due to reservoir performance and economics.

	2027	2028	2029	2030	2035
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach	1.3	1.3	1.3	1.3	1.3

7/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.

	2027	2028	2029	2030	2035
8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	859	841	827	811	727

TABLE 36

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS REQUIREMENTS - MMCF/DAY

1-IN-10 COLD TEMPERATURE YEAR & DRY HYDRO YEAR (1)

Year	CORE	NONCORE	WHOLESALE & INTERNATIONAL	Company Use & LUAF	SYSTEM TOTAL THROUGHPUT
2022	950	1,135	373	31	2,490
2023	938	1,137	363	31	2,469
2024	920	1,081	350	30	2,381
2025	907	1,057	343	29	2,336
2026	892	1,042	342	29	2,305
2027	878	1,031	341	29	2,278
2028	860	996	336	28	2,219
2029	847	985	336	28	2,195
2030	831	956	331	27	2,144
2035	750	928	330	26	2,034

NOTES:

(1) SoCalGas' Demand forecast of 1-in-10 cold temperature year and dry hydro year is used to evaluate the backbone transmission capacity and slack capacity in compliance with CPUC Decision (D.) 06-09-039 and the daily receipt capacity in compliance with D.22-07-002.

2022 CALIFORNIA GAS REPORT

CITY OF LONG BEACH ENERGY RESOURCES DEPARTMENT

CITY OF LONG BEACH ENERGY RESOURCES DEPARTMENT

The annual gas supply and forecast requirements prepared by the Long Beach Energy Resources Department (Long Beach) are shown on the following tables for the years 2022 through 2035.

Long Beach operates the fifth largest municipally owned natural gas utility in the country and is one of only three in the State. The gas utility provides safe and reliable natural gas services to about 500,000 residents and businesses via approximately 150,000 connected gas meters, delivered through more than 1,800 miles of gas pipelines. Long Beach's service territory includes the cities of Long Beach and Signal Hill, and sections of surrounding communities including Lakewood, Bellflower, Compton, Seal Beach, Paramount, and Los Alamitos. Long Beach's gas use is split at 53 percent residential and 47 percent commercial/industrial.

Long Beach serves core and noncore customers from three incremental supply sources: (1) interstate supplies delivered into the SoCalGas' intrastate pipeline system; (2) gas storage withdrawals; and (3) local gas delivered directly to Long Beach Energy Resources Department's pipeline system from gas fields within the city. Currently, local production supplies about 5 percent of Long Beach's gas use. Long Beach purchases most of its gas supplies from producers in the South-Western U.S. As a Wholesale customer, Long Beach contracts with SoCalGas for intrastate transmission service to deliver that gas from the California border to its service area.

The City of Long Beach is the only municipal government in the State of California that manages oil operations. Through its Energy Resources Department, the City operates the Wilmington Oil Field and has various financial interests in smaller oil fields throughout the City, such as the Signal Hill East and West Units, Recreation Park, and City Wasem.

As a municipal utility, Long Beach's gas rates and policies are established by the City Council, which acts as the regulatory authority. The City Charter requires the gas utility to establish its rates comparable to the rates charged by surrounding gas utilities for similar types of service.

2022 CALIFORNIA GAS REPORT

CITY OF LONG BEACH ENERGY RESOURCES DEPARTMENT – TABULAR DATA

TABLE 37 – CITY OF LONG BEACH-GAS AND OIL DEPARTMENT: TABLE 1-LB ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d RECORDED YEARS 2017-2021

LINE	GAS SUPPLY AVAILABLE	2017	2018	2019	2020	2021	LINE
	California Source Gas						
1	Regular Purchases	0.0	0.0	0.0	0.0	0.0	1
2	Received for Exchange/Transport	0.0	0.0	0.0	0.0	0.0	2
3	Total California Source Gas	0.0	0.0	0.0	0.0	0.0	3
4	Purchases from Other Utilities	0.0	0.0	0.0	0.0	0.0	4
	Out-of-State Gas						
5	Pacific Interstate Companies	0.0	0.0	0.0	0.0	0.0	5
6	Additional Core Supplies	0.0	0.0	0.0	0.0	0.0	6
7	Incremental Supplies	0.0	0.0	0.0	0.0	0.0	7
8	Out-of-State Transport	0.0	0.0	0.0	0.0	0.0	8
		0.0	0.0	0.0	0.0	0.0	
9	Total Out-of-State Gas	0.0	0.0	0.0	0.0	0.0	9
10	Subtotal	0.0	0.0	0.0	0.0	0.0	10
11	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	0.0	11
12	GAS SUPPLY AVAILABLE	0.0	0.0	0.0	0.0	0.0	12
	GAS SUPPLY TAKEN						
	California Source Gas						
13	Regular Purchases	0.6	0.6	1.1	0.7	1.3	13
14	Received for Exchange/Transport	0.0	0.0	0.0	0.0	0.0	14
15	Total California Source Gas	0.6	0.6	1.1	0.7	1.3	15
16	Purchases from Other Utilities	0.0	0.0	0.0	0.0	0.0	16
	Out-of-State Gas						
17	Pacific Interstate Companies	0.0	0.0	0.0	0.0	0.0	17
18	Additional Core Supplies	0.0	0.0	0.0	0.0	0.0	18
19	Incremental Supplies	24.6	23.9	25.2	24.8	24.2	19
20	Out-of-State Transport	0.0	0.0	0.0	0.0	0.0	20
21	Total Out-of-State Gas	24.6	23.9	25.2	24.8	24.2	21
22	Subtotal	25.2	24.5	26.3	25.5	25.5	22
23	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	0.0	23
24	TOTAL Gas Supply Taken & Transported	25.2	24.5	26.3	25.5	25.5	24

TABLE 38 – CITY OF LONG BEACH-GAS AND OIL DEPARTMENT: TABLE 1-LB
ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d
RECORDED YEARS 2017-2021 (CONTINUED)

LINE	ACTUAL DELIVERIES BY END-USE		2017	2018	2019	2020	2021	LINE
1	CORE	Residential	11.8	12.1	12.9	12.9	12.6	1
2	CORE/NONCORE	Commercial	6.0	5.9	6.1	5.3	5.7	2
3	CORE/NONCORE	Industrial	4.7	4.3	4.7	4.1	4.3	3
4		Subtotal	22.5	22.3	23.8	22.2	22.6	4
5	NON CORE	Non-EOR Cogeneration	2.2	1.9	1.7	2.5	2.3	5
6		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	6
7		Electric Utilities	0.0	0.0	0.0	0.0	0.0	7
8		Subtotal	2.2	1.9	1.7	2.5	2.3	8
9	WHOLESALE	Residential	0.0	0.0	0.0	0.0	0.0	9
10		Com. & Ind., others	0.0	0.0	0.0	0.0	0.0	10
11		Electric Utilities	0.0	0.0	0.0	0.0	0.0	11
12		Subtotal-WHOLESALE	0.0	0.0	0.0	0.0	0.0	12
13		Co. Use & LUAF	0.5	0.2	0.8	0.7	0.6	13
14		Subtotal-END USE	25.1	24.5	26.3	25.5	25.4	14
15		Storage Injection	0.0	0.0	0.0	0.0	0.0	15
16	SYSTEM TOTAL-THROUGHPUT		25.1	24.5	26.3	25.5	25.4	16
	ACTUAL TRANSPORTATION AND EXCHANGE							
17		Residential	N/A	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	2.9	3.0	3.1	2.8	3.1	18
19		Non-EOR Cogeneration	2.0	1.9	1.5	2.5	2.3	19
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	N/A	20
21		Electric Utilites	N/A	N/A	N/A	N/A	N/A	21
22		Subtotal-RETAIL	5.0	4.9	4.7	5.3	5.4	22
23	WHOLESALE	All End Uses	0.0	0.0	0.0	0.0	0.0	23
24	TOTAL TRANSPORTATION & EXCHANGE		5.0	4.9	4.7	5.3	5.4	24
	ACTUAL CURTAILMENT							
25		Residential	0.0	0.0	0.0	0.0	0.0	25
26		Commercial/Industrial	0.0	0.0	0.0	0.0	0.0	26
27		Non-EOR Cogeneration	0.0	0.0	0.0	0.0	0.0	27
28		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	28
29		Electric Utilites	0.0	0.0	0.0	0.0	0.0	29
30		Wholesale	0.0	0.0	0.0	0.0	0.0	30
31		TOTAL- Curtailment	0.0	0.0	0.0	0.0	0.0	31
32	REFUSAL		0.0	0.0	0.0	0.0	0.0	32

NOTE: Actual deliveries by end-use includes sales, transportation, and exchange volumes, but excludes actual curtailments.

TABLE 39– CITY OF LONG BEACH-GAS AND OIL DEPARTMENT: TABLE 1A-LB
ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d
AVERAGE YEAR FORECAST FOR THE 2022 CGR REPORT

LINE	ACTUAL DELIVERIES BY END-USE		2022	2023	2024	2025	2030	2035	LINE
1	CORE	Residential	12.3	12.3	12.3	12.4	12.5	12.5	1
2	CORE/NONCORE	Commercial	5.5	5.5	5.5	5.6	5.6	5.7	2
3	CORE/NONCORE	Industrial	3.9	3.9	3.9	3.9	4.0	4.1	3
4		Subtotal	21.7	21.7	21.7	21.9	22.1	22.3	4
5	NON CORE	Non-EOR Cogeneration	2.3	2.3	2.4	2.4	2.6	2.7	5
6		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	0.0	6
7		Electric Utilities	0.0	0.0	0.0	0.0	0.0	0.0	7
8		Subtotal	2.3	2.3	2.4	2.4	2.6	2.7	8
9	WHOLESALE	Residential	0.0	0.0	0.0	0.0	0.0	0.0	9
10		Com. & Ind., others	0.0	0.0	0.0	0.0	0.0	0.0	10
11		Electric Utilities	0.0	0.0	0.0	0.0	0.0	0.0	11
12		Subtotal-WHOLESALE	0.0	0.0	0.0	0.0	0.0	0.0	12
13		Co. Use & LUAF	0.9	0.9	0.9	0.9	0.9	0.9	13
14		Subtotal-END USE	24.9	24.9	25.0	25.2	25.6	25.9	14
15		Storage Injection	0.0	0.0	0.0	0.0	0.0	0.0	15
16	SYSTEM TOTAL-THROUGHPUT		24.9	24.9	25.0	25.2	25.6	25.9	16
	ACTUAL TRANSPORTATION AND EXCHANGE								
17		Residential	N/A	N/A	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	3.3	3.4	3.4	3.4	3.5	3.7	18
19		Non-EOR Cogeneration	1.7	1.8	1.8	1.8	1.8	1.9	19
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	N/A	N/A	20
21		Electric Utilites	N/A	N/A	N/A	N/A	N/A	N/A	21
22		Subtotal-RETAIL	5.0	5.1	5.1	5.1	5.3	5.6	22
23	WHOLESALE	All End Uses	0.0	0.0	0.0	0.0	0.0	0.0	23
24	TOTAL TRANSPORTATION & EXCHANGE		5.0	5.1	5.1	5.1	5.3	5.6	24
	ACTUAL CURTAILMENT								
25		Residential	0.0	0.0	0.0	0.0	0.0	0.0	25
26		Commercial/Industrial	0.0	0.0	0.0	0.0	0.0	0.0	26
27		Non-EOR Cogeneration	0.0	0.0	0.0	0.0	0.0	0.0	27
28		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	0.0	28
29		Electric Utilites	0.0	0.0	0.0	0.0	0.0	0.0	29
30		Wholesale	0.0	0.0	0.0	0.0	0.0	0.0	30
31		TOTAL- Curtailment	0.0	0.0	0.0	0.0	0.0	0.0	31
32	REFUSAL		0.0	0.0	0.0	0.0	0.0	0.0	32

NOTE: Actual deliveries by end-use includes sales, transportation, and exchange volumes, but excludes actual curtailments.

TABLE 40 – CITY OF LONG BEACH-GAS AND OIL DEPARTMENT: TABLE 2A-LB
ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d
AVERAGE YEAR FORECAST (CONTINUED)

LINE	ACTUAL DELIVERIES BY END-USE		2022	2023	2024	2025	2030	2035	LINE
1	CORE	Residential	12.3	12.3	12.3	12.4	12.5	12.5	1
2	CORE/NONCORE	Commercial	5.5	5.5	5.5	5.6	5.6	5.7	2
3	CORE/NONCORE	Industrial	3.9	3.9	3.9	3.9	4.0	4.1	3
4		Subtotal	21.7	21.7	21.7	21.9	22.1	22.3	4
5	NON CORE	Non-EOR Cogeneration	2.3	2.3	2.4	2.4	2.6	2.7	5
6		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	0.0	6
7		Electric Utilities	0.0	0.0	0.0	0.0	0.0	0.0	7
8		Subtotal	2.3	2.3	2.4	2.4	2.6	2.7	8
9	WHOLESALE	Residential	0.0	0.0	0.0	0.0	0.0	0.0	9
10		Com. & Ind., others	0.0	0.0	0.0	0.0	0.0	0.0	10
11		Electric Utilities	0.0	0.0	0.0	0.0	0.0	0.0	11
12		Subtotal-WHOLESALE	0.0	0.0	0.0	0.0	0.0	0.0	12
13		Co. Use & LUAF	0.9	0.9	0.9	0.9	0.9	0.9	13
14		Subtotal-END USE	24.9	24.9	25.0	25.2	25.6	25.9	14
15		Storage Injection	0.0	0.0	0.0	0.0	0.0	0.0	15
16	SYSTEM TOTAL-THROUGHPUT		24.9	24.9	25.0	25.2	25.6	25.9	16
	ACTUAL TRANSPORTATION AND EXCHANGE								
17		Residential	N/A	N/A	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	3.3	3.4	3.4	3.4	3.5	3.7	18
19		Non-EOR Cogeneration	1.7	1.8	1.8	1.8	1.8	1.9	19
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	N/A	N/A	20
21		Electric Utilites	N/A	N/A	N/A	N/A	N/A	N/A	21
22		Subtotal-RETAIL	5.0	5.1	5.1	5.1	5.3	5.6	22
23	WHOLESALE	All End Uses	0.0	0.0	0.0	0.0	0.0	0.0	23
24	TOTAL TRANSPORTATION & EXCHANGE		5.0	5.1	5.1	5.1	5.3	5.6	24
	ACTUAL CURTAILMENT								
25		Residential	0.0	0.0	0.0	0.0	0.0	0.0	25
26		Commercial/Industrial	0.0	0.0	0.0	0.0	0.0	0.0	26
27		Non-EOR Cogeneration	0.0	0.0	0.0	0.0	0.0	0.0	27
28		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	0.0	28
29		Electric Utilites	0.0	0.0	0.0	0.0	0.0	0.0	29
30		Wholesale	0.0	0.0	0.0	0.0	0.0	0.0	30
31		TOTAL- Curtailment	0.0	0.0	0.0	0.0	0.0	0.0	31
32	REFUSAL		0.0	0.0	0.0	0.0	0.0	0.0	32

NOTE: Actual deliveries by end-use includes sales, transportation, and exchange volumes, but excludes actual curtailments.

TABLE 41– CITY OF LONG BEACH-GAS AND OIL DEPARTMENT: TABLE 3C-LB ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d COLD YEAR FORECAST FOR THE 2022 CGR REPORT (CONTINUED)

LINE	GAS SUPPLY AVAILABLE	2022	2023	2024	2025	2030	2035	LINE
	California Source Gas							
1	Regular Purchases	0.0	0.0	0.0	0.0	0.0	0.0	1
2	Received for Exchange/Transport	0.0	0.0	0.0	0.0	0.0	0.0	2
3	Total California Source Gas	0.0	0.0	0.0	0.0	0.0	0.0	3
4	Purchases from Other Utilities	0.0	0.0	0.0	0.0	0.0	0.0	4
	Out-of-State Gas							
5	Pacific Interstate Companies	0.0	0.0	0.0	0.0	0.0	0.0	5
6	Additional Core Supplies	0.0	0.0	0.0	0.0	0.0	0.0	6
7	Incremental Supplies	0.0	0.0	0.0	0.0	0.0	0.0	7
8	Out-of-State Transport	0.0	0.0	0.0	0.0	0.0	0.0	8
		0.0	0.0	0.0	0.0	0.0	0.0	
9	Total Out-of-State Gas	0.0	0.0	0.0	0.0	0.0	0.0	9
10	Subtotal	0.0	0.0	0.0	0.0	0.0	0.0	10
11	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	0.0	0.0	11
12	GAS SUPPLY AVAILABLE	0.0	0.0	0.0	0.0	0.0	0.0	12
	GAS SUPPLY TAKEN							
	California Source Gas							
13	Regular Purchases	1.3	1.3	1.3	1.3	1.3	1.3	13
14	Received for Exchange/Transport	0.0	0.0	0.0	0.0	0.0	0.0	14
15	Total California Source Gas	1.3	1.3	1.3	1.3	1.3	1.3	15
16	Purchases from Other Utilities	0.0	0.0	0.0	0.0	0.0	0.0	16
	Out-of-State Gas							
17	Pacific Interstate Companies	0.0	0.0	0.0	0.0	0.0	0.0	17
18	Additional Core Supplies	0.0	0.0	0.0	0.0	0.0	0.0	18
19	Incremental Supplies	29.4	29.4	29.4	29.4	29.4	29.4	19
20	Out-of-State Transport	0.0	0.0	0.0	0.0	0.0	0.0	20
21	Total Out-of-State Gas	29.4	29.4	29.4	29.4	29.4	29.4	21
22	Subtotal	30.7	30.7	30.7	30.7	30.7	30.7	22
23	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	0.0	0.0	23
24	TOTAL Gas Supply Taken & Transported	30.7	30.7	30.7	30.7	30.7	30.7	24

TABLE 42– CITY OF LONG BEACH-GAS AND OIL DEPARTMENT: TABLE 4C-LB ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d COLD YEAR FORECAST FOR THE 2022 CGR REPORT (CONTINUED)

LINE	ACTUAL DELIVERIES BY END-USE		2022	2023	2024	2025	2030	2035	LINE
1	CORE	Residential	15.1	15.1	15.1	15.1	15.1	15.1	1
2	CORE/NONCORE	Commercial	7.2	7.2	7.2	7.2	7.2	7.2	2
3	CORE/NONCORE	Industrial	5.6	5.6	5.6	5.6	5.6	5.6	3
4		Subtotal	27.8	27.8	27.8	27.8	27.8	27.8	4
5	NON CORE	Non-EOR Cogeneration	2.0	2.0	2.0	2.0	2.0	2.0	5
6		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	0.0	6
7		Electric Utilities	0.0	0.0	0.0	0.0	0.0	0.0	7
8		Subtotal	2.0	2.0	2.0	2.0	2.0	2.0	8
9	WHOLESALE	Residential	0.0	0.0	0.0	0.0	0.0	0.0	9
10		Com. & Ind., others	0.0	0.0	0.0	0.0	0.0	0.0	10
11		Electric Utilities	0.0	0.0	0.0	0.0	0.0	0.0	11
12		Subtotal-WHOLESALE	0.0	0.0	0.0	0.0	0.0	0.0	12
13		Co. Use & LUAF	0.9	0.9	0.9	0.9	0.9	0.9	13
14		Subtotal-END USE	30.7	30.7	30.7	30.7	30.7	30.7	14
15		Storage Injection	0.0	0.0	0.0	0.0	0.0	0.0	15
16	SYSTEM TOTAL-THROUGHPUT		30.7	30.7	30.7	30.7	30.7	30.7	16
	ACTUAL TRANSPORTATION AND EXCHANGE								
17		Residential	N/A	N/A	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	3.6	3.6	3.6	3.6	3.6	3.6	18
19		Non-EOR Cogeneration	1.8	1.8	1.8	1.8	1.8	1.8	19
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	N/A	N/A	20
21		Electric Utilites	N/A	N/A	N/A	N/A	N/A	N/A	21
22		Subtotal-RETAIL	5.4	5.4	5.4	5.4	5.4	5.4	22
23	WHOLESALE	All End Uses	0.0	0.0	0.0	0.0	0.0	0.0	23
24	TOTAL TRANSPORTATION & EXCHANGE		5.4	5.4	5.4	5.4	5.4	5.4	24
	ACTUAL CURTAILMENT								
25		Residential	0.0	0.0	0.0	0.0	0.0	0.0	25
26		Commercial/Industrial	0.0	0.0	0.0	0.0	0.0	0.0	26
27		Non-EOR Cogeneration	0.0	0.0	0.0	0.0	0.0	0.0	27
28		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	0.0	28
29		Electric Utilites	0.0	0.0	0.0	0.0	0.0	0.0	29
30		Wholesale	0.0	0.0	0.0	0.0	0.0	0.0	30
31		TOTAL- Curtailment	0.0	0.0	0.0	0.0	0.0	0.0	31
32	REFUSAL		0.0	0.0	0.0	0.0	0.0	0.0	32

NOTE: Actual deliveries by end-use includes sales, transportation, and exchange volumes, but excludes actual curtailments.

2022 CALIFORNIA GAS REPORT

SAN DIEGO GAS & ELECTRIC COMPANY

INTRODUCTION

SDG&E is a combined gas and electric distribution utility serving more than three million people in San Diego and the southern portions of Orange counties. SDG&E delivered natural gas to 903,649 customers in San Diego County in 2021, including power plants and turbines. Total gas sales and transportation through SDG&E's system for 2021 were approximately 94 billion cubic feet (Bcf), which is an average of 258.5 MMcf/d.

GAS DEMAND

OVERVIEW

SDG&E's gas demand forecast is largely determined by the long-term economic outlook for its San Diego County service area. The county's economic trends are expected to generally parallel those of the larger SoCalGas area as discussed above.

This projection of natural gas requirements, excluding EG demand and noncore demand, begins with a usage calculator derived from end use models that integrates demographic assumptions, economic growth, energy prices, energy efficiency programs, detailed customer information, building and appliance standards, weather and other factors. After the forecast is developed, the forecast is treated for three out-of-model adjustments. The adjustments made to the forecasts include (1) allowing for less heating degree days in the average weather design each year of the forecast period to account for climate change; (2) gas demand destruction due to greater energy efficiency savings forecast over the planning period; and (3) incremental energy savings created from assumed fuel substitution. All of the energy savings incorporated into the forecast reflect market potential and were used as load modifiers to create a final forecast of demand. The baseline forecast was adjusted downward to account for the incremental energy savings influences that are expected to occur.

The introduction of potential fuel substitution into the long-term demand forecast is new for SDG&E in the CGR long term forecast development. SDG&E's own internal estimates of fuel substitution are preliminary. SDG&E is working on finding methods, using historical usage data, to identify customers who may be converting gas space and water heating to electric substitutes.

Fuel substitution was introduced into the 2021 IEPR as additional achievable fuel substitution (AAFS).[118] The AAFS2 was utilized. It includes the effects of potential updates in

[118] SEE IEPR, Chapter 2, pp. 33-49. See also Appendix A.

the Title 24 building standards and the presumed building electrification encouraged by future ratcheting driven by tighter goals, rate enhancements and higher uptake rates at future points in time.

Altogether, SDG&E's gas demand, not inclusive of gas driven EG, is projected to drop slightly from 52 Bcf in 2021 to 46 Bcf in 2035, which is an average annual rate of decline of 0.8 percent. Including EG, overall demand adjusted for average temperature conditions totaled 94 Bcf in 2021 and is expected to drop about 1.9 percent per year to 72 Bcf by 2035.

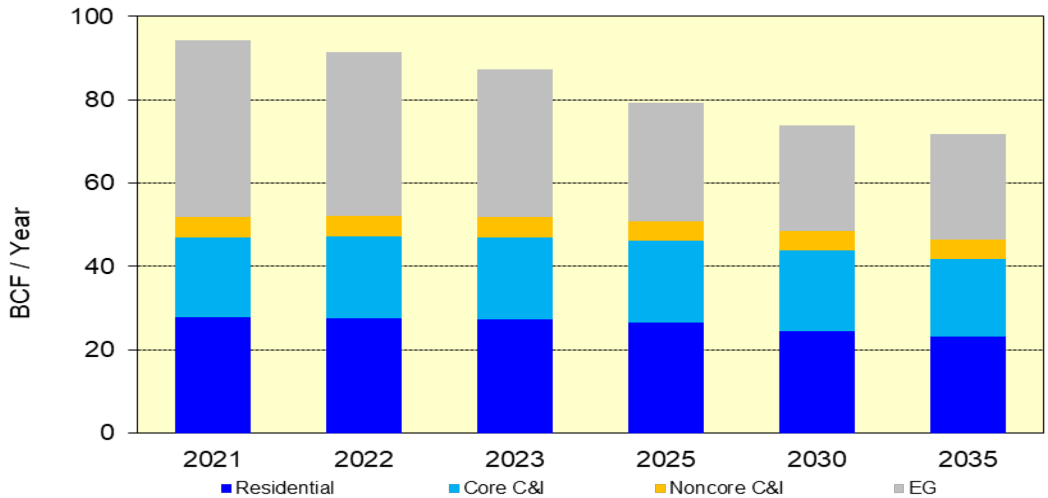
Assumptions for SDG&E's gas transportation requirements for EG are included as part of the wholesale market sector description for SoCalGas.

ECONOMICS AND DEMOGRAPHICS

SDG&E's gas demand forecast is largely determined by the long-term economic outlook for its San Diego County service area. San Diego County's total employment is forecasted to grow on average just over 1% annually from 2021 to 2035; the subset of industrial (mining and manufacturing) jobs is projected to grow an average of 0.1% per year during the same period. The number of SDG&E gas meters is expected to increase an average of about 0.8% annually from 2021 through 2035.

FIGURE 27 – SDG&E'S COMPOSITION OF NATURAL GAS THROUGHPUT AVERAGE TEMPERATURE, NORMAL YEAR (2021-2035)

(Bcf/year)



From 2021 through 2035, SDG&E's forecasted gas demand is expected to decline at an average annual rate of 1.9 percent. The decline is being driven by future projected reductions in the EG load. Additional factors reducing the load forecast are energy efficiency programs and new requirements on Title 24 building codes and standards and assumed fuel substitution over the forecast period.

MARKET SECTORS

Residential

SDG&E served approximately 873,304 residential customers in 2021. The residential usage varies for each of the various residential market segments that SDG&E serves. Conditional demand estimates based on the 2019 Residential Appliance Saturation Survey (R.A.S.S.) have allowed SDG&E to better understand customer usage and needs. The updated survey information included below was part of the estimation and resulting baseline residential market forecast.

The table below shows the weather-normalized home usage by customer type and the saturations by end use for SDG&E based upon the conditional demand study.

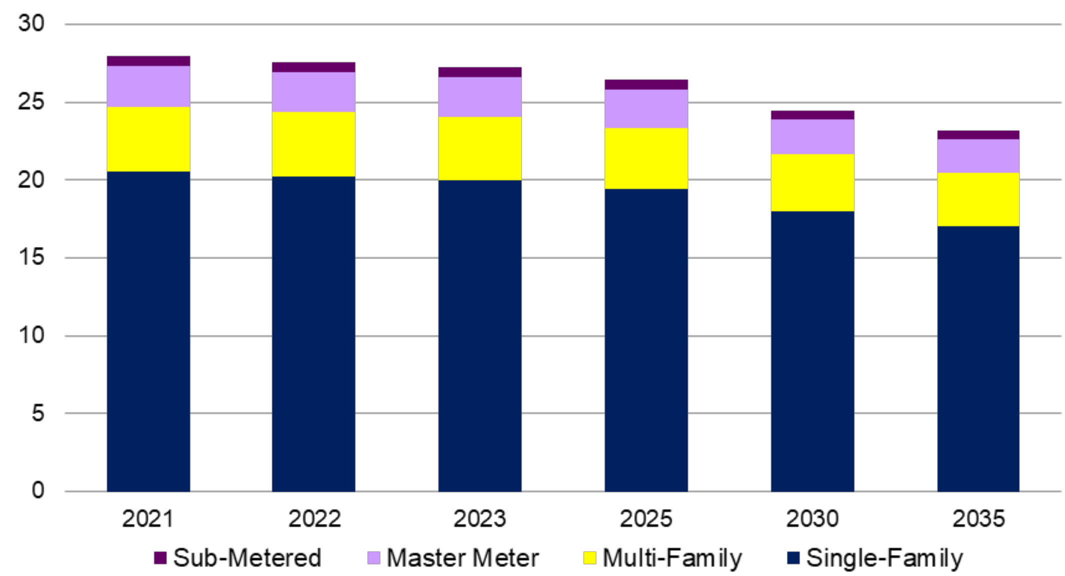
Table 43: SDG&E Residential Appliance Saturation Survey, 2019 Update

		2019 Residential Appliance Saturation Survey								
		Conditional Demand Study								
SDG&E		Single Family Unit Energy Consumption (UEC)	Single Family Saturation (%)	Single Family Intensity	Single Family Use Proportion		Multi Family Unit Energy Consumption	Multi Family Saturation	Multi Family Intensity	Multi Family Use Proportion
	Space Heat	211	98.00%	207	52.91%		107	92.62%	99	46.45%
	Water Heat	128	99.80%	128	32.69%		92	91.54%	84	39.48%
	Cooking	30	75.20%	23	5.78%		27	64.99%	18	8.23%
	Clothes Drying	31	63.71%	20	5.05%		27	40.91%	11	5.18%
	Pool Heat	144	3.40%	5	1.25%		N/A		N/A	
	Spa Heat	101	5.95%	6	1.54%		41	0.97%	0	0.19%
	Gas Fireplace	11	8.33%	1	0.23%		6	7.50%	0	0.21%
	Gas Barbecue	15	14.09%	2	0.54%		10	5.73%	1	0.27%
	Total Household SF			391 Therms/Year	100%				213 Therms/Year	100%

The conditional demand estimates based on the 2019 R.A.S.S. show that the average use per meter is 391 therms for single-family households and 213 therms for multi-family households. The use-per-customer data is constructive in forming the forecast. For the residential market, the change in the forecast from one year to the next is based on the confluence of two immediate economic drivers. In any given year, the residential load will grow due to the new customer hookups that occur. New customers generate a growth in demand. Second, the residential load will change due to existing customers' (vintage customers') changing needs. When gas appliances reach the end of their useful life, customers make a choice. The choice consists of either replacing the older appliance with a more energy efficient gas-using appliance, or changing out the replacement appliance from gas to its electric substitute, a behavior characterized as fuel substitution. The usage calculator that compiles the forecast is referred to as an end use model.

The total residential customer count for SDG&E consists of four residential segment types and each of the segment types exhibits variation in usage behavior that can be identified. The customer types are single-family and multi-family customers, as well as master-meter and sub-metered customers. Residential demand, adjusted for average temperature conditions, totaled 27.9 Bcf in 2021. By the year 2035, the residential demand is expected to drop to 23.2 Bcf. The change reflects a 1.3 percent average annual rate of decline. There are several reasons that justify the decline.

Figure 28 – Composition of SDG&E's Residential Demand Forecast
Average Year Weather Design, 2021-2035
(Bcf/year)



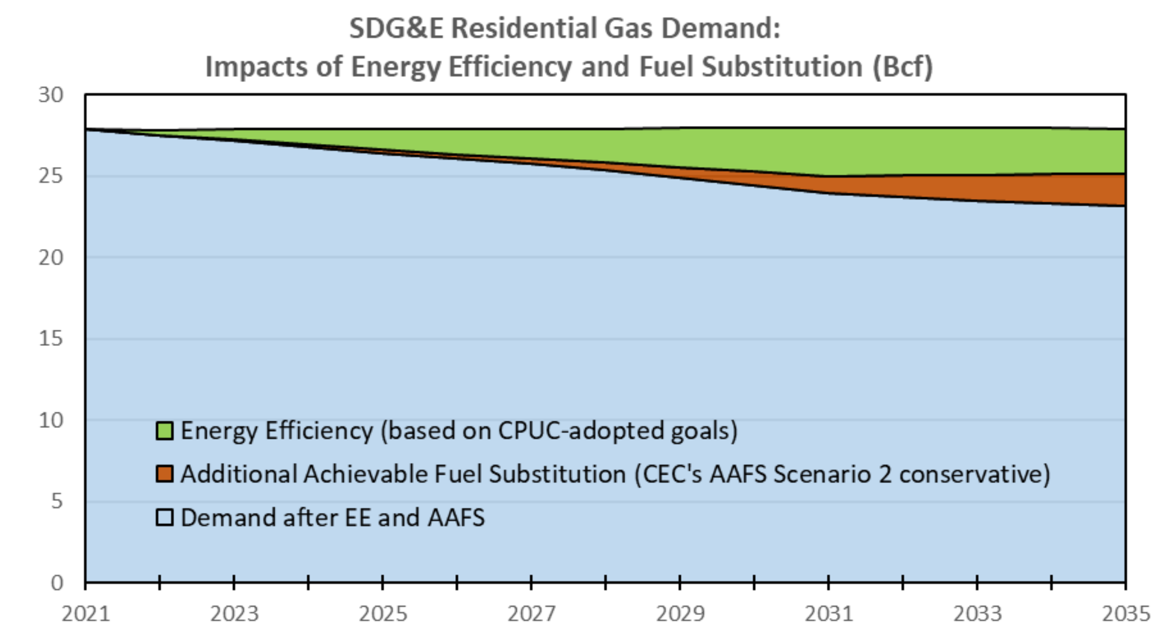
As described above, SDG&E's residential base forecast is developed from an end use model. The model results are modified by anticipated impacts of climate change as well as forecasts of policy adoptions that impact gas use. After the base forecast is developed, the forecast is modified with three out-of-model adjustments. The energy savings adjustments made to the forecast include: (1) allowing for fewer heating degree days in the average weather design for each consecutive year of the forecast to account for climate change; (2) gas demand destruction due to greater energy efficiency savings forecasted over the planning period; and (3) incremental energy savings created from assumed fuel substitution. All of these energy savings incorporated into the forecast reflect market potential and became load modifiers to create a final forecast of demand.

The major modifiers to the forecast are energy efficiency and building electrification. The energy efficiency forecast includes the confluence of two types of gas energy savings: Codes and Standards savings, which include current and expected modifications to Title 24 and the energy savings stemming from the customer programs authorized by the CPUC under D.19-08-034 and D.21-09-037. The baseline forecast was adjusted downward to account for the incremental energy saving influences that are expected to occur over the forecast period.

The final forecast also includes a load modifier for fuel substitution. For purposes of constructing a long-term reasonable forecast for the 2022 CGR, SDG&E participated in an electrification working group committee along with PG&E, SoCalGas and Southern California Edison (SCE) to evaluate different approaches and assumptions to modeling the effects of fuel substitution. After several meetings and discussions, SDG&E aligned around the relatively conservative fuel substitution forecast scenario developed by the California Energy Commission. Fuel substitution was estimated and introduced separately from energy efficiency savings by the CEC in its 2021 IEPR as additional achievable fuel substitution (AAFS). Of the five possible fuel substitution scenarios developed by the CEC, the AAFS-2 Scenario, which is the CEC's mid-low scenario for electrification, was chosen by SDG&E to prepare the final residential forecast. Scenario 2 quantifies the assumed fuel substitution that would take place with potential future updates in the Title 24 building standards and the presumed additional building electrification encouraged by future ratcheting driven by tighter goals, rate enhancements and higher uptake rates at future points in time. All of the above-mentioned gas reductions were included in the residential forecast as modifiers to the base forecast.

As can be seen from the following graph, the effects of both energy efficiency and fuel substitution have an impact on the residential market, with increasing impact out to the end of the forecast period in 2035.

Figure 29: SDG&E Residential EE and Fuel Substitution



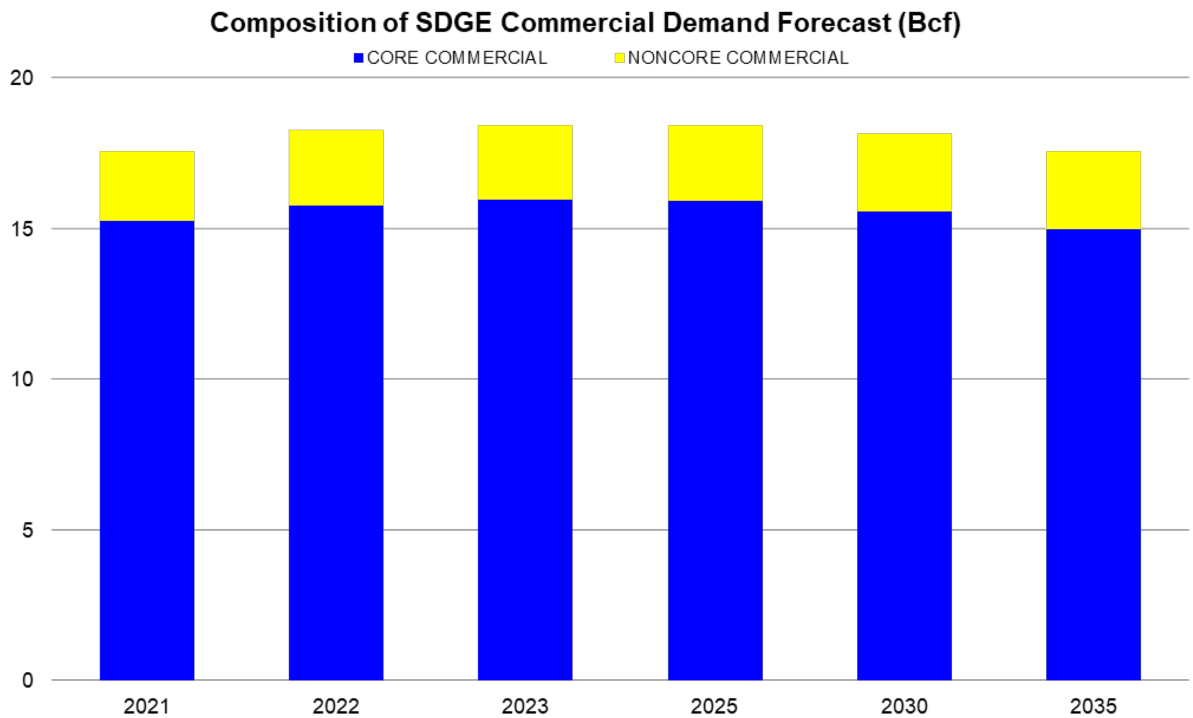
By year 2035, the *assumed* additional energy efficiency removes 10 percent of residential gas demand. Evaluated separately, the *assumed* additional fuel substitution removes another 7 percent of residential gas demand by 2035.

Commercial

On a temperature-adjusted basis, SDG&E's core commercial demand in 2021 totaled 15.23 Bcf. By the year 2035, the core commercial load is expected to decline slightly to 14.98 Bcf. The forecasted annual average rate of decline is 0.1 percent.

SDG&E's non-core commercial load in 2021 was 2.35 Bcf. Over the forecast period, gas demand in this market is projected to grow an average of 0.7 percent per year to 2.58 BCF by 2035, driven by increased economic activity.

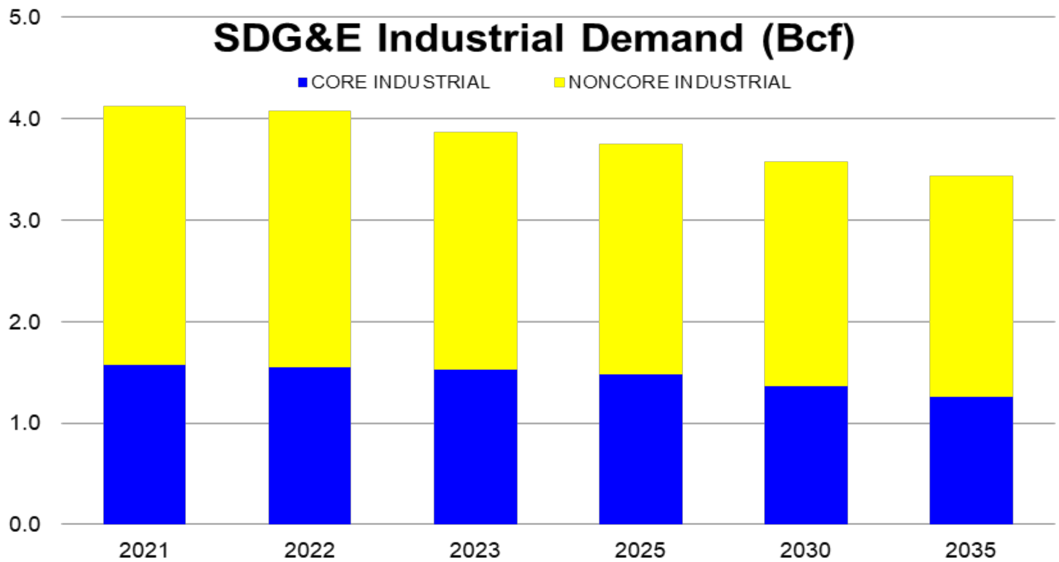
FIGURE 30 –SDG&E COMMERCIAL NATURAL GAS DEMAND FORECAST
AVERAGE YEAR WEATHER DESIGN
(2021-2035)



Industrial

Temperature-adjusted core industrial demand was 1.57 Bcf in 2021 and is expected to decline to 1.26 Bcf by 2035, an average decrease of 1.6 percent per year. This result is due to a yearly average increase in marginal gas rates and the impact of savings from CPUC-authorized energy efficiency programs in the core industrial sector.

FIGURE 31 –SDG&E INDUSTRIAL NATURAL GAS DEMAND FORECAST AVERAGE YEAR WEATHER DESIGN (2021-2035)

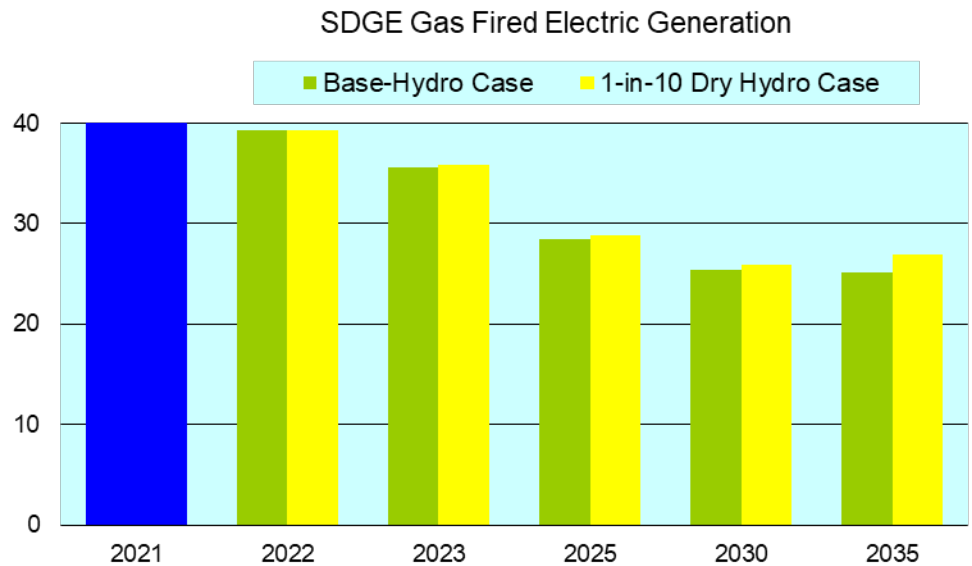


Non-core industrial load in 2019 was 2.4 Bcf and is expected to shrink about 0.6 percent per year to 2.2 Bcf by 2035. Demand-dampening effects of higher energy efficiency and higher carbon-allowance fees will more than offset slight increases from economic growth.

Electric Generation

Total EG, including cogeneration and non-cogeneration EG, was 29 Bcf in 2019. From 2019, EG load is expected to decline an average of 1.35 percent per year to 23 Bcf by 2035. The following graph shows total EG forecasts for a normal hydro year and a 1-in-10 dry hydro year.

FIGURE 32 – SDG&E'S TOTAL EG GAS DEMAND: BASE HYDRO AND 1-IN-10 DRY HYDRO DESIGN, 2021-2035
(Bcf/year)



Small Cogeneration (<20 MW)

Small Electric Generation load from self-generation totaled 7.1 Bcf in 2021 and is projected to increase an average of 0.3 percent per year to 7.3 Bcf by 2035. Economic growth is expected to slightly outpace demand-dampening effects of higher carbon-allowance fees.

Electric Generation Including Large Cogeneration (>20 MW)

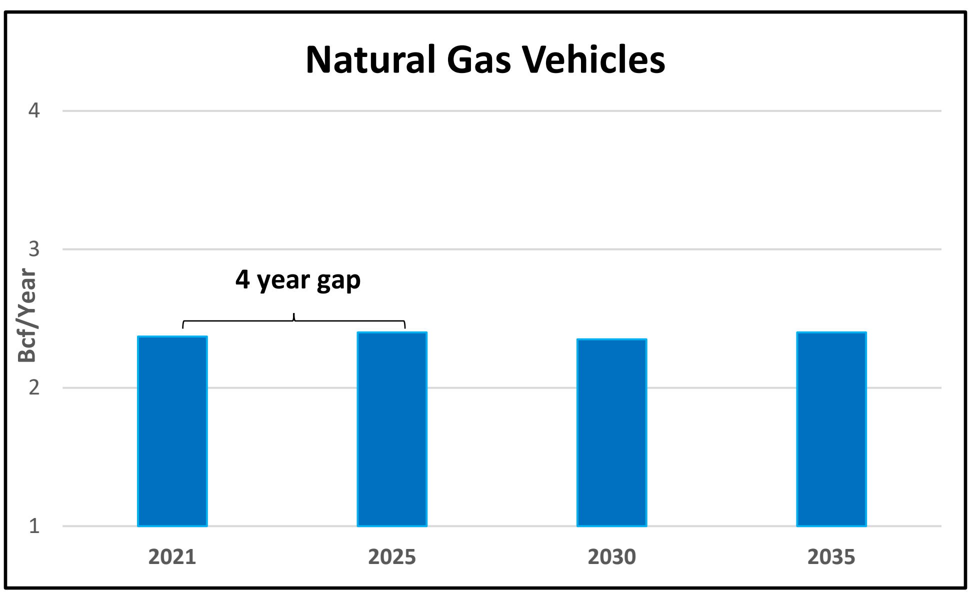
The forecast of large EG loads in SDG&E's service area is based on the power market simulation noted in SoCalGas' EG chapter for "Electric Generation Including All Cogeneration EG demand is forecasted to decrease from 32 Bcf in 2022 to 18 Bcf in 2035. This forecast includes no additional thermal generating resources in its service area, and it assumes no retirement during the same time period. It assumes the same 2021 Preferred System Plan as discussed in the Southern California Gas Company's EG section.

Natural Gas Vehicles

The clean vehicle market is expected to grow due to strong economic fundamentals, increased vehicle options, the continuation of government (federal, state, and local) incentives, additional regulations encouraging alternative fuel vehicle adoption, and regional collaboration for the deployment of necessary infrastructure. Additionally, since April 2019 SDG&E has been procuring 100 percent renewable natural gas (RNG) at all utility owned CNG stations, which provides significant GHG emission reduction benefits.

However, NGV growth may be offset by competing technologies such as vehicle electrification and hydrogen fuel-cell technologies. In addition, the COVID-19 pandemic which began in 2020, disrupted usage and consumption levels compared to a regular year. In 2021, SDG&E served 38 compressed natural gas (CNG) fueling stations located throughout the service territory and delivered approximately 2 Bcf of natural gas. The SDG&E NGV market is expected to remain stable with an average annual rate of 0.11 percent over the forecast horizon.

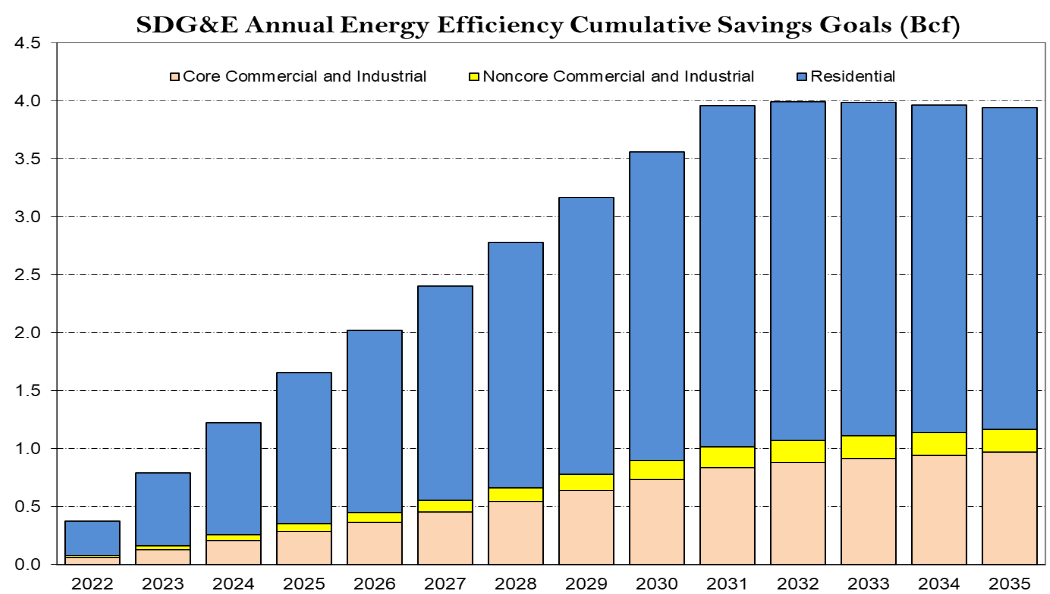
FIGURE 33 – ANNUAL NGV DEMAND FORECAST



ENERGY EFFICIENCY PROGRAMS

Conservation and energy efficiency activities encourage customers to install energy efficient equipment and weatherization measures and adopt energy saving practices that result in reduced gas usage, while still maintaining a comparable level of service. Conservation and energy efficiency load impacts are shown as positive numbers. The "total net load impact" is the natural gas throughput reduction resulting from the energy efficiency programs.

FIGURE 34 – SDG&E ANNUAL ENERGY EFFICIENCY CUMULATIVE SAVING GOALS (Bcf)



The cumulative net load impact forecast from SDG&E's integrated gas and electric energy efficiency programs for selected years is shown in the graph above. The net load impact includes all energy efficiency programs, both gas and electric, that SDG&E has forecasted to be implemented beginning in year 2022 and occurring through the year 2035 in addition to the Title 24 Codes and Standards expected over the 2022-2035 horizon. Savings and goals for these programs are based on the program goals authorized by the Commission in D.19-08-034 and D.21-09-037.

Savings reported are for measures installed under SDG&E's gas and electric Energy Efficiency programs. Credit is only taken for measures that are installed as a result of SDG&E's Energy Efficiency programs, and only for the measure lives of the measures installed.[119] Measures with useful lives less than the forecast planning period fall out of the forecast when their expected life is reached. Naturally occurring conservation that is not attributable to SDG&E's Energy Efficiency activities is not included.

Gas Supply

Beginning in April 2008, gas supplies to serve both SoCalGas' and SDG&E's retail core gas demand are procured with a combined SoCalGas/SDG&E portfolio per D.07-12-019 of December 6, 2007. For more information, refer above to the "Gas Supply, Capacity, and Storage" section in the Southern California part of this report.

[119] 1"Hard" impacts include measures requiring a physical equipment modification or replacement. SDG&E does not include "soft" impacts, e.g., energy management services type measures.110 This EE forecast does not include the impacts of fuel substitution measures (natural gas to electric measures). Fuel substitution is addressed in the overview section of the writeup.

REGULATORY ENVIRONMENT

GENERAL RATE CASE

On September 26, 2019, CPUC unanimously approved a final 2019 GRC decision that adopted a TY 2019 revenue requirement of $1.990 billion for SDG&E's combined operations ($1.590 billion for electric, $0.400 billion for gas) which is $213 million lower than the $2.203 billion that SDG&E had requested in its Update testimony. The adopted revenue requirement represents an increase of $107 million or a 5.7 percent increase over 2018. The final decision adopted PTY revenue requirement adjustments for SDG&E of $134 million for 2020 (6.7 percent increase) and $102 million for 2021 (4.8 percent increase).

In January 2020, the CPUC revised the rate case plans and implemented a 4-year GRC cycle for California IOUs. SDG&E was directed to file a PFM to revise its 2019 GRC decision to add two additional attrition years including adjustment amounts, resulting in a transitional five-year GRC period (2019-2023).

In April 2020 (then slightly revised in May), SDG&E filed a PFM of its 2019 GRC decision requesting attrition year increases of $94 million (+4.24 percent) for 2022 and $96 million (+4.13 percent) for 2023. In May 2021, the CPUC issued a decision authorizing SDG&E to apply its PTY mechanism adopted in the 2019 GRC decision to 2022 and 2023 but updated the calculations based on the 2020 4th Quarter Global Insight forecast to more fully capture the impact of Covid-19 to the economy. This decision resulted in revenue requirements of $2.3 and $2.4 billion for SDG&E for 2022 and 2023 respectively, which were slightly less than the original requests made in SDG&E's PFM.

In May 2022 SDG&E filed its 2024 General Rate Case seeking to revise its authorized revenue requirements, effective on January 1, 2024, to recover the reasonable costs of electric and gas operations, facilities, infrastructure, and other functions necessary to provide utility services to customers. SDG&E requests a combined $3.022 billion revenue requirement ($674 million gas and $2.348 billion electric), which, if approved, would be an increase of $475 million over the expected 2023 revenue requirement. SDG&E also includes post-test year revenue requirement and regulatory account-related proposals. The general rate request process is scheduled to take between 18 months and two years and is expected to conclude in late 2023.

Other Regulatory Matters

For more information on non-GRC regulatory matters, refer above to the "Regulatory Environment" section in the Southern California part of this report, which generally applies to SDG&E's gas business as well.

PEAK DAY DEMAND

Gas supplies to serve both SoCalGas' and SDG&E's retail core gas demand are procured with a combined portfolio that contains a total firm storage withdrawal capacity designed to serve the utilities' combined retail core peak day gas demand. Please see the corresponding discussion of "Peak Day Demand and Deliverability" under the SoCalGas portion of this report for an illustration of how storage and flowing supplies can meet the growth in forecasted load for the combined (SoCalGas and SDG&E) retail core peak day demand.

The table below shows SDG&E's Core 1-in-35 Year Extreme Peak Day Demand and Winter 1-in-10 Year Cold Day System Demand.

TABLE 44– SDG&E WINTER PEAK DAY DEMAND (MMcf/d)

Year	Core 1-in-35 Extreme Peak Day Demand 1/		1-in-10 Cold Day Demand			
			Core 2/	Noncore C&I 3/	EG 4/	Total
2022	**404**		380	13	116	**510**
2023	**403**		380	13	104	**496**
2024	**402**		378	13	94	**484**
2025	**400**		376	13	98	**487**
2026	**398**		375	13	102	**490**
2027	**397**		373	13	102	**488**
2028	**395**		372	13	78	**462**

Notes:
(1) The criterion for core 1-in-35 extreme peak day design is defined as a 1-in-35 likelihood for SDG&E's service area. This criteria correlates to 43.3 degrees Fahrenheit for SDG&E's service area. 1-in-35 and 1-in-10 Core peak day demand forecasts embody the baseline forecast with load modifiers that include changing weather design to account for climate change, assumed EE savings and assumed fuel substitution under AAFS 2.
(2) The criterion for 1-in-10 peak day design is defined as a 1-in-10 likelihood for SDG&E's service area. This criterion correlates to 44.8 degrees Fahrenheit for SDG&E's service area.
(3) Average daily December demand for noncore commercial and noncore industrial.
(4) Electric Generation includes UEG/EWG Base Hydro, large cogeneration, industrial and commercial cogeneration (<20MW).

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SAN DIEGO GAS & ELECTRIC COMPANY – TABULAR DATA

TABLE 45 – SDG&E
ANNUAL GAS SUPPLY TAKEN– MMcf/d
RECORDED YEARS 2017-2021

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY TAKEN (MMCF/DAY)
RECORDED YEARS 2017 -2021

LINE		2017	2018	2019	2020	2021
	CAPACITY AVAILABLE					
1	**California Sources**					
	Out of State gas					
2	California Offshore (POPCO/PIOC)					
3	El Paso Natural Gas Company					
4	Transwestern Pipeline company					
5	Kern River/Mojave Pipeline Company					
6	TransCanada GTN/PG&E					
7	Other					
8	**TOTAL Output of State**					
9	Underground storage withdrawal					
10	**TOTAL Gas Supply available**					

LINE	Gas Supply Taken	2017	2018	2019	2020	2021
	California Source Gas					
11	Regular Purchases	0	0	0	0	0
12	Received for Exchange/Transport	0	0	0	0	0
13	**Total California Source Gas**	0	0	0	0	0
14	**Purchases from Other Utilities**	0	0	0	0	0
	Out-of-State Gas					
15	Pacific Interstate Companies	0	0	0	0	0
16	Additional Core Supplies	0	0	0	0	0
17	Supplemental Supplies-Utility	111	112	128	126	126
18	Out-of-State Transport-Others	188	127	103	151	139
19	**Total Out-of-State Gas**	299	239	230	277	265
20	**TOTAL Gas Supply Taken & Transported**	299	239	230	277	265

(MMCFD)

Table 46

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY AND SENDOUT (MMCF/DAY)
RECORDED YEARS 2017-2021

Actual Deliveries by End-Use		2017	2018	2019	2020	2021
CORE	Residential	72	70	81	81	78
	Commercial	52	54	57	50	52
	Industrial	-	-	-	-	-
Subtotal -	*CORE*	124	124	138	131	130
NONCORE	Commercial	-	-	-	-	-
	Industrial	11	12	13	13	15
	Non-EOR Cogen/EG	71	51	43	84	77
	Electric Utilities	92	49	33	41	36
Subtotal -	*NONCORE*	174	112	89	138	128
WHOLESALE	All End Uses	-	-	-	-	-
Subtotal -	*Co Use & LUAF*	1	3	4	8	7
SYSTEM TOTAL THROUGHPUT		299	239	230	277	265
Actual Transport & Exchange						
CORE	Residential	1	1	1	1	-
	Commercial	13	14	14	12	11
NONCORE	Industrial	11	12	13	13	15
	Non-EOR Cogen/EG	71	51	43	84	77
	Electric Utilities	92	49	33	41	36
Subtotal -	*RETAIL*	188	127	103	151	139
WHOLESALE	All End Uses	-	-	-	-	-
TOTAL TRANSPORT & EXCHANGE		188	127	103	151	139
Storage						
	Storage Injection	-	-	-	-	-
	Storage Withdrawal	-	-	-	-	-
Actual Curtailment						
	Residential	-	-	-	-	-
	Com/Indl & Cogen	-	-	-	-	-
	Electric Generation	-	-	-	-	-
TOTAL CURTAILMENT		-	-	-	-	-
REFUSAL		-	-	-	-	-

ACTUAL DELIVERIES BY END-USE includes sales and transportation volumes

MMbtu/Mcf:	1.040	1.038	1.032	1.025	1.030

le and MMCFD Supplies are used in the odd year reports (see P 17-18 of CGR)

TABLE 47 – SDG&E: SDG&E
ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d
ESTIMATED YEARS 2022-2026
AVERAGE TEMPERATURE YEARS

AVERAGE TEMPERATURE YEAR

LINE			2022	2023	2024	2025	2026	LINE
	CAPACITY AVAILABLE [1/ & 2/]							
1	California Source Gas		0	0	0	0	0	1
2	Southern Zone of SoCalGas [1/]		574	574	574	574	574	2
3	TOTAL CAPACITY AVAILABLE		574	574	574	574	574	3
	GAS SUPPLY TAKEN							
4	California Source Gas		0	0	0	0	0	4
5	Southern Zone of SoCalGas		253	241	227	219	218	5
6	TOTAL SUPPLY TAKEN		253	241	227	219	218	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		253	241	227	219	218	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	75	75	73	72	71	9
10		Commercial	43	44	44	44	44	10
11		Industrial	4	4	4	4	4	11
12		NGV	6	6	6	6	6	12
13		Subtotal-CORE	129	129	127	126	125	13
14	NONCORE	Commercial	7	7	7	7	7	14
15		Industrial	7	6	6	6	6	15
16		Electric Generation (EG)	108	97	85	78	77	16
17		Subtotal-NONCORE	121	111	98	91	91	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		253	241	227	219	218	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	12	12	12	12	12	20
21	NONCORE	Commercial/Industrial	14	13	13	13	13	21
22		Electric Generation (EG)	108	97	85	78	77	22
23	TOTAL TRANSPORTATION & EXCHANGE		134	123	110	103	103	23
	CURTAILMENT							
24		Core	0	0	0	0	0	24
25		Noncore	0	0	0	0	0	25
26		TOTAL - Curtailment	0	0	0	0	0	26

NOTES:

1/ Nominal capacity to receive gas from the Southern Zone of SoCalGas is based on current conditions, and is an annual v based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).

2/ For 2020 and after, assume capacity at same levels. Actual capacity through the CGR timeframe is subject to change.

3/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.

4/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:

	2022	2023	2024	2025	2026
transportation (CAT) in MDth/d	120	120	118	117	116

TABLE 48 – SDG&E: -SDG&E
ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d
ESTIMATED YEARS 2027-2035
AVERAGE TEMPERATURE YEARS

AVERAGE TEMPERATURE YEAR

LINE			2027	2028	2029	2030	2035	LINE
	CAPACITY AVAILABLE [1/ & 2/]							
1	California Source Gas		0	0	0	0	0	1
2	Southern Zone of SoCalGas [1/]		574	574	574	574	574	2
3	TOTAL CAPACITY AVAILABLE		574	574	574	574	574	3
	GAS SUPPLY TAKEN							
4	California Source Gas		0	0	0	0	0	4
5	Southern Zone of SoCalGas		215	210	209	204	198	5
6	TOTAL SUPPLY TAKEN		215	210	209	204	198	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		215	210	209	204	198	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	71	69	68	67	63	9
10		Commercial	43	43	43	43	41	10
11		Industrial	4	4	4	4	3	11
12		NGV	6	6	6	6	6	12
13		Subtotal-CORE	124	122	121	120	114	13
14	NONCORE	Commercial	7	7	7	7	7	14
15		Industrial	6	6	6	6	6	15
16		Electric Generation (EG)	76	73	73	70	69	16
17		Subtotal-NONCORE	90	86	86	83	82	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		215	210	209	204	198	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	12	12	12	12	12	20
21	NONCORE	Commercial/Industrial	13	13	13	13	13	21
22		Electric Generation (EG)	76	73	73	70	69	22
23	TOTAL TRANSPORTATION & EXCHANGE		102	98	99	95	94	23
	CURTAILMENT							
24		Core	0	0	0	0	0	24
25		Noncore	0	0	0	0	0	25
26		TOTAL - Curtailment	0	0	0	0	0	26

NOTES:

1/ Nominal capacity to receive gas from the Southern Zone of SoCalGas is based on current conditions, and is an annual v
based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).

2/ For 2020 and after, assume capacity at same levels. Actual capacity through the CGR timeframe is subject to change.

3/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.

4/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d: 115 (2027), 113 (2028), 112 (2029), 111 (2030), 105 (2035)

TABLE 49 – SDG&E:
ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d
ESTIMATED YEARS 2022-2026
COLD TEMPERATURE YEAR (1-IN-35 COLD YEAR EVENT) AND DRY HYDRO YEAR

COLD TEMPERATURE YEAR (1 IN 35 COLD YEAR EVENT) & DRY HYDRO YEAR

LINE			2022	2023	2024	2025	2026	LINE
	CAPACITY AVAILABLE [1/ & 2/]							
1	California Source Gas		0	0	0	0	0	1
2	Southern Zone of SoCalGas [1/]		574	574	574	574	574	2
3	TOTAL CAPACITY AVAILABLE		574	574	574	574	574	3
	GAS SUPPLY TAKEN							
4	California Source Gas		0	0	0	0	0	4
5	Southern Zone of SoCalGas		262	251	237	229	228	5
6	TOTAL SUPPLY TAKEN		262	251	237	229	228	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		262	251	237	229	228	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	83	82	81	80	79	9
10		Commercial	45	45	45	45	45	10
11		Industrial	4	4	4	4	4	11
12		NGV	6	6	6	6	6	12
13		Subtotal-CORE	138	138	136	135	134	13
14	NONCORE	Commercial	7	7	7	7	7	14
15		Industrial	7	6	6	6	6	15
16		Electric Generation (EG)	108	98	86	79	79	16
17		Subtotal-NONCORE	121	111	99	92	92	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		262	251	237	229	228	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	13	13	13	13	13	20
21	NONCORE	Commercial/Industrial	14	13	13	13	13	21
22		Electric Generation (EG)	108	98	86	79	79	22
23	TOTAL TRANSPORTATION & EXCHANGE		134	124	112	105	104	23
	CURTAILMENT							
24		Core	0	0	0	0	0	24
25		Noncore	0	0	0	0	0	25
26		TOTAL - Curtailment	0	0	0	0	0	26

NOTES:
1/ Nominal capacity to receive gas from the Southern Zone of SoCalGas is based on current conditions, and is an annual v
based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).
2/ For 2020 and after, assume capacity at same levels. Actual capacity through the CGR timeframe is subject to change.
3/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.
4/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d: 129 129 127 126 125

TABLE 50 – SDG&E:
ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d
ESTIMATED YEARS 2027-2035
COLD TEMPERATURE YEAR (1-IN-35 COLD YEAR EVENT) AND DRY HYDRO YEAR

COLD TEMPERATURE YEAR (1 IN 35 COLD YEAR EVENT) & DRY HYDRO YEAR

LINE			2027	2028	2029	2030	2035	LINE
	CAPACITY AVAILABLE [1/ & 2/]							
1	California Source Gas		0	0	0	0	0	1
2	Southern Zone of SoCalGas [1/]		574	574	574	574	574	2
3	TOTAL CAPACITY AVAILABLE		574	574	574	574	574	3
	GAS SUPPLY TAKEN							
4	California Source Gas		0	0	0	0	0	4
5	Southern Zone of SoCalGas		226	220	220	215	212	5
6	TOTAL SUPPLY TAKEN		226	220	220	215	212	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		226	220	220	215	212	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	78	77	76	74	71	9
10		Commercial	45	45	45	44	42	10
11		Industrial	4	4	4	4	4	11
12		NGV	6	6	6	6	6	12
13		Subtotal-CORE	133	131	130	129	123	13
14	NONCORE	Commercial	7	7	7	7	7	14
15		Industrial	6	6	6	6	6	15
16		Electric Generation (EG)	78	74	74	71	74	16
17		Subtotal-NONCORE	91	87	87	84	87	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		226	220	220	215	212	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	13	13	13	13	12	20
21	NONCORE	Commercial/Industrial	13	13	13	13	13	21
22		Electric Generation (EG)	78	74	74	71	74	22
23	TOTAL TRANSPORTATION & EXCHANGE		104	100	100	97	99	23
	CURTAILMENT							
24		Core	0	0	0	0	0	24
25		Noncore	0	0	0	0	0	25
26		TOTAL - Curtailment	0	0	0	0	0	26

NOTES:

1/ Nominal capacity to receive gas from the Southern Zone of SoCalGas is based on current conditions, and is an annual valu
based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).

2/ For 2020 and after, assume capacity at same levels. Actual capacity through the CGR timeframe is subject to change.

3/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.

4/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d: 124 | 122 | 121 | 120 | 114

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GLOSSARY

GLOSSARY

A.
Application.

AAEE
Additional Achievable Energy Efficiency.

AAFS
Additional Achievable Fuel Substitution. The scenarios forecast reductions for gas consumption which are “substituted out” through electrification.

AB
Assembly Bill.

AMI
Advanced Metering Infrastructure.

APD
Abnormal Peak Day.

API
American Petroleum Institute.

A/S
ancillary services.

Average Day (Operational Definition)
Annual gas sales or requirements assuming average temperature year conditions divided by 365 days.

Average Temperature Year
Long-term average recorded temperature.

Bcf
billion cubic feet.

Bcf/d
billion cubic feet per day.

Bcf/y
billion cubic feet per year.

BTU (British Thermal Unit)
Unit of measurement equal to the amount of heat energy required to raise the temperature of one pound of water 1 degree F. This unit is commonly used to measure the quantity of heat available from complete combustion of natural gas.

CAISO
California Independent System Operator.

CalGEM
California Geologic Energy Management Division (formerly, DOGGR).

California-Source Gas
1. Regular Purchases – All gas received or forecasted from California producers, excluding exchange volumes. Also referred to as Local Deliveries.
2. Received for Exchange/Transport – All gas received or forecasted from California producers for exchange, payback, or transport.

CARB
California Air Resources Board.

CCST
California Council on Science and Technology.

CDFA
California Department of Food and Agriculture.

CEC
California Energy Commission.

CFR
Code of Federal Regulations.

CGR
California Gas Report.

CNG (Compressed Natural Gas)
Fuel for NGVs, typically natural gas compressed to 3000 pounds per square inch.

CO_2
carbon dioxide.

Cogeneration
Simultaneous production of electricity and thermal energy from the same fuel source. Also used to designate a separate class of gas customers.

Cold Temperature Year
Cold design-temperature conditions based on long-term recorded weather data.

Combined Heat and Power (CHP)
Combined Heat and Power (CHP) is the sequential production of electricity and thermal energy from the same fuel source. Historically, CHP has been perceived as an efficient technology and is promoted in California as a preferred EG resource.

Commercial (SoCalGas and SDG&E)
Category of gas customers whose establishments consist of services, manufacturing nondurable goods, dwellings not classified as residential, and farming (agricultural).

Commercial (PG&E)
Non-residential gas customers not engaged in EG, EOR, or gas resale activities with usage less than 20,800 therms per month.

Commission
California Public Utilities Commission (see also CPUC).

Company Use
Gas used by utilities for operational purposes, such as fuel for line compression and injection into storage.

Conversion Factor (LNG)
Approximate LNG liquid conversion factor for one therm (High-Heat Value).

- Pounds 4.2020
- Gallons 1.1660
- Cubic Feet 0.1570
- Barrels 0.0280
- Cubic Meters 0.0044
- Metric Tonnes 0.0019

Conversion Factor (Natural Gas)

- 1 cf (Cubic Feet) = Approximately 1,000 Btus
- 1 Ccf = 100 cf = Approximately 1 Therm
- 1 Therm = 100,000 BTUs = Approximately 100 cf = 0.1 Mcf
- 10 Therms = 1 Dth (dekatherm) = Approximately 1 Mcf
- 1 Mcf = 1,000 cf = Approximately 10 Therms = 1 MMBtu
- 1 MMcf = 1 million cubic feet = Approximately 1 MDth (1 thousand dekatherm)
- 1 Bcf = 1 billion cf = Approximately 1 million MMBtu

Conversion Factor (Petroleum Products)

Approximate heat content of petroleum products (MMBtu per Barrel).

- Crude Oil 5.800
- Residual Fuel Oil 6.287
- Distillate Fuel Oil 5.825
- Petroleum Coke 6.024
- Butane 4.360
- Propane 3.836
- Pentane Plus 4.620
- Motor Gasoline 5.253

Core Aggregator

Individuals or entities arranging natural gas commodity procurement activities on behalf of core customers. Also, sometimes known as an Energy Service Provider (ESP), a Core Transport Agent (CTA), or a Retail Service Provider.

Core Customer (PG&E)

All customers with average usage less than 20,800 therms per month.

Core Customers (SoCalGas and SDG&E)

All residential customers; all commercial and industrial customers with average usage less than 20,800 therms per month who typically cannot fuel switch. Also, those commercial and industrial customers (whose average usage is more than 20,800 therms per year) who elect to remain a core customer receiving bundled gas service from the LDC.

Core Subscription

Noncore customers who elect to use the LDC as a procurement agent to meet their commodity gas requirements.

COVID-19

Coronavirus Disease 2019.

CPUC

California Public Utilities Commission (see also Commission).

Cubic Foot of Gas
Volume of natural gas, which, at a temperature of 60 degrees F and an absolute pressure of 14.73 pounds per square inch, occupies one cubic foot.

Curtailment
Temporary suspension, partial or complete, of gas deliveries to a customer or customers.

D.
Decision.

DDRDP
Dairy Digester Research and Development Program.

DOE
Department of Energy.

DOGGR
California Division of Oil, Gas, and Geothermal Resources (now CalGEM).

ECA
Energia Costal Azul.

EG
Electric Generation (including cogeneration) by a utility, customer, or independent power producer.

Electrification (Building Electrification)
Fuel Substitution

Energy Service Provider (ESP)
Individuals or entities engaged in providing retail energy services on behalf of customers. ESP's may provide commodity procurement, but could also provide other services, e.g., metering and billing.

EO
Executive Order.

EOR (Enhanced Oil Recovery)
Injection of steam into oil-holding geologic zones to increase ability to extract oil by lowering its viscosity. Also used to designate a special category of gas customers.

Exchange
Delivery of gas by one party to another and the delivery of an equivalent quantity by the second party to the first. Such transactions usually involve different points of delivery and may or may not be concurrent.

EWG (Exempt Wholesale Generator)
A category of customers consuming gas for the purpose of generating electric power.

F
Fahrenheit.

FERC
Federal Energy Regulatory Commission.

FTA
Free Trade Agreement.

Futures (Gas)
Unit of natural gas futures contract trades in units of 10,000 MMBtu at the New York Mercantile Exchange (NYMEX). The price is based on delivery at Henry Hub in Louisiana.

Gas Accord
The Gas Accord is a multi-party settlement agreement, which restructured PG&E's gas transportation and storage services. The settlement was filed with the CPUC in August 1996, approved by the CPUC in August 1997 (D.97-08-055) and implemented by PG&E in March 1998. In D.03-12-061, the CPUC ordered the Gas Accord structure to continue for 2004 and 2005. Key features of the Gas Accord structure include the following: unbundling of PG&E's gas transmission service and a portion of its storage service; placing PG&E at risk for transmission service and a portion of its storage service; placing PG&E at risk for transmission and storage costs and revenues; establishing firm, tradable transmission and storage rights; and establishing transmission and storage rates.

Gas Sendout
That portion of the available gas supply that is delivered to gas customers for consumption, plus shrinkage.

GHG (Green House Gas)
GHGs are the gases present in the atmosphere which reduce the loss of heat into space and therefore contribute to global temperatures through the greenhouse effect. The most the most abundant GHGs are, in order of relative abundance are water vapor, CO_2, methane, nitrous oxide, ozone and CFCs.

GRC
General Rate Case.

GT&S
Gas Transmission and Storage.

GTN
Gas Transmission Northwest LLC.

H2
Hydrogen.

HDD (Heating Degree Day)
A HDD is accumulated for every degree F the daily average temperature is below a standard reference temperature (SoCalGas and SDG&E: 65 degrees F; PG&E 60 degrees F). A basis for computing how much electricity and gas are needed for space heating purposes. For example, for a 50 degrees F average temperature day, SoCalGas and SDG&E would accumulate 15 HDD, and PG&E would accumulate 10 HDD.

Heating Value
Number of BTU's liberated by the complete combustion at constant pressure of one cubic foot of natural gas at a base temperature of 60 degrees F and a pressure base of 14.73 psia, with air at the same temperature and pressure as the natural gas, after the products of combustion are cooled to the initial temperature of natural gas, and after the water vapor of the combustion is condensed to the liquid state. The heating value of the natural gas shall be corrected for the water vapor content of the natural gas being delivered except that, if such content is 7 pounds or less per one million cubic feet, the natural gas shall be considered dry.

IEPR
Integrated Energy Policy Report.

ILI
In-Line Inspection.

Industrial (PG&E)
Non-residential customers not engaged in EG, EOR, or gas resale activities using more than 20,800 therms per month.

Industrial (SoCalGas and SDG&E)
Category of gas customers who are engaged in mining and in manufacturing.

IOU
investor-owned utility.

IRP
Integrated Resource Plan.

LCFS
Low Carbon Fuel Standard.

LDC
Local electric and/or natural gas distribution company.

LNG (Liquefied Natural Gas)
Natural gas that has been super cooled to -260 degrees F (-162 degrees C) and condensed into a liquid that takes up 600 times less space than in its gaseous state.

Load Following
A utility's practice of adding additional generation to available energy supplies to meet moment-to-moment demand in the distribution system served by the utility, and for keeping generating facilities informed of load requirements to insure that generators are producing neither too little nor too much energy to supply the utilities' customers.

MCF
The volume of natural gas which occupies 1,000 cubic feet when such gas is at a temperature of 60 degrees F and at a standard pressure of approximately 15 pounds per square inch.

MHP
Mobile Home Park.

MMBtu
Million British Thermal Units. One MMbtu is equals to 10 therms or one dekatherm.

MMcf/d
Million cubic feet per day.

mmt
million metric tons.

mmtCO_2e
million metric tons of carbon dioxide equivalent.

$mtCO_2e$
metric tons of carbon dioxide equivalent.

MW
megawatt.

MWh
megawatt-hour.

NGSS
Natural Gas Storage Strategy.

NGTL
NOVA Gas Transmission Ltd.

NGV (Natural Gas Vehicle)
Vehicle that uses CNG or LNG as its source of fuel for its internal combustion engine.

Noncore Customers
Commercial and industrial customers whose average usage exceeds 20,800 therms per month, including qualifying cogeneration and solar electric projects. Noncore customers assume gas procurement responsibilities and receive gas transportation service from the utility under firm or interruptible intrastate transmission arrangements.

Non-Utility Served Load
The volume of gas delivered directly to customers by an interstate or intrastate pipeline or other independent source instead of the local distribution company.

Off-System Sales
Gas sales to customers outside the utility's service area.

OIR
Order Instituting Rulemaking.

OTC
once-through-cooling.

Out-of-State Gas
Gas from sources outside the state of California.

PFM
Petition for Modification.

PG&E
Pacific Gas and Electric Company.

PHMSA
Pipeline and Hazardous Materials Safety Administration.

Piggable
Refers to the process of using devices known as "pigs" to perform various maintenance operations such as pipeline cleaning and inspection.

Priority of Service (PG&E)
In the event of a curtailment situation, PG&E curtails gas usage to customers based on the following end-use priorities:
1. Core Residential;
2. Non-residential Core;
3. Noncore using firm backbone service (including UEG);
4. Noncore using as-available backbone service (including UEG); and
5. Market Center Services.

Priority of Service (SoCalGas + SDG&E)
In the event of a curtailment situation, SoCalGas and SDG&E curtail gas usage to customers in the following order:
- Up to 60 percent (November thru March) or 40 percent (April thru October) of dispatched EG load;
- Up to 100 percent of nonEG noncore except for refineries;
- Up to 100 percent of refineries and up to 100 percent of the remaining dispatched EG load;
- Non-Residential Core customers; and
- Residential Core customers.

PSEP
Pipeline Safety Enhancement Plan.

PSIA
Pounds per square inch absolute. Equal to gauge pressure plus local atmospheric pressure.

Pub. Util. Code
Public Utilities Code.

Purchase from Other Utilities
Gas purchased from other utilities in California.

R.
Rulemaking.

R.
Rulemaking.

R&D
Research and Development.

Requirements
Total potential demand for gas, including that served by transportation, assuming the availability of unlimited supplies at reasonable cost.

Res.
Resolution.

Resale
Gas customers who are either another utility or a municipal entity that, in turn, resells gas to end-use customers.

Residential
A category of gas customers whose dwellings are single-family units, multi-family units, mobile homes, or other similar living facilities.

RNG
Renewable Natural Gas.

RNGS
Renewable Gas Standard.

RP
Recommended Practice.

RPS
Renewables Portfolio Standard.

RSP
Reference System Plan.

SB
Senate Bill.

SDG&E
San Diego Gas & Electric Company.

Short-Term Supplies
Gas purchased usually involving 30-day, short-term contract or spot gas supplies.

SLCP
Short-Lived Climate Pollutants.

SMUD
Sacramento Municipal Utility District.

SoCalGas
Southern California Gas Company.

Spot Purchases
Short-term purchases of gas typically not under contract and generally categorized as surplus or best efforts.

Storage Banking
The direct use of local distribution company gas storage facilities by customers or other entities to store self-procured commodity gas supplies.

Storage Injection
Volume of natural gas injected into underground storage facilities.

Storage Withdrawal
Volume of natural gas taken from underground storage facilities.

Supplemental Supplies
A utility's best estimate for additional gas supplies that may be realized, from unspecified sources, during the forecast period.

SWG
Southwest Gas Corporation.

SWRCB
State Water Resources Control Board.

System Capacity or Normal System Capacity (Operational Definition)
The physical limitation of the system (pipelines and storage) to deliver or flow gas to end-users.

System Utilization or Nominal System Capacity (Operational Definition)
The use of system capacity or nominal system capacity at less than 100 percent utilization.

Take-or-Pay
A term used to describe a contract agreement to pay for a product (natural gas) whether or not the product is delivered.

Tariff
All rate schedules, sample forms, rentals, charges, and rules approved by regulatory agencies for used by the utility.

TCF
Trillion cubic feet of gas.

Therm
A unit of energy measurement, nominally 100,000 BTUs.

Total Gas Supply Available
Total quantity of gas estimated to be available to meet gas requirements.

Total Gas Supply Taken
Total quantity of gas taken from all sources to meet gas requirements.

Total Throughput
Total gas volumes passing through the system including sales, company use, storage, transportation, and exchange.

Traditional Gas
A term designated to refer to fossil fuels, including but not limited to, natural gas.

Transportation Gas
Non-utility-owned gas transported for another party under contractual agreement.

UC
University of California.

UEG
utility electric generation.

Unaccounted-For
Gas received into the system but unaccounted for due to measurement, temperature, pressure, or accounting discrepancies.

Unbundling
The separation of natural gas utility services into its separate service components, such as gas procurement, transportation, and storage with distinct rates for each service.

U.S.
United States.

USA
Underground Service Alert.

WACOG
Weighted average cost of gas.

WECC
Western Electricity Coordinating Council.

Wholesale
A category of customer, either a utility or municipal entity, that resells gas.

Wobbe
The Wobbe number of a fuel gas is found by dividing the high heating value of the gas in BTU per standard cubic feet (scf) by the square root of a specific gravity with respect to air. The higher a gases' Wobbe number, the greater the heating value of the quality of gas that will flow through a hole of a given size in a given amount of time.

2022 CALIFORNIA GAS REPORT

RESPONDENTS

RESPONDENTS

The following utilities have been designated by the California Public Utilities Commission as respondents in the preparation of the California Gas Report.

- Pacific Gas and Electric Company
- San Diego Gas and Electric Company
- Southern California Gas Company

The following utilities also cooperated in the preparation of the report.

- City of Long Beach Energy Resources Department
- Sacramento Municipal Utilities District
- Southern California Edison Company
- Southwest Gas Corporation
- ECOGAS Mexico, S. de R.L. de C.V.

A statewide committee has been formed by the respondents and cooperating utilities to prepare this report. The following individuals served on this committee.

Working Committee

- Rose-Marie Payan- SoCalGas/SDG&E- *Statewide Chair, 2022 CGR*
- Todd Peterson-PG&E

- Scott Wilder- SoCalGas/SDG&E
- Sharim Chaudhury- SoCalGas/SDG&E
- William Guo – SoCalGas/SDG&E
- Jeff Huang– SoCalGas/SDG&E
- Michelle Clay-Ijomah-SDG&E
- Nasim Ahmed- SoCalGas
- Julia Cortez- SoCalGas
- Brandon Duran-SoCalGas
- Dave Bisi- SoCalGas
- Stan Sinclair- SoCalGas
- Heng Yang- SoCalGas/SDG&E
- Athena Besa-SDG&E
- Lonnie Mansi-SDG&E
- Perla Anaya-SDG&E
- Michelle Clay-Ijomah-SDG&E
- William Flemetakis- Kern River
- Tony Chun-SoCalGas
- Anupama Pandey - PG&E
- Kurtis Kolnowski-PG&E
- Andrew Klingler-PG&E

Observers

- Jean Spencer – CPUC Energy Division
- Eileen Hlavka-CPUC Energy Division
- Melissa Jones-CEC
- Ingrid Neumann-CEC
- Robert Gulliksen-CEC

2023 CALIFORNIA GAS REPORT

RESERVATIONS

RESERVE YOUR SUBSCRIPTION

2023 CALIFORNIA GAS REPORT SUPPLEMENT

Southern California Gas Company
2023 CGR Reservation Form
C/O Rosemarie Payan
Box 3249, Mail Location GT14D6
Los Angeles, CA 90051-1249
or
Fax: (213) 244-4957
Email: Rose-Marie Payan
RPayan@semprautilities.com

- ❑ ▪Send me a 2023 CGR Supplement
- ❑ ▪New subscriber
- ❑ ▪Change of address

Company Name: ____
C/O: ____
Address: ____
City: __________________ State: _____________ Zip: _________
Phone: (____) ________________ Fax: (_____) ______________

Please visit our website for digital copies of this Report and the accompanying workpapers. They are located in the regulatory section of the following websites:

www.socalgas.com
www.SDG&E.com

RESERVE YOUR SUBSCRIPTION

2023 CALIFORNIA GAS REPORT – SUPPLEMENT

Pacific Gas and Electric Company
2023 CGR Reservation Form
C/O Todd Peterson
Mail Code B10B
P. O. Box 770000
San Francisco, CA 94177
or
Email: Todd.Peterson@pge.com

❑ ▪Send me a 2023 CGR
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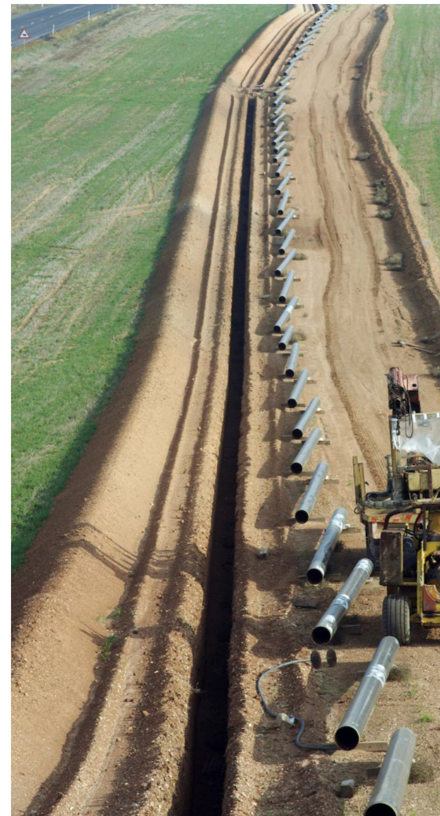
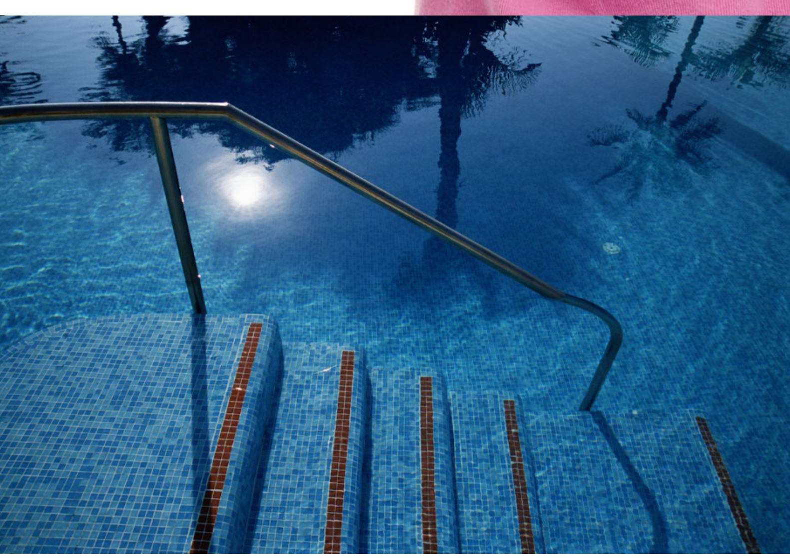
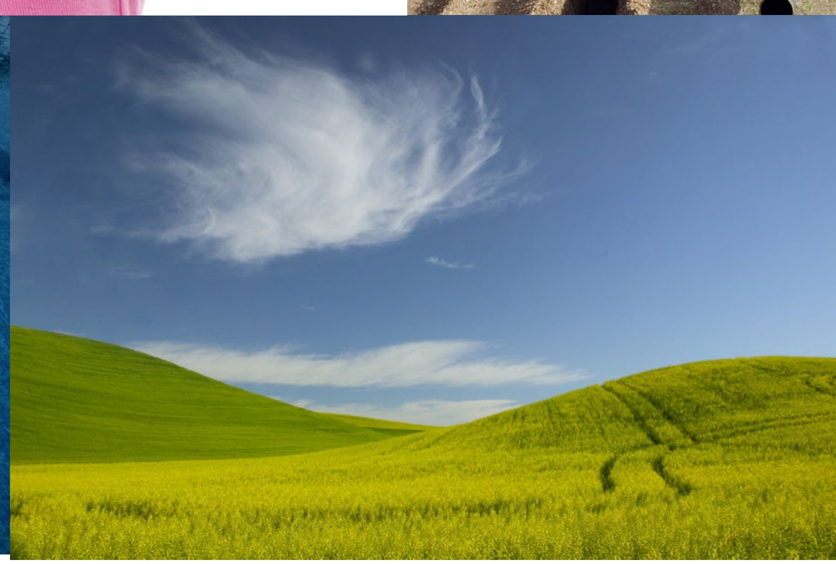
Phone: (_____) ______________ Fax: (_____) ____________

Please visit our website for digital copies of this and past reports: http://www.pge.com/pipeline/library/regulatory/cgr_index.shtml



2022 CGR


BULKLNG

Clean Energy is the largest provider of natural gas fuel for transportation in **North America**. We offer **Custom Bulk LNG Fueling Services**.

Take advantage of volume discounts and cost-efficient transfers while leaving the logistics to our reliable in-house bulk fuel delivery management team.

Willis, Texas

Production plant for Clean Energy

PRODUCTION PLANTS

Boron, California

Production plant for Clean Energy

Clean Energy owns and operates two LNG production plants, one in California and one in Texas. We're also able to source through dozens of partner plants across the United States, allowing us to distribute LNG throughout the country.

Boron, CA

180,000 LNG gallons production per day, expandable to **270,000 LNG gallons** per day.

Willis, TX

84,000 LNG gallons production per day.

1.0 million-gallon storage tank.

WHY CLEAN ENERGY

SIGNIFICANT STORAGE CAPACITY

Our plants feature some of the largest storage tanks dedicated to transportation and industrial use in the country, with a 1.8 million-gallon tank in California and a 1.0 million-gallon tank in Texas.

HIGHEST METHANE PURITY

The LNG from our plants offers 96–99% purity, making it the cleanest fuel available. This detail is especially crucial for industries like transportation, marine, and aerospace.

CALIFORNIA & TEXAS

Our LNG plant in Boron is the only large-scale LNG plant in California, and it is the largest in the Southwest. Combined with our plant in Texas, and our partner plants comes from landfills and dairy farms, drastically reducing greenhouse gas emissions by up to 300%. It is available through all of our plants.

Learn More About RNG

START THE CONVERSATION

First Name

Last Name

Your Email

Company Name

Phone Number

Project Description

Write a brief project description here

Bulk LNG Brochure

Want lower levels of emissions? Get the highest levels of expertise.

Renewable natural gas is a proven solution that works. Clean Energy fuels more than 25,000 vehicles daily with renewable natural gas, across all transportation sectors from heavy-duty fleets, to refuse trucks, to transit buses.

Let Clean Energy's full-service team guide you through your transition to renewable natural gas, whether that involves financing, engineering, construction, or operations.

Contact us

Related services

Financing & Grants

Station Constructio

Keep up-to-date with latest news on Clean Energy and renewable natural gas:

Email Address

SUBSCRIBE

Public Works (/Departments/Public-Works.aspx)

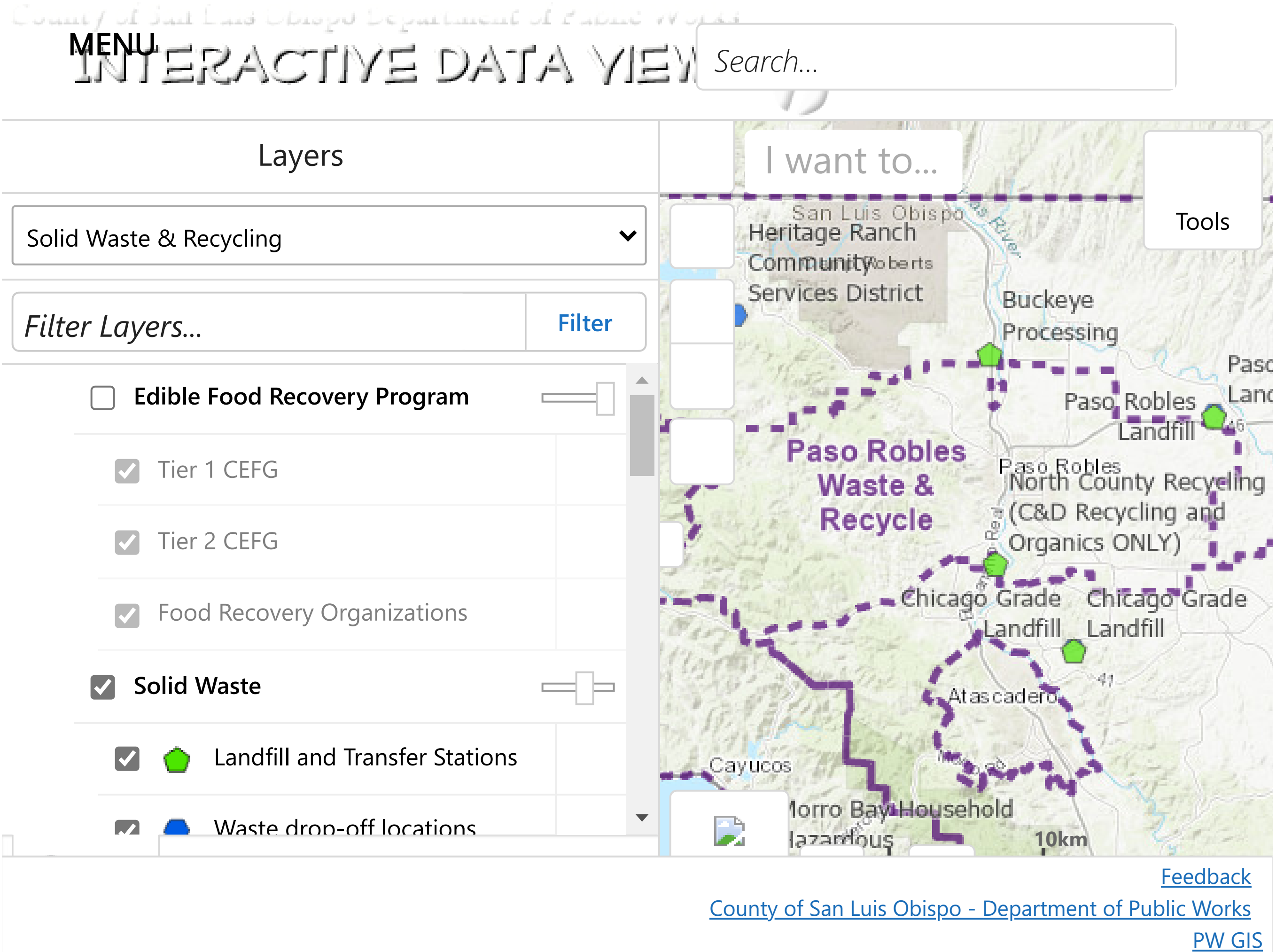
County of San Luis Obispo

Residents

If you currently do not have a solid waste, recycling, or organics service set up for your residence, please find and contact your solid waste service provider here (http://www.slocounty.ca.gov/Departments/Public-Works/Services/Programs-Outreach/Solid-Waste-Resources/Solid-Waste-Franchise-Haulers.aspx).

If you're unsure which solid waste hauler is right for your residence, please take a look at our Waste Locations Interactive Map.

Waste Locations Interactive Map - Open Map in New Tab (https://gis.slocounty.ca.gov/Html5Viewer/Index.html?configBase=/Geocortex/Essentials/REST/sites/PW_Public/viewers/PW_Viewer/virtualdirectory/Resources/Config/Default&layerTheme=4)



Here you can:

- Find out which Waste Hauler Service provides for your area.
- Locations of landfills and transfer stations
- Locations of Waste Drop-off sites where you can dispose of Household Hazardous Waste (https://iwma.com/what-to-do/hhw/).

For a full guide on what to throw in the trash, recycle, and organic waste bins, please visit the IWMA Recycling Guide (https://iwma.com/guide/).

Please see below for the following: (Click to Expand)

- Landfills, Transfer Stations, and Recycling Sites
- Household Hazardous Waste

County Government Center

1055 Monterey Street, San Luis Obispo, CA 93408

VIEW MAP (https://www.google.com/maps/place/1055+Monterey+St,+San+Luis+Obispo,+CA+93408/@35.2821867,-120.6623615,17z/data=!3m1!4b1!4m5!3m4!1s0x80ecf103f8846375:0x1a2ced6ddf2d515e!8m2!3d35.2821867!4d-120.6601675)

County Phone Directory: **805-781-5000**

(Toll free: **800-834-4636**)

Connect with the County

Guidelines for Energy Project Applications Requiring CEQA Compliance:

Pre-filing and Proponent's Environmental Assessments

November 2019

Version 1.0

Energy Division
Infrastructure Permitting and CEQA Unit
California Public Utilities Commission

Guidelines for Energy Project Applications Requiring CEQA Compliance:

Pre-filing and Proponent's Environmental Assessments

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Foreword

November 12, 2019

To: Applicants Filing Proponent's Environmental Assessments for Energy Infrastructure Projects at the California Public Utilities Commission (CPUC or Commission)

From: Merideth Sterkel (Program Manager, Infrastructure Planning and Permitting) and Mary Jo Borak and Lonn Maier, Supervisors, Infrastructure Permitting and California Environmental Quality Act, Energy Division, CPUC

Subject: Introducing revisions to the Pre-filing Guidelines for Energy Infrastructure Projects and a Unified and Updated Electric and Gas PEA Checklist

We are pleased to release a 2019 revision to the California Environmental Quality Act (CEQA) Proponent's Environmental Assessments (PEA) Checklist. This substantially revised document is now entitled "Guidelines for Energy Project Applications Requiring CEQA Compliance: Pre-filing and Proponent's Environmental Assessments" (Guidelines). Future updates to this document will be made as determined necessary. The CPUC's Rules of Practice and Procedure Sections 2.4 provide that all applications to the CPUC for authority to undertake projects that are not statutorily or categorically exempt from CEQA requirements shall include an Applicant-prepared PEA.

Updates Overview

Prior versions of the Working Draft PEA Checklist were published in 2008 and 2012. For this 2019 update, extensive revisions were made to all sections based on our experience with the prior checklist versions. All electric and natural gas projects are now addressed in a single PEA Checklist, and the following updates were made:

- **CEQA Statute and Guidelines 2019 Updates:** The PEA Checklist is updated pursuant to the 2019 CEQA Statues and Guidelines, including new energy and wildfire resource areas.
- **Pre-filing Consultation Guidelines:** Pre-filing guidelines are now provided since the pre-filing and PEA development processes are intertwined.
- **Unified PEA Checklist for Energy Projects:** All electric and natural gas projects are now addressed in a single PEA Checklist.
- **Additional CEQA Impact Questions:** Questions are included for the following PEA Checklist sections: 5.4, Biological Resources; 5.6, Energy; 5.9, Hazards, Hazardous Materials, and Public Safety; 5.16, Recreation; 5.17, Transportation; and 5.19, Utilities and Service Systems.
- **CPUC Draft Environmental Measures:** Draft measures are provided in PEA Checklist Attachment 4 for Aesthetics, Air Quality, Cultural Resources, Greenhouse Gas Emissions, Utilities and Service Systems and Wildfire.

Purpose of the Guidelines Document

The purpose and objective of the PEA Checklist included within this Guidelines document has not changed, which is to provide project Proponents (Applicants) with detailed guidance about information our CEQA Unit Staff expect in sufficient PEAs. The document details the information Applicants must provide the CPUC to complete environmental reviews that satisfy CEQA requirements. Specifically, the Pre-filing Consultation Guidelines and PEA Checklist, together, are intended to achieve the following objectives:

1. Provide useful guidance to Applicants, CPUC staff, and outside consultants regarding the type and detail of information needed to quickly and efficiently deem an application complete;

2. Ensure PEAs provide reviewers with a detailed project description and associated information sufficient to deem an application complete, avoid lengthy review periods and numerous data requests for the purpose of augmenting a PEA, and avoid unnecessary PEA production costs;
3. Increase the level of consistency between PEAs submitted and provide for more consistent review by CPUC CEQA Unit Staff and outside consultants; and
4. Promote transparency and reduce the potential for conflicts between utility and CPUC Staff about the types, scope, and thoroughness of data expected for data adequacy purposes.

The Guidelines document provides detailed instructions to Applicants for use during the Pre-filing process and PEA development. The document is intended to fully inform Applicants and focus the role of outside consultants, thus, enabling Applicants to submit more complete, useful, and immediately data-adequate PEAs.

Benefits of High Quality and Complete PEAs

CPUC CEQA Unit Staff seek to complete the environmental review process required under CEQA as quickly and efficiently as possible. Table 1 shows the average duration in months of CPUC applications that require CEQA documents. While there are tensions between speed and quality in all project management, the achievement of expeditious environmental reviews can result in lower project costs to ratepayers. Our staff have reviewed the timelines for 108 past CPUC applications that required review pursuant to CEQA and determined that the average length of time from application filing to PEA deemed complete is four months, regardless of the type of CEQA document. The goal for our agency is to deem PEAs complete within 30 days. The faster PEAs are deemed complete, the sooner staff can prepare the CEQA document. With each delay to PEA completeness, the fundamental project purpose and need and baseline circumstances may shift, requiring refreshing of the data. The Guidelines document will improve the initial accuracy of PEAs and reduce the time required to deem PEAs complete. Once an application is formally filed, the Applicant will receive a notification letter from CPUC CEQA Unit Staff when the PEA is deemed complete.

Table 1. Average Duration in Months of CPUC Applications that Require CEQA Documents (1996–2019)

	I: Application Filed to PEA Deemed Complete	II: PEA Deemed Complete to Draft Environmental Document Circulated	III: Draft Environmental Document to Final Released	IV: Final Released to Proposed Decision	V: Proposed Decision to Final Decision (with Certification of CEQA Document)	I-V: Overall Duration (1)
Environmental Impact Report (EIR; n=49)	5	13	7	5	2	**29**
Initial Study/ Mitigated Negative Declaration (IS/MND; n=56)	4	8	3	4	1	**19**
All Document Types (n=108)	4	8	4	5	2	**23**
Range: All Document Types	*1-9*	*5-18*	*2-10*	*1-7*	*1-2*	***12-38***

Note:
(1) The overall duration is not a sum of the average durations for each step. The overall duration was calculated using “n,” the number of applications with data available for the date of application filing and final decision date. Not all projects had data available for each step. The data include several instances where the CEQA document was developed in conjunction with a NEPA document, e.g., an EIR/Environmental Impact Statement or IS/MND/Environmental Assessment/Finding of No Significant Impact was prepared instead of an EIR or MND, respectively. The above data is not inclusive of projects that had averages and ranges that are statistically abnormal.

Lessons Learned about the PEA Process

In the past, Applicants have filed PEAs using the checklist to ensure the correct information was provided but have not followed the format and organization of the PEA checklist and sometimes chose not to engage in Pre-filing activities with our staff. To achieve the objectives and benefits listed above, Applicants will file all future PEAs in the same organizational format as the updated checklist and adhere to the Pre-filing Consultation Guidelines in coordination with CPUC CEQA Unit Staff.

The Guidelines document describes the level effort required for the assessments necessary to not only finalize a CEQA document but ensure its legal defensibility. While final design and survey information is preferred, the PEA may incorporate preliminary design and survey data as appropriate and in consultation with CEQA Unit Staff during Pre-filing. We recognize that projects are fact specific, and deviations from the Pre-filing Consultation Guidelines and PEA Checklist are inevitable but providing concise and accurate information as soon as possible is paramount. Any deviations from these Guidelines must include clear justification and should be discussed and submitted during the Pre-filing Consultation process to avoid subsequent delays.

The PEA Checklist is written with the assumption that an Environmental Impact Report will be prepared, however, a Mitigated Negative Declaration or other form of CEQA document (e.g., exemption) may be appropriate. This determination, however, must be made in consultation with CPUC CEQA Unit Staff during Pre-filing and prior to submittal of the Draft PEA.

Future Modifications and Improvements

Like the predecessor PEA checklists, this is a working document that will be modified over time based on experience and changes to the CEQA Statute and Guidelines. To meet the above stated objectives and maintain consistency with CEQA. We expect Applicants, their consultants, CPUC consultants, and the CPUC to engage in a regular and ongoing dialogue about specific improvements to the CEQA process overall, and these Guidelines in particular.

We look forward to working with Applicants during the Pre-filing Consultation process to ensure that the level of effort that goes into preparing PEAs can be effectively and efficiently transferred into the CEQA document prepared by CPUC Staff and consultants. Applicants are invited to debrief with our staff about the efficacy of these Guidelines.

Merideth Sterkel
/s/
Program Manager, Infrastructure Planning and Permitting
California Public Utilities Commission

Mary Jo Borak
/s/
Supervisor, Infrastructure Permitting and CEQA Unit
California Public Utilities Commission

Lonn Maier
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Supervisor, Infrastructure Permitting and CEQA Unit
California Public Utilities Commission

Pre-Filing Consultation Guidelines

The following Pre-filing Consultation Guidelines apply to all PEAs filed with applications to the CPUC and outline a process for Applicants to engage with CPUC CEQA Unit Staff about upcoming projects that will require environmental review pursuant to CEQA. The CPUC is typically the Lead Agency for large projects by investor-owned gas and electric utilities. The CPUC's CEQA Unit Staff are experienced with developing robust CEQA documents for long, linear energy projects. The PEA Checklist, starting in the next section, is based upon that experience.

Pre-filing Consultation Process

During Pre-filing Consultation, Applicants and CPUC Staff meet to discuss the upcoming application. Successful projects will commence Pre-filing Consultation no less than six months prior to application filing at the CPUC. When the application is formally filed at the CPUC, the Application and the PEA are submitted to the CPUC Docket Office.

1. Meetings with CPUC Staff

To initiate Pre-filing Consultation, Applicants will request and attend a meeting with CPUC CEQA Unit Staff at least six months prior to application filing.

a. Applicants can request a Pre-Filing Consultation meeting via email or letter. Initial contact via telephone may occur, but staff request written documentation of Pre-filing Consultation commencement.
b. For the initial meeting, Applicants will provide staff with a summary of the proposed project including maps and basic GIS data at least one week prior to the meeting.
c. Applicants will receive initial feedback on the scope of the proposed project and PEA. Staff will work with Applicants to establish a schedule for subsequent Pre-filing meetings and milestones.

2. Consultant Resources

CPUC CEQA Unit Staff will initiate the consultant contract immediately following the initial Pre-filing Consultation meeting. CPUC's consultant contract resources will be executed prior to Applicant filing of the Draft PEA. The consultant contract is critical to the Pre-filing Consultation process. Applicants are encouraged to request updates about the status of the contract. The CPUC may use its on-call consulting resources contract for these purposes. If CEQA Unit Staff determine that their on-call consulting resources are not appropriate due to the anticipated project scope, staff may initiate a request for proposals process to engage consulting resources, and the resulting contracting process will be completed and consultant contract in place prior to Draft PEA filing.

3. Draft PEA Provided Prior to PEA Filing

A complete Draft PEA will be filed at least three months prior to application filing. CPUC CEQA Unit Staff and the CPUC consultant team will review and provide comments on the Draft PEA to the Applicant early in the three-month period to allow time for Applicant revisions to the PEA.

4. Project Site Visits

One or more site visits will be scheduled with CPUC CEQA Unit Staff and their consultant at the time of Draft PEA filing (or prior). Appropriate federal, state, and local agencies will also be engaged at this time.

5. Consultation with Public Agencies

The Applicant and CPUC CEQA Unit Staff will jointly reach out and conduct consultation meetings with public agencies and other interested parties in the project area. CPUC CEQA Unit Staff may also choose to conduct separate consultation meetings if needed.

If a federal agency will be a co-lead pursuant to the National Environmental Policy Act and coordinating with the CPUC during the environmental review process, the Applicant and CPUC CEQA Unit Staff will ensure that the agency has the opportunity to comment on the Draft PEA and participate jointly with the CPUC throughout the application review process. Applicant and Commission CEQA Unit Staff coordination with the federal agency (if applicable) will likely need to occur more than six months in advance of application filing.

6. Alternatives Development

PEAs will be drafted with the assumption that an Environmental Impact Report (EIR) will be prepared. Applicants will include a reasonable range of alternatives in the PEA (even though a Mitigated Negative Declaration [MND] may ultimately be prepared), including sufficient information about each alternative. In some situations, CPUC CEQA Unit Staff and project Applicants may agree during Pre-filing Consultation that an MND is likely and a reasonable range of alternatives is not required for the PEA. This determination, however, must be made in consultation with CEQA Unit Staff during Pre-filing and is not final. The type of document to be prepared may change based on public scoping results and other findings during the environmental review process.

CEQA Unit Staff will provide feedback on the range of alternatives prior to Draft PEA filing (if possible) based on their review of the Draft PEA. It is critical that Applicants receive feedback from CEQA Unit Staff about the range of alternatives prior to filing the PEA. Applicants will ensure that each alternative is described and evaluated in the PEA with an equal level of detail as the proposed project unless otherwise instructed in writing by CEQA Unit Staff.

7. Format of PEA Submittal

Each PEA submittal will include the completed PEA Checklist tables. Each PEA submittal will be formatted and organized as shown in the Example PEA Table of Contents provided in the PEA Checklist unless otherwise directed by CPUC CEQA Unit Staff in writing prior to application filing. The example PEA Table of Contents is modeled after typical CPUC EIRs.

8. Transmission and Distribution System Information

A key component of CEQA projects analyzed during CPUC environmental reviews is the context of the project within the larger transmission and distribution system. Detailed descriptions of the regional transmission system, including GIS data, to which the proposed project would interconnect are required. The required level of detail about interconnecting systems is project specific and will be specified by CEQA Unit Staff in writing during Pre-filing Consultation. Detailed distribution system information may also be required.

9. Data and Technical Adequacy

Applicants will focus PEA development efforts on providing thorough, up-to-date data and technical reports required for CPUC CEQA Unit Staff to complete the environmental document and alternatives analysis.

The Applicant-drafted PEA Executive Summary, Introduction, Project Description, Description of Alternatives, and other chapters typically found in past CPUC EIRs and Initial Study/MNDs will be *thorough*—emulate the level of detail provided in typical CPUC EIRs. The setting sections provided for

PEA Chapter 5, Environmental Analysis, will also be thorough. Applicants will ensure that the PEA text, graphics, and file formats can be efficiently converted into CPUC's CEQA document with minimal revision, reformatting, and redevelopment by CPUC Staff and consultants.

The impact analyses and determinations provided for Chapter 5, Environmental Analysis, and Chapter 6, Comparison of Alternatives, need not be as thorough as those to be prepared by the CPUC for its CEQA document. These two sections are expected to be revised and redeveloped by CPUC Staff and consultants. Other sections of the CEQA document will only be revised and redeveloped by CPUC Staff and consultants if determined to be necessary after PEA filing.

10. Applicant Proposed Measures

The Pre-filing Consultation process can support the development Applicant Proposed Measures (APMs); measures that Applicants incorporate into the PEA project description to avoid or reduce what otherwise may be considered significant impacts. APMs that use phrases, such as, "as practicable," "as needed," or other conditional language will be superseded by Mitigation Measures if required to avoid or reduce a potentially significant impact. CPUC CEQA Unit Staff and their consultant team may review and provide comments on the Draft PEA APMs during Pre-filing Consultation.

Applicants will carefully consider each CPUC Draft Environmental Measure identified in Chapter 5 of this PEA Checklist. The measures may be applied to the proposed project if appropriate and may be subject to modification by the CPUC during its environmental review.[1]

11. PEA Checklist Deviations

CPUC CEQA Unit Staff understand that the PEA Checklist requires Applicants to develop a significant quantity of information. There are times when it is appropriate to deviate from the PEA Checklist. Deviations to the Pre-Filing Consultation Guidelines or the PEA Checklist contents may be approved by the CPUC's CEQA Unit Staff. Staff approval will be in writing and will occur prior to Applicant filing of the Draft PEA. Note that any deviations approved in writing by staff during the Pre-filing period may be reversed or modified after application and PEA filing and at any time throughout the environmental review period at the discretion of CPUC CEQA Unit Staff.

12. Submittal of Confidential Information

CPUC Staff are available during Pre-filing Consultation to discuss concerns that Applicants may have about confidentiality. However, the CEQA process requires public disclosure about projects, and such disclosure can often appear to conflict with Applicant requests for confidentiality. CPUC CEQA Unit Staff will rely on CPUC adopted confidentiality procedures to resolve confidentiality concerns. Applicants that expect aspects of a PEA filing to be confidential must follow CPUC confidentiality procedures. Applicants may mark information as confidential if allowed pursuant to General Order 66 or latest applicable Commission rule (e.g., see Public Records Act Proceeding Rulemaking (R.14-11-001).

13. Additional CEQA Impact Questions

Additional CEQA Impact Questions that are specific to the types of projects evaluated by the Commission's CEQA Unit are identified in the PEA Checklist to be considered in addition to the checklist items in CEQA Guidelines Appendix G.

The next section of this Guidelines document provides the PEA Checklist for all energy project applications that require CEQA compliance.

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[1] At this time, the CPUC environmental measures are in draft format, see PEA Checklist Attachment 4. They may be formally incorporated into Chapter 5 of future versions of the PEA Checklist.

Proponent's Environmental Assessment (PEA) Checklist

The PEA Checklist provides project Applicants (e.g., projects involving electric transmission lines, electric substations or switching stations, natural gas transmission pipelines, and underground natural gas storage facilities) with detailed guidance regarding the level of detail CPUC CEQA Unit Staff expect to deem PEAs complete. Applicants will prepare their PEAs using the same section headers and numbering as provided in the PEA Checklist. Applicants will also provide supporting data that is specific to each item within the PEA Checklist. As noted in the Pre-Filing Consultation Guidelines, the PEA Checklist is written with the assumption that an EIR will be prepared. PEA contents may not need to support the development of an EIR, but this determination can only be made in consultation with CPUC CEQA Unit Staff as described in the Pre-Filing Consultation Guidelines.

Formatting and Basic PEA Data Needs, Including GIS Data

1. Provide **editable and fully functional source files** in electronic format for all PDF files, hardcopies, maps, images, and diagrams. Files will be provided in their original file format as well as the output file format. All Excel and other spreadsheet files or modeling files will include all underlying formulas/modeling details. All modeling files must be fully functional.
2. Details about the types of **GIS data and maps** to be submitted are provided in Attachment 1. GIS data not specified in this checklist may also be requested depending on the Proposed Project and alternatives.
3. The Applicant is responsible for ensuring that all project features, including project components and temporary and permanent work areas, are included within all **survey boundaries** (e.g., biological and cultural resources).
4. Excel spreadsheets with **emissions calculations** will be provided that are complete with all project assumptions, values, and formulas used to prepare emissions calculations in the PEA. Accompanying PDF files with the same information will be provided as Appendix B to the PEA (see List of Appendices below).
5. Applicants will provide in an Excel spreadsheet a comprehensive **mailing list** that includes the names and addresses of all affected landowners and residents, including unit numbers for multi-unit properties for both the proposed project <u>and alternatives</u>.
   a. An affected resident or landowner is defined as one whose place of residence or property is:
      i. Crossed by or abuts any component of the proposed project or an alternative including any permanent or temporary disturbance area (either above or below ground) and any extra work area (e.g., staging or parking area); or
      ii. Located within approximately 1,000 feet[2] of the edge of any construction work area.
   b. Include in the following information for each resident in a spreadsheet, at minimum: parcel APN number, owner name and mailing address, and parcel physical address. If individual occupant names, facility names, or business names are available, also provide these names and addresses in the spreadsheet. A sample mailing list format is provided in Table 2.

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[2] Notice to all property owners within 300 feet of a Proposed Project is required at the time of application filing under GO 131-D. Commission notices of CEQA document preparation may be mailed to residents and property owners greater than 300 feet from a Proposed Project to ensure adequate notification (e.g., 1,000 feet) and the extent of notification will be determined on a project specific basis. Appropriate notice expectations will be discussed during Pre-filing (e.g., with respect to visual impact areas and other types of impacts specific to the Proposed Project and its study area).

Table 2. Sample Project Mailing List

Category	Company/ Agency	Name	Mailing Address	Phone Number	Email	APN	Source
State Agency	California Resources Agency	John Doe	1234 California Street City, CA 98765	(333) 456-7899	johndoe@email.com	123-456-789	County Assessor
Individual	n/a	Jane Doe	222 Main Street City, CA 97531	(909) 876-5432	janedoe@email.com	101-202-303	Public meeting on Month, Day 2019

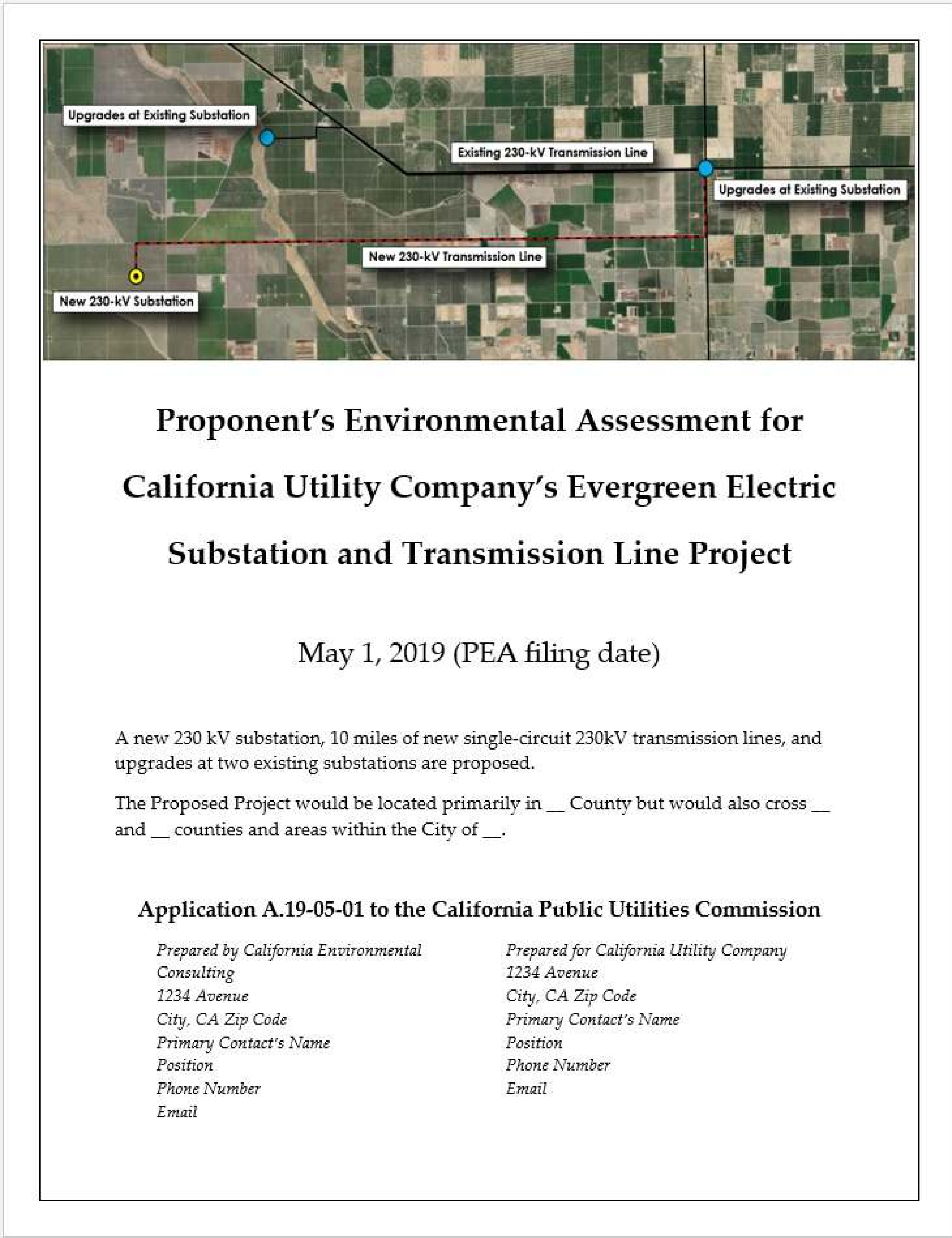
6. **PEA Organization:** This PEA Checklist is organized to include each of the chapters and sections found in typical CPUC EIRs. The following sections will serve as the outline for all Draft PEAs submitted during Pre-filing and all PEAs filed with the CPUC Docket Office. PEAs will include each chapter and section identified (in matching numerical order) unless otherwise directed by CPUC CEQA Unit Staff in writing prior to filing.

Cover

A single sheet with the following information:	Applicant Notes, Comments
Title "Proponent's Environmental Assessment" and filing date	
Proponent Name (the Applicant)	
Name of the proposed project[3]	
Technical subheading summarizing the type of project and its major components, in one sentence or about 40 words, for example: A new 1,120 MVA, 500/115kV substation, 10 miles of new singled-circuit 500kV transmission lines, 25 miles of new and replaced double-circuit 115kV power lines, and upgrades at three existing substations are proposed.	
Location of the proposed project (all counties and municipalities or map figure for the cover that shows the areas crossed)	
Proceeding for which the PEA was prepared and CPUC Docket number (if known) or simply leave a blank where the Docket number would go	
Primary Contact's name, address, telephone number, and email address for both the project Applicant(s) and entities that prepared the PEA	
See example PEA cover in Figure 1.	

[3] If approved by the California Independent System Operator (CAISO), the project name listed will match the name specified in the CAISO approval. If multiple names apply, list all versions.

Figure 1. Example PEA Cover



Proponent's Environmental Assessment for California Utility Company's Evergreen Electric Substation and Transmission Line Project

May 1, 2019 (PEA filing date)

A new 230 kV substation, 10 miles of new single-circuit 230kV transmission lines, and upgrades at two existing substations are proposed.

The Proposed Project would be located primarily in __ County but would also cross __ and __ counties and areas within the City of __.

Application A.19-05-01 to the California Public Utilities Commission

Prepared by California Environmental Consulting
1234 Avenue
City, CA Zip Code
Primary Contact's Name
Position
Phone Number
Email

Prepared for California Utility Company
1234 Avenue
City, CA Zip Code
Primary Contact's Name
Position
Phone Number
Email

Table of Contents

Sections

Order	The format of the PEA will be organized as follows:	Applicant Notes, Comments
--	Cover	
--	Table of Contents, List of Tables, List of Figures, List of Appendices	
1	Executive Summary	
2	Introduction	
3	Proposed Project Description	
4	Description of Alternatives	
5	Environmental Analysis	
5.1	Aesthetics	
5.2	Agriculture and Forestry	
5.3	Air Quality	
5.4	Biological Resources	
5.5	Cultural Resources	
5.6	Energy	
5.7	Geology, Soils, and Paleontological Resources	
5.8	Greenhouse Gas Emissions	
5.9	Hazards, Hazardous Materials, and Public Safety	
5.10	Hydrology and Water Quality	
5.11	Land Use and Planning	
5.12	Mineral Resources	
5.13	Noise	
5.14	Population and Housing	
5.15	Public Services	
5.16	Recreation	
5.17	Transportation	
5.18	Tribal Cultural Resources	
5.19	Utilities and Service Systems	
5.20	Wildfire	
5.21	Mandatory Findings of Significance	
6	Comparison of Alternatives	

7	Cumulative Impacts and Other CEQA Considerations	
8	List of Preparers	
9	References[4]	
--	Appendices	

Required PEA Appendices and Supporting Materials

Order	**Title**	**Applicant Notes, Comments**
Appendix A	Detailed Maps and Design Drawings	
Appendix B	Emissions Calculations	
Appendix C	Biological Resources Technical Reports (see Attachment 2)	
Appendix D	Cultural Resources Studies (see Attachment 3)	
Appendix E	Detailed Tribal Consultation Report[5]	
Appendix F	Environmental Data Resources Report, Phase I Environmental Site Assessment, or similar hazardous materials report	
Appendix G	Agency Consultation and Public Outreach Report and Records of Correspondence	
Appendix H	Construction Fire Prevention Plan[6]	

Potentially Required[7] Appendices and Supporting Materials

Order	**Title**	**Applicant Notes, Comments**
Appendix I	Noise Technical Studies	
Appendix J	Traffic Studies	
Appendix K	Geotechnical Investigations (may preliminary at time of PEA filing)	
Appendix L	Hazardous Substance Control and Emergency Response Plan / Hazardous Waste and Spill Prevention Plan	

4 References will be organized by section but contained in a single chapter called, “References.”

5 Include summary and timing of all correspondence to and from any Tribes and the State Historic Preservation Office/Native American Heritage Commission, including Sacred Lands File search results, and full description of any issues identified by Tribes in their interactions with the Applicant.

6 The Construction Fire Prevention Plan will be provided to federal, state, and local fire agencies for review and comment as applicable to where components of the proposed project would be located. CPUC will approve the final Construction Fire Prevention Plan. Record of the request for review and comment and any comments received from these agencies will be provided to CPUC CEQA Unit Staff.

7 Anticipated Appendix and study requirements should be discussed with CPUC CEQA Unit Staff during Pre-filing.

Appendix M	Erosion and Sedimentation Control Best Management Practice Plan / Draft Storm Water Pollution Prevention Plan (may be preliminary at time of PEA filing)	
Appendix N	FAA Notice and Criteria Tool Results	
Appendix O	Revegetation or Site Restoration Plan	
Appendix P	Health and Safety Plan	
Appendix Q	Existing Easements[8]	
Appendix R	Blasting Plan (may be preliminary at time of PEA filing)	
Appendix S	Traffic Control/Management Plan (may be preliminary at time of PEA filing)	
Appendix T	Worker Environmental Awareness Program (may preliminary at time of PEA filing)	
Appendix U	Helicopter Use and Safety Plan (may be preliminary at time of PEA filing)	
Appendix V	Electric and Magnetic Fields Management Plan (may be part of the Application rather than the PEA)	

[8] Easements should be provided military lands, conservation easements, or other lands where the real estate agreement specifies the range of activities that can be conducted

1 Executive Summary

This section will include, but is not limited to, the following:	PEA Section and Page Number[9]	Applicant Notes, Comments
1.1: Proposed Project Summary. Provide a summary of the proposed project and its underlying purpose and basic objectives.		
1.2: Land Ownership and Right-of-Way Requirements. Provide a summary of the existing and proposed land ownership and rights-of-way for the proposed project.		
1.3: Areas of Controversy. Identify areas of anticipated controversy and public concern regarding the project.		
1.4: Summary of Impacts a) Identify all impacts expected by the Applicant to be potentially significant. Identify and discuss Applicant Proposed Measures here and provide a reference to the full listing of Applicant Proposed Measures provided in the table described in Section 3.11 of this PEA Checklist. b) Identify any significant and unavoidable impacts that may occur.		
1.5: Summary of Alternatives. Summarize alternatives that were considered by the Applicant and the process and criteria that were used to select the proposed project.		
1.6: Pre-filing Consultation and Public Outreach Summary. Briefly summarize Pre-filing consultation and public outreach efforts that occurred and identify any significant outcomes that were incorporated into the proposed project.		
1.7: Conclusions. Provide a summary of the major PEA conclusions.		
1.8: Remaining Issues. Describe any major issues that must still be resolved.		

[9] The *PEA Section and Page Number* column and *Applicant Notes, Comments* column are intended to be filled out and provided with PEA submittals. The PEA Checklist is provided in Word to all Applicants to allow column resizing as appropriate to reduce PEA checklist length when completed for submittal. Landscape formatting may also be appropriate for completed PEA Checklist tables.

2 Introduction

2.1 Project Background

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
2.1.1: Purpose and Need a) Explain why the proposed project is needed. b) Describe localities the proposed project would serve and how the project would fit into the local and regional utility system. c) If the proposed project was identified by the California Independent System Operator (CAISO), thoroughly describe the CAISO's consideration of the proposed project and provide the following information: i. Include references to all CAISO Transmission Planning Processes that considered the proposed project. ii. Explain if the proposed project is considered an economic, reliability, or policy-driven project or a combination thereof. iii. Identify whether and how the Participating Transmission Owner recommended the project in response to a CAISO identified need, if applicable. iv. Identify if the CAISO approved the original scope of the project or an alternative and the rationale for their approval either for the original scope or an alternative. v. Identify how and whether the proposed project would exceed, combine, or modify in any way the CAISO identified project need. vi. If the Applicant was selected as part of a competitive bid process, identify the factors that contributed to the selection and CAISO's requirements for in-service date. d) If the project was not considered by the CAISO, explain why.		
(Natural Gas Storage Only) e) Provide storage capacity or storage capacity increase in billion cubic feet. If the project does not increase capacity, make this statement. f) Describe how existing storage facilities will work in conjunction with the proposed project. Describe the purchasing process (injection, etc.) and transportation arrangements this facility will have with its customers.		
2.1.2: Project Objectives a) Identify and describe the basic project objectives.[10] The objectives will include reasons for constructing the project based on its		

[10] Tangential project goals should not be included as basic project objectives, such as, minimizing environmental impacts, using existing ROWs and disturbed land to the maximum extent feasible, ensuring safety during construction and operation, building on property already controlled by the Applicant/existing site control. Goals of this type do not describe the underlying purpose or basic objectives but, rather, are good general practices for all projects.

purpose and need (i.e., address a specific reliability issue). The description of the project objectives will be sufficiently detailed to permit CPUC to independently evaluate the project need and benefits to accurately consider them in light of the potential environmental impacts. The basic project objectives will be used to guide the alternatives screening process, when applicable. b) Explain how implementing the project will achieve the basic project objectives and underlying purpose and need. c) Discuss the reasons why attainment of each basic objective is necessary or desirable.		
2.1.3: Project Applicant(s). Identify the project Applicant(s) and ownership of each component of the proposed project. Describe each Applicant's utility services and their local and regional service territories.		

2.2 Pre-filing Consultation and Public Outreach[11]

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
2.2.1: Pre-filing Consultation and Public Outreach a) Describe all Pre-filing consultation and public outreach that occurred, such as, but not limited to: i. CAISO ii. Public agencies with jurisdiction over project areas or resources that may occur in the project area iii. Native American tribes affiliated with the project area iv. Private landowners and homeowner associations v. Developers for large housing or commercial projects near the project area vi. Other utility owners and operators vii. Federal, state, and local fire management agencies b) Provide meeting dates, attendees, and discussion summaries, including any preliminary concerns and how they were addressed and any project alternatives that were suggested. c) Clearly identify any significant outcomes of consultation that were incorporated into the proposed project. d) Clearly identify any developments that could coincide or conflict with project activities (i.e., developments within or adjacent to a proposed ROW).		
2.2.2: Records of Consultation and Public Outreach. Provide contact information, notification materials, meeting dates and materials, meeting notes, and records of communication organized by entity as an Appendix to the PEA (Appendix G).		

[11] CPUC CEQA Unit Staff request that consultation and public outreach that occurs during the Pre-filing period and throughout environmental review include the assigned CPUC Staff person and CPUC consultant.

2.3 Environmental Review Process

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
2.3.1: Environmental Review Process. Provide a summary of the anticipated environmental review process and schedule.		
2.3.2: CEQA Review a) Explain why CPUC is the appropriate CEQA Lead agency. b) Identify other state agencies and any federal agencies that may have discretionary permitting authority over any aspect of the proposed project. c) Identify all potential involvement by federal, state, and local agencies not expected to have discretionary permitting authority (i.e., ministerial actions). d) Summarize the results of any preliminary outreach with these agencies as well as future plans for outreach.		
2.3.3: NEPA Review (if applicable). If review according to the National Environmental Policy Act (NEPA) is expected, explain the portions of the project that will require the NEPA review process. Discuss which agency is anticipated to be the NEPA Lead agency if discretionary approval by more than one federal agency is required.		
2.3.4: Pre-filing CEQA and NEPA Coordination. Describe the results of Pre-filing coordination with CEQA and NEPA review agencies (refer to CPUC's Pre-Filing Consultation Guidelines). Identify major outcomes of the Pre-filing coordination process and how the information was incorporated into the PEA, including suggestions on the type of environmental documents and joint or separate processes based on discussions with agency staff.		

2.4 Document Organization

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
2.4: PEA Organization. Summarize the contents of the PEA and provide an annotated list of its sections.		

3 Proposed Project Description[12]

3.1 Project Overview

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
3.1: Project Overview a) Provide a concise summary of the proposed project and components in a few paragraphs. b) Described the geographical location of the proposed project (i.e., county, city, etc.). c) Provide an overview map of the proposed project location.		

3.2 Existing and Proposed System

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
3.2.1: Existing System a) Identify and describe the existing utility system that would be modified by the proposed project, including connected facilities to provide context. Include detailed information about substations, transmission lines, distribution lines, compressor stations, metering stations, valve stations, nearby renewable generation and energy storage facilities, telecommunications facilities, control systems, SCADA systems, etc. b) Provide information on users and the area served by the existing system features. c) Explain how the proposed project would fit into the existing local and regional systems. d) Provide a schematic diagram of the existing system features. e) Provide detailed maps and associated GIS data for existing facilities that would be modified by the proposed project.		
3.2.2: Proposed Project System a) Describe the whole of the proposed project by component, including all new facilities and any modifications, upgrades, or expansions to existing facilities and any interrelated activities that are part of the whole of the action. b) Clearly identify system features that would be added, modified, removed, disconnected and left in place, etc. c) Identify the expected capacities of the proposed facilities, highlighting any changes from the existing system. If the project would not change existing capacities, make this statement. For electrical projects, provide the anticipated capacity increase in amps or megawatts or in the typical units for the types of facilities proposed. For gas projects, provide the total volume of gas to be		

12 Applicant review of the Administrative Draft Project Description or sections of the Administrative Draft Project Description prepared for the CEQA document may be requested by CPUC CEQA Unit Staff to ensure technical accuracy.

delivered by the proposed facilities, anticipated system capacity increase (typically in million cubic feet per day), expected customers, delivery points and corresponding volumes, and the anticipated maximum allowable operating pressure(s). d) Describe the initial buildout and eventual full buildout of the proposed project facilities. For example, if an electrical substation or gas compressor station would be installed to accommodate additional demand in the future, then include the designs for both the initial construction based on current demand and the design for all infrastructure that could ultimately be installed within the planned footprint of an electric substation or compressor station. e) Explain whether the electric line or gas pipeline will create a second system tie or loop for reliability. f) Provide information on users and the area served by the proposed system features, highlighting any differences from the existing system. g) Provide a schematic diagram of the proposed system features. h) Provide detailed maps and associated GIS data for proposed facilities that would be installed, modified, or relocated by the proposed project.		
3.2.3: System Reliability. Explain whether the electric line or gas pipeline will create a second system tie or loop for reliability. Clearly explain and show how the proposed project relates to and supports the existing utility systems.		
3.2.4: Planning Area. Describe the system planning area served or to be served by the project. Clearly define the Applicant's term for the planning area (e.g., Electrical Needs Area or Distribution Planning Area).		

3.3 Project Components

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
Required for all Project Types		
3.3.1: Preliminary Design and Engineering a) Provide preliminary design and engineering information for all above-ground and below-ground facilities for the proposed project. The approximately locations, maximum dimensions of facilities, and limits of areas that would be needed to construction and operate the facilities should be clearly defined.[13] b) Provide preliminary design drawings for project features and explain the level of completeness (i.e., percentage). c) Provide detailed project maps (approximately 1:3,000 scale) and associated GIS data of all facility locations and boundaries with attributes and spatial geometry that corresponds to information in the Project Description.		

[13] Refer to Attachment 1 for mapping and GIS data requirements for the project layout and design.

3.3.2: Segments, Components, and Phases a) Define all project segments, components, and phases for the proposed project. b) Provide the length/area of each segment or component, and the timing of each development phase. c) Provide an overview map showing each segment and provide associated GIS data (may be combined with other mapping efforts).		
3.3.3: Existing Facilities a) Identify the types of existing facilities that would be removed or modified by the proposed project (i.e., conductor/cable, poles/towers, substations, switching stations, gas storage facilities, gas pipelines, service buildings, communication systems, etc.). b) Describe the existing facilities by project segment and/or component, and provide information regarding existing dimensions, areas/footprints, quantities, locations, spans, etc. c) Distinguish between above-ground and below-ground facilities and provide both depth and height ranges for each type of facility. For poles/towers, provide the installation method (i.e., foundation type or direct bury), and maximum above-ground heights and below-ground depths. d) Explain what would happen to the existing facilities. Would they be replaced, completely removed, modified, or abandoned? Explain why. e) Identify the names, types, materials, and capacity/volumes ranges (i.e., minimum and maximum) of existing facilities that would be installed or modified by the proposed project. f) Provide diagrams with dimensions representing existing facilities to provide context on how the proposed facilities would be different. g) Briefly describe the surface colors, textures, light reflectivity, and any lighting of existing facilities.		
3.3.4: Proposed Facilities a) Identify the types of proposed facilities to be installed or modified by the proposed project (e.g., conductor/cable, poles/towers, substations, switching stations, gas storage facilities, gas pipelines, service buildings, communication systems). b) Describe the proposed facilities by project segment and/or component, and provide information regarding maximum dimensions, areas/footprints, quantities, locations, spans, etc. c) Distinguish between above-ground and below-ground facilities and provide both depth and height ranges for each type of facility. For poles/towers, provide the installation method (i.e., foundation type or direct bury), and maximum above-ground heights and below-ground depths.		

d) Identify where facilities would be different (e.g., where unique or larger poles would be located, large guy supports or snub poles). e) Provide details about civil engineering requirements (i.e., permanent roads, foundations, pads, drainage systems, detention basins, spill containment, etc.). f) Distinguish between permanent facilities and any temporary facilities (i.e., poles, shoo-fly lines, mobile substations, mobile compressors, transformers, capacitors, switch racks, compressors, valves, driveways, and lighting). g) Identify the names, types, materials, and capacity/volumes ranges (i.e., minimum and maximum) of proposed facilities that would be installed or modified by the proposed project. h) Provide diagrams with dimensions representing existing facilities. i) Briefly describe the surface colors, textures, light reflectivity, and any lighting of proposed facilities.		
3.3.5: Other Potentially Required Facilities a) Identify and describe in detail any other actions or facilities that may be required to complete the project. For example, consider the following questions: i. Could the project require the relocation (temporary or permanent), modification, or replacement of unconnected utilities or other types of infrastructure by the Applicant or any other entity? ii. Could the project require aviation lighting and/or marking? iii. Could the project require additional civil engineering requirements to address site conditions or slope stabilization issues, such as pads and retaining walls, etc.? b) Provide the location of each facility and a description of the facility.		
3.3.6: Future Expansions and Equipment Lifespans a) Provide detailed information about the current and reasonably foreseeable plans for expansion and future phases of development. b) Provide the expected usable life of all facilities. c) Describe all reasonably foreseeable consequences of the proposed project (e.g., future ability to upgrade gas compressor station to match added pipeline capacity).		
Required for Certain Project Types		
3.3.7: Below-ground Conductor/Cable Installations (as Applicable) a) Describe the type of line to be installed (e.g., single circuit cross-linked polyethylene-insulated solid-dielectric, copper-conductor cables). b) Describe the type of casing the cable would be installed in (e.g., concrete-encased duct bank system) and provide the dimensions of the casing.		

c) Describe the types of infrastructure would likely be installed within the duct bank (e.g., transmission, fiber optics, etc.).		
3.3.8: Electric Substations and Switching Stations (as Applicable) a) Provide the number of transformer banks that will be added at initial and full buildout of the substation. Identify the transformer voltage and number of each transformer type. b) Identify any gas insulated switchgear that will be installed within the substation. c) Describe any operation and maintenance facilities, telecommunications equipment, and SCADA equipment that would be installed within the substation.		
3.3.9: Gas Pipelines (as Applicable). For each segment: a) Identify pipe diameter, number and length of exposed sections, classes and types of pipe to be installed, pressure of pipe, and cathodic protection for each linear segment. b) Describe new and existing inspection facilities (e.g., pig launcher sites). c) Describe system cross ties and laterals/taps. d) Identify the spacing between each valve station. e) Describe the compressor station, if needed, for any new or existing pipeline. f) Describe all pipelines and interconnections with existing and proposed facilities: i. Number of interconnections and locations and sizes; ii. All below-ground and above-ground installations; and iii. All remote facility locations for metering, telemetry, control.		
3.3.10: Gas Storage Facilities – Background and Resource Information (as Applicable) a) Provide detailed background information on the natural gas formation contributing to the existing or proposed natural gas facility, including the following: i. Description of overlying stratigraphy, especially caps ii. Description of production, injection, and intervening strata iii. Types of rock iv. Description of types of rocks in formation, including permeability or fractures v. Thickness of strata b) Provide a graphic and/or table showing formation thicknesses. c) Identify and describe any potential gas migration pathways, such as faults, permeable contacts, abandoned wells, underground water or other pipelines. d) Provide a summary and detailed cross-section diagrams of the geologic formations and structures of the oil/gas field or area. e) Provide the first well drilling and production history, abandonment procedures, inspections, etc. f) Describe production zones, including depth, types of formations, and characteristics of field/area.		

g) Describe the existing and proposed storage capacity and limiting factors, such as injection or withdrawal capacities. h) Describe existing simulation studies that were used to predict the reservoir pressure response under gas injection and withdrawal operations, and simulation studies for how the system would change as proposed. Provide the studies as a PEA Appendix. i) Provide the history of the oil/gas field or area.		
3.3.11: Gas Storage Facilities – Well-Head Sites (as Applicable). Describe the location, depth, size and completion information for all existing, abandoned, proposed production and injection, monitoring, and test wells.		
3.3.12: Gas Storage Facilities – Production and Injection (as Applicable) a) Provide the proposed storage capacity of production and injection wells. b) Provide production and injection pressures, depths, and rates. c) Provide production and injection cycles by day, week, and year. d) Describe existing and proposed withdrawal/production wells (i.e., size, depth, formations, etc.). e) Describe existing and proposed cushion gas requirements. f) Describe any cushion gas injection—formation the well is completed in (cushion gas formation), and injection information.		
3.3.13: Gas Storage Facilities – Electrical Energy (as Applicable). Describe all existing and proposed electric lines, telecommunications facilities, and other utilities/facilities (e.g., administrative offices, service buildings, and non-hazardous storage), and chemical storage associated with the proposed project.		
3.3.14: Telecommunication Lines (as Applicable) a) Identify the type of cable that is proposed and length in linear miles by segment. b) Identify any antenna and node facilities that are part of the project. c) For below-ground telecommunication lines, provide the depth of cable and type of conduit. d) For above-ground telecommunication lines, provide: i. Types of poles that will be installed (if new poles are required) ii. Where existing poles will be used iii. Any additional infrastructure (e.g., guy wires) or pole changes required to support the additional cable on existing poles		

3.4 Land Ownership, Rights-of-Way, and Easements

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
3.4.1: Land Ownership. Describe existing land ownership where each project component would be located. State whether the proposed		

project would be located on property(ies) owned by the Applicant or if additional property would be required.		
3.4.2: Existing Rights-of-Way or Easements a) Identify and describe existing rights-of-way (ROWs) or easements where project components would be located. Provide the approximately lengths and widths in each project area. b) Clearly state if project facilities would be replaced, modified, or relocated within existing ROWs or easements.		
3.4.3: New or Modified Rights-of-Way or Easements a) Describe new permanent or modified ROWs or easements that would be required. Provide the approximately lengths and widths in each project area. b) Describe how any new permanent or modified ROWs or easements would be acquired. c) Provide site plans identifying all properties/parcels and partial properties/parcels that may require acquisition and the anticipated ROWs or easements. Provide associated GIS data. d) Describe any development restrictions within new ROWs or easements, e.g., building clearances and height restrictions, etc. e) Describe any relocation or demolition of commercial or residential property/structures that may be necessary.		
3.4.4: Temporary Rights-of-Way or Easements f) Describe temporary ROWs or easements that would be required to access project areas, including ROWs or easements for temporary construction areas (i.e., staging areas or landing zones). g) Explain where temporary construction areas would be located with existing ROWs or easements for the project or otherwise available to the Applicant without a temporary ROW or easement. h) Describe how any temporary ROWs or easements would be acquired.		

3.5 Construction

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
3.5.1 Construction Access (All Projects)		
3.5.1.1: Existing Access Roads a) Provide the lengths, widths, ownership details (both public and private roads), and surface characteristics (i.e., paved, graveled, bare soil) of existing access roads that would be used during construction. Provide the area of existing roads that would be used (see example in Table 3 below). b) Describe any road modifications or stabilization that would be required prior to construction, including on the adjacent road		

shoulders or slopes. Identify any roads that would be expanded and provide the proposed width increases. c) Describe any procedures to address incidental road damage cause by project activities following construction. d) Provide detailed maps and associated GIS data for all existing access roads.		

Table 3. Access Roads

Type of Road	Description	Area Proposed Project
Existing Dirt Road	Typically double track. May have been graded previously. No other preparation required, although a few sections may need to be re-graded and crushed rock applied in very limited areas for traction.	_____ acres
New Permanent	Would be xx feet wide, bladed. No other preparation required although crushed rock may need to be applied in very limited areas for traction.	_____ acres
Overland Access	No preparation required. Typically grassy areas that are relatively flat. No restoration would be necessary.	_____ acres

3.5.1.2: New Access Roads a) Identify any new access roads that would be developed for project construction purposes, such as where any blading, grading, or gravel placement could occur to provide equipment access outside of a designated workspace.[14] b) Provide lengths, widths, and development methods for new access roads. c) Identify any temporary or permanent gates that would be installed. d) Clearly identify any roads that would be temporary and fully restored following construction. Otherwise it will be assumed the new access road is a permanent feature. e) Provide detailed maps and associated GIS data for all new access roads.		
3.5.1.3: Overland Access Routes a) Identify any overland access routes that would be used during construction, such as where vehicles and equipment would travel over existing vegetation and where blading, grading, or gravel placement would occur. b) Provide lengths and widths for new access roads. c) Provide detailed maps and associated GIS data for all overland access routes.		
3.5.1.4: Watercourse Crossings a) Identify all temporary watercourse crossings that would be required during construction. Provide specific methods and procedures for temporary watercourse crossings.		

[14] Temporary roads that would not require these activities should be considered an overland route.

b) Describe any bridges or culverts that replacement or installation of would be required for construction access. c) Provide details about the location, design and construction methods.		
3.5.1.5: Helicopter Access. If helicopters would be used during construction: a) Describe the types and quantities of helicopters that would be used during construction (e.g., light, medium, heavy, or sky crane), and a description of the activities that each helicopter would be used for. b) Identify areas for helicopter takeoff and landing. c) Describe helicopter refueling procedures and locations. d) Describe flight paths, payloads, and expected hours and durations of helicopter operation. e) Describe any safety procedures or requirements unique to helicopter operations, such as but not limited to obtaining a Congested Area Plan from the Federal Aviation Administration (FAA).		
3.5.2 Staging Areas (All Projects)		
3.5.2.1: Staging Area Locations a) Identify the locations of all staging area(s). Provide a map and GIS data for each.[15] b) Provide the size (in acres) for each staging area and the total staging area requirements for the project.		
3.5.2.2: Staging Area Preparation a) Describe any site preparation required, if known, or generally describe what might be required (i.e., vegetation removal, new access road, installation of rock base, etc.). b) Describe what the staging area would be used for (i.e., material and equipment storage, field office, reporting location for workers, parking area for vehicles and equipment, etc.). c) Describe how the staging area would be secured. Would a fence be installed? If so, describe the type and extent of the fencing. d) Describe how power to the site would be provided if required (i.e., tap into existing distribution, use of diesel generators, etc.). e) Describe any temporary lightning facilities for the site. f) Describe any grading activities and/or slope stabilization issues.		

[15] While not all potential local site staging areas will be known prior to selection of a contractor, it is expected that approximate area and likely locations of staging areas be disclosed. The identification of extra or optional staging areas should be considered to reduce the risk of changes after project approval that could necessitate further CEQA review.

3.5.3 Construction Work Areas (All Projects)		
3.5.3.1: Construction Work Areas a) Describe known work areas that may be required for specific construction activities (e.g., pole assembly, hillside construction)[16] b) Describe the types of activities that would be performed at each work area. Work areas may include but are not necessarily limited to: i. Helicopter landing zones and touchdown areas ii. Vehicle and equipment parking, passing, or turnaround areas iii. Railroad, bridge, or watercourse crossings iv. Temporary work pads for facility installation, modification, or removal v. Excavations and associated equipment work areas vi. Temporary guard structures vii. Pull-and-tension/stringing sites viii. Jack and bore pits, drilling areas and pull-back areas for horizontal directional drills ix. Retaining walls		
3.5.3.2 Work Area Disturbance a) Provide the dimensions of each work area including the maximum area that would be disturbed during construction (e.g., 100 feet by 200 feet) (see example in Table 4 below). b) Provide a table with temporary and permanent disturbance at each work area (in square feet or acres), and the total area of temporary and permanent disturbance for the entire project (in acres).		
3.5.3.3: Temporary Power. Identify how power would be provided at work area (i.e., tap into existing distribution, use of diesel generators, etc.). Provide the disturbance area for any temporary power lines.		
3.5.4 Site Preparation (All Projects)		
3.5.4.1: Surveying and Staking. Describe initial surveying and staking procedures for site preparation and access.		
3.5.4.2: Utilities a) Describe the process for identifying any underground utilities prior to construction (i.e., underground service alerts, etc.). b) Describe the process for relocating any existing overhead or underground utilities that aren't directly connected to the project system. c) Describe the process for installing any temporary power or other utility lines for construction.		

[16] Understanding that each specific work area may not be determined until the final work plan is submitted by the construction contractor, estimate total area likely to be disturbed.

Table 4. Work Areas

	Proposed Project (approximate metrics)
Pole Diameter: • Wood • Self-Supporting Steel	 _____ inches _____inches
Lattice Tower Base Dimension: • Self-Supporting Lattice Structure	_____feet
Auger Hole Depth: • Wood • Self-Supporting Steel	 _____ to _____ feet _____ to _____ feet
Permanent Footprint per Pole/Tower: • Wood • Self-Supporting Steel • Self-Supporting Steel Tower	 _____ sq. feet _____ sq. feet _____ sq. feet
Number of Poles/Towers: • Wood • Self-Supporting Steel • Self-Supporting Steel Tower	 _____ _____ _____
Average Work Area around Pole/Towers (e.g., for old pole removal and new pole installation): • Tangent structure work areas • Dead End / Angle structure work areas	 _____ sq. feet _____ sq. feet
Total Permanent Footprint for Poles/Towers	Approximately _____ acres

3.5.4.3: Vegetation Clearing a) Describe what types of vegetation clearing may be required (e.g., tree removal, brush removal, flammable fuels removal) and why (e.g., to provide access, etc.). b) Provide calculations of temporary and permanent disturbance of each vegetation community and include all areas of vegetation removal in the GIS database. Distinguish between disturbance that would occur in previously developed areas (i.e., paved, graveled, or otherwise urbanized), and naturally vegetated areas. c) Describe how each type of vegetation removal would be accomplished. d) Describe the types of equipment that would be used for vegetation removal.		
3.5.4.4: Tree Trimming Removal a) For electrical projects, distinguish between tree trimming as required under CPUC General Order 95-D and tree removal. b) Identify the types, locations, approximate numbers, and sizes of trees that may need to be removed or trimmed substantially. c) Identify potentially protected trees that may be removed or substantially trimmed, such as but not limited to riparian trees, oaks trees, Joshua trees, or palm trees.		

d) Describe the types of equipment that would typically be used for tree removal.		
3.5.4.5: Work Area Stabilization. Describe the processes to stabilize temporary work areas and access roads including the materials that would be used (e.g., gravel).		
3.5.4.6: Grading a) Describe any earth moving or substantial grading activities (i.e., grading below a 6-inch depth) that would be required and identify locations where it would occur. b) Provide estimated volumes of grading (in cubic yards) including total cut, total fill, cut that would be reused, cut that would be hauled away, and clean fill that would be hauled to the site.		
3.5.5 Transmission Line Construction (Above Ground)		
3.5.5.1: Poles/Towers a) Describe the process and equipment for removing poles, towers, and associated foundations for the proposed project (where applicable). Describe how they would be disconnected, demolished, and removed from the site. Describe backfilling procedures and where the material would be obtained. b) Describe the process and equipment for installing or otherwise modifying poles and towers for the proposed project. Describe how they would be put into place and connected to the system. Identify any special construction methods (e.g., helicopter installation) at specific locations or specific types of poles/towers. c) Describe how foundations, if any, would be installed. Provide a description of the construction method(s), approximate average depth and diameter of excavation, approximate volume of soil to be excavated, approximate volume of concrete or other backfill required, etc. for foundations. Describe what would be done with soil removed from a hole/foundation site. d) Describe how the poles/towers and associated hardware would be delivered to the site and assembled. e) Describe any pole topping procedures that would occur, identify specific locations and reasons, and describe how each facility would be modified. Describe any special methods that would be required to top poles that may be difficult to access.		
3.5.5.2: Aboveground and Underground Conductor/Cable a) Provide a process-based description of how new conductor/cable would be installed and how old conductor/cable would be removed, if applicable. b) Identify where conductor/cable stringing/installation activities would occur. c) Provide a diagram of the general sequencing and equipment that would be used. d) Describe the conductor/cable splicing process.		

e) Provide the general or average distance between pull-and-tension sites. Describe the approximate dimensions and where pull-and-tension sites would generally be required (as indicated by the designated work areas), such as the approximate distance to pole/tower height ratio, at set distances, or at significant direction changes. Describe the equipment that would be required at these sites. f) For underground conductor/cable installations, describe all specialized construction methods that would be used for installing underground conductor or cable. If vaults are required, provide their dimensions and location/spacing along the alignment. Provide a detailed description for how the vaults would be delivered to the site and installed. g) Describe any safety precautions or areas where special methodology would be required (e.g., crossing roadways, stream crossing).		
3.5.5.3: Telecommunications. Identify the procedures for installation of proposed telecommunication cables and associated infrastructure.		
3.5.5.4: Guard Structures. Identify the types of guard structures that would be used at crossings of utility lines, roads, railroads, highways, etc. Describe the different types of guard structures or methods that may be used (i.e., buried poles and netting, poles secured to a weighted object, bucket trucks, etc.). Describe any pole installation and removal procedures associated with guard structures. Describe guard structure installation and removal process and duration that guard structures would remain in place.		
3.5.5.5: Blasting a) Describe any blasting that may be required to construct the project. b) If blasting may be required, provide a Blasting Plan that identifies the blasting locations; types and amounts of blasting agent to be used at each location; estimated impact radii; and, noise estimates. The Blasting Plan should be provided as an Appendix to the PEA. c) Provide a map identifying the locations where blasting may be required with estimated impact radii. Provide associated GIS data.		
3.5.6 Transmission Line Construction (Below Ground)		
3.5.6.1: Trenching a) Describe the approximate dimensions of the trench (e.g., depth, width). b) Provide the total approximate volume of material to be removed from the trench, the amount to be used as backfill, and any amount to subsequently be removed/disposed of offsite in cubic yards. c) Describe the methods used for making the trench (e.g., saw cutter to cut the pavement, backhoe to remove, etc.). d) Provide off-site disposal location, if known, or describe possible option(s). e) Describe if dewatering would be anticipated and if so, how the trench would be dewatered, the anticipated flows of the water,		

whether there would be treatment, and how the water would be disposed of. f) Describe the process for testing excavated soil or groundwater for the presence of pre-existing environmental contaminants that could be exposed from trenching operations. g) If a pre-existing hazardous waste were encountered, describe the process of removal and disposal. h) Describe the state of the ground surface after backfilling the trench. i) Describe standard Best Management Practices to be implemented.		
3.5.6.2: Trenchless Techniques (Microtunnel, Jack and Bore, Horizontal Directional Drilling) a) Identify any locations/features for which the Applicant expects to use a trenchless (i.e., microtunneling, jack and bore, horizontal directional drilling) crossing method and which method is planned for each crossing. b) Describe the methodology of the trenchless technique. c) Provide the approximate location and dimensions of the sending and receiving pits. d) Describe the methodology of excavating and shoring the pits. e) Provide the total volume of material to be removed from the pits, the amount to be used as backfill, and the amount subsequently to be removed/disposed of offsite in cubic yards. f) Describe process for safe handling of drilling mud and bore lubricants. g) Describe the process for detecting and avoiding "fracturing-out" during horizontal directional drilling operations. h) Describe the process for avoiding contact between drilling mud/lubricants and stream beds. i) If engineered fill would be used as backfill, indicate the type of engineered backfill and the amount that would be typically used (e.g., the top 2 feet would be filled with thermal-select backfill). j) Describe if dewatering is anticipated and, if so, how the pits would be dewatered, the anticipated flows of the water, whether there would there be treatment, and how the water would be disposed of. k) Describe the process for testing excavated soil or groundwater for the presence of pre-existing environmental contaminants. Describe the process of disposing of any pre-existing hazardous waste that is encountered during excavation. l) Describe any standard BMPs that would be implemented for trenchless construction.		
3.5.7 Substation, Switching Stations, Gas Compressor Stations		
3.5.7.1: Installation or Facility Modification. Describe the process and equipment for removing, installing, or modifying any substations, switching stations, or compressor stations including: a) Transformers/ electric components b) Gas components c) Control and operation buildings d) Driveways		

e) Fences f) Gates g) Communication systems (SCADA) h) Grounding systems		
3.5.7.2: Civil Works. Describe the process and equipment required to construct any slope stabilization, drainage, retention basins, and spill containment required for the facility.		
3.5.8 Gas Pipelines		
3.5.8.1: Gas Pipeline Construction. Describe the process for proposed pipeline construction including site development, trenching and trenchless techniques, pipe installation, and backfilling.		
3.5.8.2: Water Crossings. Describe water feature crossings that will occur during trenching, the method of trenching through stream crossings, and the process for avoiding impacts to the water features required for pipeline construction. Identify all locations where the pipeline will cross water features. Cite to any associated geotechnical or hydrological investigations completed and provide a full copy of each report as an Appendix to the PEA.[17]		
3.5.8.3: Gas Pipeline Other Requirements a) Describe hydrostatic testing process including pressures, timing, source of flushing water, discharge of water. b) Describe energy dissipation basin, and the size and length of segments to be tested. c) Describe pig launching locations and any inline inspection techniques used during or immediately post construction.		
3.5.9 Gas Storage Facilities		
3.5.9.1: Gas Storage Construction a) Describe the process for constructing the gas storage facility including constructing well pads and drilling wells. b) Describe the specific construction equipment that would be used, such as the type of drill rig (i.e., size, diesel, electric, etc.), depth of drilling, well-drilling schedule and equipment.		
3.5.9.2: Drilling Muds and Fluids. Describe the use of any drilling muds, fluids, and other drilling materials. Provided estimated types and quantities.		
3.5.10 Public Safety and Traffic Control (All Projects)		
3.5.10.1: Public Safety a) Describe specific public safety considerations during construction and best management practices to appropriately manage public safety. Clearly state when and where they each safety measure would be applied.		

[17] If a geotechnical study is not available at the time of PEA filing, provide the best information available.

b) Identify procedures for managing work sites in urban areas, covering open excavations securely, installing barriers, installing guard structures, etc. c) Identify specific project areas where public access may be restricted for safety purposes and provide the approximate durations and timing of restricted access at each location.		
3.5.10.2: Traffic Control a) Describe traffic control procedures that would be implemented during construction. b) Identify the locations, process, and timing for closing any sidewalks, lanes, roads, trails, paths, or driveways to manage public access. c) Identify temporary detour routes and locations. d) Provide a preliminary Traffic Control Plan(s) for the project.		
3.5.10.3: Security. Describe any security measures, such as fencing, lighting, alarms, etc. that may be required. State if security personnel will be stationed at project areas and anticipated duration of security.		
3.5.10.4: Livestock. Describe any livestock fencing or guards that may be necessary to prevent livestock from entering project areas. State if the fencing would be electrified and if so, how it would be powered.		
3.5.11 Dust, Erosion, and Runoff Controls (All Projects)		
3.5.11.1: Dust. Describe specific best management practices that would be implemented to manage fugitive dust.		
3.5.11.2: Erosion. Describe specific best management practices that would be implemented to manage erosion.		
3.5.11.3: Runoff. Describe specific best management practices that would be implemented to manage stormwater runoff and sediment.		
3.5.12 Water Use and Dewatering (All Projects)		
3.5.12.1: Water Use. Describe the estimated volumes of water that would be used by construction activity (e.g., dust control, compaction, etc.). State if recycled or reclaimed water would be used and provide estimated volumes. Identify the anticipated sources where the water would be acquired or purchased. Identify if the source of water is groundwater and the quantity of groundwater that could be used.		
3.5.12.2: Dewatering a) Describe dewatering procedures during construction, including pumping, storing, testing, permitted discharging, and disposal requirements that would be followed. b) Describe the types of equipment and workspace considerations to be used to dewater, store, transport, or discharge extracted water.		
3.5.13 Hazardous Materials and Management (All Projects)		
3.5.13.1: Hazardous Materials a) Describe the types, uses, and volumes of all hazardous materials that would be used during construction. b) State if herbicides or pesticides may be used during construction.		

c) If a pre-existing hazardous waste were encountered, describe the process of removal and disposal.		
3.5.13.2: Hazardous Materials Management a) Identify specific best management practices that would be followed for transporting, storing, and handling hazardous materials. b) Identify specific best management practices that would be followed in the event of an incidental leak or spill of hazardous materials. c) Provide a Hazardous Substance Control and Emergency Response Plan / Hazardous Waste and Spill Prevention Plan as an Appendix to the PEA, if appropriate.		
3.5.14 Waste Generation and Management (All Projects)		
3.5.14.1: Solid Waste a) Describe solid waste streams from existing and proposed facilities during construction. b) Identify procedures to be implemented to manage solid waste, including collection, containment, storage, treatment, and disposal. c) Provide estimated total volumes of solid waste by construction activity or project component. d) Describe the recycling potential of solid waste materials and provide estimated volumes of recyclable materials by construction activity or project component. e) Identify the locations of appropriate disposal and recycling facilities where solid wastes would be transported.		
3.5.14.2: Liquid Waste a) Describe liquid waste streams during construction (i.e., sanitary waste, drilling fluids, contaminated water, etc.) b) Describe procedures to be implemented to manage liquid waste, including collection, containment, storage, treatment, and disposal. c) Provide estimated volumes of liquid waste generated by construction activity or project component. d) Identify the locations of appropriate disposal facilities where liquid wastes would be transported.		
3.5.14.3: Hazardous Waste a) Describe potentially hazardous waste streams during construction and procedures to be implemented to manage hazardous wastes, including collection, containment, storage, treatment, and disposal. b) If large volumes of hazardous waste are anticipated, such as from a pre-existing contaminant in the soil that must be collected and disposed of, provide estimated volumes of hazardous waste that would be generated by construction activity or project component. c) Identify the locations of appropriate disposal facilities where hazardous wastes would be transported.		
3.5.15 Fire Prevention and Response (All Projects)		
3.5.15.1: Fire Prevention and Response Procedures. Describe fire prevention and response procedures that would be implemented during		

construction. Provide a Construction Fire Prevention Plan or specific procedures as an Appendix to the PEA.		
3.5.15.2: Fire Breaks. Identify any fire breaks (i.e., vegetation clearance) requirements around specific project activities (i.e., hot work). Ensure that such clearance buffers are included in the limits of the defined work areas, and the vegetation removal in that area is attributed to Fire Prevention and Response (refer to 3.5.4.3: Vegetation Clearing).		

3.6 Construction Workforce, Equipment, Traffic, and Schedule

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
3.6.1: Construction Workforce a) Provide the estimated number of construction crew members. In the absence of project-specific data, provide estimates based on past projects of a similar size and type. b) Describe the crew deployment. Would crews work concurrently (i.e., multiple crews at different sites); would they be phased? How many crews could be working at the same time and where? c) Describe the different types of activities to be undertaken during construction, the number of crew members for each activity (i.e. trenching, grading, etc.), and number and types of equipment expected to be used for the activity. Include a written description of the activity. See example in Table 5.		
3.6.2: Construction Equipment. Provide a tabular list of the types of equipment expected to be used during construction of the proposed project including the horsepower. Define the equipment that would be used by each phase as shown in the example table below (Table 5).		

Table 5. Construction Equipment and Workforce

Work Activity				Activity Production				
Equipment Description	Estimated Horse-power	Probable Fuel Type	Equipment Quantity	Estimated Workforce	Estimated Start Date	Estimated End Date	Duration of Use (Hrs./Day)	Estimated Production
Survey				**4**	**January 2020**	**December 2020**		**358 Miles**
1-Ton Truck, 4x4	300	Diesel	2		January 2020	December 2020	10	1 Mile/Day
Staging Yards				**5**	**DOP**			
1-Ton Truck, 4x4	300	Diesel	1		Duration of Project		4	
R/T Forklift	350	Diesel	1				5	
Boom/Crane Truck	350	Diesel	1				5	
Water Truck	300	Diesel	2				10	
Jet A Fuel Truck	300	Diesel	1				4	
Truck, Semi-Tractor	500	Diesel	1				6	
Road Work				**6**	**January 2020**	**March 2020**		**426 Miles**
1-Ton Truck, 4x4	300	Diesel	2		January 2020	March 2020	5	
Backhoe/Front Loader	350	Diesel	1		January 2020	March 2020	7	
Track Type Dozer	350	Diesel	1		January 2020	March 2020	7	
Motor Grader	350	Diesel	1		January 2020	March 2020	5	
Water Truck	300	Diesel	2		January 2020	March 2020	10	
Drum Type Compactor	250	Diesel	1		January 2020	March 2020	5	
Excavator	300	Diesel	1		January 2020	February 2020	7	
Lowboy Truck/Trailer	500	Diesel	1		January 2020	February 2020	4	

3.6.3: Construction Traffic a) Describe how the construction crews and their equipment would be transported to and from the proposed project site. b) Provide vehicle type, number of vehicles, and estimated hours of operation per day, week, and month for each construction activity and phase. c) Provide estimated vehicle trips and vehicles miles traveled (VMT) for each construction activity and phase. Provide separate values for construction crews commuting, haul trips, and other types of construction traffic.		
3.6.4: Construction Schedule a) Provide the proposed construction schedule (e.g., month and year) for each segment or project component, and for each construction activity and phase. b) Provide and explain the sequencing of construction activities, and if they would or would not occur concurrently. c) Provide the total duration of each construction activity and phase in days or weeks. d) Identify seasonal considerations that may affect the construction schedule, such as weather or anticipated wildlife restrictions, etc. The proposed construction should account for such factors.		
3.6.5: Work Schedule a) Describe the anticipated work schedule, including the days of the week and hours of the day when work would occur. Clearly state if work would occur at night or on weekends and identify when and where this could occur. b) Provide the estimated number of days or weeks that construction activities would occur at each type of work area. For example, construction at a stationary facility or staging area may occur for the entire duration of construction, but construction at individual work areas along a linear project would be limited to a few hours, days or weeks, and only a fraction of the total construction period.		

3.7 Post-Construction

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
3.7.1: Configuring and Testing. Describe the process and duration for post-construction configuring and testing of facilities. Describe the number of personnel and types of equipment that would be involved.		
3.7.2: Landscaping. Describe any landscaping that would be installed. Provide a conceptual landscape plan that identifies the locations and types of plantings that will be used. Identify whether plantings will include container plants or seeds. Include any water required for landscaping in the description of water use above.		

3.7.3 Demobilization and Site Restoration		
3.7.3.1: Demobilization. Describe the process for demobilization after construction activities, but prior to leaving the work site. For example, describe final processes for removing stationary equipment and materials, etc.		
3.7.3.2: Site Restoration. Describe how cleanup and post-construction restoration would be performed (i.e., personnel, equipment, and methods) on all project ROWs, sites, and extra work areas. Things to consider include, but are not limited to, restoration of the following: a) Restoring natural drainage patterns b) Recontouring disturbed soil c) Removing construction debris d) Vegetation e) Permanent and semi-permanent erosion control measures f) Restoration of all disturbed areas and access roads, including restoration of any public trails that are used as access, as well as any damaged sidewalks, agricultural infrastructure, or landscaping, etc. g) Road repaving and striping, including proposed timing of road restoration for underground construction within public roadways		

3.8 Operation and Maintenance

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
3.8.1: Regulations and Standards a) Identify and describe all regulations and standards applicable to operation and maintenance of project facilities. b) Provide a copy of any applicable Wildfire Management Plan and describe any special procedures for wildfire management.		
3.8.2: System Controls and Operation Staff a) Describe the systems and methods that the Applicant would use for monitoring and control of project facilities (e.g., on-site control rooms, remote facilities, standard monitoring and protection equipment, pressure sensors, automatic shut-off valves, and site and equipment specific for monitoring and control such as at natural gas well pads). b) If new full-time staff would be required for operation and/or maintenance, provide the number of positions and purpose.		
3.8.3: Inspection Programs a) Describe the existing and proposed inspection programs for each project component, including the type, frequency, and timing of scheduled inspections (i.e., aerial inspection, ground inspection, pipeline inline inspections). b) Describe any enhanced inspections, such as within any High Fire Threat Districts consistent with applicable Wildfire Management Plan requirements.		

c) Describe the inspection processes, such as the methods, number of crew members, and how access would occur (i.e., walk, vehicle, all-terrain vehicle, helicopter, drone, etc.). If new access would be required, describe any restoration that would be provided for the access roads.		
3.8.4: Maintenance Programs a) Describe the existing and proposed maintenance programs for each project component. b) Describe scheduled maintenance or facility replacement after the designated lifespan of the equipment. c) Identify typical parts and materials that require regular maintenance and describe the repair procedures. d) Describe any access road maintenance that would occur. e) Describe maintenance for surface or color treatment. f) Describe cathodic protection maintenance that would occur. g) Describe ongoing landscaping maintenance that would occur.		
3.8.5: Vegetation Management Programs a) Describe vegetation management programs within and surrounding project facilities. Distinguish between any different types of vegetation management. b) Describe any enhanced vegetation management, such as within any High Fire Threat Districts consistent with any applicable Wildfire Management Plan requirements. Identify the areas where enhanced vegetation management would be conducted.		

3.9 Decommissioning

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
3.9.1: Decommissioning. Provide detailed information about the current and reasonably foreseeable plans for the disposal, recycling, or future abandonment of all project facilities.		

3.10 Anticipated Permits and Approvals

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
3.10.1: Anticipated Permits and Approvals. Identify all necessary federal, state, regional, and local permits that may be required for the project. For each permit, list the responsible agency and district/office representative with contact information, type of permit or approval, and status of each permit with date filed or planned to file. For example: a) Federal Permits and Approvals i. U.S. Fish and Wildlife Service ii. U.S. Army Corps of Engineers iii. Federal Aviation Administration iv. U.S. Forest Service		

v. U.S. Department of Transportation – Office of Pipeline Safety vi. U.S. Environmental Protection Agency (Resource Conservation and Recovery Act; Comprehensive Environmental Response, Compensation, and Liability Act) b) State and Regional Permits i. California Department of Fish and Wildlife ii. California Department of Transportation iii. California State Lands Commission iv. California Coastal Commission v. State Historic Preservation Office, Native American Heritage Commission vi. State Water Resources Control Board vii. California Division of Oil, Gas and Geothermal Resources viii. Regional Air Quality Management District ix. Regional Water Quality Control Board (National Pollutant Discharge Elimination System General Industrial Storm Water Discharge Permit) x. Habitat Conservation Plan Authority (if applicable) See also Table 6 of example permitting requirements and processes.		
3.10.2: Rights-of-Way or Easement Applications. Demonstrate that applications for ROWs or other proposed land use have been or soon will be filed with federal, state, or other land-managing agencies that have jurisdiction over land that would be affected by the project (if any). Discuss permitting plans and timeframes and provide the contact information at the federal agency(ies) approached.		

3.11 Applicant Proposed Measures

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
3.11 Applicant Proposed Measures a) Provide a table with the full text of any Applicant Proposed Measure. Where applicable, provide a copy of Applicant procedures, plans, and standards referenced in the Applicant Proposed Measures. b) Within Chapter 5, describe the basis for selecting a particular Applicant Proposed Measure and how the Applicant Proposed Measure would reduce the impacts of the project.[18] c) Carefully consider each CPUC Draft Environmental Measure identified in Chapter 5 of this PEA Checklist. The CPUC Draft Environmental Measures will be applied to the proposed project where applicable.		

[18] Applicant Proposed Measures that use phrases, such as, "as practicable" or other conditional language are not acceptable and will be superseded by Mitigation Measures if required to avoid or reduce a potentially significant impact.

Table 6. Example Permitting Requirements and Processes

Note: In addition to the CPCN or PTC, the applicant may also be required to secure resource agency permits for the project.

Disclaimer: Below is a general list of permits required for transmission projects. Permit requirements for individual projects may vary slightly depending on project conditions.

Agency	Permit	Regulation	Protected Resource	Trigger	Application Process	Timing
				Federal		
Army Corps of Engineers	404 Permit	Clean Water Act	Waters of the United States (including wetlands)	Placement of dredge or fill material into waters of the U.S., including wetlands. If project impacts less than 0.5 acres a **nationwide permit (NWP)** is typically issued	**NWP:** prepare a preconstruction notification (PCN) along with the draft Corps's application (Engineer Form 4345). Information in the PCN includes, but is not limited to: results of wetland delineation including areas of waters of the U.S.; temporary and permanent impacts to waters of the U.S. and discussion of avoidance; construction techniques, timeline, and equipment that would be used; special status species that potentially occur in the project area, and discussion of mitigation (if applicable) to replace wetlands	**NWP:** takes approximately nine months from the date of application submittal (depending on level of impacts and level of consultation required by other agencies). Initial review is 30 days after which application is deemed complete or additional information is requested.
				If project would impact more than 0.5 acres a **regional or individual permit** may be required.	**Regional or Individual Permit:** Same requirements as NWP as well as preparation and submittal of 404(b)(1) Alternatives analysis which identifies the Least Environmentally Damaging Practicable Alternative (LEDPA). Public notice also required	**Regional or Individual Permit:** An additional three to six months may be required on top of the nine months expected for an NWP. A 30 day public notice is also required to inform the public about the project before the Corps issues the permit.
USFWS	Section 7 Consultation	Federal Endangered Species Act	Federally Listed Species	Potential impact to a federally listed threatened or endangered species	Biological Assessment (BA) prepared and submitted to Corps. BA contains information on each species and describes potential for "take" of species and/or habitat.	The timeline for processing and receiving a formal **Biological Opinion (BO)** from USFWS can be six months to a year from when the Corps has initiated consultation and depending on the level of impact to listed species. The typical timeline for issuance of a BO is no less than 135 days after acceptance of the BA as complete.
US Department of Agriculture, Forest Service	Special Use Authorization	National Forest Management Act/NEPA	National Forest lands	Use of federal lands managed by the USDA Forest Service for a transmission line. Typically constitutes a Major Federal Action which in turn triggers NEPA analysis.	**Special Use Authorization Application:** prepare a special use application for consideration by the Forest Service. Prior to submitting a proposal, applicant is required to arrange a preapplicaiton meeting at the local Forest Service office. Application typically includes project plan, operating plans, liability insurance, licenses/registrations and other documents. If it is determined that NEPA is required either an EA or EIS would be prepared. The NEPA document may be prepared jointly with the CEQA document.	Revies of Special Use Authorization applications is often dependent upon what level of NEPA analysis is required. An EA is typically 9-12 months, and EIS is generally 18 months. NEPA process may occur concurrently with CEQA process.
US Department of the Interior, Bureau of Land Management	Right-of-Way Grant	Federal Land Policy and Management Act/NEPA	Federal Lands	Use of federal lands managed by the BLM for a transmission line. Typically constitutes a Major Federal Action which in turn triggers NEPA analysis.	**Right-of-Way Application**: Contact the BLM office with management responsibility. Obtain an application form "Application for Transportation and Utility Systems and Facilities on Federal Lands". Arrange a pre-application meeting with a BLM Realty Specialist or appropriate staff member. Submit completed application to the appropriate BLM office. If it is determined that NEPA is required either an EA or EIS would be prepared. The NEPA document may be prepared jointly with the CEQA document.	BLM attempts to review completed applications within 60 days of submittal. Full timing is often dependent upon what level of NEPA analysis is required. An EA is typically 9-12 months, and EIS is generally 18 months. NEPA process may occur concurrently with CEQA process.

Agency	Permit	Regulation	Protected Resource	Trigger	Application Process	Timing
				State (continued)		
State Historic Preservation Officer (SHPO)	Section 106 National Historic Preservation Act (NHPA)	National Historic Preservation Act	Cultural and/or historical resources	Required if there are potential impacts to cultural and/or historical resources that are listed or eligible for listing on the National Register of Historic Places.	Information on cultural and historical resources gathered during the draft CEQA document preparation is included in a 106 Technical Report and submitted to the Corps along with the Area of Potential Effect (APE) map. The information is then evaluated by the Corps' cultural resources evaluator for potential adverse effects within the APE. Depending upon the level of potential adverse effect, the Corps then forwards its finding to SHPO for concurrence or begins the process for a Memorandum of Agreement (MOA). Native American consultation is also mandatory for the 106 process but can begin during preparation of the environmental document. All letters and correspondence for the Native American consultation must be provided to the Corps.Consultation with federally-recongized tribes may require a more extensive consultation.	Once SHPO has received the Corps' determination, it has approximately 60 days to agree or request additional information. However, SHPO has recently become more involved in projects and this timeframe is only an estimate and if a potential adverse effect to cultural or historical resources could occur, the SHPO process can take up to a year or more. Depending on the level of impacts to cultural resources, the Corps may determine no effect and issue the permit before receiving concurrence from SHPO.
California State Lands Commission (CSLC)	Right of Way Lease Agreement	Division 6 of the California Public Resources Code	California Sovereign Lands	May be triggered if the transmission line crosses state lands under the jurisdiction of the CSLC, which includes the beds of 1) more than 120 rivers, streams and sloughs; 2) nearly 40 non-tidal navigable lakes, such as Lake Tahoe and Clear Lake; 3) the tidal navigable bays and lagoons; and 4) the tide and submerged lands adjacent to the entire coast and offshore islands of the State from the mean high tide line to three nautical miles offshore.	Leases or permits may be issued to qualified applicants and the Commission shall have broad discretion in all aspects of leasing including category of lease or permit and which use, method or amount of rental is most appropriate, whether competitive bidding should be used in awarding a lease, what term should apply, how rental should be adjusted during the term, whether bonding and insurance should be required and in what amounts, whether an applicant is qualified based on what it deems to be in the best interest of the State.	Most coordination should be done concurrently with the CEQA process to ensure that any CSLC-required issues are addressed under CEQA. Once a final route/alternative is selected, the lease process may take two to three months for final Commission approval.
				Local / Other		
Air Quality Management District or Air Pollution Control District	Permit to Construct	Federal Clean Air Act	Air Quality	Depends on the air disctrict involved; may not be required for most transmission projects. Some air districts have a trigger level based on disturbed acreage.	Application forms need to be prepared and submiited to the local AQMD or APCD	Typically 30 to 90 days after submittal of a complete application.

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[19] Permitting is project specific. This table is provided for discussion purposes.

3.12 Project Description Graphics, Mapbook, and GIS Requirements

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
3.12.1: Graphics. Provide diagrams of the following as applicable: a) All pole, tower, pipe, vault, conduit, and retaining wall types b) For poles, provide typical drawings with approximate diameter at the base and tip; for towers, estimate the width at base and top. c) A typical detail for any proposed underground duct banks and vaults d) All substation, switchyard, building, and facility layouts e) Trenching, drilling, pole installation, pipe installation, vault installation, roadway construction, facility removal, helicopter uses, conductor installation, traffic control, and other construction activities where a diagram would assist the reader in visualizing the work area and construction approach f) Typical profile views of proposed aboveground facilities and existing facilities to be modified within the existing and proposed ROW (e.g., typical cross-section of existing and proposed facilities by project segment). g) Photos of representative existing and proposed structures		
3.12.2: Mapbook. Provide a detailed mapbook on an aerial imagery basemap at a scale between 1:3000 and 1:6000 (or as appropriate and legible) that show mileposts, roadways, and all project components and work areas including: a) All proposed above-ground and underground structure/facility locations (e.g., poles, conductor, substations, compressor stations, telecommunication lines, vaults, duct bank, lighting, markers, etc.) b) All existing structures/facilities that would be modified or removed c) Identify by milepost where existing ROW will be used and where new ROW or land acquisition will be required. d) All permanent work areas including permanent facility access e) All access roads including, existing, temporary, and new permanent access f) All temporary work areas including staging, material storage, field offices, material laydown, temporary work areas for above ground (e.g., pole installation) and underground facility construction (e.g., trenching and duct banks), helicopter landing zones, pull and tension sites, guard structures, shoo flys etc. g) Areas where special construction methods (e.g., jack and bore, HDD, blasting, retaining walls etc.) may need to be employed		

h) Areas where vegetation removal may occur i) Areas to be heavily graded and where slope stabilization measures would be employed including any retaining walls		
3.12.3: GIS Data. Provide GIS data for all features and ROW shown on the detailed mapbook.		
3.12.4: GIS Requirements. Provide the following information for each pole/tower that would be installed and for each pole/tower that would be removed: a) Unique ID number and type of pole (e.g., wood, steel, etc.) or tower (e.g., self-supporting lattice) both in a table and in the attributes of the GIS data provided b) Identify pole/tower heights and conductor sizes in the attributes of the GIS data provided.		
3.12.5: Natural Gas Facilities GIS Data. For natural gas facilities, provide GIS data for system cross ties and all laterals/taps, valve stations, and new and existing inspection facilities (e.g., pig launcher sites).		

4 Description of Alternatives

All Applicants will assume that alternatives will be required for the environmental analysis and that an EIR will be prepared unless otherwise instructed by CPUC CEQA Unit Staff in writing prior to application filing. See PEA Requirements at the beginning of this checklist document. The consideration and discussion of alternatives will adhere to CEQA Guidelines Section 15126.6. The description of alternatives will be provided in this chapter of the PEA, and the comparison of each alternative to the proposed project is provided in PEA Chapter 6. The amount of detail required for the description of various alternatives to the proposed project and what may be considered a reasonable range of alternatives will be discussed with CPUC during Pre-filing.

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
4.1 Alternatives Considered. Identify alternatives to the proposed project.[20] Include the following: a) All alternatives to the proposed project that were suggested, considered, or studied by the CAISO or by CAISO stakeholders b) Alternatives suggested by the public or agencies during public outreach efforts conducted by the Applicant c) Reduced footprint alternatives, including, e.g., smaller diameter pipelines and space for fewer electric transformers d) Project phasing options (e.g., evaluate the full build out for environmental clearance but consider an initial, smaller buildout that would only be expanded [in phases] if needed) e) Alternative facility and construction activity sites (e.g., substation, compressor station, drilling sites, well-head sites, staging areas) f) Renewable, energy conservation, energy efficiency, demand response, distributed energy resources, and energy storage alternatives g) Alternatives that would avoid or limit the construction of new transmission-voltage facilities or new gas transmission pipelines h) Other technological alternatives (e.g., conductor type) i) Route alternatives and route variations j) Alternative engineering or technological approaches (e.g., alternative types of facilities, or materials, or configurations) k) Assign an identification label and brief, descriptive title to each alternative described in this PEA chapter (e.g., Alternative A: No Project; Alterative B: Reduced Footprint 500/115-kV Substation; Alternative C: Ringo Hills 16-inch Pipeline Alignment; Alternative D1: Lincoln Street Route Variation; etc.). Each alternative will be easily identifiable by reading the brief title. Provide a description of each alternative. The description of each alternative will discuss to what extent it would be potentially feasible,		

[20] Reduced footprint alternatives; siting alternatives; renewable, energy conservation, energy efficiency, demand response, distributed energy resources, and energy storage alternatives; and non-wires alternatives (electric projects only) are typically required. For linear projects, route alternatives and route variations are typically required as well.

meet the project's underlying purpose, meet most of the basic project objectives, and avoid or reduce one or more potentially significant impacts. If the Applicant believes that an alternative is infeasible or the implementation is remote and speculative (CEQA Guidelines Section 15126.6(f)(3), clearly explain why. If significant environmental effects are possible without mitigation, alternatives will be provided in the PEA that are capable of avoiding or reducing any potentially significant environmental effects, even if the alternative(s) substantially impede the attainment of some project objectives or are costlier.[21]		
4.2 No Project Alternative. Include a thorough description of the No Project Alternative. The No Project Alternative needs to describe the range of actions that are reasonably foreseeable if the proposed project is not approved. The No Project Alternative will be described to meet the requirements of CEQA Guidelines Section15126.6(e).		
4.3 Rejected Alternatives. Provide a detailed discussion of all alternatives considered by the Applicant that were not selected by the Applicant for a full description in the PEA and analysis in PEA Chapter 5. The detailed discussion will include the following: a) Description of the alternative and its components b) Map of any alternative sites or routes c) Discussion about the extent to which the alternative would meet the underlying purpose of the project and its basic objectives d) Discussion about the feasibility of implementing the alternative e) Discussion of whether the alternative would reduce or avoid any significant environmental impacts of the proposed project f) Discussion of any new significant impacts that could occur from implementation of the alternative g) Description of why the alternative was rejected h) Any comments from the public or agencies about the alternative during PEA preparation		
For Natural Gas Storage Projects:		
4.4 Natural Gas Storage Alternatives. In addition to the requirements included above, alternatives to be considered for proposed natural gas storage projects include the following, where applicable: a) Alternative reservoir locations considered for gas storage including other field locations and other potential storage areas b) Alternative pipelines, road, and utility siting c) Alternative suction gas requirements, and injection/withdrawal options		

[21] CPUC CEQA Unit Staff will determine whether an alternative could *substantially* reduce one or more potentially significant impacts of the proposed project (CEQA Guidelines Section 15125.5). Applicants are strongly advised to provide more rather than less alternatives for CPUC's consideration or as determined during Pre-filing.

5 Environmental Analysis

Include a description of the environmental setting, regulatory setting, and impact analysis for each resource area. The resource areas addressed will include each environmental factor (resource area) identified in the most recent adopted version of the CEQA Guidelines Appendix G checklist and any additional relevant resource areas and impact questions that are defined in this PEA checklist.

1. Environmental Setting
    a. For each resource area, the PEA will include a detailed description of the natural and built environment in the vicinity of the proposed project area (e.g., topography, land use patterns, biological environment, etc.) as applicable to the resource area. Both regional and local environmental setting information will be provided.
    b. All setting information provided will relate in some way to the impacts of the proposed project discussed in the PEA's impacts analysis, however CPUC's impacts analysis may be more thorough, which may necessitate additional setting information than the Applicant might otherwise provide.
2. Regulatory Setting
    a. Organized by federal, State, regional, and local sections
    b. Describe the policy or regulation and briefly explain why it is applicable to the proposed project.
        i. Identify in the setting all laws, regulations, and policies that would be applicable for CPUC's exclusive jurisdiction over the siting and design of electric and gas facilities. Public utilities under CPUC's jurisdiction are expected to consult with local agencies regarding land use matters. Local laws, regulations, and policies will be considered for the consideration of potential impacts during CPUC's CEQA review (e.g., encroachment, grading, erosion control, scenic corridors, overhead line undergrounding, tree removal, fire protection, permanent and temporary noise limits, zoning requirements, general plan polices, and all local and regional laws, regulations, and policies).
3. Impact Questions
    a. Includes all impact questions in the current version of CEQA Guidelines, Appendix G.
    b. Additional impact questions that are frequently relevant to utility projects are provided in Attachment 4, CPUC Draft Environmental Measures.
4. Impact Analyses
    a. Discussion organized by CEQA Guidelines, Appendix G impact items and any Additional CEQA Impact Questions in the PEA Checklist. Assess all potential environmental impacts and make determinations, such as, No Impact, Less than Significant, Less than Significant with Mitigation, Significant and Unavoidable, or Beneficial Impact with respect to construction, operations, and maintenance activities.
    b. The impact analyses provided in PEA Chapter 5, Environmental Analysis, need not be as thorough as those to be prepared by CPUC for the CEQA environmental document. A preliminary determination will be provided but with only brief justification unless otherwise directed by CPUC Staff in writing during Pre-filing.
5. CPUC Draft Environmental Measures
    a. CPUC Draft Environmental Measures are provided for some of the resource areas in Attachment 4, CPUC Draft Environmental Measures. The measures may be applied to the proposed project as written or modified by the CPUC during its environmental review if the measure would avoid or reduce a potentially significant impact.

b. The CPUC Draft Environmental Measures should be discussed with the CPUC's CEQA Unit Staff during Pre-filing, especially with respect to the development of Applicant Proposed Measures.
c. In general, impact avoidance is preferred to the reduction of potentially significant impacts.

Additional requirements specific to each resource area are identified in the following sections.

5.1 Aesthetics

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.1.1 Environmental Setting		
5.1.1.1: Landscape Setting. Briefly described the regional and local landscape setting.		
5.1.1.2: Scenic Resources. Identify and describe any vistas, scenic highways, national scenic areas, or other scenic resources within and surrounding the project area (approximately 5-mile buffer but may be greater if necessary). Scenic resources may also include but are not limited to historic structures, trees, or other resources that contribute to the scenic values where the project would be located.		
5.1.1.3: Viewshed Analysis a) Conduct a viewshed analysis for the project area (approximately 5-mile buffer but may be greater if necessary). b) Describe the project viewshed, including important visibility characteristics for the project site, such as viewing distance, viewing angle, and intervening topography, vegetation, or structures. c) Provide a supporting map (or maps) showing project area, landscape units, topography (i.e., hillshade), and the results of the viewshed analysis. Provide associated GIS data.		
5.1.1.4: Landscape Units. Identify and describe landscape units (geographic zones) within and surrounding the project area (approximately 5-mile buffer but may be greater if necessary) that categorizes different landscape types and visual characteristics, with consideration to topography, vegetation, and existing land uses. Landscape units should be developed based on the existing landscape characteristics rather than the project's features or segments.		
5.1.1.5: Viewers and Viewer Sensitivity. Identify and described the types of viewers expected within the viewshed and landscape units. Describe visual sensitivity to general visual change based on viewing conditions, use of the area, feedback from the public about the project, and landscape characteristics.		

5.1.1.6: Representative Viewpoints a) Identify representative viewpoints from publicly accessible locations (up to approximately 5-mile buffer but may be greater if appropriate). The number and location of the viewpoints must represent a range of views of the project site from major roads, highways, trails, parks, vistas, landmarks, and other scenic resources near the project site. Multiple viewpoints should be included where the project site would be visible from sensitive scenic resources to provide context on different viewing distances, perspectives, and directions. b) Provide the following information for each viewpoint: i. Number, title, and brief description of the location ii. Types of viewers iii. Viewing direction(s) and distance(s) to the nearest proposed project features iv. Description of the existing visual conditions and visibility of the project site as seen from the viewpoint and shown in the representative photographs c) Provide a supporting map (or maps) showing project features and representative viewpoints with arrows indicating the viewing direction(s). Provide associated GIS data (may be combined with GIS data request below for representative photographs).		
5.1.1.7: Representative Photographs a) Provide high resolution photographs taken from the representative viewpoints in the directions of all proposed project features.[22] Multiple photographs should be provided where project features may be visible in different viewing directions from the same location. b) Provide the following information for each photograph: i. Capture time and date ii. Camera body and lens model iii. Lens focal length and camera height when taken c) Provide GIS data associated with each photograph location that includes coordinates (<1 meter resolution), elevations, and viewing directions, as well as the associated viewpoint.		
5.1.1.8: Visual Resource Management Areas a) Identify any visual resource management areas within and surrounding the project area (approximately 5-mile buffer). b) Describe any project areas within visual resource management areas.		

[22] All representative photographs should be taken using a digital single-lens reflex camera with standard 50-millimeter lens equivalent, which represents an approximately 40-degree horizontal view angle. The precise photograph coordinates and elevations should be collected using a high accuracy GPS unit.

c) Provide a supporting map (or maps) showing project features and visual resource management areas. Provide associated GIS data.		
5.1.2 Regulatory Setting		
5.1.2.1: Regulatory Setting. Identify applicable federal, state, and local laws, policies, and standards regarding aesthetics and visual resource management.		
5.1.3 Impact Questions		
5.1.3.1: Impact Questions. The impact questions include all aesthetic impact questions in the current version of CEQA Guidelines, Appendix G. **5.1.3.2:** Additional CEQA Impact Questions: None.		
5.1.4 Impact Analysis		
5.1.4.1: Visual Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines Appendix G for this resource area and any additional impact questions listed above.		
The following information will be included in the PEA or a technical Appendix to support the aesthetic impact analysis:		
5.1.4.2: Analysis of Selected Viewpoints. Identify the methodology and assumptions that were applied in selecting key observation points for visual simulation. It is recommended that viewpoints are selected where viewers may be sensitive to visual change (public views) and in areas that are visually sensitive, or heavily trafficked or visited.[23]		
5.1.4.3: Visual Simulation a) Identify methodology and assumptions for completing the visual simulations. The simulations should include photorealistic 3-D models of project features and any land changes within the KOP view. The visual simulations should depict conditions: i. Immediately following construction, and ii. After vegetation establishment in all areas of temporary impact to illustrate the visual impact from vegetation removal. b) Provide high resolution images for the visual simulations.		
5.1.4.4: Analysis of Visual Change a) Identify the methodology and assumptions for completing the visual change analysis.[24] The methodology should be consistent with applicable visual resource management criteria. b) Provide a description of the visual change for each selected viewpoint. Describe any conditions that would change over time, such as vegetation growth.		

[23] The KOP selection process should be discussed with CPUC during Pre-filing
[24] The visual impact assessment methodology should be discussed with CPUC during Pre-filing

c) Describe the effects of visual change that would result in the entire project area, as indicated by the selected viewpoints that were simulated and analyzed.		
5.1.4.5: Lighting and Marking. Identify all new sources of permanent lighting. Identify any proposed structures or lines that could require FAA notification. Identify any structures or line segments that could require lighting and marking based on flight patterns and FAA or military requirements. Provide supporting documentation in an Appendix (e.g., FAA notice and criteria tool results).		
5.1.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.2 Agriculture and Forestry Resources

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.2.1 Environmental Setting		
5.2.1.1: Agricultural Resources and GIS a) Identify all agricultural resources that occur within the project area including: i. Areas designated as Prime Farmland, Unique Farmland, or Farmland of Statewide Importance ii. Areas under Williamson Act contracts and provide information on the status of the Williamson Act contract iii. Any areas zoned for agricultural use in local plans iv. Areas subject to active agricultural use b) Provide GIS data for agricultural resources within the proposed project area.		
5.2.1.2: Forestry Resources and GIS a) Identify all forestry resources within the project area including: i. Forest land as defined in Public Resources Code 12220(g)25 ii. Timberland as defined in Public Resource Code section 4526 iii. Timberland zoned Timberland Production as defined in Government Code section 51104(g) b) Provide GIS data for all forestry resources within the proposed project area.		
5.2.2 Regulatory Setting		
5.2.2: Agriculture and Forestry Regulations. Identify all federal, state, and local policies for protection of agricultural and forestry resources that apply to the proposed project.		

[25] Forest land is defined in Public Resources Code as, "land that can support 10 percent native tree cover of any species, including hardwoods, under natural conditions, and that allows for management of one or more forest resources, including timber, aesthetics, fish and wildlife, biodiversity, water quality, recreation, and other public benefits."

5.2.3 Impact Questions		
5.2.3.1: Agriculture and Forestry Impact Questions. The impact questions include all agriculture and forestry impact questions in the current version of CEQA Guidelines, Appendix G. **5.2.3.2:** Additional CEQA Impact Questions: None.		
5.2.4 Impact Analyses		
5.2.4.1: Agriculture and Forestry Impacts. Provide an impact analysis for each checklist item identified in CEQA Guidelines Appendix G for this resource area and any additional impact questions listed above.		
Incorporate the following discussions into the analysis of impacts:		
5.2.4.2: Prime Farmland Soil Impacts. Calculate the acreage of Prime Farmland soils that would be affected by construction and operation and maintenance.		
5.2.4.3. Williamson Act Impacts. Describe the approach to resolve potential conflicts with Williamson Act contract (if applicable)		
5.2.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.3 Air Quality

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.3.1 Environmental Setting		
5.3.1.1: Air Quality Plans Identify and describe all applicable air quality plans and attainment areas. Identify the air basin(s) for the project area. If the project is located in more than one attainment area and/or air basin, provide the extent in each attainment area and air basin.		
5.3.1.2: Air Quality. Describe existing air quality in the project area. a) Identify existing air quality exceedance of National Ambient Air Quality Standards and California Ambient Air Quality Standards in the air basin. b) Provide the number of days that air quality in the area exceeds state and federal air standards for each criteria pollutant that where air quality standards are exceeded. c) Provide air quality data from the nearest representative air monitoring station(s).		
5.3.1.3: Sensitive Receptor Locations. Identify the location and types of each sensitive receptor locations[26] within 1,000 feet of the project area. Provide GIS data for sensitive receptor locations.		

[26] Sensitive Receptor locations may include hospitals, schools, and day care centers, and such other locations as the air district board or California Air Resources Board may determine (California Health and Safety Code § 42705.5(a)(5)).

5.3.2 Regulatory Setting		
5.3.2.1: Regulatory Setting. Identify applicable federal, state, and local laws, policies, and standards regarding aesthetics and visual resource management.		
5.3.2.2: Air Permits. Identify and list all necessary air permits.		
5.3.3 Impact Questions		
5.3.3.1: Impact Questions. The impact questions include all air quality impact questions in the current version of CEQA Guidelines, Appendix G. **5.3.3.2:** Additional CEQA Impact Questions: None.		
5.3.4 Impact Analysis		
5.3.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines Appendix G for this resource area and any additional impact questions listed above.		
The following information will be presented in the PEA or a technical Appendix to support the air quality impact analysis:		
5.3.4.2: Air Quality Emissions Modeling. Model project emissions using the most recent version of CalEEMod and/or a current version of other applicable modeling program. Provide all model input and output data sheets in Microsoft Excel format to allow CPUC to evaluate whether project data was entered into the modeling program accurately. The assumptions used in the air quality modeling must be consistent with all PEA information about the project's schedule, workforce, and equipment. The following information will be addressed in the emissions modeling, Air Quality Appendix, and PEA: a) Quantify the expected emissions of criteria pollutants from all project-related sources. Quantify emissions for both construction and operation (e.g., compressor equipment). b) Identify manufacturer's specifications for all proposed new emission sources. For proposed new, additional, or modified compressor units, include the horsepower, type, and energy source. c) Describe any emission control systems that are included in the air quality analysis (e.g., installation of filters, use of EPA Tier II, III, or IV equipment, use of electric engines, etc.). d) When multiple air basins may be affected by the project, model air emissions within each air basin and provide a narrative (supported by calculations) that clearly describes the assumptions around the project activities considered for each air basin. Provide modeled emissions by attainment area or air basin (supported by calculations).		

5.3.4.3: Air Quality Emissions Summary. Provide a table summarizing the air quality emissions for the project and applicable thresholds for each applicable attainment area. Include a summary of uncontrolled emissions (prior to application of any APMs) and controlled emissions (after application of APMs). Clearly identify the assumptions that were applied in the controlled emissions estimates.		
5.3.4.4: Health Risk Assessment. Complete a Health Risk Assessment when air quality emissions have the potential to lead to human health impacts[27]. If health impacts are not anticipated from project emissions, the analysis should clearly describe why emissions would not lead to health impacts.		
5.3.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.4 Biological Resources

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.4.1 Environmental Setting		
5.4.1.1: Biological Resources Technical Report. Provide a Biological Resources Technical Report as an Appendix to the PEA that includes all information specified in Attachment 2.		
The following biological resources information will be presented in the PEA:		
5.4.1.2: Survey Area (Local Setting). Identify and describe the biological resources survey area as documented in the Biological Resources Technical Report. All temporary and permanent project areas must be within the survey area.		
5.4.1.3: Vegetation Communities and Land Cover a) Identify, describe, and quantify vegetation communities and land cover types within the biological resources survey area. b) Clearly identify any sensitive natural vegetation communities that meet the definition of a biological resource under CEQA (i.e., rare, designated, or otherwise protected), such as, but not limited to, riparian habitat. c) Provide a supporting map (or maps) showing project features and vegetation communities and land cover type.		

27 Refer to Office of Environmental Health Hazard Assessment (OEHHA) most recent guidance for preparation of Health Risk Assessments to determine whether a Health Risk Assessment is required for the project. The need for an HRA should also be discussed with CPUC during Pre-filing.

5.4.1.4: Aquatic Features a) Identify, describe, and quantify aquatic features within the biological resources survey area that may provide potentially suitable aquatic habitat for rare and special-status species. b) Identify and quantify potentially jurisdictional aquatic features and delineated wetlands, according to the Wetland Delineation Report and Biological Resources Technical Report. c) Provide a supporting map (or maps) showing project features and aquatic resources.		
5.4.1.5: Habitat Assessment. Identify rare and special-status species with potential to occur in the project region (approximately a 5-mile buffer but may be larger if necessary). For each species, provide the following information: a) Common and scientific name b) Status and/or rank c) Habitat characteristics (i.e., vegetation communities, elevations, seasonal changes, etc.) d) Blooming characteristics for plants e) Breeding and other dispersal (range) behavior for wildlife f) Potential to occur within the survey area (i.e., Present, High Potential, Moderate Potential, Low Potential, or Not Expected), with justification based on the results of the records search, survey findings, and presence of potentially suitable habitat g) Specific types and locations of potentially suitable habitat that correspond to the vegetation communities and land cover and aquatic features		
5.4.1.6: Critical Habitat a) Identify and describe any critical habitat for rare or special-status species within and surrounding the project area (approximately a 5-mile buffer). b) Provide a supporting map (or maps) showing project features and critical habitat.		
5.4.1.7: Native Wildlife Corridors and Nursery Sites a) Identify and describe regional and local wildlife corridors within and surrounding the project area (approximately a 5-mile buffer), including but not limited to, landscape and aquatic features that connect suitable habitat in regions otherwise fragmented by terrain, changes in vegetation, or human development. b) Identify and describe regional and local native wildlife nursery sites within and surrounding the project area (approximately a 5-mile buffer), as identified through the records search, surveys, and habitat assessment.		

c) Provide a supporting map (or maps) showing project features, native wildlife corridors, and native nursery sites.		
5.4.1.8: Biological Resource Management Areas a) Identify any biological resource management areas (i.e., conservation or mitigation areas, HCP or NCCP boundaries, etc.) within and surrounding the project area (approximately 5-mile buffer). b) Identify and quantify any project areas within biological resource management areas. c) Provide a supporting map (or maps) showing project features and biological resource management areas.		
5.4.2 Regulatory Setting		
5.4.2.1: Regulatory Setting. Identify applicable federal, state, and local laws, policies, and standards regarding biological resources.		
5.4.2.2: Habitat Conservation Plan. Provide a copy of any relevant Habitat Conservation Plan.		
5.4.3 Impact Questions		
5.4.3.1: Impact Questions. The impact questions include all biological resource impact questions in the current version of CEQA Guidelines, Appendix G. **5.4.3.2:** Additional CEQA Impact Question: Would the project create a substantial collision or electrocution risk for birds or bats?		
5.4.4 Impact Analysis		
5.4.4.1: Impact Analysis Provide an impact analysis for each checklist item identified in CEQA Guidelines, Appendix G for Biological Resources and any additional impact questions listed above.		
The following information will be included in the impact analysis:		
5.4.4.2: Quantify Habitat Impacts. Provide the area of impact in acres by each habitat type. Quantify temporary and permanent impacts. For all temporary impacts provide the following: a) Description of the restoration and revegetation approach b) Vegetation species that would be planted within the area of temporary disturbance c) Procedures to reduce invasive weed encroachment within areas of temporary disturbance d) Expected timeframe for restoration of the site		
5.4.4.3: Special-Status Species Impacts. Identify anticipated impacts on special-status species. Identify any take permits that are anticipated for the project. If an existing habitat conservation plan (HCP) or natural communities conservation plan (NCCP) would be used for the project, provide current accounting of take coverage included in the HCP/NCCP		

to demonstrate that there is sufficient habitat coverage remaining under the existing permit.		
5.4.4.4: Wetland Impacts. Quantify the area (in acres) of temporary and permanent impacts on wetlands. Include the following details: a) Provide a table identifying all wetlands, by milepost and length, crossed by the project and the total acreage of each wetland type that would be affected by construction. b) Discuss construction and restoration methods proposed for crossing wetlands. c) If wetlands would be filled or permanently lost, describe proposed measures to compensate for permanent wetland losses. d) If forested wetlands would be affected, describe proposed measures to restore forested wetlands following construction.		
5.4.4.5: Avian Impacts. Describe avian obstructions and risk of electrocution from the project. Describe any standards that will be implemented as part of the project to reduce the risk of collision and electrocution.		
5.4.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.5 Cultural Resources[28]

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.5.1 Environmental Setting		
5.5.1.1: Cultural Resource Reports. Provide a cultural resource inventory and evaluation report that addresses the technical requirement provided in Attachment 3.		
5.5.1.2: Cultural Resources Summary. Summarize cultural resource survey and inventory results and survey methods. Do not provide any confidential cultural resource information within the PEA chapter.		
5.5.1.3: Cultural Resource Survey Boundaries. Provide a map with mileposts showing the boundaries of all survey areas in the report. Provide the GIS data for the survey area. Provide confidential GIS data for the resource locations and boundaries separately under confidential cover.		
5.5.2 Regulatory Setting		
5.5.2.1: Regulatory Setting. Identify applicable federal and state regulations for protection of cultural resources.		

[28] For a description and evaluation of cultural resources specific to Tribes, see Section 5.18, Tribal Cultural Resources.

5.5.3 Impact Questions		
5.5.3.1: Impact Questions. The impact questions include all cultural resource impact questions in the current version of CEQA Guidelines, Appendix G. **5.5.3.2:** Additional CEQA Impact Questions: None.		
5.5.4 Impact Analysis		
5.5.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines, Appendix G for this resource area and any additional impact questions listed above.		
Include the following information in the impact analysis		
5.5.4.2: Human Remains. Describe the potential for encountering human remains or grave goods during the trenching or any other phase of construction. Describe the procedures that would be used if human remains are encountered.		
5.5.4.3: Resource Avoidance. Describe avoidance procedures that would be implemented to avoid known resources.		
5.5.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.6 Energy

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.6.1 Environmental Setting		
5.6.1.1: Existing Energy Use. Identify energy use of existing infrastructure if the proposed project would replace or upgrade an existing facility.		
5.6.2 Regulatory Setting		
5.6.2.1: Regulatory Setting. Identify applicable federal, state, or local regulations or policies applicable to energy use for the proposed project.		
5.6.3 Impact Questions		
5.6.3.1: Impact Questions: The impact questions include all energy impact questions in the current version of CEQA Guidelines, Appendix G. **5.6.3.2:** Additional CEQA Impact Question: Would the project add capacity for the purpose of serving a non-renewable energy resource?		

5.6.4 Impact Analysis		
5.6.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines Appendix G for this resource area and any additional impact questions listed above.		
Include the following information in the impact analysis:		
5.6.4.2: Nonrenewable Energy. Identify renewable and non-renewable energy projects that may interconnected to or be supplied by the proposed project.		
5.6.4.3: Fuels and Energy Use a) Provide an estimation of the amount of fuels (gasoline, diesel, helicopter fuel, etc.) that would be used during construction and operation and maintenance of the project. Fuel estimates should be consistent with Air Quality calculations supporting the PEA. b) Provide the following information on energy use: i. Total energy requirements of the project by fuel type and end use ii. Energy conservation equipment and design features iii. Identification of energy supplies that would serve the project		
5.6.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.7 Geology, Soils, and Paleontological Resources

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.7.1 Environmental Setting		
5.7.1.1: Regional and Local Geologic Setting. Briefly describe the regional and local physiography, topography, and geologic setting in the project area.		
5.7.1.2: Seismic Hazards a) Provide the following information on potential seismic hazards in the project area: i. Identify and describe regional and local seismic risk including any active faults within and surrounding the project area (will be a 10-mile buffer unless otherwise instructed in writing by CEQA Unit Staff during Pre-filing) ii. Identify any areas that are prone to seismic-induced landslides iii. Provide the liquefaction potential for the project area b) Provide a supporting map (or maps) showing project features and major faults, areas of landslide risk, and areas at high risk of liquefaction. Provide GIS data for all faults, landslides, and areas of high liquefaction potential.		

5.7.1.3: Geologic Units. Identify and describe the types of geologic units in the project area. Include the following information for each geologic unit: a) Summarize the geologic units within the project area. b) Identify any previous landslides in the area and any areas that are at risk of landslide. c) Identify any unstable geologic units. d) Provide a supporting map (or maps) showing project features and geologic units. Clearly identify any areas with potentially hazardous geologic conditions. Provide associated GIS data.		
5.7.1.4: Soils. Identify and describe the types of soils in the project area. a) Summarize the soils within the project area. b) Clearly identify any soils types that could be unstable (e.g., at risk of lateral spreading, subsidence, liquefaction, or collapse). c) Provide information on erosion susceptibility for each soil type that occurs in the project area. d) Provide a supporting map (or maps) showing project features and soils. Provide associated GIS data.		
5.7.1.5: Paleontological Report. Provide a paleontological report that includes the following: a) Information on any documented fossil collection localities within the project area and a 500-foot buffer. b) A paleontological resource sensitivity analysis based on published geological mapping and the resource sensitivity of each rock type. c) Supporting maps and GIS data.		
5.7.2 Regulatory Setting		
5.7.2.1: Regulatory Setting. Identify applicable federal, state, and local laws, policies, and standards regarding geology, soils, and paleontological resources.		
5.7.3 Impact Questions		
5.7.3.1: Impact Questions. The impact questions include all geology, soils, and paleontological resource impact questions in the current version of CEQA Guidelines, Appendix G. **5.7.3.2:** Additional CEQA Impact Questions: None.		
5.7.4 Impact Analysis		
5.7.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines, Appendix G for this resource area and any additional impact questions listed above.		
Include the following information in the impact analysis:		

5.7.4.2: Geotechnical Requirements. Identify any geotechnical requirements that would be implemented to address effects from unstable geologic units or soils. Describe how the recommendation would be applied (i.e., when and where).		
5.7.4.3: Paleontological Resources. Identify the potential to disturb paleontological resources based on the depth of proposed excavation and paleontological sensitivity of geologic units within the project area.		
5.7.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.8 Greenhouse Gas Emissions

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.8.1 Environmental Setting		
5.8.1.1: GHG Setting. Provide a description of the setting for greenhouse gases (GHGs). The setting should consider any GHG emissions from existing infrastructure that would be upgraded or replaced by the proposed project.		
5.8.2 Regulatory Setting		
5.8.2.1: Regulatory Setting. Identify applicable federal, state, and local laws, policies, and standards for greenhouse gases.		
5.8.3 Impact Questions		
5.8.3.1 Impact Questions. The impact questions include all greenhouse gas impact questions in the current version of CEQA Guidelines, Appendix G. **5.8.3.2:** Additional CEQA Impact Questions: None.		
5.8.4 Impact Analysis		
5.8.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines, Appendix G for this resource area and any additional impact questions listed above.		
Include the following information in the impact analysis:		
5.8.4.2: GHG Emissions. Provide a quantitative assessment of GHG emissions for construction and operation and maintenance of the proposed project. Provide model results and all model files. Modeling will be conducted using the latest version of the emissions model at the time of application filing (e.g., most recent version of CalEEMod). GHG emissions will be provided for the following conditions: a) Uncontrolled emissions (before APMs are applied) b) Controlled emissions considering application of APMs i. Based on the modeled GHG emissions, quantify the project's contribution to and analyze the project's effect on		

climate change. Identify and provide justification for the timeframe considered in the analysis. ii. Discuss any programs already in place to reduce GHG emissions on a system-wide level. This includes the Applicant's voluntary compliance with the EPA SF6 reduction program, reductions from energy efficiency, demand response, LTPP, etc. iii. For any significant impacts, identify potential strategies that could be employed by the project to reduce GHGs during construction or operation and maintenance consistent with OPR Advisory on CEQA and Climate Change.		
Natural Gas Storage		
5.8.4.3: Natural Gas Storage Accident Conditions. In addition to the requirements above, identify the potential GHG emissions that could result in the event of a gas leak.		
5.8.4.4: Monitoring and Contingency Plan. Provide a comprehensive monitoring plan that would be implemented during project operation to monitor for gas leaks. The plan should identify a monitoring schedule, description of monitoring activities, and actions to be implemented if gas leaks are observed.		
5.8.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.9 Hazards, Hazardous Materials, and Public Safety[29]

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.9.1 Environmental Setting		
5.9.1.1: Hazardous Materials Report. Provide a Phase I Environmental Site Assessment or similar hazards report for the proposed project area. Describe any known hazardous materials locations within the project area and the status of the site.		
5.9.1.2: Airport Land Use Plan. Identify any airport land use plan(s) within the project area.		
5.9.1.3: Fire Hazard. Identify if the project occurs within federal, state, or local fire responsibility areas and identify the fire hazard severity rating for all project areas, including temporary work areas and access roads.		
5.9.1.4: Metallic Objects. For electrical projects, identify any metallic pipelines or cables within 25 feet of the project.		

[29] For fire risk specific to state responsibility areas or lands classified as very high fire hazard severity zones, see Section 5.20, Wildfire.

5.9.1.5: Pipeline History (for Natural Gas Projects). Provide a narrative describing the history of the pipeline system(s) to which the project would connect, list of previous owner and operators, and detailed summary of the pipeline systems' safety and inspection history.		
5.9.2 Regulatory Setting		
5.9.2.1: Regulatory Setting. Identify applicable federal, state, and local laws, policies, and standards for hazards, hazardous materials, and public safety.		
5.9.2.2: Touch Thresholds. Identify applicable standards for protection of workers and the public from shock hazards.		
5.9.3 Impact Questions		
5.9.3.1: Impact Questions. The impact questions include all hazards and hazardous materials impact questions in the current version of CEQA Guidelines, Appendix G. **5.9.3.2:** Additional CEQA Impact Questions: a) Would the project create a significant hazard to air traffic from the installation of new power lines and structures? b) Would the project create a significant hazard to the public or environment through the transport of heavy materials using helicopters? c) Would the project expose people to a significant risk of injury or death involving unexploded ordnance? d) Would the project expose workers or the public to excessive shock hazards?		
5.9.4 Impact Analysis		
5.9.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines Appendix G for this resource area and any additional impact questions listed above.		
Include the following information in the impact analysis:		
5.9.4.2: Hazardous Materials. Identify the hazardous materials (i.e., chemicals, solvents, lubricants, and fuels) that would be used during construction and operation of the project. Estimate the quantity of each hazardous material that would be stored on site during construction and operation.		
5.9.4.3: Air Traffic Hazards. If the project involves construction of above-ground structures (including structure replacement) within the airport land use plan area, provide a discussion of how the project would or would not conflict with height restrictions identified in the airport land use plan and how the project would comply with any FAA or military requirements for the above ground facilities.		
5.9.4.4: Accident or Upset Conditions. Describe how the project facilities would be designed, constructed, operated, and maintained to		

minimize potential hazard to the public from the failure of project components as a result of accidents or natural catastrophes.		
5.9.4.5: Shock Hazard. For electricity projects, identify infrastructure that may be susceptible to induced current from the proposed project. Describe strategies (e.g., cathodic protection) that the project would employ to reduce shock hazards and avoid electrocution of workers or the public.		
For Natural Gas and Gas Storage:		
5.9.4.6: Health and Safety Plan. Include in the Health and Safety Plan, plans for addressing gas leaks, fires, etc. Identify sensitive receptors, methods of evacuation, and protection measures. The Plan will be provided as an Appendix to the PEA.		
5.9.4.7: Health Risk Assessment. Provide a Health Risk Assessment including risk from potential gas leaks, fires, etc. Identify sensitive receptors that would be affected and potential impacts on them if there is a gas release.[30]		
5.9.4.8: Gas Migration. Describe potential for and effects of gas migration through natural and manmade pathways. a) Provide Applicant Proposed Measures for avoiding gas emissions at the surface from gas migration pathways. b) Provide Applicant Proposed Measures for avoiding emissions of mercaptan and/or other odorizing agents.		
5.9.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.10 Hydrology and Water Quality

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.10.1 Environmental Setting		
5.10.1.1: Waterbodies. Identify by milepost all ephemeral, intermittent, and perennial surface waterbodies crossed by the project. For each, list its water quality classification, if applicable.		
5.10.1.2: Water Quality. Identify any downstream waters that are on the state 303(d) list and identify whether a total maximum daily load (TMDL) has been adopted or the date for adoption of a TMDL. Identify existing sources of impairment for downstream waters. Describe any management plans that are in place for downstream waters.		
5.10.1.3: Groundwater Basin. Identify all known EPA and state groundwater basins and aquifers crossed by the project.		

[30] Refer to the requirements for Health Risk Assessments in Section 5.3.4.4.

5.10.1.4: Groundwater Wells and Springs. Identify the locations of all known public and private groundwater supply wells and springs within 150 feet of the project area.		
5.10.1.5: Groundwater Management. Identify the groundwater management status of any groundwater resources in the project area and any groundwater resources that may be used by the project. Describe if groundwater resources in the basin have been adjudicated. Identify any sustainable groundwater management plan that has been adopted for groundwater resources in the project area or describe the status of groundwater management planning in the area.		
5.10.2 Regulatory Setting		
5.10.2.1: Regulatory Setting. Identify applicable federal, state, and local laws, policies, and standards regarding hydrologic and water quality.		
5.10.3 Impact Questions		
5.10.3.1: Impact Questions. The impact questions include all hydrology and water quality impact questions in the current version of CEQA Guidelines, Appendix G. **5.10.3.2:** Additional CEQA Impact Questions: None.		
5.10.4 Impact Analysis		
5.10.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in the current version of CEQA Guidelines, Appendix G for this resource area and any additional impact questions listed above.		
Include the following information in the impact analysis:		
5.10.4.2: Hydrostatic Testing. Identify all potential sources of hydrostatic test water, quantity of water required, withdrawal methods, treatment of discharge, and any waste products generated.		
5.10.4.3: Water Quality Impacts. Describe impacts to surface water quality, including the potential for accelerated soil erosion, downstream sedimentation, and reduced surface water quality.		
5.10.4.4: Impermeable Surfaces. Describe increased run-off and impacts on groundwater recharge due to construction of impermeable surfaces. Provide the acreage of new impermeable surfaces that will be created as a result of the project.		
5.10.4.5: Waterbody Crossings. Identify by milepost all waterbody crossings. Provide the following information for crossing: a) Identify whether the waterbody has contaminated waters or sediments. b) Describe the waterbody crossing method and any approaches to avoid the waterbody. c) Describe typical additional work area and staging area requirements at waterbody and wetland crossings.		

d) Describe any dewatering or water diversion that will be required during construction near the waterbody. Identify treatment methods for any dewatering. e) Describe any proposed restoration methods for work near or within the waterbody.		
5.10.4.6: Groundwater Impacts. If water would be obtained from groundwater supplies, evaluate the project's consistency with any applicable sustainable groundwater management plan.		
5.10.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.11 Land Use and Planning

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.11.1 Environmental Setting		
5.11.1.1: Land Use. Provide a description of land uses within the area traversed by the project route as designated in the local General Plan (e.g., residential, commercial, agricultural, open space, etc.).		
5.11.1.2: Special Land Uses. Identify by milepost and segment all special land uses within the project area including: a) All land administered by federal, state, or local agencies, or private conservation organizations b) Any designated coastal zone management areas c) Any designated or proposed candidate National or State Wild and Scenic Rivers crossed by the project d) Any national landmarks		
5.11.1.3: Habitat Conservation Plan. Provide a copy of any Habitat Conservation Plan applicable to the project area or proposed project. Also required for Section 5.4, Biological Resources.		
5.11.2 Regulatory Setting		
5.11.2.1: Regulatory Setting. Identify applicable federal, state, and local laws, policies, and standards for land use and planning.		
5.11.3 Impact Questions		
5.11.3.1: Impact Questions. The impact questions include all land use questions in the current version of CEQA Guidelines, Appendix G. **5.11.3.2:** Additional CEQA Impact Questions: None.		
5.11.4 Impact Analysis		
5.11.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines, Appendix G for this resource area and any additional impact questions listed above.		

5.11.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.12 Mineral Resources

This section will include, but is not limited to, the following:	**PEA Section and Page Number**	**Applicant Notes, Comments**
5.12.1 Environmental Setting		
5.12.1.1: Mineral Resources. Provide information on the following mineral resources within 0.5 mile of the proposed project area: a) Known mineral resources b) Active mining claims c) Active mines d) Resource recovery sites		
5.12.2 Regulatory Setting		
5.12.2.1: Regulatory Setting. Identify applicable federal, state, and local laws, policies, and standards for minerals.		
5.12.3 Impact Questions		
5.12.3.1: Impact Questions. The impact questions include all mineral resource impact questions in the current version of CEQA Guidelines, Appendix G. **5.12.3.2:** Additional CEQA Impact Questions: None.		
5.12.4 Impact Analysis		
5.12.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines, Appendix G for this resource area and any additional impact questions listed above.		
5.12.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.13 Noise

This section will include, but is not limited to, the following:	**PEA Section and Page Number**	**Applicant Notes, Comments**
5.13.1 Environmental Setting		
5.13.1.1: Noise Sensitive Land Uses. Identify all noise sensitive land uses within 1,000 feet of the proposed project. Provide GIS data for sensitive receptors within 1,000 feet of the project.		
5.13.1.2: Noise Setting. Provide the existing noise levels (Lmax, Lmin, Leq, and Ldn sound level and other applicable noise parameters) at noise sensitive areas near the proposed project. All noise measurement data and the methodology for collecting the data will be provided in a noise study as an Appendix to the PEA.		

5.13.2 Regulatory Setting		
5.13.2.1: Regulatory Setting. Identify applicable state, and local laws, policies, and standards for noise.		
5.13.3 Impact Questions		
5.13.3.1 Impact Questions. The impact questions include all noise questions in the current version of CEQA Guidelines, Appendix G. **5.13.3.2:** Additional CEQA Impact Questions: None.		
5.13.4 Impact Analysis		
5.13.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines, Appendix G for this resource area and any additional impact questions listed above.		
Include the following information in the impact analysis:		
5.13.4.2: Noise Levels a) Identify noise levels for each piece of equipment that could be used during construction. b) Provide a table that identifies each phase of construction, the equipment used in each construction phase, and the length of each phase at any single location (see example in Table 7 below). c) Estimate cumulative equipment noise levels for each phase of construction. d) Include phases of operation if noise levels during operation have the potential to frequently exceed pre-project existing conditions. e) Identify manufacturer's specifications for equipment and describe approaches to reduce impacts from noise.		

Table 7. Construction Noise Levels

Equipment Required	Equipment Noise Levels (Leq; 50 feet)	Phase Noise Level (Leq; 50 feet)	Phase Duration at Each Location	Receptor Nearest to Construction Phase	Noise Level at Nearest Receptor (Leq)	Exceeds Noise Standard at Nearest Receptor?	Distance to Not Exceed Standard
Site Preparation/Grading							
Dozer	78 dBA	82 dBA	5 days	Residence on Main Street; 100 feet from Substation Site	76 dBA	Yes	112 feet
Gradall	79 dBA						
Dump Truck	73 dBA						
Construct Tower Foundation							
Auger Rig	77 dBA	82 dBA	11 days	School on Education Avenue; 130 feet from Tower A12	73 dBA	No	N/A
Dump Truck	73 dBA						
Excavator	77 dBA						
Concrete Truck	75 dBA						

For Natural Gas:		
5.13.4.3: Compressor Station Noise. Provide site plans of compressor stations or other noisy, permanent equipment, showing the location of the nearest noise sensitive areas within 1 mile of the proposed ROW. If new compressor station sites are proposed, measure or estimate the existing ambient sound environment based on current land uses and		

activities. For existing compressor stations (operated at full load), include the results of a sound level survey at the site property line and nearby noise-sensitive areas. Include a plot plan that identifies the locations and duration of noise measurements.		
5.13.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.14 Population and Housing

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.14.1 Environmental Setting		
5.14.1.1: Population Estimates. Identify population trends for the areas (county, city, town, census designated place) where the project would take place.		
5.14.1.2: Housing Estimates. Identify housing estimates and projections in areas where the project would take place.		
5.14.1.3: Approved Housing Developments a) Provide the following information for all housing development projects within 1 mile of the proposed project that have been recently approved or may be approved around the PEA and application filing date: i. Project name ii. Location iii. Number of units and estimated population increase iv. Approval date and construction status v. Contact information for developer (provided in the public outreach Appendix) b) Ensure that the project information provided above is consistent with the PEA analysis of cumulative project impacts.		
5.14.2 Regulatory Setting		
5.14.2.1: Regulatory Setting. Identify any applicable federal, state or local laws or regulations that apply to the project.		
5.14.3 Impact Questions		
5.14.3.1: Impact Questions. The impact questions include all population and housing impact questions in the current version of CEQA Guidelines, Appendix G. **5.14.3.2:** Additional CEQA Impact Questions: None.		
5.14.4 Impact Analysis		
5.14.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines, Appendix G for this resource area and any additional impact questions listed above.		

Include the following information in the impact analysis:		
5.14.4.2: Impacts to Housing. Identify if any existing or proposed homes occur within the footprint of any proposed project elements or right-of-way. Describe housing impacts (e.g., demolition and relocation of residents) that may occur as a result of the proposed project.		
5.14.4.3: Workforce Impacts. Describe on-site manpower requirements, including the number of construction personnel who currently reside within the impact area, who would commute daily to the site from outside the impact area or would relocate temporarily within the impact area. Chapter 4 of this document can be referenced as applicable. Identify any permanent employment opportunities that would be create by the project and the workforce conditions in the area that the jobs would be created.		
5.14.4.4: Population Growth Inducing. Provide information on the project's growth inducing impacts, if any. The information will include, but is not necessarily limited to, the following: a) Any economic or population growth in the surrounding environment that will directly or indirectly result from the project b) Any obstacles to population growth that the project would remove c) Any other activities directly or indirectly encouraged or facilitated by the project that would cause population growth leading to a significant effect on the environment, either individually or cumulatively		
5.14.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.15 Public Services

This section will include, but is not limited to, the following:	**PEA Section and Page Number**	**Applicant Notes, Comments**
5.15.1 Environmental Setting		
5.15.1.1 Service Providers a) Identify the following service providers that serve the project area and provide a map showing the service facilities that could serve the project: i. Police ii. Fire (identify service providers within local and state responsibility areas) iii. Schools iv. Parks v. Hospitals		

b) Provide the documented performance objectives and data on existing emergency response times for service providers in the area (e.g., police or fire department response times).		
5.15.2 Regulatory Setting		
5.15.2.1 Regulatory Setting. Identify any applicable federal, state or local laws or regulations for public services that apply to the project.		
5.15.3 Impact Questions		
5.15.3.1: Impact Questions. The impact questions include all public services impact questions in the current version of CEQA Guidelines, Appendix G. **5.15.3.2:** Additional CEQA Impact Questions: None.		
5.15.4 Impact Analysis		
5.15.4.1 Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines, Appendix G for this resource area and any additional impact questions listed above.		
Include the following information in the impact analysis:		
5.15.4.2: Emergency Response Times a) Describe whether the project would impede ingress and egress of emergency vehicles during construction and operation. b) Include an analysis of impacts on emergency response times during project construction and operation, including impacts during any temporary road closures. Describe approaches to address impacts on emergency response times.		
5.15.4.3: Displaced Population. If the project would create permanent employment or displace people, evaluate the impact of the new employment or relocated people on governmental facilities and services and describe plans to reduce the impact on public services.		
5.15.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.16 Recreation

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.16.1 Environmental Setting		
5.16.1.1: Recreational Setting a) Describe the regional and local recreation setting in the project area including: i. Any recreational facilities or areas within and surrounding the project area (approximately 0.5-mile buffer) including the recreational uses of each facility or area		

ii. Any available data on use of the recreational facilities including volume of use b) Provide a map (or maps) showing project features and recreational facilities and provide associated GIS data.		
5.16.2 Regulatory Setting		
5.16.2.1: Regulatory Setting. Identify applicable federal, state, and local laws, policies, and standards regarding recreation.		
5.16.3 Impact Questions		
5.16.3.1: Impact Questions. The impact questions include all recreation impact questions in the current version of CEQA Guidelines, Appendix G. **5.16.3.2:** Additional CEQA Impact Questions: a) Would the project reduce or prevent access to a designated recreation facility or area? b) Would the project substantially change the character of a recreational area by reducing the scenic, biological, cultural, geologic, or other important characteristics that contribute to the value of recreational facilities or areas? c) Would the project damage recreational trails or facilities?		
5.16.4 Impact Analysis		
5.16.4.1: Impact Analysis: Provide an impact analysis for each checklist item identified in CEQA Guidelines, Appendix G for this resource area and any additional impact questions listed above.		
5.16.4.2: Impact Details. Clearly identify the maximum extent of each impact, and when and where the impacts would or would not occur. Organize the impact assessment by project phase, project component, and/or geographic area, as necessary.		
5.16.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.17 Transportation

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.17.1 Environmental Setting		
5.17.1.1: Circulation System. Briefly describe the regional and local circulation system in the project area, including modes of transportation, types of roadways, and other facilities that contribute to the circulation system.		
5.17.1.2: Existing Roadways and Circulation a) Identify and describe existing roadways that may be used to access the project site and transport materials during		

construction or are otherwise adjacent to or crossed by linear project features. Provide the following information for each road: i. Name of the road ii. Jurisdiction or ownership (i.e., State, County, City, private, etc.) iii. Number of lanes in both directions of travel iv. Existing traffic volume (if publicly available data is unavailable or significantly outdated, then it may be necessary to collect existing traffic counts for road segments where large volumes of construction traffic would be routed or where lane or road closures would occur) v. Closest project feature name and distance b) Provide a supporting map (or maps) showing project features and the existing roadway network identifying each road described above. Provide associated GIS data. The GIS data should include all connected road segments within at least 5 miles of the project.		
5.17.1.3: Transit and Rail Services a) Identify and describe transit and rail service providers in the region. b) Identify any rail or transit lines within 1,000 feet of the project area. c) Identify specific transit stops, and stations within 0.5 mile of the project. Provide the frequency of transit service. d) Provide a supporting map (or maps) showing project features and transit and rail services within 0.5 mile of the project area. Provide associated GIS data.		
5.17.1.4: Bicycle Facilities a) Identify and describe any bicycle plans for the region. b) Identify specific bicycle facilities within 1,000 feet of the project area. c) Provide a supporting map (or maps) showing project features and bicycle facilities. Provide associated GIS data.		
5.17.1.5: Pedestrian Facilities a) Identify and describe important pedestrian facilities near the project area that contribute to the circulation system, such as important walkways. b) Identify specific pedestrian facilities that would be near the project, including on the road segments identified per 5.17.1.2. c) Provide a supporting map (or maps) showing project features and important pedestrian facilities. Provide associated GIS data.		

5.17.1.6: Vehicle Miles Traveled (VMT). Provide the average VMT for the county(s) where the project is located.		
5.17.2 Regulatory Setting		
5.17.2.1: Regulatory Setting. Identify applicable federal, state, and local laws, policies, and standards regarding transportation.		
5.17.3 Impact Questions		
5.17.3.1: Impact Questions. All impact questions for this resource area in the current version of CEQA Guidelines, Appendix G. **5.17.3.2:** Additional CEQA Impact Questions: a) Would the project create potentially hazardous conditions for people walking, bicycling, or driving or for public transit operations? b) Would the project interfere with walking or bicycling accessibility? c) Would the project substantially delay public transit?		
5.17.4 Impact Analysis		
5.17.4.1: Impact Analysis. Provide an impact analysis for each significance criteria identified in Appendix G of the CEQA Guidelines for transportation and any additional impact questions listed above[31].		
Include the following information in the impact analysis:		
5.17.4.2: Vehicle Miles Traveled (VMT) a) Identify whether the project is within 0.5 mile of a major transit stop or a high-quality transit corridor. b) Identify the number of vehicle daily trips that would be generated by the project during construction and operation by light duty (e.g., worker vehicles) and heavy-duty vehicles (e.g., trucks). Provide the frequency of trip generation during operation. c) Quantify VMT generation for both project construction and operation. d) Provide an excel file with the VMT assumptions and model calculations, including all formulas and values. e) Evaluate the project VMT relative to the average VMT for the area in which the project is located.		
5.17.4.3: Traffic Impact Analysis. Provide a traffic impact study. The traffic impact study should be prepared in accordance with guidance from the relevant local jurisdiction or Caltrans, where appropriate.		
5.17.4.4: Hazards. Identify any traffic hazards that could result from construction and operation of the project. Identify any lane closures and traffic management that would be required to construct the project.		

[31] Discuss with CPUC during Pre-filing whether a traffic study is needed.

5.17.4.5: Accessibility. Identify any closures of bicycle lanes, pedestrian walkways, or transit stops during construction or operation of the project.		
5.17.4.6: Transit Delay. Identify any transit lines that could be delayed by construction and operation of the project. Provide the maximum extent of the delay in minutes and the duration of the delay.		
5.17.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.18 Tribal Cultural Resources[32]

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.18.1 Environmental Setting		
5.18.1.1: Outreach to Tribes. Provide a list of all tribes that are on the Native American Heritage Commission (NAHC) list of tribes that are affiliated with the project area. Provide a discussion of outreach to Native American tribes, including tribes notified, responses received from tribes, and information of potential tribal cultural resources provided by tribes. Any information of potential locations of tribal cultural resources should be submitted in an Appendix under clearly marked confidential cover. Provide copies of all correspondence with tribes in an Appendix.		
5.18.1.2: Tribal Cultural Resources. Describe tribal cultural resources (TCRs) that are within the project area. a) Summarize the results of attempts to identify possible TCRs using publicly available documentary resources. The identification of TCRs using documentary sources should include review of archaeological site records and should begin during the preparation of the records search report (see Attachment 3). During the inventory phase, a formal site record would be prepared for any resource identified unless tribes object. b) Summarize attempts to identify TCRs by speaking directly with tribal representatives.		
5.18.1.3: Ethnographic Study. The ethnographic study should document the history of Native American use of the area and oral history of the area.		
5.18.2 Regulatory Setting		
5.18.2.1: Regulatory Setting. Identify any applicable federal, state or local laws or regulations for tribal cultural resources that apply to the project.		

[32] For a description of historical resources and requirements for cultural resources that are not tribal cultural resources, refer to Section 5.5 Cultural Resources.

5.18.3 Impact Questions		
5.18.3.1: Impact Questions. The impact questions include all tribal cultural resources impact questions in the current version of CEQA Guidelines, Appendix G. **5.18.3.2:** Additional CEQA Impact Questions: None.		
5.18.4 Impact Analysis		
5.18.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines, Appendix G for this resource area and any additional impact questions listed above.		
Include the following information in the impact analysis:		
5.18.4.2: Information Provided by Tribes. Include an analysis of any impacts that were identified by the tribes during the Applicant's outreach.		
5.18.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.19 Utilities and Service Systems

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.19.1 Environmental Setting		
5.19.1.1: Utility Providers. Identify existing utility providers and the associated infrastructure that serves the project area.		
5.19.1.2: Utility Lines. Describe existing utility infrastructure (e.g., water, gas, sewer, electrical, stormwater, telecommunications, etc.) that occurs in the project ROW. Provide GIS data and/or as-built engineering drawings to support the description of existing utilities and their locations.		
5.19.1.3: Approved Utility Projects. Identify utility projects that have been approved for construction within the project ROW but that have not yet been constructed.[33]		
5.19.1.4: Water Supplies. Identify water suppliers and the water source (e.g., aqueduct, well, recycled water, etc.). For each potential water supplier, provide data on the existing water capacity, supply, and demand.		
5.19.1.5: Landfills and Recycling. Identify local landfills that can accept construction waste and may service the project. Provide documentation of landfill capacity and estimated closure date. Identify any recycling centers in the area and opportunities for construction and demolition waste recycling.		

[33] Note that this project information should be consistent with the cumulative project description included in Chapter 7.

5.19.2 Regulatory Setting		
5.19.2.1: Regulatory Setting. Identify any applicable federal, state or local laws or regulations for utilities that apply to the project.		
5.19.3 Impact Questions		
5.19.3.1: Impact Questions. All impact questions for this resource area in the current version of CEQA Guidelines, Appendix G. **5.19.3.2:** Additional CEQA Impact Question: Would the project increase the rate of corrosion of adjacent utility lines as a result of alternating current impacts?		
5.19.4 Impact Analysis		
5.19.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines, Appendix G for this resource area and any additional impact questions listed above.		
Include the following information in the impact analysis:		
5.19.4.2: Utility Relocation. Identify any project conflicts with existing utility lines. If the project may require relocation of existing utilities, identify potential relocation areas and analyze the impacts of relocating the utilities. Provide a map showing the relocated utility lines and GIS data for all relocations.		
5.19.4.3: Waste a) Identify the waste generated by construction, operation, and demolition of the project. b) Describe how treated wood poles would be disposed of after removal, if applicable. c) Provide estimates for the total amount of waste materials to be generated by waste type and how much of it would be disposed of, reused, or recycled.		
5.19.4.4: Water Supply a) Estimate the amount of water required for project construction and operation. Provide the potential water supply source(s). b) Evaluate the ability of the water supplier to meet the project demand under a multiple dry year scenario. c) Provide a discussion as to whether the proposed project meets the criteria for consideration as a project subject to Water Supply Assessment Requirements under Water Code Section 10912. d) If determined to be necessary under Water Code Section 10912, submit a Water Supply Assessment to support conclusions that the proposed water source can meet the project's anticipated water demand, even in multiple dry year scenarios. Water Supply Assessments should be approved by		

the water supplier and consider normal, single-dry, and multiple-dry year conditions.		
5.19.4.5: Cathodic Protection. Analyze the potential for existing utilities to experience corrosion due to proximity to the proposed project. Identify cathodic protection measures that could be implemented to reduce corrosion issues and where the measures may be applied.		
5.19.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.20 Wildfire

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.20.1 Environmental Setting		
5.20.1.1: High Fire Risk Areas and State Responsibility Areas a) Identify areas of high fire risk or State Responsibility Areas (SRAs) within the project area. Provide GIS data for the Wildland Urban Interface (WUI) and Fire Hazard Severity Zones (FHSZ) mapping along the project alignment. Include areas mapped by CPUC as moderate and high fire threat districts as well as areas mapped by CalFire. b) Identify any areas the utility has independently identified as High FHSZ known to occur within the proposed project vicinity.		
5.20.1.2: Fire Occurrence. Identify all recent (within the last 10 years) large fires that have occurred within the project vicinity. For each fire, identify the following: a) Name of the fire b) Location of fire c) Ignition source and location of ignition d) Amount of land burned e) Boundary of fire area in GIS		
5.20.1.3: Fire Risk. Provide the following information for assessment of baseline fire risk in the area: a) Provide fuel modeling using Scott Burgan fuel models, or other model of similar quality. b) Provide values of wind direction and speed, relative humidity, and temperature for representative weather stations along the alignment for the previous 10 years, gathered hourly. c) Digital elevation models for the topography in the project region showing the relationship between terrain and wind patterns, as well as localized topography to show the effects of terrain on wind flow, and on a more local area to show effect of slope on fire spread.		

d) Describe vegetation fuels within the project vicinity and provide data in map format for the project vicinity. USDA Fire Effects Information System or similar data source should be consulted to determine high-risk vegetation types. Provide the mapped vegetation fuels data in GIS format.		
5.20.1.4: Values at Risk. Identify values at risk along the proposed alignment. Values at risk may include: Structures, improvements, rare habitat, other values at risk, (including utility-owned infrastructure) within 1000 feet of the project. Provide some indication as to its vulnerability (wood structures vs. all steel features). Communities and/or populations near the project should be identified with their proximity to the project defined.		
5.20.1.5: Evacuation Routes. Identify all evacuation routes that are adjacent to or within the project area. Identify any roads that lack a secondary point of access or exit (e.g., cul-de-sacs).		
5.20.2 Regulatory Setting		
5.20.2.1: Regulatory Setting. Identify applicable federal, state, and local laws, policies, and standards for wildfire.		
5.20.2.2: CPUC Standards. Identify any CPUC standards that apply to wildfire management of the new facilities.		
5.20.3 Impact Questions		
5.20.3.1: Impact Questions. All impact questions for this resource area in the current version of CEQA Guidelines, Appendix G. **5.20.3.2:** Additional CEQA Impact Questions: None.		
5.20.4 Impact Analysis		
5.20.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines, Appendix G for this resource area and any additional impact questions listed above.		
Include the following information in the impact analysis:		
5.20.4.2: Fire Behavior Modeling. For any new electrical lines, provide modeling to support the analysis of wildfire risk.		
5.20.4.3: Wildfire Management. Describe approaches that would be implemented during operation and maintenance to manage wildfire risk in the area. Provide a copy of any Wildfire Management Plan.		
5.20.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.21 Mandatory Findings of Significance[34]

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.21.1: Impact Assessment for Mandatory Findings of Significance. Provide an impact analysis for each of the mandatory findings of significance provided in Appendix G of the CEQA Guidelines. The impact analysis can reference relevant information and conclusion from the biological resources, cultural resources, air quality, hazards, and cumulative sections of the PEA, where applicable.		

6 Comparison of Alternatives

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
6.1: Alternatives Comparison a) Compare the ability of each alternative described in Chapter 4 against the proposed project in terms of its ability to avoid or reduce a potentially significant impact. The alternatives addressed in this section will each be: i. Potentially feasible ii. Meet the underlying purpose of the proposed project iii. Meet most of the basic project objectives, and iv. Avoid or reduce one or more potentially significant impacts. b) The relative effect of the various potentially significant impacts may be compared using the following or similar descriptors and an accompanying analysis: i. Short-term versus long-term impacts ii. Localized versus widespread impacts iii. Ability to fully mitigate impacts c) Impacts that the Applicant believes would be less than significant with mitigation may also be included in the analysis, but only if the steps listed above fail to distinguish among the remaining few alternatives.		
6.2: Alternatives Ranking. Provide a detailed table that summarizes the Applicant's comparison results and ranks the alternatives in order of environmental superiority.[35]		

[34] PEAs need only include a Mandatory Findings of Significance section if CPUC CEQA Unit Staff determine that a Mitigated Negative Declaration may be the appropriate type of document to prepare for the project, as determined through Pre-filing consultation. If no such determination has been made, then a Mandatory Findings of Significance section and the requirements below are not required.

[35] If the proposed project does not rank #1 on the list, the Applicant should provide the rationale for selecting the proposed project.

7 Cumulative and Other CEQA Considerations

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
7.1 Cumulative Impacts		
7.1.1: List of Cumulative Projects a) Provide a detailed table listing past, present, and reasonably foreseeable future projects within and surrounding the project area (approximately 2-mile buffer)[36]. The following information should be provided for each project in the table: i. Project name and type ii. Brief description of the project location(s) and associated actions iii. Distance to and name of the nearest project component iv. Project status and anticipated construction schedule v. Source of the project information and date last checked (for each individual project), including links to any public websites where the information was obtained so it can be reviewed and updated (the project information should be current when the PEA is filed) b) Provide a supporting map (or maps) showing project features and cumulative project locations and/or linear features. Provide associated GIS data.		
7.1.2: Geographic Scope. Define the geographic scope of analysis for each resource topic. The geographic scope of analysis for each resource topic should consider the extent to which impacts can be cumulative. For example, the geographic scope for cumulative noise impacts would be more limited in scale than the geographic scope for biological resource impacts because noise attenuates rapidly with distance. Explain why the geographic scope is appropriate for each resource.		
7.1.3: Cumulative Impact Analysis. Provide an analysis of cumulative impacts for each resource topic included in Chapter 5. Evaluate whether the proposed project impacts are cumulatively considerable[37] for any significant cumulative impacts.		
7.2 Growth-Inducing Impacts		
7.2.1: Growth-Inducing Impacts. Provide an evaluation of the following potential growth-inducing impacts:		

[36] Information on cumulative projects may be obtained from federal, state, and local agencies with jurisdiction over planning, transportation, and/or resource management in the area. Other projects the Applicant is involved in or aware of in the area should be included.

[37] "Cumulatively considerable" means that the incremental effects of an individual project are significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects.

a) Would the proposed project foster any economic or population growth, either directly or indirectly, in the surrounding environment? b) Would the proposed project cause any increase in population that could further tax existing community service facilities (i.e., schools, hospitals, fire, police, etc.)? c) Would the proposed project remove any obstacles to population growth? d) Would the proposed project encourage and facilitate other activities that would cause population growth that could significantly affect the environment, either individually or cumulatively?		

8 List of Preparers

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
8.1: List of Preparers. Provide a list of persons, their organizations, and their qualifications for all authors and reviewers of each section of the PEA.		

9 References

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
9.1: Reference List a) Organize all references cited in the PEA by section within a single chapter called "References." b) Within the References chapter, organize all of the Chapter 5 references under subheadings for each resource area section.		
9.2: Electronic References a) Provide complete electronic copies of all references cited in the PEA that cannot be readily obtained for free on the Internet. This includes any company-specific documentation (e.g., standards, policies, and other documents). b) If the reference can be obtained on the Internet, the Internet address will be provided.		

PEA Checklist Attachments

Attachment 1: GIS Data Requirements

This Attachment includes specific requirements and format of GIS data that is intended to be applicable to all PEAs. The specific GIS data requirements may be updated on a project-specific basis during Pre-filing coordination with CPUC's CEQA Unit Staff.

1. GIS data will be provided in an appropriate format (i.e., point, line, polygon, raster) and scale to adequately verify assumptions in the PEA and supporting materials and determine the level of environmental impacts. At a minimum, all GIS data layers will include the following metadata properties:
    a. The source (e.g., report reference), date, title, and preparer (name or company)
    b. Description of the contents and any limitations of the data
    c. Reference scale and accuracy of the data
    d. Complete attributes that correspond to the detailed mapbook, project description, and figures presented in the PEA and/or supporting application materials, including unique IDs, labels, geometry, and other appropriate project details
2. Where precise boundaries of project features may change (e.g., staging areas and temporary construction work areas), the Applicant will provide GIS data layers with representative boundaries to evaluate potential environmental impacts as a worst-case scenario.
3. Provide GIS data for:
    a. All proposed <u>and alternative</u> project facilities including but not limited to existing and proposed/alternative ROWs; substations and switching stations; pole/tower locations; conduit; vaults, pipelines; valves; compressor stations; metering stations; valve stations, gas wellheads; other project buildings, facilities, and components (both temporary and permanent); telecommunication and distribution lines modifications or upgrades related to the project; marker ball and lighting locations; and mileposts, facility perimeters, and other demarcations or segments as applicable
    b. All proposed areas required for construction and construction planning, including all proposed and alternative disturbance areas (both permanent and temporary); access roads; geotechnical work areas; extra work areas (e.g., staging areas, parking areas, lay-down areas, work areas at and around specific pole/tower sites, pull and tension sites, helicopter landing areas); airport landing areas; underground installation areas (e.g. trenches, vaults, underground work areas); horizontal directional drilling, jack and bore, or tunnel areas; blasting areas; and any areas where special construction methods may need to be employed
    c. Within the PEA checklist there are also specific requirements for environmental resources within Chapter 5. All environmental resource GIS data must meet the minimum mapping standards specified in this Attachment.

Attachment 2: Biological Resource Technical Report Standards

Definitions

The following biological resources will be considered within the scope of the PEA and the Biological Resources Technical Report:

Sensitive Vegetation Communities and Habitats

a) Sensitive vegetation communities/habitats identified in local or regional plans, policies, or regulations, or designated by CDFW38 or USFWS
b) Areas that provide habitat for locally unique biotic species/communities (e.g., oak woodlands, grasslands, and forests)
c) Habitat that contains or supports rare, endangered, or threatened wildlife or plant species as defined by CDFW and USFWS
d) Habitat that supports CDFW Species of Special Concern
e) Areas that provide habitat for rare or endangered species and that meet the definition in CEQA Guidelines Section 15380
f) Existing game and wildlife refuges and reserves
g) Lakes, wetlands, estuaries, lagoons, streams, and rivers
h) Riparian corridors

Special-Status Species

a) Species listed or proposed for listing as threatened or endangered under the federal Endangered Species Act (ESA) (50 CFR § 17.12 [listed plants], 17.11 [listed animals] and various notices in the Federal Register [proposed species])
b) Species that are candidates for possible future listing as threatened or endangered under the federal ESA (61 FR § 40, February 28, 1996)
c) Species listed or proposed for listing by the State of California as threatened or endangered under the California ESA (14 CCR § 670.5)
d) Plants listed as rare or endangered under the California Native Plant Protection Act (California Fish and Game Code, Section 1900 et seq.)
e) Species that meet the definitions of rare and endangered under CEQA. CEQA Guidelines Section 15380 provides that a plant or animal species may be treated as “rare or endangered” even if not on one of the official lists.
f) Plants considered by the California Native Plant Society (CNPS) to be “rare, threatened or endangered in California” (California Rare Plant Rank 1A, 1B, 2A, and 2B) as well as California Rare Plant Rank 3 and 4 plant species
g) Species designated by CDFW as Fully Protected or as a Species of Special Concern
h) Species protected under the Federal Bald and Golden Eagle Protection Act
i) Birds of Conservation Concern or Watch List species
j) Bats considered by the Western Bat Working Group to be “high” or “medium” priority (Western Bat Working Group 2015)

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[38] CDFW’s Rarity Ranking follows NatureServe’s Heritage Methodology (Faber-Langendoen, et al. 2016) in which communities are given a G (global) and S (state) rank based on their degree of imperilment (as measured by rarity, trends, and threats). Communities with a Rarity Ranking of S1 (critically imperiled), S2 (imperiled), or S3 (vulnerable) are considered sensitive by CDFW.

Biological Resource Technical Report Minimum Requirements

Report Contents

The Biological Resource Technical Report will include the following information at a minimum.

a) **Preliminary Agency Consultation.** Describe any pre-survey contact with agencies. Describe any agency approvals that were required for biologists or agency protocols that were applied to the survey effort. Provide copies of correspondence and meeting notes with the names and contact information for agency staff and the dates of consultation as an appendix to the Biological Resources Technical Report.
b) **Records Search.** Provide the results of all database and literature searches for biological resources within and surrounding the project area. Identify all sources reviewed (e.g., CNDDB, CNPS, USFWS, etc.).
c) **Biological Resource Survey Method.** Identify agency survey requirements and protocols applicable to each biological survey that was conducted. Identify the areas where each survey occurred. Identify any limitations for the surveys (e.g., survey timing or climatic conditions) that could affect the survey results.
d) **Vegetation Communities and Land Cover.** Identify all vegetation communities or land cover types (e.g., disturbed or developed) within the biological survey area. The biological survey area should include a 1,000-foot buffer from project facilities to support CPUC's evaluation of indirect effects.
e) **Aquatic Resources.** Identify any wetlands, streams, lakes, reservoirs, estuarine, or other aquatic resources within the biological survey area. Provide a wetland delineation and all data sheets including National Wetlands Inventory maps (or the appropriate state wetland maps, if National Wetlands Inventory maps are not available) that show all proposed facilities and include milepost locations for proposed pipeline routes. Provide a copy of agency verification of the wetland delineation if the delineation has been verified by the U.S. Army Corps of Engineers or CDFW. If the delineation has not been verified, describe the process and timing for obtaining agency verification.
f) **Habitat Assessments.** Evaluate the potential for suitable habitat in the biological survey area for each species identified in the database and literature search.
g) **Native Wildlife Corridors and Nursery Sites.** Identify any wildlife corridors or nursery sites that occur within the biological survey area.
h) **Survey Results.** Describe all survey results and include a copy of any focused (e.g., rare plant, protocol special-status wildlife) biological resources survey reports.

Mapping and GIS Data

Provide detailed maps (at approximately 1:3,000 scale or similar), and all associated GIS data for the Biological Resources Technical Report and any supporting biological survey reports, including:

a) Biological survey area for each survey that was conducted
b) Vegetation communities and land cover types
c) Aquatic resource delineation
d) Special-status plant locations
e) Special-status wildlife locations
f) Avian point count locations
g) Critical habitat
h) California Coastal Commission or Bay Conservation and Development Commission jurisdictional areas

Attachment 3: Cultural Resource Technical Report Standards

Cultural Resource Inventory Report

Provide a cultural resource inventory report that includes archaeological, unique archaeological, and built-environment resources within all areas that could be affected by the proposed project including areas of indirect effect. The inventory report will include the results of both a literature search and pedestrian survey. The contents will address the requirements in *Archaeological Resource Management Reports: Recommended Contents and Guidelines*. The methodology and results of the inventory should be sufficient to provide the reader with an understanding of the nature, character, and composition of newly discovered and previously identified cultural resources so that the required recommendations about the resource(s) CRHR eligibility are clearly understood. No information regarding the location of the cultural resources will be included in these descriptions. The required Department of Parks and Recreation (DPR) 523 forms, including location information and photographs of the resources, are to be included in a removable confidential appendix to the report.[39]

The inventory report will meet the following requirements:

a) The report should clearly discuss the methods used to identify unique archaeological resources (e.g., how the determination was made about the resources' eligibility).
b) The report should identify large resources such as districts and landscapes where resources indicate their presence, even if federal agencies disagree. It is understood that often only a few contributing elements may be in the project area, and that the boundaries of the large resource may need to be revisited as part of future projects. It is acknowledged that boundaries of districts and landscapes can be difficult to define and there is not always good recorded data on these resources.
c) In the case of archaeological resources, the report should discuss whether each one is also a unique archaeological resource and explain why or why not.
d) Descriptions of resources should include spatial relationships to other nearby resources, raw materials sources, and natural features such as water sources and mountains.
e) The evidence that indicates a particular function or age for a resource should be explicitly described with a clear explanation, not simply asserted.

Cultural Resource Evaluation Report

Provide a cultural resource evaluation report. The report contents required by the state of California are outlined in the *Archaeological Resource Management Reports: Recommended Contents and Guidelines*. The evaluation report should also include:

a) Resource descriptions and evaluations together, and not in separate volumes or report sections. This will facilitate understanding of each resource.
b) An evaluation of each potential or eligible California Register of Historical Resources (CRHR) resource within the public archaeology laboratory (PAL) for all seven aspects of integrity[40] using specific examples for each resource. This evaluation needs to be included in the evaluation

[39] Any aspect of the PEA and associated data that Applicants believe to be confidential will be provided in full but may be marked confidential if allowed pursuant to General Order 66 or latest applicable Commission rule (e.g., see Public Records Act Proceeding R.14-11-001).

[40] The seven aspects of integrity are location, design, setting, materials, workmanship, feeling, and association, as defined in "***Types of Historical Resources and Criteria for Listing in the California Register of Historical Resources***" [14 CCR 4852(c)]).

report for all resources that could be affected by the project even if the resources were not previously evaluated. Previous evaluations should be reviewed to address change over time.

c) An evaluation of each potential or eligible CRHR resource within the PAL under all four criteria using specific examples for each resource. This evaluation needs to be included in the evaluation report for all resources that could be affected by the project even if the resources were not previously evaluated. The cultural resources professional should make their own recommendation regarding eligibility, which does not need to agree with previous recommendations for CRHR or NRHP, as long as it is clearly explained.
d) For **prehistoric archaeological resources**, Criteria 1, 2 and 3[41] should be explicitly considered. Research efforts to search for important events and persons related to the resource must be described. This evaluation needs to be included in the evaluation report for all resources that could be affected by the project even if the resources were not previously evaluated. The cultural resources professional should make their own recommendation, which does not need to agree with previous recommendations for CRHR or NRHP eligibility, as long as it is clearly explained.
e) While **potential unique archaeological resources** could be identified in the records search report or inventory report, the justification for each individual resource to be considered a resource under CEQA should be presented in this report.
f) If surface information collected during survey is sufficient to make an eligibility recommendation, this reasoning should be outlined explicitly for each resource. This is particularly the case for resources that are believed to have buried subsurface components.
g) If archaeological testing or additional historical research was required in order to evaluate a resource, the evaluation report will be explicit about why the work was required, the results for each resource, and the subsequent eligibility recommendation.
h) For large projects with multiple similar resources where the eligibility justifications for similar resources are essentially identical, it is acceptable to discuss these resources as a group. However, eligibility justifications for each individual resource is preferred, so if the grouping strategy is used, the criteria used to group resources must be clearly justified.
i) Large resources such as districts and landscapes may be challenging to fully evaluate in the context of a single project. CPUC encourages the identification and evaluation of these resources with the understanding that often only a few contributing elements may be located within the project area, and that the boundaries of the large resource may need to be revisited as part of future projects. It is understood that a full evaluation of the resource may be beyond the scope of one project. Regardless, the potential for the project to affect any resources within a district or landscape must be defined.

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[41] Criteria for Designation on the California Register are as follows (defined in http://ohp.parks.ca.gov/?page_id=21238):

- Criterion 1: Associated with events that have made a significant contribution to the broad patterns of local or regional history or the cultural heritage of California or the United States.
- Criterion 2: Associated with the lives of persons important to local, California or national history.
- Criterion 3: Embodies the distinctive characteristics of a type, period, region or method of construction or represents the work of a master or possesses high artistic values.
- Criterion 4: Has yielded, or has the potential to yield, information important to the prehistory or history of the local area, California or the nation.

Attachment 4: CPUC Draft Environmental Measures

About this Attachment: The following CPUC Draft Environmental Measures are provided for consideration during PEA development. They should be discussed with the CPUC's CEQA Unit Staff during Pre-filing, especially with respect to the development of Applicant Proposed Measures. The CPUC Draft Environmental Measures may form the basis for mitigation measures in the CEQA document if appropriate to the analysis of potentially significant impacts. These and other CPUC Draft Environmental Measures may be formally incorporated into Chapter 5 of future versions of the PEA Checklist.

5.1 Aesthetics

Aesthetics Impact Reduction During Construction

All project sites will be maintained in a clean and orderly state. Construction staging areas will be sited away from public view where possible. Nighttime lighting will be directed away from residential areas and have shields to prevent light spillover effects. Upon completion of project construction, project staging and temporary work areas will be returned to pre-project conditions, including re-grading of the site and re-vegetation or re-paving of disturbed areas to match pre-existing contours and conditions.

5.3 Air Quality

Dust Control During Construction

The Applicant shall implement measures to control fugitive dust in compliance with all local air district(s) standards. Dust control measures shall include the following at a minimum:

- All exposed surfaces with the potential of dust-generating shall be watered or covered with coarse rock to reduce the potential for airborne dust from leaving the site.
- The simultaneous occurrence of more than two ground disturbing construction phases on the same area at any one time shall be limited. Activities shall be phased to reduce the amount of disturbed surfaces at any one time.
- Cover all haul trucks entering/leaving the site and trim their loads as necessary.
- Use wet power vacuum street sweepers to sweep all paved access road, parking areas, staging areas, and public roads adjacent to project sites on a daily basis (at minimum) during construction. The use of dry power sweeping is prohibited.
- All trucks and equipment, including their tires, shall be washed off prior to leaving project sites.
- Apply gravel or non-toxic soil stabilizers on all unpaved access roads, parking areas, and staging areas at project sites.
- Water and/or cover soil stockpiles daily.
- Vegetative ground cover shall be planted in disturbed areas as soon as possible and watered appropriately until vegetation is established.
- All vehicle speeds shall be limited to fifteen (15) miles per hour or less on unpaved areas.
- Implement dust monitoring in compliance with the standards of the local air district.
- Halt construction during any periods when wind speeds are in excess of 50 mph.

5.5 Cultural Resources

Human Remains (Construction and Maintenance)

Avoidance and protection of inadvertent discoveries that contain human remains shall be the preferred protection strategy with complete avoidance of such resources ensured by redesigning the project. If human remains are discovered during construction or maintenance activities, all work shall be diverted from the area of the discovery, and the CPUC shall be informed immediately. The Applicant shall contact the County Coroner to determine whether or not the remains are Native American. If the remains are determined to be Native American, the Coroner will contact the Native American Heritage Commission (NAHC). The NAHC will then identify the person or persons it believes to be the most likely descendant of the deceased Native American, who in turn would make recommendations for the appropriate means of treating the human remains and any associated funerary objects.

If the remains are on federal land, the remains shall be treated in accordance with the Native American Graves Protection and Repatriation Act (NAGPRA). If the remains are not on federal land, the remains shall be treated in accordance with Health and Safety Code Section 7050.5, CEQA Section 15064.5(e), and Public Resources Code Section 5097.98.

5.8 Greenhouse Gas Emissions

Greenhouse Gas Emissions Reduction During Construction

The following measures shall be implemented to minimize greenhouse gas emissions from all construction sites:

- If suitable park-and-ride facilities are available in the project vicinity, construction workers shall be encouraged to carpool to the job site.
- The Applicant shall develop a carpool program to the job site.
- On road and off-road vehicle tire pressures shall be maintained to manufacturer specifications. Tires shall be checked and re-inflated at regular intervals.
- Demolition debris shall be recycled for reuse to the extent feasible.
- The contractor shall use line power instead of diesel generators at all construction sites where line power is available.
- The contractor shall maintain construction equipment per manufacturing specifications.

5.19 Utilities and Service Systems

Notify Utilities with Facilities Above and Below Ground

The Applicant shall notify all utility companies with utilities located within or crossing the project ROW to locate and mark existing underground utilities along the entire length of the project at least 14 days prior to construction. No subsurface work shall be conducted that would conflict with (i.e., directly impact or compromise the integrity of) a buried utility. In the event of a conflict, areas of subsurface excavation or pole installation shall be realigned vertically and/or horizontally, as appropriate, to avoid other utilities and provide adequate operational and safety buffering. In instances where separation between third-party utilities and underground excavations is less than 5 feet, the Applicant shall submit the intended construction methodology to the owner of the third-party utility for review and approval at least 30 days prior to construction. Construction methods shall be adjusted as necessary to assure that the integrity of existing utility lines is not compromised.

5.20 Wildfire

Construction Fire Prevention Plan

A project-specific Construction Fire Prevention Plan for both construction and operation of the project shall be submitted for review prior to initiation of construction. A draft copy of the Plan shall be provided to the CPUC and state and local fire agencies at least 90 days before the start of any construction activities in areas designated as Very High or High Fire Hazard Severity Zones. Plan reviewers shall also include federal, state, or local agencies with jurisdiction over areas where the project is located. The final Plan shall be approved by the CPUC at least 30 days prior to the initiation of construction activities. The Plan shall be fully implemented throughout the construction period and include the following at a minimum:

- The purpose and applicability of the Plan
- Responsibilities and duties
- Preparedness training and drills
- Procedures for fire reporting, response, and prevention that include:
    - Identification of daily site-specific risk conditions
    - The tools and equipment needed on vehicles and to be on hand at sites
    - Reiteration of fire prevention and safety considerations during tailboard meetings
    - Daily monitoring of the red-flag warning system with appropriate restrictions on types and levels of permissible activity
- Coordination procedures with federal and local fire officials
- Crew training, including fire safety practices and restrictions
- Method(s) for verifying that all Plan protocols and requirements are being followed

A project Fire Marshal or similar qualified position shall be established to enforce all provisions of the Construction Fire Prevention Plan as well as perform other duties related to fire detection, prevention, and suppression for the project. Construction activities shall be monitored to ensure implementation and effectiveness of the Plan.

Fire Prevention Practices (Construction and Maintenance)

The Applicant shall implement ongoing fire patrols during the fire season as defined each year by local, state, and federal fire agencies. These dates vary from year to year, generally occurring from late spring through dry winter periods. During Red Flag Warning events, as issued daily by the National Weather Service, all construction/maintenance activities shall cease, with an exception for transmission line testing, repairs, unfinished work, or other specific activities which may be allowed if the facility/equipment poses a greater fire risk if left in its current state.

All construction/maintenance crews and inspectors shall be provided with radio and cellular telephone access that is operational in all work areas and access routes to allow for immediate reporting of fires. Communication pathways and equipment shall be tested and confirmed operational each day prior to initiating construction/maintenance activities at each work site. All fires shall be reported to the fire agencies with jurisdiction in the area immediately upon discovery of the ignition.

All construction/maintenance personnel shall be trained in fire-safe actions, initial attack firefighting, and fire reporting. All construction/maintenance personnel shall be trained and equipped to extinguish small fires in order to prevent them from growing into more serious threats. All construction/maintenance personnel shall carry at all times a laminated card and be provided a hard hat sticker that list pertinent telephone numbers for reporting fires and defining immediate steps to take if a fire starts. Information on laminated contact cards and hard hat stickers shall be updated and redistributed to all construction/maintenance personnel and outdated cards and hard hat stickers shall be destroyed prior to the initiation of construction/maintenance activities on the day the information change goes into effect.

Construction/maintenance personnel shall have fire suppression equipment on all construction vehicles. Construction/maintenance personnel shall be required to park vehicles away from dry vegetation. Water tanks and/or water trucks shall be sited or available at active project sites for fire protection during construction. The Applicant shall coordinate with applicable local fire departments prior to construction/maintenance activities to determine the appropriate amounts of fire equipment to be carried on vehicles and, should a fire occur, to coordinate fire suppression activities.

Long-Term Gas Planning Rulemaking

On January 27, 2020, the Commission issued an Order Instituting Rulemaking (OIR) to respond to past and prospective events that together will require changes to certain policies, processes, and rules that govern the natural gas utilities in California. With respect to past events, several operational issues in Southern California prompt the Commission to reconsider the reliability and compliance standards for gas public utilities. Over the next 25 years, state and municipal laws concerning greenhouse gas emissions will result in the replacement of gas-fueled technologies and, in turn, reduce the demand for natural gas.

For the proceeding docket card, which contains documents on the record, rulings, and decisions, click here. For other documents or a quick link to certain proceeding documents, see below.

Senate Bill (SB) 350 (de León, Chapter 547, 2015) requires the CPUC to focus energy procurement decisions on reducing greenhouse gas (GHG) emissions by 40 percent by 2030, including efforts to achieve at least 50 percent renewable energy procurement, doubling of energy efficiency, and promoting transportation electrification.

Proceeding Documents

- December 22, 2022: Staff Proposal on Gas Distribution Decommissioning Framework in Support of Climate Goals
- December 1, 2022: CPUC Creates New Framework To Advance California's Transition Away From Natural Gas (CPUC Press Release)
- July 7, 2022: Final Track 2 Equity Report on March 29, 2022 Workshop
- July 7, 2022: Final Track 2 Gas Infrastructure Report on January, 2022 Workshops
- January 5, 2022: Amended Track 2 Scoping Memo
- October 14, 2021: Track 2 Scoping Memo
- June 25, 2021: Updated Staff Proposal on Track 1A Scoping Memo Issue 1c: How should the CPUC respond to a utility's sustained failure to meet minimum design standards?
- October 2, 2020: Track 1A and Track 1B Workshop Report and Staff Recommendations
- October 2, 2020: Energy Division Staff White Paper on California Gas Utility Reliability

Events

- **March 16, 2022, 10:00 a.m - 12:00 p.m.: Gas 101 Webinar**
- **March 29, 2022, 9:30 a.m. - 1:00 p.m.: Equity Workshop**
  - Recording link: https://youtu.be/aJpHCPXQN8U
  - Meeting material:
    - Agenda
    - Workshop Slides

January 24, 2022, 9:30 a.m. - 4:30 p.m.: Track 2 Workshop 2 - Develop and Implement a Long-Term Planning Strategy

- Recording link: https://youtu.be/m7-ybGnqISc

- Meeting materials:
  - Agenda
  - Workshop Slides
- **January 10, 2022, 9:30 a.m. - 4:30 p.m.: Track 2 Workshop 1 - Develop and Implement a Long-Term Planning Strategy**
  - Recording* link: https://www.youtube.com/watch?v=YnNumWvDrHo
    - *There is a recording gap for Southwest Gas, Self-Help Enterprises, and Coalition for Renewable Natural Gas presentations. See pending workshop report for presentation summaries.
  - Meeting materials:
    - Agenda
    - Workshop Slides
- **July 21, 2020, 9:30 a.m. - 4:30 p.m.: Track 1B Workshop - Market Structure and Regulations**
  - Recording link: https://cpuc.webex.com/cpuc/lsr.php?RCID=3dec7e93c5d54cebb697f5dfd1d796c5, meeting password: Gasplanning123
  - Meeting materials
    - Agenda
    - Workshop Slides
- **July 7, 2020, 9:30 a.m. - 4:15 p.m: Track 1A Workshop - Natural Gas Reliability Standards**
  - Recording link: https://cpuc.webex.com/cpuc/lsr.php?RCID=5c0d99984f4144f2a04f8d7141bdeeb8, meeting password: Gasplanning123
  - Meeting materials
    - Agenda
    - Workshop Slides

Reports

- December 27, 2021: Gas Planning and Reliability in California, Graduate Intern White Paper

Data

- December 22, 2022: Gas System Data Provided by Utilities

  This data is posted as provided by utilities to the R.20-01-007 service list on November 4, 2022, except where noted. Utilities have redacted some data, requesting confidentiality. This data replaces the previous versions posted on May 21, 2022, except where noted.

  - PG&E

  - Gas System Summary Statistics (xlsx)
  - Gas System Census Tract Data (csv) (notes pdf)
  - Consumption Data by Census Tract (csv)
  - Consumption Data by Zip Code (csv)
  - Supplemental Data (xlsx) (May 20 xlsx)
  - Risk Assessment Methods, PHMSA Gas Distribution Data (pdf)
  - Cover Description (pdf) (availability pdf)
  - Confidentiality Motion (pdf)

  o SoCalGas
  - Gas System Summary Statistics (xlsx, file assembled CPUC staff)
  - Gas System Census Tract Data (csv) (demand nodes csv) (May 20 demand nodes csv) (notes pdf) (notes Q2 xlsx) (May 20 notes xlsx)
  - Consumption Data by Census Tract (csv) (notes pdf)
  - Consumption Data by Zip Code (csv)

- Supplemental Data (xlsx)
- PHMSA Gas Distribution Data (pdf)
- Risk Assessment Methods (pdf)
- Cover Description (pdf)
- Confidentiality Motion (pdf)

o SDG&E

- Gas System Summary Statistics (xlsx)
- Gas System Census Tract Data (xlsx)
- Consumption Data by Census Tract (xlsx) (notes pdf)
- Consumption Data by Zip Code (xlsx)
- Supplemental Data (xlsx) (May 20 xlsx)
- PHMSA Gas Distribution Data (pdf)
- Risk Assessment Methods (pdf)
- Cover descriptions (pdf)
- Confidentiality Motion (pdf)

o Southwest Gas

- Gas System Summary Statistics (xlsx)
- Gas System Census Tract Data (xlsx)
- Consumption Data by Census Tract (xlsx)
- Consumption Data by Zip Code (xlsx)
- Cover Description, Risk Assessment Methods, PHMSA Gas Distribution Data (pdf)

o Selected Rulings Describing Required Data

- October 28, 2022: Confidentiality Ruling (pdf)
- September 21, 2022: Revised Gas System Data Ruling (pdf)
- March 1, 2022: Gas System Data Ruling (pdf)

Economic Analysis of the US Renewable Natural Gas Industry

December 2022

Key Assumptions & Methodology

Data Sources: RNG facility capacity and cost information (e.g., volume and status) provided by The Coalition for Renewable Natural Gas.

Data reflects the annual operational capacity of facilities (e.g., MMBTUs), capital expenditures of facilities under construction, and planned number of facilities as of October of 2022.

Economic modeling of capital expenditures and operational production capacity was conducted using IMPLAN software.

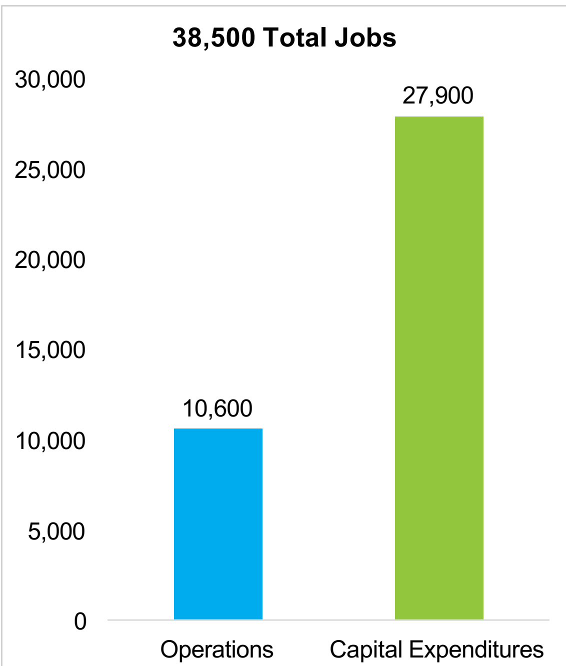
Note: Many of the significant changes seen between this update and the previous study (completed in December 2021) are a result of improved data collection and therefore should be carefully considered in terms of indicative trends.

Executive Summary

Highlights from 2022

Renewable natural gas (RNG) is estimated to contribute 38,500 in jobs, $4.8B in GDP, and $9.5B in total business sales in 2022 based on RNG operational capacity and expected capital expenditures

These numbers include the direct, indirect, and induced economic impacts of RNG. Capital expenditures represent jobs (27,900) associated with facilities currently under construction and only persist for the construction timeline. Operational jobs (10,600) are for the current year 2022 and are anticipated to continue into future years.



Highlights from 2022

Although it is a relatively small industry today, RNG has the potential to create thousands of jobs

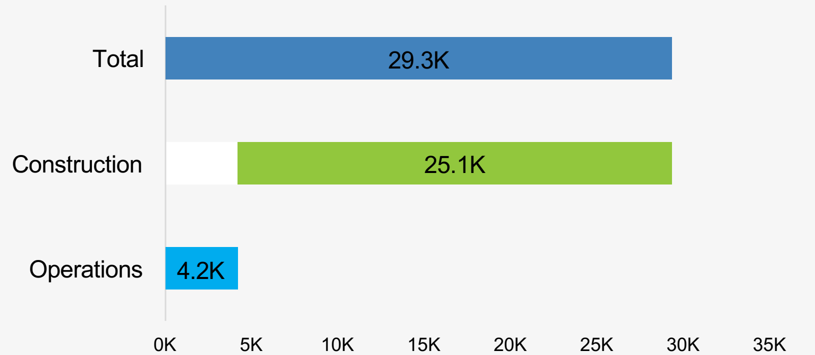
RNG facilities support the creation of operational jobs. The construction of 100 new RNG facilities would support 25,100 construction jobs and 4,200 operational jobs.

1.6 operations jobs are created for every $1 million spent on RNG production in 2022

22 operations jobs are created per 1 million MMBTUs of RNG generated in 2022

2 operations jobs created per 1 million EGE of RNG produced in 2022

100 new RNG facilities create an average of 4,200 operations jobs and 25,100 construction jobs



Highlights from 2022

Construction jobs vary by RNG feedstock

Construction of a wastewater project creates an average of 268 total jobs, an agricultural waste project an average of 216 total jobs, a food waste project an average of 424 total jobs, and a MSW project an average of 328 jobs.[1]

Construction of a wastewater project creates an average of:

109 direct jobs
63 indirect jobs
97 induced jobs
268 total jobs

Construction of an agricultural waste project creates an average of:

88 direct jobs
50 indirect jobs
78 induced jobs
216 total jobs

Construction of a food waste project creates an average of:

172 direct jobs
99 indirect jobs
153 induced jobs
424 total jobs

Construction of a MSW project creates an average of:

115 direct jobs
85 indirect jobs
129 induced jobs
328 total jobs

[1]Calculations are based on the average jobs per facility under construction for each feedstock in 2022. These numbers were provided by the RNG Coalition.

Highlights from 2022

Operations and maintenance jobs, across the supply chain, vary by RNG feedstock

Across the full supply chain, operation and maintenance of a wastewater project creates an average of 18 total jobs, an agricultural waste project an average of 16 total jobs, a food waste project an average of 41 total jobs, and a MSW project an average of 91 jobs.[1]

Operation and maintenance of a wastewater project creates an average of:

3 direct jobs
7 indirect jobs
8 induced jobs

18 total jobs

Operation and maintenance of an agricultural waste project creates an average of:

3 direct jobs
6 indirect jobs
7 induced jobs

16 total jobs

Operation and maintenance of a food waste project creates an average of:

8 direct jobs
15 indirect jobs
18 induced jobs

41 total jobs

Operation and maintenance of a MSW project creates an average of:

17 direct jobs
33 indirect jobs
40 induced jobs

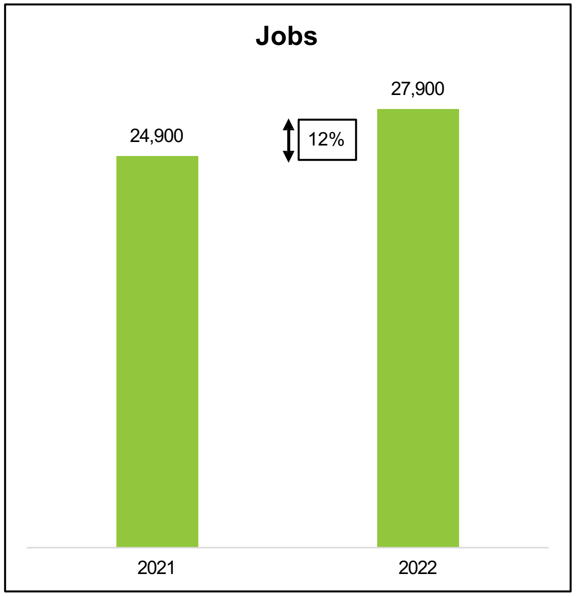
91 total jobs

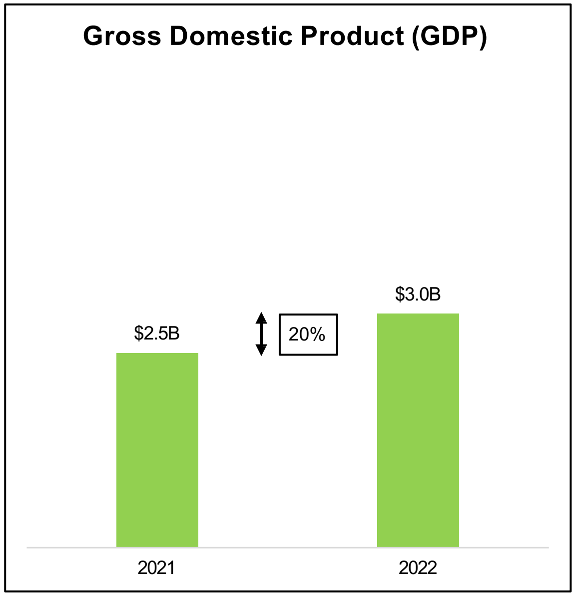
[1]Calculations are based on the average jobs per operating facility for each feedstock in 2022. These numbers were provided by the RNG Coalition.

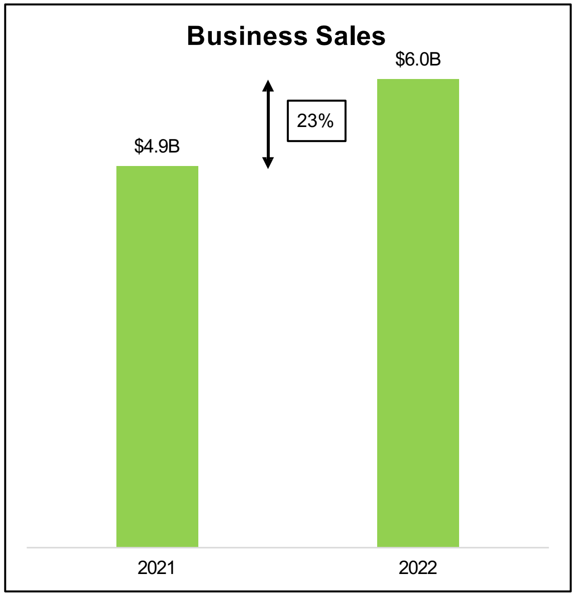
Comparison between 2021 and 2022

Economic impacts: capital expenditures

The economic impacts associated with RNG facilities under construction increased by 12% for jobs, 20% for GDP, and 23% for business sales between 2021 and 2022. This increase is driven by changes in the number of facilities, the amount of MMBTUs per facility, changes in costs, and increased inflation.





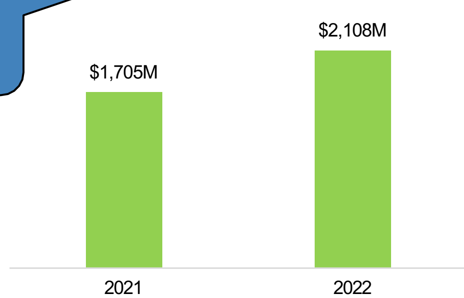


Comparison between 2021 and 2022

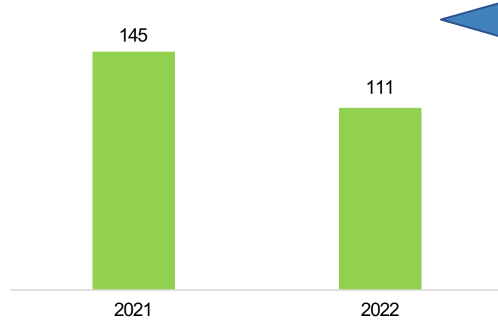
Capital expenditures by facility increased from 2021 to 2022

Why did Capital expenditures increase by 24% from 2021 to 2022…..

Capital Expenditures 2021 vs. 2022



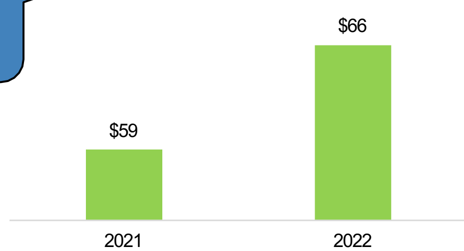
Capital Expenditures # of Facilities



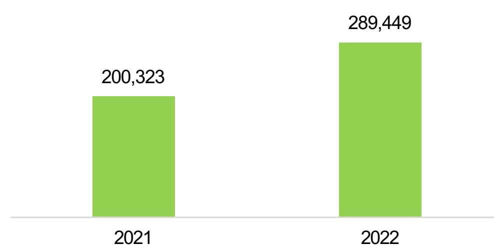
….when the number of facilities under construction went down by 23%?

Its because the cost of construction per MMBTU went up by 12%....

Capital Expenditures Cost per MMBTU



Capital Expenditures MMBTUs per Facility

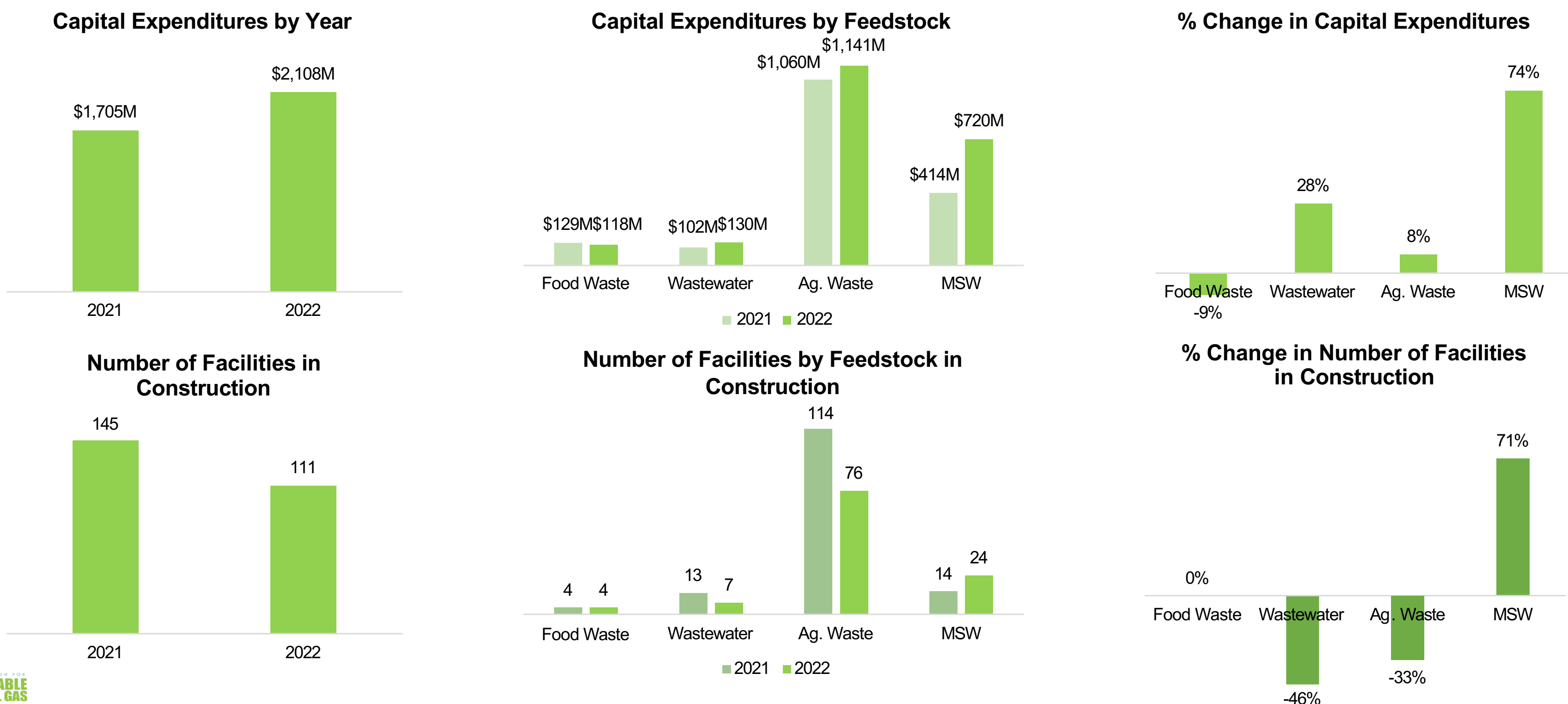


…. and the average # of MMBTUs per facility increased by 44%

Comparison between 2021 and 2022

Capital expenditures increased across every feedstock except food waste

MSW saw the largest increase in capital expenditures (74%) primarily because the number of MSW facilities under construction increased by 71%. The capital expenditures on ag. waste facilities increased by 8% despite the number of ag. waste construction projects decreasing by 33%.

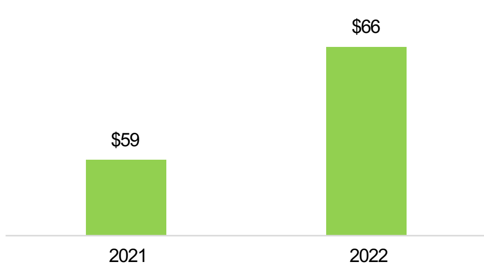


Comparison between 2021 and 2022

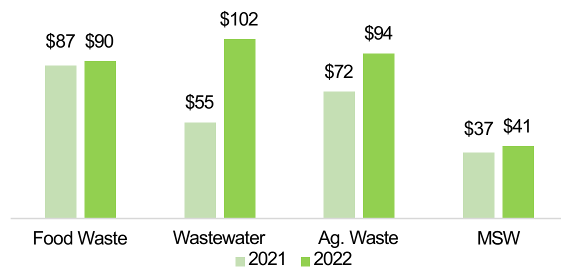
Drivers of capital expenditure increases

The increase in construction costs per MMBTU and the increased facility size were the primary drivers of increased capital expenditures. Wastewater saw the largest increase in cost per MMBTU (87%) and the average facility size increased by 44%, driven primarily by productivity increases in wastewater (28%) and ag. waste (24%).

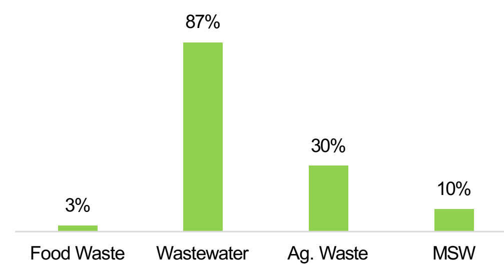
Cost per MMBTU by Year



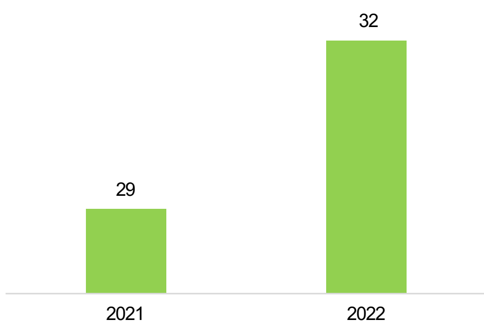
Cost per MMBTU by Feedstock



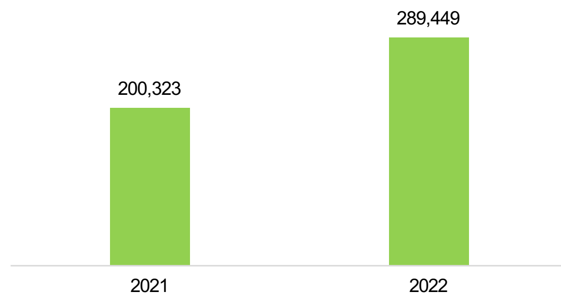
% Change in Cost per MMBTU



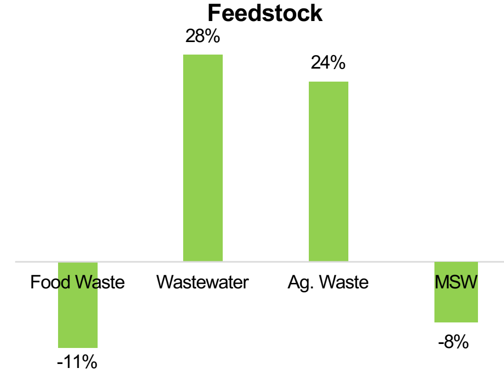
Millions of MMBTUs by Year



MMBTUs per Facility by Year



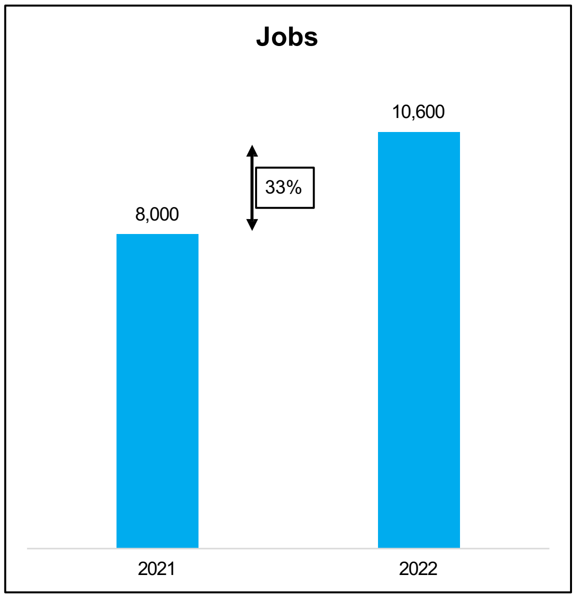
% Change in MMBTUs per Facility by Feedstock

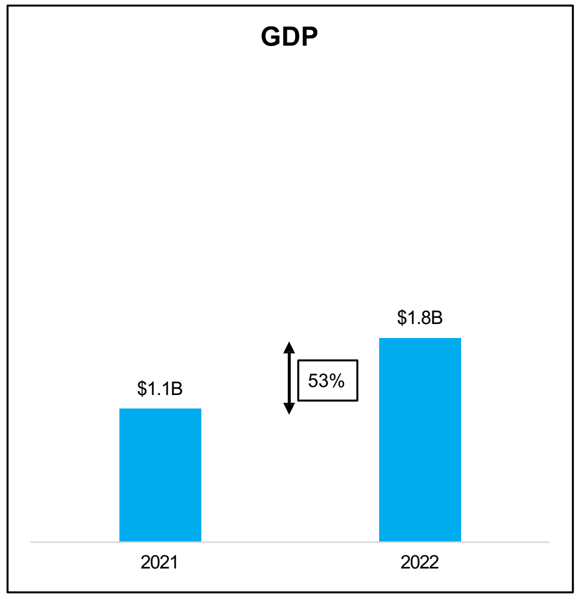


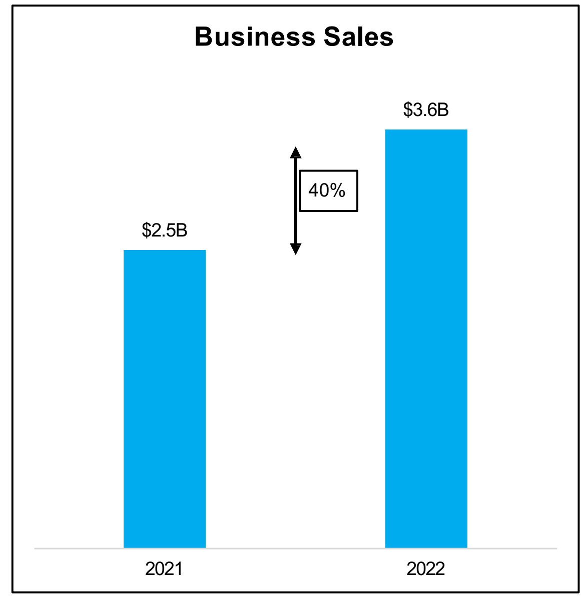
Comparison between 2021 and 2022

Economic impacts: operating facilities

The economic impacts associated with RNG facilities currently in operation increased by 33% for jobs, 56% for GDP, and 40% for business sales between 2021 and 2022. This increase is driven by changes in the number of operating facilities, MMBTUs produced per facility, changes in costs, and increased inflation.



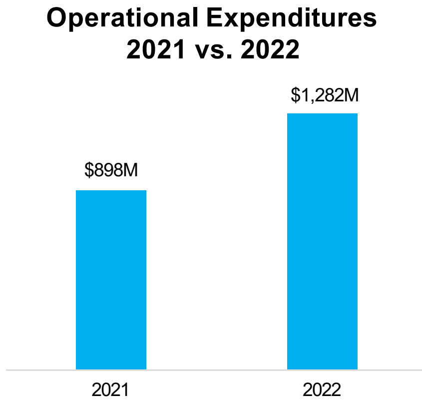


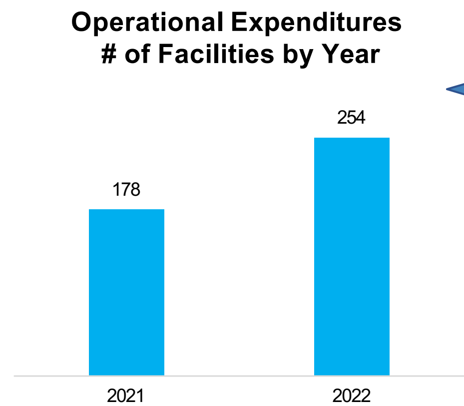


Comparison between 2021 and 2022

Capital expenditures by facility increased from 2021 to 2022

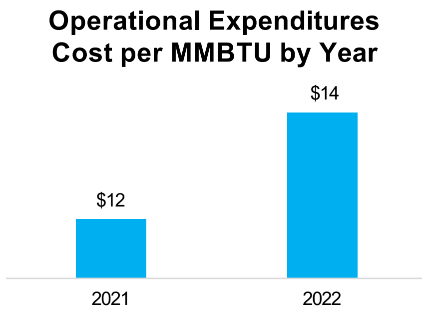
Operational expenditures increased by 43% from 2021 to 2022…..

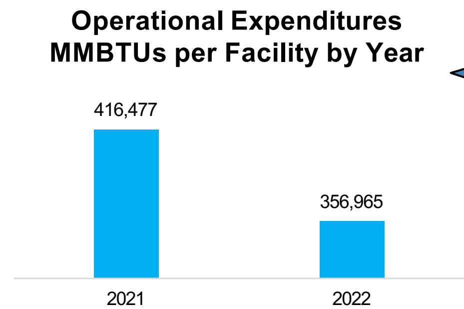




….primarily driven by the 43% increase in the # of operating facilities….

…..and because operational costs per MMBTU increased by 17%......





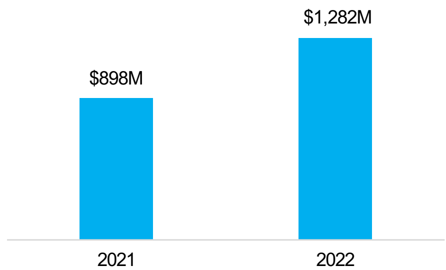
…. despite a 14% decrease in the average # of MMBTUs per facility

Comparison between 2021 and 2022

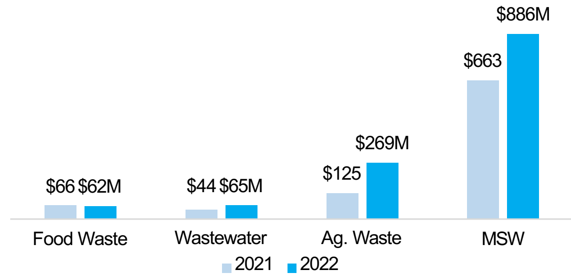
Operational expenditures increased across every feedstock except food waste

The number of RNG facilities in operation increased 43% from 2021 to 2022. Ag. waste saw the largest percent increase in capital expenditures (116%) primarily driven by an 89% increase in the number of facilities. MSW continued to have the highest operational costs (69% of all costs).

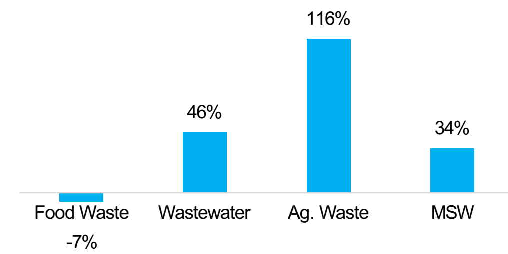
Operational Expenditures by Year



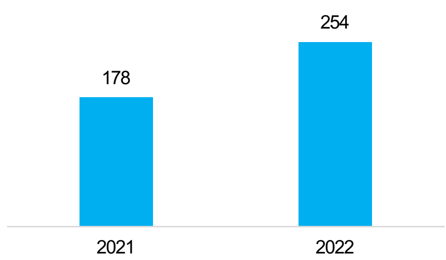
Operational Expenditures by Feedstock



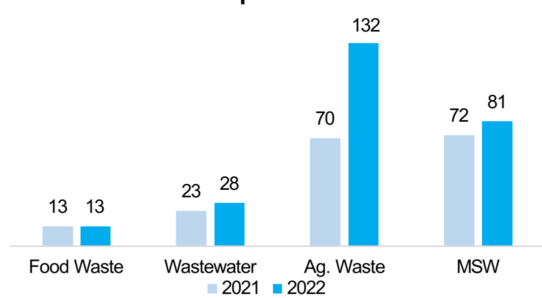
% Change in Operational Expenditures by Feedstock



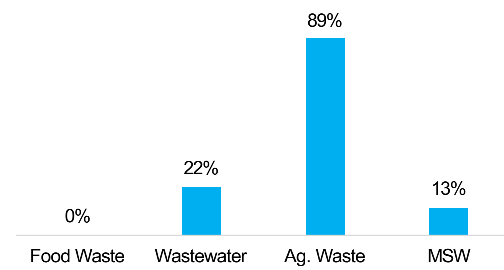
Number of Facilities in Operation



Number of Facilities by Feedstock in Operation



% Change in # of Facilities in Construction

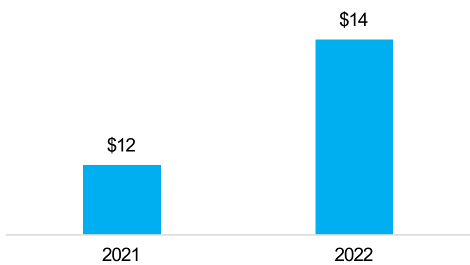


Comparison between 2021 and 2022

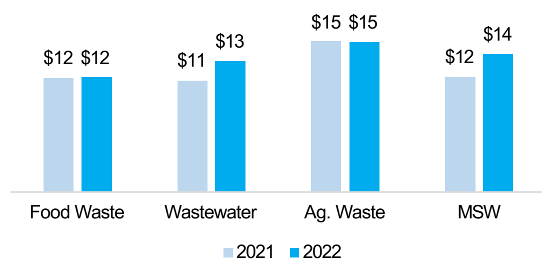
Drivers of operational expenditure increases

Operating costs per MMBTU increased by 17% from 2021 to 2022 driven by cost increases within wastewater (17%) and MSW (20%) feedstocks. The 22% increase in RNG MMBTUs produced resulted in higher operations costs despite a 14% drop in the average number of MMBTUs produced per facility. Ag. waste had the highest overall increase in MMBTUs produced (117%).

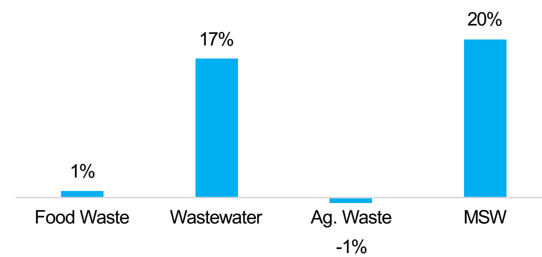
Cost per MMBTU by Year



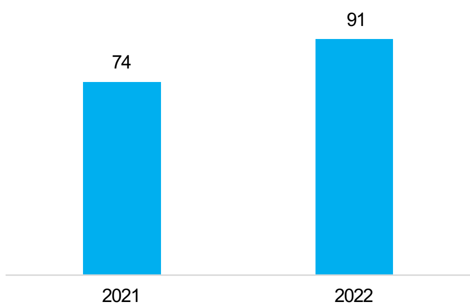
Cost per MMBTU by Feedstock



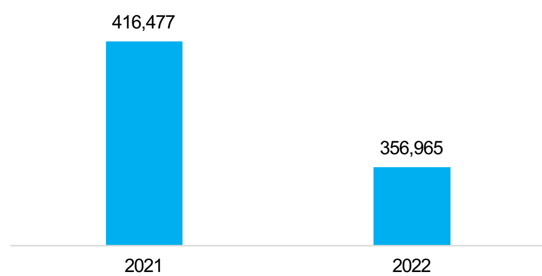
% Change in Cost per MMBTU



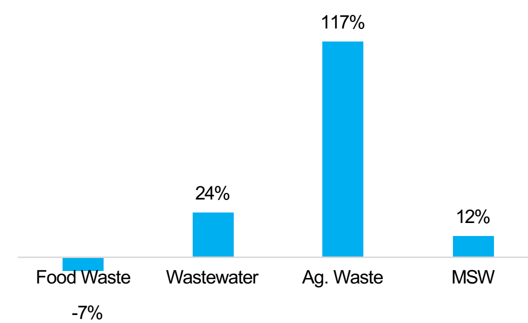
Millions of MMBTUs by Year



MMBTUs per Facility by Year



% Change in MMBTUs by Feedstock



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This study sets out to analyze the current economic contribution of Renewable Natural Gas (RNG) to the US economy in 2022

This report is comprised of four sections:

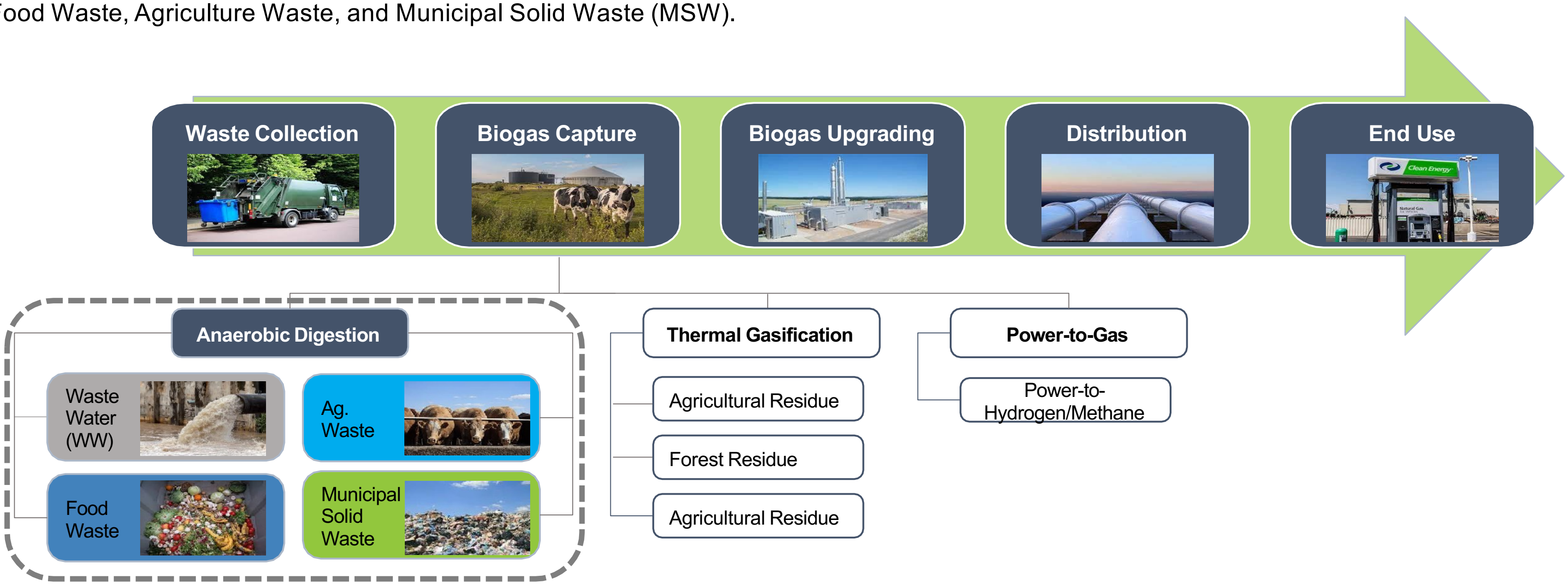
1	2	3	4
RNG Overview Introduces renewable natural gas (RNG)	**RNG Value Chain** Overview of the RNG value chain from waste collection to final use	**Expenditure Analysis** Calculates the spending associated with RNG 1) operations and 2) capital expenditures	**Economic Impact** Estimates jobs, GDP, and sales associated with RNG 1) operations and 2) capital expenditures

This study answers the following questions:

1. What is RNG and how is it produced?
2. What are the stages within the RNG value chain?
3. What are the costs of RNG?
4. What impact does RNG have on the U.S. economy?

1 RNG Overview: RNG is a clean, affordable, and reliable waste-derived fuel that can be used for transportation fuel for vehicles, generation of electricity, and thermal heating applications

Renewable Natural Gas (RNG) is type of fuel that comes from a variety of waste sources. As that waste breaks down, biogas is captured through Anaerobic Digestion, Thermal Gasification, or Power-to-Gas technologies. The biogas is upgraded into biomethane after carbon dioxide, hydrogen sulfide, and other gases are removed. The biomethane is fully interchangeable with natural gas and can be used for local uses or injected into natural gas distribution systems. This report will cover the four feedstocks of Anaerobic Digestion, the most common RNG technology: Wastewater, Food Waste, Agriculture Waste, and Municipal Solid Waste (MSW).



1 RNG Overview: Because of its greenhouse gas (GHG) reducing potential, RNG is considered a low-carbon fuel under the federal Renewable Fuel Standard and state low-carbon fuel standards

All sectors of the U.S. economy will need to decarbonize dramatically to reach the 2050 GHG emissions targets set by a growing number of states, enabling new business opportunities for renewable natural gas. RNG produced from organic wastes leads to GHG reductions in two ways:

1. Displacing the use of diesel in vehicles

RNG can facilitate the displacement of life-cycle GHG emissions from fossil fuel use in vehicles[2]

RNG reduces **660** million gallons of diesel consumed by heavy duty vehicles[3]

Filling approximately **3 million** semi trucks or **7.3 million** transit buses

Reducing **14,792** million pounds of CO_2 emissions

2. Reducing emissions from waste management

Waste management accounts for one third of U.S. methane production and 3 percent of total U.S. GHG emissions.[4] Food waste is often sent to a landfill where methane is released or burned (e.g., turned into carbon dioxide) which enters the atmosphere. Other types of organic waste are placed in an open lagoon and release methane. To produce RNG, these gases are captured and cleaned rather than being released directly into the atmosphere


Waste Lagoon


Landfill Fire

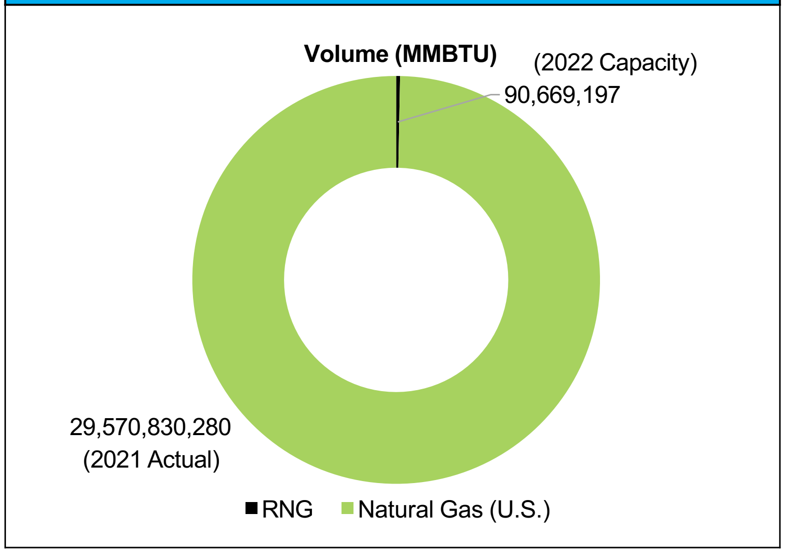

Anaerobic Digestors

[2]RNG's life-cycle net impact on GHG emissions also depends on the feedstock used, how much GHG would have otherwise been produced from fossil fuels, and how much methane escapes during RNG capture & upgrade
[3]Total RNG production capacity for 2022 converted from RNG in Ethanol Gallon Equivalents (EGE) to Diesel Gallon Equivalents (DGE) using conversions found at: https://nhcleancities.org/2017/04/can-compare-energy-content-alternative-fuels-gasoline-diesel/
[4]World Resources Institute, 2015

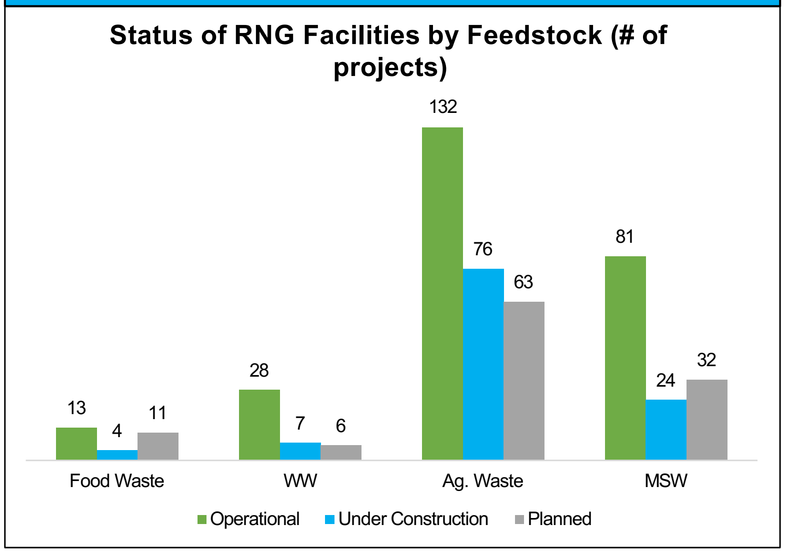
1 RNG Overview: With the total natural gas market at nearly 30 billion MMBTUs in 2021, current RNG production capacity represents an estimated 0.31% of the total market

Current renewable natural gas (RNG) production capacity in 2022 is nearly 91 trillion BTU's. When compared to total natural gas production in 2021, RNG production only accounts for 0.31% of the total market[5] and equates to over 1 billion gallons of ethanol gallon equivalent (EGE) or 710 million gallons of gasoline gallon equivalent (GGE). There are currently 254 operational RNG facilities and 223 facilities under construction or planned. The agriculture sector has the most projects currently under construction (76).[6]

Estimated U.S. Natural Gas Market (MMBTU)



Facility Status 2022

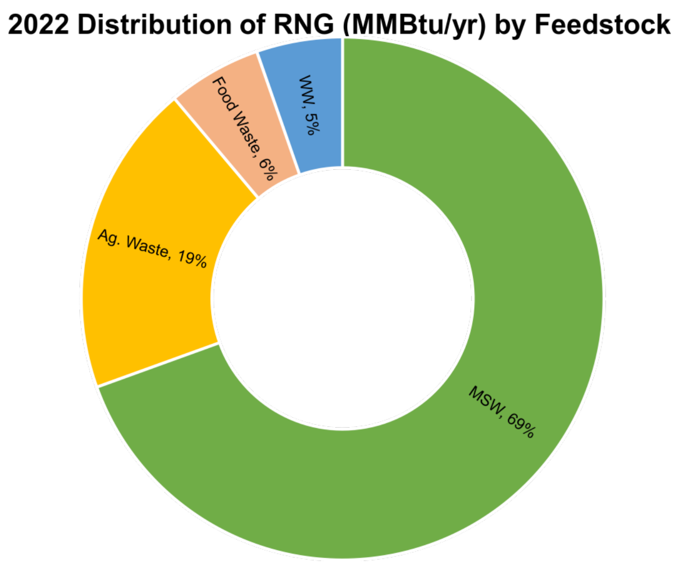


[5]Values for total RNG production and the U.S. natural gas market (U.S. Energy Information Administration (EIA)) are for the year 2021. This study assumes 100% of production capacity is utilized in 2022.
[6]2022 RNG capacity production volumes and capital expenditures data were provided by the RNG Coalition

1 RNG Overview: Sources of RNG by Feedstock

Current operating RNG facilities have the capacity to product nearly 91 trillion British thermal units (BTU) of biomethane in 2022. Of this, 69% is expected to come from landfills (MSW).[7]

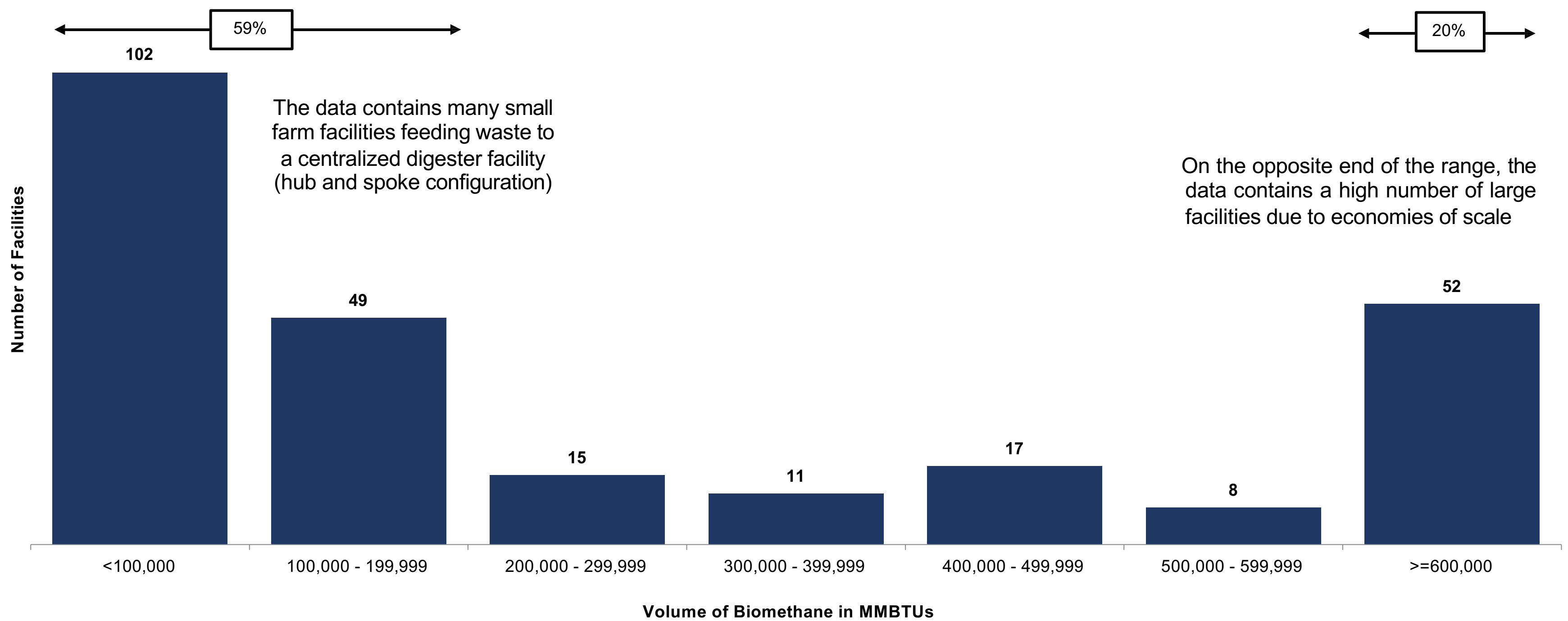
Distribution of Total Biomethane



[7]Data provided by the RNG Coalition and the Argonne National Laboratory (ANL)

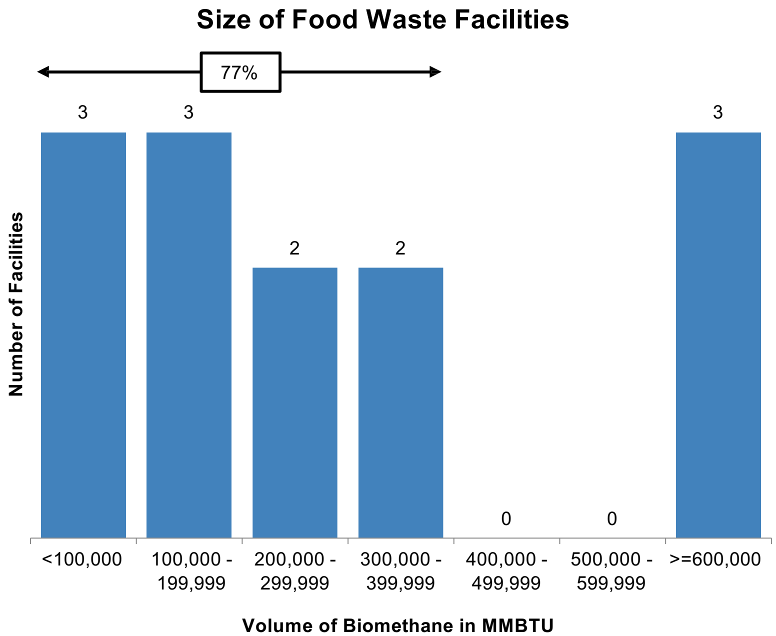
1 RNG Overview: There is a range of Operational RNG facility sizes by volume of MMBTUs

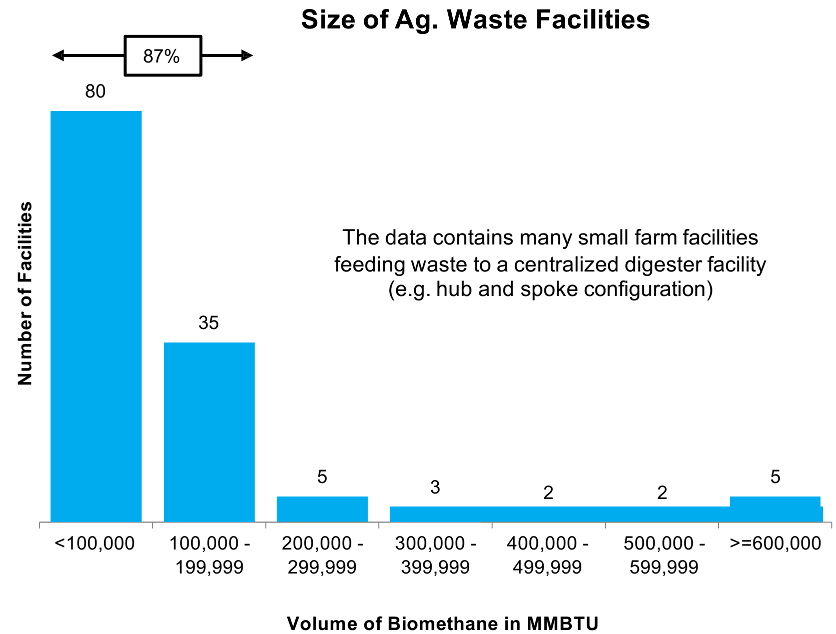
Presented below are the histograms for all operational RNG facilities grouped by range of biomethane production capacity (in MMBTUs). One hundred and two facilities produce less than 100,000 MMBTUs while 49 facilities produce between 100,000 and less than 200,000 MMBTUs (both ranges from primarily agriculture waste). Combined, these 151 facilities represent 59% of all operating RNG facilities. On the upper end of the spectrum, 52 facilities (primarily MSW) produce 600,000 or more MMBTUs of RNG (20%).



1 RNG Overview: There is a range of Operational RNG facility sizes by volume of MMBTUs for each feedstock

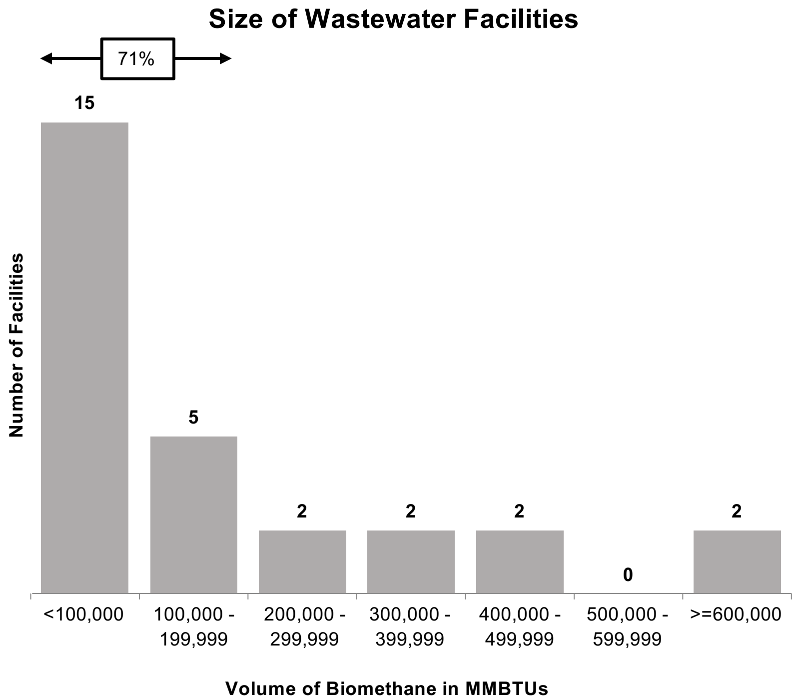
Presented below are the histograms for Food Waste and Agricultural Waste facilities grouped by range of biomethane production capacity (in MMBTUs). Seventy seven percent of all Food Waste facilities produce less than 400,000 MMBTUs of RNG while 87% of all Agricultural Waste facilities produce less than 200,000 MMBTUs of RNG (61%: <=100,000 MMBTUs and 27% between 100,000 and less than 200,000 MBTUs).

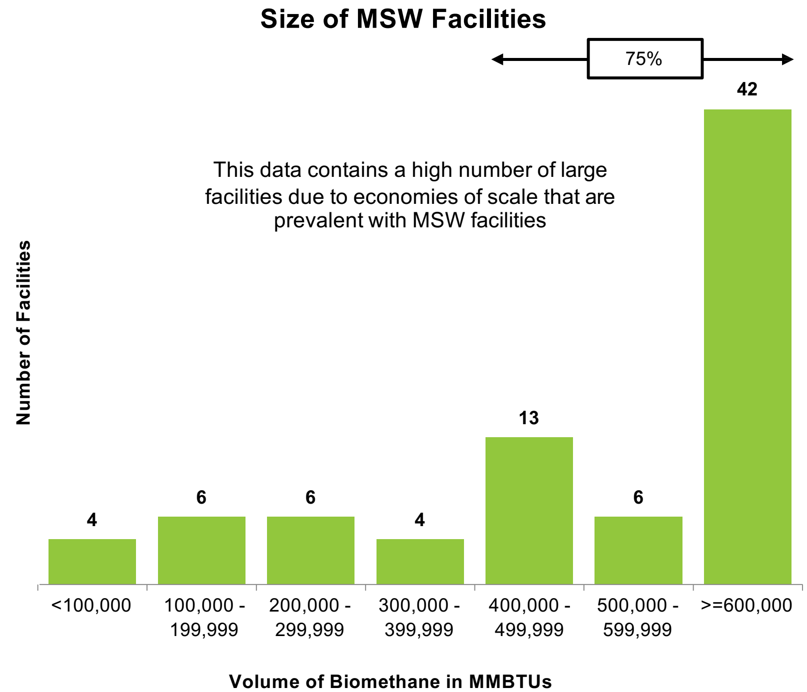




1 RNG Overview: There is a range of Operational RNG facility sizes by volume of MMBTUs for each feedstock

Presented below are the histograms for Wastewater and MSW facilities grouped by range of biomethane production capacity (in MMBTUs). For Wastewater, 71% of facilities produce less than 200,000 MMBTUs whereas 75% of MSW facilities produce more than or equal to 400,000 MMBTUs of RNG.





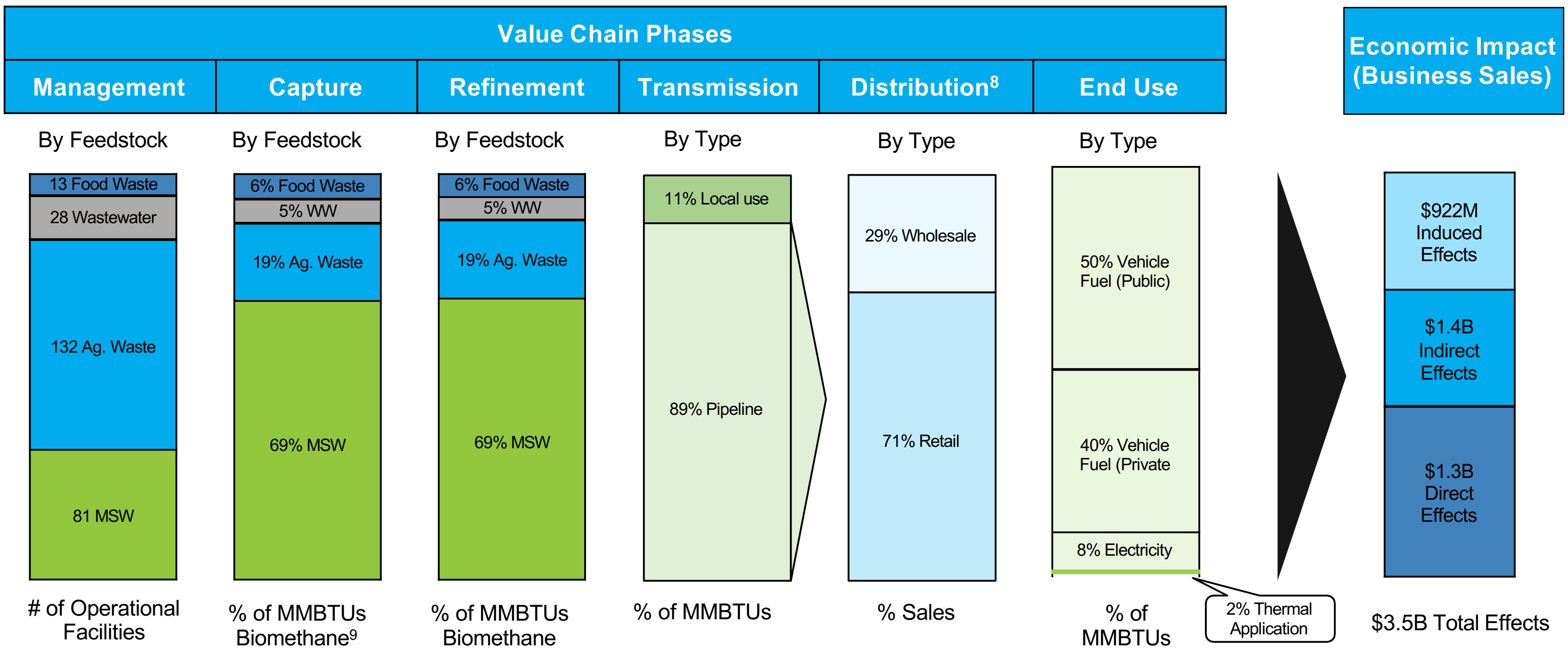
2 RNG Value Chain: The are 6 stages within the RNG value chain

Each stage of the value chain plays a role in the capture and upgrade of RNG ranging from management (waste collection) to distribution. A portion of RNG is transported via local pipeline for local vehicle usage while the remaining portion is injected into the natural gas pipeline system. The value chain is important to understanding the operation costs associated with RNG which is used to calculate its economic impact.

		Value Chain Phases					
Size	**Description**	**Management**	**Capture**	**Refinement**	**Transmission**	**Distribution**	**End Use**
Small Ops (aggregate waste to larger facility)	On/Off site anerobic digestion (hub & spoke)	Collection of waste	Anerobic digestion of waste (on-site or off-site)	Biogas is upgraded to biomethane by removing $C0_2$, H_2S, and other trace gasses	Use of local pipeline or injection of RNG into the Natural Gas pipeline network	Vehicle fuel is distributed to end users via local pipeline or through wholesale / retail channels.	Vehicle fuel, electricity generation, and thermal heating application
Large Ops (Onsite capture)	Onsite anerobic digestion (pipeline)		Anerobic digestion of waste (on-site)				

2 RNG Value Chain: Each stage becomes an input into the economic impact of RNG

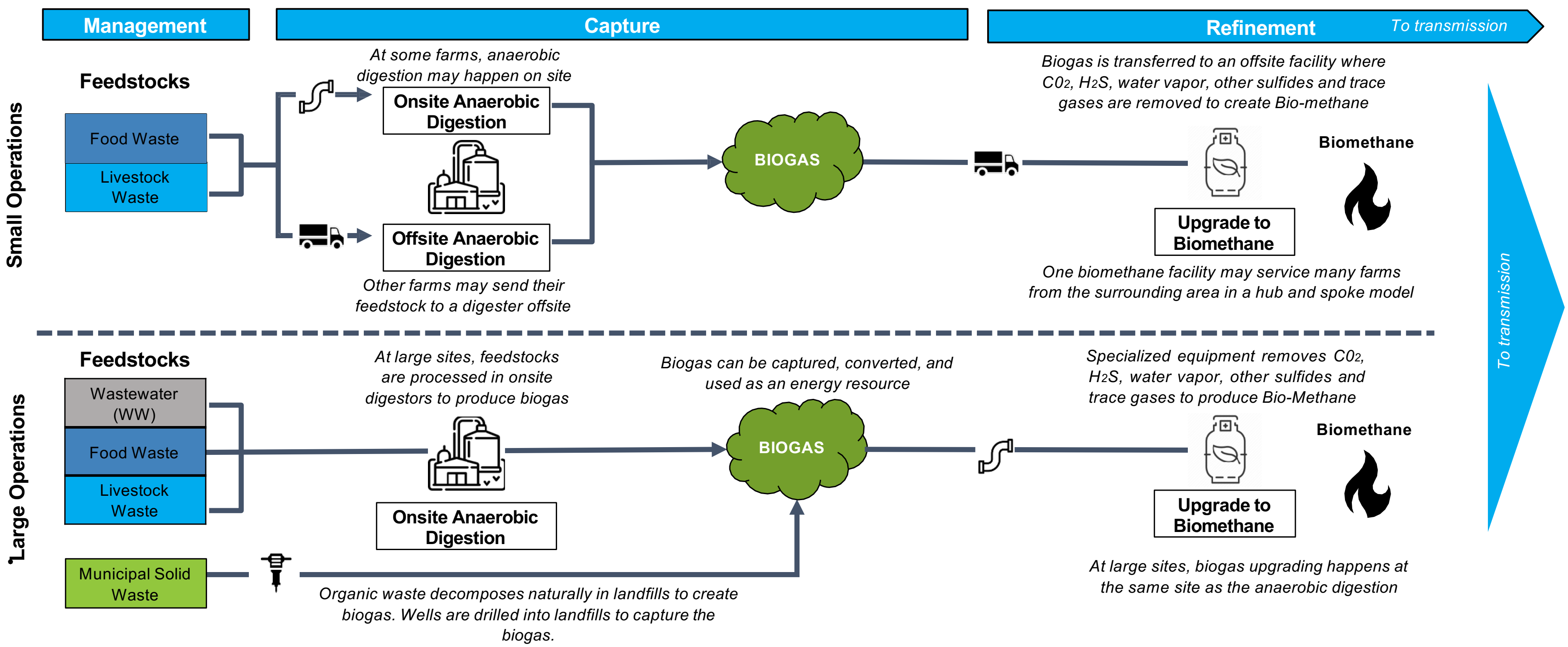
This diagram details the percentage of feedstock contribution associated with the first three phases of the value chain and how they ultimately feed into the economic impact of the RNG industry in 2022.



[8]Distribution types for vehicle fuel
[9]RNG Coalition data only included MMBtu volumes of Biomethane

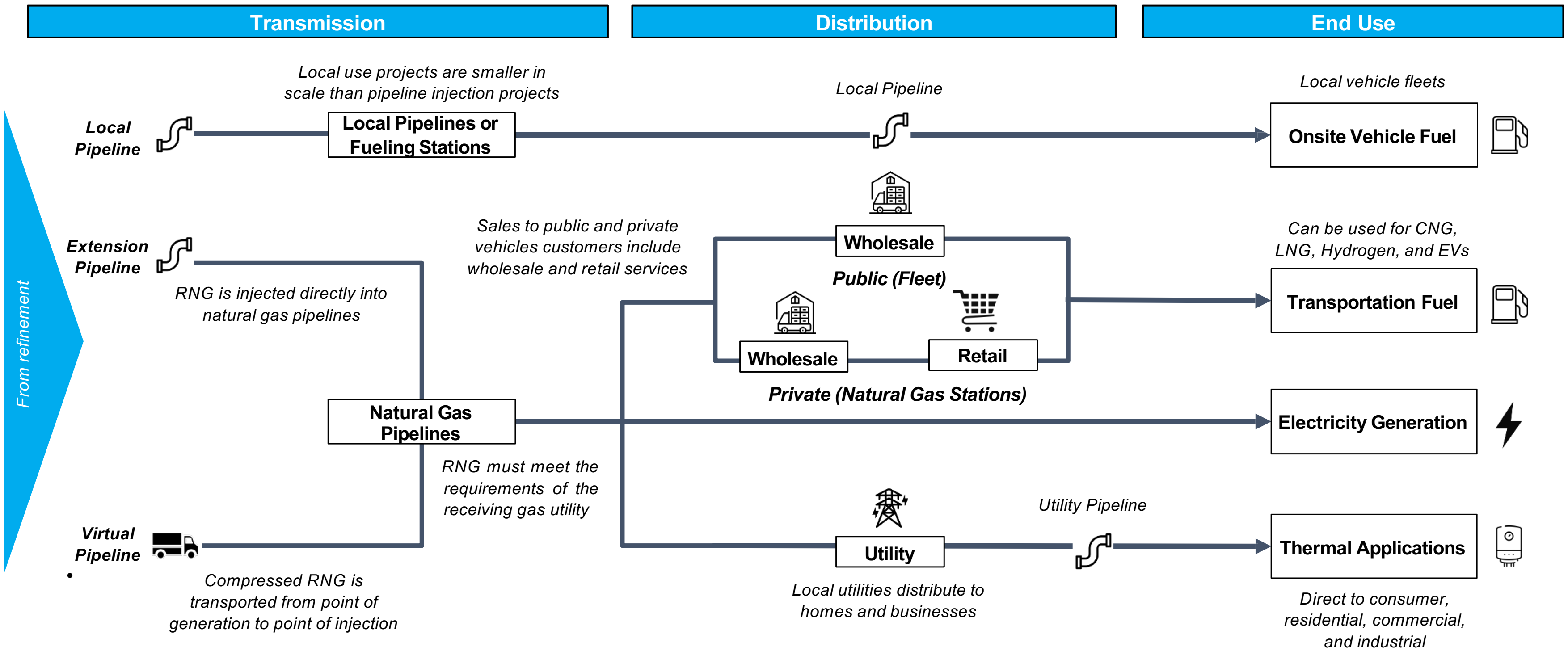
2 RNG Value Chain: This diagram illustrates the management, capture, and refinement phases of the Anaerobic Digestion value chain

There are generally two streams for the management, capture, and refinement phases of the value chain. Many small operations must capture and refine their biogas offsite, resulting in a hub and spoke model for upgrading, while many large operations can capture and refine biogas onsite.



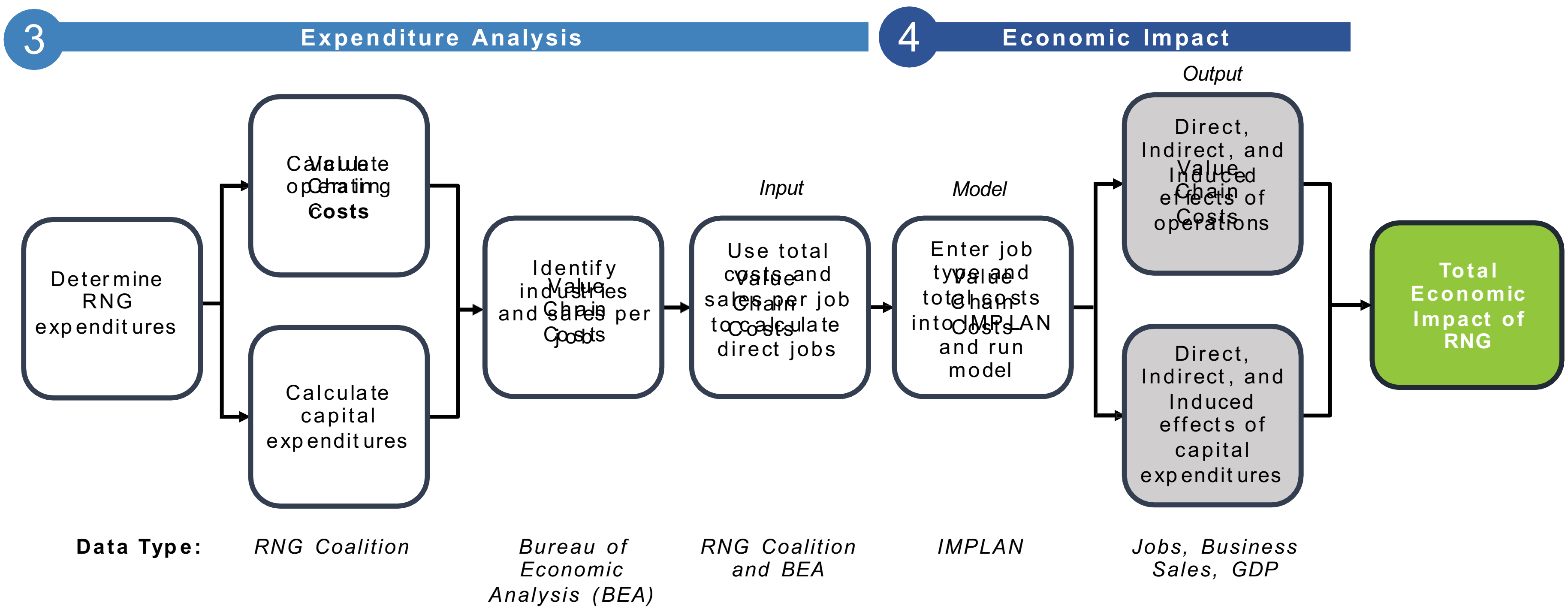
2 RNG Value Chain: This diagram illustrates the transmission, distribution, and end use phases of the Anaerobic Digestion value chain

All biomethane, whether produced onsite or at a centralized upgrading location, is transmitted through one of three ways:



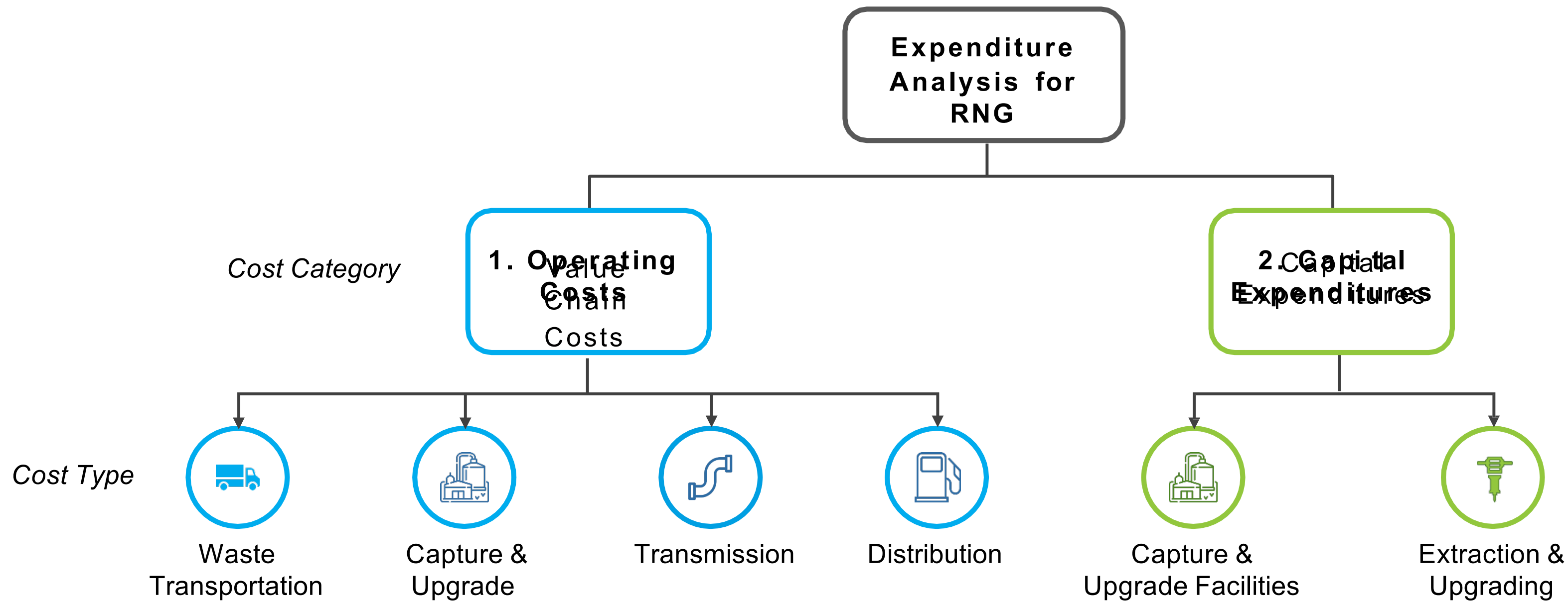
3 Expenditure Analysis: This study uses an input-output analysis model to analyze the economic impacts of RNG to the US economy in 2022

This study employed an input-output economic impact method of analysis since the primary focus is the economic impacts of RNG operations and capital expenditures on the U.S. economy. This analysis method is the most appropriate for this task. The diagram below illustrates the steps, outputs, and data types used to calculate the total current economic impact of RNG.



3 Expenditure Analysis: The inputs to the 2022 economic impact analysis are based on two cost categories: 1) operating costs and 2) capital expenditures

Operating costs refer to the ongoing expenses incurred from the normal day-to-day of running of the waste transportation, capture and upgrade, transmission, and distribution phases of the value chain. Capital expenditures refers to the construction costs for the extraction, capture, and upgrade of biogas into RNG. Each cost category is broken down further into cost types as depicted below:



3 Expenditure Analysis: Understanding the operating costs of RNG

Within operating costs, there are four types of costs mapped onto the five phases of the value chain depicted below. Sources of information to calculate costs for each cost type are also cited below.

Operating Costs

Cost Type:	Waste Transportation	Capture and Upgrade	Transmission	Distribution
Value Chain Phase:	Management	Capture Refinement	Transmission	Distribution
Costs Source:	Tons of waste collected	1) MMBTUs of biomethane produced & 2) number of administrative jobs	Value of MMBTUs sold (market prices)	Value of MMBTUs sold (market prices)

3 Expenditure Analysis: Waste transportation costs - $23.3M

Waste collection is the initial step in producing RNG from Food Waste and Agricultural Waste feedstocks. Using data from the Argonne National Lab and the Coalition for Renewable Natural Gas, we determined how much waste was needed to produce the amount of biomethane generated by each feedstock facility. Estimates of transportation cost per ton were then used to determine the total transportation costs of moving food and agricultural waste from generation site to RNG facility. Wastewater and municipal solid waste were not included in these estimates because collection of these feedstocks would have occurred regardless of any biogas capture and upgrading.

Waste Transportation Costs

Feedstock	MMBTU	Tons of Waste per MMBTU[10]	Tons of Waste	Cost per Ton[11]	Transp. Costs
Food Waste	5.3T	0.48	2.5M tons	$1.69/ton	$4.3M
Ag. Waste	17.5T	0.66	11.6M Tons	$1.69/ton	$19.5M
Total	22.8T		14M Tons		$23.8M

[10]Based on feedstock weighted average from Argonne National Labs database.
[11]Bioenergy Supply in Ireland 2015 – 2035. Sustainable Energy Authority of Ireland.

3 Expenditure Analysis: Capture and upgrade costs for RNG consist of two sources: 1) upgrading biogas to biomethane (RNG) and 2) administrative costs

Upgrading biogas to biomethane is the second type of operational cost associated with the production of RNG. The process of estimating capture and upgrading and administrative costs are illustrated below.

RNG Capture & Upgrade

1. RNG Capture & Upgrading

- Identify ranges of average cost of biogas capture & upgrade per $/MMBTU
- Assign range of costs to specific levels of Biomethane production (in MMBTUs)
- Multiply the capture & upgrading cost per MMBTUs times the volume for each facility

2. Administrative Costs

- Identify and count the number of RNG Facilities
- Add one administrative job per facility
- Sum the number of administrative jobs for all RNG facilities

3 Expenditure Analysis: The average $/MMBTU cost of upgrading biogas to RNG ranges from $7 per MMBTU up to $23 per MMBTU

To calculate the capture and upgrading costs of biogas to biomethane for different levels of volume, Guidehouse used a variety of data sources indicating capture and upgrading costs ($/MMBTU) ranged from $7 per MMBTU up to $23 per MMBTU. These costs were then assigned to different levels of biogas and biomethane volumes based on information contained in the EPA report. Converting the units of SCF per minute into annual MMBTUs of biomethane, Guidehouse created a RNG Cost/Volume matrix to reflect the average costs associated with different volumes of biogas capture and biomethane generation for each facility.

Averaging the ranges of $/MMBTU from the reports resulted in an average cost range of $7.44 to $23.60

Sources

- World Resources Institute — Working Paper — The Production and Use of Renewable Natural Gas as a Climate Strategy in the United States
- EPA — United States Environmental Protection Agency
- A Report to the Washington State Legislature, December 2018 — Energy Program; Department of Commerce
- ICF — Study on the Use of Biofuels (Renewable Natural Gas) in the Greater Washington, D.C. Metropolitan Area, March 2020
- Guidehouse Proprietary Research

RNG Cost/Volume Matrix

Biogas Capture	Upgrade to Biomethane	Costs ($/MMBTU)	Production Costs
SCF/Min	MMBTU/Year[12]	Average	Average
50	13,600	$23.60	$0.321M
100	27,200	$17.77	$0.483M
200	54,400	$12.56	$0.683M
300	81,599	$12.56	$1.025M
475	129,199	$10.92	$1.411M
650	176,799	$9.29	$1.642M
1,125	305,998	$7.65	$2.342M
1,600	435,197	$7.44	$3.239M
2,300	625,595	$7.44	$4.656M

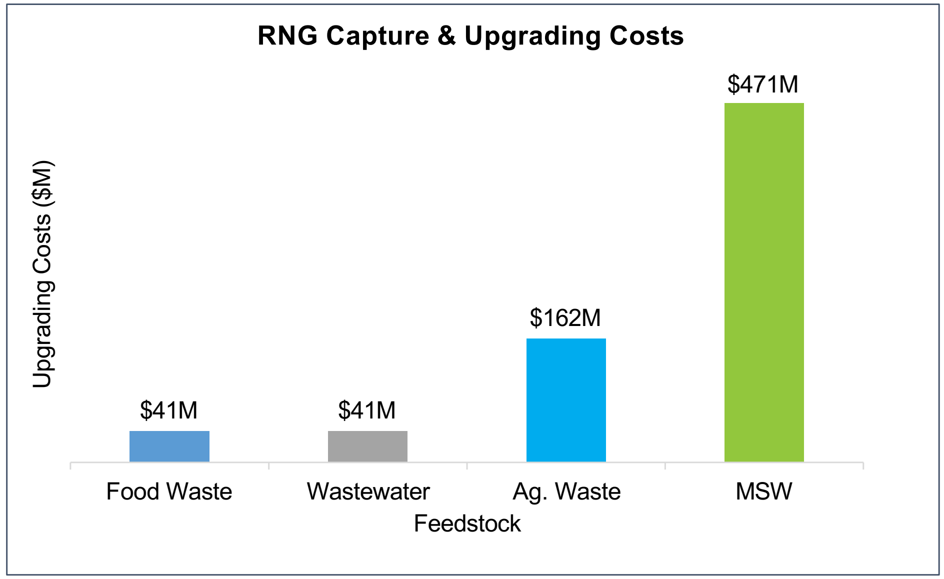
[12] Guidehouse used the Argonne National Lab Methodology to convert SCFM to MMBTU/Year: SCFD *.001 * 365 *.9 = MMBTU (Assumes 1,000 BTU/SCFD, 90% run time, 365 days)

3 Expenditure Analysis: Total capture and upgrade costs are estimated to be $715M in 2022

Guidehouse used the RNG Cost/Volume Matrix to estimate capture and upgrading costs by multiplying the MMBTUs produced times the $ per MMBTU for each facility and then aggregated across all feedstock types.[13] These values represent the costs of capturing the biogas and upgrading it into biomethane.

Total Cost of RNG Upgrading			
Feedstock(s)	**Volume (MMBTU/Year)**	**$ per MMBTU**	**Upgrading Costs**
Food Waste	5,267,000	$7.44 to $23.60	$41M
Wastewater	4,830,000		$41M
Ag. Waste	17,562,000		$162M
Municipal Solid Waste	63,003,000		$471M
Total	90,669,000		$715M

Municipal solid waste has the largest volume of RNG and therefore has the highest associated costs of $471 million. The total cost for upgrading RNG across all four feedstocks is $715 million.



[13]RNG costs were calculated using the sources outlined on slide 23. Volume amounts were provided by the RNG Coalition.

3 Expenditure Analysis: Administrative costs for RNG capture and upgrade are estimated to be $20.2M in 2022

The second cost component for capture and upgrade is administrative jobs. These jobs include overseeing financial transactions, bookkeeping, transactions, and other support services. To account for these activities, Guidehouse estimated 1 administrative job per operating facility based on guidance from RNG Coalition. Assuming an average income of $79k per admin job (U.S. Bureau of Economic Analysis) Guidehouse estimated the total administrative costs for each feedstock.

Total Administrative Costs					
Feedstock(s)	**Number of Operational Facilities**	**Admin Jobs per Facility**	**Number of Admin Jobs**	**Cost per Job[14]**	**Total Admin Costs**
Food waste	13	1	13	$79,609	$1.0M
Wastewater	28	1	28	$79,609	$2.2M
Ag. Waste	132	1	132	$79,609	$10.5M
Municipal Solid Waste	81	1	81	$79,609	$6.4M
Total	254		254	$79,609	$20.2M

[14]Average incomewage for office and administrative support jobs (BEA)

3 Expenditure Analysis: Adding upgrading costs and administrative costs together, the total cost for RNG capture and upgrade for all four feedstocks is estimated to be $735M in 2022

Costs associated with biogas capture, upgrade to biomethane (RNG), and administrative costs are combined to reflect the total RNG Capture and Upgrade Costs grouped by type of feedstock.

RNG Capture and Upgrade Costs

Input		Capture and Upgrade Costs		Total Cost
Feedstock(s)	**Volume (MMBTU/Year)**	**1 Biogas Upgrading Costs**	**2 Total Admin Costs**	**Total Cost of Capture and Upgrade**
Food Waste	5,267,000	$41M	$1.0M	$42M
Wastewater	4,830,000	$41M	$2.2M	$43M
Ag. Waste	17,562,000	$162M	$10.5M	$173M
Municipal Solid Waste	63,003,000	$471M	$6.4M	$478M
Total	90,669,000	$715M	$20.2M	$735M

3 Expenditure Analysis: Estimated cost of RNG transmission is $464M

Transmission is the third type of cost type in generating RNG. Of the 91 trillion BTUs of RNG production capacity in 2022, 81 trillion BTUs (89%) is estimated to be injected into the natural gas pipeline transmission system. Ninety percent of the RNG injected into the system is used for transportation fuel. Natural gas pricing information for each of the final uses was based on data from the U.S. Energy Information Administration (EIA). These prices and their associated volumes (in units of 1,000 SCF) were used to estimate total transmission sales.

Transmission

Final Use	MMBTUs[15]	% of Total	Volume (1,000 SCF)	Natural Gas Price	Sales
Vehicle (Public)	40,225,599	50%	38,790,356	$6.01	$233M
Vehicle (Private)	32,462,764	40%	31,304,498	$6.01	$188M
Electricity	6,461,188	8%	6,230,654	$4.67	$29M
Thermal	1,615,297	2%	1,557,663	$8.98	$14M
Total	80,764,849	100%	77,883,171		$464M

Definitions

Vehicles (Public) Government Agency Fleets

Vehicles (Private) Retail Natural Gas Stations

[15] Adjusted for only pipeline volume.

3 Expenditure Analysis: The total cost of distribution (wholesale and retail) for RNG was $58.2M

Distribution is the fourth type of cost in generating RNG. Of the four final uses, sales to public and private vehicles customers include wholesale and retail services. In addition to the transmission sales, wholesale (4%) and retail (22%) markup percentages were applied to account for distribution services provided. Wholesale services cost an additional $16.9M and retail services cost an additional $41.3M to distribute RNG to final users (e.g., public fleets and private natural gas retail stations).

Distribution

Final Use	Sales	Wholesale margin	Wholesale Sales	Retail Margin	Retail Sales	Total Sales
Vehicles (Public)	$233M	4%	$9.3M			$9.3M
Vehicles (Private)	$188M	4%	$7.5M	22%	$41.3M	$48.9M
Total	$421M		$16.9M		$41.3M	$58.2M

Definitions

Retail Margin The margin (e.g. mark-up) added to T&D sales to reflect associated retail costs

Wholesale Margin The margin (e.g. mark-up) added to T&D sales to reflect associated wholesale costs

3 Expenditure Analysis: RNG operations costs are estimated to support 2,105 direct jobs in 2022

The total costs from the four major cost categories of the value chain were used to estimate the direct number of jobs for RNG production. Total costs are divided by the industry productivity ratios (e.g., sales per job) provided by the BEA. The calculations below illustrate how each of the 4 cost categories are used to estimate direct jobs by industry.

Waste Transportation

Capture and Upgrade

Transmission

Distribution

Direct Effects		Industry Unit Relationships (sales per job)		Direct Jobs	Industry
$24M (Transportation)	÷	$257,000 / job	=	93	*Waste management*
$715M (Capture & Upgrade)	÷	$697,000 / job	=	1,026	*Misc. Chemical Product Mfg*
$20M (Admin)	÷	$79,600/ job	=	254	*Office Administrative Services*
$464M (Transmission)	÷	$1,258,000 / job	=	369	*Natural Gas Distribution*
$17M (Wholesale)	÷	$1,561,000 / job	=	11	*Wholesale – Petroleum*
$41M (Retail)	÷	$157,000 / job	=	263	*Retail – Gasoline Stores*
Total: $1.3B		**Total Direct Jobs**		**2,015**	

3 Expenditure Analysis: Capital Expenditures associated with facility construction

The second cost category for producing RNG is capital expenditures. There are two types of capital expenditures: 1) Construction of Capture and Upgrade facilities and 2) Construction of Extraction and Upgrade facilities. These costs vary depending on the type of feedstock.

Capital Expenditures

Value Chain

Cost Type:

Capture & Upgrade Facilities

Extraction and Upgrade

Feedstock:

Food Waste

Ag. Waste

Wastewater

Food Waste, Ag. Waste, and Wastewater require construction of an anaerobic digestor to capture biogas. The biogas is then conditioned and upgraded into biomethane

MSW

MSW requires drilled wells to capture (extract) the biogas created by decomposing organic waste. The biogas is then conditioned and upgraded into biomethane

3 Expenditure Analysis: Across all feedstock types, the total cost of capital expenditures is estimated to be $2.1B

For food waste, agricultural waste, and wastewater, capturing and converting biogas into biomethane requires a digester and upgrading facilities. For municipal solid waste, the landfill acts as a digester and pipes are drilled into the ground to extract the biogas that naturally is generated. Costs per MMBTU and amount of MMBTUs expected to be produced were used to estimate construction costs for facilities without an original estimate.

Construction of Capture and Upgrade Facilities

Extraction and Upgrading

Feedstock	Expenditure Type	Expenditure ($)
Food Waste	Capture (Digester) and Upgrade	$118M
Agricultural Waste	Capture (Digester) and Upgrade	$1.1BM
Wastewater	Capture (Digester) and Upgrade	$130M
Municipal Solid Waste	Extraction and Upgrade	$720M
Total		$2.1B

Definitions

Capture and Upgrade The cost of capture via anaerobic digester and biomethane upgrading

Extraction and Upgrade The cost of capture via wells and biomethane upgrading

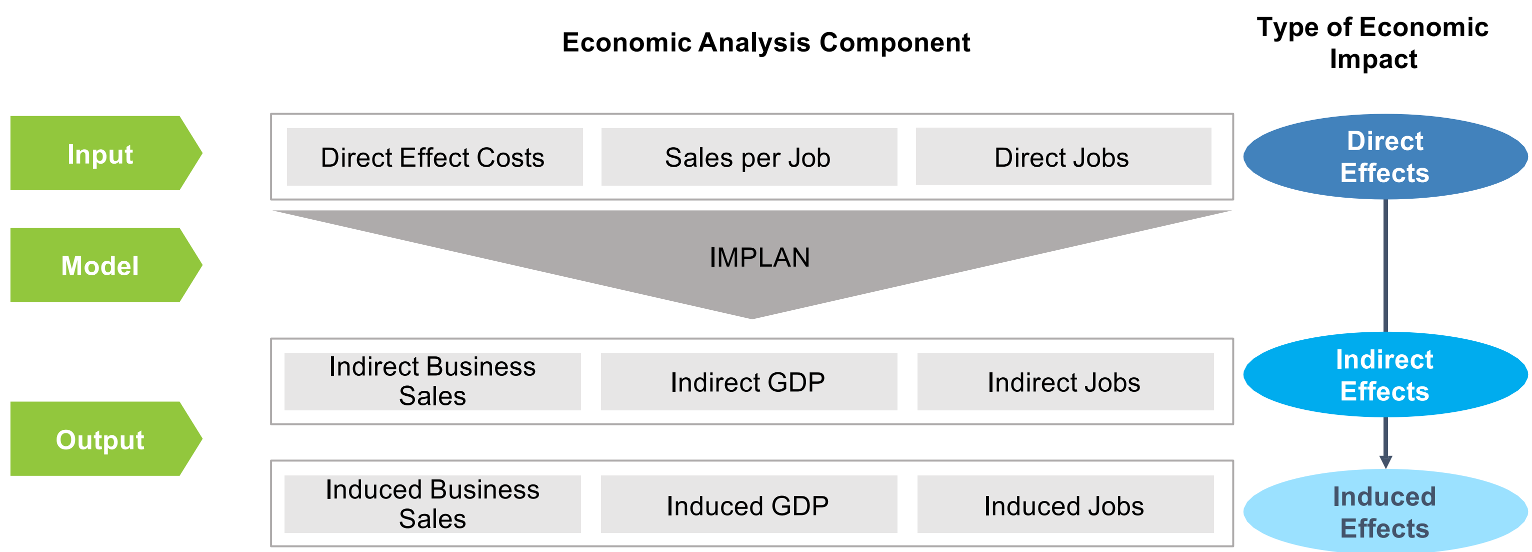
3 Expenditure Analysis: Based on RNG capital expenditure estimates, we estimate 10,855 direct jobs will be created from construction of RNG facilities during 2022

Total capital expenditures across all feedstocks are estimated to cost over $1.03B during 2022. These estimates were derived by dividing the construction costs by industry productivity ratios (e.g., sales per job) provided by the BEA (within IMPLAN). The calculations below illustrate how construction costs are used to estimate the 10,855 direct job counts by industry.

	Direct Effects		Industry Unit Relationships (sales per job)		Direct Jobs	Industry
Construction of Capture & Upgrade Facilities	$1.4B (Capture & Upgrading)	÷	$171,400 / job	=	8,104	*Construction (non-residential)*
Extraction & Upgrade	$360M (Extraction) $360M (Upgrading)	÷	$262,000 / job	=	2,751	*Drilling Oil & Gas well & Construction (non-residential) &*
	Total: $2.1B		**Total Direct Jobs**		**10,855**	

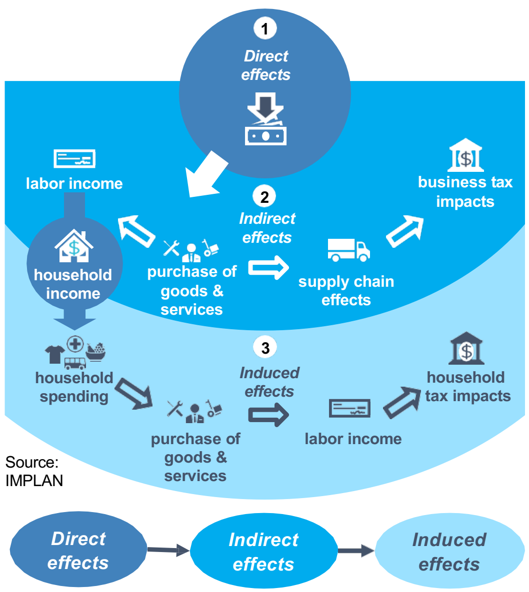
4 Economic Impact: The modeling tool IMPLAN calculates direct, indirect, and induced effects of RNG

The expenditures analysis produced three values for the operating costs and the capital expenditures of RNG – RNG Business Costs, Average Sales per Job, and the Number of Direct Jobs. This information is used as inputs in the economic modeling tool IMPLAN to calculate indirect and induced effects. This modeling indicates how much additional economic activity is supported by supplier purchases (indirect) and employee spending (induced) beyond the initial RNG capture and upgrade.



4 Economic Impact: Economic impact analysis allows us to understand the direct, indirect, and induced effects of RNG on the economy

The IMPLAN Input-output model estimates how money flows through the economy based on supply chain relationships; the effects are categorized into direct, indirect, and induced impacts. This analysis uses three types of metrics to reflect changes in the U.S. economy referenced in this report; business sales, Gross Domestic Product (GDP), and jobs.



Source: IMPLAN

Type of impact	RNG Example
Direct Effects resulting from direct spending	Spending within the RNG value chain
Indirect Effects resulting from industries purchasing from each other	Spending on materials, components, and services
Induced Effects resulting from household spending of labor income	Spending on housing, healthcare, transportation, food, retail and entertainment by workers

Metrics used in this report

Business Sales	Sales of goods and services across the supply chain.
Gross Domestic Product (GDP)	The sum of the value added or 'premium' created from each stage of the supply chain
Jobs	The number of jobs created from the supply chain activity stimulated through expenditure

4 Economic Impact: Economic impact measures reflect changes in the economy but are subsets of one another, meaning that they should not be added together

Business sales

Taxes

Profits

Income

Inputs: Goods & Services

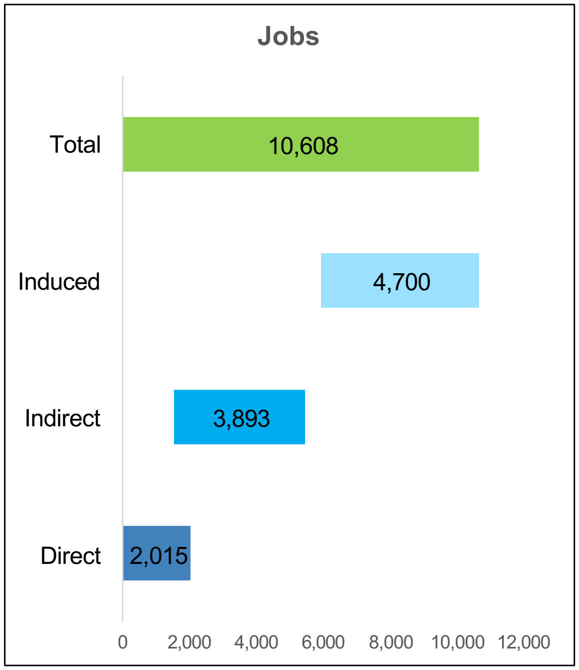
Value Added or Gross Domestic Product (GDP)

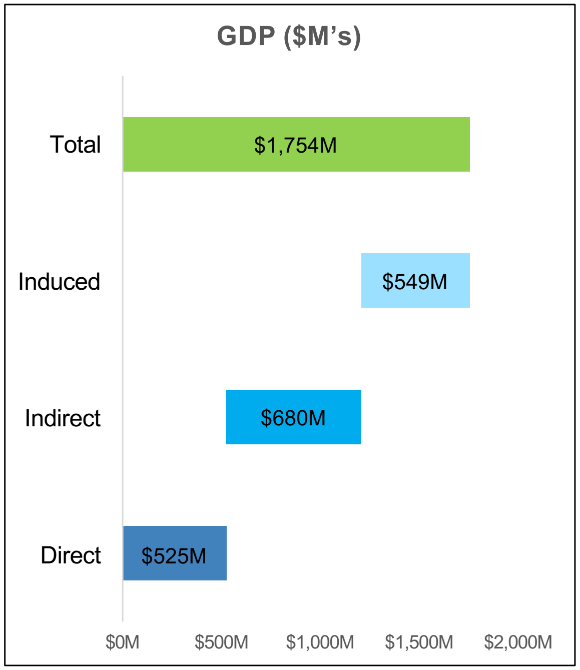
Jobs

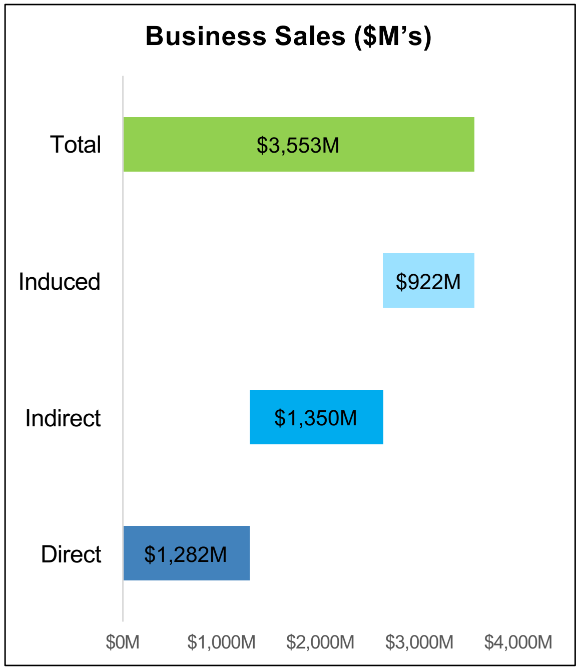
	Taxes
	Profits
+	Income
=	Value Added (GDP)
+	Inputs
=	Business Sales

4 Economic Impact: RNG operations are estimated to support a total of 10,600 jobs, generate a total of $1.8B in GDP, and result in over $3.5B in business sales in 2022

Based on the spending for RNG operations, the direct, indirect, and induced economic impacts are presented below in terms of jobs, GDP, and Business Sales. Over 2,015 direct jobs were attributed to activities within the RNG value chain with a total of 10,600 jobs. RNG supported a total of $1.8B in GDP and over $3.5B in business sales.

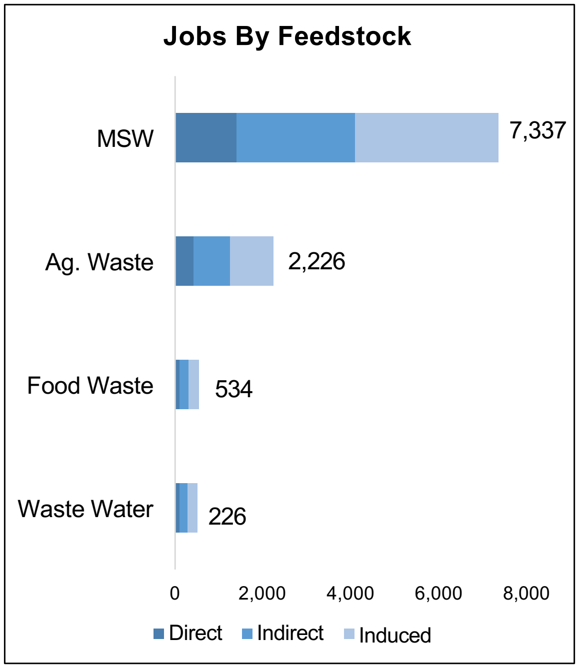


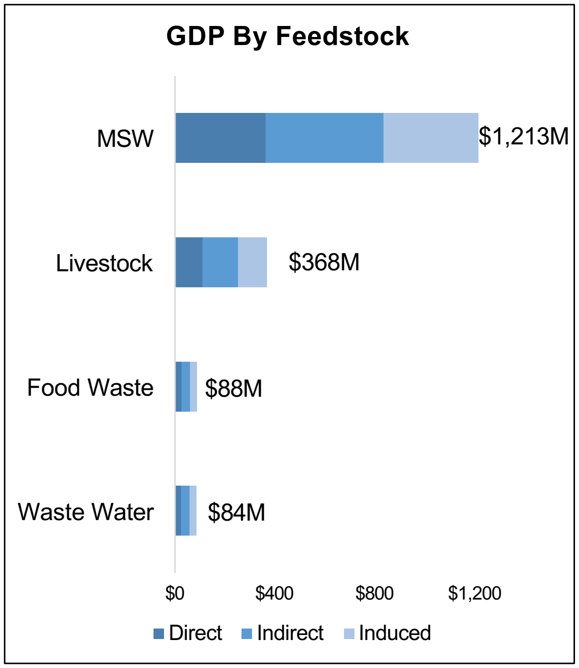


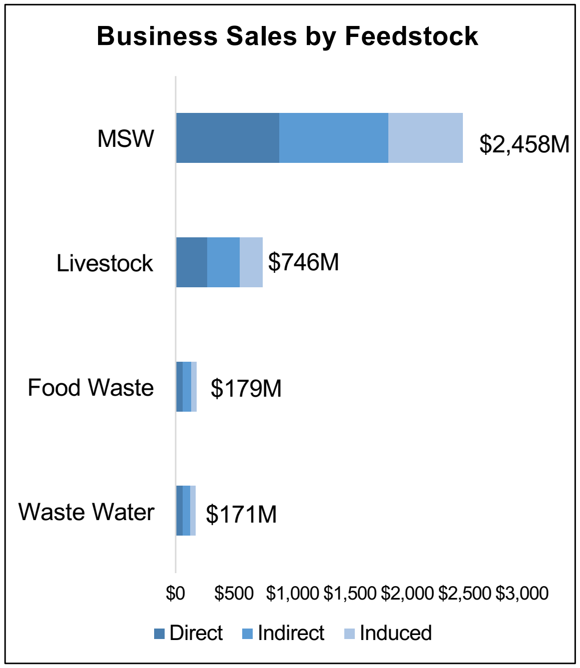


4 Economic Impact: MSW had the greatest economic impact from operations of the four feedstocks, accounting for 7,300 total jobs and supporting $1.2B in GDP and $2.5B in business sales in 2022

The economic impacts by feedstock type are presented below with most impacts supported by RNG produced from municipal solid waste (MSW) with over 7,300 jobs. The remaining 31% of all jobs are spread across the other three feedstocks.

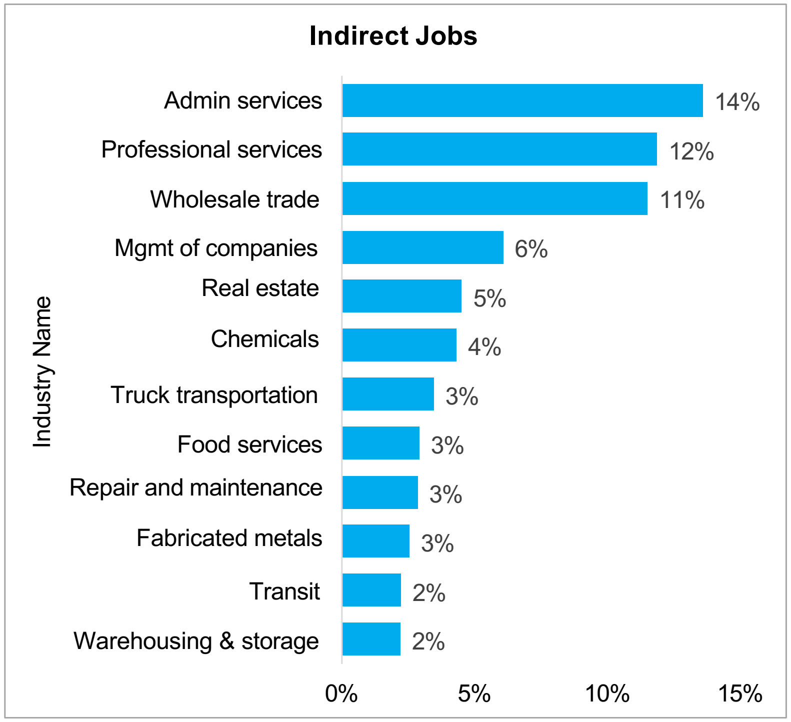


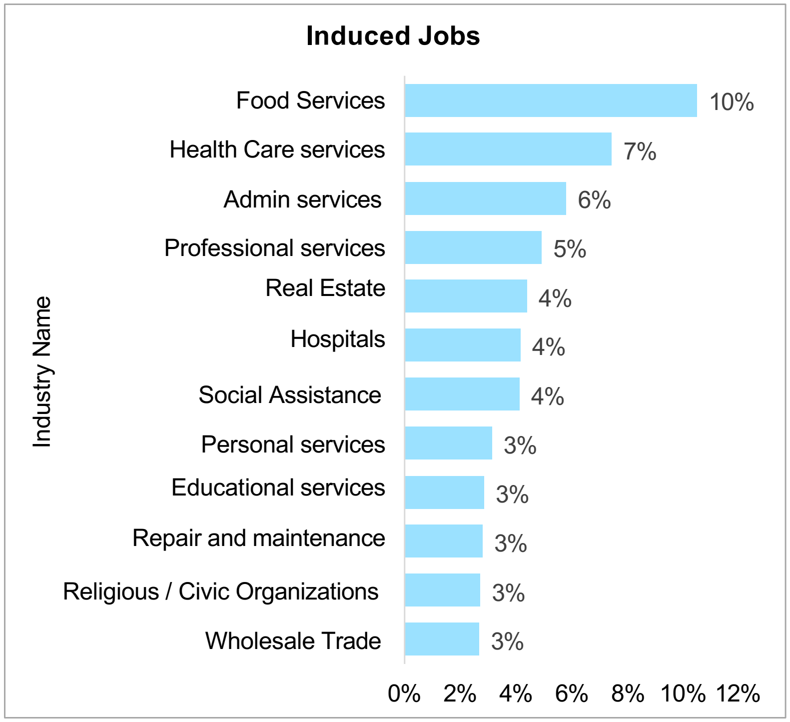




4 Economic Impact: Purchases within the supply chain based on buyer/supplier relationships generate indirect and induced jobs across a spectrum of industries

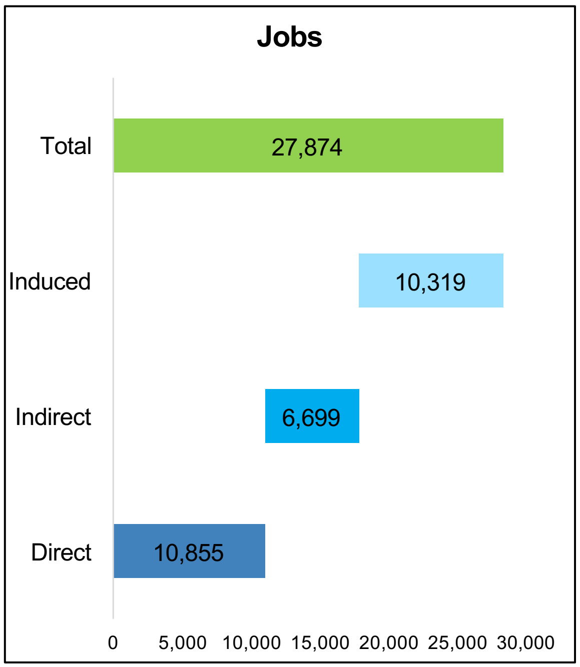
The industries with the most indirect jobs are administrative services, professional services, and wholesale trade. The industries with the most induced jobs are food services, health care services, and administrative services.

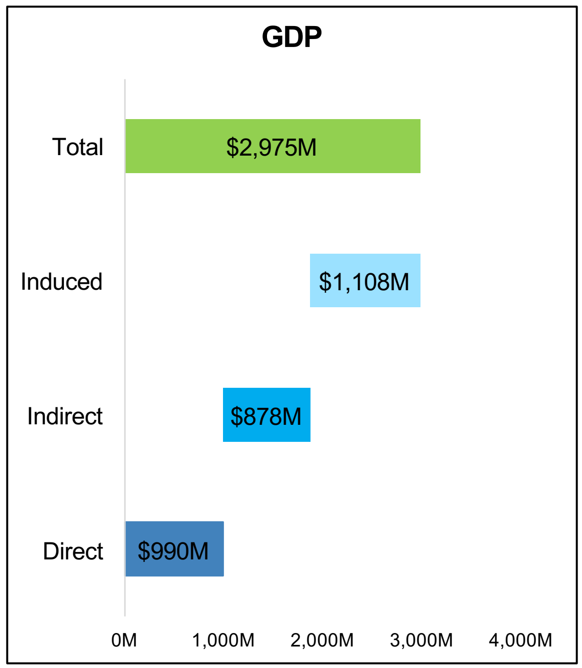


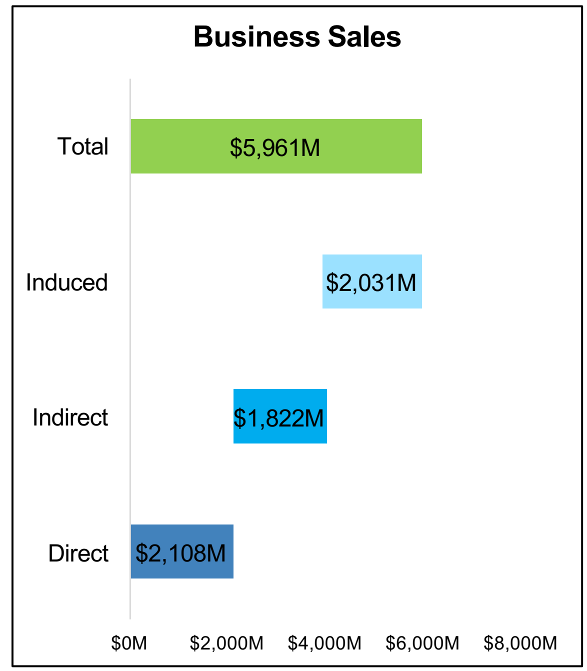


Economic Impact: RNG capital expenditures are estimated to support a total of 27,900 jobs, generate a total of $3.0B in GDP, and result in nearly $6B in business sales in 2022

Based on the spending for RNG Capital expenditures, the direct, indirect, and induced economic impacts are presented below in terms of jobs, GDP, and Business Sales.

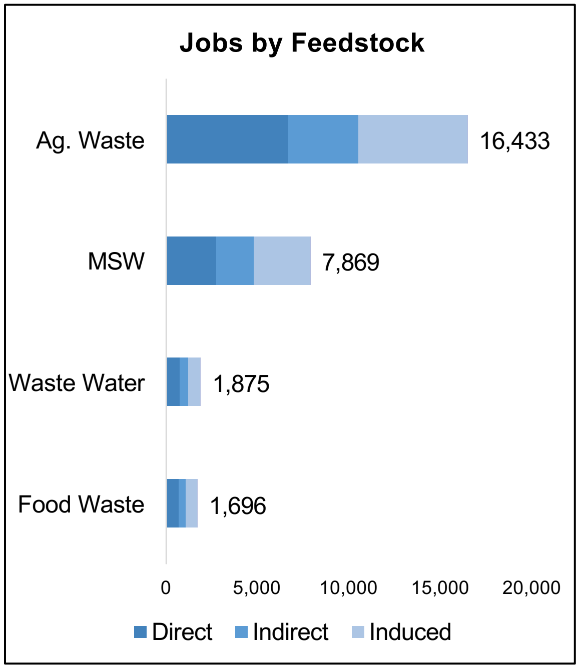


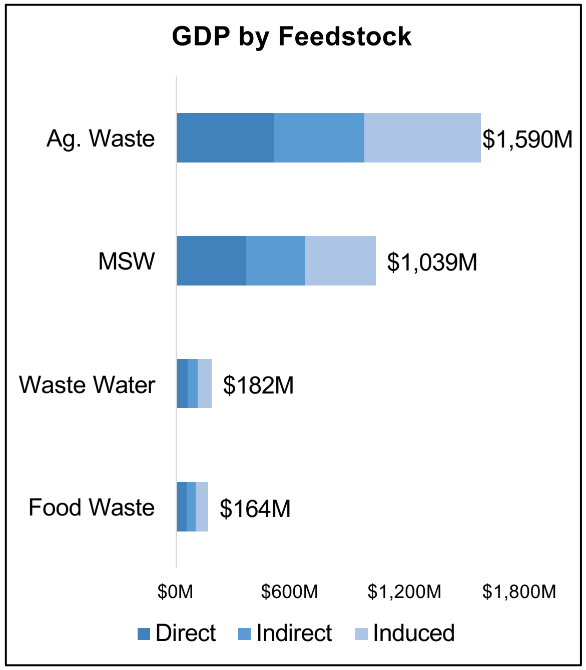


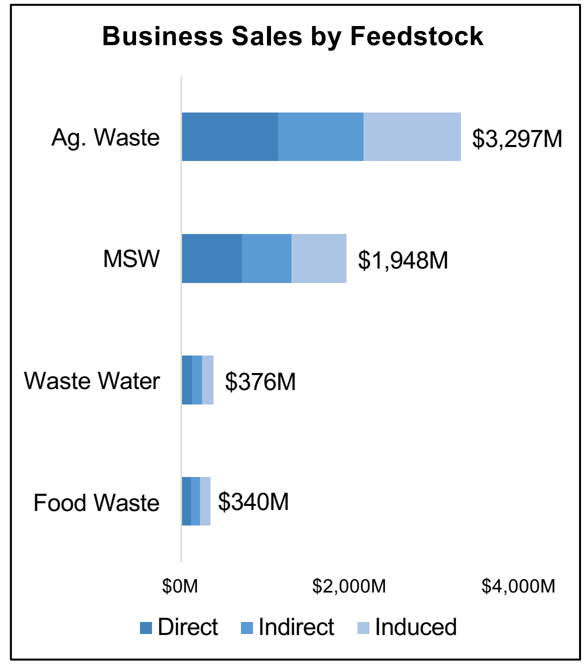


4 Economic Impact: Agricultural waste was estimated to have the greatest economic impact from capital expenditures of the four feedstocks, supporting 16,400 total jobs, generating $1.6B in GDP, and resulting in $3.3B in business sales

The economic impacts by feedstock type are presented below with most impacts supported by RNG produced from Agricultural Waste with 16,400 total jobs. The remaining 41% of all jobs are spread across the other three feedstocks.



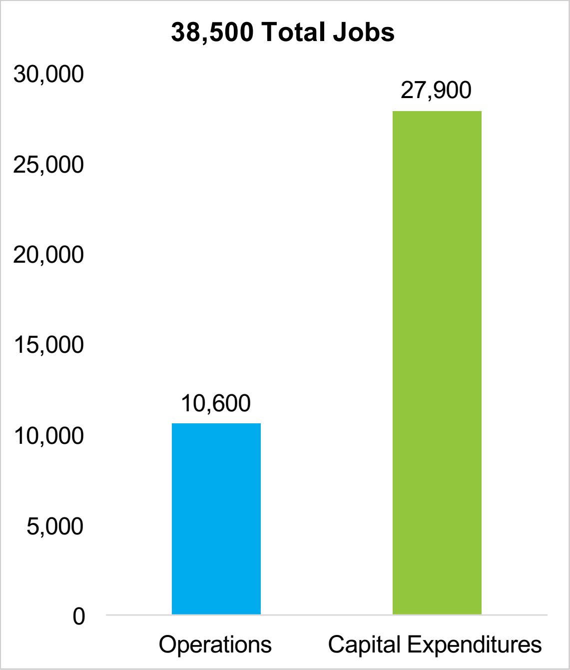




Economic Impact: Renewable natural gas is estimated to support 10,600 in jobs, generate $1.8B in GDP, and result in $3.5B in total business sales based on current operational capacity and 27,900 jobs, $3B in GDP, and $6B in total business sales for capital expenditures in 2022

4

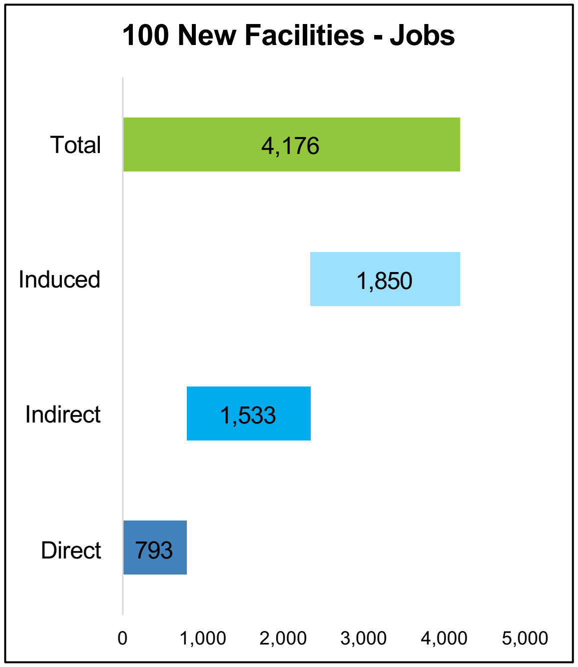
These numbers include the direct, indirect, and induced effects of RNG. Operations jobs are ongoing at completed RNG facilities however, capital expenditure or construction jobs terminate after approximately one year after a new facility is completed.

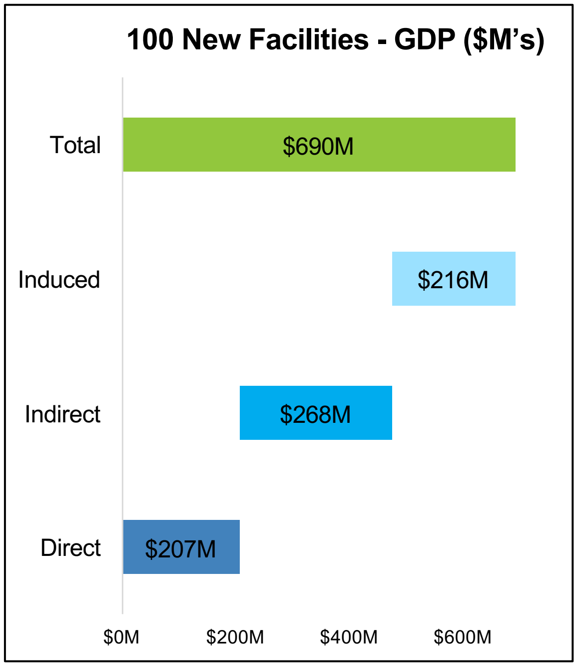


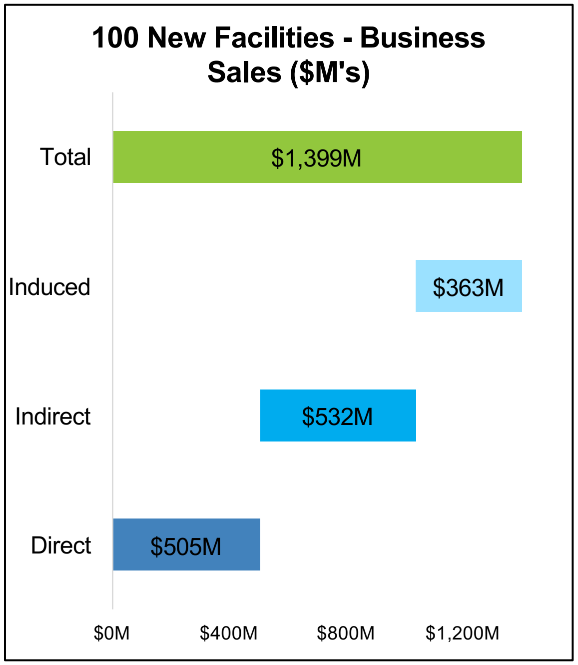
THE COALITION FOR RENEWABLE NATURAL GAS

4 Economic Impact: Using the current inventory of RNG facilities, we estimated the economic impact for the operations and maintenance of 100 new RNG facilities

Nearly 800 direct jobs could be attributed the operations and maintenance of 100 new RNG facilities with a total of 4,200 jobs. 100 new facilities could also generate a total of $690M in GDP and nearly $1.4B in business sales.[16]



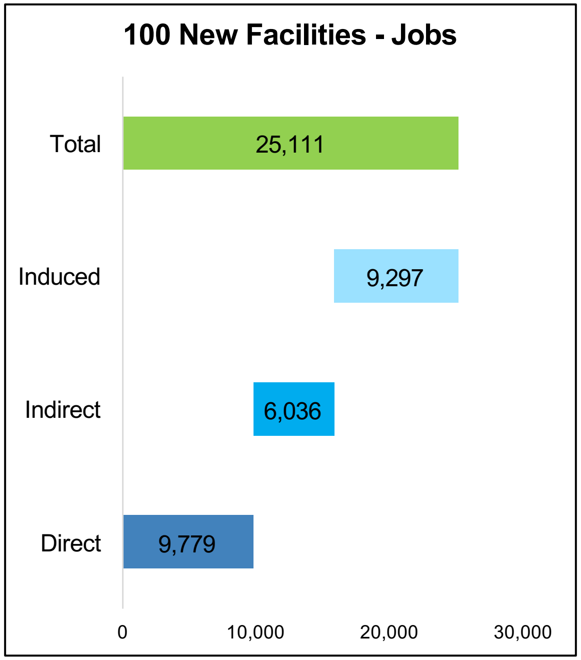


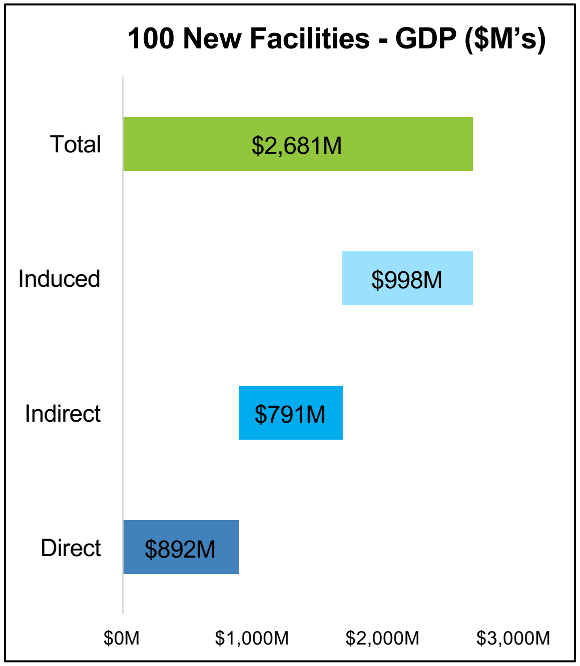


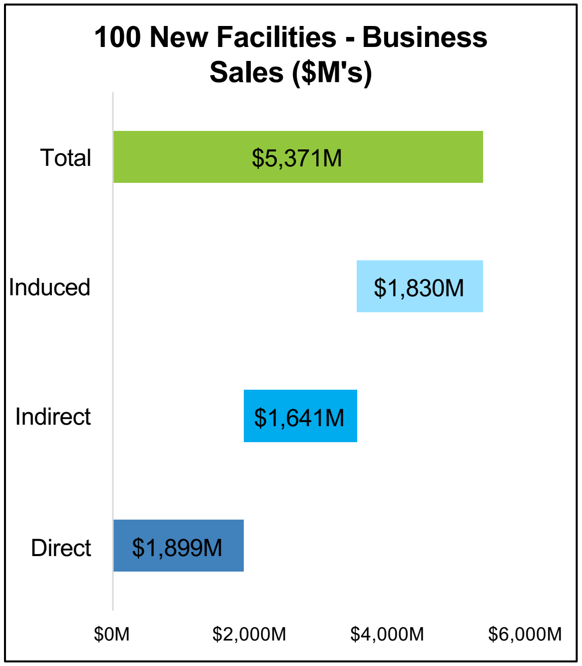
[16]Calculations are based on the average number of jobs per facility for each feedstock in 2022. Operations jobs ratios were calculated using current operation facilities in 2022. These numbers were provided by the RNG Coalition.

4 Economic Impact: Using the current inventory of RNG facilities, we estimated the economic impact for construction of 100 new RNG facilities

Nearly 9,800 direct jobs could be attributed the construction of 100 new RNG facilities with a total of 25,100 jobs. 100 new facilities could also generate a total of $2.7B GDP and nearly $5.4B in business sales.[17]



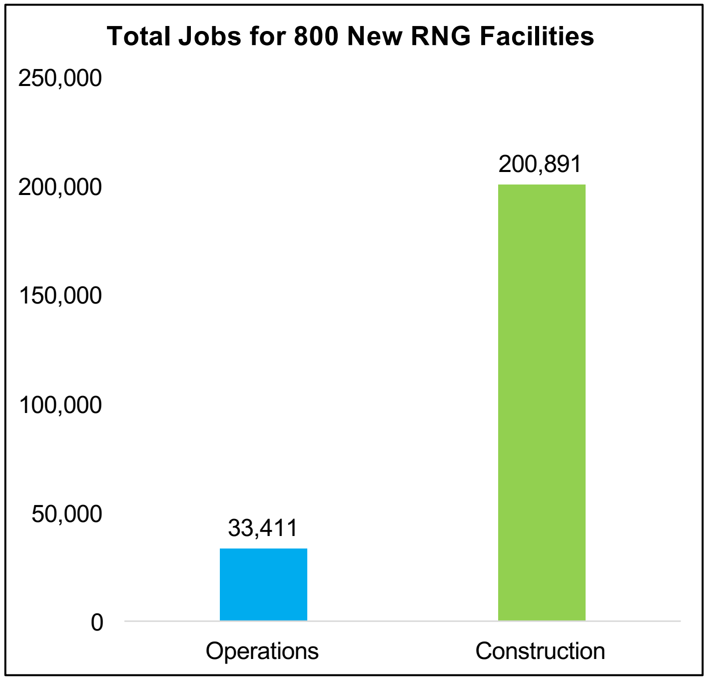


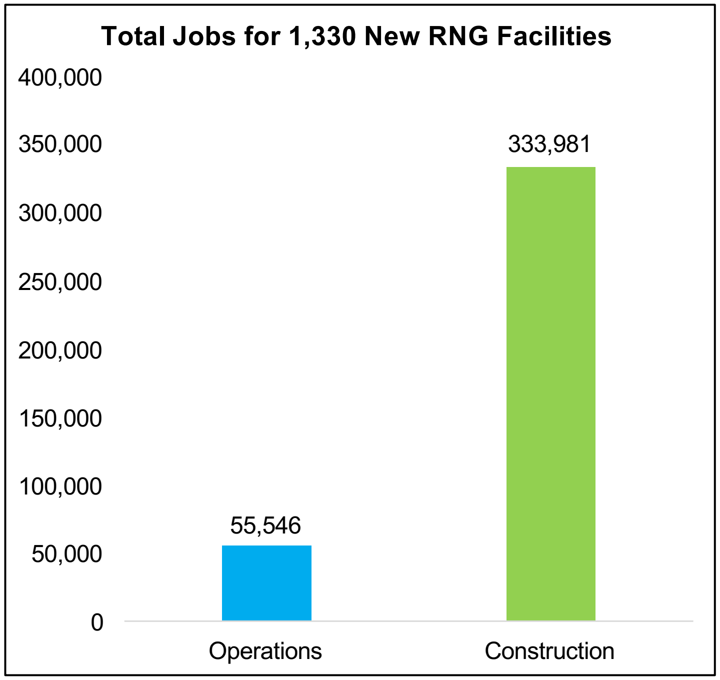


[17]Calculations are based on the average number of jobs per facility for each feedstock in 2022. Construction job ratios were calculated using the number of facilities currently under construction in 2022. These numbers were provided by the RNG Coalition.

4 Economic Impact: Using current estimates for the number of jobs per volume of RNG, we estimated the numbers of jobs created for 800 and 1,330 new RNG facilities

An additional 800 new facilities would create an estimated 33,400 total jobs from RNG production and 200,900 total construction jobs while 1,330 new facilities would create an estimated 55,500 total jobs from RNG production and 334,000 total construction jobs.[18]

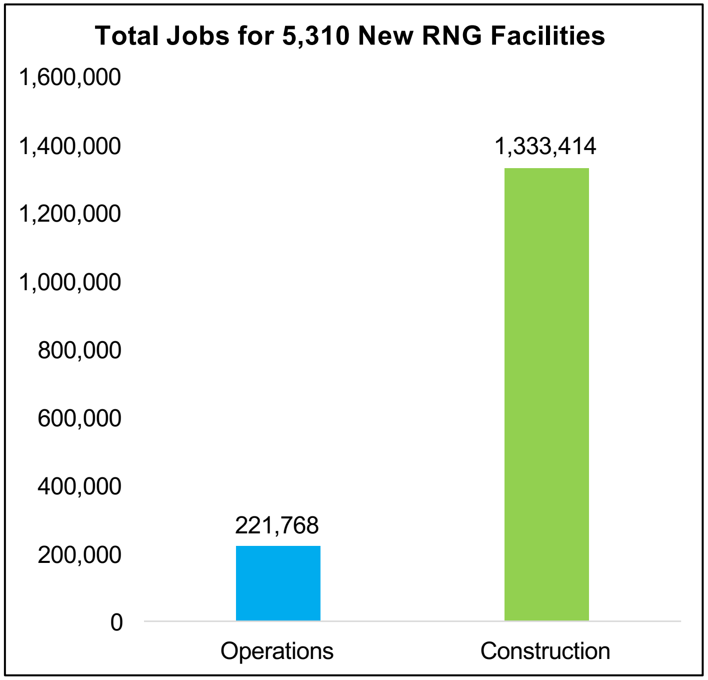


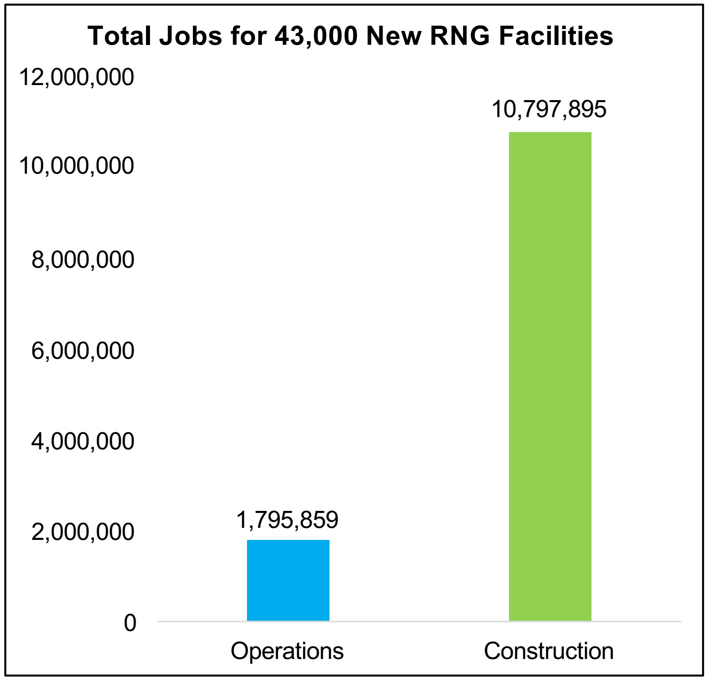


[18]Calculations are based on the average jobs per facility for each feedstock in 2022. Operations jobs ratios were calculated using current operation facilities in 2022 while construction job ratios were calculated using the number of facilities currently under construction in 2022. These numbers were provided by the RNG Coalition. These calculations do not take into consideration yearly economic changes that might affect RNG job numbers.

4 Economic Impact: Using current estimates for the number of jobs per volume of RNG and capital expenditures, we estimated the numbers of jobs created for 5,310 and 43,000 new RNG facilities

The IEA Global Report Model estimates 5,310 new facilities by 2050, which could create an estimated 221,800 additional total jobs from RNG production and 1.3M additional total construction jobs. RNG Coalition estimates that 43,000 new RNG facilities by 2050 based on its SMART goals would create an estimated 1.8M additional total jobs from RNG production and 10.8M additional total construction jobs.[19]





[19]Calculations are based on the average jobs per facility for each feedstock in 2022. Operations jobs ratios were calculated using current operation facilities in 2022 while construction job ratios were calculated using the number of facilities currently under construction in 2022. These numbers were provided by the RNG Coalition. These calculations do not take into consideration yearly economic changes that might affect RNG job numbers.

THE COALITION FOR
RENEWABLE
NATURAL GAS

Liquefied Natural Gas (LNG)

Office of Fossil Energy and Carbon Management

Today, the United States is the world’s largest producer of natural gas. Natural gas supplies about 1/3 of the **United States’ primary energy** consumption, with its primary uses being heating and generating electricity. While the majority of natural gas is delivered in its gaseous form via pipeline in the United States, the growth in the international market for natural gas has given rise to the use of natural gas in a liquefied form, or LNG.

LNG Basics

Liquefied natural gas (LNG) is natural gas that has been cooled to a liquid state, at about -260° Fahrenheit, for shipping and storage. The volume of natural gas in its liquid state is about 600 times smaller than its volume in its gaseous state. This process makes it possible to transport natural gas to places pipelines do not reach.

Liquefying natural gas is a way to move natural gas long distances when pipeline transport is not feasible. Markets that are too far away from producing regions to be connected directly to pipelines have access to natural gas because of LNG. In its compact liquid form, natural gas can be shipped in special tankers to terminals around the world. At these terminals, the LNG is returned to its gaseous state and transported by pipeline to distribution companies, industrial consumers, and power plants.

LNG Trade

For large-volume ocean transport, LNG is loaded onto double-hulled ships, which are used for both safety and insulating purposes. Once the ship arrives at the receiving port, LNG is off-loaded into well-insulated storage tanks, and later regasified for entrance into a pipeline distribution network.

LNG can also be shipped in smaller quantities, usually over shorter ocean distances. There is a growing trade in small-scale LNG shipments, which are most commonly made using the same containers used on trucks and in international trade, specially outfitted with cryogenic tanks. Other small-scale LNG activities include "peak-shaver" liquefaction and storage facilities, which can hold gas compactly for when it is needed in local markets in the U.S. during times of peak demand. LNG is also sometimes imported or exported by truck from this kind of facility.

In 2020, the U.S. exported almost 2,400 billion cubic feet (Bcf) of natural gas in the form of LNG in large LNG tanker ships, along with a small quantity shipped by container or in trucks. In total, as of August 2021, U.S. LNG has been delivered to 40 countries on five continents. The U.S. also still imports some LNG, mostly to New England, a region of the country constrained by limited pipeline and storage capacity.

DOE's Role

The Department of Energy has regulatory responsibilities related to LNG. Companies that want to export natural gas must get authorization to do so from DOE's Office of Fossil Energy and Carbon Management (FECM). The **Natural Gas Act** (NGA) requires DOE to make public interest determinations on applications to export LNG to countries where the U.S. does not have existing free trade agreements. FECM's natural gas import-export regulatory program is implemented by the **Division of Regulation** in the Office of Regulation, Analysis, and Engagement.

There are two standards of review under the NGA for LNG export applications, based on destination countries. Applications to export LNG to countries with which the United States has a free trade agreement (FTA countries) or to import LNG from any source are deemed automatically in the public interest. The NGA directs DOE to evaluate applications to export LNG to non-FTA countries. DOE is required to grant export authority to non-FTA countries, unless the Department finds that the proposed exports will not be consistent with the public interest, or where trade is explicitly prohibited by law or policy. DOE acts on long-term LNG export applications to non-FTA countries after completing a public interest review that includes several criteria, including economic and environmental review of the proposed export. Typically, the Federal Energy Regulatory Commission (FERC) has jurisdiction over the siting, construction, and operation of LNG export facilities in the U.S. In these cases, FERC leads the environmental impact assessments of proposed projects consistent with the National Environmental Policy Act, and DOE is typically a cooperating agency as part of these reviews. Obtaining a DOE authorization to export LNG to non-FTA countries is an important step for most projects in their path toward financing and construction.

Some of the companies that have LNG export authorizations from DOE have not reached final investment decisions on their projects. Construction of large facilities takes years to complete and costs billions of dollars. A complete list of long-term LNG export applications and their current status can be found in DOE's **Summary of LNG Export Applications**.

DOE also promotes market transparency with published reports on LNG export volumes, destinations, and prices in its **LNG Monthly Report**. The first-ever exports of domestically-produced LNG from the lower-48 states occurred in February 2016. Cheniere Energy's Sabine Pass Liquefaction, LLC exported the first LNG tanker cargo from the Sabine Pass LNG Terminal in Louisiana, with a shipment to Brazil.

LNG projects that have DOE authorizations report their status and construction progress to the Department twice per year via **Semi-Annual Reports**. Customers wishing to purchase LNG from the United States can contact one of the companies that is authorized or is seeking export authority, as listed in the **Online Docket Room**.

QUICK LINKS

- Division of Regulation
- Detailed Monthly and Annual LNG Import and Export Statistics
- LNG Export Studies
- Other Information Pertaining to LNG Export Studies
- 2012 LNG Safety Research Report to Congress
- FERC's LNG Website

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Article

Battery Durability and Reliability under Electric Utility Grid Operations: Analysis of On-Site Reference Tests

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Abstract: Grid-tied energy storage will play a key role in the reduction of carbon emissions. Systems based on Li-ion batteries could be good candidates for the task, especially those using lithium titanate negative electrodes. In this work, we will present the study of seven years of usage of a lithium titanate-based battery energy storage system on an isolated island grid. We will show that, even after seven years, the modules' capacity loss is below 10% and that overall the battery is still performing within specifications. From our results, we established a forecast based on the internal degradation mechanisms of the hottest and coldest modules to show that the battery full lifetime on the grid should easily exceed 15 years. We also identified some inaccuracies in the online capacity estimation methodology which complicates the monitoring of the system.

Keywords: battery energy storage system; BESS; titanate; LTO; incremental capacity; SOH

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1. Introduction

Battery energy storage systems (BESS) play a key role in tomorrow's grids as crucial building blocks towards higher integration of intermittent renewable energy generation [1–5]. This will be essential to allow small grids, such as the ones that power the Hawaiian Islands, to reach emission reduction targets. In Hawaiʻi, the Renewable Portfolio Standards law mandates a 100% clean energy and transportation environment by 2045 [6].

Despite the large number of BESS deployed [7,8], most of the published studies so far are focused on modeling [9–17] with sizing, load modeling, or life cost analysis, as well as battery management system development [18,19]. Within the modeling studies, little to no effort was devoted to degradation modeling using realistic battery models.

In addition to the modeling studies, there are, to the best of our knowledge, only a few publications with results from field studies. Consiglio et al. [20] reported on the site acceptance test of a 0.5 MW system, Koller et al. [21] reported on the impact of different applications on a 1 MW system, Bila et al. [22] showcased initial performance of a grid connected household BESS. Some studies were more focused on field usage analysis. This includes our 3-year study of a grid deployed 1 MW BESS [23], a one year study for a 5 MW system by Münderlein et al. [24], the validation of smoothing algorithms [25], and some sweat testing under different applications [26]. In addition, the international Renewable Energy Agency reported results on some case studies [27,28]. Even Fewer studies reported electrochemical data. At the system level, Karouia et al. [29] compared Li-ion and a ZEBRA-based BESS of different sizes from 0.1 to 5 KW, and Kubiak et al. [30] analyzed the calendar aging induced degradation on a 250 kW/500 kWh system. At the cell level, and in addition to our previous work [31–33], Benato et al. [34] tested cells of different chemistries under realistic conditions, and Li et al. [35] tested nickel cobalt manganese cells for stationary applications. Finally, Podias et al., White et al., Elliot et al. as well as Zhang et al. investigated grid usage of recycled EV or bus batteries [36–39].

The Hawaiʻi Natural Energy Institute (HNEI) at the University of Hawaiʻi at Mānoa has been working on assessing the benefits of grid-scale BESS for the past decade [23,31–33,40–42]. One of our demonstration BESS is installed on the Hawaii Electric Light Company power grid on northern tip of the Big Island of Hawaiʻi (star on the left of Figure 1) at the point of common coupling (PCC) between the 10.6 MW Hawaii Renewable Development Windfarm and the Waimea substation. It has been operational since December 2012 and consists of 384 modules in series with each module containing 7 cells in parallel. This amounts to a total of 268,850 Ah Altairnano Generation 1 cells composed of a lithium titanate (LTO) negative electrode (NE) and a blended positive electrode (PE) made of lithium cobalt oxide (LCO) and lithium nickel-cobalt-aluminum oxide (NCA) in a 55/45 ratio [32]. The modules are arranged symmetrically on both side of the container, Figure 1 right. The system is rated for 1 MW of power and 250 kWh of energy. The module nominal power is around 800 W which leads to a nominal power (P) for the BESS of 310 kW. Data, such as grid frequency and voltage, are logged by a Schweitzer SEL-735 meter at a 5 Hz sampling rate. Other data, such as cell group voltages and temperatures are sampled at 1 Hz. More details on the BESS and its installation can be found in [40]. HNEI's work encompassed grid performance assessment, closed-loop control algorithms optimization to maximize grid support, as well as single cell and module laboratory testing for better understanding of degradation mechanisms. In previous works [23,31,32], three years' worth of 1 MW/250 kWh Li-ion titanate BESS battery usage was analyzed and replicated on single cells leading to a forecast of cell durability based on the actual degradation observed in the laboratory.

Figure 1. Outside and inside view of the BESS.

In this work, the laboratory results will be compared with the real degradation associated with seven years of real usage on the grid where the BESS was primarily used for frequency regulation. This study will report on the durability of the BESS according to different metrics such as power, energy, efficiency, and capacity as calculated from two types of reference tests, one from the manufacturer and one custom. Moreover, a complete degradation analysis obtained from replaced modules will be used to discuss the accuracy of the online capacity estimation, the impact of modules temperature, the origin of the degradation, as well as to allow the forecast of the BESS remaining useful life using a realistic battery degradation model. The degradation model will be constructed from the evolution forecast for the three battery degradation modes: the loss of lithium inventory (LLI) and the loss of active material (LAM) on both electrodes [43].

2. Experimental

2.1. Overall Systems Description and Usage

The BESS stored close to 2.3 GWh of energy in seven years, which corresponds to 2.6 MAh of capacity or around 7500 equivalent full cycles. This represents more than 1000 equivalent full cycles a year or around 3 full cycles per day. Days of intense usage showcased more than 15 equivalent full cycles, black line on Figure 2. The system state of charge (SOC) was around 50% on average with daily excursions of 26% SOC. The average module temperatures were between 28 and 33 °C (with a 5 °C average temperature gradient within the modules). The overall usage of the BESS throughout its seven years of service is summarized in Figure 2. The hours of charging and discharging generally trended down starting in early 2015; this is due to adjustments to the primary frequency response algorithm that reduced cycling while still maintaining a significant portion of the grid benefit. This will be discussed in more detail in Section 4.1 below. A detailed analysis of the usage throughout the first three years was already published [23] and will not be repeated here. To assess the performance of the BESS, two types of periodic reference tests were performed, the manufacturer-recommended reference Test (MRT) and a custom HNEI reference test (HRT). The letters at the top of Figure 2 show when the tests were performed, with a blue M for the MRT and a red H for the HRT.

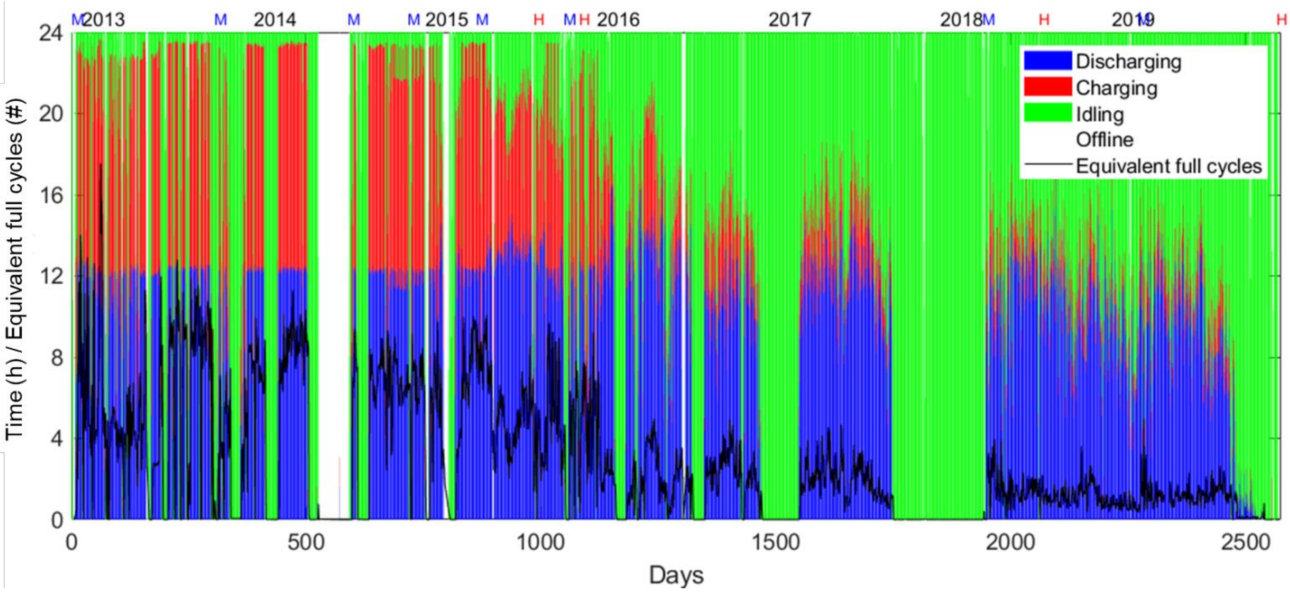

Figure 2. 2013–2019 Battery Energy Storage System activity showcasing discharging time (blue), charging time (red), idling time (green) and offline time (white). The M and H letters highlight the running of reference testing following the manufacturer and HNEI's protocols, respectively. The black curve represents the daily equivalent full cycle total.

2.2. Manufacturer's Reference Testing

The MRT consisted of three separate protocols to assess power ability, efficiency, energy ability as well as module capacities and resistances. The date at which those tests were carried on are highlighted by the letter M on the top of Figure 2. To date, the tests were repeated eight times at days 0, 302, 585, 713, 861, 1050, 1939 and 2268.

The power test consisted of 10 min 1 MW (3P) pulses in between 10 min rest periods. The test started and ended at a full charge state with the aid of a top-up pulse as shown in Figure 3. The first objective of this test is to first verify that the BESS can still provide over 1 MW of power at the PCC level. The second is to assess the power capability at the BESS level (i.e., how much power is needed to get 1 MW at the PCC level). The third is to calculate the efficiency (power in/power out).

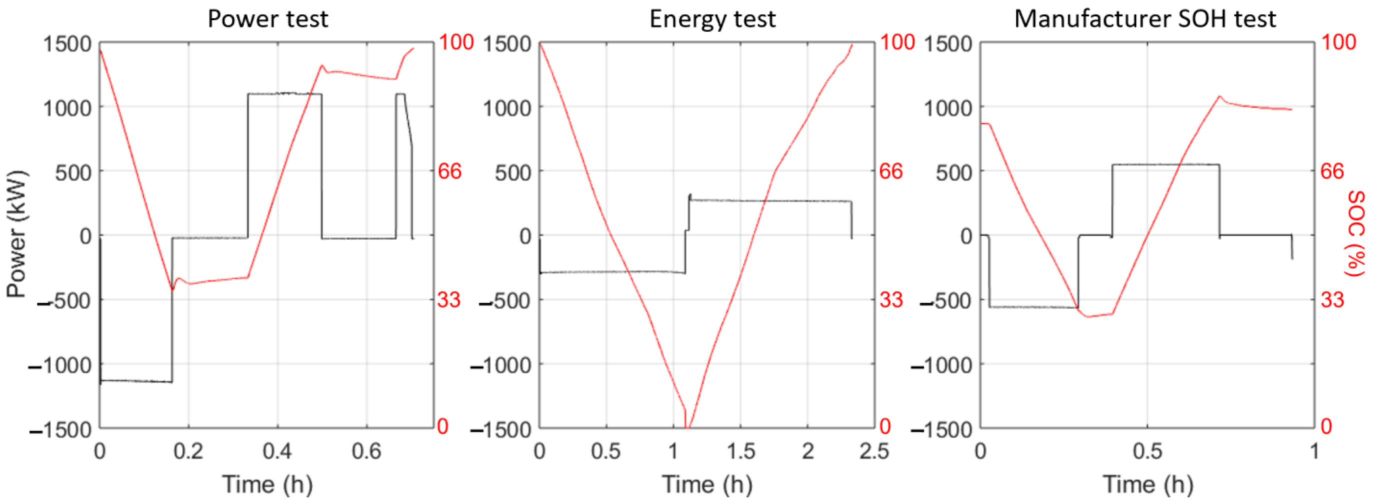

Figure 3. Example of the manufacturer tests: power, energy, and SOH.

To pass the test, the power rating must be above 1 MW and the efficiency rating above 80% minus 1% per year of service. The equations provided were the following:

$$Power\ rating = \frac{|E_{dis} + E_{cha}|}{2 \times 600\ \text{s}} \times 3600\ \geq 1.0\ \text{MW} \tag{1}$$

$$Efficiency\ rating = \frac{|E_{dis} + E_{rest\_dis}|}{|E_{cha} + E_{rest2+}E_{residual}|}\ \geq 80\% - 1\%/year \tag{2}$$

The energy test consisted of a discharge and a charge at 250 kW (at PCC level, P/1.25) on the entire SOC range (0–100% from BESS SOC meter, denoted SOC_B) with no rest in between as shown in Figure 2. The energy rating is calculated as the average of the charge and discharge energy. To pass the test, the energy storage capacity must be above 250 kWh. The equation provided by Altairnano was the following:

$$Energy\ Storage\ capacity = \frac{|E_{dis} + E_{cha}|}{2}\ \geq 250\ \text{kWh} \tag{3}$$

The state of health (SOH) test consisted of a charge and discharge at 500 kW (1.6P) between 30% and 80% SOC with 10 min rest periods before, in-between and after (Figure 3). The methodology to extract the module capacity and the resistance from this data was not explicitly stated by Altairnano but was assumed to be the following: for the module capacity, the rest cell voltages (RCV) should correspond to the open circuit voltage (OCV). From this OCV and a reference OCV vs. state of charge (SOC) curve, the ΔSOC between the two rests can be calculated. Dividing the corresponding measured capacity by the ΔSOC yield module capacity. For the module resistance, it was assumed that the ohmic drop (ΔV) between the rest and the application of the charge and discharge current were used. Based on the ohmic drops and knowing the current and Ohm's law, the resistance can be calculated as R = ΔV/ΔI = ΔV/(I − 0) where I is the requested current and the "0" is the OCV current. Unlike the power and energy tests, the SOH test was not run consistently, and the charge and discharge power varied between 300 kW (2nd and 3rd iterations), 500 kW (1st, 5th,7th, and 8th iterations) and 1 MW (4th and 6th iterations).

2.3. HNEI's Reference Testing (HRT)

HNEI's reference testing consisted of slow charge and discharge (50 kW, P/6.5) on the entire SOC window with long rests (>5 h vs. 10 min for MRT SOH test), Figure 4. This test was designed to accurately track capacity fading as well as changes in the modules OCV response. It also allowed the application of electrochemical voltage spectroscopies [44] such as incremental capacity (IC) to compare the degradation in the field to those observed in the laboratory [31,32]. Module capacities were extracted by dividing the measured capacity between two rests by the ΔSOC. This test could not be run often because it required significant downtime for the BESS (>40 h), but it was performed four times at days 984, 1081, 2060 and 2564. It also must be noted that there were some issues in the execution of the protocol for the first two iterations. In the first one, the charge power was not kept constant. In the second iteration, some pulses were performed at the end of the discharge prior to resting. Because of the significant downtime, tests could not be repeated and will therefore be analyzed as is.

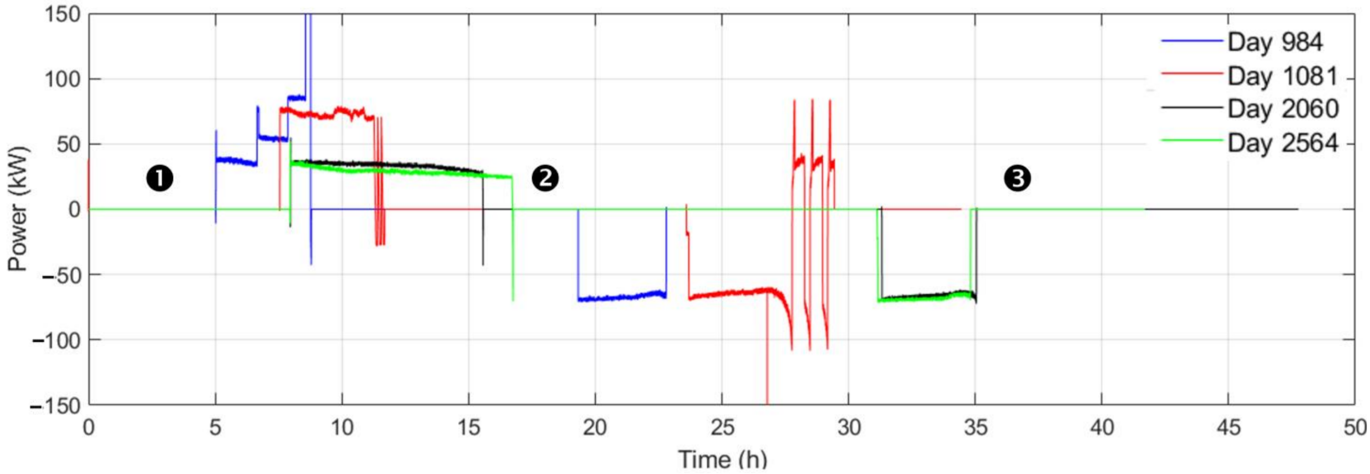

Figure 4. Power vs. time curves for the four iterations of the HNEI performance test.

2.4. HNEI's Laboratory Battery Testing & Incremental Capacity Analysis

On two occasions, around day 1000 and 2500, some modules were replaced in the deployed BESS. The 12 removed modules were shipped to HNEI laboratory and tested on a calibrated 20-channel ARBIN LBT-25 V-100 A machine. Prior to the testing, all channels were current- and voltage-calibrated against a common reference (NIST-traceable Keithley 2700 source meter unit) to ensure consistency across the experiment. A reference performance test was performed at 25 °C and comprised C/25, C/10 and C/5 full cycles with 4-h rests before and after residual capacity measurements at C/50. More details on the reference test can be found in [45].

IC curve simulations were performed using the proprietary *'alawa* toolbox [46] using HNEI mechanistic degradation model [47]. Experimental validation supporting the simulation results based on LLI and LAM degradation modes has been reported by other groups [48–50]. The stock library of the *'alawa* toolbox was used for the half-cell data. More details on the process for these cells it out of the scope of this paper and it can be found in our previous work [32].

3. Results

3.1. Field Data

Figure 5a–c present the evolution of the power, efficiency, and energy ratings as a function of time. The power rating was stable for the seven years the BESS had been in service. It dropped slightly below 1 MW around Day 300 but recovered after. The efficiency also stayed above the threshold value throughout the 7 years of usage. The energy rating started above 280 kWh and quickly faded to around 240 kWh after day 800. This triggered the replacement of two modules around Day 1000. After modules replacement, the energy rating increased to around 270 kWh and remained rather constant between days 1000 and 2000 before starting to lower again.

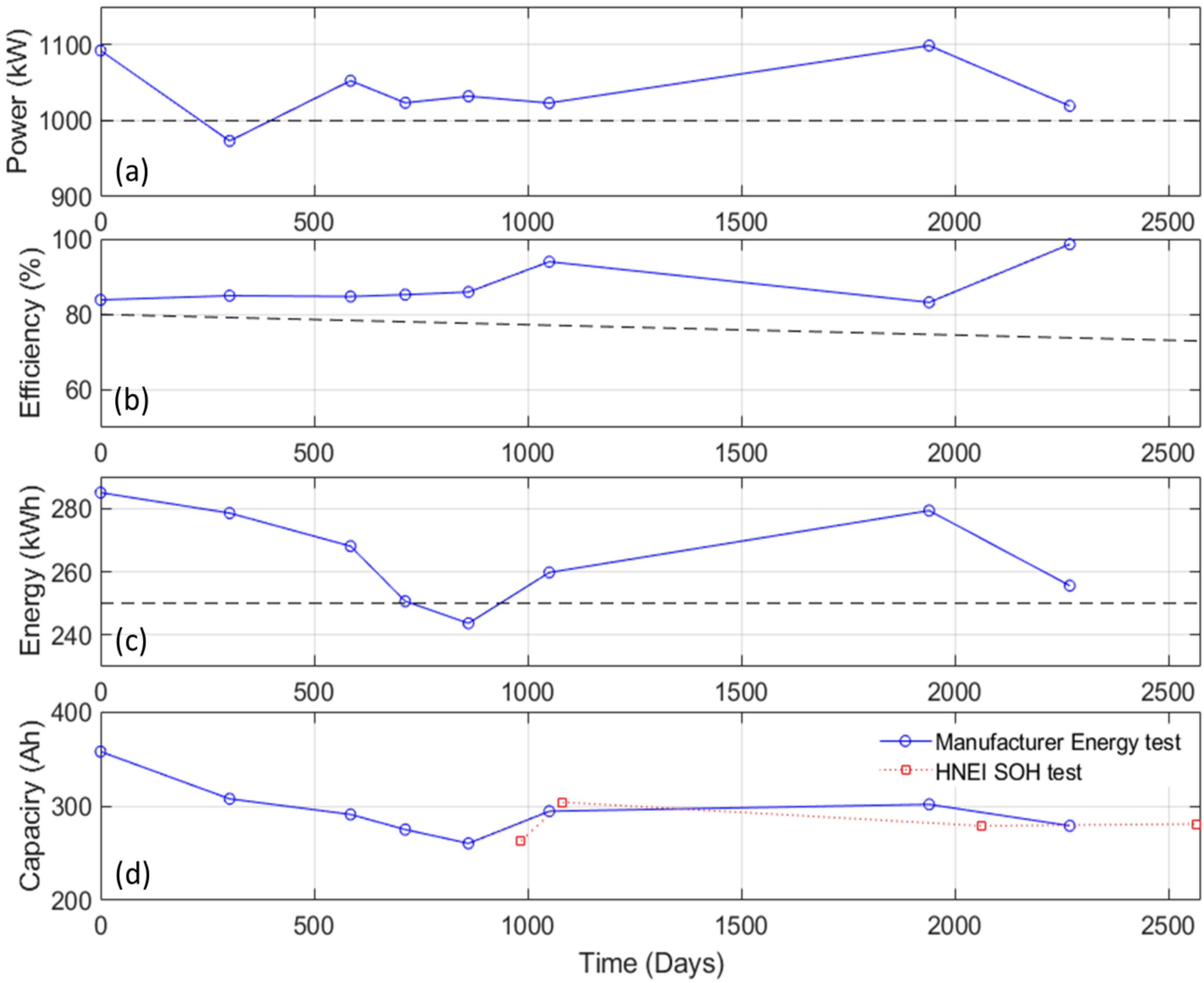

Figure 5. BESS (**a**) power, (**b**) efficiency, (**c**) energy, and (**d**) capacity evolution with time.

Since both the MRT energy rating test and HNEI's protocol were performed on the full SOC window, their exchanged capacity can be compared (Figure 5d). The BESS started with a capacity above 350 Ah which was expected with modules comprising 7 × 50 Ah cells in parallel. The capacity decreased to 260 Ah (−25%) before modules replacement and increased back to around 300 Ah (−15%) after then remained rather stable.

Figure 5c is intriguing as the available energy seems to increase between day 1000 and day 2000 from the MRT results. To investigate the origin of this increase, Figure 6a plots the voltage vs. capacity curves associated with all the MRT energy tests. From these plots, it is apparent that the overall end of discharge and end of charge potential are respectively increasing and decreasing (arrows on Figure 6a). This suggests that more of the voltage window of the cells is utilized and that therefore the ΔSOC used for the energy test is increasing. However, looking at the ΔSOC_B (the SOC reported by the BESS), Figure 6b, it is always between 100 and 0. This indicates that SOC_B does not have a 1:1 correspondence with the true SOC of the BESS. This is confirmed by the fact that SOC_B and the capacity do not have a linear relationship, whether from the MRT test (Figure 6b) or the HRT test at low rate (Figure 6c). A deviation from a linear relationship can be seen at high and low SOC but also in the 40 to 60% region with a significant hysteresis especially visible in charge.

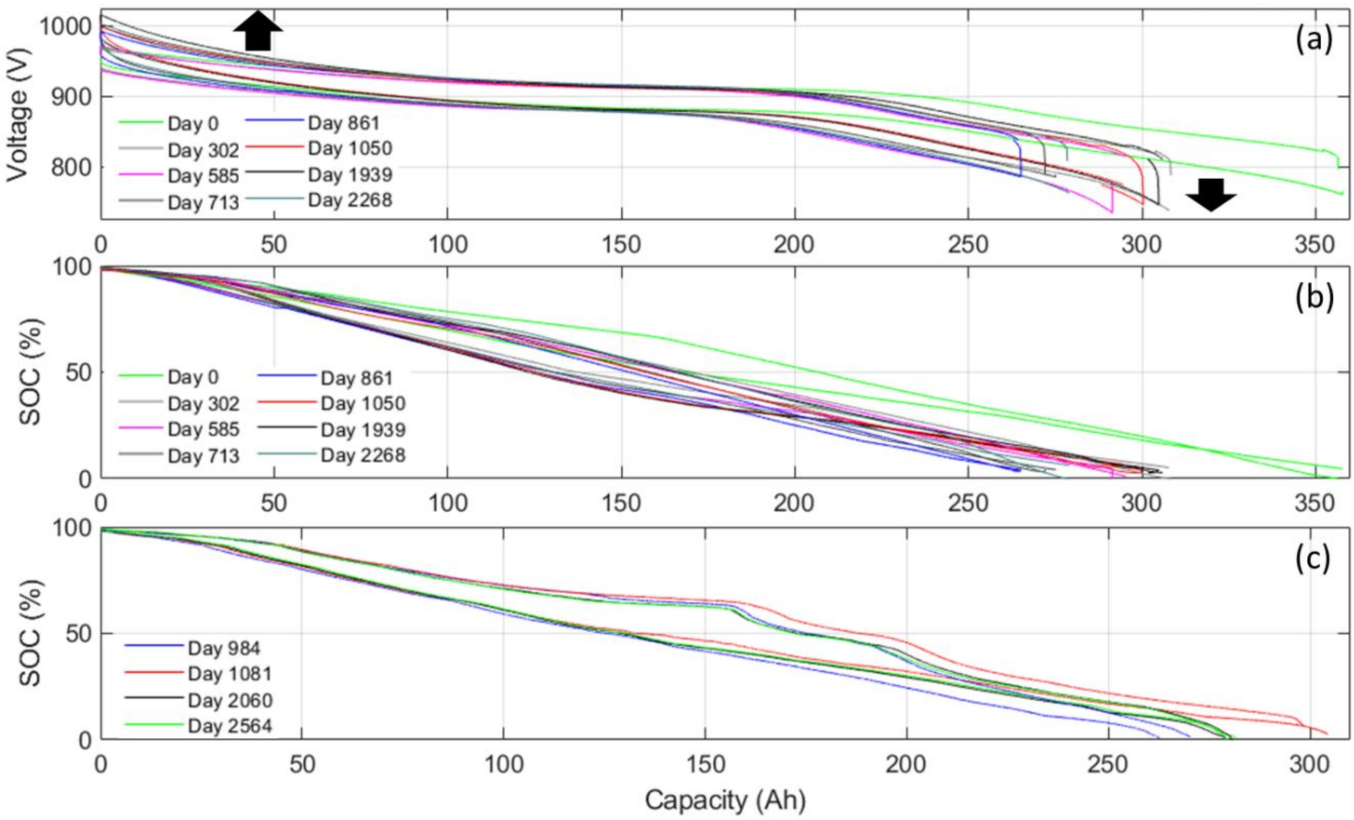

Figure 6. (**a**) Voltage vs. capacity curves for the MRT Energy tests. And (**b**) associated SOC vs. capacity curves. (**c**) SOC vs. capacity curves for the HRT tests. Arrows on (**a**) indicates overall evolution with aging.

One of the most important features of the manufacturer's and the HNEI's SOH tests is the ability to estimate the capacity associated with each module. Because the modules are connected in series, they all see the same current and thus discharge the same amount of capacity. Therefore, the modules capacity cannot be deciphered directly. To calculate each module's individual capacity, the exchanged capacity needs to be related with the associated ΔSOC in each module. This is usually done by using rest cell voltages and an OCV vs. SOC curve but this step is not straight forward, and multiple sources of error can arise. The first error source is usually caused by the fact the RCVs are not fully stabilized. Figure 7 presents an example of voltage vs. time curves for the six different RCVs considered in this work. Three RCVs were measured from the manufacture's SOH test (①–③, Figure 3) that in most cases lasted less than 0.2 h and, the other three RCVs were measured from HNEI's test (❶–❸, Figure 4) that lasted 5 h or more. Although all RCVs, even the short 10 min ones, appeared to be stable when the step was completed, the changes of voltages in the last 2 min of the relaxation steps were investigated to quantify the stability of the voltages. It was found that for RCVs ①–③, the potential still varied between 0.8 and 1.9 mV in average. For the long rests, the same measurement showed changes below 0.1 mV in average during the last 2 min. To address the significance of these changes, the voltage variations between 8 and 10 min of the long HRT relaxations were reviewed. They were found to be of 0.4 mV in average for ❶ and ❷ and around 5 mV for ❸. Moreover, the recorded potentials after 10 min were 5, 19 and 70 mV off the final voltage in average for ❶, ❷, and ❸ respectively. This shows that, although potentials ①–③ appear mostly stable after 10 min, they could be far from the OCV value since 0.4 mV variations after 10 min, lower that the one observed, could lead up to 70 mV further variation after several hours. The impact of these results, as well as other errors, will be discussed further in the next section.

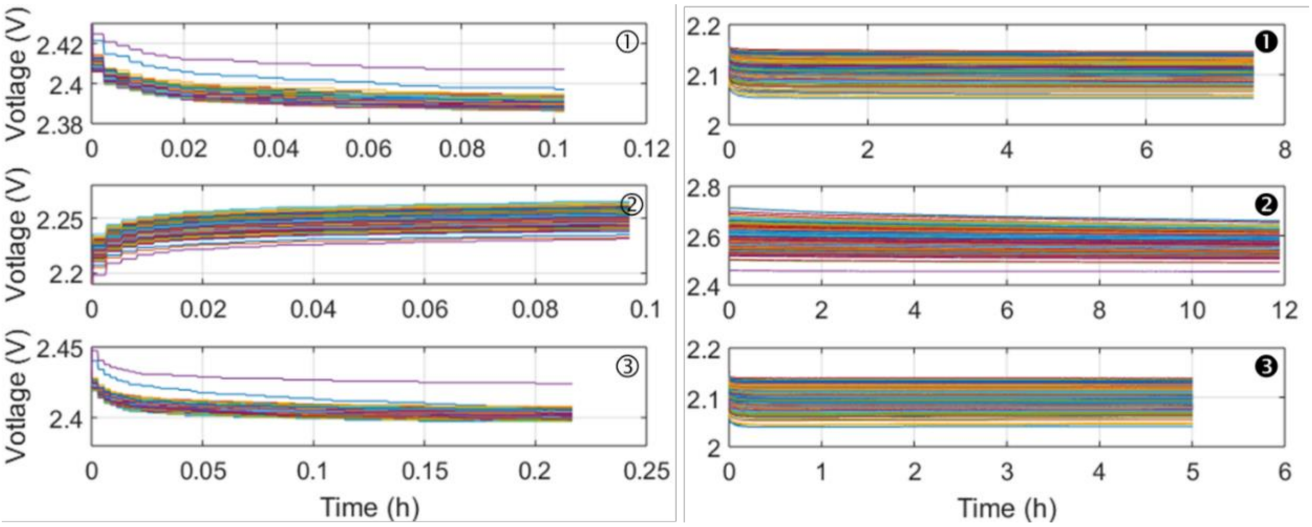

Figure 7. Example of relaxation vs. time curves for the manufacturer test (①–③) and HNEI test (❶–❸). Note that example ② is the relaxation after a charging cycle.

Temperature is one of the most significant parameters to influence capacity retention and capacity loss. Figure 8 presents the evolution of the maximum daily maximum temperature as a function of day. The BESS was used more aggressively during the first 1000 days causing the temperature to be higher than for the latter days. Temperature stayed mostly below 40 °C. Also plotted in Figure 8 is the minimum module temperature at the same time as when the maximum was recorded. This showcases a temperature imbalance that could be responsible for some inhomogeneous degradation within the modules. The temperature difference between modules is typically between 5 and 10 °C.

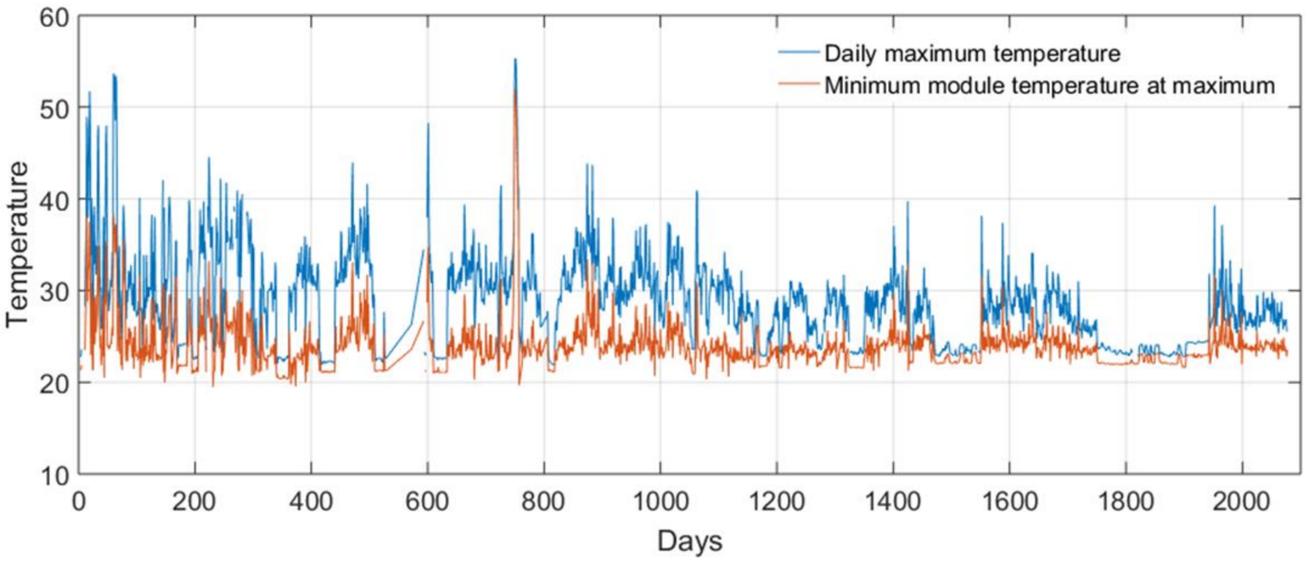

Figure 8. Maximum daily temperature evolution with associated minimum module temperature.

3.2. *Laboratory Data*

The modules that were replaced were analyzed in HNEI's battery testing laboratory. The modules in this BESS are organized in line replacement units (LRU) that each contain two modules. Therefore, with two LRUs replaced after 1000 days, four modules were exchanged. Of those, two were believed to be damaged (modules 25 and 170) and two behaved normally (modules 26 and 169). Four LRUs were also replaced after day 2500 including two that experienced the highest temperatures (modules 353 to 356) and two than experience the lowest temperatures (modules 201 to 204).

Figure 9a presents the C/25 discharge curves for the modules replaced at Day 1000 showing that only one the modules (#170) was actually defective with a capacity 15% lower than the others which were all within 1% around 384 Ah, close to the maximum capacity of 392 Ah from a pristine module [31]. For the modules changed after 2500 days, their capacities were between 387 and 393 Ah for the low temperature modules and between 386 and 389 Ah for the high temperature modules (Figure 9b).

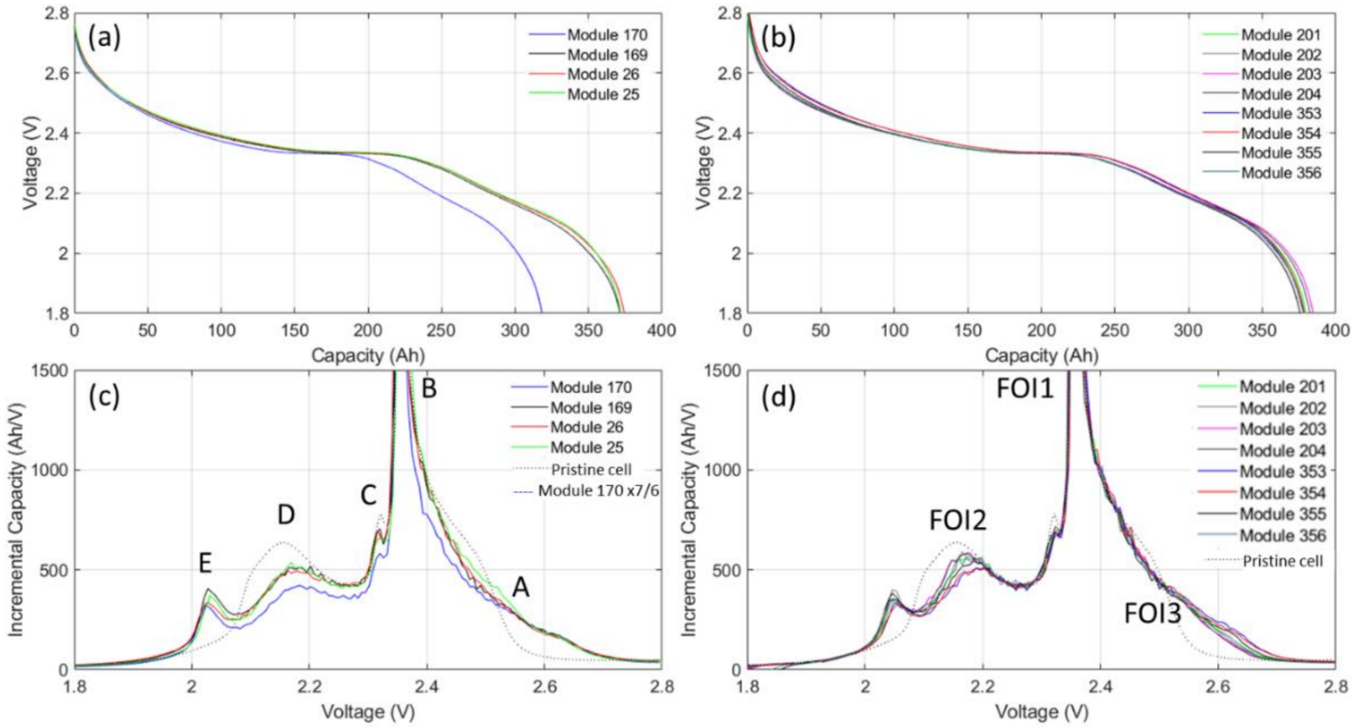

Figure 9. (**a**,**b**) C/25 discharges and (**c**,**d**) corresponding C/25 charge and discharge IC signature of replaced modules after day 1000 (**a**,**c**) and 2500 (**b**,**d**).

To enhance the changes in the voltage response, Figure 9c,d display the modules' incremental capacity (IC, dQ/dV = f(V)) signatures where it can be seen that they exhibited some differences in peak intensities which indicates disparities in SOH. Compared to a pristine cell, for which details can be found in [32], Feature A is broadened, Peak B is thinner, Peak D shrank and Peak E developed. All are clearly indicating (at least) loss of active material on both the positive and negative electrodes. Module 170 presents lower intensities for peaks B, C, D, and E compared to the other cells. Interestingly, the multiplication of the IC signature of module 170 by 7/6, nearly overlaps the signature of the other modules (dash curve). This indicates that the observed degradation might not be associated to an accelerated degradation but rather to the failure or disconnection of one of the cells in parallel within the module. The other module marked as defective (#25) did not show any specific difference compared to the others, which might indicate that there was an intermittent connection problem of one cell within the module. The single cells are encapsulated in a significant amount of hard resin, and they unfortunately could not be separated for individual testing despite some attempts. After 2500 days, the capacity differences between modules that experienced the same temperatures was minimal. Comparing modules that experienced higher temperatures to the lower temperature ones, Peak E is less intense and Peak A broader for the cells that were used at higher temperature. This suggests only a slight path dependence in the degradation process.

4. Discussion

4.1. Overall Usage of the BESS

As showcased by Figure 2, the usage of the BESS varied throughout the 7 years of deployment. The BESS, installed at a 10.6 MW wind farm, is equipped with two real-time control algorithms: primary frequency response, and wind smoothing. The wind smoothing algorithm was rarely used (123 total days between 1 January 2013 and 31 December 2018). Between 2013 and 2014, the frequency response algorithm was generally fixed to an aggressive gain setting of 30 MW/Hz with no dead-band (a range of grid frequency deviations that are ignored by the BESS). Starting on 22 January 2015, dead-bands of 20 mHz and 40 mHz were tested along with gains of 20 MW/Hz, 30 MW/Hz and 40 MW/Hz. The BESS was also limited to respond with ±300 kW, ±500 kW, and ±1000 kW (max). Various combinations of settings were cycled over several days through June 2016 when the gain was set to 40 MW/Hz with a dead-band of 40 mHz for the remainder of the period. Further discussion on the impact of different settings in out of the scope of this paper and will be published at a later date.

4.2. Open Circuit Voltages & Module Capacities

Proper indirect estimation of capacity requires satisfaction of several conditions:

- First, two good RCVs where the modules reached their equilibrium voltages. This usually requires long rests, ideally at a charged and discharged state.
- Second, the measured RCVs must not be on a voltage plateau.
- Third, an accurate OCV vs. SOC curve. Based on the information provided to us, Altairnano might be using a 10 points OCV vs. SOC curve. The method of interpolation between the points was not disclosed. From our laboratory testing, a higher resolution OCV vs. curve (1001 points, extracted from [31]) was available and used in this work.
- Finally, the OCV vs. SOC curve needs to be updated upon aging. Depending on the battery degradation, the OCV vs. SOC curve will change with SOH as the cells degrade differently along with usage [32,43].

Figure 10b presents a comparison of a 10 and 1001 points OCV vs. SOC curve as well as associated SOC estimation errors. The error is around 3% on average with a maximum of 10% at 60% SOC. Figure 10b also provides the SOC estimation error based on RCV measurement errors of 1 mV (the resolution of the voltage sensors), 5 mV, 10 mV and 20 mV. According to our analysis of the relaxation curves (Figure 7) RCVs ①–③ were not stabilized and this could lead to significant errors since, for a 20 mV measurement error, SOC estimation could be on average ±5% off and up to ±20% off in the worst case scenario. The 1 mV resolution was found only be an issue only in the 45 to 55% SOC range were errors of ±2.5% are possible.

To start to quantify the possible errors on the capacity estimation, Figure 10a displays the spreads of RCVs for ①–③ and ❶–❸ on the initial OCV vs. SOC curve. None of them appear to be on a voltage plateau nor in areas of high possible SOC estimation errors. Nonetheless, the error induced by errors in voltage measurements up to 20 mV for ① and ③ could lead to SOC estimation errors up to 4% and 2% for ②. This SOC estimation error leads to ΔSOC errors in the order of 5% between the low and high SOC points and thus up to 10% underestimation of the capacity (5% on a ~50% SOC range), which is significant.

It must be noted that the shape of the error is similar to the observed mismatch between SOC and normalized capacity (Figure 6). Discussion on the evolution of the OCV curves with aging will be provided in the next section.

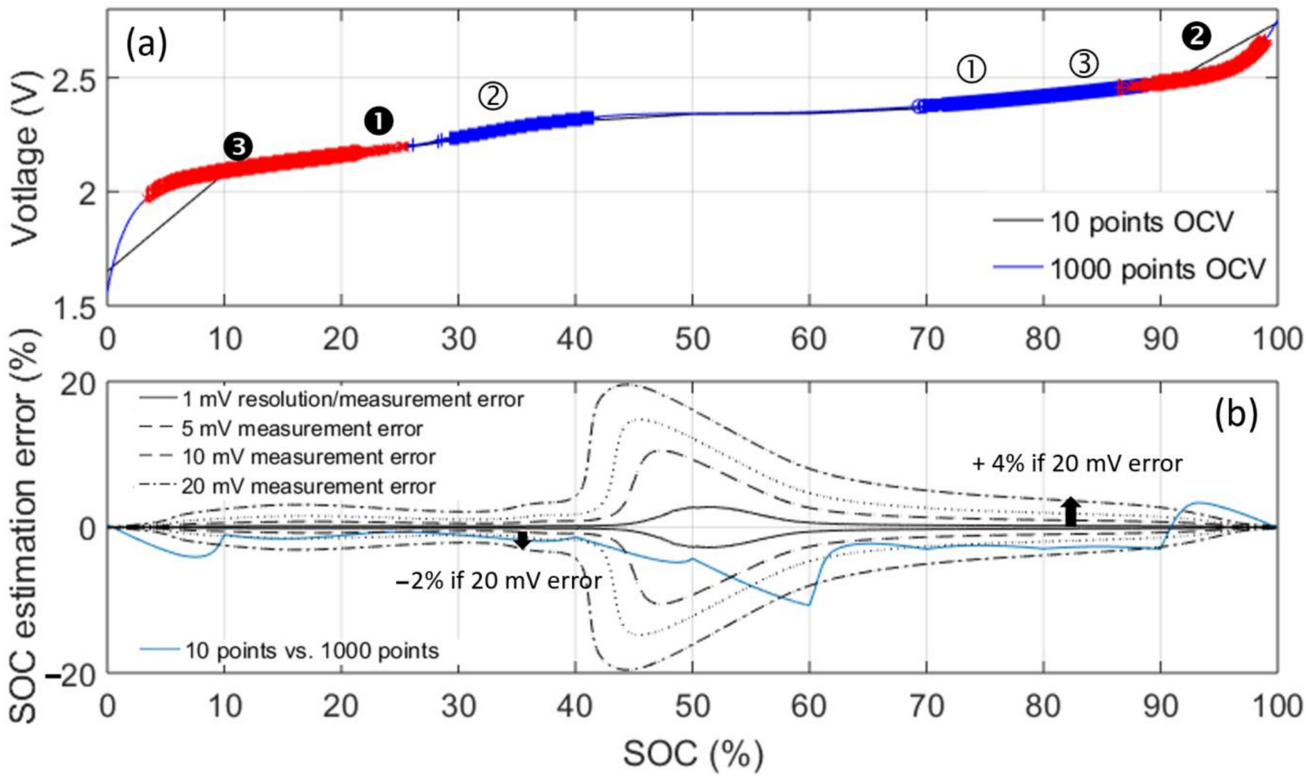

Figure 10. (**a**) Comparison of the 10 and 1000 points OCV curves with the different spread of measured RCVs. (**b**) SOC error associated with using a 10-point OCV instead of a 1000-point OCV as well as with measurement errors of 1, 5, 10 and 20 mV.

With three sets of relaxation voltages available per dataset, module capacities could be calculated between points 1 and 2 as well as between points 2 and 3. Figure 11a presents the comparison between the two sets of capacities estimated from rests ①–② and from rests ②–③. If the SOC determination was accurate, they should be equal. They are close except for the test at Day 713 where capacities calculated from points ①–② are 40 Ah higher (~10%) than the one measured from points ②–③. From a closer look at the data, the rests all look ok, but the charge capacity between ② and ③ was abnormally high. The origin of that capacity measurement error is unclear but likely associated with a calibration error for the current or the coulomb counting in charge. For the HRT test, Figure 11b and rests ❶–❸, the calculated capacities are overlapping for the first and fourth tests. For the second and third tests, there is an almost constant difference of 20 Ah and 10 Ah respectively. The origin of this difference is also likely related to calibration differences. Since the last four MRT tests were performed at similar time as the HRT tests, the calculated capacities can be compared and Figure 11c showcases the comparison of capacities ①–② and ❷–❸ for the four common tests, all gathered during the same regime and thus the same calibration. MRT capacities were all overestimated for Test 1, underestimated for tests 2 and 3 and scattered for Test 4. This illustrates that the correlation between the two datasets was weak at first then fast decreasing (Pearson correlation coefficient of 0.75, 0.4, 0.4 and 0.03 respectively for days 984, 1081, 2060, and 2564). This is interesting because it shows that the voltage measurement error impact is different for every module as the error is not constant. The accuracy of the MRT-determined capacities could potentially be improved by extrapolating the relaxation curves to estimate the final voltages [51,52] but this is out of the scope of this work. Figure 11 also shows that the module changes at Day 1000 did perturb the system significantly as the correlation coefficient dropped from 0.75 to 0.4 in less than 100 days. Finally, on both the HRT and the MRT test prior to Day 1000, two modules are consistently showing capacities around 30 Ah lower than the spread of others. These were the replaced modules.

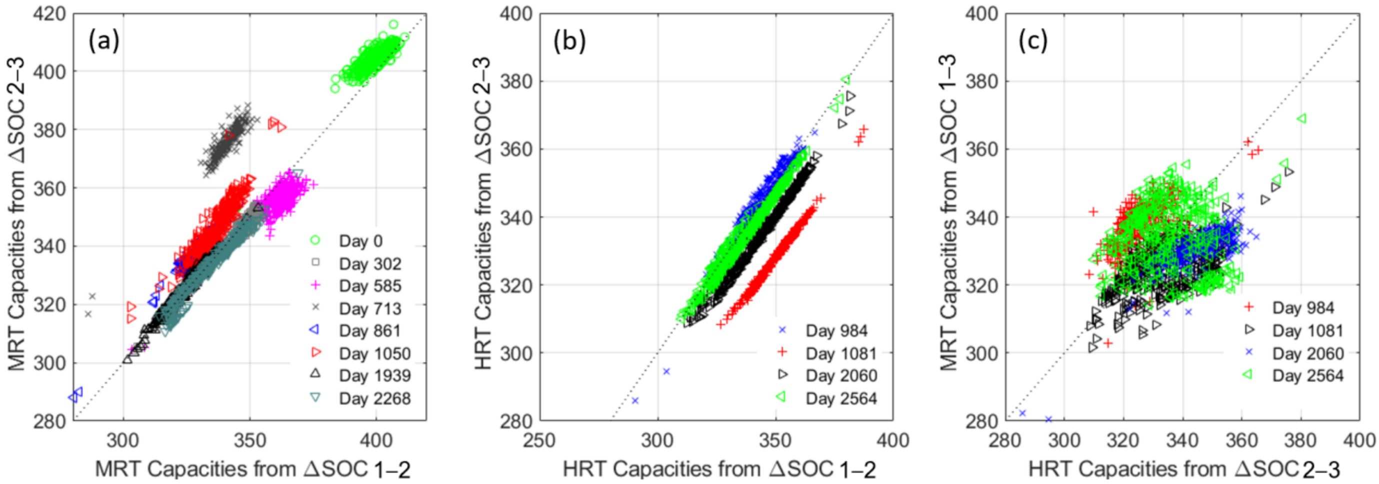

Figure 11. (**a**) MRT capacities calculated from ΔSOC 1–2 vs. ΔSOC 2.3, (**b**) HRT capacities calculated from ΔSOC 1–2 vs. ΔSOC 2–3, and (**c**) capacities HRT calculated from ΔSOC 2–3 vs. MRT calculated from ΔSOC 1–2. All calculations were performed using the initial OCV vs. SOC curve.

Figure 12 presents the measured capacity loss versus time for both the MRT and the HRT experiments. Since no initial point was available for the HRT experiment, the maximum capacity measured during our cell-to-cell variation analysis [31], with the calendar aging accounted for, was used as a starting point. It seems that the modules did not degrade homogenously as the difference in capacity loss in-between modules spans for more than 15% after 2500 days with between 10 and 25% capacity loss (HRT test). According to the MRT results, this spreading might have been gradual. The inaccuracy of the MRT is exemplified by the capacity loss going up and down depending on the test. It must be noted that the capacity loss on the modules did also decreased for the HRT test after module replacement. The origin of this is unclear at this point but it might be associated to the BESS being set offline for while awaiting module replacement as capacity can sometimes be recovered after long rests. This might be related to a change in calibration or with electrode overhang and the fact that some lithium ions that migrated to the inactive part of the electrode can migrate back into the active area [53]. Some of the new modules also appear to degrade faster than the rest of the modules which resembles the fast capacity loss observed during the first 300 days for the other modules.

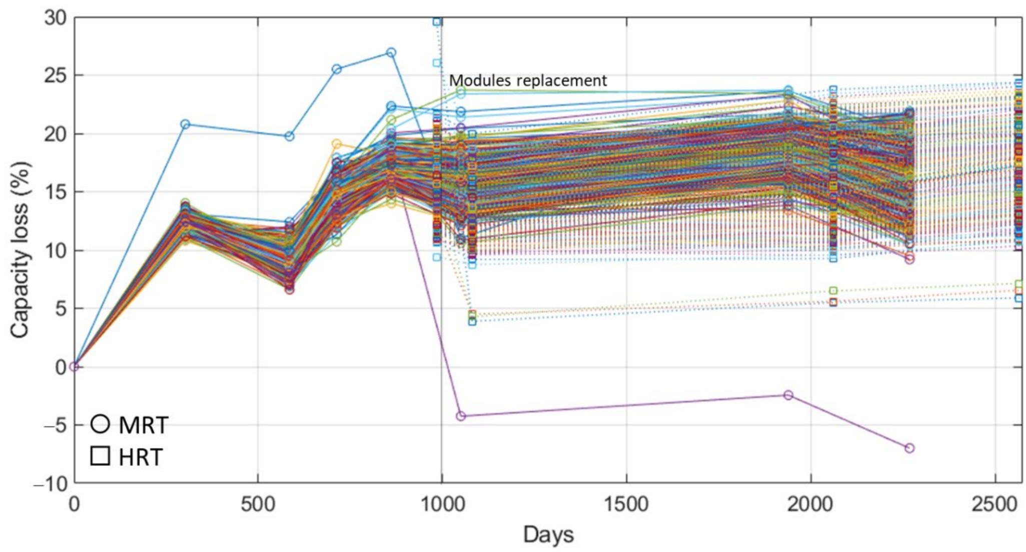

Figure 12. Capacity loss vs. time. Colors corresponds to different modules.

The increase of the spread of capacity loss between modules can usually be attributed to different usage patterns, different temperatures and different intrinsic degradation rates [54]. All modules are in series, so they all experience the same current. Since modules are comprised of seven cells in parallel, it is possible that some cells were used more than others within the modules. However, our recent modeling work on the impact of cell-to-cell variations in modules with cells in parallel showed limited impact of inhomogeneous degradation on the module performance [55]. The second possible contributing factor is the temperature. Some temperature gradients were observed within the BESS (Figure 8) and it is therefore possible that the hottest modules degraded faster than the coolest ones. An analysis of the module temperatures showed that the same modules were consistently hotter than others. Figure 13a shows the positions of these modules within the BESS. Hotter modules were on the top row near the middle of the stack on both sides. Cooler modules were always on the bottom. Figure 13b compares the capacity losses with modules average temperatures and Figure 13c the capacity loss with the time each module spent above 35, 45 and 50 °C. In all cases, Pearson correlations coefficient are below 0.15, there is therefore no impact of the temperature on the modules' inhomogeneous degradation. This was verified for both HRT and MRT measured capacities. This was also validated with direct capacity measurement from the replaced modules (Figure 9) that experienced the highest and lowest average temperatures and show less than 1% capacity difference in average. Another explanation for the spread of capacity loss could be the intrinsic degradation rate [54]. Previous studies on other types of cells showed differences of more than 5% after 1000 cycles, therefore 10% after 6500 cycles is not out of the range of possibilities. This is tempered however by the laboratory test results where the four replaced modules for each temperature (both at low and high) were compared and where the observed maximum spread between the cells was around 1%, higher than in between different temperatures, but much lower than 10%.

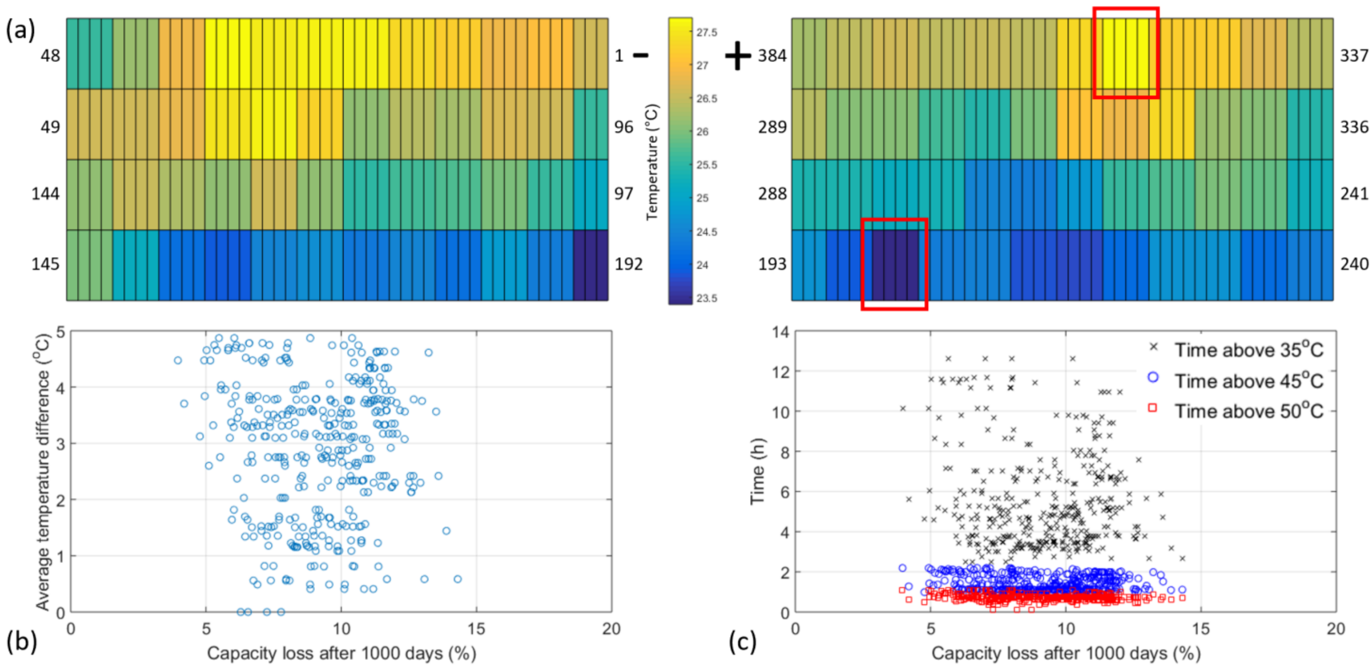

Figure 13. (**a**) Average temperature in each module for the 1st 1000 days as a function of module position in the trailer. (**b**) Average module temperature vs. capacity loss and (**c**) Time above 35 °C, 45 °C and 50 °C as a function of capacity loss.

Based on the observations above, the most likely explanation could be inaccuracies in capacity estimation. Such inaccuracies can originate from inadequate rest cell voltage measurements, inaccurate OCV vs. SOC curves and errant capacity measurements. An easy way to determine if there is any significant error in the capacity estimation is to compare the last capacity estimated for the 12 modules that were replaced with the one directly measured during the laboratory tests, Figure 14. Figure 14a presents the comparison of the estimated capacity versus the measured capacity for the 12 modules that were replaced. The estimated capacities show neither precision nor accuracy. All were underestimated by at least 8% and by more than 13% in average and their correlation was also rather weak at 0.6 and 0.7 for the MRT and the HRT respectively. To verify the validity of the capacity estimation method, the capacity obtained during the laboratory test were also estimated using both the initial OCV curve and an updated OCV curve, calculated from averaging the C/25 charge and discharge [45], for each module (triangles in Figure 14a). In both cases, the estimated capacity is at most of 0.7% different than and the measured one with a correlation higher than 0.99. This illustrates that, for these cells and under these conditions, the accuracy of OCV curve used does not matter much if the cells rest in areas of limited error towards the end of charge and the end of discharge (Figure 10). This is confirmed by Figure 14b where the module capacities were estimated using the RCV measured from the MRT and HRT tests and the true OCV curve for each module (calculated from the HRT test). Figure 14b shows marginally better estimation with an average error of 9% (4% less) and the same correlation. The estimation difference is higher between the two OCV curves because, from the BESS, the measured relaxations were not truly at the end of charge and the end of discharge and thus in areas of larger error (Figure 10). The impact of the quality of the rest cell measurements has already been discussed and should not be a major factor for the HRT dataset, therefore this error must originate elsewhere.

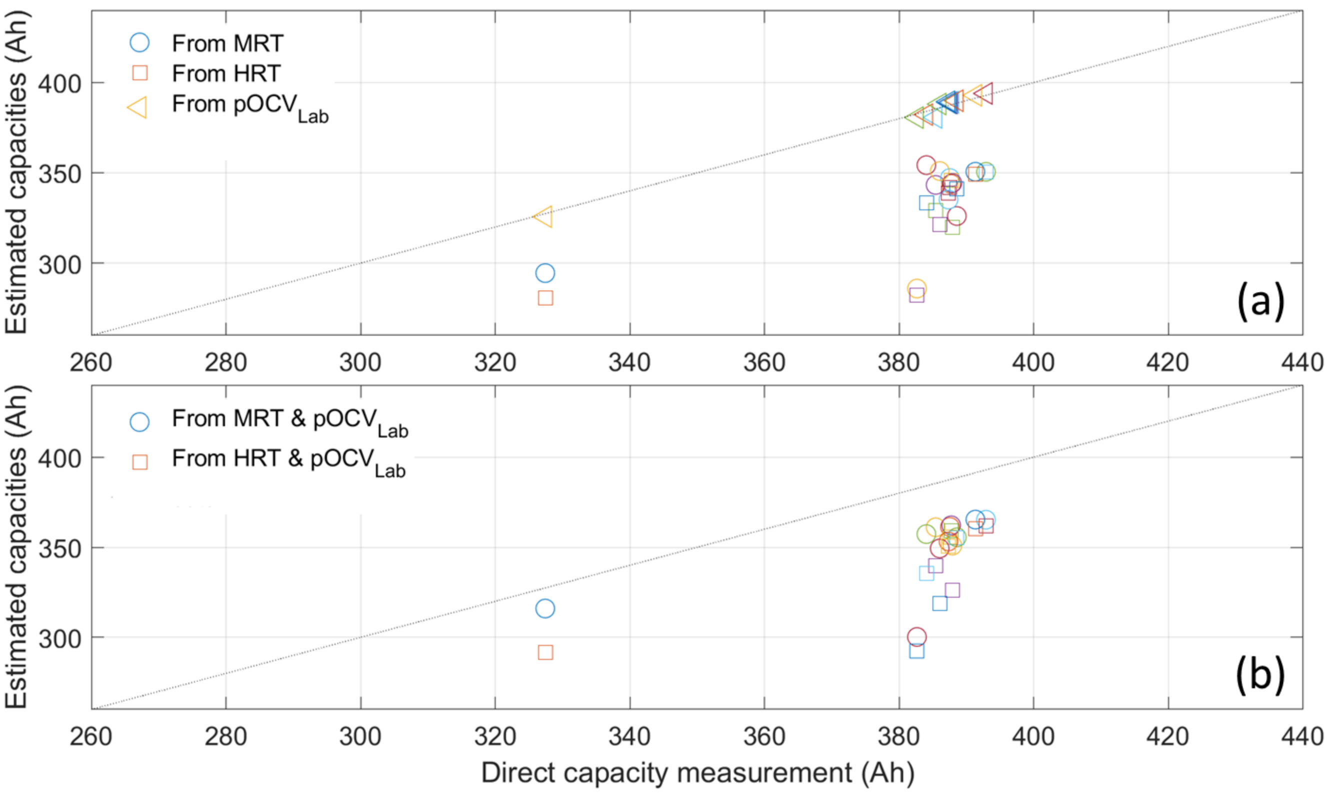

Figure 14. (**a**) comparison of the measured capacity and the estimated ones from the BESS MRT and HRT test and from the laboratory test OCV curves. (**b**) comparison of the measured capacity and the estimated ones from the BESS MRT and HRT tests using each module true OCV curves.

With errors coming from the accuracy of the OCV curves and the one from RCV removed, the only possibility left is some inaccuracies in the capacity measurements. This was not considered at first because, since all the modules are in series, this error was believed to be constant. However, the different calibration issues observed Figure 11 seems to show that there might be some problems. This was acknowledged by the manufacturer and this could explain the accuracy issue. In addition, one important parameter was not considered: cell balancing. In the BESS, balancing is continuous throughout the SOC range whenever the lowest cell group SOC is greater than or equal to 5%. The lowest SOC cell group is compared to all other cell groups to determine balance of the BESS. Any cell group that is Δ3% SOC or more compared to the lowest cell group SOC will receive a 150 mA resistive load to remove energy from the cell group. Therefore, modules might receive more capacity than was recorded in our data, and this could explain the precision issues. Balancing data was unfortunately not available to us.

4.3. Degradation Analysis

Despite the setback in not being able to track the real capacity loss from all the modules, we can still investigate the degradation based on the modules that were removed from the BESS. In our previous work [32], the electrochemical behavior of the single cells was investigated and a sensibility analysis was performed to determine the most relevant features of interest (FOI) to diagnose the degradation mechanisms. Based on this analysis, the loss of active material on both component of the PE, LAM_{NCA} and LAM_{LCO} respectively and of the NE (LAM_{NE}) were decipherable directly from FOIs. The last degradation mode, the loss of lithium inventory, had to be estimated from the best possible fit of the electrochemical behavior. The three FOI were the area between 2.3 and 2.4 V to quantify LAM_{LCO}, the area between 2.15 and 2.3 V to quantify LAM_{NCA} and the intensity at 2.44 V to quantify the total LAM_{PE}. Given the shape of the IC curves, no capacity appears to be outside of the potential window and therefore, LAM_{NE} was estimated from the capacity loss.

Based on the FOIs and the methodology we proposed in [32] to quantify the degradation mechanisms on these cells, the degradation of the lower temperatures modules comprised, on average, 5.2 (±2.6)% $LAM_{LTO,}$ 7.6 (±0.8)% LAM_{NCA}, 1.9 (±0.8)% LAM_{LCO}, and 6.0 (±0.9) LLI. For the higher temperature modules, the degradation was composed of 5.9 (±2.2)% $LAM_{LTO,}$ 13.5 (±3.2)% LAM_{NCA}, 2.6 (±1.0)% LAM_{LCO}, and 8.8 (±0.9) LLI. The observed ratios between the degradation modes are comparable to the one measured during the laboratory experiment [32]. This confirms that our laboratory test was successful in replicating realistic aging for the BESS system.

Since the data for the MRT energy and HRT tests were done on the entire SOC_B range at a relatively low rate for high power cells, P/1.25 and P/6.5, the same FOI analysis was tried on the field data. Unfortunately, it was found not to be possible as the FOI values extracted from the tests before the modules swap did not match the one observed experimentally in the laboratory for the replaced modules. This could be related to several issues: First, the voltage response at the single level is rather noisy and so significant smoothing was necessary to have clear IC features which modify IC peaks shape, area and intensity and thus FOI detection. Second, the HRT and MRT tests were done under constant power regime which affected the IC peaks at beginning and end of regime where voltage variations are significant and where FOI 2 and 3 were measured. Third, not all the cells used the same SOC range and so, information was missing for some cells. Finally, as shown above, the capacity cannot be estimated with accuracy and thus LAM_{NE} is not quantifiable directly which hampers the derivation of LLI even if the LAM_{PE} was accurate. For interested readers, the obtained IC curves for the MRT test after smoothing are presented in Figure A1 in Appendix A. No sign of LAM_{PE} induced capacity loss was found. LLI does not seems to be a factor in capacity loss either, but it is impossible to be sure because most cells did not reach their end of charge cutoff before 100% SOC_B. From what is observable, it appears that none of the modules have started any accelerated degradation stage at the time of this writing.

One solution to estimate the remaining useful life for the deployed BESS is to extrapolate from the diagnosis that was performed on the replaced modules in the laboratory. If the observed degradation is considered normal, these trends can be extended and they should be representative. Our analysis showed an increasing spread in between cells and to take that into account, the extent of each degradation will be varied in the simulations to accommodate inhomogeneous aging pace. Simulations were performed from the average values for lower and higher temperature modules as well as with variations corresponding to one- and two-times the observed standard deviation, σ. All combinations of standard deviations (on the three LAMs and LLI) were simulated and only the worst-case scenario was plotted. Results from these simulations are presented in Figure 15. From the degradation mode quantification, and if the BESS usage remained consistent, an acceleration of the aging could start around day 2500 (~seven years) for the higher temperature modules only if the cell-to-cell variations are in the 2σ range and in the worst-case scenario (lower than average LLI and LAM_{LCO}, higher than average LAM_{LTO} and LAM_{NCA}). If within σ, accelerated aging only stars after 14 years of usage under the same conditions. For the modules at lower temperatures, no significant acceleration is expected within 20 years of usage. Since our observations at Day 1939 (Figure A1) show no sign of accelerated aging, the BESS is believed to be in the middle to upper portion of the spread and thus be able to last up more than 15 years with capacity loss on the modules below 30%.

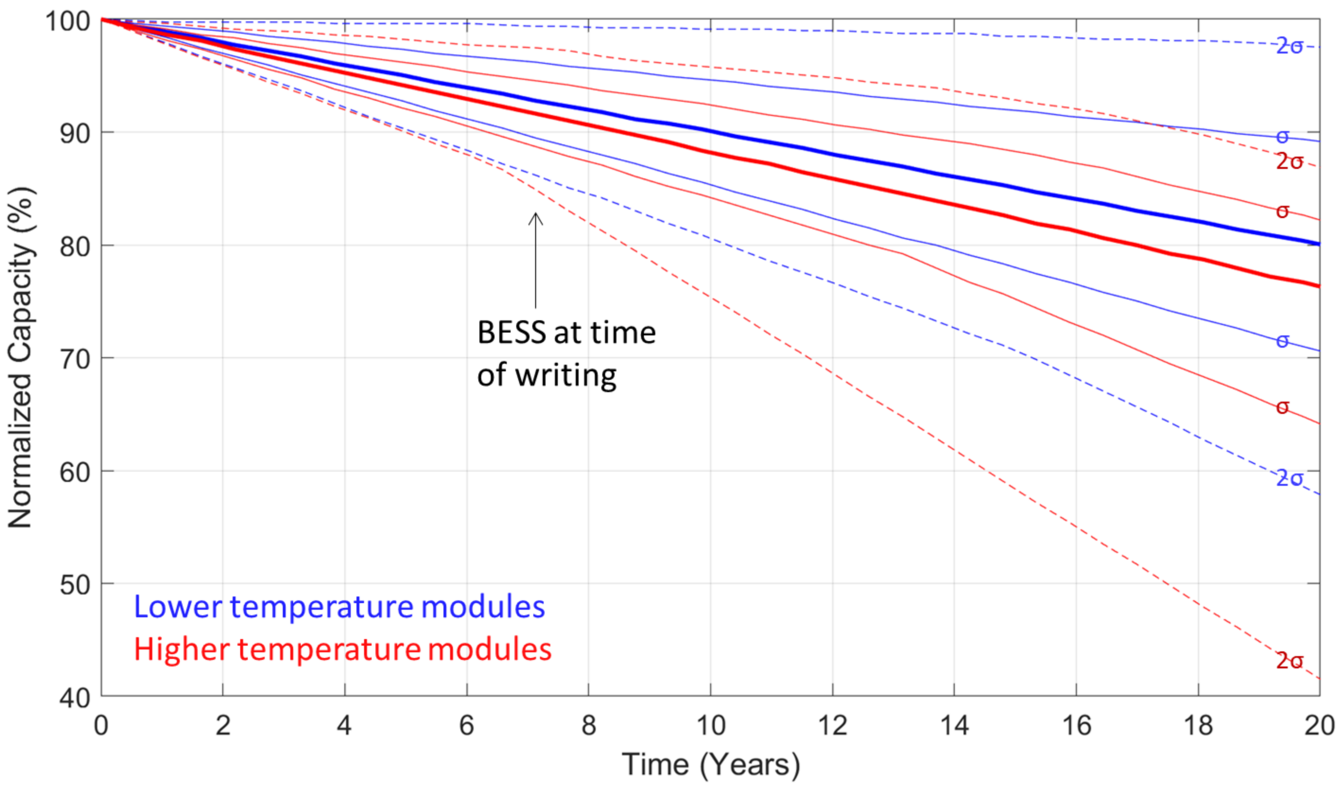

Figure 15. Forecast of capacity loss based on degradation modes extrapolation with ±3% of the estimation performed around day 1000 on 3 modules believed to be representative of the BESS.

5. Conclusions

This study spans more than seven years of usage of a grid-tied BESS system on the Island of Hawai'i in the Hawaiian archipelago. The BESS has been well used and is continuing to provide significant storage capability for the grid. Its performance is still within specifications and the only maintenance performed was the replacement of two modules that appeared to suffer from the disconnection of one of the seven cells in parallel. Despite some temperature inhomogeneities, with some modules running consistently 5 °C or more hotter than others, the capacity of the BESS was not affected much with a difference of around 1% between the hottest and the coolest modules. However, the temperature induced a slightly different degradation pattern that might induce accelerated degradation for the hotter modules later in life. The overall capacity loss on the modules was estimated to be between 5 and 10% after 7 years of usage compared to 15% at the BESS level. This calculation was only obtainable from swapped modules after 2500 days of usage. The internal module capacity estimation was vastly overestimated by between 10 and 25% despite our best efforts. We believe that inaccuracies in the capacity measurement, and the lack of information on the balancing, prevented the correct estimation. This could prove problematic for future deployments and better solutions need to be enacted to ensure accurate estimation. This could include better safeguards for capacity estimation and the option to stop balancing, or monitor it better, while performing reference tests. Nonetheless, the BESS is performing well and, according to the forecast, its useful lifespan should exceed 15 years on the grid with a capacity loss below 30%.

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Abbreviations and Nomenclature

The following abbreviations was used in this manuscript:

BESS	Battery Energy Storage System
FOI	Feature of Interest
HNEI	Hawaii Natural Energy Institute
HRT	HNEI Reference Test
IC	Incremental Capacity
LAM	Loss of Active Material
LCO	Lithium Cobalt Oxide
LLI	Loss of Lithium Inventory
LRU	Line Replacement Unit
LTO	Lithium Titanium Oxide
MRT	Manufacturer Reference Test
NCA	Nickel Aluminum Cobalt Oxide
NE	Negative Electrode
OCV	Open Circuit Voltage
PE	Positive Electrode
PCC	Point of Common Coupling
RCV	Rest Cell Voltage
SOH	State of Health
SOC	State of Charge

The following nomenclature was used in this manuscript:

- P/x refers to rated power usage, P/1 being a full charge or discharge in 1 h.
- Black circled numbers refer to the RCV measured during the HRT test.
- White circled numbers refer to the RCV measured during the MRT test.
- Letters A to F refer to electrochemical peaks on Figure 8.
- Q refers to capacity, V to voltage, and I to current.

Appendix A

Figure A1 presents the IC curves (dQ/dV = f(V)) for the 384 modules gathered from the MRT test at days 0, 302, 585, 713, 861, 1050, and 1939. The voltage curves were smoothed before derivation. The modules electrochemical behavior is homogeneous in the early days then some imbalance starts to be visible from day 585. Because of the growing imbalance, the lowest voltage peak and the high voltage shoulder starts to be inaccessible for some cells which affected the overall BESS capacity retention. This explain why the capacity loss of the BESS seems to be higher than the one of the modules. At day 1939, the voltage response of the modules shows no sign of accelerated aging.

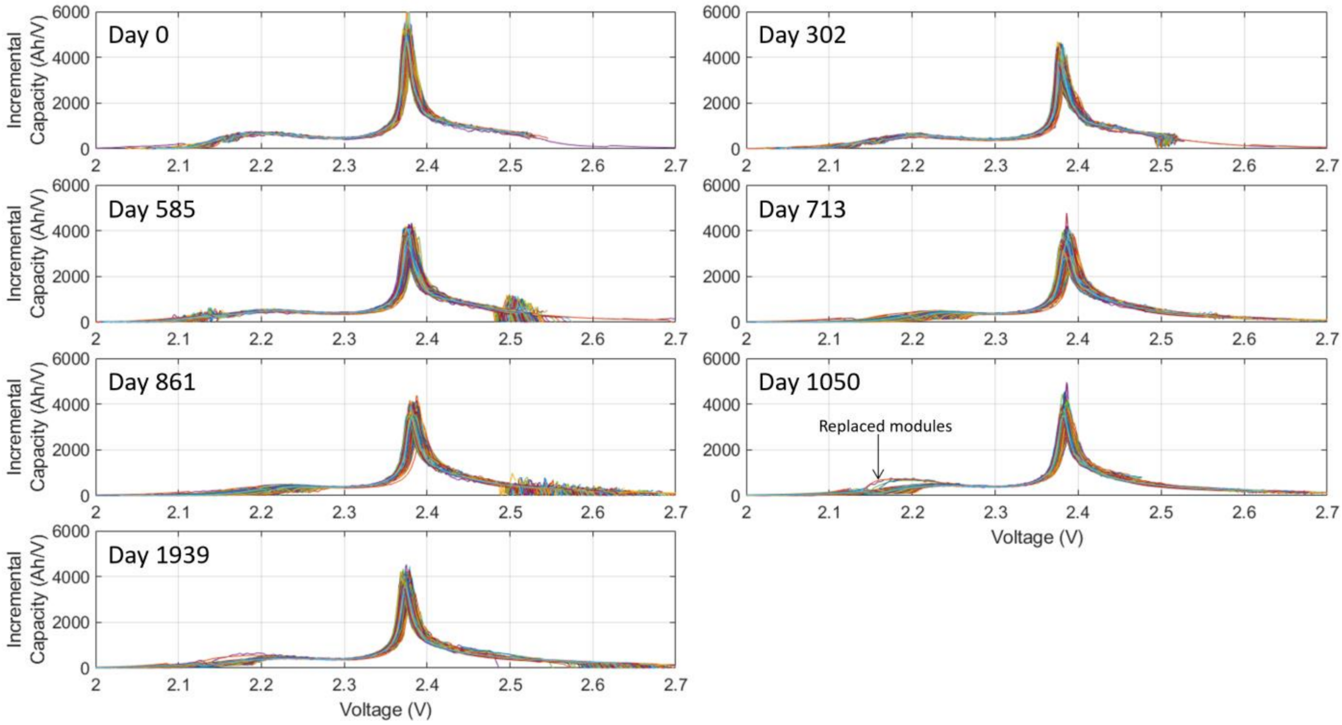

Figure A1. IC signatures for the charges during the energy test. Different colors correspond to the BESS 384 modules.

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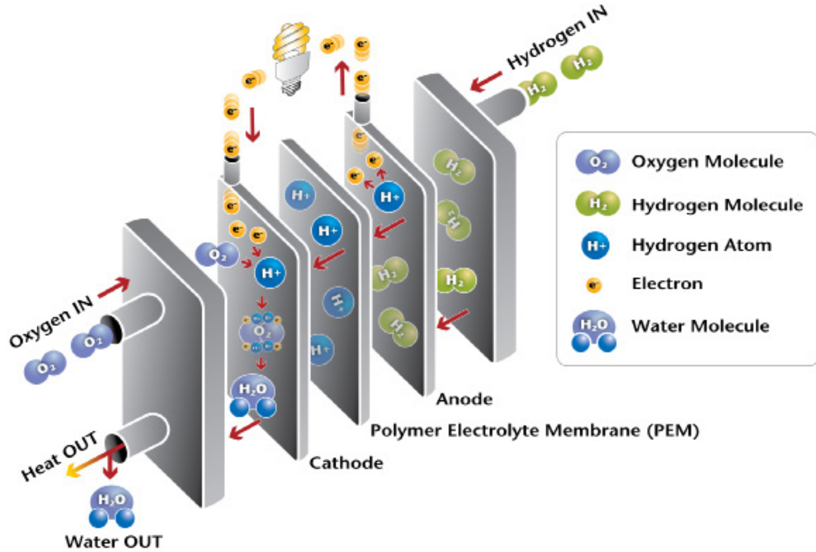
Fuel Cells

Fuel cells are the most energy efficient devices for extracting power from fuels. Capable of running on a variety of fuels, including hydrogen, natural gas, and biogas, fuel cells can provide clean power for applications ranging from less than a watt to multiple megawatts.

Our transportation—including personal vehicles, trucks, buses, marine vessels, and other specialty vehicles such as lift trucks and ground support equipment, as well as auxiliary power units for traditional transportation technologies—can be powered by fuel cells. They can play a particularly important role in the future by enabling replacement of the petroleum we currently use in our cars and trucks with cleaner, lower-emission fuels like hydrogen or natural gas.

Stationary fuel cells can be used for backup power, power for remote locations, distributed power generation, and cogeneration (in which excess heat released during electricity generation is used for other applications). They can take advantage of inexpensive natural gas and low-carbon fuels like biogas, enabling significant efficiency improvement and greenhouse gas reduction when compared to combustion-based power generators.

Fuel cells can power almost any portable application that typically uses batteries, from hand-held devices to portable generators.



Fuel cells directly convert the chemical energy in hydrogen to electricity, with pure water and potentially useful heat as the only byproducts. Hydrogen-powered fuel cells are not only pollution-free, but also can have more than two times the efficiency of traditional combustion technologies.

Why Fuel Cells?

Fuel cells directly convert the chemical energy in hydrogen to electricity, with pure water and potentially useful heat as the only byproducts. Hydrogen-powered fuel cells are not only pollution-free, but they can also have more than two times the efficiency of traditional combustion technologies.

A conventional combustion-based power plant typically generates electricity at efficiencies of 33 to 35%, while fuel cell systems can generate electricity at efficiencies up to 60% (and even higher with cogeneration).

The gasoline engine in today's typical car is less than 20% efficient in converting the chemical energy in gasoline into power that moves the vehicle, under normal driving conditions. Fuel cell vehicles, which use electric motors, are much more energy efficient. The fuel cell system can use 60% of the fuel's energy—corresponding to more than a 50% reduction in fuel consumption compared to a conventional vehicle with a gasoline internal combustion engine. When using hydrogen produced from natural gas, fuel cell vehicles are expected to have well-to-wheels greenhouse gas emissions less than half that of current gasoline-powered vehicles.

In addition, fuel cells operate quietly, have fewer moving parts, and are well suited to a variety of applications.

Excess power produced by intermittent renewable sources like solar and wind can be stored in the form of hydrogen, and either fed back into the power grid when needed or used to power fuel cell electric vehicles. In this way, fuel cells could play an important role in aiding the widespread deployment of clean renewable power sources.

How Do Fuel Cells Work?

A single fuel cell consists of an electrolyte sandwiched between two electrodes, an anode and a cathode. Bipolar plates on either side of the cell help distribute gases and serve as current collectors. In a Polymer Electrolyte Membrane (PEM) fuel cell, which is widely regarded as the most promising for light-duty transportation, hydrogen gas flows through channels to the anode, where a catalyst causes the hydrogen molecules to separate into protons and electrons. The membrane allows only the protons to pass through it. While the protons are conducted through the membrane to the other side of the cell, the stream of negatively-charged electrons follows an external circuit to the cathode. This flow of electrons is electricity that can be used to do work, such as power an electric motor.

On the other side of the cell, air flows through channels to the cathode. When the electrons return from doing work, they react with oxygen in the air and the protons (which have moved through the membrane) at the cathode to form water. This union is an exothermic reaction, generating heat that can be used outside the fuel cell.

The power produced by a fuel cell depends on several factors, including the fuel cell type, size, temperature at which it operates, and pressure at which gases are supplied. A single fuel cell produces roughly 0.5 to 1.0 volt, barely enough voltage for even the smallest applications. To increase the voltage, individual fuel cells are combined in series to form a stack. (The term "fuel cell" is often used to refer to the entire stack, as well as to the individual cell.) Depending on the application, a fuel cell stack may contain only a few or as many as hundreds of individual cells layered together. This "scalability" makes fuel cells ideal for a wide variety of applications, from vehicles (50-125 kW) to laptop computers (20-50 W), homes (1-5 kW), and central power generation (1-200 MW or more).

Comparison of Fuel Cell Technologies

In general, all fuel cells have the same basic configuration — an electrolyte and two electrodes. But there are different types of fuel cells, classified primarily by the kind of electrolyte used. The electrolyte determines the kind of chemical reactions that take place in the fuel cell, the temperature range of operation, and other factors that determine its most suitable applications.

Challenges and Research Directions

Reducing cost and improving durability are the two most significant challenges to fuel cell commercialization. Fuel cell systems must be cost-competitive with, and perform as well or better than, traditional power technologies over the life of the system. Ongoing research is focused on identifying and developing new materials that will reduce the cost and extend the life of fuel cell stack components including membranes, catalysts, bipolar plates, and membrane-electrode assemblies. Low-cost, high-volume manufacturing processes will also help to make fuel cell systems cost competitive with traditional technologies.

For More Information

More information on the Fuel Cell Technologies Office is available at http://www.hydrogenandfuelcells.energy.gov.

Comparison of Fuel Cell Technologies

Fuel Cell Type	Common Electrolyte	Operating Temperature	Typical Stack Size	Electrical Efficiency (LHV)	Applications	Advantages	Challenges
Polymer Electrolyte Membrane (PEM)	Perfluoro sulfonic acid	<120°C	<1 kW - 100 kW	60% direct H_2;[i] 40% reformed fuel[ii]	• Backup power • Portable power • Distributed generation • Transportation • Specialty vehicles	• Solid electrolyte reduces corrosion & electrolyte management problems • Low temperature • Quick start-up and load following	• Expensive catalysts • Sensitive to fuel impurities
Alkaline (AFC)	Aqueous potassium hydroxide soaked in a porous matrix, or alkaline polymer membrane	<100°C	1 - 100 kW	60%[iii]	• Military • Space • Backup power • Transportation	• Wider range of stable materials allows lower cost components • Low temperature • Quick start-up	• Sensitive to CO_2 in fuel and air • Electrolyte management (aqueous) • Electrolyte conductivity (polymer)
Phosphoric Acid (PAFC)	Phosphoric acid soaked in a porous matrix or imbibed in a polymer membrane	150 - 200°C	5 - 400 kW, 100 kW module (liquid PAFC); <10 kW (polymer membrane)	40%[iv]	• Distributed generation	• Suitable for CHP • Increased tolerance to fuel impurities	• Expensive catalysts • Long start-up time • Sulfur sensitivity
Molten Carbonate (MCFC)	Molten lithium, sodium, and/ or potassium carbonates, soaked in a porous matrix	600 - 700°C	300 kW - 3 MW, 300 kW module	50%[v]	• Electric utility • Distributed generation	• High efficiency • Fuel flexibility • Suitable for CHP • Hybrid/gas turbine cycle	• High temperature corrosion and breakdown of cell components • Long start-up time • Low power density
Solid Oxide (SOFC)	Yttria stabilized zirconia	500 - 1000°C	1 kW - 2 MW	60%[vi]	• Auxiliary power • Electric utility • Distributed generation	• High efficiency • Fuel flexibility • Solid electrolyte • Suitable for CHP • Hybrid/gas turbine cycle	• High temperature corrosion and breakdown of cell components • Long start-up time • Limited number of shutdowns

i NREL Composite Data Product 8, "Fuel Cell System Efficiency," http://www.nrel.gov/hydrogen/docs/cdp/cdp_8.jpg
ii Panasonic Headquarters News Release, "Launch of New 'Ene-Farm' Home Fuel Cell Product More Affordable and Easier to Install," http://panasonic.co.jp/corp/news/official.data/data.dir/2013/01/en130117-5/en130117-5.html
iii G. Mulder et al., "Market-ready stationary 6 kW generator with alkaline fuel cells," ECS Transactions 12 (2008) 743-758
iv Doosan PureCell® Model 400 System Specifications, http://www.doosanfuelcell.com/en/solutions/system.do
v FuelCell Energy DFC300 Product Specifications, http://www.fuelcellenergy.com/assets/DFC300-product-specifications1.pdf
vi Ceramic Fuel Cells Gennex Product Specifications, http://www.cfcl.com.au/Assets/Files/Gennex_Brochure_%28EN%29_Apr-2010.pdf

U.S. DEPARTMENT OF ENERGY
Energy Efficiency & Renewable Energy

For more information, visit:
hydrogenandfuelcells.energy.gov

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Floodway

A "Regulatory Floodway" means the channel of a river or other watercourse and the adjacent land areas that must be reserved in order to discharge the base flood without cumulatively increasing the water surface elevation more than a designated height. Communities must regulate development in these floodways to ensure that there are no increases in upstream flood elevations. For streams and other watercourses where FEMA has provided Base Flood Elevations (BFEs), but no floodway has been designated, the community must review floodplain development on a case-by-case basis to ensure that increases in water surface elevations do not occur, or identify the need to adopt a floodway if adequate information is available.

National Flood Insurance Program Requirements

- 59.1 - Definition
- 60.3 - Floodplain management criteria for floodprone areas
- 60.3 (c) (10) - Cumulative Effects of Development
- 60.3 (d) (2) - Floodway Adoption
- 60.3 (d) (3) - Floodway Encroachment
- 60.3 (d) (4) - Floodway Encroachments that Cause an Increase

Last updated July 8, 2020

National Terrorism Advisory System

Land Use & Solar Development

As the industry grows and states explore significant increases in solar penetration, the land necessary for solar projects will become more and more valuable. With thoughtful preparation, solar development can be a net positive for the environment and a boon for local communities.

Land Use & Solar Development

Harnessing the sun's energy and converting it to electricity offers one of the most technologically viable and cost-effective means to produce pollution-free, sustainable power. Generating electricity at the scale necessary to achieve ambitious carbon emission reduction goals requires long-term planning for efficient and responsible project development.

Responsible Land Use

There is tremendous solar power generation potential in the United States. In five minutes, enough sunlight shines on the continental U.S. to satisfy our electricity demand for an entire month. The U.S. Southwest has particularly abundant and high quality resources for utility-scale solar power. Research from the National Renewable Energy Laboratory shows that the entire U.S. could be powered by utility-scale solar occupying just 0.6% of the nation's land mass.

Depending on the specific technology, a utility-scale solar power plant may require between 5 and 10 acres per megawatt (MW) of generating capacity. Like fossil fuel power plants, solar plant development requires some grading of land and clearing of vegetation. For example, many concentrating solar power (CSP) plants need to be constructed on flat land with less than 1-percent slope. Utility-scale photovoltaics (PV), on the other hand, can utilize land with steeper slopes and no water access.

Environmental Impacts of Utility-Scale Solar

There are a number of environmental factors related to the construction and maintenance of utility-scale solar power plants, including water use, habitat conservation, and land use.

Keep Reading

Related Links

- Habitat Conservation Planning
- Water Use Management

Additional Resources on Land Use & Solar Development

Factsheets

Solar & Agricultural Land Use

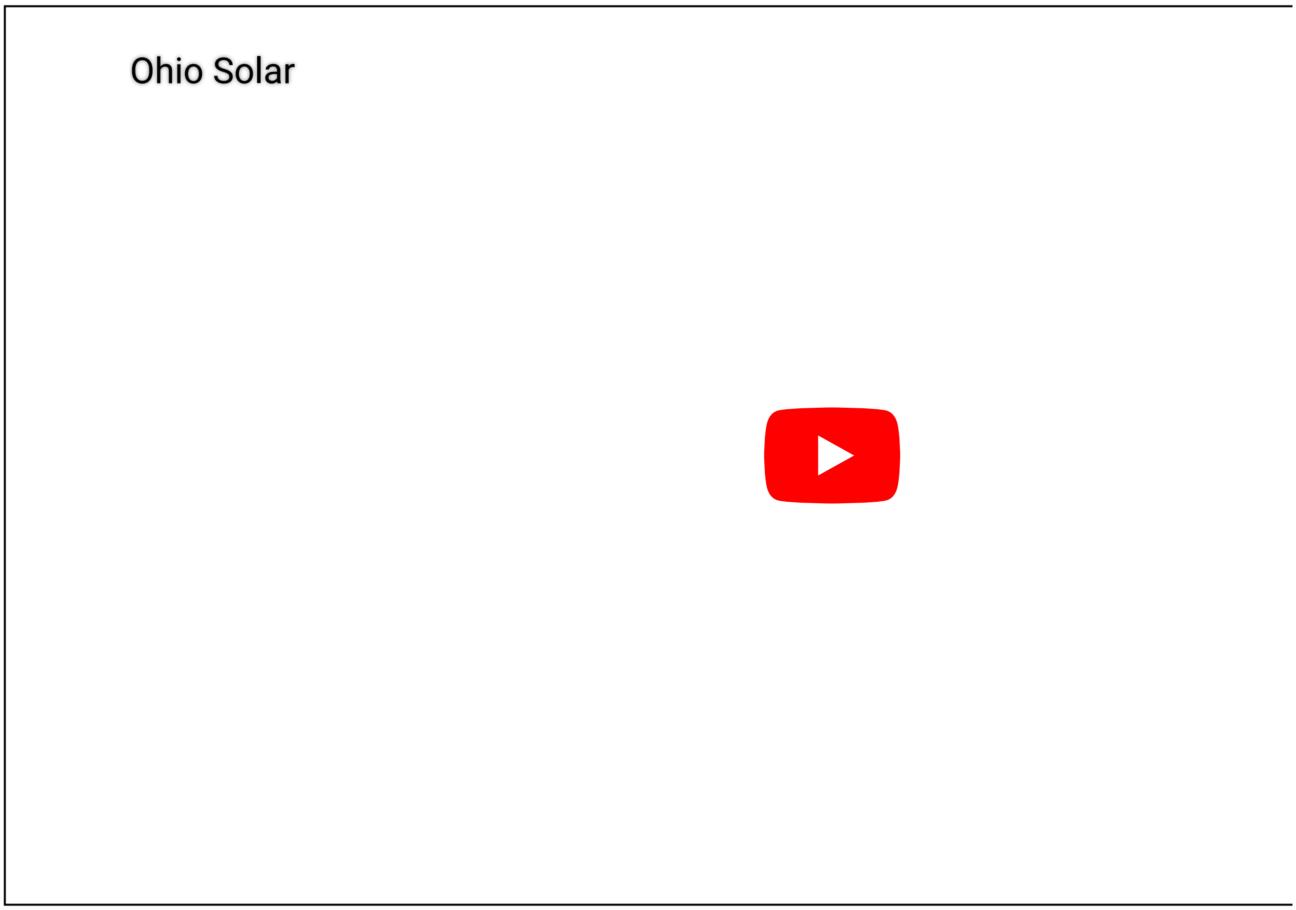
Solar & Property Value

Solar & Multiuse Farming

Other Resources

Whitepaper: Recommendations for Utility-Scale Developers

SEIA Guide to Land Leases for Solar



Siting & Permitting

Siting and permitting a solar power plant is a complex process. Land use, access to transmission, and water rights must be considered, and securing access to a suitable site is only the first step in the siting process. Solar power plants are subject to strict review processes through federal, state, and local regulators. Solar companies provide detailed project construction plans, conduct numerous environmental studies, and propose mitigation strategies to aid in this process. These practices, as well as today's utility-scale solar power technologies, ensure that any environmental impact is minimized.

The majority of solar power plants today are located on privately-held land. When a power plant is proposed on private land, various state and local agencies must grant the necessary approvals prior to construction. The siting and permitting process can take more than three to five years to complete. SEIA supports the adoption of best practices and policies that expedite the permitting of worthy projects.

When power plants are proposed on federal land managed by the U.S. Bureau of Land Management (BLM), the BLM, in coordination with other agencies such as the U.S. Fish and Wildlife Service and state and local authorities, is authorized to permit development of solar and other energy projects. SEIA supports the use of federal land for solar power plant development and is actively engaged in BLM's process for crafting the rules that govern how a solar power plant is permitted and built.

Environmental Review

Environmental review of a proposed solar power plant on public land can take three to five years. This time period can be less if the plant is located on private or previously disturbed land. Many areas ideal for USP development are on public lands overseen by the BLM. The BLM right-of-way (ROW) permits undergo a strict review process before being issued, as required by the National Environmental Policy Act of 1969. Companies provide detailed project construction plans, environmental impact assessments and mitigation strategies. The BLM, in coordination with state and local authorities, conducts analyses of the site and holds public hearings with members of the community to gauge the impact of the project on the area. An official Environmental Impact Statement (EIS) is issued for each project before an official Record of Decision is announced.

Additional Reading on Utility-Scale Solar

Renewable Energy Standards Learn More

Land Use & Solar Development Learn More

Transmission Learn More

Habitat Conservation Planning

Learn More

Water Use Management

Learn More

ADDRESS

Solar Energy Industries Association
1425 K Street, N.W., Suite 1000
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SOUTHERN CALIFORNIA GAS COMPANY

CPUC-ENERGY DIVISION DATA REQUEST 5
RE: VENTURA COMPRESSOR STATION
DATE REQUESTED: July 23, 2021
DATE RESPONDED: August 6, 2021

On August 5, 2021, SoCalGas received a letter from the CPUC's Executive Director, Rachel Peterson, and shares the CPUC's commitment expressed therein to hear from the community and explore solutions to address its concerns about the Ventura compressor station, including different potential compression options. We appreciate the Commission's continuing guidance on this matter and are working towards meeting the goals set out in its letter.

QUESTION 1:

JPL NASA detected methane emissions on October 16, 2017, at or near the Ventura Compressor Station site. Please provide details of the incident, including, but not limited to the questions below:

a) Where did the leak or venting of methane occur?

b) Did any sensors (including air/emissions monitoring and/or pressure-loss sensors) get activated?

c) Was it a blowdown purge? (Evacuating trapped gas when shutting compressor station.)

d) How often does SoCalGas have to purge the blowdown stack?

e) If it wasn't a blowdown purge, what caused the incident?

f) What equipment was leaking?

g) What measures were taken to fix the methane leak?

h) What activities were performed at the Ventura Compressor Station on about October 16, 2017. Please include a list of all Operation and Maintenance on that date.

RESPONSE 1:

It is SoCalGas's understanding that JPL NASA conducted two flights over the facility during times relevant to this response and provides information based on this understanding. The first flight occurred on September 7, 2017, approximately one month before the October 2017 flyover, and did not identify any methane emissions at the facility. The second flight occurred on October 16, 2017, which did identify methane emissions that appeared to be related to the facility.

SoCalGas notes that the methane emission event identified on October 16, 2017 does not meet the definition of an "incident" under 49 Code of Federal Regulations (CFR) §191.3.[1]

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[1] 49 CFR §191.3 defines an incident as:

Notwithstanding, for purposes of this data request response, SoCalGas provides the following information relating to the methane emissions detected by the JPL NASA flight on October 16, 2017. SoCalGas believes such indications were most likely related to methane emissions on station metering equipment, as further described below.

a) The measured methane emissions occurred at the northern portion of the facility from station metering equipment near the existing compressor building.

b) No.

c) No.

d) In addition to the compressor equipment, there are several pipelines that enter the station and utilize one of several blowdown stacks in order to purge the pipelines out of service. These pipeline blowdown stacks are utilized on an as needed basis to accommodate emergencies and maintenance work. The compressor station has its own blowdown stack to accommodate its emergency shutdown (ESD) system and maintenance work.

   A compressor station's ESD is a critical safety system that quickly evacuates natural gas from the station's piping and equipment in order to remove the potential for ignition. The system is required to be tested on an annual basis. The Ventura Compressor Station's ESD is designed to completely evacuate all the gas within the station within three minutes after an ESD is initiated, which is consistent with pipeline safety regulations. During the testing of the ESD, the gas is captured and not released to atmosphere. Additionally, in the past four years there have been 10 events that have triggered the ESD (8 were unplanned and two were planned), which resulted in the venting of methane.

---

(1) An event that involves a release of gas from a pipeline, gas from an underground natural gas storage facility (UNGSF), liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences

(i) A death, or personal injury necessitating in-patient hospitalization;

(ii) Estimated property damage of $122,000 or more, including loss to the operator and others, or both, but excluding the cost of gas lost. For adjustments for inflation observed in calendar year 2021 onwards, changes to the reporting threshold will be posted on PHMSA's website. These changes will be determined in accordance with the procedures in appendix A to part 191.

(iii) Unintentional estimated gas loss of three million cubic feet or more.

(2) An event that results in an emergency shutdown of an LNG facility or a UNGSF. Activation of an emergency shutdown system for reasons other than an actual emergency within the facility does not constitute an incident.

(3) An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraph (1) or (2) of this definition

Please refer to Table 1: Ventura Compressor Station ESD Information (Unplanned Events) which provides the dates and the amounts vented during those unplanned events.

Table 1: Ventura Compressor Station ESD Information (Unplanned Events)

Date	Amount Vented (Mscf)
3/1/2017	49.7
5/9/2017	54.2
5/22/2017	54.2
7/27/2017	56.8
12/7/2018	35.3
9/14/2019	56.3
1/19/2021	46
7/2/2021	5.4

e) Subject to the clarification of an incident in this response as noted above, the methane emissions detected by the JPL NASA flight on October 16, 2017 were most likely released from threaded connection fittings on station metering equipment.

f) Please see the response to Question 1.e above.

g) SoCalGas investigated and identified the source of methane emissions. The repair was made by tightening multiple threaded connection fittings on the station metering equipment.

The Ventura Compressor Station is among the many SoCalGas facilities subject to the stringent statewide California Air Resource Board (CARB) Oil & Gas methane rule, per California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4, Subarticle 13: Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities, has been in effect since January 1, 2018. These regulations include quarterly third-party leak detection and repair (LDAR) inspections. The purpose of this regulation is to establish greenhouse gas emission standards for natural gas facilities and is designed to serve the purposes of the California Global Warming Solutions Act, AB 32, as codified in sections 38500-38599 of the Health and Safety Code. The rule is intended to minimize methane associated with compressor operations and components in fugitive service. The rule also includes timeframes for conducting timely repairs and re-inspections should a component be found to be leaking methane.

h) Please note this subpart to Question 1 was requested as a supplement to the original data request on August 2, 2021.

Table 2 below lists the operation and maintenance activities performed at Ventura Compressor Station on October 16, 2017.

Table 2: Ventura Compressor Station Operation and Maintenance Activities on October 16, 2017	
Activity	**Activity Status**
HAZMAT Storage Area Inspection	Activity completed on 10/16/17
Quarterly Compliance Emission Testing	Activity completed on 10/16/17
Compressor Unit #3 Critical Parts Inventory	Activity completed on 10/16/17
Compressor Unit #1 Replacement of Ring Gear on Flywheel	Activity started on 10/16/17

QUESTION 2:

Please provide specific analyses of technical feasibility, costs, metrics, and engineering constraints that were conducted for considering the use of electric-driven compressors. If no formal analysis was done, please explain in detail why not and what barriers exist to using electric compressors at this site.

a. SoCalGas has stated that one reason it decided not to use electric compressors was the local risk of public safety power shut-off (PSPS) events. If electric compressors were used and the power went out for an extended period, can the La Goleta storage field provide enough withdrawal capacity and/or pressure to keep gas flowing to customers at a rate sufficient to avoid a widespread need to relight customer pilot lights? If so, how many hours/days could La Goleta supply adequate gas/pressure?

b. Can back-up electricity generation be installed at Ventura to support electric-driven compressors during PSPS events or other outages e.g., batteries, hydrogen fuel cells, or natural gas fuel cells? Can a dedicated and/or redundant electric line be brought into the compressor station to ensure continued service during a PSPS event?.

c. Is it possible to install a hybrid half-electric, half-gas driven compressor configuration in Ventura, similar to what is planned for the Moreno Compressor Station?

    i. What horsepower are the proposed gas and electric compressors at Moreno Compressor Station?

RESPONSE 2:

SoCalGas shares the CPUC's commitment, as expressed in their August 5, 2021 letter, to hear from the community and explore potential solutions to address its concerns, including exploring the use of electric driven compressors. As noted in SoCalGas's response to Question 7 of Data Request 4, SoCalGas did not initially consider the use of electric driven compressors at the Ventura Compressor Station during its development of the project. This is primarily because electronic driven compressors rely predominantly on electricity obtained from the electric grid. As previously noted, PSPS events on the Southern California Edison Company (SCE) electric grid, which serves the Ventura Compressor Station, can destabilize the energy delivery system and compromise reliability.

The Ventura Compressor Station provides reliability that is crucial to safely and reliably deliver natural gas service to customers north of the facility given (1) the location of this facility (2) the need to meet the La Goleta Storage Field's summer injection requirements to maintain core reliability, and (3) the need to meet gas demand on the coastal system, which has been impacted by reduced local gas production.

a. As noted, SoCalGas remains concerned that PSPS events on the SCE electric grid could destabilize the energy delivery system and compromise reliability. The ability to continue to serve customers at a rate sufficient to avoid a widespread disruption of service would be dependent on the amount of natural gas contained in the La Goleta Storage Field at the time of the prolonged power outage. The La Goleta Storage Field holds 21.5 billion cubic feet (bcf) when full and its ability to remain full is dependent on the Ventura Compressor Station to support injecting the natural gas for storage and subsequent later usage during peak demand periods.

Storage field levels will fluctuate over the year based on system demand, which is often predicated on weather patterns; cold weather during winter increases direct customer use and hot weather during the summer increases the demand for electric generation, which in turn increases natural gas demand to serve those customers. One billion cubic feet of gas is enough to supply about 5 million homes for a day. There are approximately a quarter million customers alone on SoCalGas' Coastal System north of the Ventura Compressor Station that are served by the La Goleta Storage Field, which also supports customers south of the compressor station including the City of Ventura as well as occasionally in the Los Angeles Basin.

b. SoCalGas is committed to conducting additional review and will evaluate different equipment configuration alternatives, such as configurations that include electrification measures, to further refine the scope of the project and reduce potential air emissions. SoCalGas has already commissioned engineering analysis on the use of hydrogen for blending of the fuel-gas for the new compressors. As currently designed, the new natural gas compressors can accommodate a hydrogen blend. We anticipate this analysis to be completed by Q1 2022.

SoCalGas did not previously conduct a quantitative analysis of the potential use of electric driven compressors at the Ventura Compressor Station. As such, at this time we are unable to provide specific analyses of technical feasibility or costs.

The ability to provide a dedicated and/or redundant electric line to the Ventura Compressor Station would require detailed engineering analysis in coordination with SCE. The Ventura region is served by SCE through a series of overhead transmission lines that carry power from generating sources primarily outside of the area. The placement of additional electric infrastructure, such as new poles or towers, may result in potential environmental impacts, depending on the location.

C. As previously noted, SoCalGas did not conduct a quantitative analysis regarding the use of electric driven compressors. As such, at this time we are unable to provide specific analyses of technical feasibility, costs, metrics, and engineering constraints to determine if it is possible to install a hybrid -gas and electric driven compressor configuration in Ventura, similar to what is planned for the Moreno Compressor Station. However, as noted above, SoCalGas is committed to conducting additional review and will evaluate different equipment configuration alternatives, such as configurations that include electrification measures.

i. To comply with South Coast Air Quality Management District's Regional Clean Air Incentives Market (RECLAIM) sunset requirements, the Moreno Compressor Station Modernization Project includes decommissioning three reciprocating compressors rated at 995 HP each and four turbine-driven centrifugal compressors rated at 1,100 HP each and two reciprocating compressors rated at 3,000 HP each. A new hybrid compression plant will include two new gas turbine-driven centrifugal compressors rated at 5,825 HP each and two new electric motor-driven reciprocating compressors rated at 4,000 HP each. An existing reciprocating natural gas compressor rated at 3,200 HP will be retrofit with selective catalytic reduction equipment and will remain in use at the facility.

QUESTION 3:

Do the existing compressor safety devices have dual-system controls (electronics and air pneumatic)? Would the new compressors have the same safety devices and controls as the old compressors, fewer safety devices and controls, or more safety devices and controls?

RESPONSE 3:

Yes, the existing compressor safety devices have dual-system controls. The new compressors will have similar safety devices and enhanced electronics and air pneumatic controls. The new compressors are designed with more robust controls and will be equipped with a state-of-the-art emissions control system.

QUESTION 4:

Are there any other sites where this compressor station could be located while still providing its essential functions? If so, please explain in detail what the relative pros and cons are for the alternative site(s) compared to the existing site. If not, please explain in detail what barriers exist to locating this compressor station elsewhere.

RESPONSE 4:

As noted in the response to Data Request 4, Question 7, SoCalGas retained a consultant to evaluate the Ventura Compressor Station. At a conceptual level, any alternative location considered would be evaluated based on a number of factors including:

- System operational requirements, including adequate horsepower to compress gas;
- Safety considerations such as compliance with DOT regulations;
- Compatibility with local agency land use designation and zoning (Ventura Compressor Station is located on land designated by the Ventura General Plan as "Industry" and zoned "M-2, General Industrial."[2]);
- Minimizing resource impacts, such as loss of environmentally sensitive habitat, impact to sensitive wildlife species, impacts to historical and Native American resources, and avoidance of creeks and waterways;
- Minimizing significant hillside grading, dust generation and need for retaining walls
- Adequate property acreage;
- Minimizing the need to relocate pipelines and other infrastructure and maintain adequate separation to reduce potential landslide risk; and
- If a hybrid gas and electric driven compressor configuration is contemplated, the availability of electric infrastructure to serve electric driven compressors.

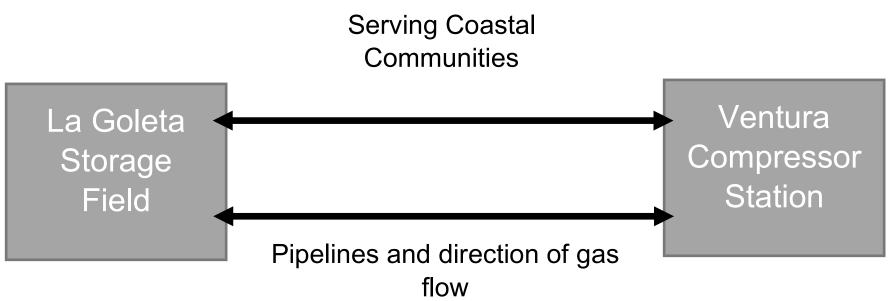
SoCalGas is committed to conducting additional review and will continue to evaluate alternative sites for the compressor station, consistent with the request in the CPUC's August 5, 2021 letter.

[2] Notwithstanding, the CPUC has general regulatory authority over public utilities such as SoCalGas. Courts have recognized that the CPUC has exclusive jurisdiction over utility matters because the construction, design, operation, and maintenance of public utilities are matters of state-wide concern and cannot be subject to a checkerboard of regulations by local governments. San Diego Gas & Electric v. City of Carlsbad, 64 Cal.App.4th 785, 798 (1998).

Alternative Site: Compression at La Goleta Storage Field

SoCalGas has conceptually evaluated the potential option to install compression at the La Goleta Storage Field. The installation of new compression equipment at the La Goleta Storage Field would serve some of the essential functions of the Ventura Compressor Station, but would not achieve the same operational benefits as the proposed Ventura Compressor Modernization Project, as further described herein. Any potential relocation of the Ventura Compressor Station would require detailed engineering and environmental analysis and obtaining required permits and authorizations from applicable agencies. The applicable agency permits would be dependent on the scope of the project and the location selected.

Figure 1



There are several considerations regarding relocating the compression equipment at the Ventura Compressor Station to the La Goleta Storage Field. The Ventura Compressor Station discharges into two high pressure pipelines, which are typically operated at a common pressure (see Figure 1). In other words, the pressure of gas flowing into the station from the south is lower than that of gas flowing out of the station and therefore requires compression to overcome the pressure differential and move gas north. The two pipelines, running between Ventura and La Goleta Storage Field, diverge upon leaving Ventura Compressor Station, ranging from being located 0.25 to 3.3 miles apart, and do not converge until reaching the La Goleta Storage Field, approximately 40 miles away. This pipeline spacing provides greater system reliability against pipeline outages caused by land movement than if the two pipelines shared a common pipeline route.

If compression was relocated to the La Goleta Storage Field, the existing compressors at the La Goleta Storage Field would need to be reworked or replaced to accommodate lower pressures to meet its firm injection requirements. In general, it is less efficient and requires greater horsepower requirements to compress at the end of a pipeline system rather than at the beginning. SoCalGas would also need to review if infrastructure improvements are required to meet customer demand on the distribution pipeline systems north of the current Ventura Compressor Station site. These improvements could range from rebuilding or replacing regulator stations and large customer meter sets to installing new pipelines. SoCalGas' current design for the compression equipment at Ventura Compressor Station would allow the station to support customer demand north of Ventura during a high-sendout condition should gas supply from the La Goleta Storage Field be unavailable, or during milder demand conditions in order to preserve the inventory at the storage field for the winter heating season.

Permitting requirements for a project at the La Goleta Storage Field are also a consideration. The La Goleta Storage Field falls within the Appeals Jurisdiction Area[3] of the Coastal Zone,[4] where the Coastal Commission has delegated authority to the County of Santa Barbara, (County) (upper portion of the property where main facility is located) and the Permit Jurisdiction of the Coastal Zone, where the State retains permitting authority (lower portion of the property near Atascadero Creek). The facility is governed by a County Development Plan permit and Coastal Development Permit. Depending on the scope of any proposed compression equipment and associated facility improvements, a discretionary Revised Development Plan and Coastal Development Permit subject to approval by the California Coastal Commission and/or County Planning Commission would be anticipated. These permits may take up to 24 months (occasionally longer) from application submittal to decision-maker hearing and additional permit compliance activities may be required, further extending the start of construction. Environmental resource constraints, such as cultural and natural resources, which are known to be present at the La Goleta Storage Field, would be evaluated in the context of any permit process.

As with the Ventura Compressor Station, La Goleta Storge Field is currently subject to local, state, and federal air quality rules and regulations. If a project were to be pursued at the facility, an Authority to Construct and Title V permit modification application package would need to be submitted to the Santa Barbara County Air Pollution Control District. The draft Title V permit modification would be subject to review by the EPA as part of the approval process.

Other Site Alternatives

While SoCalGas believes that the modernization project meets safety and reliability needs while minimizing air emissions and other potential environmental impacts and optimizing a property that has been a compressor station since 1923, SoCalGas shares the CPUC's commitment to hear

[3] An Appeal Jurisdiction include lands where the California Coastal Commission has delegated original permit jurisdiction to the local government for areas subject to the public trust but which are determined by the California Coastal Commission to be filled, developed and committed to urban use (California Public Resources Code Section 30613).
[4] Santa Barbara County ArcGIS Land Use and Zoning Map. Accessed online August 3, 2021: arcgis.com/home/webmap/viewer.html?webmap=fa3545a29dac49aeacc81669b956e3e5&extent=-120.9142,34.093,-118.9408,35.4355

from the community and explore solutions to address their concerns. We appreciate the Commission's continuing guidance on this matter and are working towards meeting the goals set out in its letter dated August 5, 2021.

Notwithstanding the information provided herein, SoCalGas has not conducted a comprehensive environmental and operational analysis or associated studies regarding relocation of the Ventura Compressor Station, and any potential relocation would require detailed engineering and environmental analysis. However, as noted above, SoCalGas is committed to conducting additional review, and will continue to evaluate alternative sites for the compressor station.

In addition to operational and safety considerations, which are paramount, most land within the general vicinity of the Ventura Compressor Station is already developed with a mix of residential and commercial uses similar to those near the existing station. Extending away from the station in a radius of a mile, topography to the west becomes steep and rural, primarily agricultural land. Topography to the east within the City of Ventura also becomes steep and rural. In each case, a significant amount of earthwork would be required to establish a pad for the facility and to install access roads sufficient to meet operational, safety and first responder requirements (typically 16 to 24-feet in width). Pipelines would need to be routed into the new location, also causing a significant amount of earthwork and potentially requiring landowner easements and/or city/county franchise agreements. These areas are also less disturbed and therefore more likely to contain habitat for sensitive plant and wildlife species. Finally, land use and zoning designations in these areas are generally classified as agricultural, rather than industrial. Land north of the existing station along the coast would be within the Coastal Zone as well.

QUESTION 5:

Please provide a map of pipelines going into and out of Ventura Compressor Station that includes the pipeline numbers, diameter, and maximum and minimum operating pressure.

RESPONSE 5:

Please note that the attachment submitted as part of this response contains confidential and protected material pursuant to PUC Section 583, GO 66-D, D.17-09-023 and the accompanying confidentiality declaration.

Please see the attachment submitted concurrently with this response.

QUESTION 6:

Does the compressor station play a role in directing flow into different converging pipelines? If so, would relocating the compressors affect operations for directional flow management?

RESPONSE 6:

SoCalGas interprets “directional flow management” to mean the control of natural gas flowrate in the pipeline system. Please see response to Question 4 above. Additionally, relocating the compressor equipment as described above would not impact the directional flow management of the system. However, even if compression equipment were to be relocated, the pipelines, valves and other facilities at the Ventura Compressor Station that are not specifically related to compression, would need to remain at the location because they serve necessary pipeline operational control and safety functions.

QUESTION 7:

What are the logistical requirements and cost for relocating Ventura Compressor Station to a different site.

RESPONSE 7:

Please note this question was requested as a supplement to the original data request on August 2, 2021.

SoCalGas has not yet conducted an assessment of the logistical requirements and costs for a potential relocation of the Ventura Compressor Station to a different site. As noted in response to Question 4 of this data request, the following are preliminary high-level considerations:

- System operational requirements, including adequate horsepower to compress gas;
- Safety considerations such as compliance with DOT regulations;
- Compatibility with local agency land use designation and zoning (Ventura Compressor Station is located on land designated by the Ventura General Plan as "Industry" and zoned "M-2, General Industrial."[5]);
- Minimizing resource impacts, such as loss of environmentally sensitive habitat, impact to sensitive wildlife species, impacts to historical and Native American resources, and avoidance of creeks and waterways;
- Minimizing significant hillside grading, dust generation and need for retaining walls
- Adequate property acreage;
- Minimizing the need to relocate pipelines and other infrastructure and maintain adequate separation to reduce potential landslide risk; and
- If a hybrid station is contemplated, the availability of electric infrastructure to serve electric driven compressors.

SoCalGas is evaluating the various considerations above and will provide an update within 90 days.

[5] Notwithstanding, the CPUC has general regulatory authority over public utilities such as SoCalGas. Courts have recognized that the CPUC has exclusive jurisdiction over utility matters because the construction, design, operation, and maintenance of public utilities are matters of state-wide concern and cannot be subject to a checkerboard of regulations by local governments. San Diego Gas & Electric v. City of Carlsbad, 64 Cal.App.4th 785, 798 (1998).

QUESTION 8:

Please provide the estimated combined noise decibels for the new compressors compared to the existing compressors.

RESPONSE 8:

Please note this question was requested as a supplement to the original data request on August 2, 2021.

SoCalGas performed a noise study on the proposed compressor station modernization in January of 2020. The study evaluated the proposed equipment in the proposed configuration under the operating condition that generates the highest noise levels. The study analyzed the make/model of compressor and engine, building construction, location within the facility, perimeter fencing/walls, exhaust stack and silencer selection and the ancillary equipment. The study determined an upgrade was required to the exhaust silencer specified in the Front-End Engineering and Design Study (FEED). The engineering design was modified to redesign the silencer so that it meets the Ventura City noise ordinances.

SoCalGas will perform follow-up work to collect noise data on the existing station for a comparison as needed.

Please also refer to the response to Data Request 1, Question 4.

Natural Gas Compressor Stations on the Interstate Pipeline Network: Developments Since 1996

November 7, 2007

This special report looks at the use of natural gas pipeline compressor stations on the interstate natural gas pipeline network that serves the lower 48 States. It examines the compression facilities added over the past 10 years and how the expansions have supported pipeline capacity growth intended to meet the increasing demand for natural gas. Questions or comments on the contents of this article may be directed to James Tobin at James.Tobin@eia.doe.gov or (202) 586-4835.

The U.S. interstate natural gas pipeline network relies on more than 1,200 natural gas compressor stations to maintain the continuous flow of natural gas between supply area and consumers. Compressor stations are “pumping” facilities that advance the flow of natural gas. They are usually situated between 50 and 100 miles apart along the length of a natural gas pipeline system and are designed to operate on a nonstop basis. The average station is capable of moving about 700 million cubic feet (MMcf) of natural gas per day, while the largest can move as much as 4.6 billion cubic feet (Bcf) per day.

Between 1996 and 2006, the number of natural gas pipeline compressor stations attached to the interstate mainline natural gas pipeline grid increased significantly. In 1996 there were approximately 1,047 mainline compressor stations, with installed horsepower of about 13.4 million and a combined throughput capability of approximately 743 billion cubic feet per day. By 2006, these figures had grown to 1,201 mainline compressor stations, 16.9 million installed horsepower, and a throughput capability of 881 Bcf per day). This expansion represented a 26-percent increase in installed horsepower and a 19-percent increase in throughput capacity during the period.

This growth was not driven solely by an increase in overall natural gas production and consumption during the period. In fact, compared with 1996 levels, both natural gas production and consumption in the United States in 2006 are slightly lower, although both measures increased somewhat (about a 4-percent increase by 2001 in production) during the interim. Rather, a series of factors, reflecting the changing character of the U.S. natural gas industry, influenced this expansion in mainline compression facilities:

- New domestic production sources were developed in areas that required installation of new natural gas pipeline systems or expansion of existing ones.
- As domestic natural gas production reached a plateau during the 1990s, demand increased for Canadian natural gas supplies and new pipelines to transport them were created.
- Major growth in the number of large-volume natural-gas-fired electric power generating plants required additional capacity in specific markets.
- Regulatory demands to reduce the environmental footprint of compressor stations increased the scale of station revitalization and retrofits with improved technology.

Meanwhile, the decrease in U.S. natural gas production overall and the decrease in natural gas supplies flowing from declining production areas contributed to deactivating 22 mainline compressor stations and the downsizing of 45 more stations during the period. The loss in installed horsepower and/or throughput capacity from deactivation, however, was more than offset by the installation of more than 176 new compressor stations, and upgrades to over 250 other stations, throughout the national network.

See full report

U.S. Energy Information Administration

NATURAL GAS EXPLAINED

LIQUEFIED NATURAL GAS

BASICS

What is LNG?

Liquefied natural gas (LNG) is natural gas that has been cooled to a liquid state (*liquefied*), at about -260° Fahrenheit, for shipping and storage. The volume of natural gas in its liquid state is about 600 times smaller than its volume in its gaseous state in a natural gas pipeline. This *liquefaction* process, developed in the 19th century, makes it possible to transport natural gas to places natural gas pipelines do not reach and to use natural gas as a transportation fuel.

LNG increases markets for natural gas

Where natural gas pipelines are not feasible or do not exist, liquefying natural gas is a way to move natural gas from producing regions to markets, such as to and from the United States and other countries. Asian countries combined account for the largest share of global LNG imports.

LNG export facilities receive natural gas by pipeline and liquefy the gas for transport on special ocean-going LNG ships or *tankers*. Most LNG is transported by tankers called *LNG carriers* in large, onboard, super-cooled (cryogenic) tanks. LNG is also transported in smaller International Organization for Standardization (ISO)-compliant containers that can be placed on ships and on trucks.

At import terminals, LNG is offloaded from ships and is stored in cryogenic storage tanks before it is returned to its gaseous state or *regasified*. After regasification, the natural gas is transported by natural gas pipelines to natural gas-fired power plants, industrial facilities, and residential and commercial customers.

did you know?

Natural gas is transported on specially designed ships as liquefied natural gas (LNG). LNG is natural gas that is cooled to -260° Fahrenheit, the temperature at which natural gas becomes a liquid. The volume of the liquid is 600 times smaller than the gaseous form.

An ocean-going LNG carrier

Source: Stock photo (copyrighted)

In the United States, some power plants make and store LNG onsite to generate electricity when electricity demand is high, such as during cold and hot weather, or when pipeline delivery capacity is constrained or insufficient to meet increased demand for natural gas by other consumers. This process is called *peak shaving*. The power plants take natural gas from natural gas pipelines, liquefy it in small-scale liquefaction facilities, and store it in cryogenic tanks. The LNG is regasified and burned by the power plants when needed. Some ships, trucks, and buses have specially designed LNG tanks to use LNG as fuel.

U.S. LNG imports peaked in 2007

The United States imported very small amounts of LNG until 1995, and then LNG imports generally increased each year until peaking in 2007 at about 771 billion cubic feet (Bcf) and equal to about 17% of total natural gas imports. LNG imports declined in most years since 2007 as increases in U.S. natural gas production and expansion of the natural gas pipeline network reduced the need to import natural gas.

In 2021, the United States imported about 21.59 Bcf of LNG from just two countries. This was equal to about 1% of total U.S. natural gas imports in 2021.

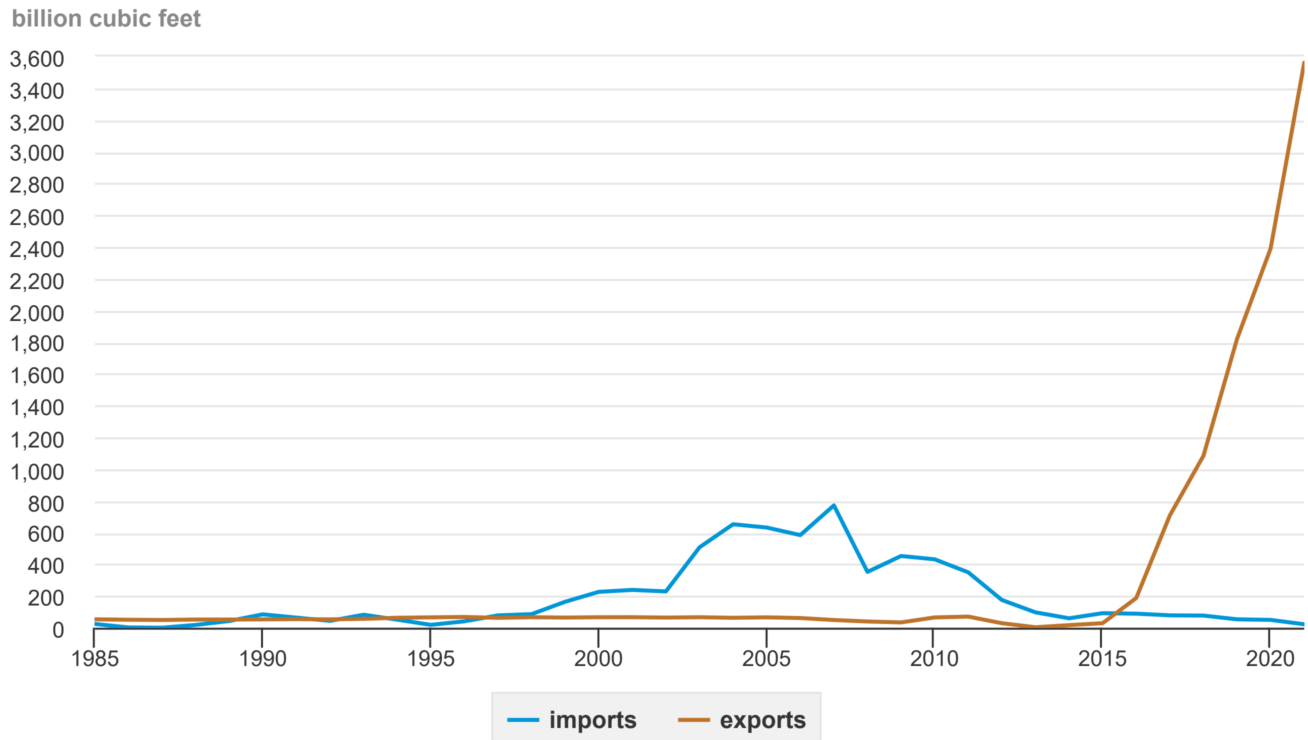
The source countries, amounts, and percentage shares of total U.S. LNG imports in 2021 were:

99.8%
21.42 Bcf
Trinidad and Tobago

0.8%
0.17 Bcf
Canada

The Everett regasification terminal near Boston, Massachusetts, receives most U.S. LNG imports, and in 2021, it receved 99% of total U.S. LNG imports, all from Trinidad and Tobago. New England states: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont, may have significant pipeline constraints when heating demand increases substantially during periods of very cold weather. LNG imports help to meet natural gas demand in New England because the region currently has limited pipeline interconnections with the Northeast and other U.S. natural gas producing regions.

U.S. LNG imports and exports, 1985-2021



Data source: U.S. Energy Information Administration, *Natural Gas Monthly*, March 2021; data for 2021 are preliminary

U.S. LNG export capacity and exports increased substantially between 2016 and 2021

The United States was a net exporter of LNG in 2017 through 2021 (exports were greater than imports), largely because of increases in U.S. natural gas production, declines in natural gas imports by pipeline and as LNG, and increases in LNG export terminal capacity.

U.S. LNG total baseload export capacity increased from less than 1 billion cubic feet per day (Bcf/d) in 2015 to about 10.78 Bcf/d at the end of 2021. Total peak export capacity in 2021 was about 12.98 Bcf/d. In 2015, total U.S. LNG exports were about 28 Bcf to seven countries. In 2021, U.S. LNG exports reached a record high of about 3,561 Bcf to 45 countries, and LNG exports accounted for 54% of total U.S. natural gas exports. About half of LNG exports went to five countries in 2021.

The top five destination countries, amounts exported, and percentage shares of total U.S. LNG exports in 2021 were:

12.7%
453.5 Bcf
South Korea

12.6%
449.7 Bcf
China

10.0%
354.9 Bcf
Japan

8.6%
307.7 Bcf
Brazil

6.0%
215.1 Bcf
Spain

In 2021, LNG carriers transported nearly all U.S. LNG exports. About 1.4 Bcf of U.S. LNG exports were by truck in ISO containers to Canada and Mexico, with 91% going to Mexico.

Sometimes, when natural gas prices are favorable to do so, the United States re-exports some of the LNG that it originally imported. However, in 2021, the United States did not re-export any LNG.

LNG export terminals consume some of the natural gas delivered to the facility to operate the liquefaction equipment. The U.S. Energy Information Administration (EIA) estimates that about 8% to 10% of the volume of natural gas delivered to LNG export facilities is used for liquefaction, with additional volumes used for processes not directly related to liquefaction at export terminals, such as on-site power generation.[1]

U.S. LNG exports are expected to increase in coming years as new U.S. LNG export capacity comes online. See detailed information about existing and under-construction large-scale U.S. liquefaction facilities (xls).

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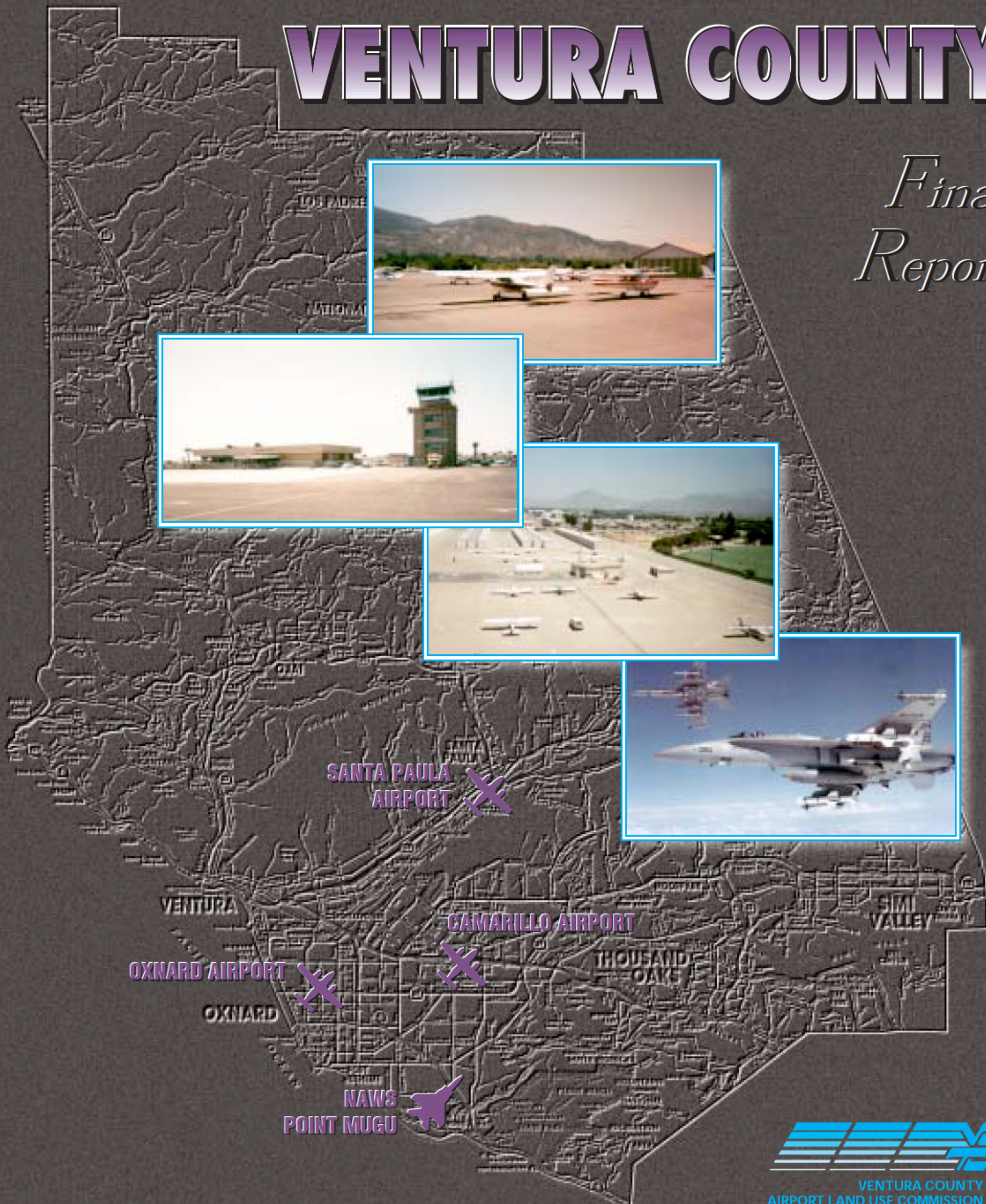
[1] EIA does not publish aggregated data specifically on the volumes of natural gas consumed for LNG liquefaction. Those volumes are included, but are not itemized, in the data for natural gas consumption for pipeline and distribution use.

Last updated: May 19, 2022, with most recent data available at the time of update; data for 2021 are preliminary.

Airport Comprehensive Land Use Plan for

VENTURA COUNTY

Final Report



VENTURA COUNTY
AIRPORT LAND USE COMMISSION

AIRPORT COMPREHENSIVE LAND USE PLAN UPDATE FOR VENTURA COUNTY

FINAL

Prepared for
Ventura County Airport Land Use Commission
by
Coffman Associates, Inc.

Adopted July 7, 2000

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VENTURA COUNTY
Comprehensive Airport
Land Use Plan

FINAL

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Ventura County AIRPORT LAND USE PLAN

Chapter One
INTRODUCTION

Chapter One
INTRODUCTION

1.1 BACKGROUND

In November 1991, the Ventura County Airport Land Use Commission approved an *Airports Comprehensive Land Use Plan* (1991 CLUP) for the three public use airports and one military airport in the County (P&D Aviation 1991). That document replaced an interim CLUP prepared in 1989. The current study is an update of the 1991 CLUP.

A combination of events caused the Airport Land Use Commission to decide to update the 1991 CLUP. First, a new Air Installation Compatible Use Zone (AICUZ) study had been prepared for Naval Air Weapons Station (NAWS) Point Mugu in 1992 (Dames & Moore 1992). The 1992 AICUZ study reflected changes in the use of the facility since the previous AICUZ study was done in 1986. Second, the State Department of Transportation, Aeronautics Program, published an updated *Airport Land Use Planning Handbook* in 1993, reflecting updated information about aircraft accidents and experience with the administration of CLUPs throughout the State (Hodges & Shutt 1993). Third, an updated master plan for Camarillo Airports was prepared and approved in 1996 (Coffman Associates). Fourth, the Ventura County Department of Airports had committed to undertake Noise Compatibility Studies for Oxnard and Camarillo Airports in 1997-1998 (Coffman Associates 1997a and 1997b). The updated CLUP is to take into consideration these developments.

1.2 PURPOSE AND SCOPE

The *Airport Comprehensive Land Use Plan for Ventura County* is intended to protect and promote the safety and welfare of residents near the military and public use airports in the County, as well as airport users, while promoting the continued operation of those airports. Specifically, the plan seeks to protect the public from the adverse effects of aircraft noise, to ensure that people and facilities are not concentrated in areas susceptible to aircraft accidents, and to ensure that no structures or activities encroach upon or adversely affect the use of navigable airspace.

Implementation of this plan will promote compatible urban development and restrict incompatible development in the vicinity of the County's airports, thus allowing for the continued operation of those airports. Three areas of compatibility are considered in the Plan:

> Compatibility of surrounding land uses with airport noise levels;
>
> Compatibility of surrounding land uses with respect to the safety of persons on the ground and persons on board aircraft making controlled crash landings;
>
> Protection of airspace needed for safe air navigation near airports.

The Plan applies to four airports in the County: Camarillo and Oxnard Airports, operated by the Ventura County Department of Airports; Santa Paula Airport, a privately owned airport open for public use; and NAWS Point Mugu. The location of these airports within the County is shown on **Exhibit 1A**.

1.3 LEGAL AUTHORITY

The Public Utilities Code of the State of California, Sections 21670 et seq., requires the County Board of Supervisors to establish an Airport Land Use Commission (ALUC) in each county with an airport operated for the benefit of the general public. The Code also sets forth the range of responsibilities, duties, and powers of the Commission.

Instead of creating a new body to serve as the ALUC, State law allows the county board of supervisors to authorize an appropriately designated body to fulfill ALUC responsibilities. (See Section 21670.1.) In Ventura County, the Board of Supervisors has designated the Ventura County Transportation Commission to act as the ALUC for the County.

1.4 RESPONSIBILITIES OF AIRPORT LAND USE COMMISSION

Section 21675 requires the Airport Land Use Commission to formulate a comprehensive land use plan for the area surrounding each public use airport. The Commission may also formulate a plan for the area surrounding any federal military airport located in the County.

Section 21675 specifies that the comprehensive land use plans shall:

Exhibit 1A
LOCATION MAP

> (a) . . . provide for the orderly growth of each public airport and the area surrounding the airport within the jurisdiction of the Commission, and will safeguard the general welfare of the inhabitants within the vicinity of the airport and the public in general. The Commission plan shall include a long-range master plan or an airport layout plan . . . that reflects the anticipated growth of the airport during at least the next 20 years. In formulating a land use plan, the Commission may develop height restrictions on buildings, specify use of land, and determine building standards, including soundproofing adjacent to airports, within the planning area. The comprehensive land use plan shall be reviewed as often as necessary in order to accomplish its purposes, but shall not be amended more than once in any calendar year.
>
> (b) The Commission may include, within its plan formulated pursuant to subdivision (a), the area within the jurisdiction of the Commission surrounding any federal military airport for all the purposes specified in subdivision (a)...

Section 21676, part of which is quoted below, requires that local general plans conform with the ALUC's comprehensive airport land use plan and grants the ALUC the authority to review amendments to general plans, specific plans, and zoning ordinances and building regulations applying within the airport planning boundary.

> (b) Prior to the amendment of a general plan or specific plan, or the adoption or approval of a zoning ordinance or building regulation within the planning boundary established by the airport land use commission pursuant to Section 21675, the local agency shall first refer the proposed action to the commission. If the commission determines that the proposed action is inconsistent with the commission's plan, the referring agency shall be notified. The local agency may, after a public hearing, overrule the commission by a two-thirds vote of its governing body if it makes specific findings that the proposed action is consistent with the purposes of this article.
> ...
>
> (c) Each public agency owning any airport within the boundaries of an airport land use commission plan shall, prior to modification of its airport master plan, refer such proposed change to the airport land use commission. If the commission determines that the proposed action is inconsistent with the commission's plan, the referring agency shall be notified. The public agency may, after a public hearing, overrule the commission by a two-thirds vote of its governing body if it makes

specific findings that the proposed action is consistent with the purposes of this article. ...

(d) Each commission determination pursuant to subdivision (b) or (c) shall be made within 60 days from the date of referral of the proposed action. If a commission fails to make the determination within that period, the proposed action shall be deemed consistent with the commission's plan.

1.5 ABOUT THE PLAN

Chapters Two through Five provide background information about each airport and the surrounding area. This information includes a discussion of existing and planned airport facilities, existing and forecast airport operations (takeoffs and landings), existing and planned future land use in the airport vicinity, and airport noise exposure in each area.

Chapter Six provides the updated airport land use compatibility policies.

Three appendices present important background information. Appendix A is a reference document providing interested readers with important background information relevant to the establishment of airport compatibility policies. It reviews the airport compatibility policies of the 1991 CLUP. It also discusses Federal and State regulations and guidelines relating to airport compatibility. Finally, Appendix A includes a discussion of CLUP policies in selected other California counties.

Appendix B discusses in some detail the policies in local general plans that relate to the four airports in the County.

Appendix C includes a detailed discussion of the methodology and assumptions used in developing noise contours for Santa Paula Airport. (Noise contours for the other airports were taken from other recent studies.)

Appendix D provides sample documents for an avigation easement, fair disclosure statement, and F.A.R. Part 77 requirements.

Appendix E provides a policy discussion of airport land use compatibility based on the information in Chapters Two through Five and Appendix A.

REFERENCES

Coffman Associates, 1996a. *Airport Master Plan for Camarillo Airport, Camarillo, California*. Prepared for Ventura County, November 1996.

Coffman Associates, 1996b. *Airport Master Plan for Oxnard Airport, Oxnard, California*. Prepared for Ventura County, November 1996.

Coffman Associates, 1997a. *Camarillo Airport: F.A.R. Part 150 Noise Compatibility Study*. Prepared for Ventura County Department of Airports.

Coffman Associates, 1997b. *Oxnard Airport: F.A.R. Part 150 Noise Compatibility Study*. Prepared for Ventura County Department of Airports.

Dames & Moore 1992. *NAWS Point Mugu AICUZ Update*. Submitted to Western Division, Naval Facilities Engineering Command, San Bruno, California, July 1992.

Hodges & Shutt 1993. *Airport Land Use Planning Handbook*. Prepared for CALTRANS Division of Aeronautics, by Hodges & Shutt in association with Flight Safety Institute, Chris Hunter & Associates, and University of California, Berkeley, Institute of Transportation Studies. December 1993.

P&D Aviation 1991. *Airports Comprehensive Land Use Plan Update for Ventura County*. Prepared for Ventura County Airport Land Use Commission and Ventura County Transportation Commission, November 1991.

Chapter Two

CAMARILLO AIRPORT AND ENVIRONS

Chapter Two
CAMARILLO AIRPORT AND ENVIRONS

This chapter presents an overview of Camarillo Airport and the surrounding area. The background information in this chapter is as follows:

- A description of the study area and existing land uses in the area.
- A discussion of the local land use planning and regulatory framework in the study area.
- A description of key airport facilities and navigational aids.
- A discussion of noise abatement procedures, airport activity, and flight tracks.
- A description of current and forecast noise exposure around the airport.

2.1 AIRPORT SETTING

Camarillo Airport is classified in the *National Plan of Integrated Airport Systems* (NPIAS) as a general aviation reliever airport for the Los Angeles metropolitan area (FAA 1995, p. A-15). Reliever airports play a key role in the nation's aviation system by providing an alternative to general aviation users in major metropolitan areas.

Camarillo Airport is within the corporate limits of the City of Camarillo, three miles southwest of the city's central business district (CBD). The airport is situated less than one mile south of Ventura Freeway (Highway 101) and seven miles west of the Pacific Ocean coastline. Access to the airport is provided by Pleasant Valley Road immediately south of the airport. The airport is bordered to the east by Las Posas Road which links the airport to the Ventura Freeway and the City of Camarillo to the north as well as Naval Air Weapons Station (NAWS) Point Mugu and the Pacific Coast Highway (State Highway 1) to the south.

2.2 STUDY AREA

Exhibit 2A, Camarillo Airport Study Area and Jurisdictional Boundaries, shows an area of 40.5 square miles. The area is generally rectangular with the western boundary following Rose Avenue. The southern boundary extends east from the Rose Avenue and Highway 1 intersection along the extension of Channel Islands Boulevard to Lewis Road. The eastern border follows Lewis Road north to U.S. 101 (the Ventura Freeway), continuing north in an irregular pattern following Arneill Road and Anacapa Drive. The northern border is an east-west line running from the extension of Anacapa Drive west to Rose Avenue.

The study area is primarily for convenience in mapping existing land uses and general plan land use designations. The area was designed to be large enough to contain the bulk of the imaginary airspace protection surfaces in the airport vicinity. Specifically, it was designed to accommodate the F.A.R. Part 77 conical surface.

2.3 EXISTING LAND USE

Exhibit 2B, Generalized Existing Land Use in Camarillo Airport Area, shows existing land use in the study area. The land use classification system, shown in **Table 2A**, has been designed to fit the requirements of airport noise compatibility planning. Residential land uses and noise-sensitive institutions are identified. The other land use categories, which are generally considered to be compatible with aircraft noise, include commercial, industrial, transportation, and utilities; agriculture; parks and open space; and undeveloped land.

Most of the study area is in agricultural use. The northeast quadrant of the study area is developed land in the City of Camarillo and primarily includes residential areas. Commercial and industrial development is concentrated along the Ventura Freeway (U.S. 101). Some residential development is south of the Ventura Freeway east of the airport and directly along the extended runway centerline.

The City of Oxnard lies west of the airport. Most of the Oxnard part of the study area is a large industrial/business area which is only partially developed. Some residential development is on the west edge of the study area.

Noise-sensitive institutions, including schools, places of worship, and one community center are scattered through the study area.

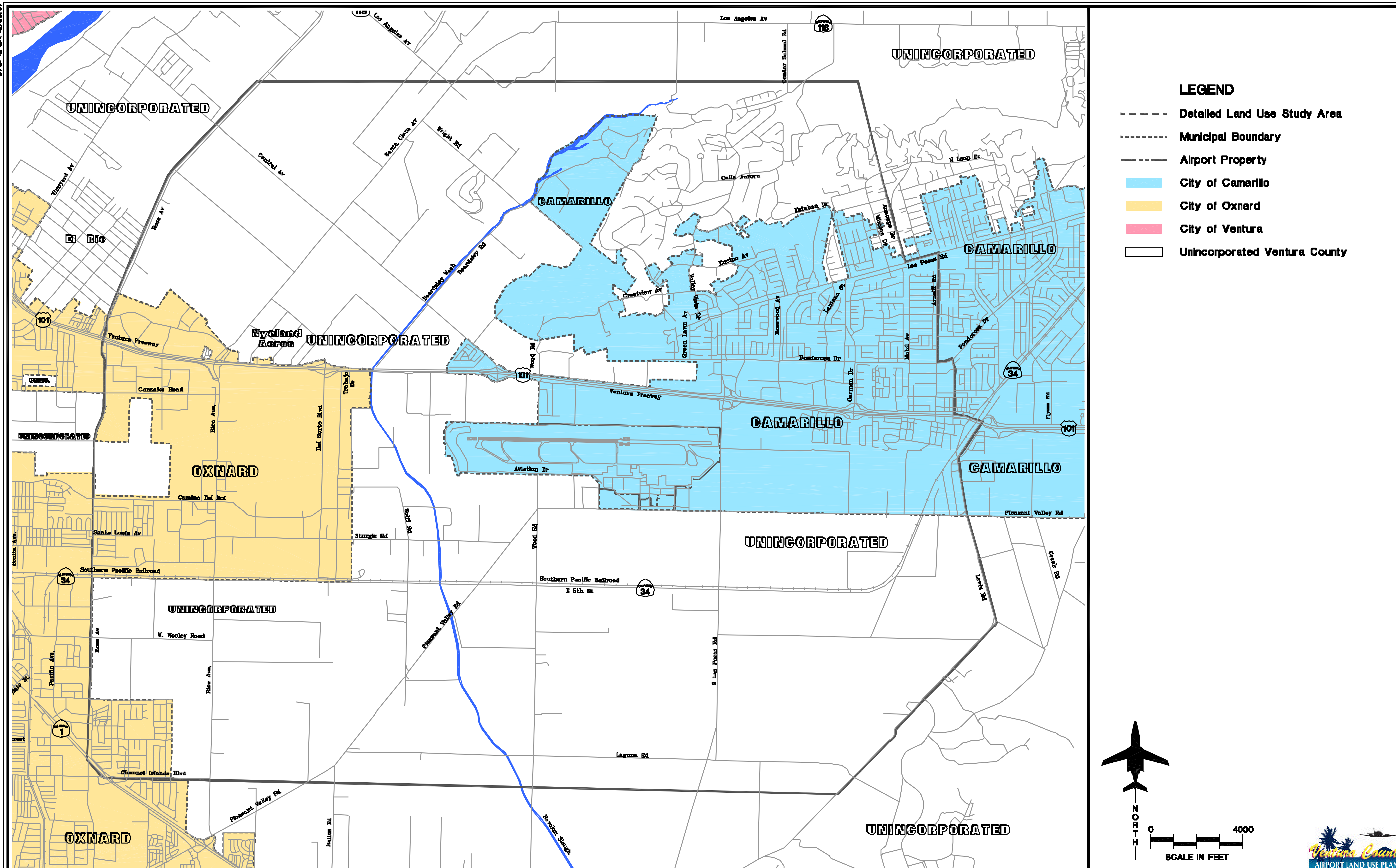


Exhibit 2A
CAMARILLO AIRPORT STUDY AREA
AND JURISDICTIONAL BOUNDARIES

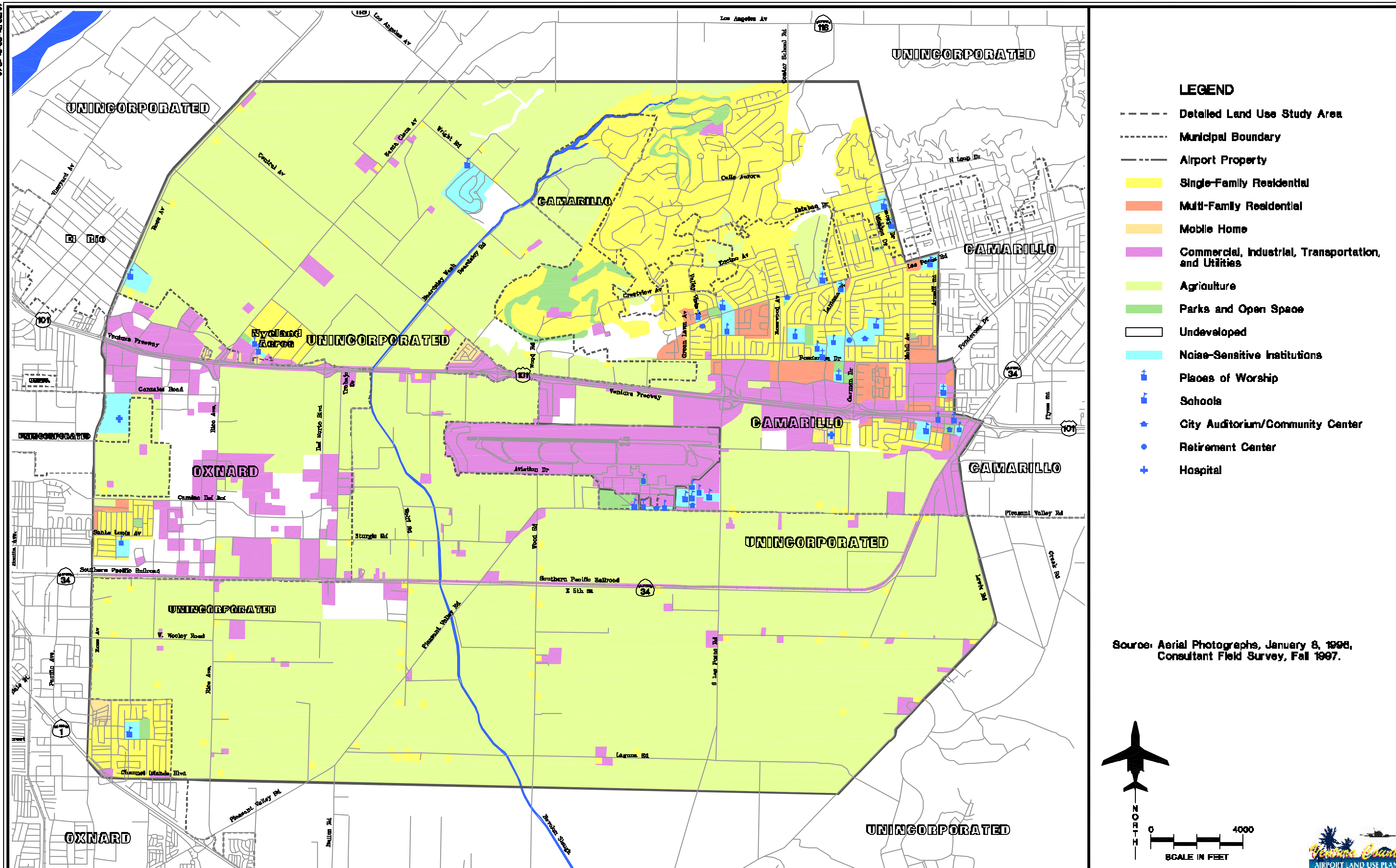


Exhibit 2B
GENERALIZED EXISTING LAND USE IN CAMARILLO AIRPORT AREA

TABLE 2A
Land Use Categories Shown on Existing Land Use Map

Category	Land Uses Included
Single-family Residential	Single-family homes.
Multi-family Residential	Duplexes; Townhouses; Apartment and condominium buildings.
Mobile Homes	Mobile and manufactured homes.
Commercial, Industrial, Transportation, Utilities	Businesses; Offices; Industrial uses; Utilities; Transportation facilities; Intensively developed commercial agriculture areas including equipment storage areas and greenhouses.
Noise-Sensitive Institutions	Places of worship; Schools; Nursing homes; Residential group quarters; Hospitals; Community centers.
Agriculture	Orchards; Cultivated fields.
Parks and Open Space	Parks; Golf courses; Cemeteries; Ponds; Nature preserves.
Undeveloped	Vacant lots; Open parcels of uncultivated land.

The Regional Information Center for the California Historic Resources Inventory was contacted for information about any sites in the study area determined to be of historical significance. No sites in the study area are listed on the National Register of Historic Places, nor are any sites listed as California Historical Landmarks or California Points of Historical Interest.

2.4 LAND USE PLANNING POLICIES AND REGULATIONS

The State of California requires all local governments to enact a "general plan" establishing framework policies for future development of the city or county. (See Government Code, Sections 65300, *et seq*.) The local general plan is the most important land use regulatory instrument in California. It establishes overall development policy and provides the legal foundation for all other kinds of land use and development regulation in the community. According to California law, the general plan must contain at least seven elements: land use, circulation, housing, conservation, open space, noise, and safety (Curtin 1996, pp. 9-10). Other elements may be prepared as needed and desired.

The policies of the general plan are implemented through specific ordinances regulating development. Chief among these is the zoning ordinance. Zoning regulates the use of land, the density of development, and the height and bulk of buildings. Subdivision regulations are another important land use regulatory tool, regulating the platting of land. Local communities also regulate development through building codes which set detailed standards for construction.

This section briefly summarizes the land use elements of the general plans of the study area jurisdictions. **Exhibit 2C**, **Future Land Use Plan in Camarillo Airport Area**, shows the land use designations of the general plans in the study area. A more detailed discussion of each jurisdiction's general plan is in Appendix B.

2.4.1 CAMARILLO GENERAL PLAN

The Land Use Element of the Camarillo General Plan establishes the basic pattern for future development of the City (City of Camarillo 1996, p. 28). The main theme of the Land Use Element is the desire to preserve the quality of life that exists through much of the area and specifically to "promote Camarillo as a rural suburban community that has a quality, small town, family atmosphere." It includes sets of principles, standards, and proposals for each of seven land use categories: agricultural, residential, commercial, industrial, urban reserve, public uses, and quasi-public uses.

The General Plan Map designates proposed land uses throughout the City's sphere of influence. The "sphere of influence" is an area defined by the Local Agency Formation Commission (LAFCO) which delineates the limits beyond which a city cannot annex territory. It includes the land within the city limits and unincorporated land within the City's service area.

Exhibit 2C shows the Camarillo General Plan land use designations within the Camarillo Airport study area. Land in the north part of the study area, north of Ponderosa Drive, is designated for residential use of varying densities. Land at the interchanges of the Ventura Freeway and Las Posas

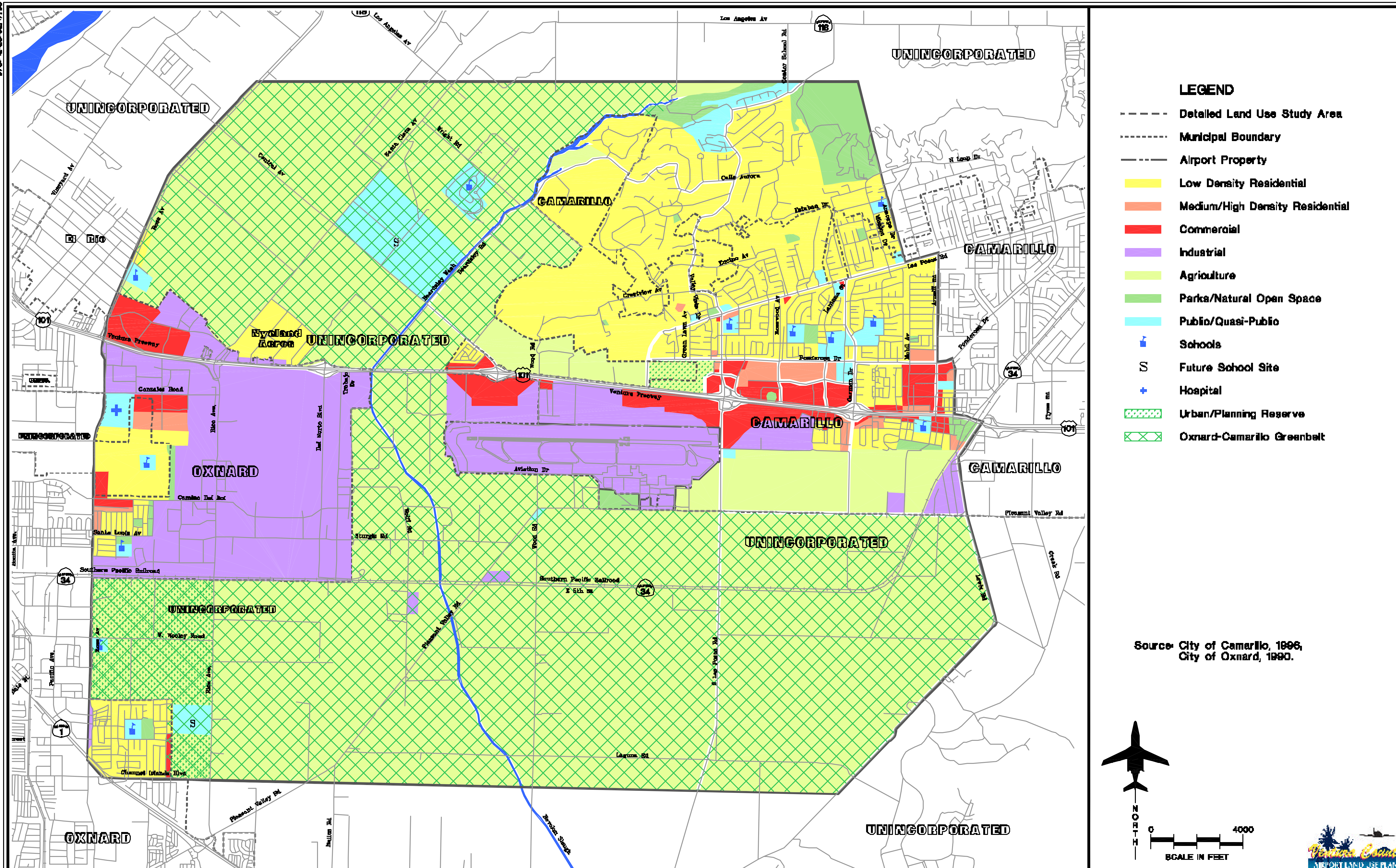


Exhibit 2C
FUTURE LAND USE PLAN IN
CAMARILLO AIRPORT AREA

Road and Central Avenue show commercial development. Land off the east end of the airport is designated for a combination of commercial, industrial (research and development), and agriculture.

2.4.2 OXNARD GENERAL PLAN

The Oxnard General Plan was adopted in 1990. It includes eleven planning elements: growth management, land use, circulation, public facilities, open space/conservation, safety, noise, economic development, community design, parks and recreation, and housing. The Noise Element includes several goals and policies related to airport compatibility planning (City of Oxnard 1990, p. IX-16). The most directly relevant says that "municipal policies shall be consistent with the Ventura County Airport Land Use Commission's adopted land use plan..."

Exhibit 2C shows the future land use plan for the Oxnard portion of the Camarillo Airport study area. Land northwest and southwest of the airport is designated for agriculture. This area is covered by the Oxnard-Camarillo Greenbelt Agreement. This agreement designates a large tract of land west of the airport for permanent agriculture and open space. The Growth Management Element specifically discusses the importance of maintaining this greenbelt agreement (City of Oxnard 1990, p. IV-19). A narrow strip of agriculturally designated land is west of the runway. Further west, the land is designated for industrial use. Much of the land west of Lombard along the extended runway centerline is designated for residential use.

2.4.3 VENTURA COUNTY GENERAL PLAN

The Ventura County General Plan was adopted in 1988 and has been amended several times since then. The Plan includes several documents. The overall framework of goals and policies is in a document called *Goals, Policies and Programs* (Ventura County 1996a.) Supporting documentation is in a series of technical appendices (Ventura County 1994a, 1994b, 1994c, 1996b). The General Plan also includes several area plans where local issues and concerns are dealt with in greater detail than in the framework document.

In the Camarillo Airport study area, the County's future land use designations in most of the unincorporated area outside the City's Sphere of Influence are primarily agricultural, a use that is compatible with aircraft noise. This is shown in **Exhibit 2C**.

Agriculture is a major industry in Ventura County. The County General Plan establishes policies to encourage the preservation of prime farmland. Among them is a policy to retain and expand existing Greenbelt Agreements in the County and to encourage the formation of additional agreements (Ventura County 1996a, p. 21). Greenbelt agreements have been formed between various cities in Ventura County. They delineate areas between the cities which are declared off limits to urban development and are to be preserved for agriculture and open space. The cities of Oxnard and Camarillo have a greenbelt agreement for the area between the two cities, part of which is in the Camarillo Airport study area. This is shown in **Exhibit 2C**.

The County General Plan also includes policies relating to airport hazards and noise compatibility. Land in airport approach and departure zones is to be designated for agriculture or open space uses (Ventura County 1996a, p. 20). Noise-sensitive land uses are not permitted where airport noise exceeds 65 CNEL. These uses may be permitted in the 60 to 65 CNEL contour only if measures are taken to reduce interior noise levels to 45 CNEL or less.

2.5 AIRPORT FACILITIES

Existing and future proposed facilities at Camarillo Airport are shown on **Exhibit 2D, Camarillo Airport Layout Plan**.

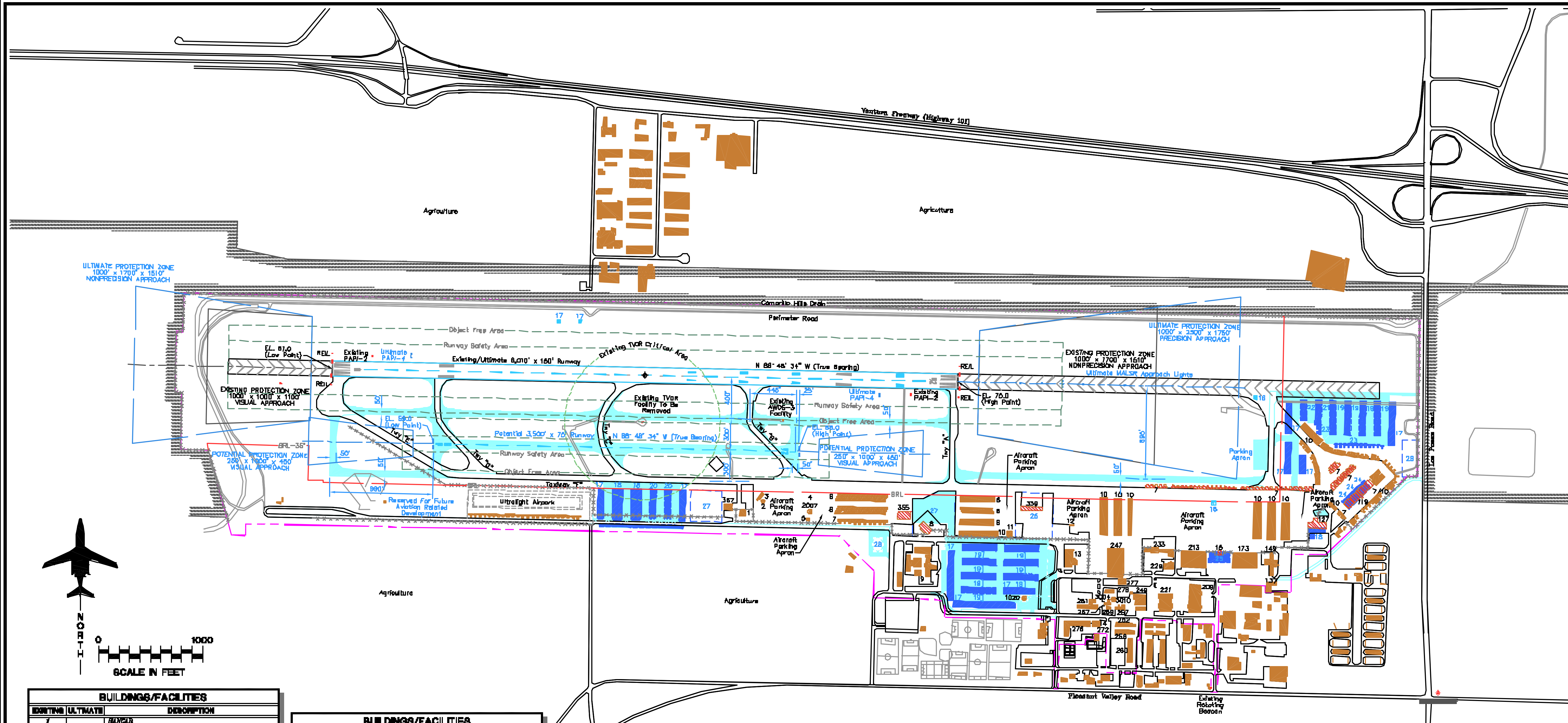
2.5.1 RUNWAYS

Camarillo Airport is served by Runway 8-26 which is 6,010 feet long by 150 feet wide and aligned in an east-west direction. The runway surface is asphalt and is in good condition. The current *Airport/Facility Directory* listing for Camarillo Airport indicates runway load bearing strength for Runway 8-26 as 48,000 pounds for single wheel loading, 65,000 pounds for dual wheel loading, and 110,000 pounds for dual tandem wheel loading (National Ocean Service 1997a, p. 46).

The original runway was 9,000 feet long with 1,000-foot paved overruns at each end. The full runway length was used by the military when the airport served as Oxnard Air Force Base. The present runway length was established through an agreement between Ventura County and the City of Camarillo after the County acquired the abandoned Base. The same agreement limits the pavement strength to a maximum of 115,000 pounds for dual wheel loading (DWL). **Table 2B** summarizes runway data for Camarillo Airport.

As indicated on **Exhibit 2D**, improvements to the runway system are planned. The existing runway is planned to remain at its current length and width, however, the pavement strength has been planned to increase from 65,000 pounds DWL to 70,000 pounds DWL to better accommodate corporate aircraft currently utilizing the airport.

To accommodate future operations without significant delays on landing and takeoff, a potential parallel runway location for small general aviation aircraft is being reserved. As indicated on **Exhibit 2D,** this reserved potential runway lies between the existing runway and Taxiway F. The potential runway is planned to be 3,500 feet long for use by aircraft weighing less than 12,500 pounds. It would be a visual runway used primarily by touch-and-go traffic. It should be noted, however, that construction of this runway would require further study including an environmental impact report (EIR) to determine its feasibility.



BUILDINGS/FACILITIES

EXISTING	ULTIMATE	DESCRIPTION
1		HANGAR
2		AIR TRAFFIC CONTROL TOWER (ATCT)
3		FAA OFFICES
4		SELF-SERVICE FUEL ISLAND
5		PUBLIC RESTROOMS
6		T-HANGAR (Nested)
7		T-HANGAR
8		FIRE DEPARTMENT (Maintenance Facility)
9		ANIMAL CONTROL FACILITY
10		BOX HANGAR
11		EXPERIMENTAL AIRCRAFT HANGAR
12		SELF-MAINTENANCE HANGAR
13		SHERIFF ACADEMY
14		WORK FURLOUGH
15		FUEL FARM
118		ALERT HANGARS/CAMARILLO AVIATION
127		COUNTY STORAGE/PUBLIC RESTROOMS
137		AIRPORT MAINTENANCE
149		FIRE DEPARTMENT (Headquarters)
173		HANGAR 1 (Western Cardinal)
209		AIRPORT ADMINISTRATION/CAMARCO
213		HANGAR 2 (Channel Islands Aviation)
221		ENGINEERING MANAGEMENT CONCEPTS
229		OFFICE SPACE
233		WAY POINT CAFE/CHANNEL ISLANDS AVIATION
247		HANGAR 3 (Camarillo Aircraft/Search & Rescue)
249		OFFICE SPACE
252		CORRECTIONAL SERVICES
256		CORRECTIONAL SERVICES
257		MCL BUILDERS
260		OFFICE SPACE

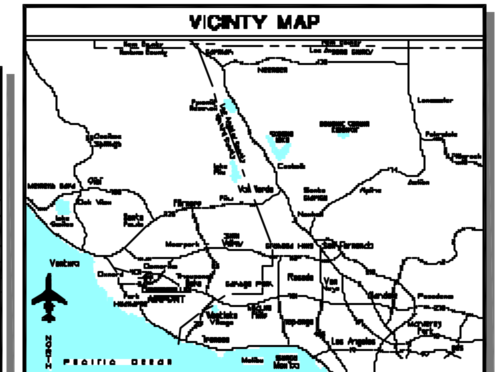
BUILDINGS/FACILITIES

EXISTING	ULTIMATE	DESCRIPTION
267		GENERATOR BUILDING
269		WATER PUMP BUILDING
272		CORRECTIONAL SERVICES
276		WORK FURLOUGH
277		FIRE DISPATCH
279		OFFICE SPACE
281		OFFICE SPACE
359		CONFEDERATE AIR FORCE
355		FIRE DEPARTMENT (Station 50)
367		GTE
1020		STORAGE TANK
2007		STANDBY GENERATOR/STORAGE
3004		STORAGE TANK
3010		STORAGE TANK
16	16	HELIPAD
	17	EXECUTIVE HANGAR (60' x 60')
	18	EXECUTIVE HANGAR (80' x 80')
	19	T-HANGAR (Nested, 14 Unit)
	20	T-HANGAR (Nested, 12 Unit)
	21	T-HANGAR (Nested, 10 Unit)
	22	T-HANGAR (Nested, 8 Unit)
	23	RELOCATED T-HANGAR
	24	CONVENTIONAL HANGAR (100' x 100')
	25	GENERAL AVIATION TERMINAL/ADMINISTRATION
	26	CONFEDERATE AIR FORCE PARCEL
	27	AVIATION DEVELOPMENT PARCEL
	28	CONSOLIDATED FUEL FARM
	29	FIRE STATION/ARFF PARCEL

LEGEND

EXISTING	ULTIMATE	DESCRIPTION
		ABANDONED PAVEMENT
		AIRPORT PROPERTY LINE
		AIRPORT REFERENCE POINT (ARP)
		AIRPORT ROTATING BEACON
		AVIGATION EASEMENT
		BUILDING TO BE REMOVED OR RELOCATED
		BUILDING
	BRL	BUILDING RESTRICTION LINE (BRL)
		PAVEMENT
		FENCING
VASI-4	PAPI-4	NAVIGATIONAL AID INSTALLATION
		RUNWAY END IDENTIFICATION LIGHTS (REIL)
		RUNWAY THRESHOLD LIGHTS
		SEGMENTED CIRCLE/WIND INDICATOR
		TOPOGRAPHY
		WIND INDICATOR (Lighted)

VICINITY MAP



LOCATION MAP

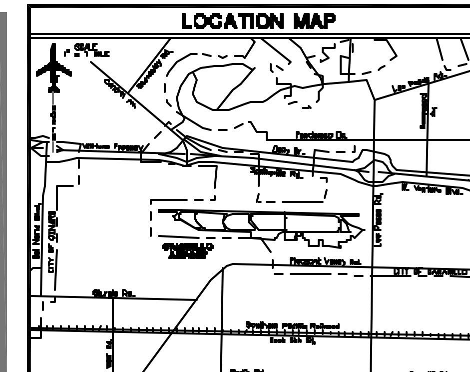


Exhibit 2D
CAMARILLO AIRPORT LAYOUT PLAN

The adopted Camarillo Airport Master Plan not only describes the parallel runway as only a "potential" runway, it further states that "it will not be developed without a feasibility study/ environmental impact report (EIR) that proves the runway will benefit the community without significant environmental impact. The feasibility study/EIR will include a noise analysis and a complete public review process involving the community and airport users. Actual construction would be subject to approval by the Camarillo Airport Authority and the Ventura County Board of Supervisors." As such, the potential parallel runway will be considered within its own review process which will in all likelihood, if approved, culminate in a Master Plan Amendment. And according to State law, all Airport Master Plans and amendments must be reviewed by the ALUC.

Therefore, the parallel runway is being included in the CLUP for information only at this time. The safety zones shown on the map in Exhibit 7A are also included for information only, and the land use compatibility standards in Table 7B do not apply to those zones. As virtually all of the property within those zones is on airport property, the County of Ventura, as the owner of the airport, is encouraged to the greatest extent possible to plan and develop its facilities in a manner consistent with these potential zones in the event the parallel runway is considered and approved in the future.

TABLE 2B
Runway Data
Camarillo Airport

	RUNWAYS	
	8	**26**
Length (ft.)	6,010	
Width (ft.)	150	
Surface Material	Asphalt	
Pavement Strength (lbs.)		
Single Wheel Loading	48,000	
Dual Wheel Loading	65,000	
Dual Tandem Wheel Loading	110,000	
Approach Slope Ratio	20:1	34:1
Approach Aids		
ILS	No	No
VOR/DME	No	Yes
GPS	No	Yes
PAPI	P2L	P2L
REIL	Yes	Yes
Runway Lighting	MIRL	
Runway Marking	Nonprecision	
Weather Observation	AWOS-3	

Source: *Airport/ Facility Directory*, National Ocean Service 1997a, p. 46.

2.5.2 TAXIWAYS

Runway 8-26 is served by a full length parallel taxiway (Taxiway F) on the south side of the runway as well as five entrance/exit taxiways which run between the parallel taxiway and the runway. Taxiway A is a 90-degree exit/entrance taxiway located at the Runway 26 threshold. Taxiways B, C, D, and E are curved and serve as entrance/exit taxiways from the runway. **Exhibit 2D** shows future taxiway improvements. The most significant taxiway improvements include the construction of a parallel taxiway located 400 feet south of the Runway 8-26 threshold and a parallel taxiway north of the terminal area. These would provide for two-way circulation, improving operational safety and efficiency. Other taxiway improvements indicated on the exhibit would be necessary only if the construction of the potential parallel runway is necessary.

2.5.3 FIXED BASE AND SPECIALTY OPERATORS

Terminal services are provided by several fixed base operators (FBOs) located in the terminal area at the airport. Channel Islands Aviation is a full service fixed base operator (FBO) located on the eastern portion of the airport. Services include a flight school, aircraft charter, aircraft rental, major aircraft maintenance, aircraft sales, line services, and fuel sales. The FBO operates two facilities on the airport. One accommodates aircraft maintenance and storage and includes office space. The other building consists of office and classroom space. The FBO owns 17 fixed wing aircraft and maintains 21 tie-down positions on the apron. Channel Islands Aviation provides both Jet A and 100 low lead (Avgas) fueling.

Western Cardinal, Inc. is another full service FBO on the airport. It operates out of a conventional hangar and offers flight training, aircraft rental, aircraft sales (Piper Dealer), aircraft maintenance, and fuel sales. Western Cardinal, Inc. provides both Jet A and Avgas fueling services.

Sun Air Aviation is another FBO located in the northeastern corner of the airport. This FBO provides aircraft rental, charter services, pilot instruction, and aircraft maintenance. Sun Air owns and operates nine aircraft.

Other specialty operators at the airport include Avex and Camarillo Aircraft which provide aircraft sales and maintenance, respectively. The Confederate Air Force (CAF) operates out of a large conventional hangar east of Taxiway A. The CAF restores and maintains vintage military aircraft and participates in air shows across the country.

2.5.4 OTHER FACILITIES

An ultralight flight park is on the west side of the airport immediately south of parallel Taxiway F and is situated on a piece of property 1,200 feet long by 200 feet wide. The flight park is served by a gravel and oil runway of indeterminate length oriented in an east-west direction nearly parallel Runway 8-26.

Besides the aviation facilities, the Ventura County Department of Airports has developed an industrial/business park on the non-aviation portions of the deactivated air base property. Some tenants lease buildings dating back to the Air Base, while others have developed new facilities on the property leased from the airport. The development of the industrial/business park has not only become a viable source of income to support airport operations at both Camarillo and Oxnard Airports, but it is also a significant employment base for the community.

Ventura County also maintains several public safety facilities on the airport. The Ventura County Fire Department has a fire station located next to the airfield, southwest of Taxiway A. The fire station serves the needs of the surrounding community as well as the airport. The station is within the airport secure area. Vehicles responding to off-airport emergencies exit the secure area through a motorized gate just southwest of the fire station. The Fire Department also leases space in the industrial/business park for a dispatch center and administration.

The Ventura County Sheriff's Department utilizes hangar and apron space for its search and rescue helicopter unit. A Sheriff's training academy is also located on the airport. Located in the southwestern corner of airport property is a bermed pistol range used by the Sheriff's Department for firearms training.

2.6 TYPICAL FLIGHT PROCEDURES

2.6.1 INSTRUMENT APPROACHES

Instrument approaches are defined using electronic and visual navigational aids to assist pilots in landing when visibility is reduced below specified minimums. Instrument approaches are classified as precision and nonprecision. Both provide runway alignment and course guidance, while precision approaches also provide glide slope information for the descent to the runway.

Utilizing the Camarillo VOR/DME or the global positioning system (GPS), one published nonprecision approach is available at Camarillo (National Ocean Service 1997b, p. 42). The VOR or GPS Runway 26 approach provides for either a straight-in or circling approach. The straight-in approach can be flown when cloud ceilings are 700 feet above ground level (AGL) or greater and visibility is one mile for aircraft with approach speeds of up to 121 knots and 1-3/4 miles for aircraft with approach speeds between 121 and 141 knots. The circling approach requires a cloud ceiling of 700 feet AGL and one mile visibility for aircraft with approach speeds up to 141 knots. The visibility minimums increase to 800 feet and 2-1/4 miles for aircraft with approach speeds greater than 121 knots but less than 141 knots.

Aircraft equipped with DME have two other options provided by the VOR or GPS approach to Runway 26. Utilizing the DME, straight-in approaches can be flown when cloud ceilings are 600 feet AGL or greater and visibility is one mile for aircraft with approach speeds of up to 121 knots and 1-1/2 miles for aircraft with approach speeds between 121 and 141 knots. Circling approaches utilizing DME require 700-foot cloud ceilings and one mile visibility for aircraft with approach speeds up to 121 knots. For aircraft with approach speeds between 121 and 141 knots, the DME aided circling approach can be flown with cloud ceilings of 800 feet and visibility of 2 1/4 miles.

2.6.2 NOISE ABATEMENT PROCEDURES

The Ventura County Department of Aviation has developed and published, in consultation with the Airport Traffic Control Tower (ATCT) and airport users, noise abatement procedures for VFR operations at Camarillo Airport. Instructions are outlined regarding departures, arrivals, and pattern procedures at the airport which are aimed at minimizing noise exposure over noise-sensitive areas without compromising safety. Pilots are requested to follow the published procedures unless circumstances render them unsafe, weather conditions do not allow, or they are otherwise instructed to deviate by the Airport Traffic Control Tower. The procedures are described below:

- No aircraft departures between 0000-0500 without prior approval of the Airport Administrator.
- Aircraft are instructed to stay as high as practical over residential areas during overflight, approaches, and departures.
- Use best rate of climb when departing any runway.
- No formation take-offs or landings without prior written approval of the Airport Administrator.
- Utilize low energy approaches.
- Avoid residential overflights, fly quietly and safely.
- North traffic fly downwind over Ventura Freeway (Highway 101).
- Runway 26 traffic pattern - Published traffic pattern altitude (TPA) is established as 875 MSL feet for single engine aircraft and 1,075 MSL feet for twin engine/turbine aircraft. Utilize the best rate of climb, conditions permitting, turn crosswind when reaching 700 feet AGL or the airport boundary, whichever comes first. Maintain pattern altitude until turning base leg.
- Runway 26 Departure - When departing the airport traffic area use best rate of climb, remain on runway heading until beyond the departure end of the runway and 700 feet AGL before proceeding on course.
- Runway 26 Arrival - Straight-in VFR approaches are prohibited. Right or left traffic during those hours the ATCT is in operation should commence with a 45-degree entry to the downwind and a base leg turn at or before reaching Las Posas Road.
- Runway 8 traffic pattern - Published traffic pattern altitude (TPA) is established as 875 MSL feet for single engine aircraft and 1,075 MSL feet for twin engine/ turbine aircraft. Utilize the best rate of climb, conditions permitting, turn crosswind before reaching Las Posas

Road. Maintain pattern altitude until turning base leg.

- Runway 8 Departure - When departing the airport traffic areause best rate of climb and when altitude permits turn so as to avoid residential overflight before proceeding on course. Exercise extreme caution due to opposite direction instrument approach traffic.

- Runway 8 Arrival - Avoid overflight of the City of Camarillo when entering downwind.

- When the ATCT is closed, make left turns to Runway 26 and right turns to Runway 8.

2.6.3 OPERATIONAL LETTERS OF AGREEMENT

The Camarillo ATCT has entered into several letters of agreement with local aircraft operators to define specific operational procedures. The letters of agreement serve both the ATCT personnel and the aircraft operators by establishing procedures to promote efficient use of the airfield and airspace and to minimize operational conflicts.

The Camarillo ATCT and ultralight aircraft operators have entered into an operational letter of agreement. As illustrated on **Exhibit 2D**, an ultralight airpark is located in the southwest corner of the airfield. The ultralight airpark has a paved runway nearly parallel to Runway 8-26. Because of its proximity to the airfield, the potential exists for airspace conflicts between the slower ultralight aircraft and higher performance aircraft utilizing the airport. The letter of agreement details departure and arrival procedures that ultralight aircraft are to follow, some of which are mandatory. Mandatory requirements include a traffic pattern south of the runway and the need for specific approval of requests for a pattern which is opposite of runway traffic.

Another letter of agreement is established between the Oxnard and Camarillo ATCT, NAWS Point Mugu Radar Air Traffic Control Facility (RATCF), Aspen Helicopters, and Sinton Helicopters. It defines operational procedures for agriculture helicopters requesting special visual flight rules (SVFR) operations during IFR weather conditions. Helicopter pilots are to maintain contact with the appropriate ATC facility and maintain adequate separation as assigned by the controlling ATC facility. This letter of agreement also designates SVFR routes for arrivals and departures to and from Oxnard and Camarillo Airports. For Camarillo, two routes have been established: Aspen/Sinton Ag Routes Foxtrot and Tango. Route Foxtrot runs from the Camarillo Airport to Fifth Street, then east via Fifth Street to the shoreline at or below 500 feet. Route Tango runs from the western end of Runway 8-26, then northwest over the Saticoy Bridge at or below 500 feet.

Another letter of agreement has been established between the Camarillo ATCT and the Ventura County Sheriff's Department. It establishes procedures for VFR operations to and from Camarillo Airport and establishes arrival and departure routes. These defined procedures and routes are for the use of the Sheriff's Department helicopters or other helicopters authorized by the Sheriff's Department while operating in Camarillo Class D Airspace. The letter of agreement stipulates that arrivals and departures shall be in accordance with the established routes and altitudes and shall begin and terminate at the Hangar 3 ramp unless otherwise coordinated. The established routes are as follows:

- Central Departure, West/Northwest -- Cross Taxiway Echo and proceed westbound, remaining south of the runway centerline to Revolon Slough, then northbound to Highway 101, then on course. Traffic permitting, the tower will call an early northbound turn.

- City Departure, Northeast over the City of Camarillo -- Proceed eastbound, remaining south of the runway until instructed by the tower to cross the extended centerline to Camarillo.

- 3M Departure, Northeast/Southeast -- Proceed eastbound over Pleasant Valley Road until abeam the 3M plant in southeast Camarillo, then on course.

- Bean Barn Departure, South/Southwest -- Proceed to the Bean Barn Fix (gray barn at Fifth Street and Pleasant Valley Road), then on course.

- Central Arrival, West/Northwest -- Proceed to the Central Fix (intersection of Central Avenue and Highway 101), then eastbound, remaining north of the airport until instructed by the tower to cross the runway.

- City Arrival, Northeast over the City of Camarillo -- Proceed to the City Fix (old Navy housing at Las Posas and Crestview), south to Highway 101, then westbound, remaining north of the airport until instructed by the tower to cross the runway.

- 3M Arrival, Northeast/Southeast -- Proceed to the 3M Fix, then westbound, direct to Hangar 3, remaining south of the runway centerline.

- Hospital Arrival, South/Southeast -- Proceed to the Hospital Fix (intersection of Fifth Street and Las Posas Road), then direct to Hangar 3.

- Bean Barn Arrival, South/Southeast -- Proceed to the Bean Barn Fix, then direct to Hangar 3.

The letter stipulates that all routes shall be flown at or below 500 feet above ground level (AGL) except:

- Central Departure -- Remain at or below 200 feet AGL until north of the runway centerline, then at or below 300 feet AGL until north of Highway 101.

- City Departure -- Climb as required for noise abatement when approved by the tower.

- All other operations within one mile of the runway shall be at or below 300 feet AGL.

2.7 AIRPORT ACTIVITY DATA

Detailed airport activity data are needed for noise modeling and for establishing airport safety zones and standards. Among the most important information is the number of aircraft operations (takeoffs and landings), the mix of aircraft types using the airport, runway use percentages, and flight tracks.

This section summarizes key airport activity data. This information was used in developing airport noise contours in the F.A.R. Part 150 Noise Compatibility Study for Camarillo Airport (Coffman Associates 1997, pp. 2-2 to 2-9). More detailed information is available in that study.

2.7.1 OPERATIONS

Air traffic statistics at Camarillo Airport are recorded by airport management from information supplied by the Federal Aviation Administration (FAA). The FAA's airport traffic control tower (ATCT) located on the airport collects and reports aircraft operations (takeoffs and landings). Aircraft operations have been recorded by the ATCT since the tower opened in July, 1989. **Table 2C** presents a summary of annual operations from 1990 through 1997. As indicated on the table, operations at Camarillo fluctuated between 1990 and 1994, then reached a low of 167,116 in 1995. Over the last two years, operations have increased, reaching 178,344 for the twelve-month period between November 1996 and October 1997.

TABLE 2C
Annual Operations (Takeoffs and Landings) History
Camarillo Airport

		General Aviation			
Year	**Air Taxi**	**Local**	**Itinerant**	**Military**	**Total**
1990	5,799	115,285	91,346	1,243	213,673
1991	3,469	132,132	78,492	913	215,006
1992	1,744	99,030	83,295	1,412	185,481
1993	1,721	98,857	77,474	973	179,025
1994	2,025	103,567	82,661	2,597	190,850
1995	1,366	90,737	74,179	834	167,116
1996	2,031	86,885	83,860	129	172,905
1997*	1,835	86,758	89,708	43	178,344

Note: 1997 operational data is for the twelve-month period from November 1996 through October 1997.

Source: FAA Air Traffic Control Statistical Reports.

2.7.2 FLEETMIX

The selection of individual aircraft types is important to the modeling process because different aircraft types generate different noise levels. The business jet and turboprop fleet mix at Camarillo Airport was developed based on airport landing fee reports for aircraft weighing more than 12,500 pounds. The fleet mix of smaller prop aircraft was developed using a based aircraft list provided by airport staff. **Table 2D** summarizes the fleet mix data input into the noise analysis by annual aircraft operations.

Operations for the 1998 study year are based on the data recorded for the 12-month period from November 1996 through October 1997. Note that the data include an extra 10,000 operations than were recorded by the ATCT. This is an estimate of ultralight operations at the airport. This estimate was developed by the Consultant after interviews with air traffic control personnel and ultralight users. (Ultralight operations are not recorded by ATCT.)

Table 2D also presents forecasts for 2003 and 2018. These were taken from the F.A.R. Part 150 Noise Compatibility Study (Coffman Associates 1997, p. 2-4). Total operations are projected to increase to 224,800 in 2003 and 315,800 in 2018.

2.7.3 RUNWAYUSE

In interviews with the Consultant, ATCT staff indicated that approximately 85 percent of the aircraft arrive and depart on Runway 26. Arrivals and departures on Runway 8, approximately 15 percent of the total, usually occur in Santa Ana wind conditions (strong winds from the north) or if requested by the pilot.

2.7.4 FLIGHTTRACKS

Flight track data was derived from discussions with air traffic controllers, airport management, and airport users. These discussions were used to develop consolidated flight tracks which describe the average flight route corridors to and from Camarillo Airport.

Although the consolidated flight tracks appear as distinct paths, they actually represent average flight routes and illustrate the areas of the surrounding community where aircraft operations can be expected most often. At a busy general aviation airport such as Camarillo Airport, aircraft traffic is expected over most areas around the airport. Air traffic density generally increases nearer the airport as it is funneled to and dispersed from the runway system. The consolidated tracks were developed to reflect these common patterns and to account for the inevitable flight track dispersions around the airport.

Exhibit 2E, Camarillo Airport Departure Tracks, illustrates the consolidated departure flight tracks used for modeling noise exposure at Camarillo. Typically, aircraft departing Camarillo Airport desire a north/northwest, east/northeast, or south/southeast departure route.

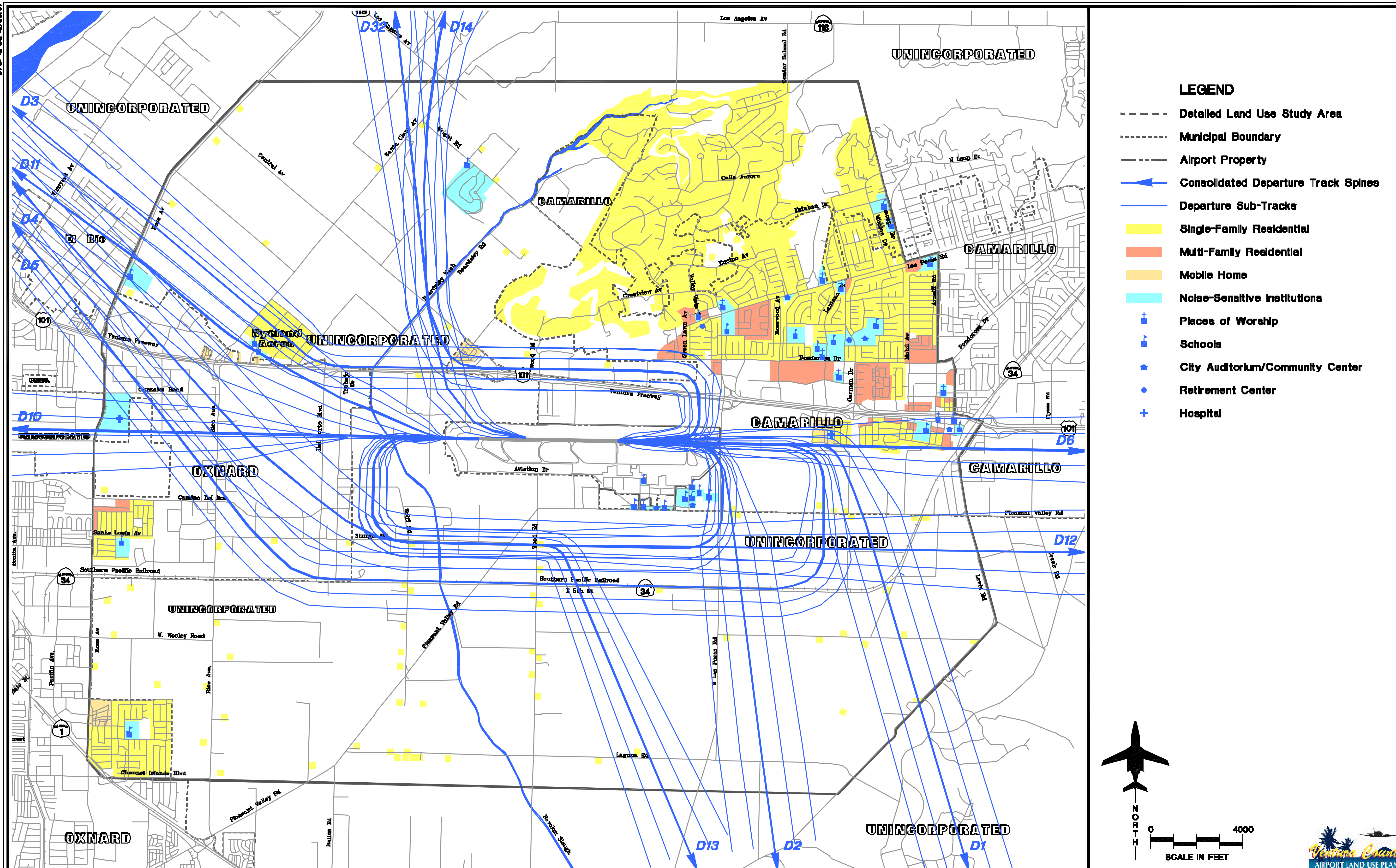


Exhibit 2B
CAMMARILLO AIRPORT DEPARTURE TRACKS

TABLE 2D
Annual Operations by Aircraft Type
Camarillo Airport

	Existing 1998	Forecast 2003	Forecast 2018
Itinerant Operations			
Air Taxi			
Beech Super King Air	1,000	1,200	1,500
Twin Engine Turboprop	535	600	1,000
Twin Engine	300	400	800
General Aviation			
Lear-25	179	213	0
Gulfstream III	179	213	0
Lear-35	179	213	1,061
Citation 500 Series	179	213	1,061
Gulfstream IV	179	213	772
DC-6 (Constellation)	179	194	138
DC-3	718	774	552
Beech Super King Air	795	930	2,358
Twin Engine Turboprop	5,729	5,854	10,540
Twin Engine	14,965	16,850	22,543
Light Single-Variable Pitch Propeller	30,529	30,579	41,381
Light Single-Fixed Pitch Propeller	30,529	30,579	41,381
Bell-206 Helicopter	2,154	2,210	4,185
Robinson-22 Helicopter	2,135	2,710	4,685
UH-1 Helicopter	1,080	1,355	2,343
Military			
Twin Engine Turboprop	18	1,000	1,000
Bell-206 Helicopter	19	500	500
Subtotal--Itinerant	91,580	96,800	137,800
Local Operations			
General Aviation			
Light Twin	4,486	6,088	8,668
Light Single-Variable Pitch Propeller	35,139	47,696	67,906
Light Single-Fixed Pitch Propeller	35,139	47,696	67,906
Bell-206 Helicopter	6,000	7,260	10,760
Robinson-22 Helicopter	5,994	8,260	11,760
Ultralight[1]	10,000	10,000	10,000
Military			
Bell-206 Helicopter	6	1,000	1,000
Subtotal--Local	96,764	128,000	178,000
TOTAL OPERATIONS	188,344	224,800	315,800

[1] Ultralight operations are not recorded by the Airport Traffic Control Tower. These estimates were developed by Coffman Associates based on interviews with ultralight operators and air traffic controllers.

Source: Coffman Associates 1997, p. 2-4.

As depicted on the exhibit, aircraft departing Runway 8 with a north/northwest destination have various alternative routes. Some aircraft turn right after departure, gain altitude and maintain the airport traffic pattern through the downwind leg. Once the downwind leg is completed and the aircraft is traveling west past the Runway 8 threshold, the aircraft turns to the north/northwest. The exhibit also depicts a similar but expanded track for use by larger business jet and turboprop aircraft. Small aircraft with a north/northwesterly destination from Runway 8 also turn left near Las Posas Road, circling back to the west then ultimately turning to the north/northwest. Aircraft departing Runway 8 with an east/northeast destination depart straight out according to their instructed heading. Aircraft with south/southeasterly destinations depart Runway 8 then turn to the south.

Aircraft departing Runway 26 with a west, north, or westerly destination depart the runway and turn to their instructed heading. Aircraft with an easterly destination, especially larger aircraft, may elect to depart the runway, turn to the northwest, and turn back to the east in the vicinity of the Saticoy Bridge. South, southeast, and easterly departures are generally accomplished with a left turn after departing Runway 26 and maintaining the airport traffic pattern. Aircraft then elect to depart from the airport traffic pattern at a desirable location.

The consolidated arrival flight tracks for Camarillo Airport are presented on **Exhibit 2F, Camarillo Airport Arrival Tracks**. Generally, the arrival tracks mirror the departing tracks with few exceptions. Aircraft arriving on Runway 8 can approach straight-in from the north/northwest or west, or enter in the traffic pattern from the east, south, or southeast.

Aircraft arriving on Runway 26 from the northwest travel into a traffic pattern north or south of the runway. Aircraft approaching from the east arrive via the published VOR or GPS approach or make an approach over the runway making a descending left turn into the airport traffic pattern.

Illustrated on **Exhibit 2G, Camarillo Airport Helicopter and Touch-and-Go Tracks**, are the helicopter arrival and departure tracks as well as the touch-and-go pattern tracks. Helicopters operated by the Ventura County Sheriff's Department follow departure and arrival tracks delineated in the letter of agreement. In general, these helicopters depart from Hangar 3 to one of the following four visual checkpoints, or fixes: Bean Barn Fix (west, south, southwest), Hospital Fix (south/southeast), 3M Fix (east/southeast), or Central Fix (west, north, northeast, or northwest).

Helicopters equipped for aerial agricultural pesticide/fertilizer application are based at the airport. They arrive and depart an area immediately north and east of the triangular hangar configuration on the east side of the airport. These rotorcraft typically depart/arrive the airport to/from farm fields to the south/southeast, west/southwest, and north/northwest.

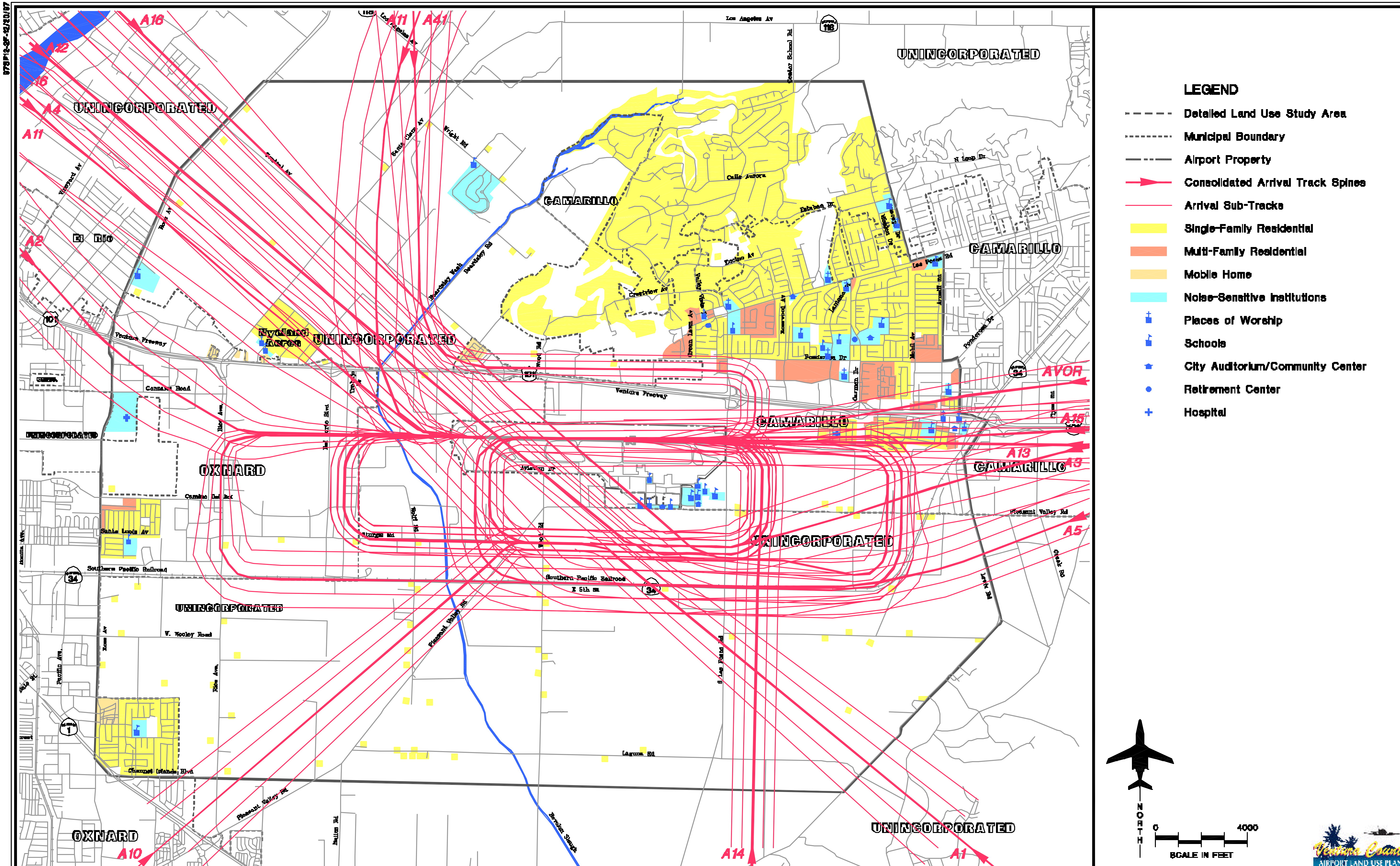


Exhibit 2F
CAMARILLO AIRPORT ARRIVAL TRACKS

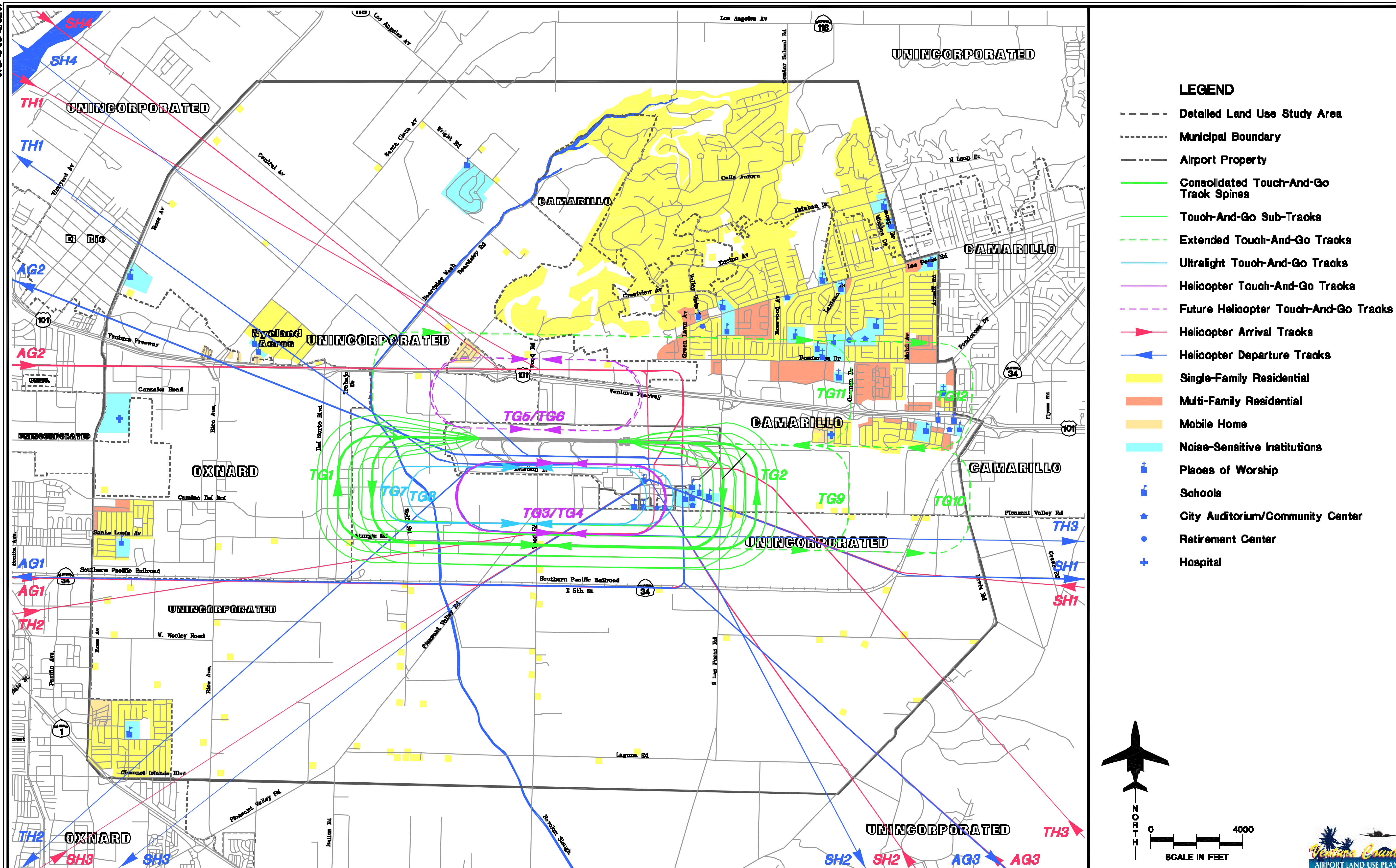


Exhibit 2G
CAMARILLO AIRPORT HELICOPTER AND TOUCH-AND-GO TRACKS

Transient helicopters generally depart/arrive the airport from the northwest, east, and south. These rotorcraft operate to/from a designated helipad immediately north of the parallel taxiway and west of the T-hangars lining the north side of the parallel taxiway.

As depicted on **Exhibit 2G**, the touch-and-go tracks for Runway 8 and 26 both follow a pattern south of the runway. Helicopters currently utilize an area on the parallel taxiway west of the airport traffic control tower for touch-and-go training. Helicopter training patterns are also maintained to the south of the runway, inside of the fixed-wing aircraft traffic pattern. It should be noted that the 20-year scenario depicts helicopter training on the northwest side of Runway 8-26. This area was selected as the best location for helicopter training operations in the Airport Master Plan Study (Coffman Associates 1996). The traffic pattern for the proposed helicopter training pads would be north of Runway 8-26.

2.8 AIRPORT NOISE EXPOSURE

2.8.1 1998 NOISE CONTOURS

Exhibit 2H, 1998 Noise Exposure - Camarillo Airport, shows the 1998 CNEL noise contours for the airport developed in the F.A.R. Part 150 Noise Compatibility Study (Coffman Associates 1997, p. 2-9). The overall shape of the noise pattern around the airport reflects the prevalence of departures on Runway 26. The contours are longer and wider to the west reflecting the higher proportion of departures in this direction. A small extension of the 60 CNEL noise contour is present to the south reflecting the helicopter activity. A small node in the 65 CNEL noise contour is caused by the ultralight aircraft operating from a small strip of pavement south of the parallel taxiway.

To the south and east, the 60 CNEL contour remains on airport property. The 60 CNEL extends approximately 3,000 feet west of the airport. The 60 CNEL contour bows out approximately 1,000 feet from airport property on the north.

The 65 CNEL noise contour has a similar shape to the 60 CNEL contour. Small portions of the 65 CNEL noise contour extend off airport property to the north and west

The 70 and 75 CNEL noise contours remain close to the runway and are elongated about the runway centerline. These contours remain on airport property.

2.8.2 2003 NOISE CONTOURS

Exhibit 2J, 2003 Noise Exposure - Camarillo Airport, shows the CNEL noise contours for 2003 forecast conditions (Coffman Associates 1997, p. 2-10). These projections assume the forecast increase in airport operations with no change in operational procedures or airport facilities. The 2003 contours are similar in shape to the 1998 contours, although they are slightly larger due to the forecast increase in operations.

2.8.3 2018 NOISE CONTOURS

Exhibit 2K, 2018 Noise Exposure - Camarillo Airport, shows the CNEL noise contours for 2018 forecast conditions (Coffman Associates 1997, p. 2-10). These represent the projected noise conditions based on the forecasts of future operations with one change in operational procedures. Helicopter pads for training activity proposed in the Airport Master Plan are located north of the runway. This extends the 60 CNEL noise contour approximately 1,500 feet north of airport property. The 65 CNEL extends approximately 500 feet north of airport property. The 70 CNEL is wider than the 1998 and 2003 noise contour counterparts off the sides of the runway due to the presence of helicopter activity north of the runway. The 75 CNEL is similar in shape to the 1998 and 2003 noise contours.

The contours are slightly larger than the 1998 contours due to the forecast increase in operations. However, the 2018 noise contours are slightly smaller than the 2003 noise contours. This is due to the retirement of older Stage 2 business jets from the fleet by the year 2018.

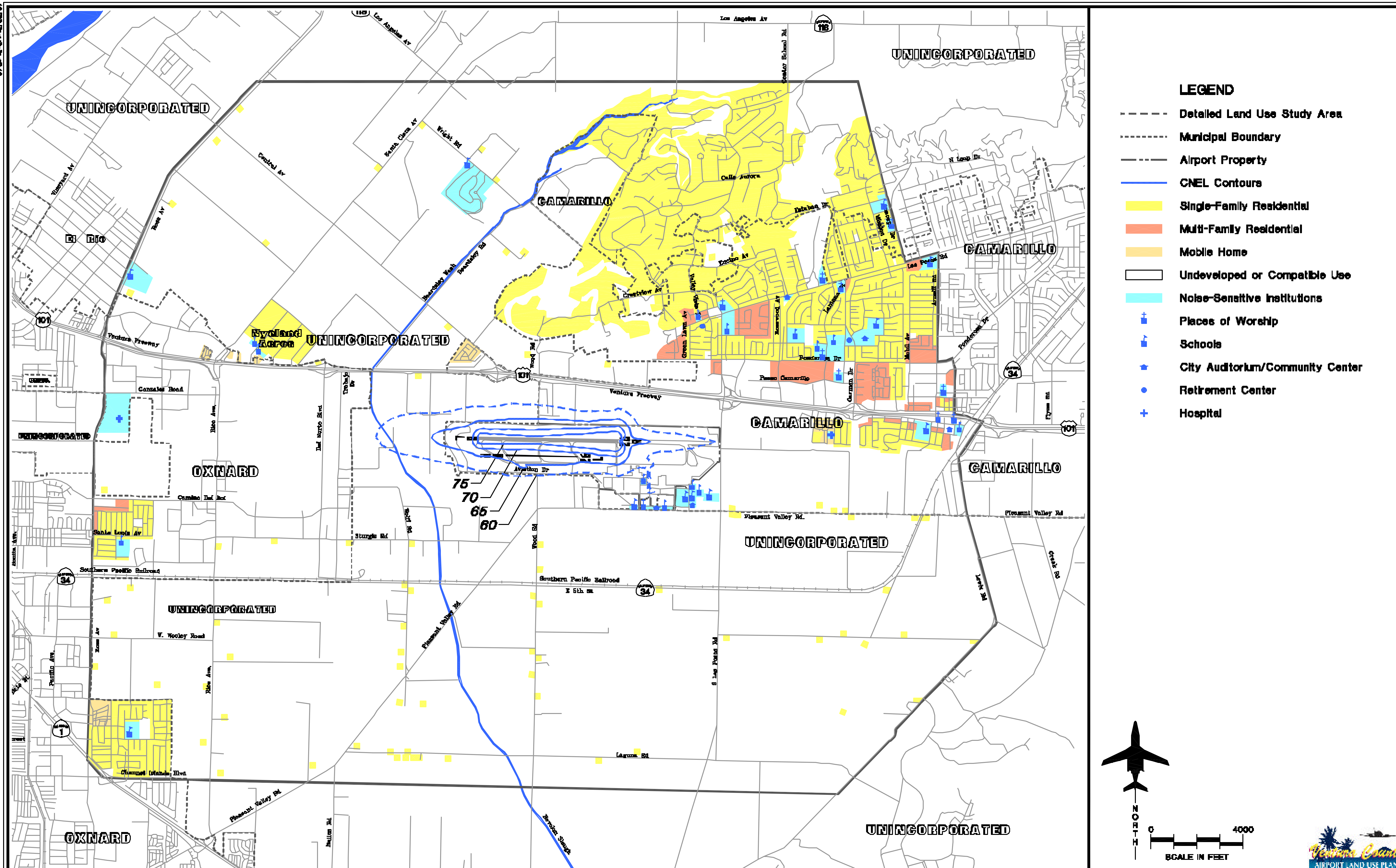


Exhibit 2H
CAMARILLO AIRPORT 1998 NOISE EXPOSURE

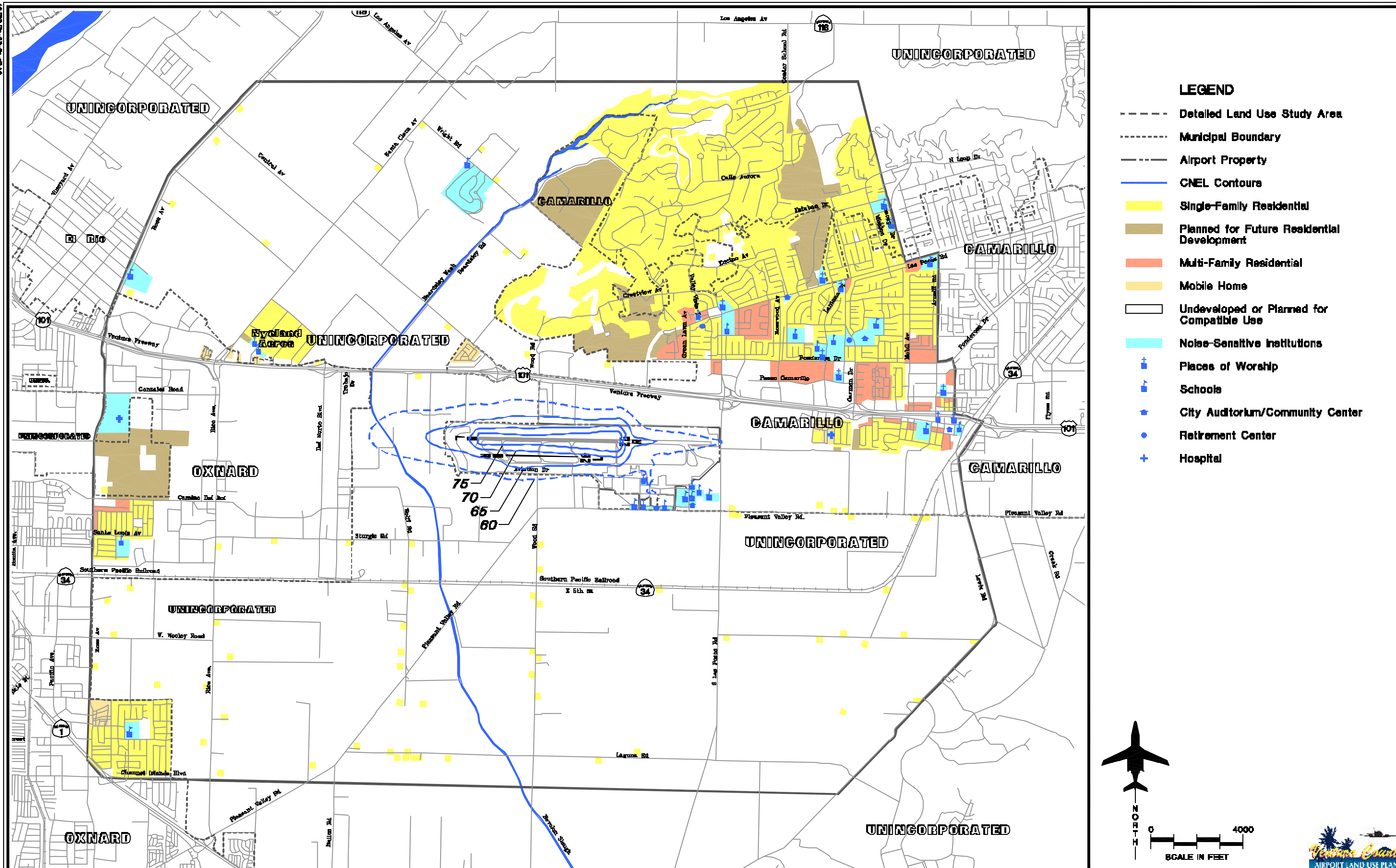


Exhibit 2J
CAMARILLO AIRPORT 2003 NOISE EXPOSURE

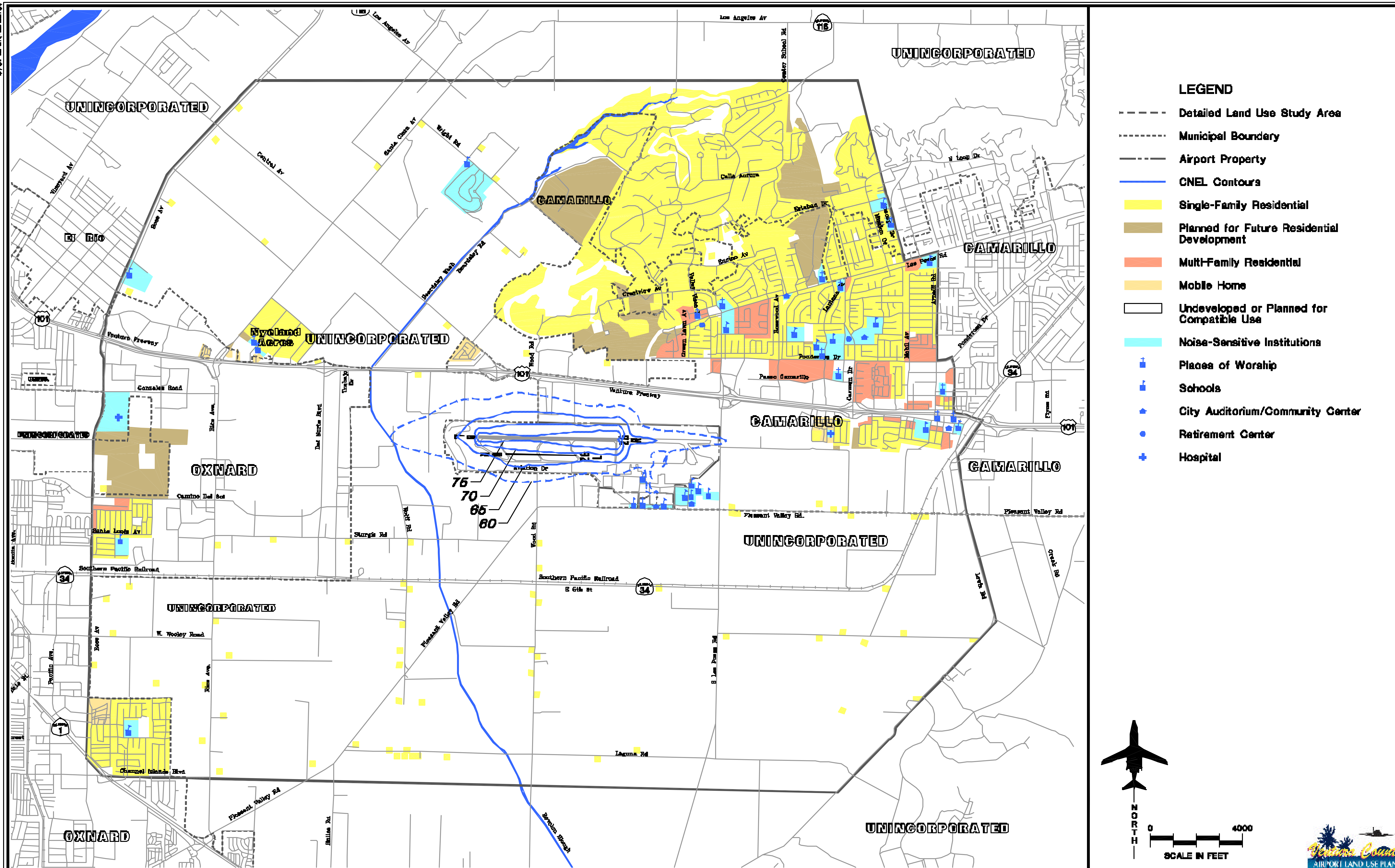


Exhibit 2K
CAMARILLO AIRPORT 2018 NOISE EXPOSURE

REFERENCES

City of Camarillo, 1996. *City of Camarillo General Plan*. Includes amendments through August 28, 1996.

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Chapter Three

OXNARD AIRPORT AND ENVIRONS

Chapter Three
OXNARD AIRPORT AND ENVIRONS

This chapter presents an overview of Oxnard Airport and the surrounding area. The background information in this chapter is as follows:

- A description of the study area and existing land uses in the area.
- A discussion of the local land use planning and regulatory framework in the study area.
- A description of key airport facilities and navigational aids.
- A description of noise abatement procedures, airport activity, and flight tracks.
- A description of current and forecast noise exposure around the airport.

3.1 AIRPORT SETTING

Oxnard Airport is classified in the *National Plan of Integrated Airport Systems* (NPIAS) as a primary commercial service airport (FAA 1995, p. A-14). Oxnard is also considered a non-hub commercial airport because it enplanes less than 0.05 percent of U.S. domestic passengers.

Oxnard Airport lies one and one-half miles east of the Pacific Ocean coastline on approximately 216 acres of land. The airport is bordered on three sides by major arterial roadways. Ventura Road and Victoria Avenue run north-south along the eastern and western edges of airport property, respectively. Fifth Avenue, running east-west along the southern edge of airport property between Ventura Road and Victoria

Avenue, provides primary airport access. The airport is afforded regional access by the Ventura Freeway (U.S. Highway 101) located four miles north of the airport and the Pacific Coast Highway (State Highway 1) located approximately one mile east of the airport.

Situated along the coastal edge of the 200-square mile Oxnard Plain, the City of Oxnard lies equidistant between Santa Barbara to the northwest and Los Angeles to the southeast. Immediately adjacent to the City of Oxnard is the City of Port Hueneme which operates the largest deep sea port between San Francisco and Los Angeles.

3.2 *STUDY AREA*

Exhibit 3A, Oxnard Airport Study Area and Jurisdictional Boundaries, shows an area ranging from Bard Road on the south, approximately one-half mile west of Rice Road on the east, to the Olivas Park and Buenaventura Municipal golf courses to the north, and the Pacific Ocean coastline on the west. It includes parts of the cities of Oxnard, Port Hueneme, Ventura, and parts of unincorporated Ventura County.

An oval-shaped area, designated the detailed land use study area, is in the middle of the map. It corresponds to the outer boundary of the F.A.R. Part 77 conical surface around the airport. Existing and future land use designations will be mapped in this area. It is anticipated that primary areas of airport compatibility concern will be directed to the detailed land use study area.

3.3 *EXISTING LAND USE*

Exhibit 3B, Generalized Existing Land Use in the Oxnard Airport Area, shows existing land use in the study area. The land use classification system, shown in **Table 3A**, has been designed to fit the requirements of airport noise compatibility planning. Residential land use and noise-sensitive institutions are identified. The other land use categories, which are generally considered to be compatible with aircraft noise, include commercial, industrial, transportation, and utilities; agriculture; parks and open space; and undeveloped land.

Most of the south and east part of the study area is urbanized. Residential neighborhoods in Oxnard lie southwest, south, east, and north of the airport. Commercial and industrial development is concentrated near the airport, in downtown Oxnard just east of the airport, along Vineyard Avenue between the Ventura Freeway and State Highway 1, and in Port Hueneme south of the airport.

Most of the northwest quadrant of the study area is in agricultural use. A large park and open space area is at the north edge of the study area along the Santa Clara River. Noise-sensitive institutions, including schools, places of worship, one hospital, and one library are scattered through the east and south parts of the study area.

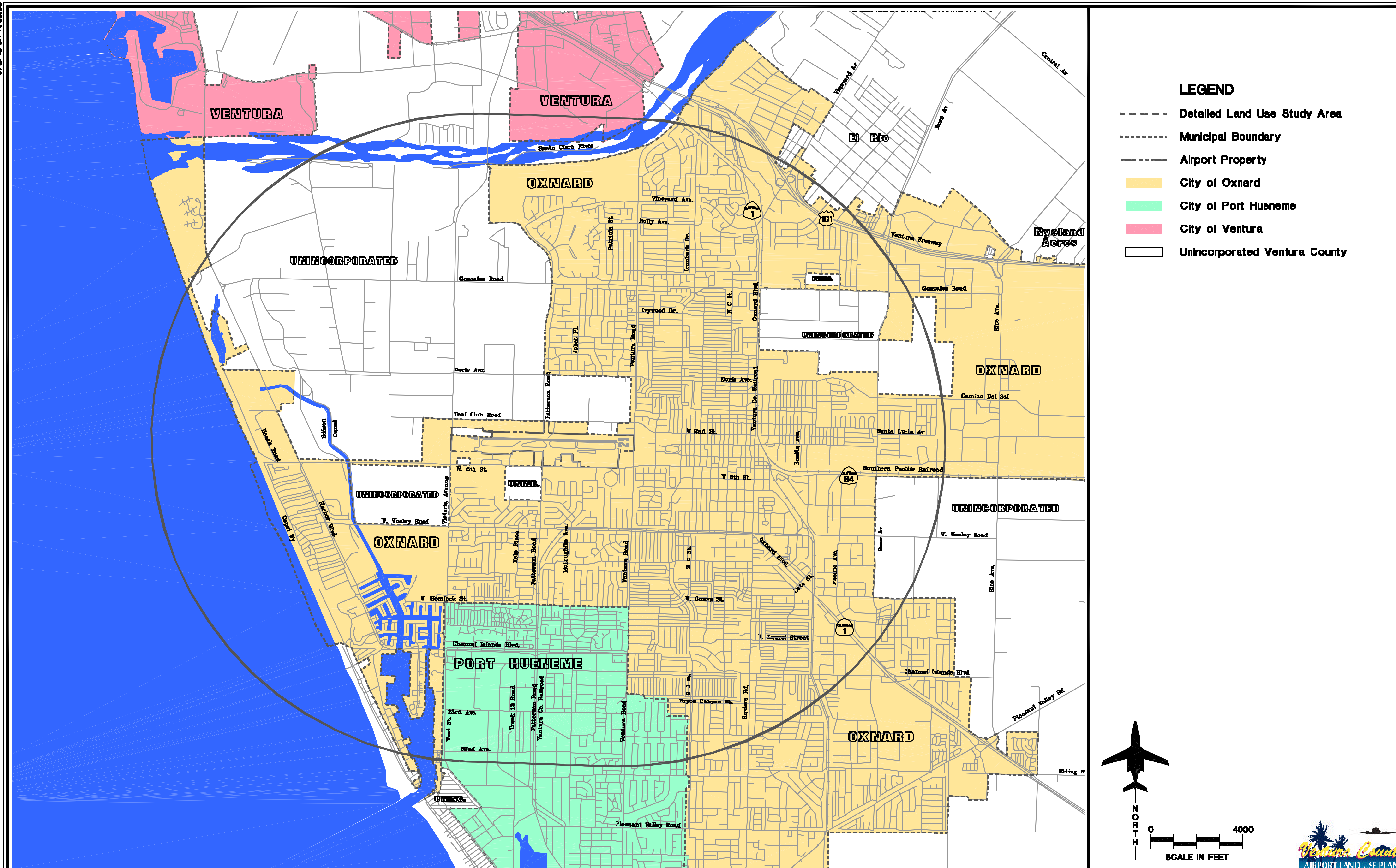


Exhibit 3A
OXNARD AIRPORT STUDY AREA AND JURISDICTIONAL BOUNDARIES

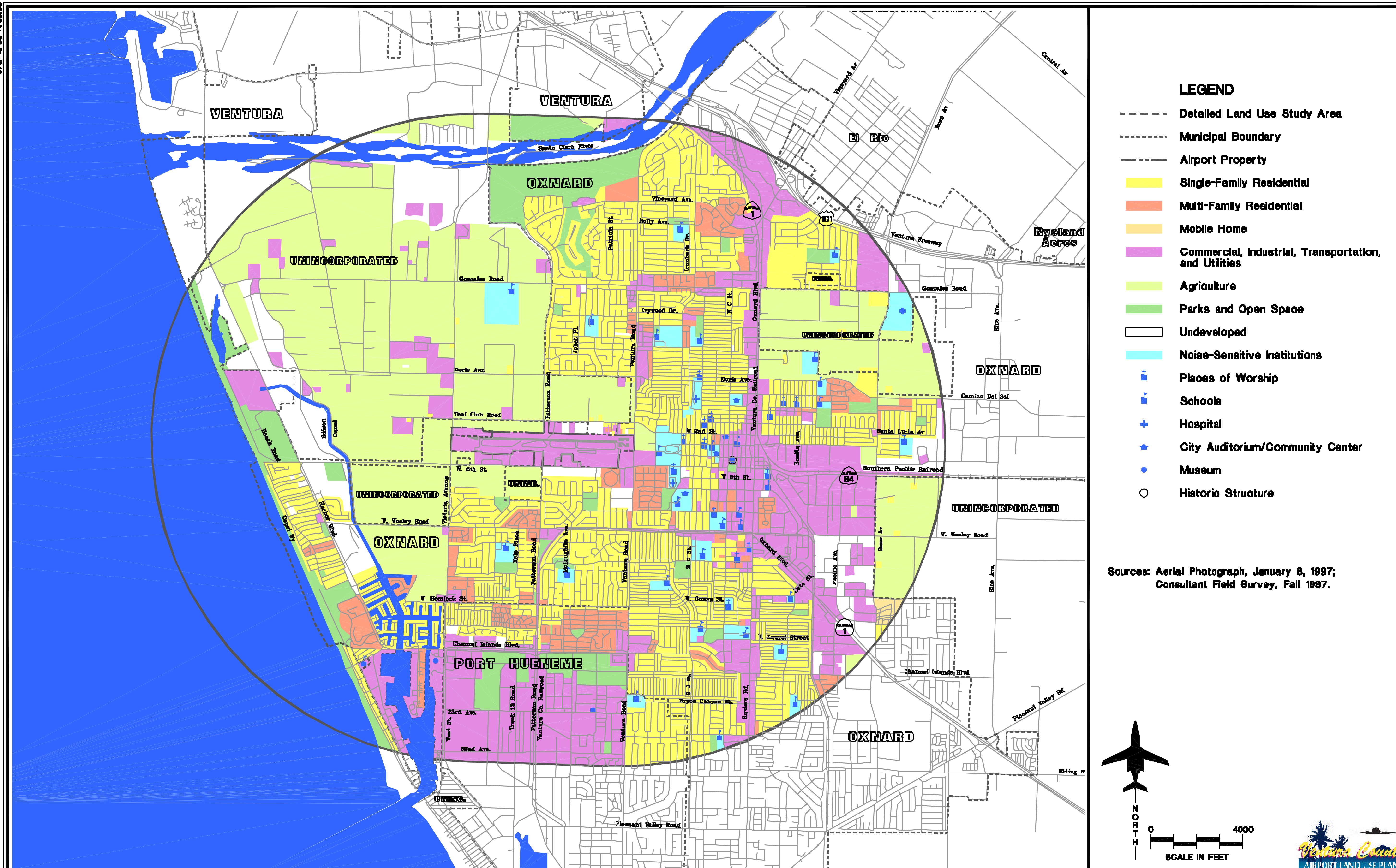


Exhibit 3B
GENERALIZED EXISTING LAND USE
IN OXNARD AIRPORT AREA

TABLE 3C
Land Use Categories Shown on Existing Land Use Map

Category	Land Uses Included
Single-family Residential	Single-family homes.
Multi-family Residential	Duplexes; Townhouses; Apartment and condominium buildings.
Mobile Homes	Mobile and manufactured homes.
Commercial, Industrial, Transportation, Utilities	Businesses; Offices; Industrial uses; Utilities; Transportation facilities; Intensively developed commercial agriculture areas including equipment storage areas and greenhouses.
Noise-Sensitive Institutions	Places of worship; Schools; Nursing homes; Residential group quarters; Hospitals; Community centers.
Agriculture	Orchards; Cultivated fields.
Parks and Open Space	Parks; Golf courses; Cemeteries; Ponds; Nature preserves.
Undeveloped	Vacant lots; Open parcels of uncultivated land.

The Regional Information Center for the California Historic Resources Inventory was contacted for information about any sites in the study area determined to be of historical significance. One building, the former Oxnard Public Library at 424 South C Street, is listed on the National Register of Historic Places. This building now houses the Carnegie Cultural Arts Center. No sites are listed as California Historical Landmarks or California Points of Historical Interest.

3.4 LAND USE PLANNING POLICIES AND REGULATIONS

The State of California requires all local governments to enact a "general plan" establishing framework policies for future development of the city or county. (See Government Code, Sections 65300, *et seq*.) The local general plan is the most important land use regulatory instrument in California. It establishes overall development policy and provides the legal foundation for all other kinds of land use and development regulation in the community. According to California law, the general plan must contain at least seven elements: land use, circulation, housing, conservation, open space, noise, and safety (Curtin 1996, pp. 9-10). Other elements may be prepared as needed and desired.

The policies of the general plan are implemented through specific ordinances regulating development. Chief among these is the zoning ordinance. Zoning regulates the use of land, the density of development, and the height and bulk of buildings. Subdivision regulations are another important land use regulatory tool, regulating the platting of land. Local communities also regulate development through building codes which set detailed standards for construction.

This section briefly summarizes the land use elements of the general plans of the study area jurisdictions. **Exhibit 3C, Future Land Use Plan in Oxnard Airport Area**, shows the land use designations of the general plans in the study area. A more detailed discussion of each jurisdiction's general plan is in Appendix B.

3.4.1 OXNARD GENERAL PLAN

The Oxnard General Plan was adopted in 1990. It includes eleven planning elements: growth management, land use, circulation, public facilities, open space/conservation, safety, noise, economic development, community design, parks and recreation, and housing. The Noise Element includes several goals and policies related to airport compatibility planning (City of Oxnard 1990, p. IX-16). The most directly relevant says that "municipal policies shall be consistent with the Ventura County Airport Comprehensive Land Use Commission's adopted land use plan..."

The City also has developed a Coastal Land Use Plan for the coastal zone (City of Oxnard 1982.) Policies and land use designations of the Coastal Land Use Plan have been incorporated into the City's General Plan.

Exhibit 3C shows the future land use plan for the Oxnard portion of the Oxnard Airport study area. Land west and northwest of the airport is designated for agriculture. Most of this area is covered by the San Buenaventura-Oxnard Greenbelt Agreement. This area has been designated for permanent agriculture and open space in accordance with a proposal made in the Open Space/Conservation Element of the General Plan (City of Oxnard 1990,

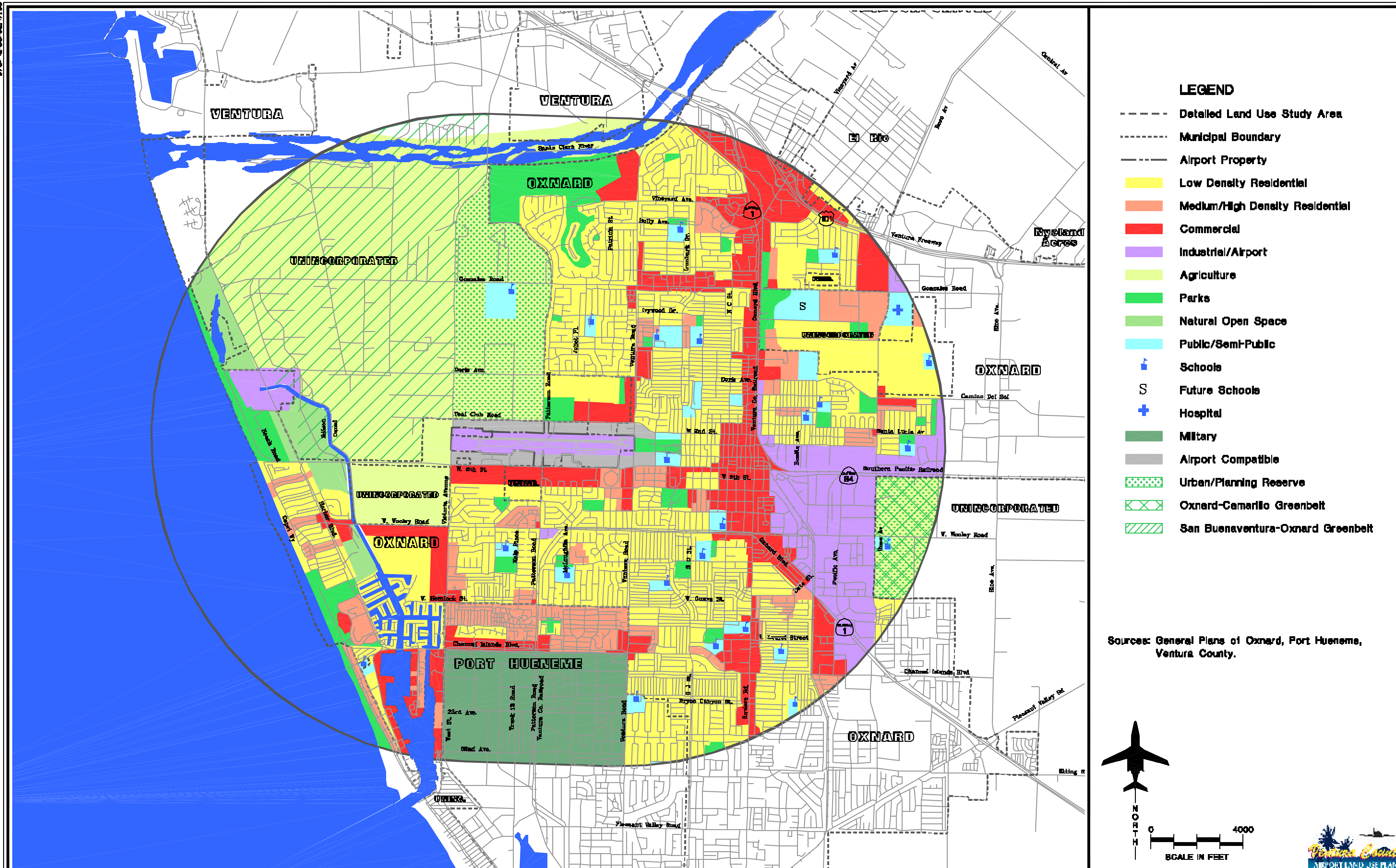


Exhibit 3C
FUTURE LAND USE PLAN
IN OXNARD AIRPORT AREA

p.VII-71). Most of the land north and south of the airport is designated for low-density residential development. Due east of the airport the land is designated for commercial and industrial use and includes the Oxnard central business district and the central industrial area.

3.4.2 PORT HUENEME GENERAL PLAN

The Port Hueneme General Plan was adopted in 1997 and establishes policies for a planning period through the year 2015 (Cotton/Beland/Associates, Inc., 1997). It includes seven elements: land use, circulation/infrastructure, housing, conservation/open space/environmental resources, noise, public safety and facilities, and economic development. The Land Use Element is the only element that is directly relevant to compatibility planning in the vicinity of Oxnard Airport. Port Hueneme also has a Local Coastal Program certified by the California Coastal Commission. The updated General Plan reflects the policies of the Local Coastal Program.

The City of Port Hueneme has very little undeveloped land. Much of the Land Use Element, therefore, is devoted to neighborhood preservation and redevelopment to strengthen the City's economic base.

Exhibit 3C shows the future land use designations in the Oxnard Airport Study Area which includes the northern edge of Port Hueneme. Most of the area north of Channel Islands Boulevard is designated for a mix of residential uses. Commercial use is designated along most of Channel Islands Boulevard. Land south of Channel Islands Boulevard and west of Ventura Road is designated for military use.

3.4.3 VENTURA COUNTY GENERAL PLAN

The Ventura County General Plan was adopted in 1988 and has been amended several times since then. The Plan includes several documents. The overall framework of goals and policies is in a document called *Goals, Policies and Programs* (Ventura County 1996a.) Supporting documentation is in a series of technical appendices (Ventura County 1994a, 1994b, 1994c, 1996b). The General Plan also includes several area plans where local issues and concerns are dealt with in greater detail than in the framework document. Ventura County also has *Coastal Area Plan* (Ventura County 1996c). It establishes various land use and conservation policies in the coastal zone.

As shown in **Exhibit 3C**, most of the area within the County's jurisdiction in the Oxnard Airport Study Area is designated as agriculture. Smaller areas are designated as open space, including the McGrath Lake area and the beach west of Channel Islands Harbor.

Agriculture is a major industry in Ventura County. The County General Plan establishes policies to encourage the preservation of prime farmland. Among them is a policy to retain and expand existing Greenbelt Agreements in the County and to encourage the formation of additional agreements (Ventura County 1996a, p. 21). Greenbelt agreements have been formed between various cities in Ventura County. They delineate areas between the cities which are declared off limits to urban development and are to be preserved for agriculture and open space. The cities of Oxnard and Ventura have a greenbelt agreement for much of the area between the two cities, part of which is in the Oxnard Airport study area. This is shown in **Exhibit 2C**.

The County General Plan also includes policies relating to airport hazards and noise compatibility. Land in airport approach and departure zones is to be designated for agriculture or open space uses (Ventura County 1996a, p. 20). Noise-sensitive land uses are not permitted where airport noise exceeds 65 CNEL. These uses may be permitted in the 60 to 65 CNEL contour only if measures are taken to reduce interior noise levels to 45 CNEL or less.

3.5 AIRPORT FACILITIES

Existing and proposed future facilities at Oxnard Airport are shown in **Exhibit 3D, Oxnard Airport Layout Plan**.

3.5.1 RUNWAYS

Oxnard Airport is served by Runway 7-25 which is 5,950 feet long by 100 feet wide, aligned in an east-west direction. The Runway 25 threshold is displaced 1,372 feet for obstacle clearance safety. The runway surface is asphalt and is in good condition. The current *Airport/Facility Directory* listing for Oxnard Airport indicates the following runway load bearing strength for Runway 7-25: 30,000 pounds for single wheel loading and 60,000 pounds for dual wheel loading (National Ocean Service 1997a, p. 90). No changes to the runway system are planned. Runway data for the airport is summarized in **Table 3B**.

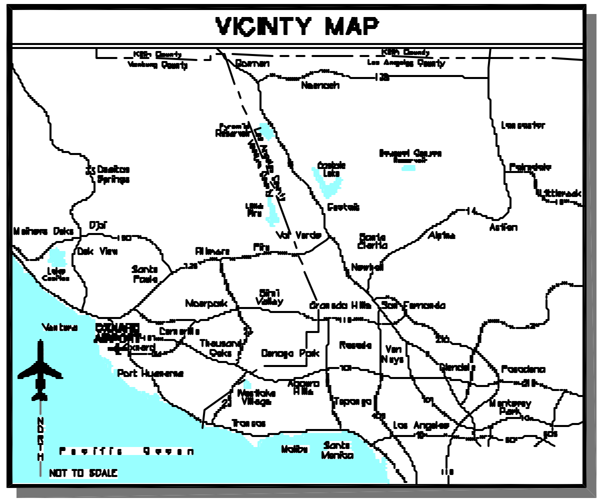
3.5.2 TAXIWAYS

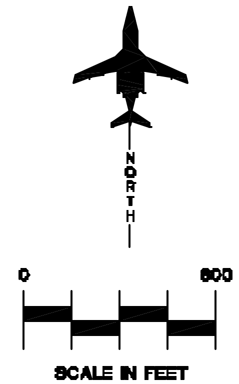
Runway 7-25 is served by a full length parallel taxiway (Taxiway A) on the south side of the runway. The runway is also served by five entrance/exit taxiways which run between the parallel taxiway and the runway. Taxiway B is an exit/entrance taxiway located just west of the Runway 25 displaced threshold. Taxiways C and D are high speed exits from the runway. **Exhibit 3D** shows the construction of two exit taxiways in the future (one near each runway end). The additional exits will improve airfield capacity by giving aircraft additional options for exiting the runway.

3.5.3 PASSENGER TERMINAL

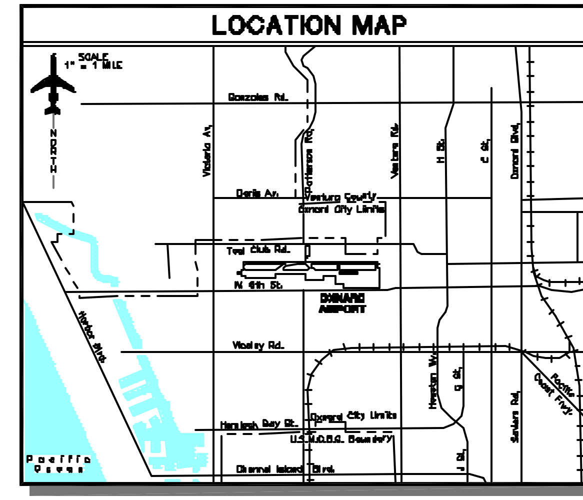
The passenger terminal at Oxnard is located on the south side, approximately midfield of Runway 7-25. The terminal building provides space for United Express Airlines, rental car and travel agencies, and a restaurant. The terminal building is afforded automobile access via Fifth Street. **Exhibit 3D** indicates that the terminal is planned to be expanded in the future.

VICINITY MAP





LOCATION MAP



LEGEND

EXISTING	ULTIMATE	DESCRIPTION
		ABANDONED PAVEMENT
		AIRPORT PROPERTY LINE
		AIRPORT REFERENCE POINT (ARP)
		AIRPORT ROTATING BEACON
		AVIGATION EASEMENT
		BUILDING TO BE REMOVED OR RELOCATED
		BUILDING
	BRL	BUILDING RESTRICTION LINE (BRL)
		PAVEMENT
		FENCING
VASI-4	PAPI-4	NAVIGATIONAL AID INSTALLATION
		RUNWAY END IDENTIFICATION LIGHTS (REIL)
		RUNWAY THRESHOLD LIGHTS
		SEGMENTED CIRCLE/WIND INDICATOR
		TOPOGRAPHY (USGS Maps)
		WIND INDICATOR (Lighted)

BUILDINGS/FACILITIES

EXISTING	ULTIMATE	DESCRIPTION
1	11	TERMINAL BUILDING
2		AIR TRAFFIC CONTROL TOWER (ATCT)
3	12	AIRPORT RESCUE and FIREFIGHTING (ARFF)
4	13	FIXED BASE OPERATION HANGAR
5	14	CONVENTIONAL HANGAR
6	15	PORTABLE HANGARS
7		AIRPORT MAINTENANCE
8	16	FUEL FACILITY
9		ELECTICAL VAULT
10		WELL
	17	T-HANGAR (20 Unit Nested)
	18	CORPORATE PARCEL

Source: Coffman Associates 1996, p. 6-12.

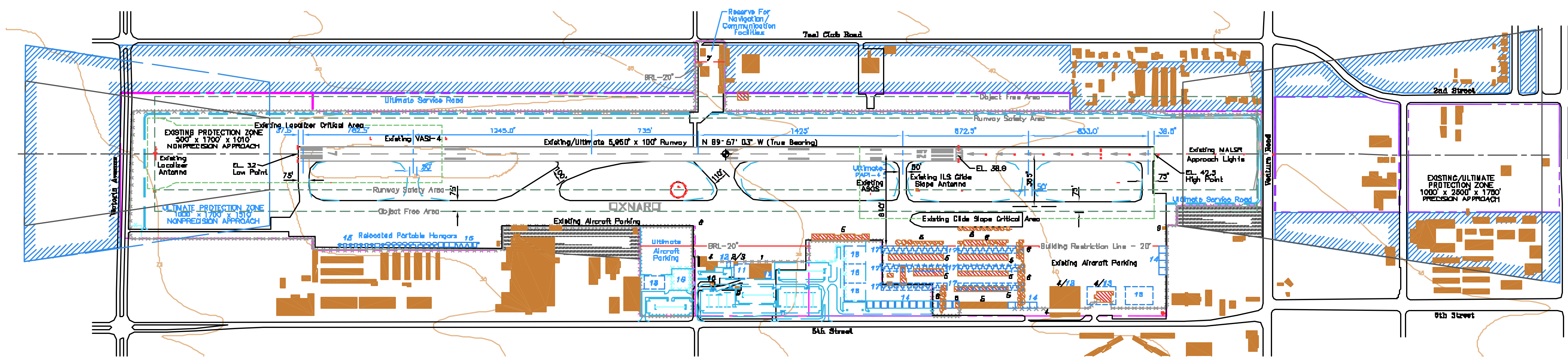


Exhibit 3D
OXNARD AIRPORT LAYOUT PLAN

The actual expansion of the building will not be considered until warranted by increasing passenger enplanement levels.

TABLE 3B
Runway Data
Oxnard Airport

	RUNWAYS	
	7	**25**
Length (ft.) Width (ft.) Surface Material	6,032 150 Asphalt	
Pavement Strength (lbs.) Single Wheel Loading Dual Wheel Loading	30,000 60,000	
Approach Slope Ratio	34:1	34:1
Approach Aids		
ILS	No	Yes
VOR/DME	Yes	Yes
GPS	Yes	Yes
VASI	V4L	V4L
MALSR	No	Yes
Runway Lighting	MIRL	
Runway Marking	Nonprecision	Precision

Source: *Airport/ Facility Directory*, National Ocean Service 1997a, p. 90.

3.5.4 GENERAL AVIATION COMPLEX

Two master tenants provide services or sublease to tenants who provide services at Oxnard Airport. Aeroflight Flight Academy and Sam's Aircraft Service are both located on the southeast side of Runway 7-25. These FBO's provide a full range of general aviation services including aircraft maintenance, fueling, and pilot training.

3.5.5 OTHER FACILITIES

Aspen Helicopters is a specialty business operator located immediately west of the ATCT. This operator maintains 17 aircraft (12 helicopters) for commercial charter and flight training operations.

3.6 TYPICAL FLIGHT PROCEDURES

3.6.1 INSTRUMENT APPROACHES

Instrument approaches are defined using electronic and visual navigational aids to assist pilots in landing when visibility is reduced below specified minimums. Instrument approaches are classified as precision and nonprecision. Both provide runway alignment and course guidance, while precision approaches also provide glide slope information for the descent to the runway.

3.6.1.a Precision Instrument Approaches

Oxnard Airport has one published precision approach to Runway 25 (National Ocean Service 1997b, p. 250). Runway 25 is equipped with an instrument landing system (ILS) consisting of a localizer, glide slope, and a medium intensity approach lighting system with runway alignment lights (MALSR) in addition to middle and outer marker beacons. The precision ILS approach to Runway 25 at Oxnard uses a standard 3.0 degree glideslope.

Typically, a precision ILS approach aided by a localizer, glideslope, and MALSR will provide Category I minimums (one-half mile visibility and 200-foot cloud ceiling). For Oxnard, however, obstructions located in the approach require weather minimums for the ILS Runway 25 approach to be at or above one mile visibility and 300-foot cloud ceilings.

3.6.1.b Nonprecision Approaches

Utilizing the Camarillo VOR/DME or the global positioning system (GPS), two nonprecision approaches are available at Oxnard (National Ocean Service 1997b, pp. 251-252). The VOR or GPS Runway 25 approach can be flown when cloud ceilings are 500 feet above ground level (AGL) or greater and visibility is one mile for aircraft with approach speeds of up to 121 knots, 1-1/4 miles for aircraft with approach speeds less than 141 knots, and 1-1/2 miles for aircraft with approach speeds less than 166 knots. The VOR or GPS Runway 25 approach also provides for a circling approach. The circling approach also requires a cloud ceiling of 500 feet AGL for aircraft with approach speeds less than 141 knots. Visibility requirements are the same for aircraft with approach speeds less than 121 knots, but increase to 1-1/2 miles for aircraft with approach speeds less than 141 knots. For aircraft with approach speeds greater than 141 knots but less than 166 knots, the circling approach minimums increase to 700 feet AGL cloud ceilings and 2-1/4 mile visibility.

The VOR/DME or GPS approach to Runway 7 is the second published nonprecision approach at Oxnard. VOR signals used with DME fixes ensure adequate terrain and obstruction clearances during final approach to the runway. The VOR/DME or GPS approach to Runway 7 can be flown when cloud ceilings are 500 feet AGL or greater and visibility is one mile for aircraft with approach speeds of less than 121 knots, 1-1/4 miles for aircraft with approach speeds greater than 121 but less than 141 knots, and 1-1/2 miles for aircraft with approach speeds greater than 141 knots but less than 166 knots. The VOR/DME or GPS Runway 7 approach also allows a circling approach. The minimums for the circling approach are the same as the circling VOR or GPS approach to Runway 25.

3.6.2 STANDARD INSTRUMENT DEPARTURES

Currently, two standard instrument departure (SID) procedures are published for Oxnard Airport -- the Skiff Four and the Camarillo Three SID (National Ocean Service 1997b, pp. 253-254).

Aircraft departing Runway 7 utilizing the Skiff Four SID are directed to turn left after take-off and intercept the Camarillo VOR/DME radial 249. Aircraft are to continue climbing westbound to the Skiff intersection then via a transition or assigned route. Aircraft departing Runway 25 climb via the Camarillo VOR/DME radial 249 to the Skiff intersection. Once at the Skiff intersection, aircraft continue via a published transition route or other route assigned by air traffic control.

Aircraft departing Runway 7 utilizing the Camarillo Three SID climb to the Camarillo VOR/DME thence via an assigned or published transition route. Aircraft utilizing the Camarillo Three SID departing Runway 25 turn right after take-off and intercept the Camarillo VOR/DME radial 249 thence via an assigned or transition route.

Discussions with Oxnard ATCT staff indicate that the SIDs are not often used. For noise abatement purposes, radar vectors are given to aircraft in order to avoid noise-sensitive areas. ATCT staff indicate that aircraft departing Runway 25 are assigned a heading of 270 degrees between 7:00 and 8:00 a.m. and 255 degrees between 8:00 a.m. and 9:00 p.m.

3.6.3 NOISE ABATEMENT PROCEDURES

The Ventura County Department of Aviation has developed and published, in consultation with the Airport Traffic Control Tower (ATCT) and airport users, noise abatement procedures for VFR operations at Oxnard Airport. Instructions are outlined regarding departures, arrivals, and pattern procedures at the airport which are aimed at minimizing noise exposure over noise-sensitive areas without compromising safety. Pilots are requested to follow the published procedures unless circumstances render them unsafe, weather conditions do not allow, or they are otherwise instructed to deviate by the airport traffic control tower. The procedures are described below:

- Aircraft are instructed to stay as high as practical over residential areas during overflight, approaches, and departures.
- Use best rate of climb when departing any runway.

- No formation take-offs or landings without prior written approval of the Airport Administrator.
- Touch-and-go/stop-and-go operations are prohibited between the hours of 8:00 p.m. and 7:00 a.m.
- Full stop/taxi back operations will be permitted only if the aircraft plans to depart the airport traffic area.
- No high power engine runups for maintenance between 7:00 p.m. and 7:00 a.m. the following day.
- Runway 7-25 traffic pattern - Published traffic pattern altitude (TPA) is established as 1,043 MSL feet for single engine aircraft and 1,443 MSL feet for twin engine/turbine aircraft. Utilize the best rate of climb, conditions permitting, turn crosswind when reaching the departure end of the runway and an altitude within 300 feet of pattern altitude. Maintain pattern altitude until turning base leg.
- Runway 25 Departure - When departing the airport traffic area use best rate of climb, remain on runway heading until beyond the departure end of the runway and 700 feet AGL before proceeding on course.
- Runway 25 Arrival - Straight-in cross the Camarillo Airport at or above 2,000 feet and remain as high as practical over the city until commencing final descent. Exercise extreme caution due to Camarillo traffic and instrument approaches being conducted to OXR Runway 25.
- Runway 7 Departure - Departures from the mid-field intersection (Taxiway C) are prohibited. When departing the airport traffic area use best rate of climb and remain on runway heading until reaching the airport boundary (Ventura Road) before proceeding on course. Exercise extreme caution due to opposite direction instrument approach traffic.
- A left-hand traffic pattern is in effect when the airport traffic control tower is closed.

3.6.4 OPERATIONAL LETTERS OF AGREEMENT

The Oxnard ATCT has entered into several letters of agreement with local aircraft operators. These serve both the ATCT personnel and the aircraft operators in establishing specific procedures to minimize operational conflicts and promote efficient use of the airfield and airspace.

One letter of agreement has been established between the Oxnard and Camarillo ATCT, NAWS Point Mugu Radar Air Traffic Control Facility (RATCF), Aspen Helicopters, and Sinton Helicopters. It defines operational procedures for agriculture helicopters requesting special visual flight rules (SVFR) operations during instrument flight rule (IFR) weather conditions. Helicopter pilots are to maintain contact with the appropriate ATC facility and maintain adequate separation as assigned by the controlling ATC facility. The letter of agreement also designates SVFR routes for arrivals and departures to and from Oxnard and Camarillo Airports. For Oxnard, four routes have been established: SVFR Routes Victor, Romeo, Foxtrot, and Papa. Route Victor directs aircraft from the western boundary of Oxnard Airport direct to the Ventura Marina at or below 500 feet. Route Romeo directs aircraft from the eastern boundary of the Oxnard Airport direct to the Financial Plaza to remain west of the Saticoy Bridge, and clear of the Camarillo Surface Area at or below 500 feet. Route Foxtrot runs from the airport via Fifth Street westward to the shoreline at or below 500 feet. Route Papa directs southwest bound aircraft via Victoria Road to the Port Hueneme Harbor at of below 500 feet.

The Oxnard ATCT has also entered into an agreement with Aspen and Petroleum Helicopters for VFR helicopter arrival and departure procedures. These procedures apply to VFR conditions during ATCT operational hours only.

- Helicopters shall operate at or below 500 feet AGL unless otherwise instructed.
- Helicopters shall avoid the following noise sensitive areas: Deckside Villas, just south/southwest of Wooley Road; Oxnard Shores area south of Fifth Street along the shoreline; housing development just south/southeast of the airport in the vicinity of Ventura Road and Wooley Road; directly over the homes just north of the east end of Runway 7-25.

Specific arrival routes include:

- Fifth Street Arrival, from east or west--proceed via Fifth Street to the Airport
- Teal Club Arrival, from east or west --proceed via Teal Club Road to the Airport (note: an imaginary line extends Teal Club Road to the shoreline on the west or Rice Road on the east).
- Victoria Road Arrival, from north or south --proceed via Victoria Road to the Airport remaining north or south of runway/taxiway. If crossing is desired, advise controller on initial contract.

Departure routes have been established as follows:

- Fifth Street Departure, east or west --proceed via Fifth Street either west to the shoreline or east to Rice Road.
- Teal Club Road Departure, east or west -- proceed via Teal Club Road west to the shoreline or east to Rice Road.
- Victoria Street Departure, south -- proceed westbound via Fifth Street to Victoria Road then south to southwest bound to beach area.
- Victoria Street Departure, north -- proceed westbound via Teal Club Road to Victoria Road then north bound out of the Class D Surface Area.

3.7 AIRPORT ACTIVITY AND NOISE EXPOSURE DATA

This CLUP Update does not include updated activity and noise exposure data for the Oxnard Airport. At the time this plan was prepared, the Oxnard Airport Master Plan had not yet been adopted. Therefore, the activity and noise exposure information in the 1991 CLUP has not yet been updated and thus represents the most recent adopted information available. As such, the 1991 CLUP activity data, noise contours, and safety zone boundaries at Oxnard Airport are incorporated unchanged into this update.

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Chapter Four

SANTA PAULA AIRPORT AND ENVIRONS

Chapter Four
SANTA PAULA AIRPORT AND ENVIRONS

This chapter presents an overview of Santa Paula Airport and the surrounding area. The information in this chapter includes:

- A description of the study area and existing land uses in the area.
- A discussion of the local land use planning and regulatory framework in the study area.
- A description of key airport facilities.
- A discussion of noise abatement procedures, airport activity, and flight tracks.
- A description of noise exposure around the airport.

4.1 AIRPORT SETTING

Santa Paula Airport is classified in the *National Plan of Integrated Airport Systems* (NPIAS) as a general aviation airport (FAA 1995, p. A-17). The airport is within the corporate limits of the City of Santa Paula between State Route 126 and the Santa Clara River. Access to the airport is provided by Santa Maria Street.

4.2 STUDY AREA

Exhibit 4A, Santa Paula Airport Study Area and Jurisdictional Boundaries, shows a rectangular area of 24.5 square miles. At the center of the map is an oval-shaped area centered on the airport. This is the "detailed land use study area". Within this area, detailed information on existing land use and planned future land use will be mapped. The study area boundary corresponds with the F.A.R. Part 77 conical surface and defines the area within which airport compatibility concerns are most likely to apply.

4.3 EXISTING LAND USE

Exhibit 4B, Generalized Existing Land Use in Santa Paula Airport Area, shows existing land use in the study area. The land use classification system, shown in **Table 4A**, has been designed to fit the requirements of airport noise compatibility planning. Residential land uses and noise-sensitive institutions are identified. The other land use categories, which are generally considered to be compatible with aircraft noise, include commercial, industrial, transportation, and utilities; agriculture; parks and open space; and undeveloped land.

The northern half of the study area lies within the City of Santa Paula and is developed for urban use. Most of the area south of the airport is farmland or undeveloped land. Most of the developed area involves housing. Farmland rings the City in areas which can be cultivated. Undeveloped open space lies in the hillier areas around the City. Commercial and industrial development is concentrated along Main Street, the Southern Pacific Railroad, the east edge of the City along the Santa Paula Freeway (S.R. 126), and near the airport.

Noise-sensitive institutions, including schools, places of worship, community centers, and a hospital are scattered across the city.

4.4 LAND USE PLANNING POLICIES AND REGULATIONS

The State of California requires all local governments to enact a "general plan" establishing framework policies for future development of the city or county. (See Government Code, Sections 65300, *et seq*.) The local general plan is the most important land use regulatory instrument in California. It establishes overall development policy and provides the legal foundation for all other kinds of land use and development regulation in the community. According to California law, the general plan must contain at least seven elements: land use, circulation, housing, conservation, open space, noise, and safety (Curtin 1996, pp. 9-10). Other elements may be prepared as needed and desired.

The policies of the general plan are implemented through ordinances regulating development. Chief among these is the zoning ordinance. Zoning regulates the use of land, the density of development, and the height and bulk of buildings. Subdivision regulations are another important land use regulatory tool, regulating the platting of land. Local communities also regulate development through building codes which set detailed standards for construction.

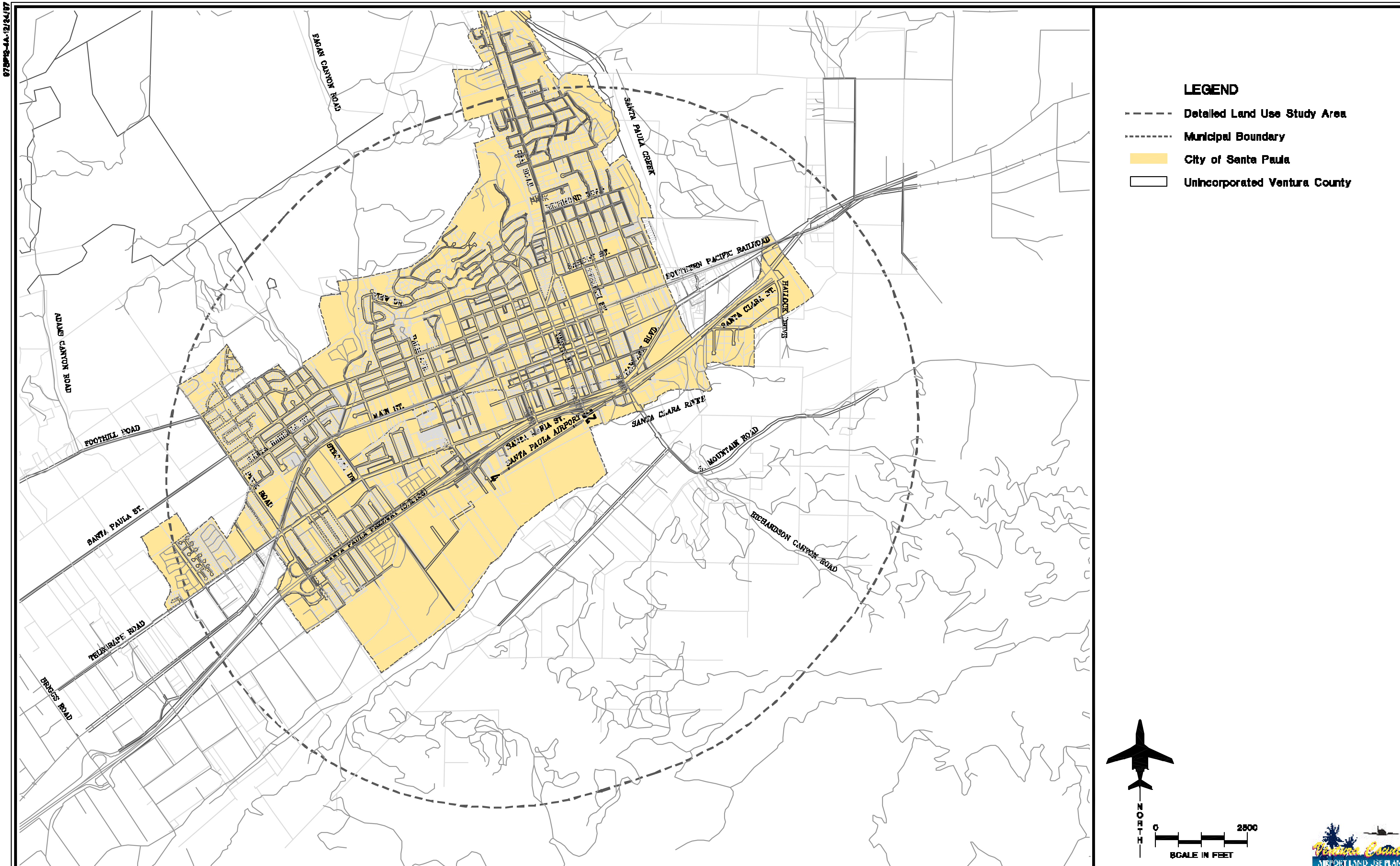


Exhibit 4A
SANTA PAULA AIRPORT STUDY AREA
AND JURISDITIONAL BOUNDARIES

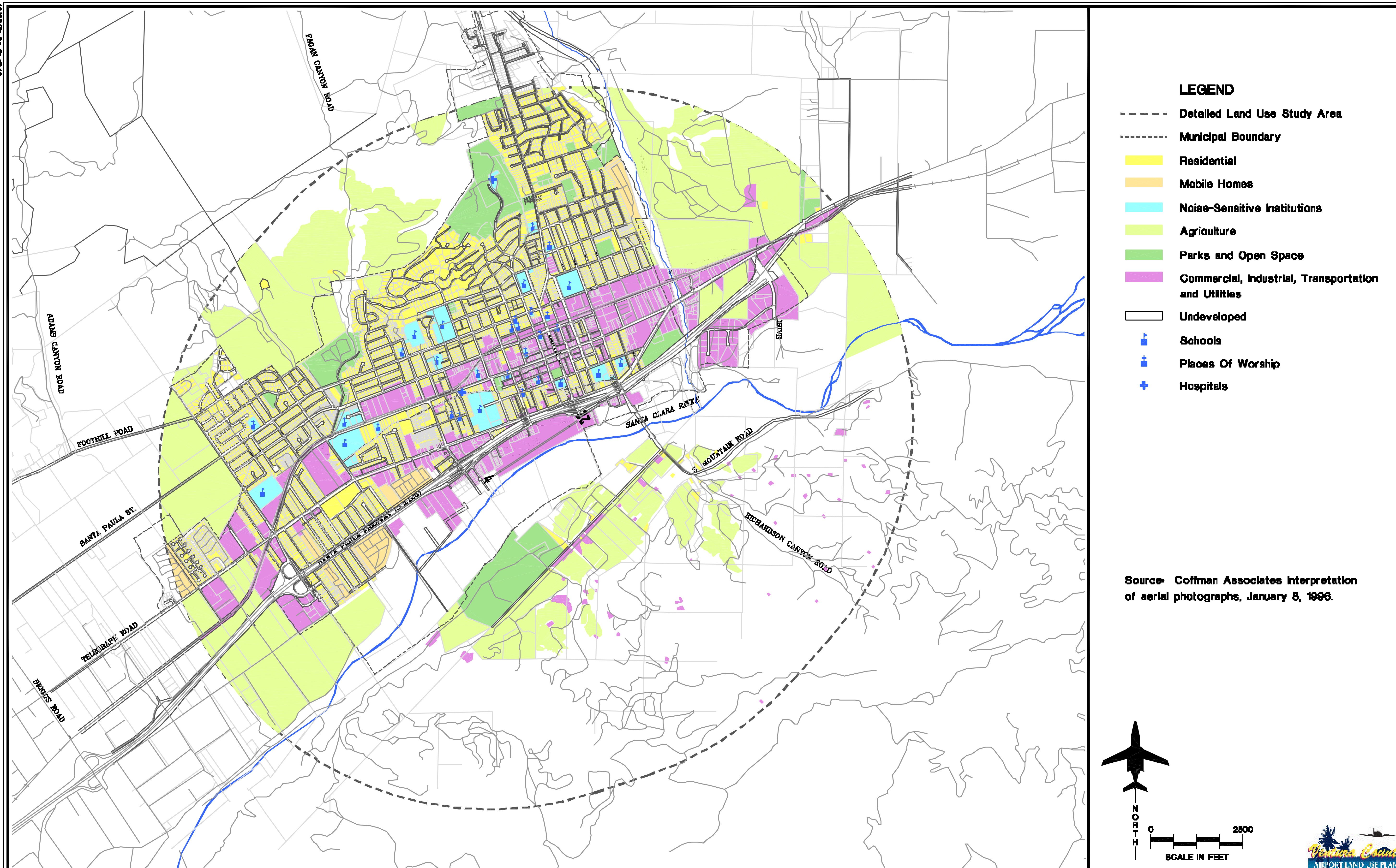


Exhibit 4B
GENERALIZED EXISTING LAND USE
IN SANTA PAULA AIRPORT AREA

TABLE 4A
Land Use Categories Shown on Existing Land Use Map

Category	Land Uses Included
Residential	Single-family homes; Duplexes; Townhouses; Apartment and condominium buildings..
Mobile Homes	Mobile and manufactured homes.
Commercial, Industrial, Transportation, Utilities	Businesses; Offices; Industrial uses; Utilities; Transportation facilities; Intensively developed commercial agriculture areas including equipment storage areas and greenhouses.
Noise-Sensitive Institutions	Places of worship; Schools; Nursing homes; Residential group quarters; Hospitals; Community centers.
Agriculture	Orchards; Cultivated fields.
Parks and Open Space	Parks; Golf courses; Cemeteries; Ponds; Nature preserves.
Undeveloped	Vacant lots; Open parcels of uncultivated land.

This section briefly summarizes the general plans of the study area jurisdictions -- Santa Paula and Ventura County. **Exhibit 4C**, **Future Land Use Plan in Santa Paula Airport Area**, shows the land use designations of the general plans in the study area. A more detailed discussion of each jurisdiction's general plan is in Appendix B.

4.4.1 SANTA PAULA GENERAL PLAN

The Santa Paula General Plan was recently updated and adopted in mid-1998. The Plan includes a Land Use Element, a Housing Element, a Circulation Element, a Conservation and Open Space Element, a Safety Element, and a Noise Element. Four elements (land use, circulation, safety, and noise) have objectives and policies relating to Santa Paula Airport. Those policies are discussed in this section.

4.4.1.a Land Use Element

The Land Use Element identifies the policies that lay the foundation for mapping future land use designations throughout the City and its planning area. An updated future land use plan map, however, was not yet ready when this document was drafted.

The land use goals, objectives, and policies are classified into several different subject areas. The airport is addressed in two subject areas: land use distribution and land use compatibility (City of Santa Paula 1997b, pp. LU-43 to LU-54). The policies state that the land use plan should provide for the continuance and enhancement of the airport and airport-related uses. The policies note that development near the airport should be compatible with the airport and the County's Airport Comprehensive Land Use Plan.

4.4.1.b Circulation Element

The circulation goals, objectives, and policies are classified into several different subject areas, including aviation, which addresses Santa Paula Airport (City of Santa Paula 1997a, pp. CI-41 to CI-42). The Plan calls for the preservation and enhancement of the airport, noting that only compatible uses should be permitted in the airport vicinity. It also calls for the acquisition of the "clear zones" (now known as runway protection zones) and the extension of runway overruns to promote increased safety.

4.4.1.c Noise Element

The noise goals, objectives, and policies are tied to specific noise sources, including the airport (City of Santa Paula 1997c, pp. N-17). The policies note that new development near the airport should comply with the noise compatibility standards set forth in the Plan. (Those standards are shown in Exhibit B1 in Appendix B.) The policies also call for City officials to coordinate with the airport operators to minimize the effect of airport noise on nearby residents.

4.4.1.d Safety Element

The goals, objectives, and policies of the Safety Element are tied to specific kinds of hazards, including the risk of aircraft accidents (City of Santa Paula 1997d,

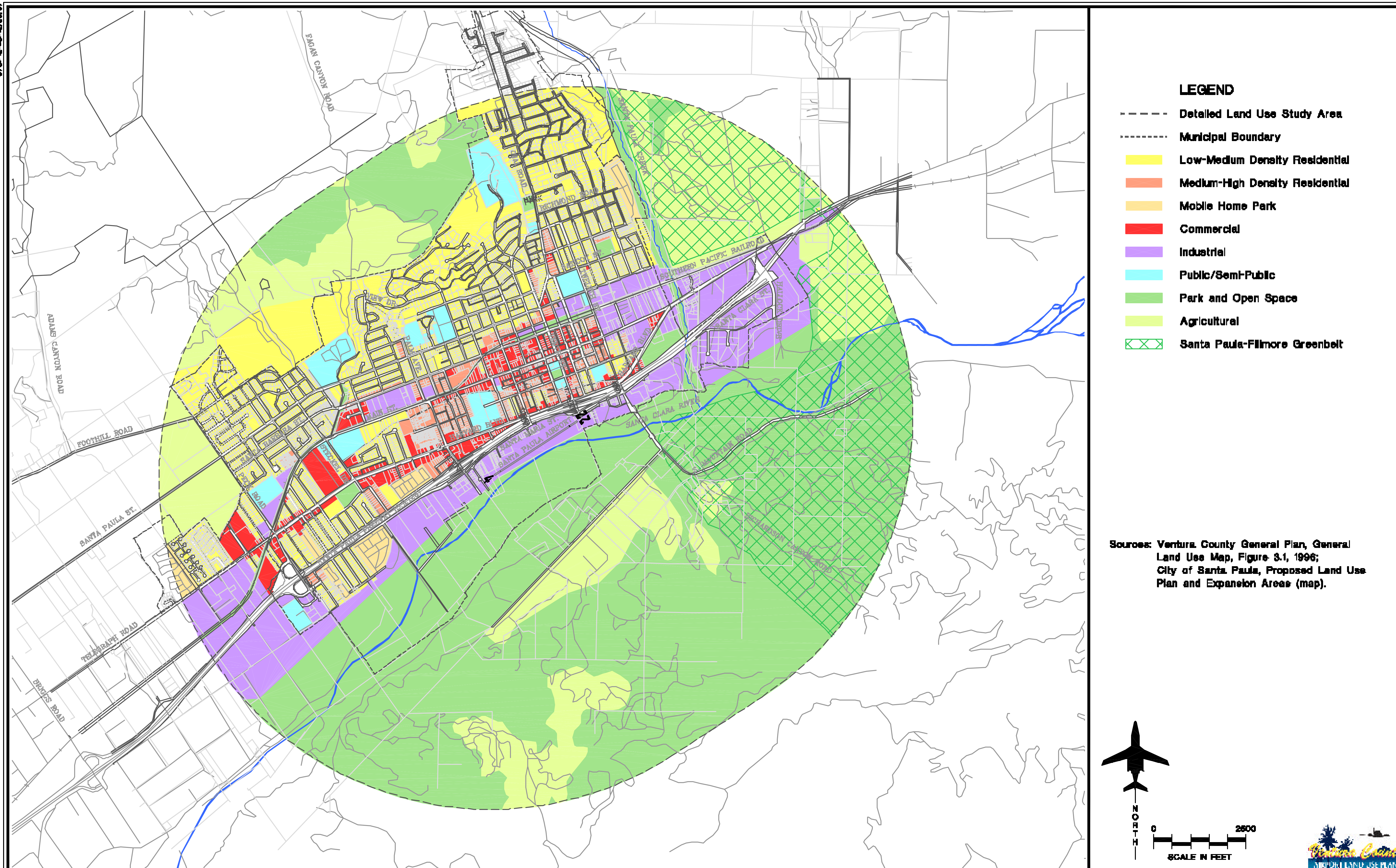


Exhibit 4C
FUTURE LAND USE PLAN
IN SANTA PAULA AIRPORT AREA

pp. S-43 to S-44). The Plan proposes that development near the airport should comply with the County's Airport Comprehensive Land Use Plan. The Safety Element also reiterates the need to purchase the "clear zones" (runway protection zones) and to extend the runway overruns.

Two implementation measures relating to these goals, objectives, and policies are called out in the Safety Element (City of Santa Paula 1997d, p. S-54).

61. The City of Santa Paula should change the land use designations in the Inner Safety Zone at both ends of the Santa Paula Airport runway to agricultural or other conforming uses.

62. The City should pass legislation which would allow funding by the State for purchase of the property in the Inner Safety Zone.

4.4.2 VENTURA COUNTY GENERAL PLAN

The Ventura County General Plan was adopted in 1988 and has been amended several times since then. The Plan includes several documents. The overall framework of goals and policies is in a document called *Goals, Policies and Programs* (Ventura County 1996a.) Supporting documentation is in a series of technical appendices (Ventura County 1994a, 1994b, 1994c, 1996b).

The General Plan also includes several area plans where local issues and concerns are dealt with in greater detail than in the framework document.

In the Santa Paula Airport study area, the County's future land use designations in the unincorporated area outside the City's Sphere of Influence are agricultural and open space, both of which are compatible with aircraft noise. This is shown in **Exhibit 4C, Future Land Use Plan**.

Agriculture is a major industry in Ventura County. The County General Plan establishes policies to encourage the preservation of prime farmland. Among them is a policy to retain and expand existing Greenbelt Agreements in the County and to encourage the formation of additional agreements (Ventura County 1996a, p. 21). Greenbelt agreements have been formed between various cities in Ventura County. They delineate areas between the cities which are declared off limits to urban development and are to be preserved for agriculture and open space. Santa Paula is a party to two greenbelt agreements. One is with the City of Ventura and concerns land west of the City, just outside the study area. The other agreement is with the City of Fillmore and is east of the City. A small part of this area lies within the Santa Paula Airport study area. The Santa Paula General Plan proposes an increase in its sphere of influence in this area. That would require an amendment in the Santa Paula-Fillmore Agreement to remove the affected area (City of Santa Paula 1997b, p. LU-27).

The County General Plan also includes policies relating to airport hazards and noise compatibility. Land in airport approach and departure zones is to be designated for agriculture or open space uses (Ventura County 1996a, p. 20). Noise-sensitive land uses are not permitted where airport noise exceeds 65 CNEL. These uses may be permitted in the 60 to 65 CNEL contour only if measures are taken to reduce interior noise levels to 45 CNEL or less.

4.5 AIRPORT FACILITIES

Existing facilities at Santa Paula Airport are shown on **Exhibit 4D**, **Santa Paula Airport Layout**.

4.5.1 RUNWAYS AND TAXIWAYS

Santa Paula Airport is served by Runway 4-22 which is 2,650 feet long by 40 feet wide and aligned in a northeast-southwest direction. The runway surface is asphalt. The current *Airport/Facility Directory* listing for Santa Paula Airport indicates runway load bearing strength as 8,000 pounds for single wheel loading (National Ocean Service 1997a, p. 114). The threshold of Runway 4 is displaced 130 feet, and Runway 22 is displaced 233 feet. This is for obstacle clearance.

The only taxiways on the airport provide access to the hangars and entrance and exit to the runway. The runway lacks a system of parallel taxiways.

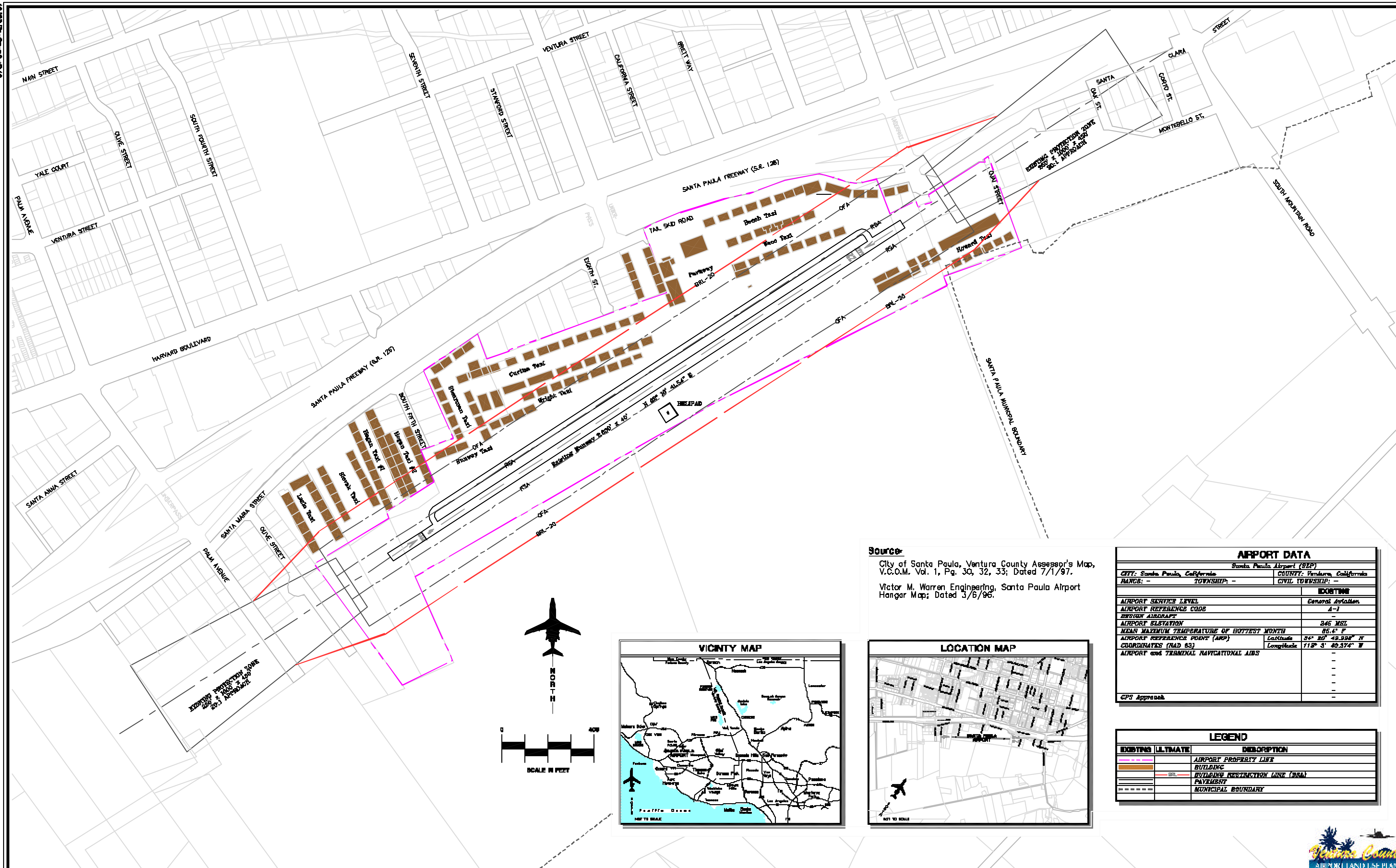
4.5.2 FIXED BASE OPERATORS

Terminal services are provided by several fixed base operators (FBOs). Aerobatic Safety Unlimited, CP Aviation, Krybus Aviation, and Screaming Eagle Aviation all provide 80 and 100 low lead fueling. Other FBOs include Santa Paula Flight Center and Santa Paula Flight Services (AOPA 1996, p. 3-95).

4.6 TYPICAL FLIGHT PROCEDURES

Since it lacks an airport traffic control tower, the airport operates according to Federal regulations governing flight at non-towered airports (F.A.R. Part 91, Section 91.126). Federal regulations establishing visual flight rules (VFR) must also be complied with (F.A.R. Part 91, Sections 91.151 *et seq*.).

A pilot guide has been published for Santa Paula Airport. (See "Welcome to Santa Paula Airport", published June 1996.) It notes several noise abatement and other operating procedures. The developed part of the City north of the freeway and a mobile home park west of the airport are specifically called out as noise-sensitive areas. Runway 22 is designated the calm wind runway. Pilots are instructed to use a left-hand pattern on this runway. A right-hand pattern has been established for Runway 4. This keeps the traffic pattern south of the airport and off the City. Pilots are instructed to maintain an altitude of 1,500 feet MSL on the



Source:

City of Santa Paula, Ventura County Assessor's Map, V.C.O.M. Vol. 1, Pg. 30, 32, 33; Dated 7/1/97.

Victor M. Warren Engineering, Santa Paula Airport Hangar Map; Dated 3/6/96.

AIRPORT DATA

Santa Paula Airport (SZP)

CITY: Santa Paula, California		COUNTY: Ventura, California
RANGE: – TOWNSHIP: –		CIVIL TOWNSHIP: –
		EXISTING
AIRPORT SERVICE LEVEL		General Aviation
AIRPORT REFERENCE CODE		A-1
DESIGN AIRCRAFT		–
AIRPORT ELEVATION		245 MSL
MEAN MAXIMUM TEMPERATURE OF HOTTEST MONTH		86.4° F
AIRPORT REFERENCE POINT (ARP) COORDINATES (NAD 83)	Latitude	34° 20' 49.998" N
	Longitude	119° 3' 40.374" W
AIRPORT and TERMINAL NAVIGATIONAL AIDS		–
		–
		–
		–
		–
		–
GPS Approach		–

LEGEND

EXISTING	ULTIMATE	DESCRIPTION
		AIRPORT PROPERTY LINE
		BUILDING
	BRL	BUILDING RESTRICTION LINE (BRL)
		PAVEMENT
		MUNICIPAL BOUNDARY

Exhibit 4D
SANTA PAULA AIRPORT LAYOUT

upwind leg over the city and to enter the pattern with a 90-degree turn from the upwind to the crosswind leg. Forty-five degree pattern entries are discouraged.

Other noise abatement procedures are as follows:

- Long straight-in approaches are discouraged.
- Overhead approaches are discouraged.
- Helicopters need prior written permission to operate at the airport.
- All helicopter arrivals and departures must be south of the runway and are not to cross over the runway.
- Touch-and-goes are not permitted on weekends.
- Night operations are not permitted. (The airport is unlighted.)

4.7 AIRPORT ACTIVITY DATA

Detailed airport activity data are needed for noise modeling and for establishing airport safety zones and standards. Among the most important information is the number of aircraft operations (takeoffs and landings), the mix of aircraft types using the airport, runway use percentages, and flight tracks. This section summarizes key airport activity data.

4.7.1 OPERATIONS

Air traffic statistics at Santa Paula Airport are not regularly recorded since the airport does not have an airport traffic control tower. Aircraft operations (takeoffs and landings) are currently estimated by airport management at approximately 52,000 per year. It is estimated that 14,000 are itinerant operations with origins and destinations away from the immediate airport area. The remaining 38,000 are estimated to be local operations, primarily touch-and-goes. This is summarized in **Table 4B**.

Operations forecasts used by the California Department of Transportation Aeronautics Program indicate that total operations at Santa Paula Airport will remain relatively constant through the year 2015. Working from a 1993 base year estimate of 50,090 operations, the 2015 forecast shows 51,192 operations (SCAG 1996, p. XI-24).

For purposes of the noise analysis undertaken in this study, operations at Santa Paula Airport are anticipated to remain constant at 52,000 per year.

4.7.2 FLEET MIX

An estimate of the mix of aircraft using the airport was developed by the consultant based on the proportions of aircraft based at the airport. (In 1997, 255 aircraft were reported to be based at the airport, including 248 single engine aircraft, six multi-engine aircraft, and one helicopter.) The estimated operational fleet mix is shown in **Table 4C**. Most operations are conducted by light single engine aircraft. Only about 2,500 operations per year are by twin-engine aircraft. An estimated 800 annual operations are by helicopters.

TABLE 4B Estimated Current and Forecast Operations Santa Paula Airport	
Operations	**1997 and 2015**
Itinerant	
General Aviation/Fixed Wing Helicopter	13,200 800
Local	
General Aviation/Fixed Wing	38,000
Total	52,000
Source: AirNav information from the World Wide Web, www.airnav.com/cgi-bin/airport.info?SZP, and interview with airport manager.	

For purposes of the noise analysis, it was assumed that the current fleet mix would be a reasonable projection of the forecast fleet mix since no growth in operations is projected nor are any significant changes to the airfield.

4.7.3 RUNWAY USE

The airport manager estimates that 90 percent of arrivals and departures are on Runway 22. This is because of the prevailing westerly winds and the designation of the runway as the calm wind runway.

4.7.4 FLIGHT TRACKS

Exhibit 4E, Santa Paula Airport Generalized Flight Tracks, shows the prevailing flight tracks at the airport. The tracks designating the traffic pattern are based on the published pilot guide.

4.8 AIRPORT NOISE EXPOSURE

Exhibit 4F, 2015 Noise Exposure -- Santa Paula Airport, shows noise contours for the airport based on both current and projected future conditions in the year 2015. The 60 CNEL noise contour is cigar shaped with a small arrival spike to the northeast of the airport. It extends 3,000 feet west of the runway end and 600 feet east of the runway end. At its widest point, the 60 CNEL contour spans 1,800 feet., centered on the runway. The 65 CNEL contour has a similar shape as the 60 CNEL but without the arrival spike on the east side. It extends 1,500 feet off the west end of the runway. The 70 and 75 CNEL noise contours remain close to Runway 4-22 and are elongated about the runway centerline.

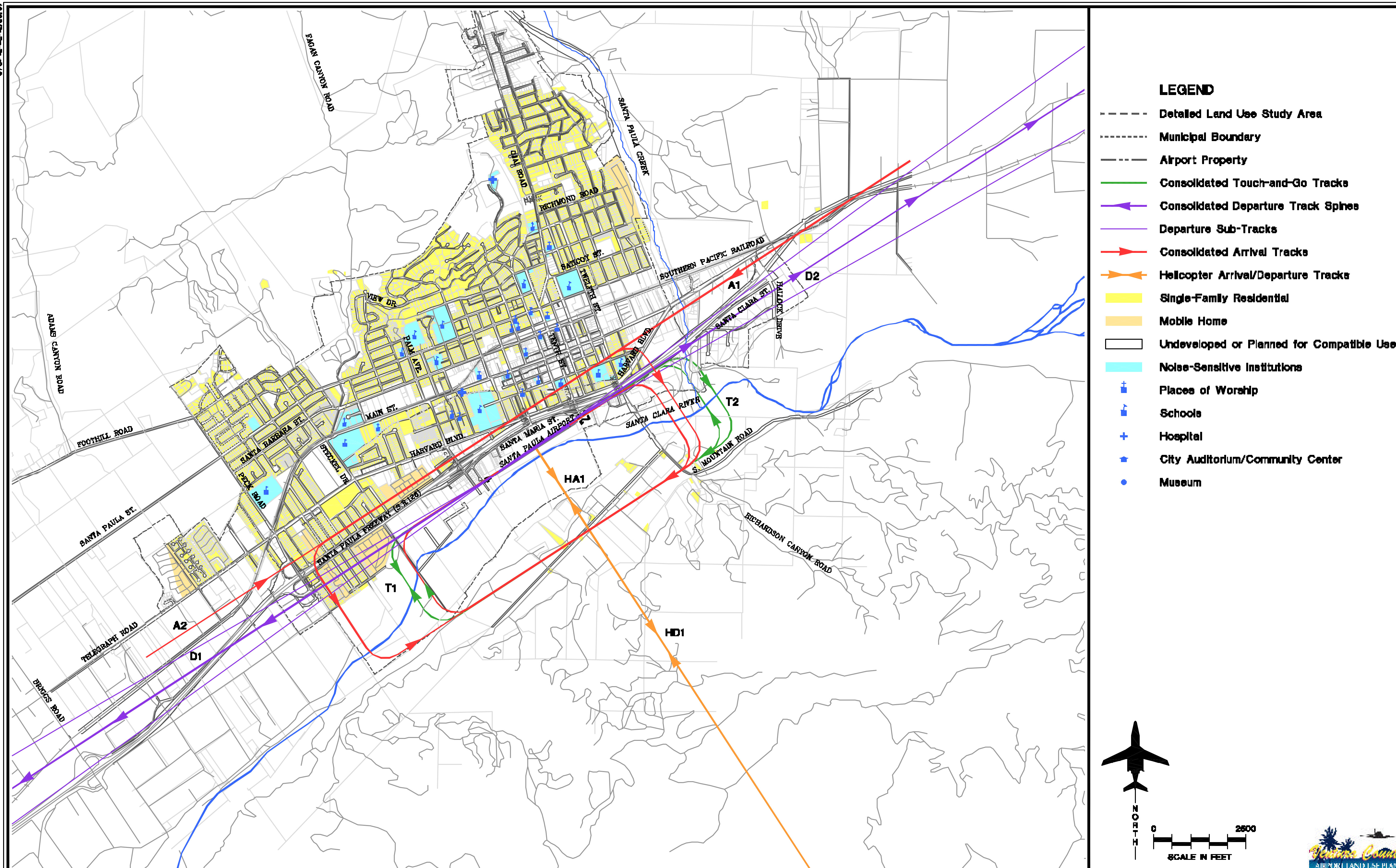


Exhibit 4E
SANTA PAULA AIRPORT
GENERALIZED FLIGHT TRACKS

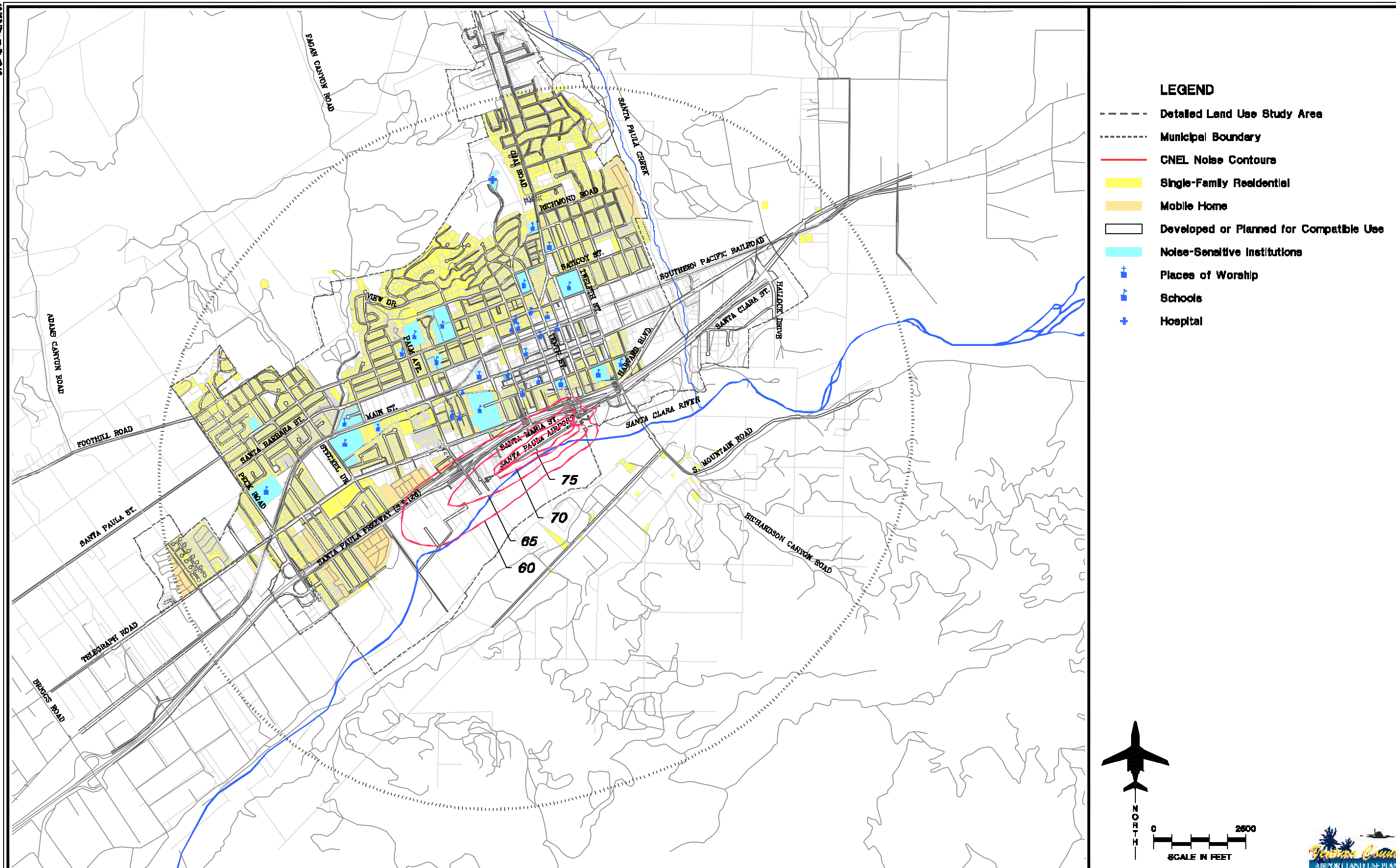


Exhibit 4F
2015 NOISE EXPOSURE
SANTA PAULA AIRPORT

TABLE 4C
Annual Operations by Aircraft Type
Santa Paula Airport

	1997 and 2015
Itinerant Operations	
General Aviation	
Twin Engine	660
Light Single-Variable Pitch Prop.	6,270
Light Single-Fixed Pitch Propeller	6,270
Bell 206 Helicopter	800
Subtotal--Itinerant	14,000
Local Operations	
GENERAL AVIATION	
Light Twin	1,900
Light Single-Variable Pitch Prop.	18,050
Light Single-Fixed Pitch Propeller	18,050
Subtotal--Local	38,000
Total	52,000

Source: Estimates by Coffman Associates based on AirNav information (www.airnav.com/cgi-bin/airport.info?SZP) and interview with airport manager.

The shape of the contours reflects the prevailing runway use. Most departures are to the southwest on Runway 22. Since departures are generally louder than arrivals, the noise contours are larger to the southwest.

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Ventura County
AIRPORT LAND USE PLAN

Chapter Five
NAS POINT MUGU AND ENVIRONS

Chapter Five
NAS POINT MUGU AND ENVIRONS

This chapter presents an overview of Naval Air Station (NAS) Point Mugu and the surrounding area. The information in this chapter includes:

- A description of the study area and existing land uses in the area.
- A discussion of the local land use planning and regulatory framework in the study area.
- A description of key aviation facilities and navigational aids.
- A description of noise abatement procedures, airport activity, and flight tracks.
- A description of noise exposure around the airport.

5.1 AIRPORT SETTING

NAS Point Mugu lies approximately six and one-half miles southeast of Oxnard on the Pacific coast. Access to the facility is provided by State Route 1 which defines the eastern boundary of the base.

5.2 STUDY AREA

Exhibit 5A, NAS Point Mugu Study Area and Jurisdictional Boundaries, shows an area of nearly 88 square miles around Point Mugu. It includes most of the City of Port Hueneme, much of the City of Oxnard, the south part of the City of Camarillo, and a small part of the City of Thousand Oaks. Much of the area on the map is unincorporated Ventura County.

In the middle of the map is an irregular shaped area designated the "detailed land use study area." The size and shape of the area accommodates the outer boundary of the F.A.R. Part 77 conical surface and the 60 CNEL noise contour around the airport. Existing and future land use designations will be mapped in this area. It is anticipated that airport compatibility concerns will be concentrated within the detailed land use study area.

5.3 EXISTING LAND USE

Exhibit 5B, Generalized Existing Land Use in Point Mugu Area, shows existing land use in the study area. The land use classification system, shown in **Table 5A**, has been designed to fit the requirements of airport noise compatibility planning. Residential land use and noise-sensitive institutions are identified. The other land use categories, which are generally considered to be compatible with aircraft noise, include commercial, industrial, transportation, and utilities; agriculture; parks and open space; and undeveloped land.

Most of the study area is farmland. Commercial, industrial, transportation, and utilities uses are concentrated at NAS Point Mugu and along the coast to the west. The commercial-industrial uses dotting the study area are agriculture-related uses such as greenhouses and storage and processing buildings. Residential areas lie to the west in Oxnard, to the north in Camarillo, and at the Point Mugu facility itself. Three noise-sensitive uses are in the study area, including two schools in Oxnard and the sprawling campus of the Camarillo State Hospital directly northeast of NAS Point Mugu.

5.4 LAND USE PLANNING POLICIES AND REGULATIONS

The State of California requires all local governments to enact a "general plan" establishing framework policies for future development of the city or county. (See Government Code, Sections 65300, *et seq*.) The local general plan is the most important land use regulatory instrument in California. It establishes overall development policy and provides the legal foundation for all other kinds of land use and development regulation in the community. According to California law, the general plan must contain at least seven elements: land use, circulation, housing, conservation, open space, noise, and safety (Curtin 1996, pp. 9-10). Other elements may be prepared as needed and desired.

The policies of the general plan are implemented through ordinances regulating development. Chief among these is the zoning ordinance. Zoning regulates the use of land, the density of development, and the height and bulk of buildings. Subdivision regulations are another important land use regulatory tool, regulating the platting of land. Local communities also regulate development through building codes which set detailed standards for construction.

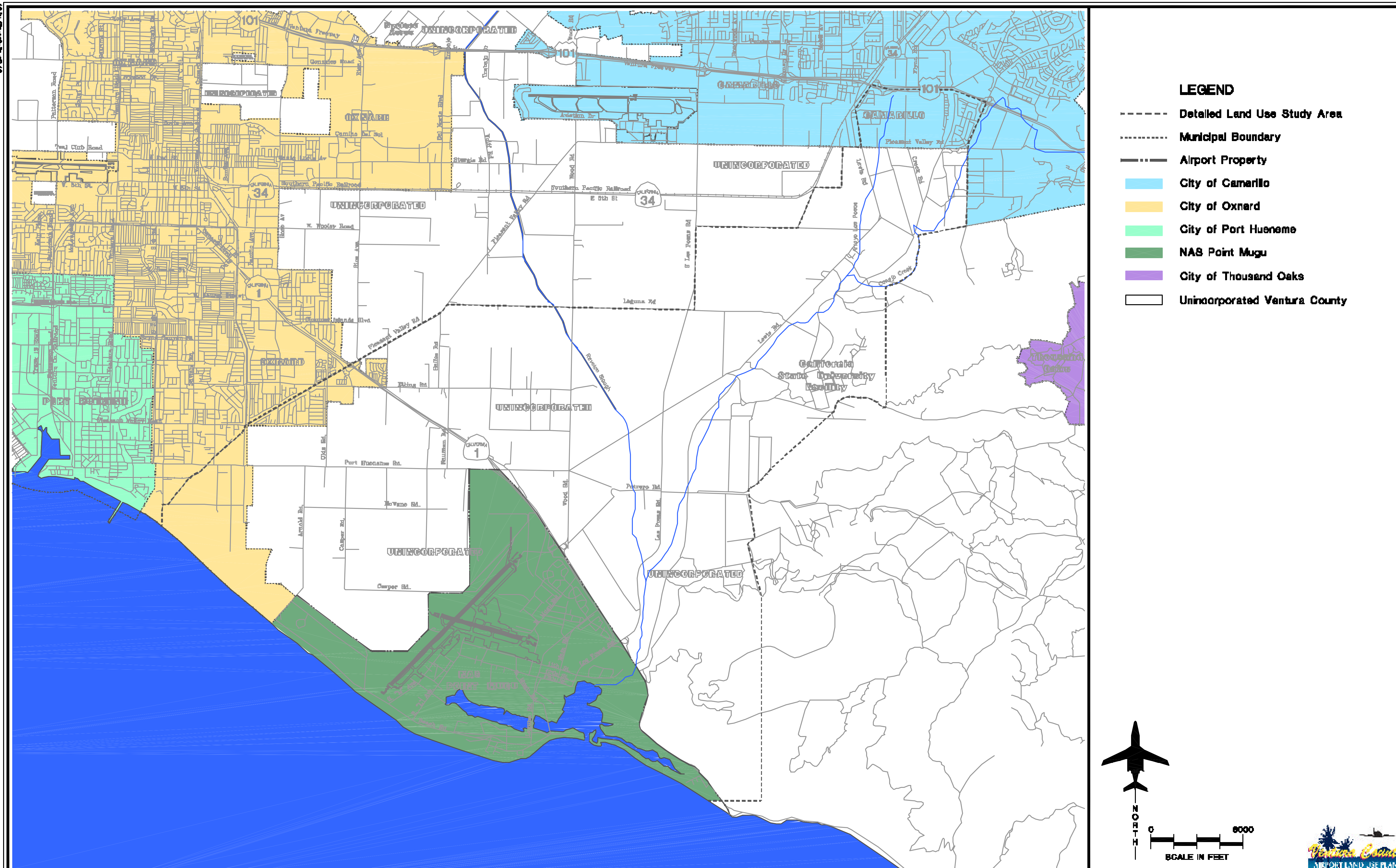

Exhibit 5A
NAS POINT MUGU STUDY AREA
AND JURISDICTIONAL BOUNDARIES

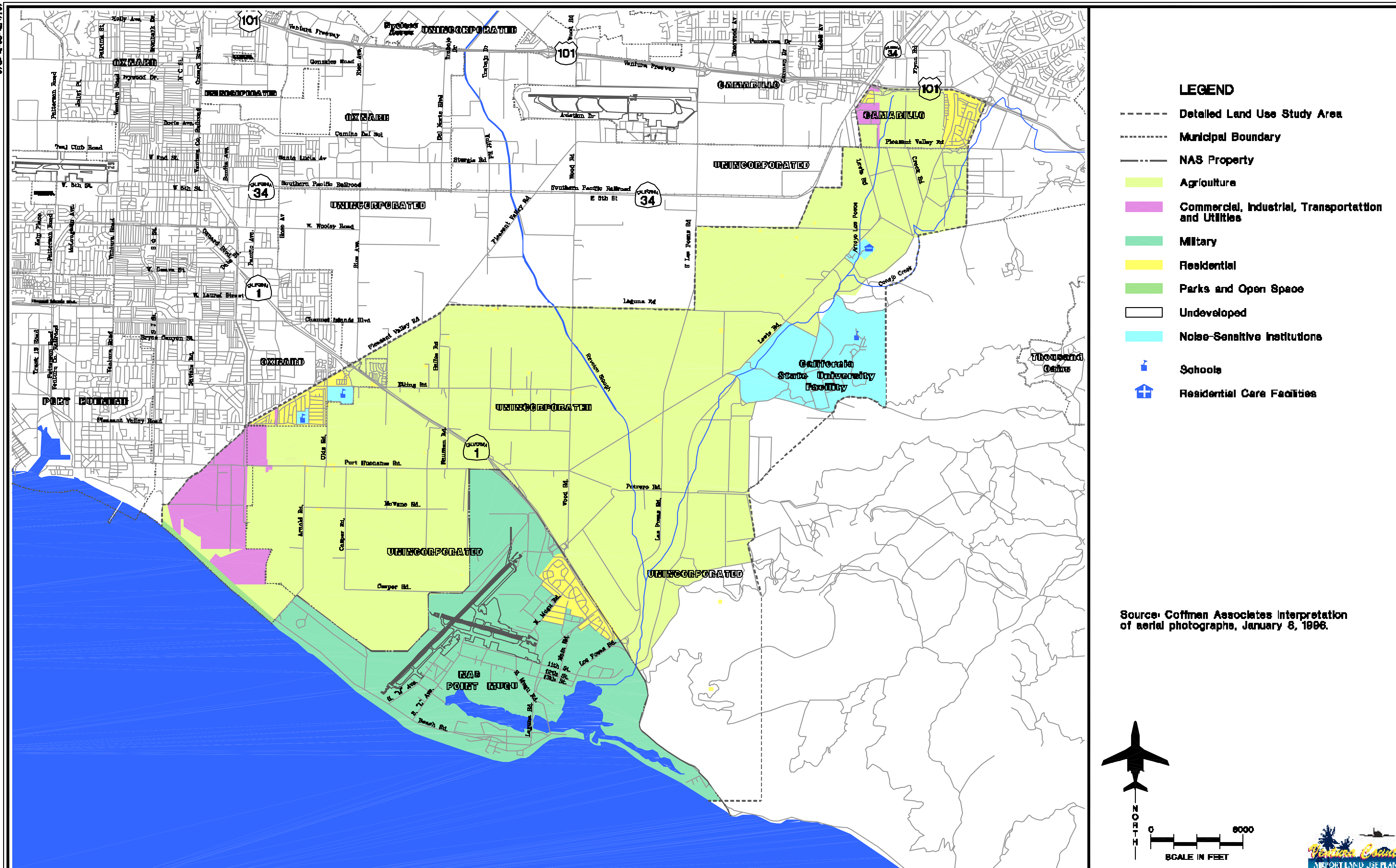

Exhibit 5B
GENERALIZED EXISTING LAND USE
IN POINT MUGU AREA

TABLE 5A
Land Use Categories Shown on Existing Land Use Map

Category	Land Uses Included
Residential	Single-family homes; Duplexes; Townhouses; Apartment and condominium buildings; Mobile and manufactured homes.
Commercial, Industrial, Transportation, Utilities	Businesses; Offices; Industrial uses; Utilities; Transportation facilities; Intensively developed commercial agriculture areas including equipment storage areas and greenhouses.
Noise-Sensitive Institutions	Places of worship; Schools; Nursing homes; Residential group quarters; Hospitals; Community centers.
Agriculture	Orchards; Cultivated fields.
Parks and Open Space	Parks; Golf courses; Cemeteries; Ponds; Nature preserves.
Undeveloped	Vacant lots; Open parcels of uncultivated land.

Exhibit 5C, Future Land Use Plan in Point Mugu Area, shows the land use designations of the general plans in the study area. This section briefly summarizes the general plans of the study area jurisdictions. A more detailed discussion of each jurisdiction's general plan is in Appendix B.

5.4.1 CAMARILLO GENERAL PLAN

The Land Use Element of the Camarillo General Plan establishes the basic pattern for future development of the City (City of Camarillo 1996, p. 28). The main theme of the Land Use

Element is the desire to preserve the quality of life that exists through much of the area and specifically to "promote Camarillo as a rural suburban community that has a quality, small town, family atmosphere." It includes sets of principles, standards, and proposals for each of seven land use categories: agricultural, residential, commercial, industrial, urban reserve, public uses, and quasi-public uses.

The Noise Element of the General Plan establishes policies that promote compatible land uses within areas exposed to high noise levels. Exhibit B1 in Appendix B shows guidelines used in Camarillo to assess the compatibility of proposed land uses with noise of various magnitudes. The policies also require developers of proposed residential and noise-sensitive uses within a 60 CNEL contour to submit noise study reports for both exterior and interior living spaces. Interiors must be sound-insulated to achieve an indoor noise level of 45 CNEL or less (City of Camarillo 1996, p. 420).

The General Plan Map designates proposed land uses throughout the City's sphere of influence. The "sphere of influence" is an area defined by the Local Agency Formation Commission (LAFCO) which delineates the limits beyond which a city cannot annex territory. It includes the land within the city limits and unincorporated land within the City's service area.

Exhibit 5C shows the Camarillo General Plan land use designations within the NAS Point Mugu study area. Only a small area at the extreme northern end of the study area, generally lying between the Ventura Freeway (U.S. 101) and Pleasant Valley Road, is covered by the Camarillo General Plan. It shows a combination of residential, agricultural, and industrial land use

5.4.2 OXNARD GENERAL PLAN

The Oxnard General Plan was adopted in 1990. It includes eleven planning elements: growth management, land use, circulation, public facilities, open space/conservation, safety, noise, economic development, community design, parks and recreation, and housing. The Noise Element includes several goals and policies related to airport compatibility planning (City of Oxnard 1990, p. IX-16). The most directly relevant says that "municipal policies shall be consistent with the Ventura County Airport Comprehensive Land Use Commission's adopted land use plan..."

The City also has developed a Coastal Land Use Plan for the coastal zone (City of Oxnard 1982.) Policies and land use designations of the Coastal Land Use Plan have been incorporated into the City's General Plan.

Exhibit 5C shows the future land use plan for the Oxnard portion of the Oxnard Airport study area. Land west and northwest of Point Mugu in the Oxnard planning area is designated for a combination of commercial-industrial, medium to high density residential, and low density residential uses.

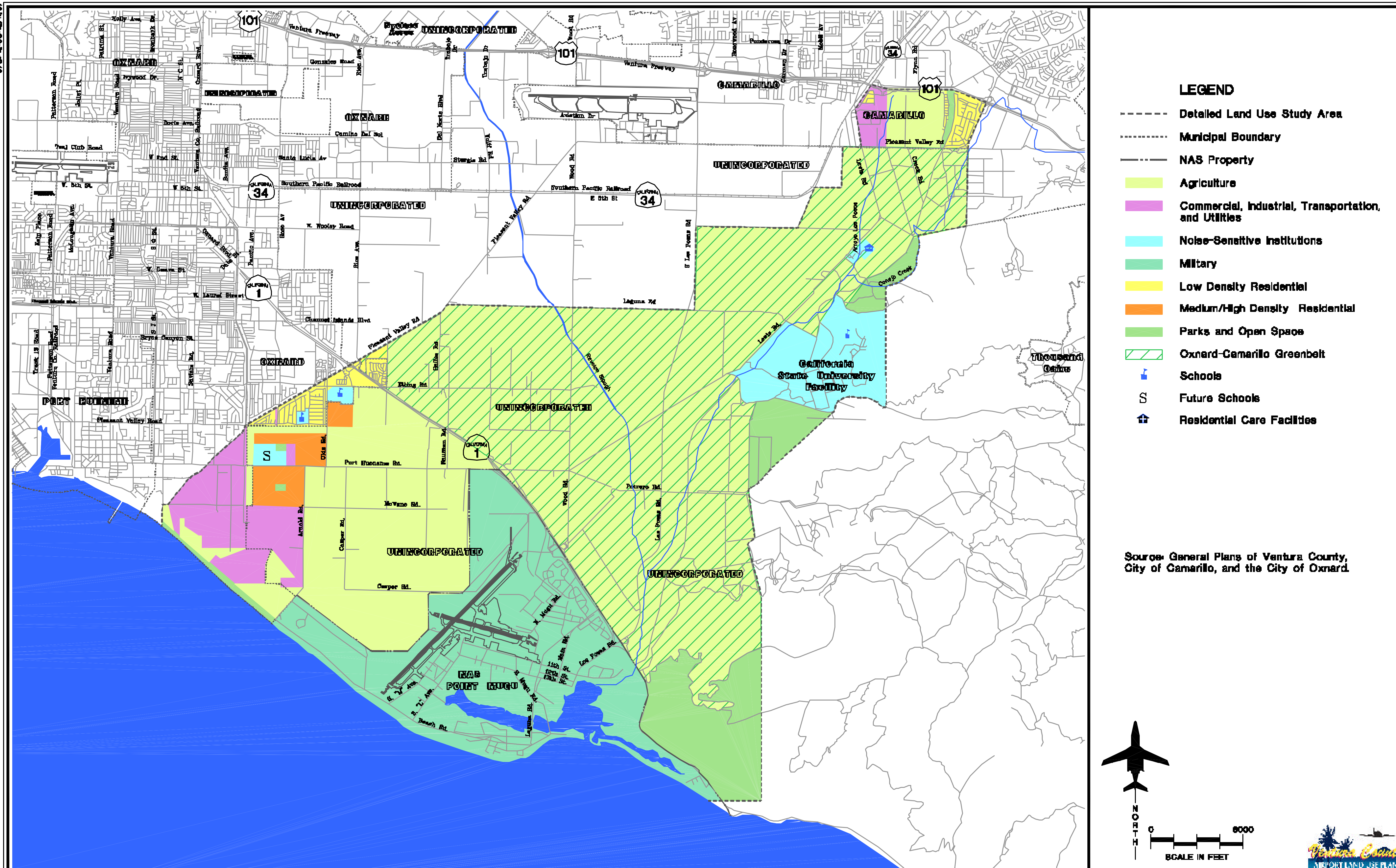

Exhibit 5C
FUTURE LAND USE PLAN
IN POINT MUGU AREA

5.4.3 VENTURA COUNTY GENERAL PLAN

The Ventura County General Plan was adopted in 1988 and has been amended several times since then. The Plan includes several documents. The overall framework of goals and policies is in a document called *Goals, Policies and Programs* (Ventura County 1996a.) Supporting documentation is in a series of technical appendices (Ventura County 1994a, 1994b, 1994c, 1996b). The General Plan also includes several area plans where local issues and concerns are dealt with in greater detail than in the framework document. Ventura County also has *Coastal Area Plan* (Ventura County 1996c). It establishes various land use and conservation policies in the coastal zone.

As shown in **Exhibit 5C**, most of the area within the County's jurisdiction in the NAS Point Mugu Study Area is designated as agriculture. Agriculture is a major industry in Ventura County. The County General Plan establishes policies to encourage the preservation of prime farmland. Among them is a policy to retain and expand existing Greenbelt Agreements in the County and to encourage the formation of additional agreements (Ventura County 1996a, p. 21). Greenbelt agreements have been formed between various cities in Ventura County. They delineate areas between the cities which are declared off limits to urban development and are to be preserved for agriculture and open space. The cities of Oxnard and Camarillo have a greenbelt agreement for much of the area between the two cities, part of which is in the Point Mugu study area.

Other land uses designated in the Ventura County General Plan include the Camarillo State Hospital and small amounts of open space along the east edges of the study area.

The County General Plan also includes policies relating to airport hazards and noise compatibility. Land in airport approach and departure zones is to be designated for agriculture or open space uses (Ventura County 1996a, p. 20). Noise-sensitive land uses are not permitted where airport noise exceeds 65 CNEL. These uses may be permitted in the 60 to 65 CNEL contour only if measures are taken to reduce interior noise levels to 45 CNEL or less.

5.5 *AIRPORT FACILITIES*

Existing facilities at NAS Point Mugu are shown in **Exhibit 5D, NAS Point Mugu Airport Layout Plan**.

5.5.1 RUNWAYS

NAS Point Mugu is served by two paved runways -- Runway 3-21 which is 11,100 feet long by 200 feet wide, and Runway 9-27 which is 5,500 feet long by 200 feet wide. Runway 3-21 is the main runway and serves most takeoffs and landings.

5.5.2 TAXIWAYS

Runway 3-21 is served by partial parallel taxiways on the east side in addition to four exit taxiways. Runway 9-27 is served by a full length parallel taxiway on the south side of the runway in addition to two exit taxiways. **Exhibit 5 D** shows the location of the taxiways.

5.5.3 AIRCRAFT ACTIVITY AREAS

Aircraft parking ramps are located on both sides of Runway 9-27 and on the east side of Runway 3-21. Numerous hangars and aviation support buildings adjoin the ramps.

5.5.4 INSTRUMENT APPROACHES

Instrument approaches are defined using electronic and visual navigational aids to assist pilots in landing when visibility is reduced below specified minimums. Instrument approaches are classified as precision and nonprecision. Both provide runway alignment and course guidance, while precision approaches also provide glide slope information for the descent to the runway.

NAS Point Mugu has both precision and non-precision approaches to Runways 3 and 21. Runways 9 and 27 have only visual approaches.

5.6 AVIATION ACTIVITY

Airport activity data are needed for noise modeling and for establishing airport safety zones and standards. Among the most important information is the number of aircraft operations (takeoffs and landings), the mix of aircraft types using the airport, runway use percentages, and flight tracks. This section summarizes key airport activity data.

5.6.1 OPERATIONS

Air traffic activities at NAS Point Mugu are recorded by the Air Traffic Control Tower. **Table 5B** summarizes annual operations at Point Mugu for 1995 and 1996. They are classified as military, air carrier, and general aviation. The air carrier category includes special charter flights carrying military personnel. The general aviation category includes operations by contractors or rented aircraft.

In 1995, operations totaled 25,166. They increased by nearly 50 percent to 37,334 in 1996. Military activity increased by nearly 10,000 operations from 1995 to 1996.

Exhibit 5D
NAS POINT MUGU
AIRPORT LAYOUT PLAN

TABLE 5B Annual Operations (Takeoffs and Landings) History -- 1995 and 1996 NAS Point Mugu				
Year	**Military**	**Air Carrier**	**General Aviation**	**Total**
1995	19,866	1,183	4,117	25,166
1996	29,497	1,898	5,939	37,334

Source: Air Traffic Activity Reports from Point Mugu ATC.

5.6.2 FLEET MIX

In 1997, nine different military aviation units were based at NAS Point Mugu. The aircraft include 23 C-130s, 18 F-14s, 14 P-3s, 11 F-4s, and 8-HH-60 helicopters. The FBI has two light aircraft and two helicopters based at Point Mugu. Four other turbo prop aircraft (one CV-340 and three CV-580) are used to shuttle personnel from base to base. In addition, F/A-18 aircraft based at China Lake frequently use Point Mugu for weapons systems operations. Transient and rental helicopters are often used at the facility for target retrieval and for transporting personnel (Norris 1997). A wide variety of transient aircraft use Point Mugu on occasion.

In 1990, an aircraft noise study was done for Point Mugu (HMMH 1990). The noise contours developed in that study were used in the 1992 AICUZ Study (Dames & Moore 1992). **Table 5C** shows the operational fleet mix used in developing that noise analysis. Helicopters (H-46, H-60, UH-1, and "transient") accounted for over 35 percent of operations (takeoffs and landings). The C-130 was the next most frequently used aircraft at 14.9 percent, followed by the F-18 at 13.4 percent. The P-3 was next with 8.5 percent. F-14s and A-7s accounted for 6.6 and 6.5 percent of operations, respectively. All other aircraft types accounted for less than five percent each.

5.6.3 RUNWAY USE

According to the 1992 AICUZ study, Runway 21 was the most commonly used runway accounting for 57 percent of arrivals and departures. Runway 3 was used for 23 percent of arrivals and departures. Runway 27 was used for 17 percent, and Runway 9 was used for 3 percent of operations (Dames & Moore 1992, p. 13).

5.6.4 FLIGHT TRACKS

Flight tracks were developed for use in the 1990 *Aircraft Noise Survey* (HMMH 1990). Sketches of flight tracks were developed by individual squadrons and cross-checked with tracings taken from air traffic control radar scopes (Dames

& Moore 1992, p. 10). This process resulted in a dense network of flight tracks, as shown in **Exhibits 5E** through **5J**.

TABLE 5C
Average Busy Day Operations by Aircraft Type -- 1990
NAS Point Mugu

Aircraft	**Percent of Total Operations**
Based Types	
A-3	2.5
A-6	1.1
A-7	6.5
C-12	3.5
C-130	14.9
F-4	3.2
F-14	6.6
F-18	13.4
F-86	1.4
H-46	4.2
H-60 and UH-1	28.8
P-3	8.5
Transient	
T-38	0.8
Other Fixed Wing	2.2
Helicopters	2.4
TOTAL	100.0

Source: HMMH 1990. Cited in Dames & Moore 1992, p. 12.

These flight tracks are generalized for purposes of analysis. Each track indicates the center of a corridor where aircraft can most often be expected. Individual flight paths will vary from time to time depending on a wide variety of circumstances, including weather, winds, pilot technique, air traffic control instructions, and other air traffic in the area.

5.7 AIRPORT NOISE EXPOSURE

Exhibit 5L, 1990 Noise Exposure -- NAS Point Mugu, shows the CNEL noise contours for the facility as presented in the 1992 AICUZ study (Dames & Moore 1992, p. 21). These were developed in a study undertaken in 1990 (HMMH 1990). These were the

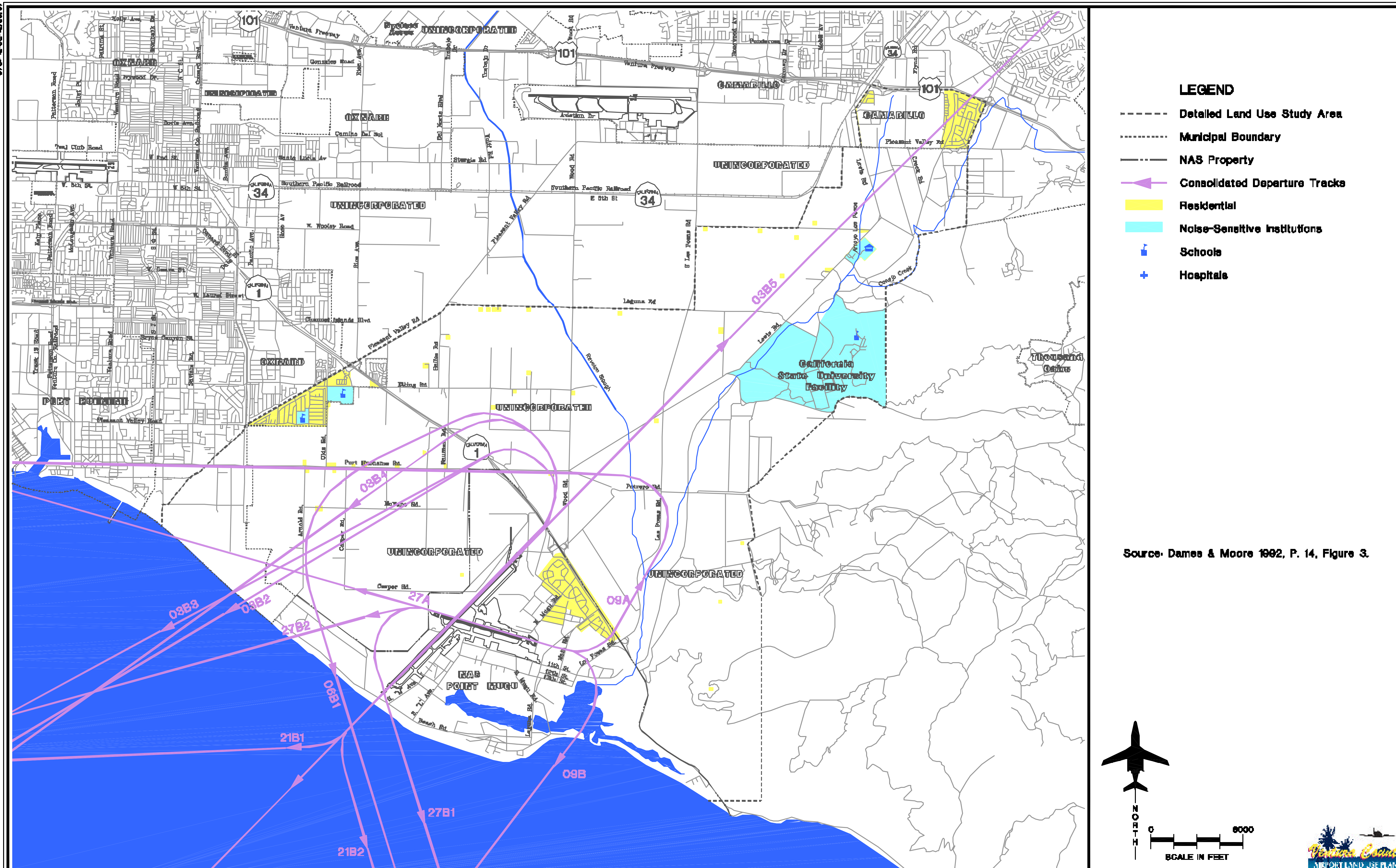

Exhibit 5B
NAS POINT MUGU
FIXED WING DEPARTURE TRACKS

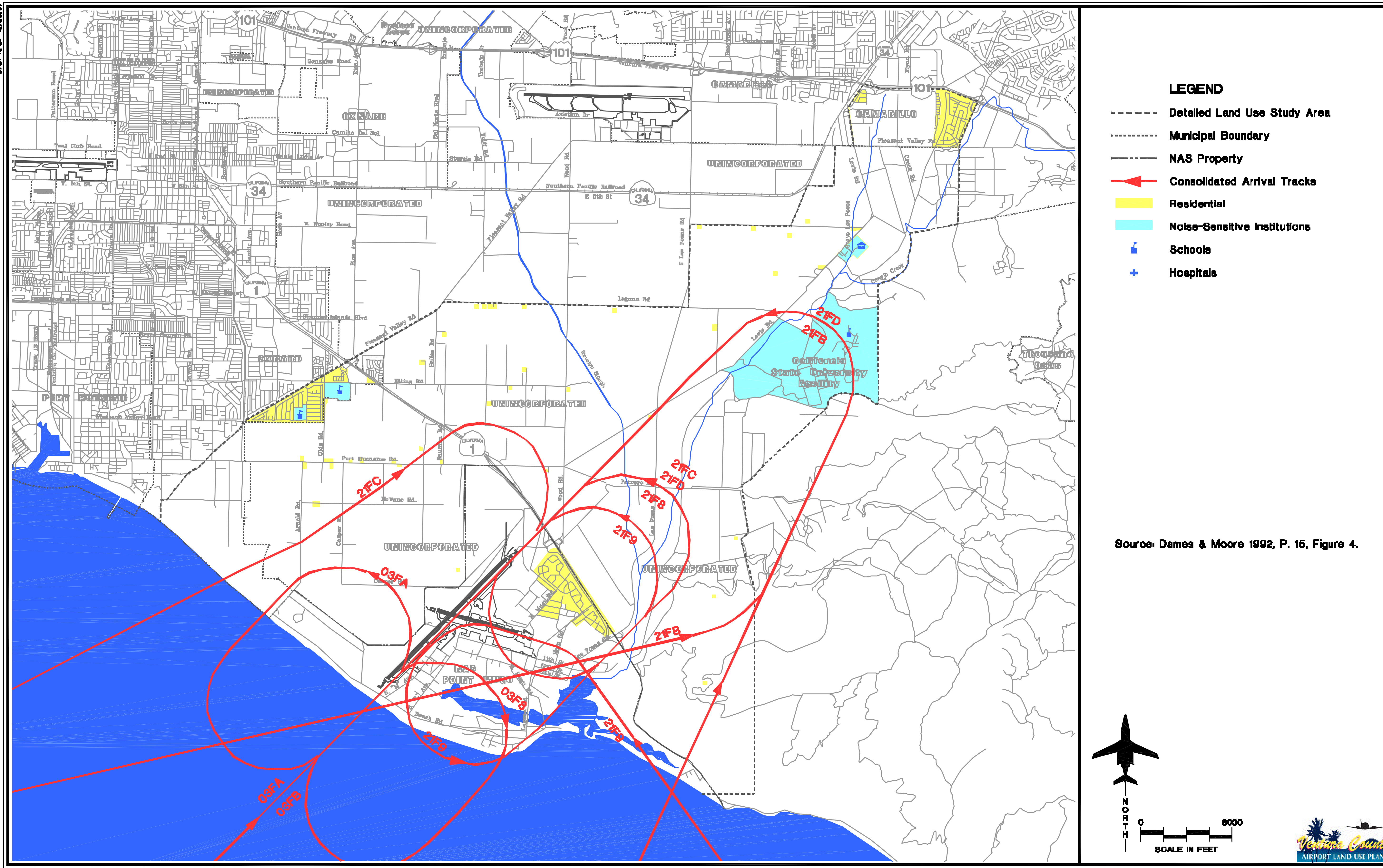

Exhibit 5F
NAS POINT MUGU
OVERHEAD BREAK ARRIVAL TRACKS

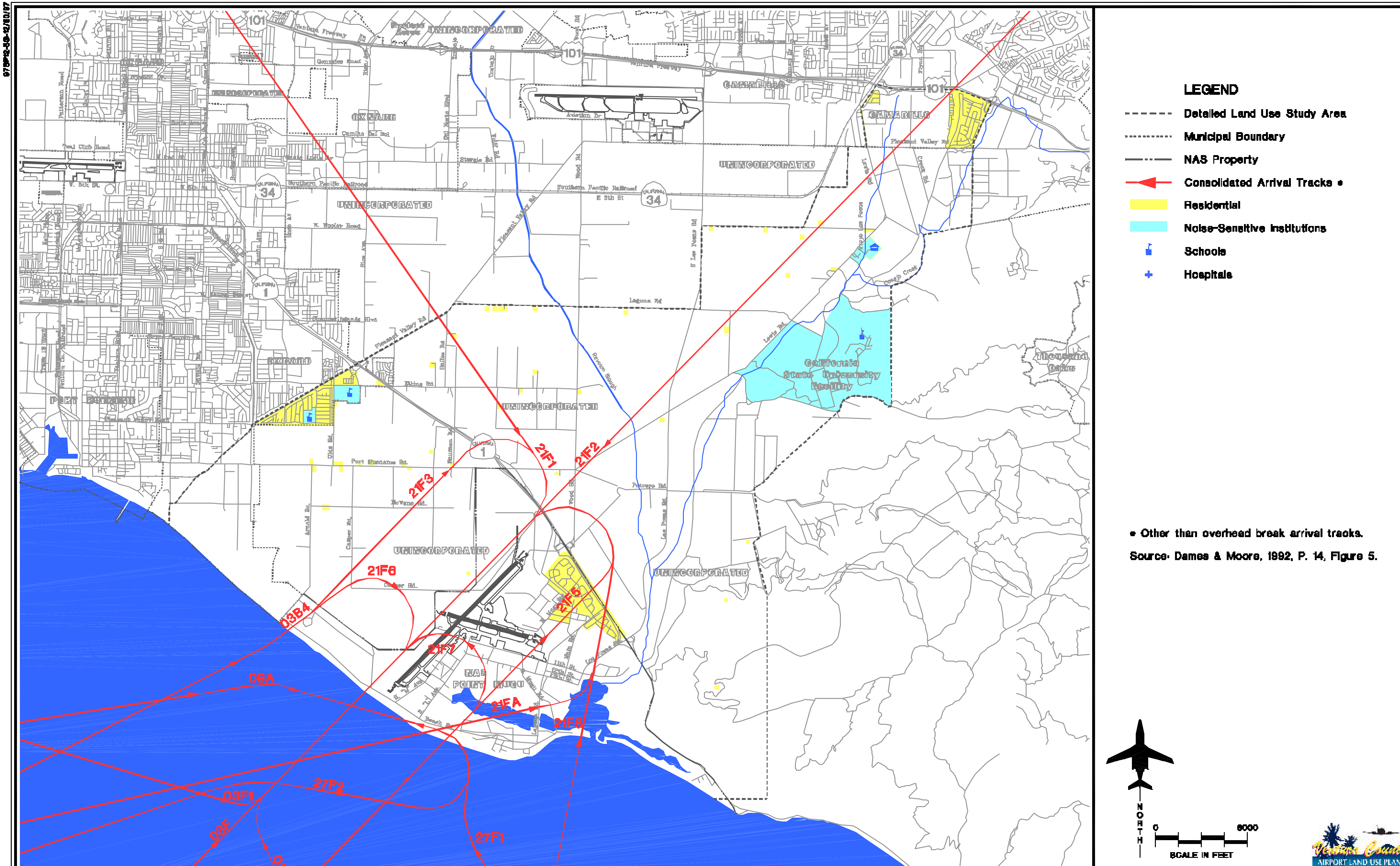

Exhibit 5G
NAS POINT MUGU
FIXED WING ARRIVAL TRACKS

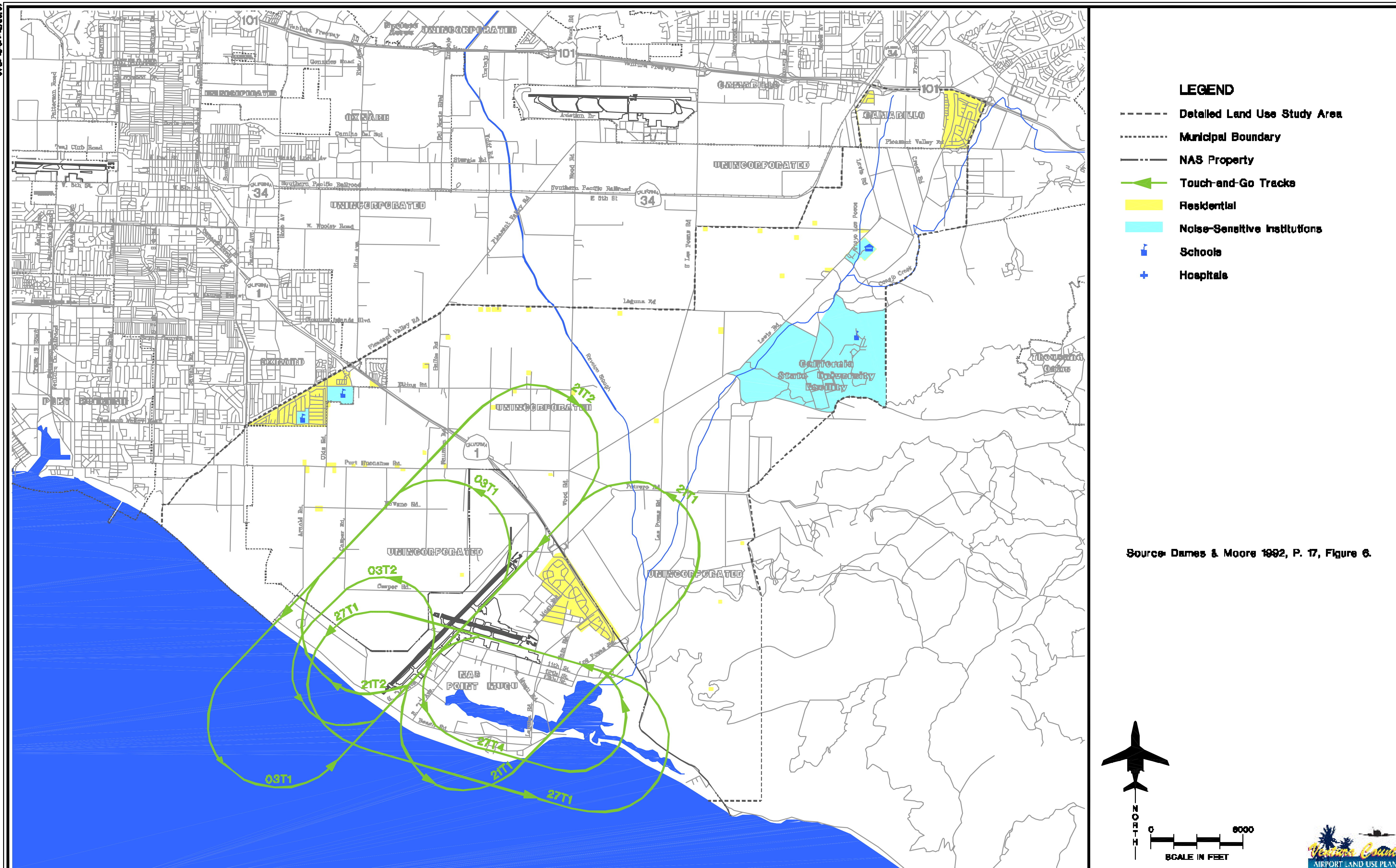

Exhibit 5H
NAS POINT MUGU
FIXED WING PATTERN TRACKS

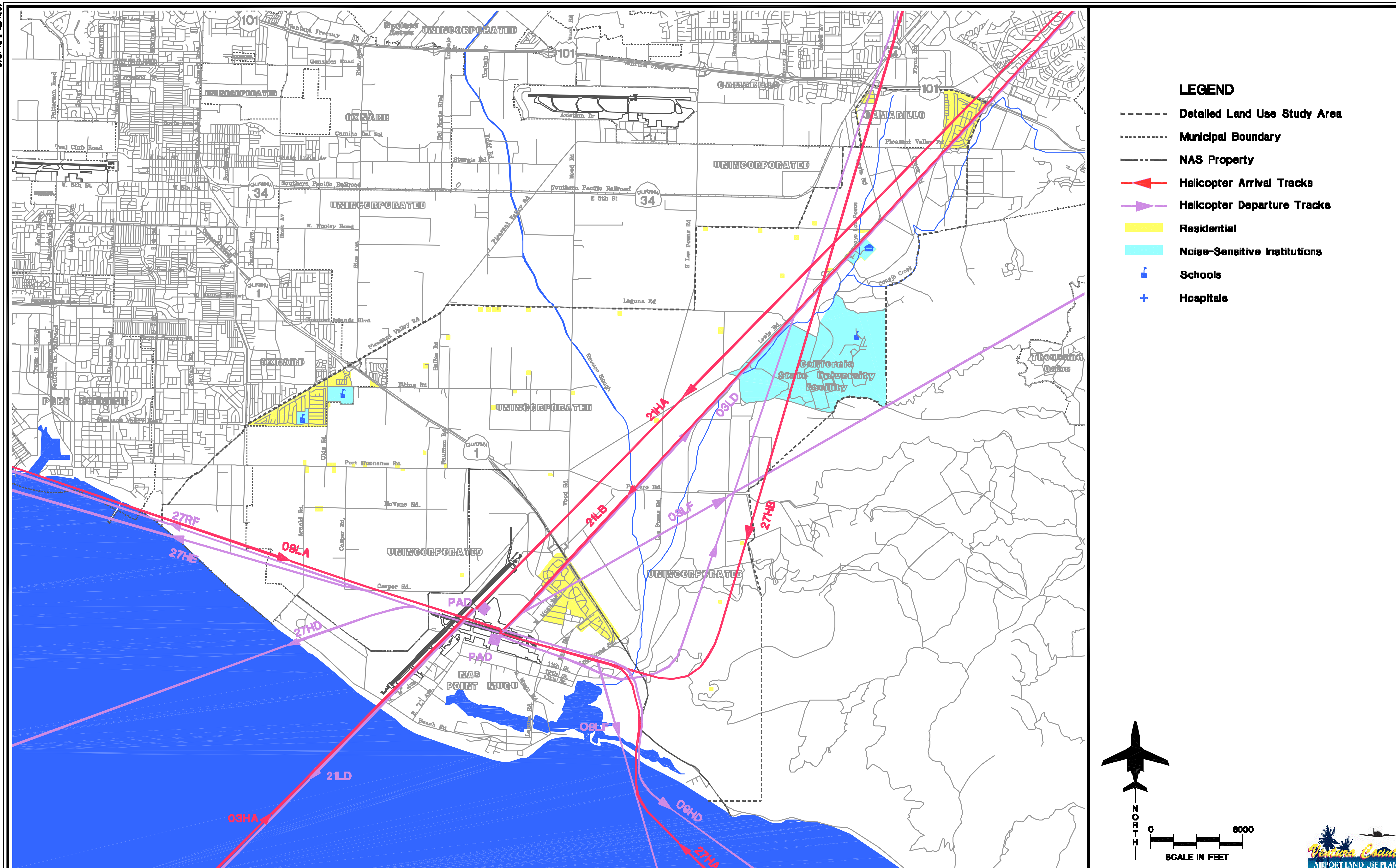

Exhibit 5J
NAS POINT MUGU ROTARY WING
ARRIVAL AND DEPARTURE TRACKS

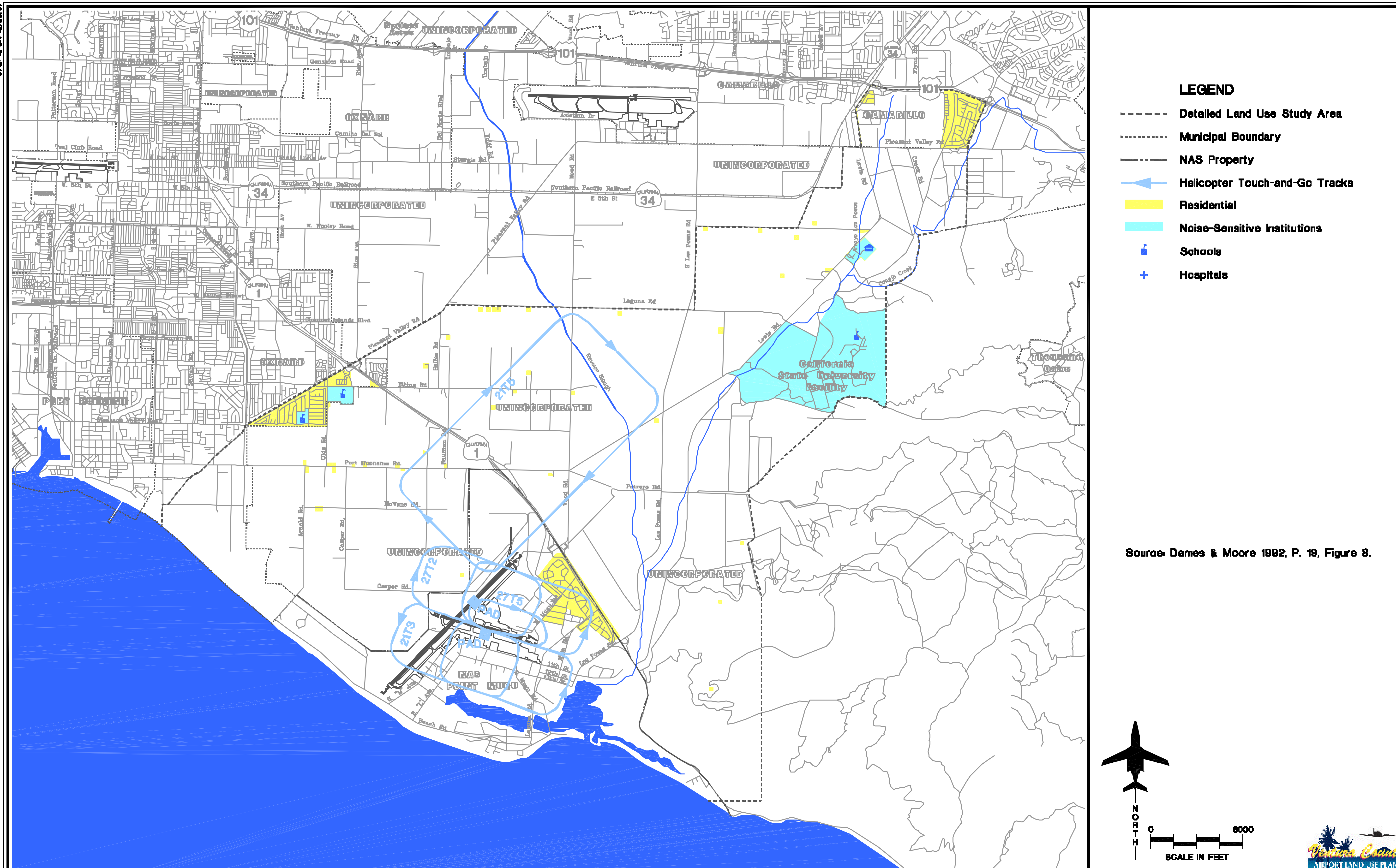

Exhibit 5K
NAS POINT MUGU
ROTARY WING PATTERN TRACKS

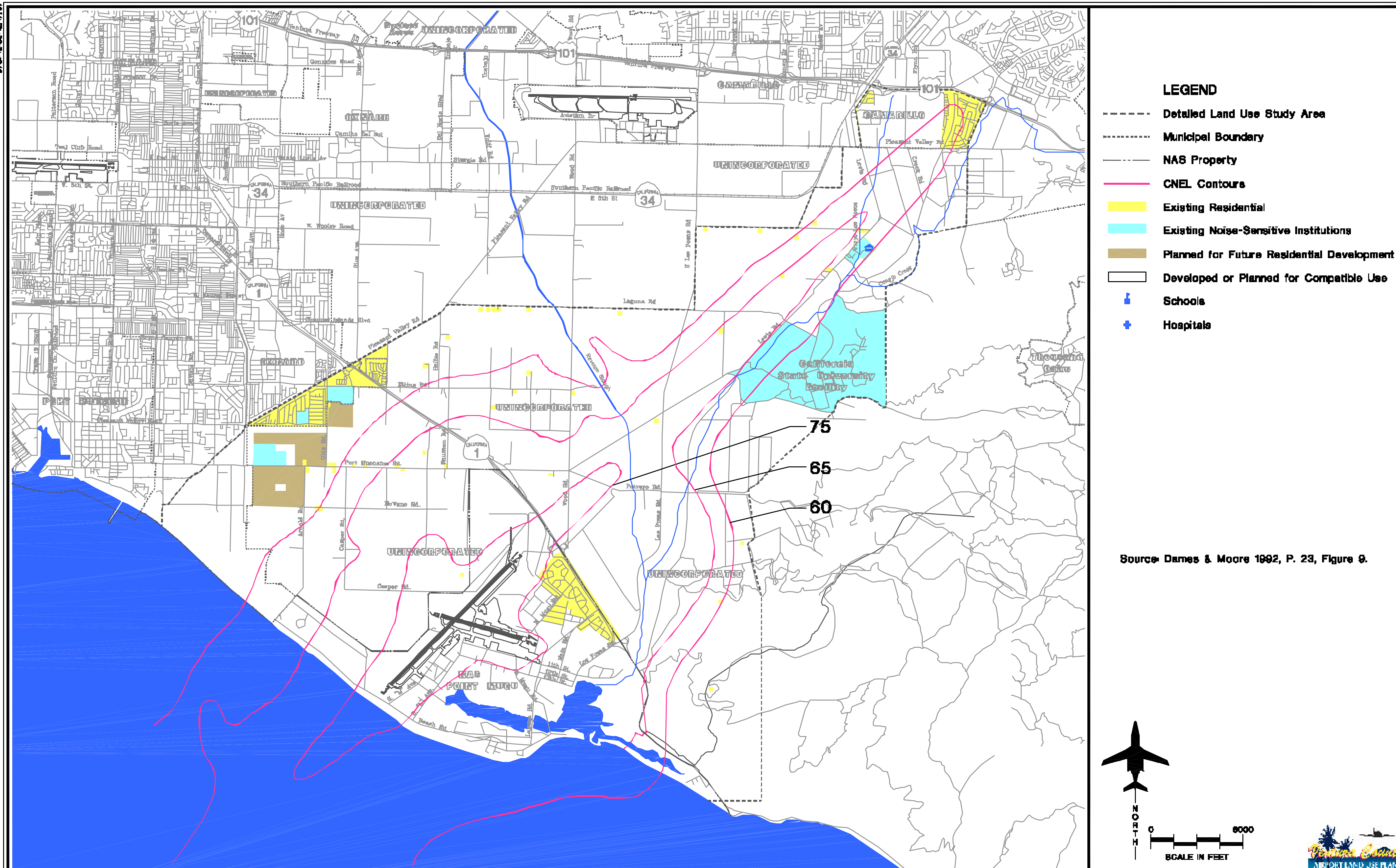

Exhibit 5L
1990 NOISE EXPOSURE
NAS POINT MUGU

only noise contours presented in the AICUZ study. These will be the contours used for planning purposes in the update of the Ventura County Comprehensive Land Use Plan.

The shape of the noise pattern reflects the prevalence of arrivals and departures on Runway 21. The contours are long and narrow to the northeast, reflecting the arrivals to Runway 21. Near the facility, the contours balloon out, reflecting the traffic patterns and overhead approach flight tracks. The 60 CNEL contour extends nearly 42,000 feet northeast of the runway end. At its widest point, it extends 28,000 feet across the airfield.

The 65 CNEL contour has a similar shape as the 60 CNEL contour. It extends 32,000 feet northeast of the runway end and has a width of 24,000 feet.

Most of the 75 CNEL contour is contained on the air station, although it crosses S.R. 1 northeast of Runway 3-21, and extends off the property on the west side of the facility.

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Chapter Six
ADOPTED AIRPORT COMPREHENSIVE LAND USE POLICIES

Chapter Six
ADOPTED AIRPORT COMPREHENSIVE LAND USE POLICIES

This chapter presents the adopted policy framework for noise and safety compatibility and airspace protection at all Ventura County airports.

6.1 *NOISE COMPATIBILITY*

6.1.1 NOISE COMPATIBILITY STANDARDS

The current noise compatibility standards remain substantially as they were in 1991. Some modifications have been adopted; they are reflected in **Table 6A**.

1. The current noise reduction measures should be revised to specify the noise level reduction (NLR) in terms of A-weighted decibels (dBA), rather than CNEL. This is a more standard way of expressing this concept.

2. For all conditionally acceptable land uses, the recording of a fair disclosure agreement and covenant shall be required. (A sample fair disclosure agreement is in Appendix D.)

3. The "recommendation" for noise disclosure covenants and avigation easements for residential uses outside the 60 CNEL but inside the Traffic Pattern Zone has been deleted from the noise compatibility standards table. This has been transferred to the table of safety compatibility standards since it is a requirement relating directly to a safety zone rather than a noise contour.

4. The former footnote "j" has been deleted. It had not been referenced in the original table and more properly relates to safety compatibility standards. (Footnote "j" read as follows: "Land uses involving concentrations of people are unacceptable.")

Table 6A shows the adopted land use compatibility standards related to noise.

TABLE 6A
Adopted Land Use Compatibility Standards Related to Aircraft Noise for Ventura County Airports

	CNEL Range (dB)				
Land Use	**60-65**	**65-70**	**70-75**	**75-80**	**Over 80**
Residential [l]					
Single Family	C [a]	U	U	U	U
Multi-Family	C [a]	U	U	U	U
Mobile Home Parks	U	U	U	U	U
Public/Institutional					
Hospitals/Convalescent Homes	C [a]	C [b]	U	U	U
Schools	C [a]	C [b]	U	U	U
Churches/Synagogues	C [a]	C [b]	U	U	U
Auditoriums/Theaters	C [a]	C [b]	C [c]	U	U
Transportation Terminals	A	A	C [d]	C [e]	C [f]
Communication/Utilities	A	A	C [d]	C [e]	C [f]
Automobile Parking	A	A	C [d]	C [e]	C [f]
Commercial					
Hotels and Motels	C [a]	C [b]	C [c]	U	U
Offices and Business/ Professional Services	A	A	C [g]	C [h]	U
Wholesale	A	A	C [d]	C [e]	C [f]
Retail	A	A	C [g]	C [h]	U
Industrial					
Manufacturing-General/ Heavy	A	A	C [d]	C [e]	C [f]
Light Industrial	A	A	C [d]	C [e]	C [e]
Research and Development	A	A	C [d]	C [e]	C [e]
Business Parks/Corporate Offices	A	A	C [d]	C [e]	C [e]
Recreation/Open Space					
Outdoor Sports Arenas	A	C	C	U	U
Outdoor Amphitheaters	U	U	U	U	U
Parks	A	A	A	U	U
Outdoor Amusement	A	A	A	U	U
Resorts and Camps	A	A	A	U	U
Golf Courses and Water Recreation	A	A	A	U	U
Agriculture	A	A	A	A	A

TABLE 6A (Continued)
Adopted Land Use Compatibility Standards
Related To Aircraft Noise For Ventura County Airports

NOTES

A = Acceptable land use
C = Land use is conditional upon meeting compatibility criteria (see footnotes)
U = Unacceptable land use

A fair disclosure covenant shall be recorded for all conditionally acceptable land uses.

[a] New construction or development may be undertaken only after an analysis of noise reduction requirements and necessary noise insulation is included in the design.

[b] Noise level reduction [NLR] from outdoor to indoor of at least 25 A-weighted decibels (dBA) must be achieved by incorporation of noise attenuation into the design and construction of the structure.

[c] Noise level reduction [NLR] from outdoor to indoor of at least 30 dBA must be achieved by incorporation of noise attenuation into the design and construction of the structure.

[d] Measures to achieve NLR of 25 dBA must be incorporated into the design and construction of portions of these buildings where the public is received, office areas, noise sensitive areas or where the normal noise level is low.

[e] Measures to achieve NLR of 30 dBA must be incorporated into the design and construction of portions of these buildings where the public is received, office areas, noise sensitive areas or where the normal noise level is low.

[f] Measures to achieve NLR of 35 dBA must be incorporated into the design and construction of portions of these buildings where the public is received, office areas, noise sensitive areas or where the normal noise level is low.

[g] Noise level reduction [NLR] of 25 dBA is required.

[h] Noise level reduction [NLR] of 30 dBA is required.

[i] Noise level reduction [NLR] of 35 dBA is required.

6.1.2 REGULATORY NOISE CONTOURS

Noise contours for each airport have been updated to represent the latest information. The contours chosen as the basis for noise compatibility regulation represent the area of noise exposure risk now and into the future.

At Camarillo Airport, a composite set of noise contours are used based on the combination of the 2003 and 2018 forecasts developed in the latest F.A.R. Part 150 Noise Compatibility Study. (This is consistent with the methodology used in the 1991 CLUP.) The forecasts are similar to each other but differ in small ways in different areas. The contours for Camarillo Airport are shown in **Exhibits 6A.**

As the Oxnard Airport Master Plan has not yet been adopted, no changes are recommended for the Oxnard Airport. Therefore, noise contours for the Oxnard Airport will be the same as shown in the 1991 CLUP, which is shown in **Exhibit 6B**.

At Santa Paula Airport, the 2015 forecast contours developed for this study have been used as the regulatory noise contours. These are shown in **Exhibit 6C**.

At NAS Point Mugu, the 1990 contours presented in the most recent version of the Air Installation Compatible Use Zones (AICUZ) Study have been used. These are the most up-to-date noise contours available for that facility and are the same as those in the 1991 CLUP. The contours are shown in **Exhibit 6D**.

6.2 SAFETY COMPATIBILITY

6.2.1 SAFETY ZONES

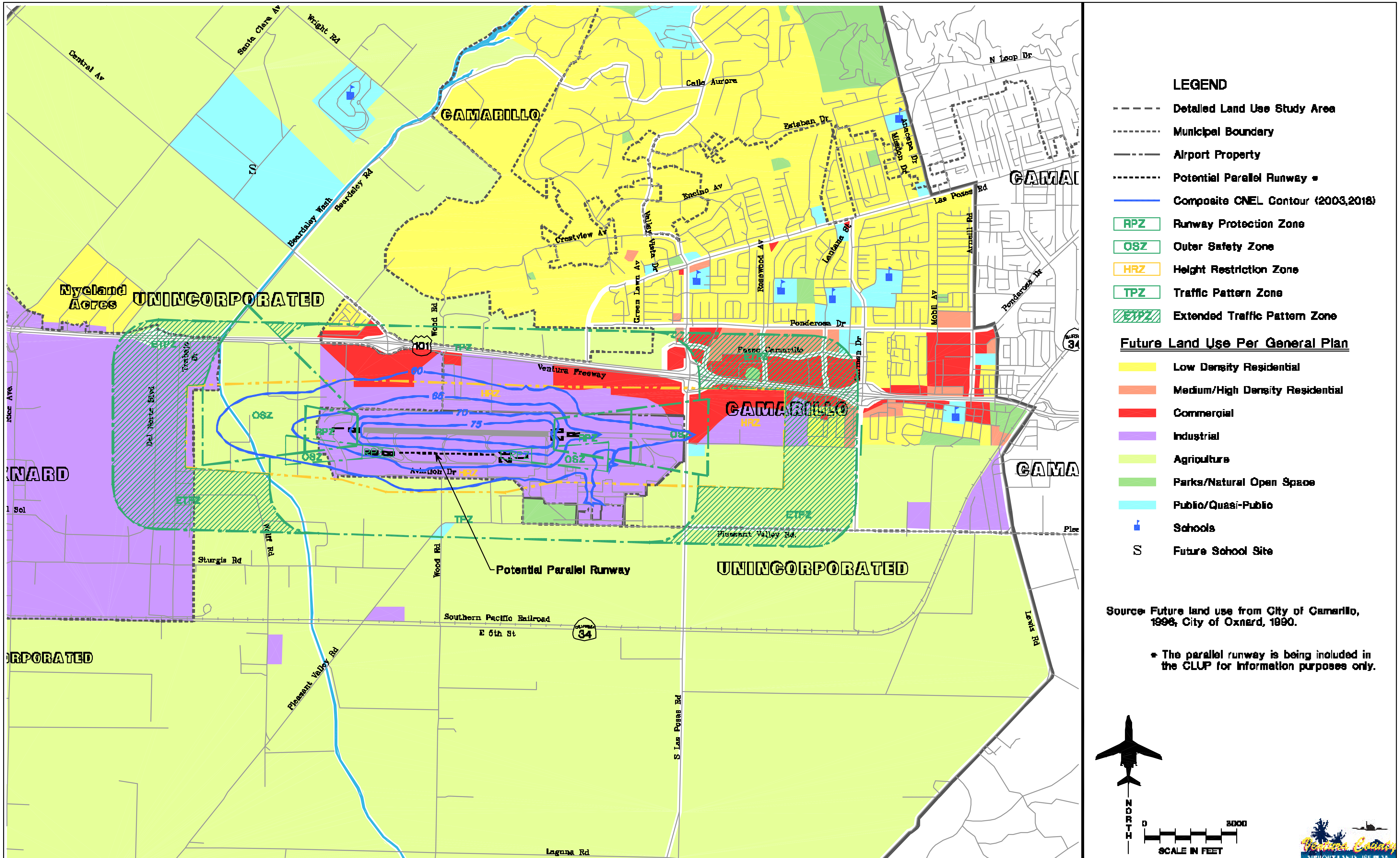
At NAS Point Mugu, a new safety zone has been added. The new zone is called the Traffic Pattern Zone (TPZ) and is based on the outer boundary of the F.A.R. Part 77 horizontal surface. The horizontal surface extends 7,500 feet off all runway ends. All other zones remain as shown in the latest version of the AICUZ study. The NAS Point Mugu safety zones are shown in **Exhibit 6D**.

At the civilian airports, several adjustments have been made.

1. The Inner Safety Zone (ISZ) has been renamed the Runway Protection Zone (RPZ) and corresponds with the RPZ as shown in the latest adopted Master Plan/Airport Layout Plan for each airport.

2. The Outer Safety Zones (OSZ) continues to be located immediately outside the RPZ and has been adjusted in width depending on any changes made in the RPZ. At Camarillo, they should continue to extend out 5,000 feet from the edge of the primary surface. At Santa Paula, they should extend out 3,500 feet from the edge of the primary surface. (The primary surface ends 200 feet off the runway end.)

3. At Camarillo, the OSZ off the west end of the runway has been adjusted to reflect the common right turns made by departing aircraft. The north boundary has been drawn at a 45-degree angle from the extended runway centerline, starting at the northeast corner of the RPZ. It should extend out 5,000 feet. (This is a small adjustment in the zone as formerly mapped. It had used an angle of approximately 41 degrees which appears to have been a mapping error.)


LEGEND
Detailed Land Use Study Area
Municipal Boundary
Airport Property
Potential Parallel Runway *
Composite CNEL Contour (2003,2018)
RPZ Runway Protection Zone
OSZ Outer Safety Zone
HRZ Height Restriction Zone
TPZ Traffic Pattern Zone
ETPZ Extended Traffic Pattern Zone
Future Land Use Per General Plan
Low Density Residential
Medium/High Density Residential
Commercial
Industrial
Agriculture
Parks/Natural Open Space
Public/Quasi-Public
Schools
S Future School Site
Source: Future land use from City of Camarillo, 1996, City of Oxnard, 1990.
* The parallel runway is being included in the CLUP for information purposes only.
NORTH
0 3000
SCALE IN FEET
Ventura County AIRPORT LAND USE PLAN
CAMARILLO
UNINCORPORATED
Nyeland Acres
Potential Parallel Runway
Ventura Freeway
Southern Pacific Railroad
E 5th St
Pleasant Valley Rd
Las Posas Rd
Ponderosa Dr
Central Av
Santa Clara Av
Wright Rd
Beardsley Wash
Beardsley Rd
Calle Aurora
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Sturgis Rd
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S Las Posas Rd
Aviation Dr
Paseo Camarillo
60
65
70
75

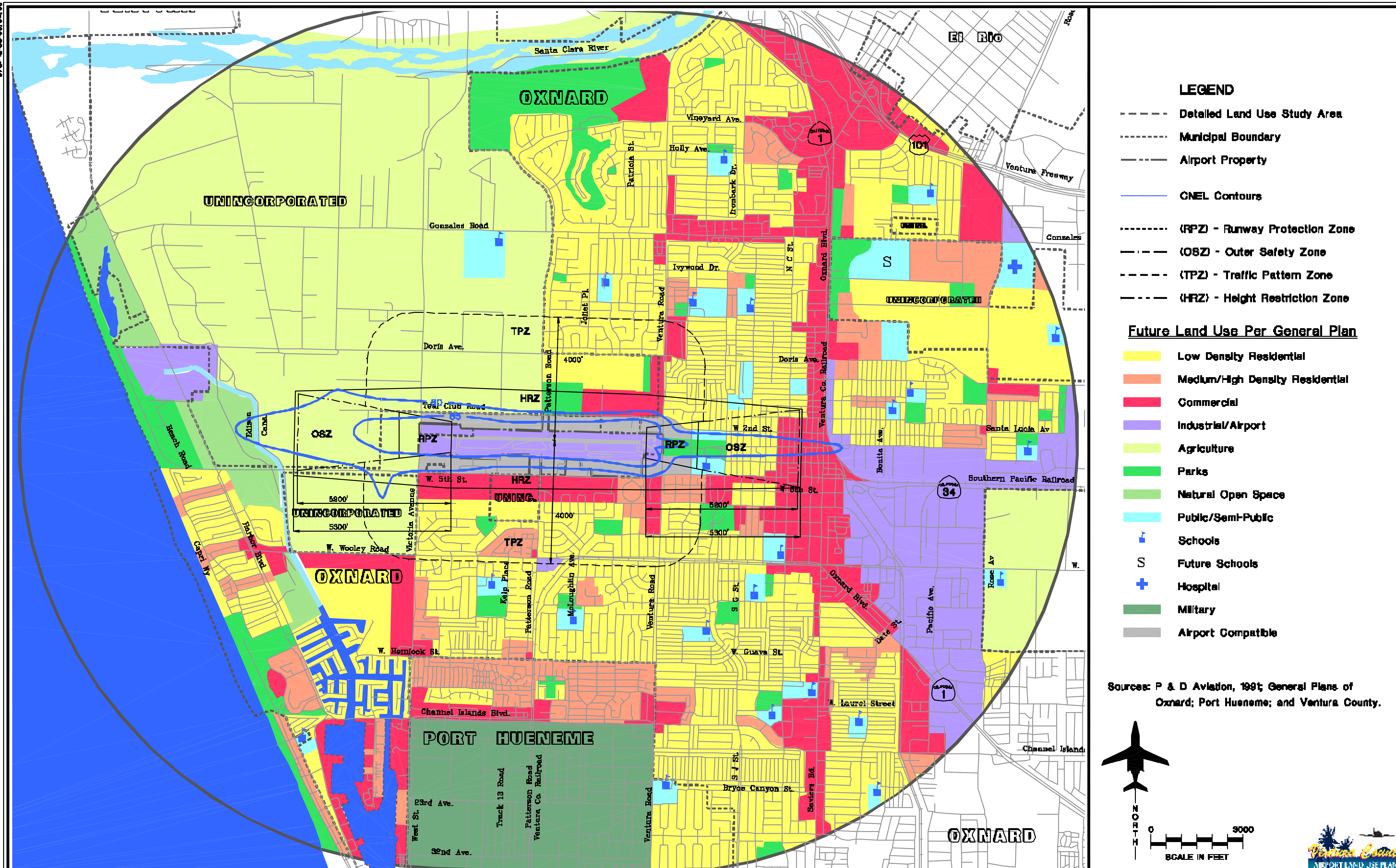


Exhibit 6B
1991 AIRPORT COMPREHENSIVE LAND USE PLAN
FOR OXNARD AIRPORT

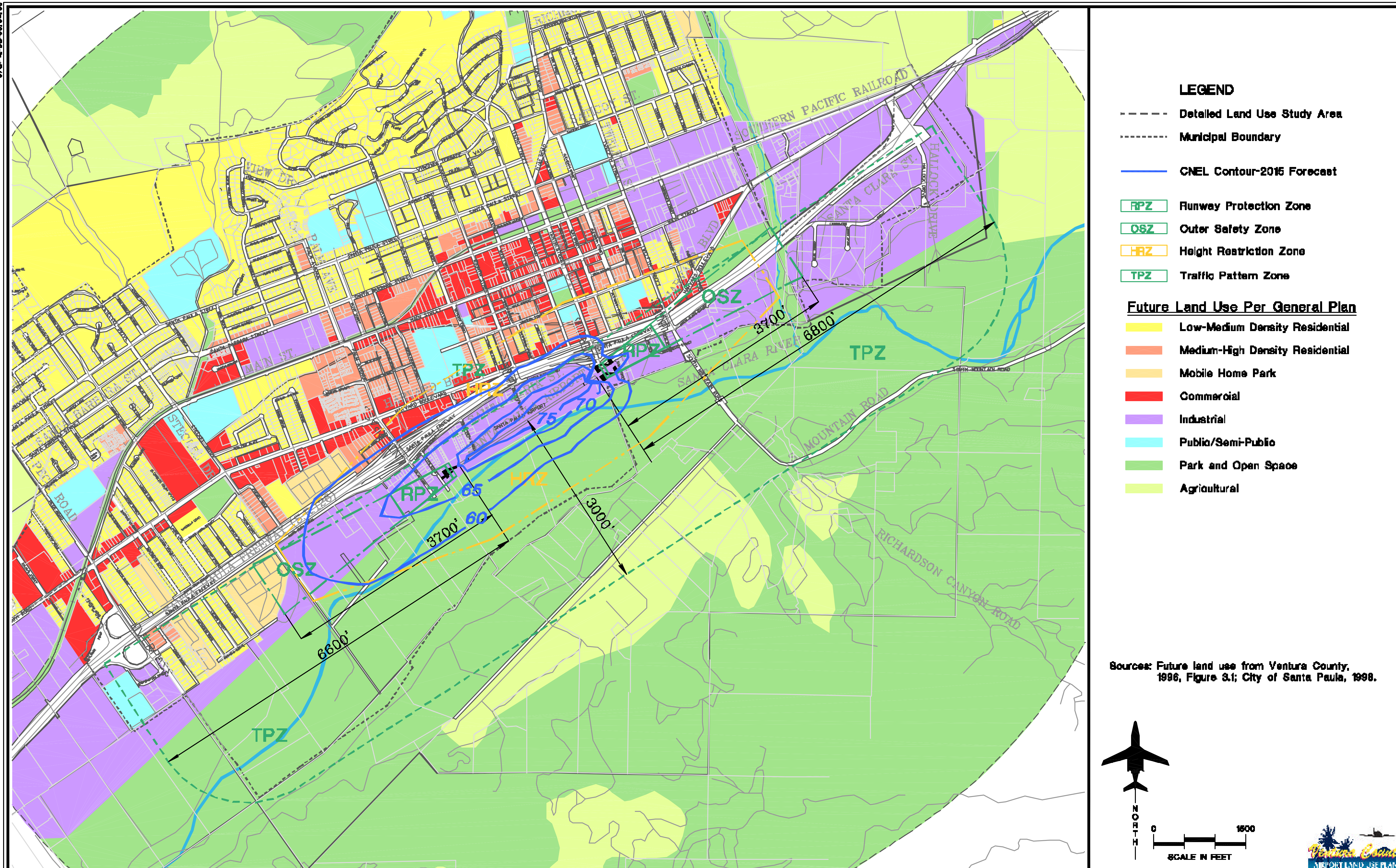


Exhibit 6C
ADOPTED AIRPORT COMPREHENSIVE LAND USE PLAN
FOR SANTA PAULA AIRPORT

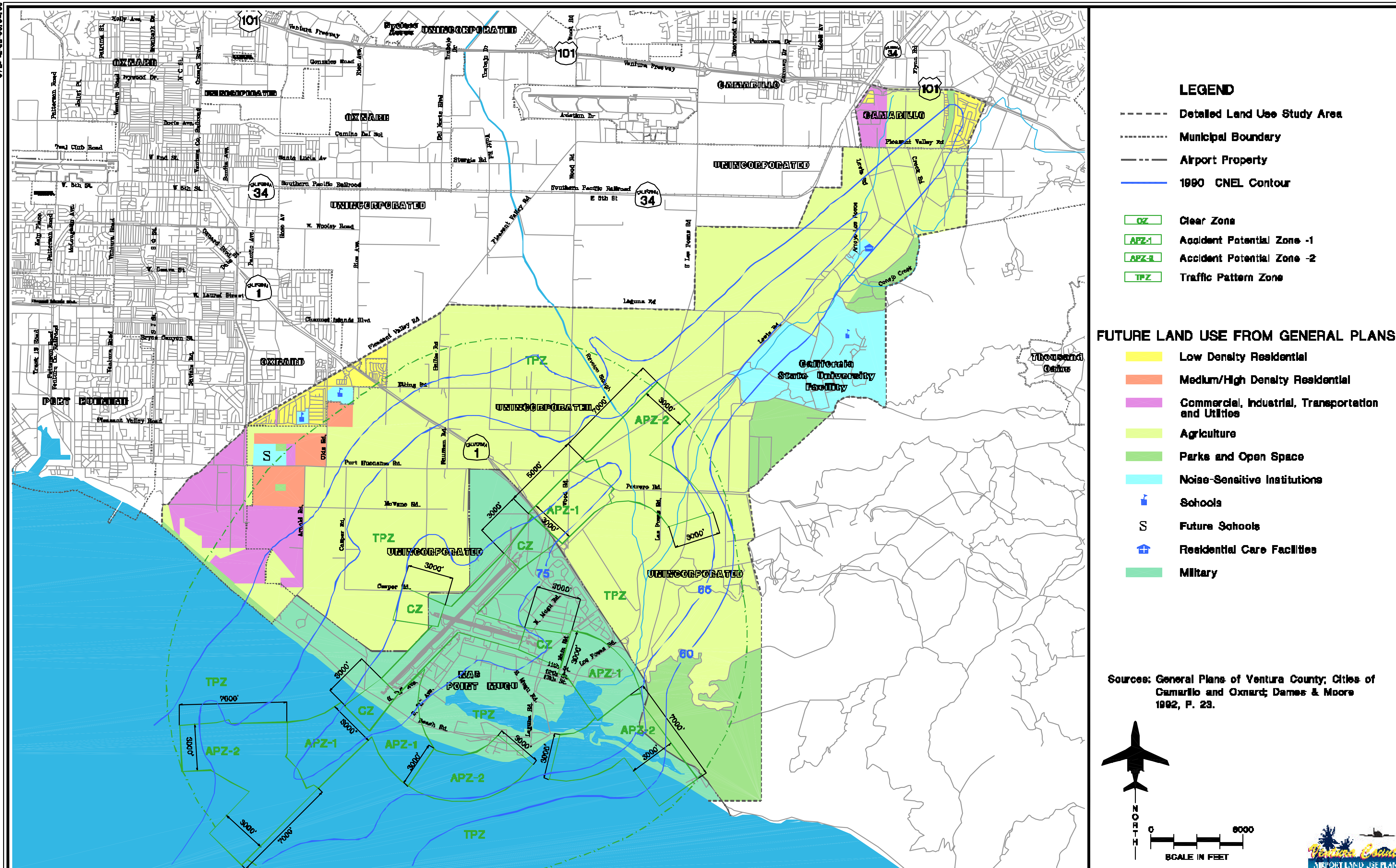


Exhibit 6D
ADOPTED NOISE AND SAFETY AREAS
FOR NAS POINT MUGU

4. At Camarillo Airport, a new zone has been established known as the "Extended Traffic Pattern Zone." It is based on the area which is beneath the extended traffic pattern on a "typical or average" busy day.

The adopted safety zones for Camarillo Airport are shown in **Exhibit 6A**, for Oxnard Airport in **Exhibit 6B** (unchanged from 1991 CLUP), and for Santa Paula Airport in **Exhibit 6C** (unchanged from 1991 CLUP).

6.2.2 SAFETY COMPATIBILITY STANDARDS

Adopted safety compatibility standards for the civilian airports are shown in **Table 6B**. The safety zone headings indicate the addition of the new Extended Traffic Pattern Zone (TPZ). Within the new Extended TPZ, <u>all land uses are acceptable.</u> New residential and institutional uses (including resorts and camps) in the Extended TPZ are required to record fair disclosure agreements and covenants; it is further recommended that avigation easements be dedicated. Conditionally acceptable land uses in the OSZ and the TPZ are also recommended to dedicate avigation easements and required to record fair disclosure covenants.

Land use density is measured in terms of structural coverage. However, the land use classification system has been adjusted slightly. Transportation, communication, and utilities have been placed in the industrial category rather than the institutional category. This is a more typical land use classification convention. (This would move the "transportation terminals, communications/utilities, and automobile parking" land uses to the industrial category from the institutional category.)

TABLE 6B
Adopted Land Use Compatibility Standards in Safety Zones for Civilian Airports

Land Use	Runway Protection Zone	Outer Safety Zone	Traffic Pattern Zone	Extended Traffic Pattern Zone
Residential				
Single Family	U	U	C [a, e]	A [e]
Multi-Family	U	U	C [a, e]	A [e]
Mobile Home Parks	U	U	C [a, e]	A [e]
Public/Institutional				
Hospitals/Convalescent Homes	U	U	U	A [e]
Schools	U	U	U	A [e]
Churches/Synagogues	U	U	U	A [e]
Auditoriums/Theaters	U	U	U	A [e]
Commercial				
Hotels and Motels	U	U	C [c, e]	A [e]
Offices and Business/Professional Services	U	C [a, e]	C [c, e]	A
Wholesale	U	C [a, e]	C [c, e]	A
Retail	U	C [a, e]	C [c, e]	A
Industrial, Transportation, Communication, and Utilities				
Manufacturing-General/Heavy	U	C [a, e]	C [c, e]	A
Light Industrial	U	C [a, e]	C [c, e]	A
Research and Development	U	C [a, e]	C [c, e]	A
Business Parks/Corporate Offices	U	C [a, e]	C [c, e]	A
Transportation Terminals	U	U	A	A
Communication/Utilities	C [b]	A	A	A
Automobile Parking	C [b]	A	A	A
Recreation/Open Space				
Outdoor Sports Arenas	U	U	U	A
Outdoor Amphitheaters	U	U	U	A
Parks	U	C [a]	A	A
Outdoor Amusement	U	C [a, e]	A	A
Resorts and Camps	U	C [a, e]	A [e]	A [e]
Golf Courses and Water Recreation	C [d]	A	A	A
Agriculture	A	A	A	A

TABLE 6B (Continued)
Adopted Land Use Compatibility Standards in
Safety Zones for Civilian Airports

NOTES

A = Acceptable land use.
C = Land use is conditionally acceptable upon meeting required criteria (see footnotes below).
U = Unacceptable land use.

[a] Maximum structural coverage must be no more than 25 percent. "Structural coverage" is defined as the percent of building footprint area to total land area, including streets and greenbelts.

[b] The placing of structures or buildings in the Runway Protection Zone is unacceptable. Aboveground utility lines and parking are allowed only if approved by the Federal Aviation Administration (FAA) as not constituting a hazard to air navigation.

[c] Maximum structural coverage must not exceed 50 percent. "Structural coverage" is defined as the percent of building footprint area to total land area, including streets and greenbelts. Where development is proposed immediately adjacent to the airport property, structures should be located as far as practical from the runway.

[d] Clubhouse is unacceptable in this zone.

[e] An avigation easement is recommended and a fair disclosure agreement and covenant shall be recorded by the owner and developer of the property.

The adopted safety standards at NAS Point Mugu are shown in **Table 6C**. The standards in the CZ, the APZ-1, and the APZ-2 are the same as in the current CLUP. The standards in the TPZ zone are the same as in the civilian Extended TPZ zone. As was done in the civilian table, the land use classification system has been changed to add transportation, communication, and utilities to the industrial category.

TABLE 6C
Adopted Land Use Compatibility Standards In Safety Zones For NAS Point Mugu

Land Use	Clear Zone	APZ-1	APZ-2	Traffic Pattern Zone
Residential				
Single Family	U	U	C [a, [i]]	A [i]
Multi-Family	U	U	U	A [i]
Mobile Home Parks	U	U	U	A [i]
Public/Institutional				
Hospitals/Convalescent Homes	U	U	U	A [i]
Schools	U	U	U	A [i]
Churches/Synagogues	U	U	C [b, [i]]	A [i]]
Auditoriums/Theaters	U	U	U	A [i]
Commercial				
Hotels and Motels	U	U	U	A [i]
Offices and Business/Professional Services	U	U	C [e, [i]]	A
Wholesale	U	C [b, [i]]	A	A
Retail	U	C [b, [i]]	C [b, [i]]	A
Industrial				
Manufacturing-General/Heavy	U	C [b, [i]]	A	A
Light Industrial	U	C [b, [i]]	A	A
Research and Development	U	U	C [b, [i]]	A
Business Parks/Corporate Offices	U	U	C [b, [i]]	A
Transportation Terminals	U	U	A	A
Communication/Utilities	C [c]	C [d]	A	A
Automobile Parking	C [c]	A	A	A
Recreation/Open Space				
Outdoor Sports Arenas	U	U	U	A
Outdoor Amphitheaters	U	U	U	A
Parks	U	C [f]	C [f]	A
Outdoor Amusement	U	U	C [f]	A
Resorts and Camps	U	U	U	A [i]
Golf Courses and Water Recreation	U	C [f, g]	A	A
Agriculture	U	C [h]	A	A

TABLE 6C (Continued)
Adopted Land Use Compatibility Standards In Safety Zones For NAS Point Mugu

NOTES

A = Acceptable land use.
C = Land use is conditionally acceptable upon meeting required criteria (see footnotes below).
U = Unacceptable land use.

[a] Maximum density must be 1-2 dwelling units per acre, possibly increased under a Planned Unit Development (PUD) where maximum lot coverage is less than 20 percent. "Lot coverage" is defined as the average percent of building footprint area to lot area.

[b] Uses must be evaluated separately due to the variation of densities of people and structures.

[c] The placing of structures or buildings in the Clear Zone is unacceptable. Above ground utility lines and parking area allowed only if approved by the DOD as not constituting a hazard to air navigation.

[d] Passenger terminals and major above-ground transmission lines are unacceptable in APZ-1.

[e] Low-intensity office uses only. Meeting places, etc. are unacceptable.

[f] Facilities must be low intensity.

[g] Clubhouse is unacceptable in this zone.

[h] Factors to be considered: labor intensity, structural coverage, explosive characteristics, air pollution.

[i] An avigation easement is recommended and a fair disclosure agreement and covenant shall be recorded by the owner and developer of the property.

6.3 AIRSPACE PROTECTION

The Height Restriction Zone (HRZ) remains essentially unchanged at all three civilian airports. The same methodology used in 1991 was used this time but the zone boundaries on the maps are slightly different in Camarillo and Santa Paula due to apparent mapping errors in 1991. The 1991 mapping was produced by hand drawings on USGS maps. The current mapping utilizes digital mapping. The outer boundary of the HRZ is the F.A.R. Part 77 Transitional Surface. It begins at ground level at the Primary Surface around each runway. It extends upward at a slope of 7:1 until it reaches the Horizontal Surface at an elevation 150 feet above the airport elevation. (**Exhibit 6E** describes the F.A.R. Part 77 imaginary surfaces at a hypothetical airport.) The following standard applies within the HRZ.

- Any structures proposed within the HRZ must remain below the Approach and Transitional Surface.

The HRZ zones at each civilian airport are shown in **Exhibits 6A** through **6C**.

F.A.R. Part 77 requires people proposing to construct certain tall structures (over 200 feet) or other structures near airports that would penetrate imaginary surfaces defined in Part 77 to notify the FAA of the proposed construction. The FAA will review the proposal and issue an acknowledgment stating that the proposal (1) would not exceed any airspace protection surfaces defined on the airport's F.A.R. Part 77 Airspace Plan; or (2) would exceed a standard of the F.A.R. Part 77 Airspace Plan but would not be a hazard to air navigation; or (3) would exceed a standard of the F.A.R. Part 77 Airspace Plan and may be a hazard to air navigation, pending a further aeronautical study. Within 30 days, the project sponsor may request the aeronautical study. Until an aeronautical study is completed, the proposed structure shall be presumed to be a hazard to air navigation. A copy of the reporting requirements of F.A.R. Part 77 is in Appendix D.

Despite the reporting and review requirements of F.A.R. Part 77, the FAA has no land use regulatory authority. The FAA cannot prevent the construction of hazards to air navigation. It can only require that they be marked. Where proposed structures are determined to be hazards to air navigation, the FAA notifies the local land use regulatory authority and requests that they use their authority to prohibit the structure or require it to be modified. As a national policy, the FAA has requested for many years that local governments enact F. A.R. Part 77 Height and Hazard Zoning to deal with these situations. The FAA has even promulgated a model Height and Hazard Zoning Ordinance. (See FAA Advisory Circular 150/5190-4A.)

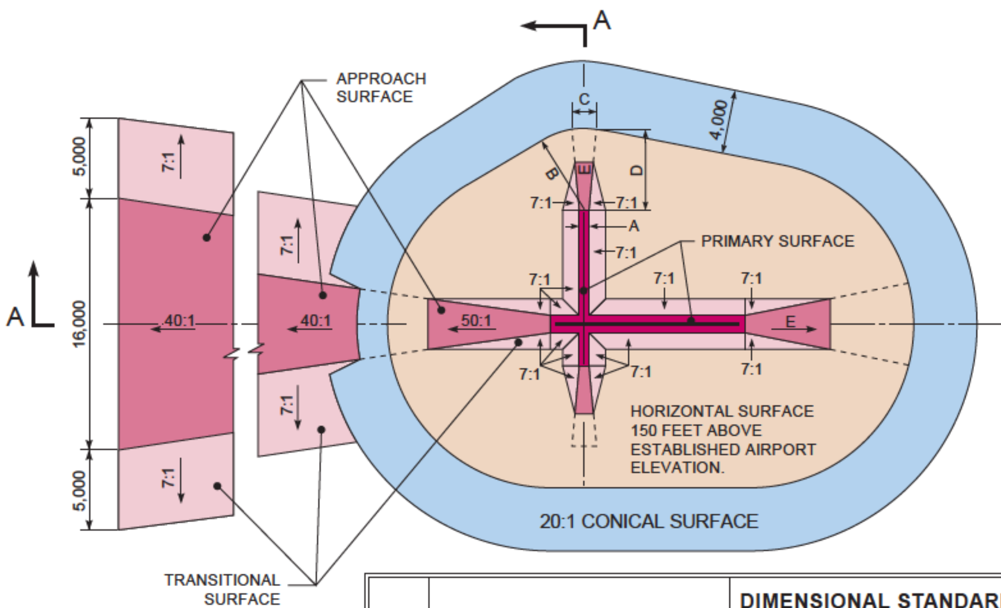
In view of the foregoing information, the following new airspace protection standards are adopted. It is anticipated that they would most often apply to proposed towers.

1. Any structures proposed within any part of the F.A.R. Part 77 Airspace Plan which require a variance, conditional use, or special use permit because they exceed the permitted height requirements of the zoning ordinance shall be reviewed by the Airport Land Use Commission if the height of the proposed structure would penetrate any F.A.R. Part 77 surface.

2. If the FAA reviews the proposed structure and finds that the structure would represent a hazard to air navigation, the proposal shall be disapproved. The proposal shall also be disapproved if the FAA finds that the structure would require the raising of approach minimums at any military or public use airport in the County.

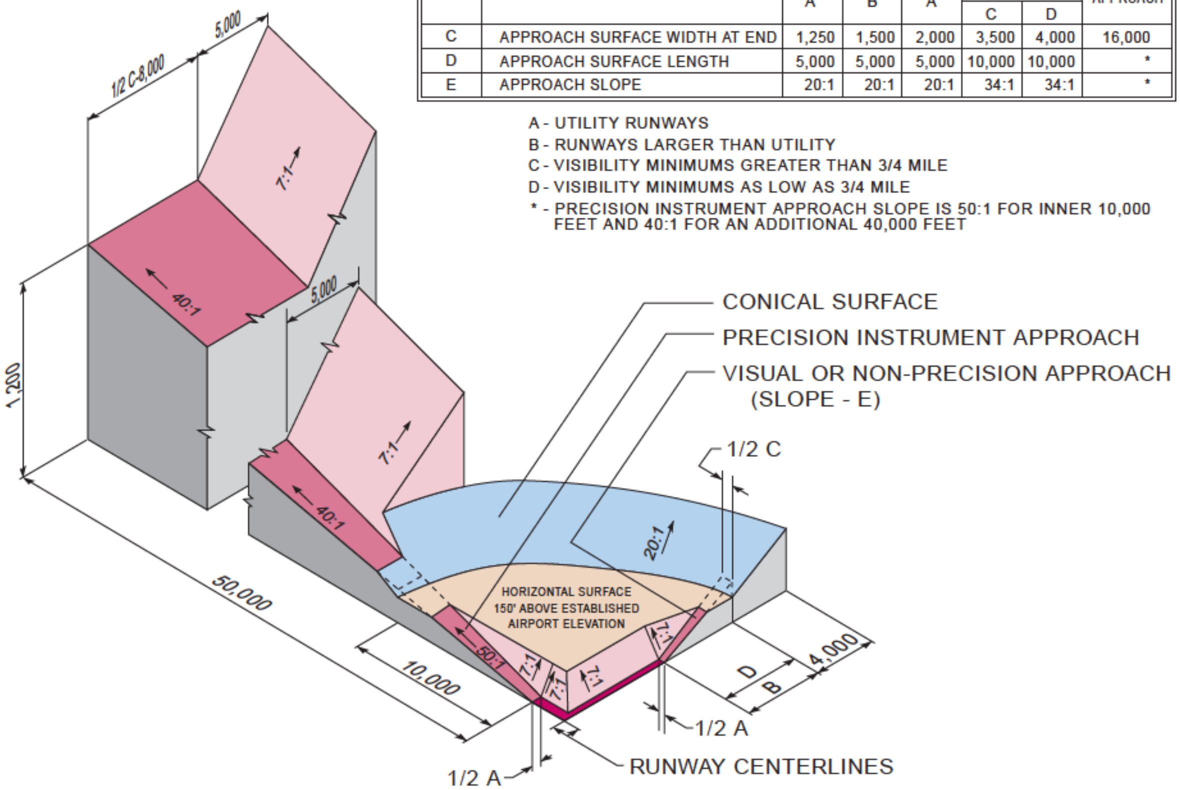
3. If the Federal Aviation Administration (FAA) reviews the proposed structure and makes a finding of "no hazard," the structure shall be permitted, provided that it shall be marked and lighted in accordance with the recommendations of the FAA.

97SP12-6E-8/11/00



DIM	ITEM	DIMENSIONAL STANDARDS (FEET)					
		VISUAL RUNWAY		NON-PRECISION INSTRUMENT RUNWAY			PRECISION INSTRUMENT RUNWAY
		A	B	A	B		
					C	D	
A	WIDTH OF PRIMARY SURFACE AND APPROACH SURFACE WIDTH AT INNER END	250	500	500	500	1,000	1,000
B	RADIUS OF HORIZONTAL SURFACE	5,000	5,000	5,000	10,000	10,000	10,000
		VISUAL APPROACH		NON-PRECISION INSTRUMENT APPROACH			PRECISION INSTRUMENT APPROACH
		A	B	A	B		
					C	D	
C	APPROACH SURFACE WIDTH AT END	1,250	1,500	2,000	3,500	4,000	16,000
D	APPROACH SURFACE LENGTH	5,000	5,000	5,000	10,000	10,000	*
E	APPROACH SLOPE	20:1	20:1	20:1	34:1	34:1	*

A - UTILITY RUNWAYS
B - RUNWAYS LARGER THAN UTILITY
C - VISIBILITY MINIMUMS GREATER THAN 3/4 MILE
D - VISIBILITY MINIMUMS AS LOW AS 3/4 MILE
* - PRECISION INSTRUMENT APPROACH SLOPE IS 50:1 FOR INNER 10,000 FEET AND 40:1 FOR AN ADDITIONAL 40,000 FEET



ISOMETRIC VIEW OF SECTION A-A

SOURCE: 14 CFR Part 77, Section 77.25, Civil Airport Imaginary Surfaces.

Ventura County AIRPORT LAND USE PLAN

Exhibit 6E
EXAMPLE OF F.A.R. PART 77 CRITERIA

4. F.A.R. Part 77 Airspace Plans for each airport are shown in **Exhibits 6F** through **6L**.

6.4 SUMMARY

This chapter has reviewed adopted policies for noise compatibility, safety compatibility, and height protection. Several revisions to the 1991 CLUP have been adopted.

The most significant change in the noise compatibility standards involves the use of updated noise contours at Camarillo and Santa Paula to define the area regulated for noise purposes. The noise contours for Oxnard and Point Mugu are unchanged. At Camarillo the updated noise contours are generally smaller than the contours in the current CLUP. At Santa Paula, the contours are somewhat larger. The land use compatibility standards applying within the noise contours remain virtually unchanged.

The most important change in the safety compatibility standards is the establishment of a new zone at Camarillo and Point Mugu. These zones are the Traffic Pattern Zone (Pt. Mugu) and Extended Traffic Pattern Zone (Camarillo). Within these areas, new sensitive development are now required to record fair disclosure covenants and avigation easements are recommended. No other land use regulations would apply in the area. One other zone has been renamed, but the land use regulations would remain the same in those zones. The "Inner Safety Zone" has become the "Runway Protection Zone." In addition, some relatively small changes in safety zone boundaries have been made to reflect changes in the airport layout plans.

The only change adopted for the airspace protection standards is a requirement for the Airport Land Use Commission to review applications for tall structures requiring variances, conditional use, or special use permits because they exceed the height standards of the local zoning ordinances. The intent is to prohibit tall structures, most commonly expected to be towers and antennas, which would penetrate the F.A.R. Part 77 surfaces around the airports and create a hazard to air navigation.

REFERENCES

City of Camarillo, 1996. *City of Camarillo General Plan*. Includes amendments through August 28, 1996.

City of Oxnard, 1990. *City of Oxnard 2020 General Plan*. Adopted by City Council Resolutions 10050 and 10052, October 7 and 14, 1990.

City of Santa Paula, 1998. "Proposed Land Use Plan and Expansion Areas, Draft," (map).

Coffman Associates, 1997a. *Camarillo Airport: F.A.R. Part 150 Noise Compatibility Study*. Prepared for Ventura County Department of Airports.

Coffman Associates, 1997b. *Oxnard Airport: F.A.R. Part 150 Noise Compatibility Study*. Prepared for Ventura County Department of Airports.

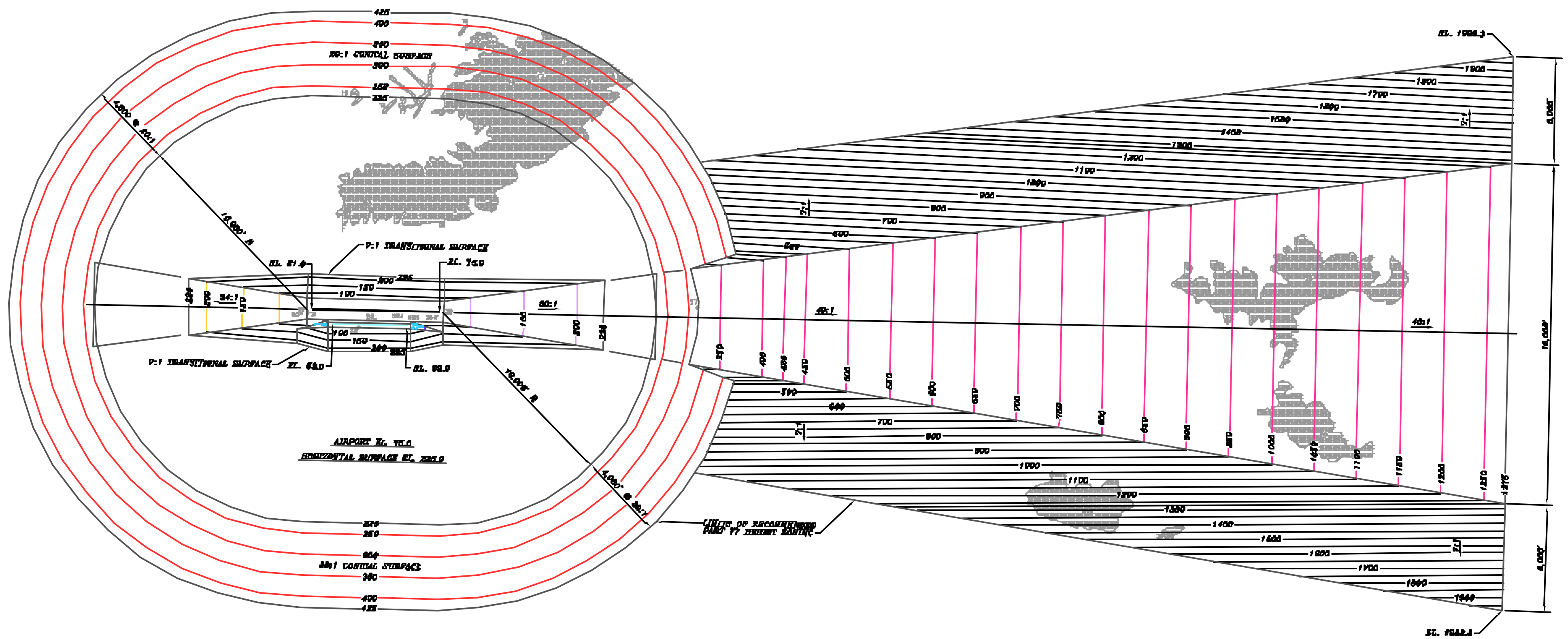
Cotton/Beland/Associates, Inc. 1997. *City of Port Hueneme General Plan*, hearing draft. Prepared by Cotton/Beland for the City of Port Hueneme, April 1997.

Dames & Moore, 1992. *Air Installation Compatible Use Zones (AICUZ) Study: NAWS Point Mugu*. Submitted to Western Division, Naval Facilities Engineering Command, San Bruno, California, July 1992.

Ventura County, 1996. *Ventura County General Plan: Goals, Policies and Programs*. Adopted by the Ventura County Board of Supervisors, May 24, 1988, with amendments through December 17, 1996.

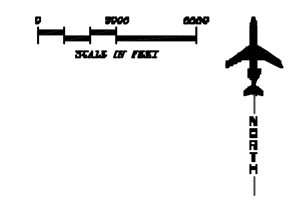
GENERAL NOTES:

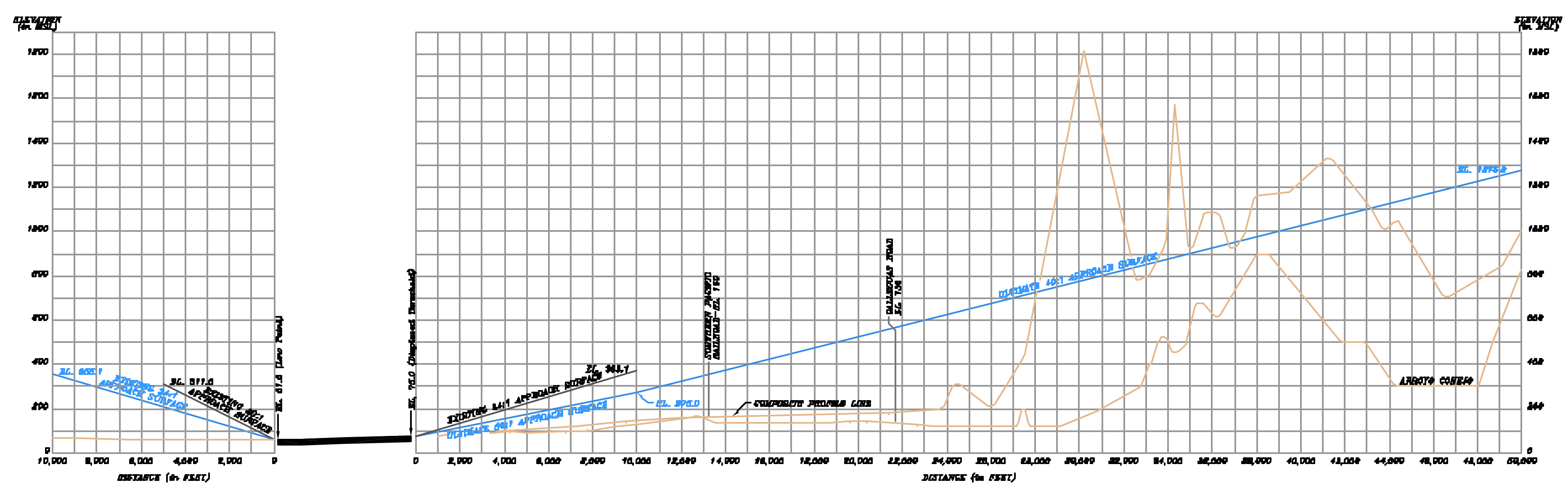
1. Obstructions, clearances, and locations are calculated from ultimate runway end elevations and ultimate approach surfaces, unless otherwise noted.
2. Depiction of features and objects within the primary, transitional, and horizontal Part 77 surfaces, is illustrated on the PART 77 AIRSPACE PLAN, sheet 2 of these plans.
3. Depiction of features and objects within the outer portion of the approach surfaces, is illustrated on the APPROACH ZONES PROFILES, sheet 2 of these plans.
4. Depiction of features and objects within the inner portion of the approach surfaces, is illustrated on the PROTECTION ZONES PLAN, sheet 3 of these plans.
5. Additional obstruction data is illustrated on National Ocean Survey document OC 674, AIRPORT OBSTRUCTION CHART dated May 1991.
6. Existing and future height and hazard ordinances are to be amended and/or referenced upon approval of updated PART 77 AIRSPACE PLAN.



OBSTRUCTION LEGEND

- OBSTRUCTION
- GROUP or MULTIPLE OBSTRUCTIONS
- TOPOGRAPHIC OBSTRUCTION





RUNWAY 8-26 APPROACH ZONE PROFILES

VERTICAL SCALE IN FEET

HORIZONTAL SCALE IN FEET

OBSTRUCTION TABLE

Object Description	Object Elevation	Obstructed Part 77 Surface	Surface Elevation	Object Penetration	Proposed Object Disposition
1. TOPOGRAPHIC	380 MSL	HORIZONTAL SURFACE	225 MSL	155'	REQUEST AERONAUTICAL STUDY
2. TREE	368 MSL	HORIZONTAL SURFACE	225 MSL	143'	REQUEST AERONAUTICAL STUDY
3. TREE	441 MSL	HORIZONTAL SURFACE	225 MSL	216'	REQUEST AERONAUTICAL STUDY
4. TREE	348 MSL	HORIZONTAL SURFACE	225 MSL	123'	REQUEST AERONAUTICAL STUDY
5. TREE	350 MSL	HORIZONTAL SURFACE	225 MSL	125'	REQUEST AERONAUTICAL STUDY
6. TREE	351 MSL	HORIZONTAL SURFACE	225 MSL	126'	REQUEST AERONAUTICAL STUDY
7. TREE	347 MSL	HORIZONTAL SURFACE	225 MSL	122'	REQUEST AERONAUTICAL STUDY
8. TREE	516 MSL	CONICAL SURFACE	238 MSL	278'	REQUEST AERONAUTICAL STUDY
9. TREE	518 MSL	HORIZONTAL SURFACE	225 MSL	293'	REQUEST AERONAUTICAL STUDY
10. TREE	614 MSL	CONICAL SURFACE	370 MSL	244'	REQUEST AERONAUTICAL STUDY
11. TREE	620 MSL	CONICAL SURFACE	386 MSL	234'	REQUEST AERONAUTICAL STUDY
12. TREE	586 MSL	CONICAL SURFACE	335 MSL	251'	REQUEST AERONAUTICAL STUDY
13. TREE	626 MSL	CONICAL SURFACE	399 MSL	227'	REQUEST AERONAUTICAL STUDY
14. TREE	442 MSL	CONICAL SURFACE	380 MSL	62'	REQUEST AERONAUTICAL STUDY
15. TREE	432 MSL	CONICAL SURFACE	380 MSL	52'	REQUEST AERONAUTICAL STUDY
16. TREE	431 MSL	CONICAL SURFACE	396 MSL	35'	REQUEST AERONAUTICAL STUDY
17. TREE	276 MSL	HORIZONTAL SURFACE	225 MSL	51'	REQUEST AERONAUTICAL STUDY
18. TREE	280 MSL	HORIZONTAL SURFACE	225 MSL	55'	REQUEST AERONAUTICAL STUDY
19. TREE	268 MSL	CONICAL SURFACE	233 MSL	35'	REQUEST AERONAUTICAL STUDY
20. WINDSOCK	71 MSL	34:1 APPROACH SURFACE	69 MSL	2'	FIX BY FUNCTIONAL PURPOSE
21. FENCE POST	64 MSL	PRIMARY SURFACE	61 MSL	3'	TO BE REMOVED
22. PIPE	70 MSL	PRIMARY SURFACE	62 MSL	8'	TO BE REMOVED
23. OL ON VOR/DME	86 MSL	PRIMARY SURFACE	68 MSL	18'	TO BE REMOVED
24. WINDSOCK	79 MSL	PRIMARY SURFACE	70 MSL	9'	FIX BY FUNCTIONAL PURPOSE
25. SWITCHBOX	72 MSL	PRIMARY SURFACE	71 MSL	1'	TO BE RELOCATED
26. WINDSOCK	90 MSL	PRIMARY SURFACE	74 MSL	16'	FIX BY FUNCTIONAL PURPOSE
27. POLE ON STANDPIPE	321 MSL	CONICAL SURFACE	225 MSL	96'	REQUEST AERONAUTICAL STUDY
28. TOPOGRAPHIC	1173 MSL	40:1 APPROACH SURFACE	1039 MSL	134'	REQUEST AERONAUTICAL STUDY
29. TOPOGRAPHIC	1338 MSL	40:1 APPROACH SURFACE	1054 MSL	284'	REQUEST AERONAUTICAL STUDY
30. TOPOGRAPHIC	1814 MSL	7:1 TRANSITIONAL SURFACE	1310 MSL	504'	REQUEST AERONAUTICAL STUDY
31. TOPOGRAPHIC	1571 MSL	7:1 TRANSITIONAL SURFACE	1475 MSL	96'	REQUEST AERONAUTICAL STUDY

Source: Coffman Associates 1997a.

Exhibit 6F
F.A.R. PART 77 AIRSPACE PLAN FOR CAMARILLO AIRPORT

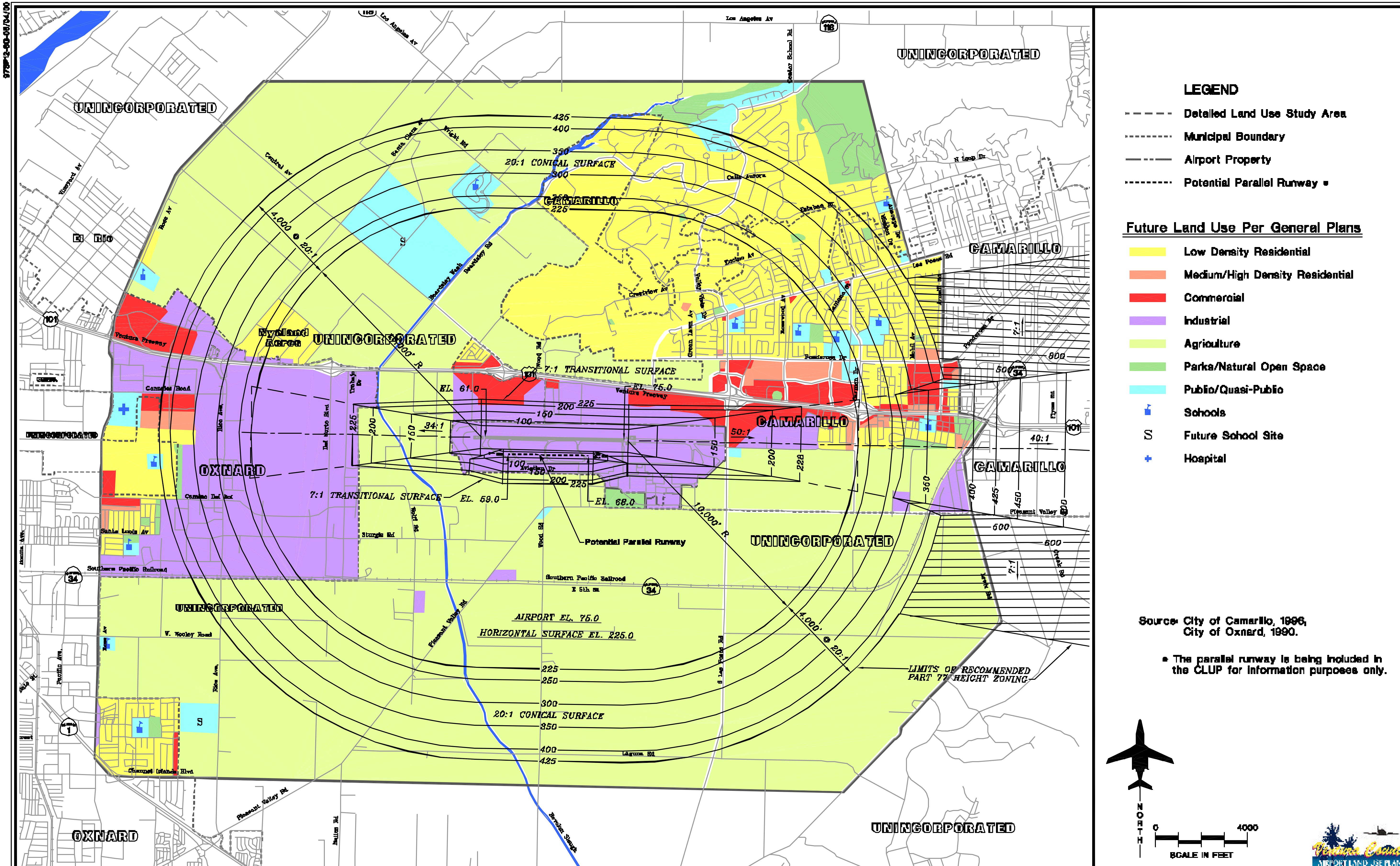
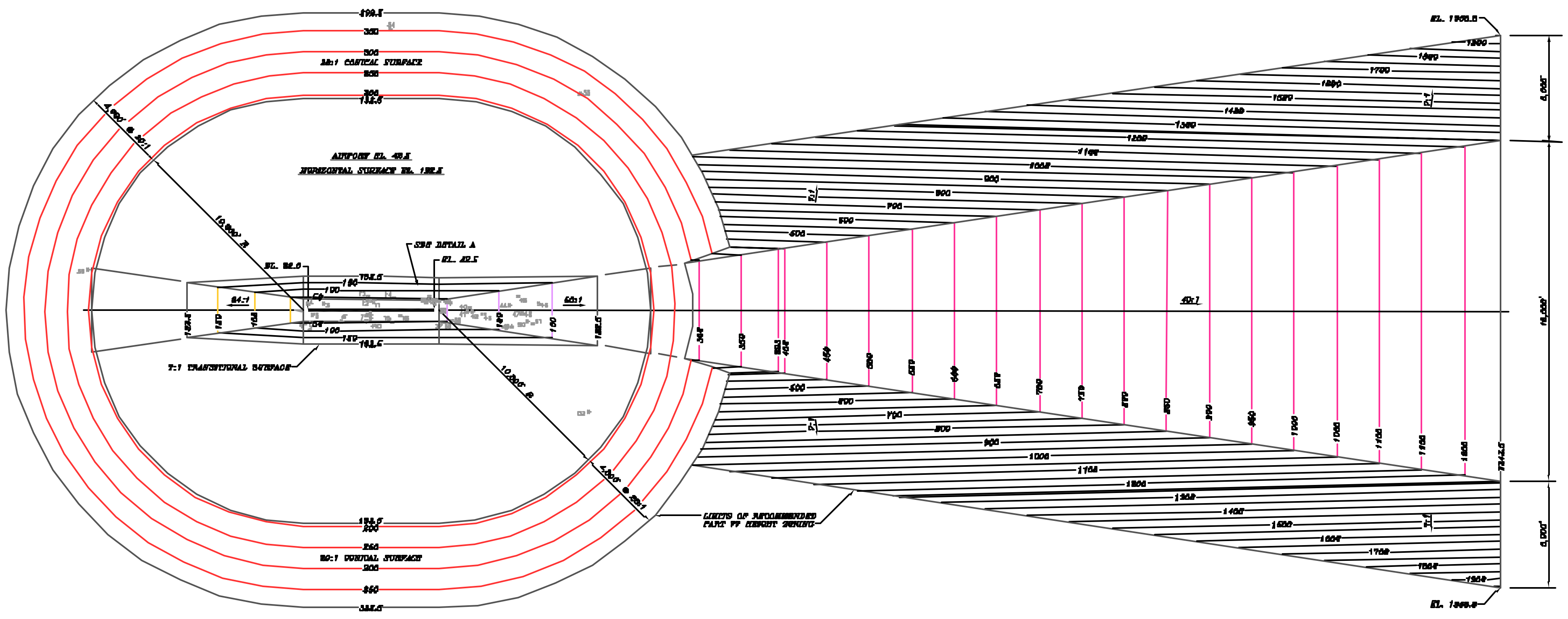


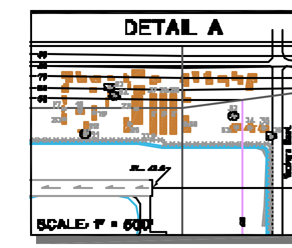
Exhibit 6G
F.A.R. PART 77 AIRSPACE PLAN IN
IMMEDIATE CAMARILLO AIRPORT AREA



1. Obstructions, clearances, and locations are calculated from ultimate runway end elevations and ultimate approach surfaces, unless otherwise noted.
2. Distance for road obstructions and clearances reflect a safety clearance of 15' for noninterstate roads, 17' for interstate roads, and 23' for railroads.
3. Depiction of features and objects within the primary, transitional, and horizontal Part 77 surfaces, is illustrated on the PART 77 AIRSPACE PLAN, sheet 2 of these plans.
4. Depiction of features and objects within the outer portion of the approach surfaces, is illustrated on the APPROACH ZONES PROFILES, sheet 2 of these plans.
5. Depiction of features and objects within the inner portion of the approach surfaces, is illustrated on the PROTECTION ZONES PLAN, sheet 3 of these plans.
6. Additional obstruction data is illustrated on National Ocean Survey document OC 674, AIRPORT OBSTRUCTION CHART dated May 1991.
7. Existing and future height and hazard ordinances are to be amended and/or referenced upon approval of updated PART 77 AIRSPACE PLAN.

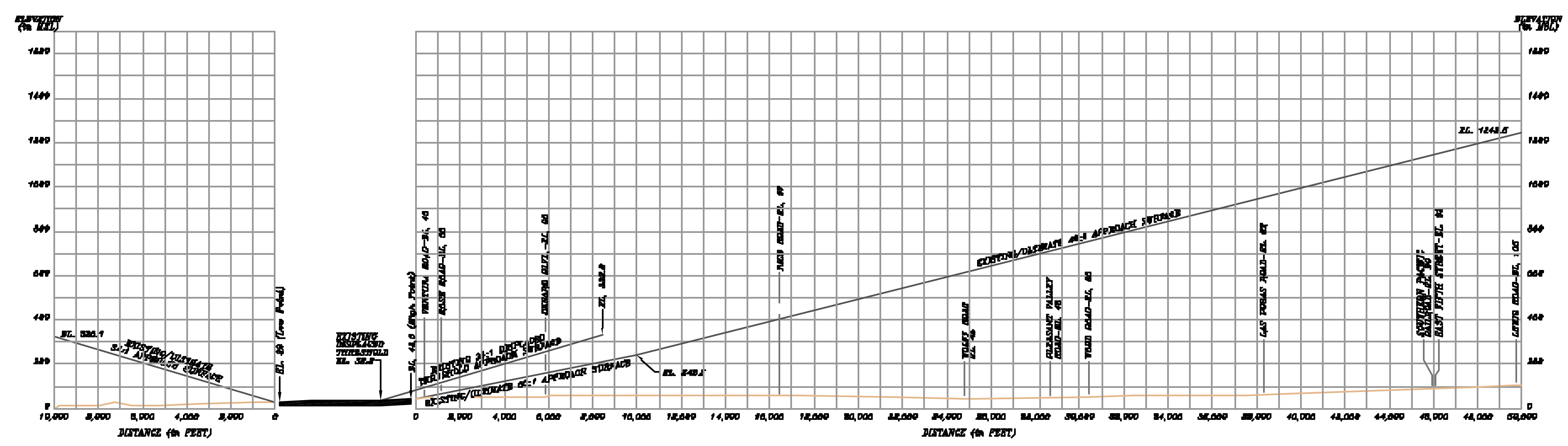
OBSTRUCTION LEGEND

- OBSTRUCTION
- GROUP or MULTIPLE OBSTRUCTIONS
- TOPOGRAPHIC OBSTRUCTION



OBSTRUCTION TABLE

Object Description	Object Elevation	Obstructed Part 77 Surface	Surface Elevation	Object Penetration	Proposed Object Disposition
OL ON LIGHT STANDARD	58 MSL	7:1 TRANSITIONAL SURFACE	52 MSL	6'	TO REMAIN LIGHTED
OL ON LIGHT STANDARD	59 MSL	7:1 TRANSITIONAL SURFACE	49 MSL	10'	TO REMAIN LIGHTED
WINDSOCK	41 MSL	PRIMARY SURFACE	32 MSL	9'	FIX BY FUNCTIONAL PURPOSE
FENCE	34 MSL	PRIMARY SURFACE	32 MSL	2'	TO BE RELOCATED
FENCE	37 MSL	PRIMARY SURFACE	33 MSL	4'	TO BE RELOCATED
VENT ON BUILDING	51 MSL	7:1 TRANSITIONAL SURFACE	38 MSL	13'	TO BE LIGHTED
OL ANEMOMETER	57 MSL	PRIMARY SURFACE	36 MSL	21'	TO REMAIN LIGHTED
OL WINDSOCK	52 MSL	PRIMARY SURFACE	36 MSL	16'	TO REMAIN LIGHTED
FENCE	40 MSL	7:1 TRANSITIONAL SURFACE	38 MSL	2'	TO BE RELOCATED
ATCT	115 MSL	7:1 TRANSITIONAL SURFACE	75 MSL	40'	TO REMAIN LIGHTED
BUILDING	53 MSL	PRIMARY SURFACE	36 MSL	17'	REQUEST AERONAUTICAL STUDY
VENT ON BUILDING	60 MSL	PRIMARY SURFACE	36 MSL	24'	TO BE LIGHTED
ANTENNA	97 MSL	7:1 TRANSITIONAL SURFACE	55 MSL	42'	TO BE LIGHTED
OL HANGAR	83 MSL	7:1 TRANSITIONAL SURFACE	51 MSL	32'	TO REMAIN LIGHTED
WINDVANE ON HANGAR	62 MSL	7:1 TRANSITIONAL SURFACE	46 MSL	16'	TO BE LIGHTED
OL GLIDE SLOPE	71 MSL	PRIMARY SURFACE	39 MSL	32'	FIX BY FUNCTIONAL PURPOSE
BUILDING	50 MSL	PRIMARY SURFACE	41 MSL	9'	REQUEST AERONAUTICAL STUDY
BUILDING	55 MSL	PRIMARY SURFACE	41 MSL	14'	REQUEST AERONAUTICAL STUDY
BUILDING	60 MSL	PRIMARY SURFACE	42 MSL	18'	REQUEST AERONAUTICAL STUDY
BUILDING	50 MSL	PRIMARY SURFACE	41 MSL	9'	REQUEST AERONAUTICAL STUDY
TREE	77 MSL	PRIMARY SURFACE	41 MSL	36'	TO BE REMOVED
BUILDING	52 MSL	PRIMARY SURFACE	41 MSL	11'	REQUEST AERONAUTICAL STUDY
TREE	102 MSL	7:1 TRANSITIONAL SURFACE	61 MSL	41'	TO BE REMOVED
TREE	109 MSL	7:1 TRANSITIONAL SURFACE	54 MSL	55'	TO BE REMOVED
BUILDING	50 MSL	PRIMARY SURFACE	43 MSL	7'	REQUEST AERONAUTICAL STUDY
BUILDING	61 MSL	PRIMARY SURFACE	43 MSL	18'	REQUEST AERONAUTICAL STUDY
BUILDING	52 MSL	PRIMARY SURFACE	43 MSL	9'	REQUEST AERONAUTICAL STUDY
BUILDING	52 MSL	PRIMARY SURFACE	43 MSL	9'	REQUEST AERONAUTICAL STUDY
BUILDING	52 MSL	PRIMARY SURFACE	43 MSL	9'	REQUEST AERONAUTICAL STUDY
BUILDING	52 MSL	PRIMARY SURFACE	43 MSL	9'	REQUEST AERONAUTICAL STUDY
SIGN/LIGHT	69 MSL	PRIMARY SURFACE	43 MSL	26'	TO BE REMOVED
TREE	105 MSL	50:1 APPROACH SURFACE	49 MSL	56'	DISPLACE THRESHOLD
BUILDING	56 MSL	PRIMARY SURFACE	49 MSL	7'	REQUEST AERONAUTICAL STUDY
BUILDING	56 MSL	PRIMARY SURFACE	51 MSL	5'	REQUEST AERONAUTICAL STUDY
BUILDING	56 MSL	PRIMARY SURFACE	53 MSL	3'	REQUEST AERONAUTICAL STUDY
TREE	92 MSL	50:1 APPROACH SURFACE	53 MSL	39'	DISPLACE THRESHOLD
SPIRE	72 MSL	7:1 TRANSITIONAL SURFACE	50 MSL	22'	REQUEST AERONAUTICAL STUDY
SPIRE	73 MSL	7:1 TRANSITIONAL SURFACE	50 MSL	23'	REQUEST AERONAUTICAL STUDY
LIGHT POLE	76 MSL	50:1 APPROACH SURFACE	55 MSL	21'	DISPLACE THRESHOLD
FLAG POLE	88 MSL	50:1 APPROACH SURFACE	71 MSL	17'	DISPLACE THRESHOLD
UTILITY POLE	87 MSL	50:1 APPROACH SURFACE	69 MSL	18'	DISPLACE THRESHOLD
UTILITY POLE	93 MSL	50:1 APPROACH SURFACE	74 MSL	19'	DISPLACE THRESHOLD
FLOODLIGHT	116 MSL	50:1 APPROACH SURFACE	84 MSL	32'	DISPLACE THRESHOLD
TREE	144 MSL	50:1 APPROACH SURFACE	108 MSL	36'	DISPLACE THRESHOLD
TREE	143 MSL	50:1 APPROACH SURFACE	117 MSL	26'	DISPLACE THRESHOLD
TREE	175 MSL	50:1 APPROACH SURFACE	136 MSL	39'	DISPLACE THRESHOLD
CHURCH SPIRE	154 MSL	50:1 APPROACH SURFACE	121 MSL	33'	DISPLACE THRESHOLD
TREE	163 MSL	50:1 APPROACH SURFACE	121 MSL	42'	DISPLACE THRESHOLD
TREE	132 MSL	50:1 APPROACH SURFACE	111 MSL	21'	DISPLACE THRESHOLD
TREE	150 MSL	50:1 APPROACH SURFACE	126 MSL	24'	DISPLACE THRESHOLD
TREE	140 MSL	50:1 APPROACH SURFACE	131 MSL	9'	DISPLACE THRESHOLD
OL RADIO TOWER	196 MSL	HORIZONTAL SURFACE	193 MSL	3'	TO REMAIN LIGHTED
OL BUILDING	381 MSL	CONICAL SURFACE	301 MSL	80'	TO REMAIN LIGHTED
OL RADIO MAST	366 MSL	CONICAL SURFACE	353 MSL	13'	TO REMAIN LIGHTED
OL ROD ON STACK	218 MSL	CONICAL SURFACE	209 MSL	9'	TO REMAIN LIGHTED



RUNWAY 7-25 APPROACH ZONE PROFILES

VERTICAL SCALE IN FEET
HORIZONTAL SCALE IN FEET

Source: Coffman Associates 1997b.

Exhibit 6H
F.A.R. PART 77 AIRSPACE PLAN FOR OXNARD AIRPORT

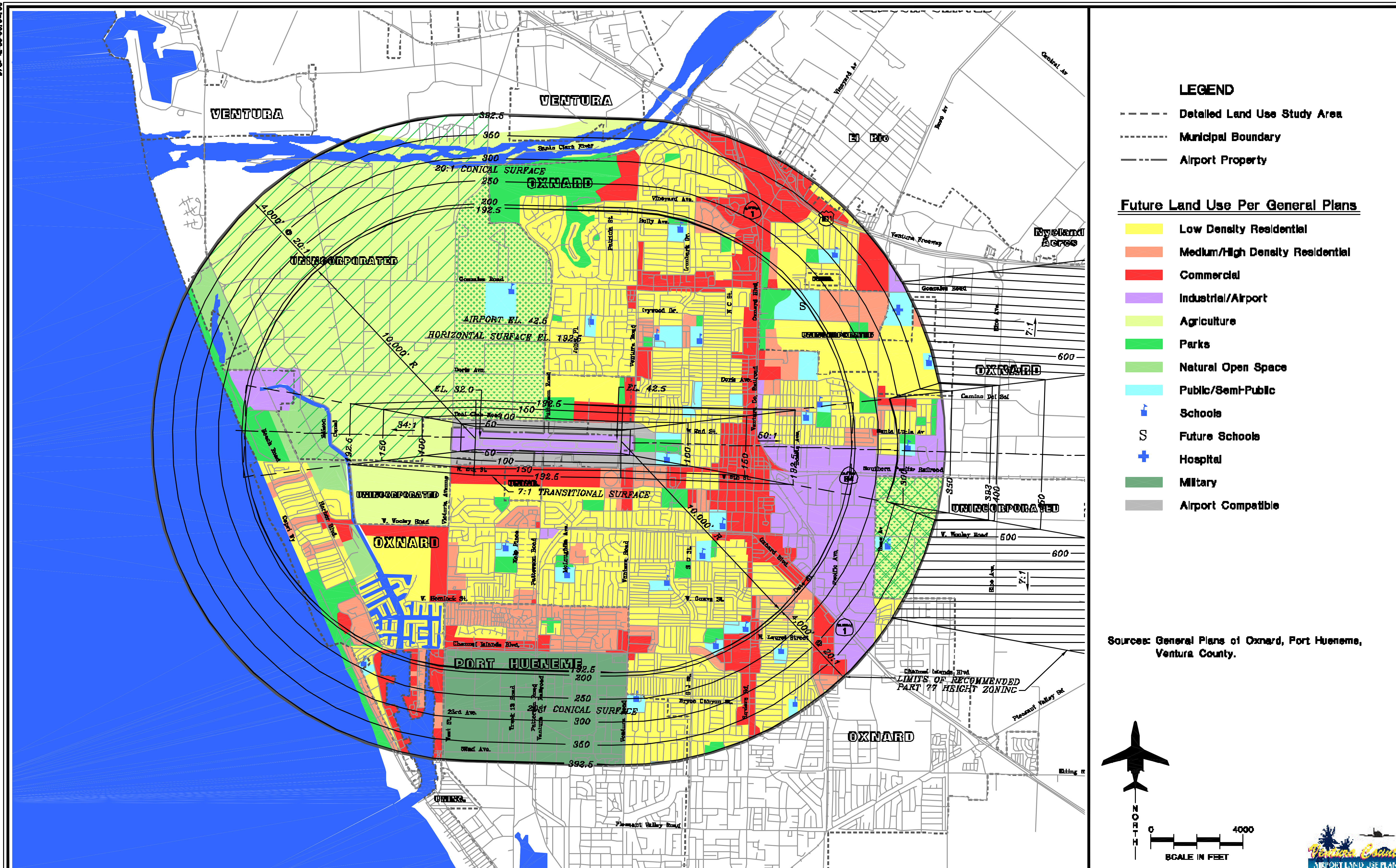


Exhibit 6J
F.A.R. PART 77 AIRSPACE PLAN IN
IMMEDIATE OXNARD AIRPORT AREA

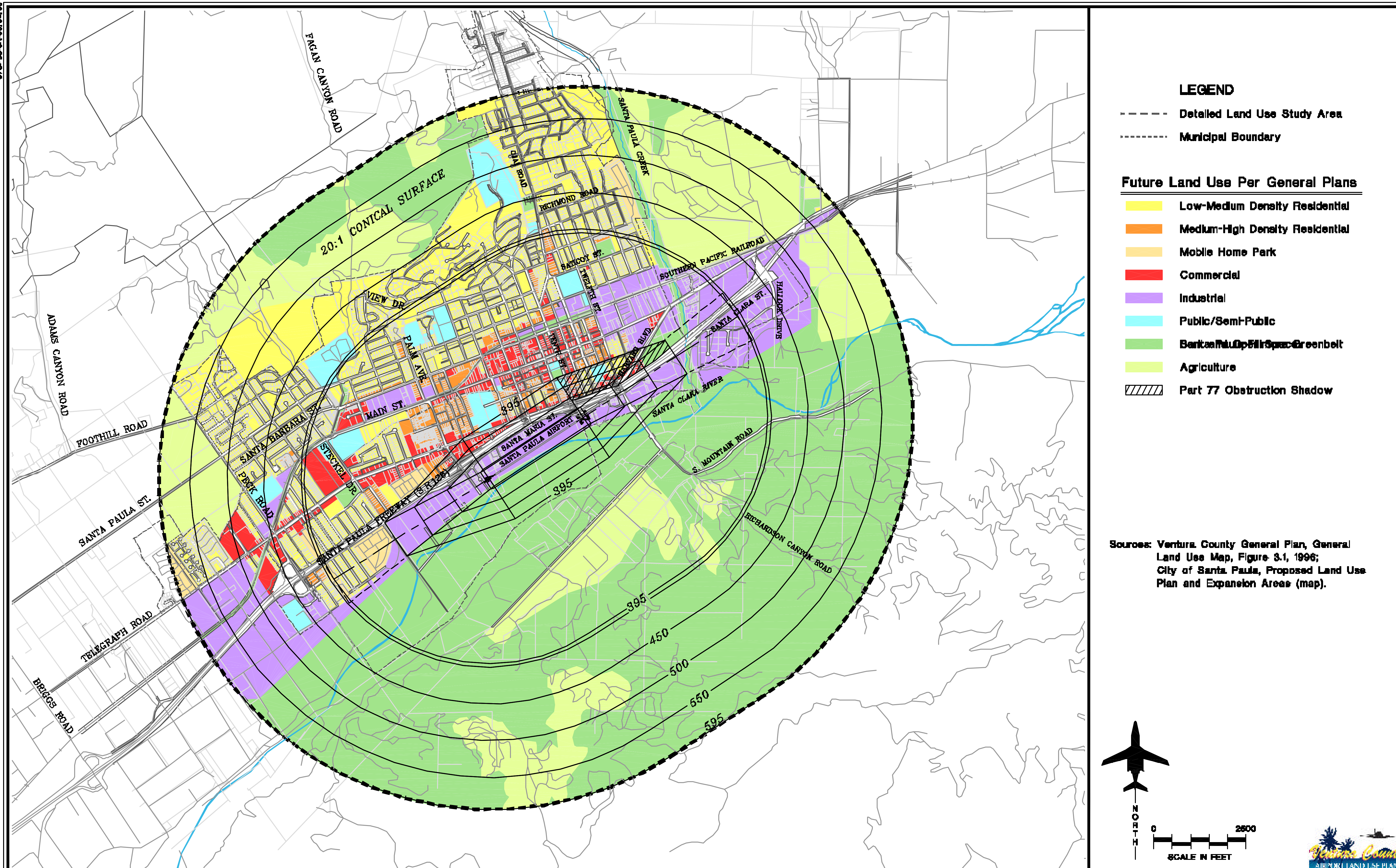


Exhibit 6K
F.A.R. PART 77 AIRSPACE PLAN
FOR SANTA PAULA AIRPORT

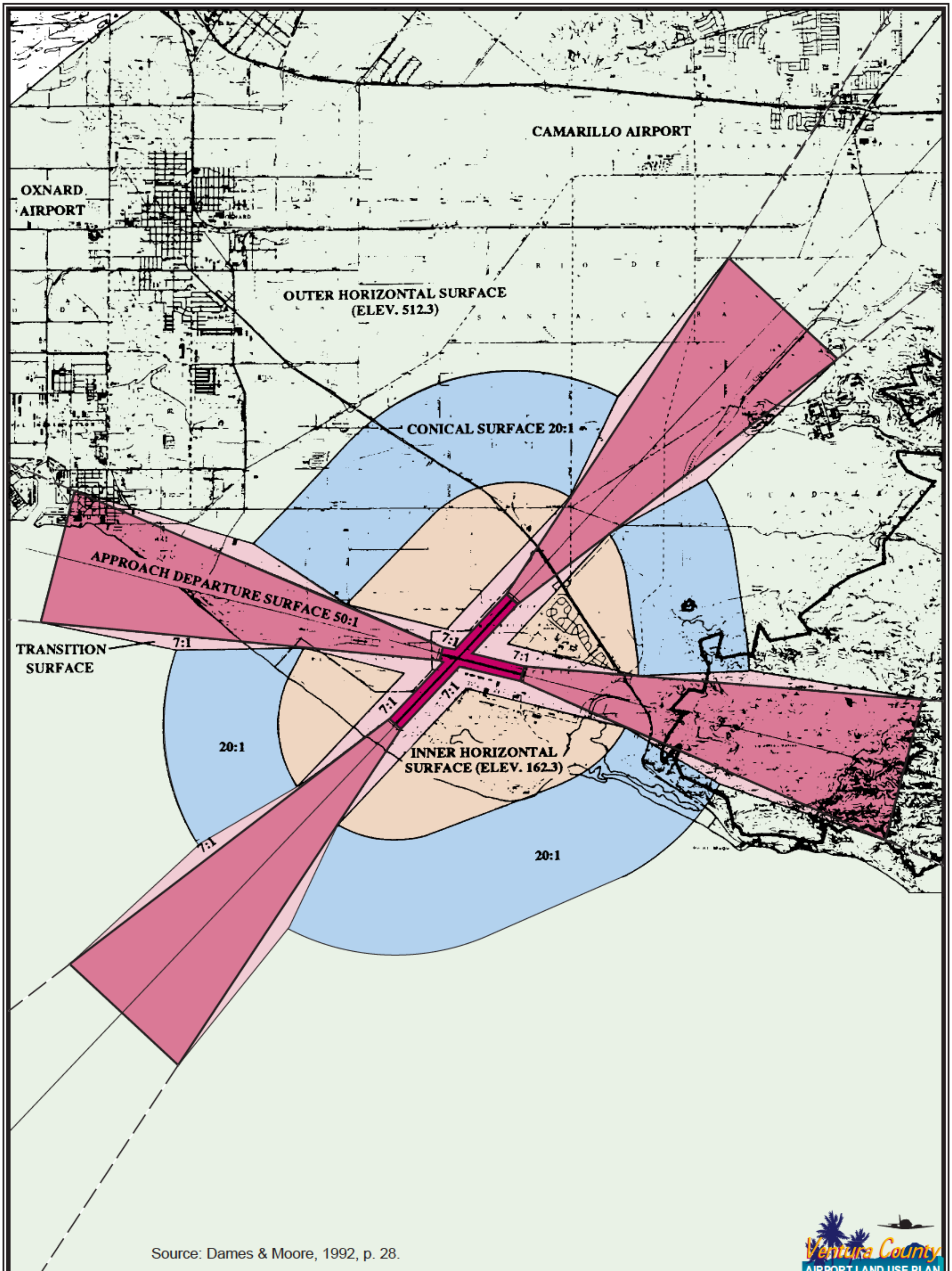


Exhibit 6L
F.A.R. PART 77 AIRSPACE PLAN
FOR NAS POINT MUGU

Appendix A
ALTERNATIVE APPROACHES FOR SETTING CLUP POLICIES

Appendix A:
ALTERNATIVE APPROACHES FOR SETTING CLUP POLICIES

EXECUTIVE SUMMARY

This discussion paper is intended as a reference document that was used by the Project Advisory Committee and the Airport Land Use Commission review the existing *Airports Comprehensive Land Use Plan for Ventura County* (the 1991 CLUP). While the document contains considerable detail, distinct trends and tendencies emerge. The discussion also sheds light on some of the issues deserving attention during the update of the Ventura County CLUP. These concerns and issues are described for each substantive policy area covered by the CLUP: noise compatibility, safety, and airspace protection.

NOISE COMPATIBILITY STANDARDS AND ISSUES

While there are many different sets of guidelines for noise and land use compatibility, there is reasonably good agreement among the various approaches. The definition of "noise-sensitive land uses", for example, is generally agreed to be housing, institutions with a residential component, and public gathering places where quiet is essential for the conduct of typical activities. The noise compatibility standards also agree on the use of a cumulative noise dosage metric to define areas of different noise exposure. In most of the United States, the DNL (day-night sound level) metric is used for this purpose, while California State law requires the use of the similar CNEL (community noise equivalent level) metric.

The major point on which various systems of noise compatibility standards differ is the threshold at which aircraft noise should be considered significant for purposes of compatible land use planning. While Federal standards are concerned only with noise exceeding 65 CNEL (or DNL), State guidelines and some local standards are concerned with noise down to 60 or even 55 CNEL (or DNL).

The current noise compatibility guidelines of the 1991 CLUP are reasonable in light of the California state guidelines. The current policies state that aircraft noise above 60 CNEL is a concern for housing and noise-sensitive institutions. Between 60 and 65 CNEL, new construction of these uses is permitted "only after an analysis of noise reduction requirements and necessary noise insulation is included in the design." Housing is not permitted in areas exposed to noise above 65 CNEL. Noise-sensitive institutions are not permitted in areas exposed to noise above 70 CNEL. Between 65 and 70 CNEL, noise-sensitive institutions must be sound-insulated to achieve an outdoor-to-indoor noise level reduction of 25 CNEL.

While the CLUP's current noise compatibility guidelines are reasonable, they merit reconsideration. The 1993 *Airport Land Use Planning Handbook* recommends that no housing be allowed within the 60 CNEL in quiet communities. Other counties also use the 60 CNEL contour as the maximum permitted for housing and noise-sensitive institutions. The complaint history at the airports in the County indicates public concerns with aircraft noise at levels far below 65 CNEL, the current incompatibility threshold. This is a common situation in areas where a premium is placed on outdoor living. This also indicates the limited value of sound insulation as a noise mitigation technique in such areas.

If the noise impact threshold is kept at the current level, it would be helpful to clarify the intent of the requirement for an "analysis of noise reduction requirements" within the 60 to 65 CNEL contour range. A target noise level or noise level reduction should be specified in the policy.

At two of the four airports in the County, multiple noise contour maps are available, representing different operational levels. In selecting the regulatory noise contours at each airport, it would make sense to choose the largest set of contours, thus defining a reasonable worst case noise impact area. If different contours are larger in different areas, a composite set of contours should be created to define the noise exposure risk envelope.

Are guidelines needed for determining the location of noise contours on the ground? In some communities, the contours are squared off to follow roads or natural features. In other communities, the location of noise contours on the ground is simply scaled off the maps as best as possible.

The current noise compatibility policies attempt to promote "fair disclosure" of the aircraft noise and overflight situation outside the 60 CNEL contour and within the "traffic pattern zone". The policy requires a review of noise attenuation requirements, a disclosure covenant, and an avigation easement. Some refinements in this policy may be appropriate. First, the intent of the "review of noise attenuation requirements" and appropriate performance standards should be set or this policy should be discontinued. Second, this policy may be more appropriately placed in the section on safety policies tied to the traffic pattern zone.

SAFETY COMPATIBILITY STANDARDS AND ISSUES

There is considerable variation among safety compatibility standards and guidelines in California counties. This is to be expected since the safety standards necessarily require judgements to be made about the risk of rare events -- namely aircraft accidents.

Specific points of variability among safety area standards include the definition of safety area boundaries and the land use standards that should apply within various safety areas. These standards, however, all recognize the same basic principles. The risk of aircraft accidents increases as distance from the runway and extended runway centerline decreases. This gives rise to the common requirements that more open space should be preserved and less housing and population density should be permitted in areas near the runway and the extended runway centerline.

Different sets of safety compatibility standards vary in their clarity and ease of implementation. Some, for example, include only a very general list of land uses to which the standards apply. This forces ALUCs and their staffs to interpret whether the standards were meant to apply to various specific development proposals that will arise. Many other standards relate to the density of people permitted at any given land use. If this is to be practical, a clear method for unambiguously calculating this factor must be agreed upon.

The following issues deserve discussion in the Ventura County CLUP.

In some counties, specific land uses that would be inherently hazardous or cause serious problems in disrupted community services in the event of an aircraft accident are specifically prohibited in various safety zones. (Examples include bulk storage of flammable materials and power substations.) Should the safety standards be revised to add these kinds of criteria?

The CLUPs in some counties specify maximum occupancy levels for land uses in some close-in safety zones. Is there any interest in applying such standards in Ventura County? If so, guidelines for computing the occupancy rate of structures and land uses will be needed.

Is there any interest in redrawing the safety areas to reflect the updated *Airport Land Use Planning Handbook*? One refinement that deserves consideration is to curve the "outer safety zone" to follow any common, close-in, turning tracks. In addition, the traffic pattern zone boundaries should be reconsidered to ensure that they encompass all areas typically overflown by aircraft in the traffic pattern. (In the 1991 CLUP, the traffic pattern zones at the three civilian airports appear to be too small.)

The Point Mugu AICUZ study does not define a "traffic pattern zone". Should such an area be defined for purposes of the CLUP?

Some of the land use criteria applying to the safety zones in the Point Mugu safety zones are vague. Terms such as "low intensity uses" must be defined in quantitative terms if the regulations are to be uniformly administered.

AIRSPACE PROTECTION STANDARDS AND ISSUES

The 1991 CLUP uses the F.A.R. Part 77 imaginary surfaces as the basis for its airspace protection standards. This approach is typical of other counties in California and elsewhere in the country. There is no reason to alter the thrust of the CLUP's approach to airspace protection. Minor refinements may be advisable depending on the ALUC's actual experience in implementing these standards. At this point, one change deserves consideration.

The standards do not include any provision for building in areas where the terrain penetrates the Part 77 surfaces. In order to avoid claims of unconstitutional taking of property without just compensation, the ALUC should consider setting criteria providing for the construction of safe structures in such situations. At a minimum, these criteria should set a maximum building height, noting that issuance of a permit is conditioned on an FAA aeronautical study and a finding that the structure would not be a hazard to air navigation. The criteria should note that marking and lighting of the structure may be required.

Alternative Approaches for Setting CLUP Policies

A.1 INTRODUCTION

This discussion paper considers alternative ways of establishing airport compatibility policies. First, it reviews the policies in the 1991 *Airports Comprehensive Land Use Plan Update for Ventura County* (the 1991 CLUP). These are then compared with standards and planning criteria provided by the Federal government, the State of California, and the comprehensive land use plans of other selected counties. After considering this information, it is anticipated that the Project Advisory Committee will be able to reflect on the suitability of the County's existing CLUP policies and identify possible refinements to consider during the CLUP update process. The intent is to either reaffirm the existing policy framework or establish a refined policy framework which can be used in evaluating the particular land use compatibility planning situations at each airport.

A.2 POLICIES OF 1991 CLUP

The policies of the 1991 CLUP are categorized in terms of noise compatibility, safety, and height limitation. The comprehensive land use plans at each airport--Camarillo, Oxnard, Santa Paula, and Naval Air Station (NAS) Point Mugu – are shown in **Exhibits A1** through **A4**.

A.2.1 NOISE

Noise contours were developed for the three civilian airports for estimated 1990 conditions and projected 2010 conditions. The largest set of contours was used to define the various noise compatibility zones. For Santa Paula, this was the 2010 forecast. For Oxnard and Camarillo, the 1990 contours were generally larger, although the 2010 contours were larger off the east ends of the airports. For these airports, composite sets of contours were developed by overlaying the 1990 and 2010 contours. The outermost boundary of each noise contour was used for establishing the noise compatibility boundaries.

For NAS Point Mugu, a 2010 noise forecast was used to define the noise compatibility zones.

The noise policies of the 1991 CLUP are summarized in **Table A1**. They were based on the State noise compatibility guidelines from the 1983 *Airport Land Use Planning Handbook* (Metropolitan Transportation Commission 1983), and guidelines of the U.S. Department of Defense. In most cases, the most restrictive of the two sets of standards was used.

In the 60 to 65 CNEL range, mobile home parks and outdoor amphitheaters are considered "unacceptable." Other residential uses, hotels and motels, and various noise-sensitive institutions (i.e., schools, hospitals, places of worship, auditoriums) are considered "conditionally acceptable." New construction of these uses is permitted only after an analysis of noise reduction requirements is made, although no specific criteria are stipulated. The intent may be to defer to State law which requires new multi-family and hotel construction within the 60 CNEL contour to be sound-insulated to achieve an interior sound level of 45 CNEL. Noise easements are also "recommended" for these uses within the 60 to 65 CNEL range.

In the 65 to 70 CNEL range, all housing is considered unacceptable. Hotels and noise-sensitive institutions are required to be sound-insulated to achieve and outdoor to indoor noise level reduction of 25 decibels. Noise easements are also recommended for these uses.

In the 70 to 75 CNEL range, most noise-sensitive institutions are considered unacceptable. Auditoriums and hotels are required to be sound-insulated to achieve a noise level reduction of 30 decibels. Noise easements are recommended for these uses. Commercial and industrial uses are conditionally compatible if noise-sensitive areas are designed to achieve a noise level reduction of 25 decibels.

In the 75 to 80 CNEL range, auditoriums and hotels are unacceptable. Commercial and industrial uses must be designed to achieve a noise level reduction of 30 decibels.

97SP12-A1-9/4/97

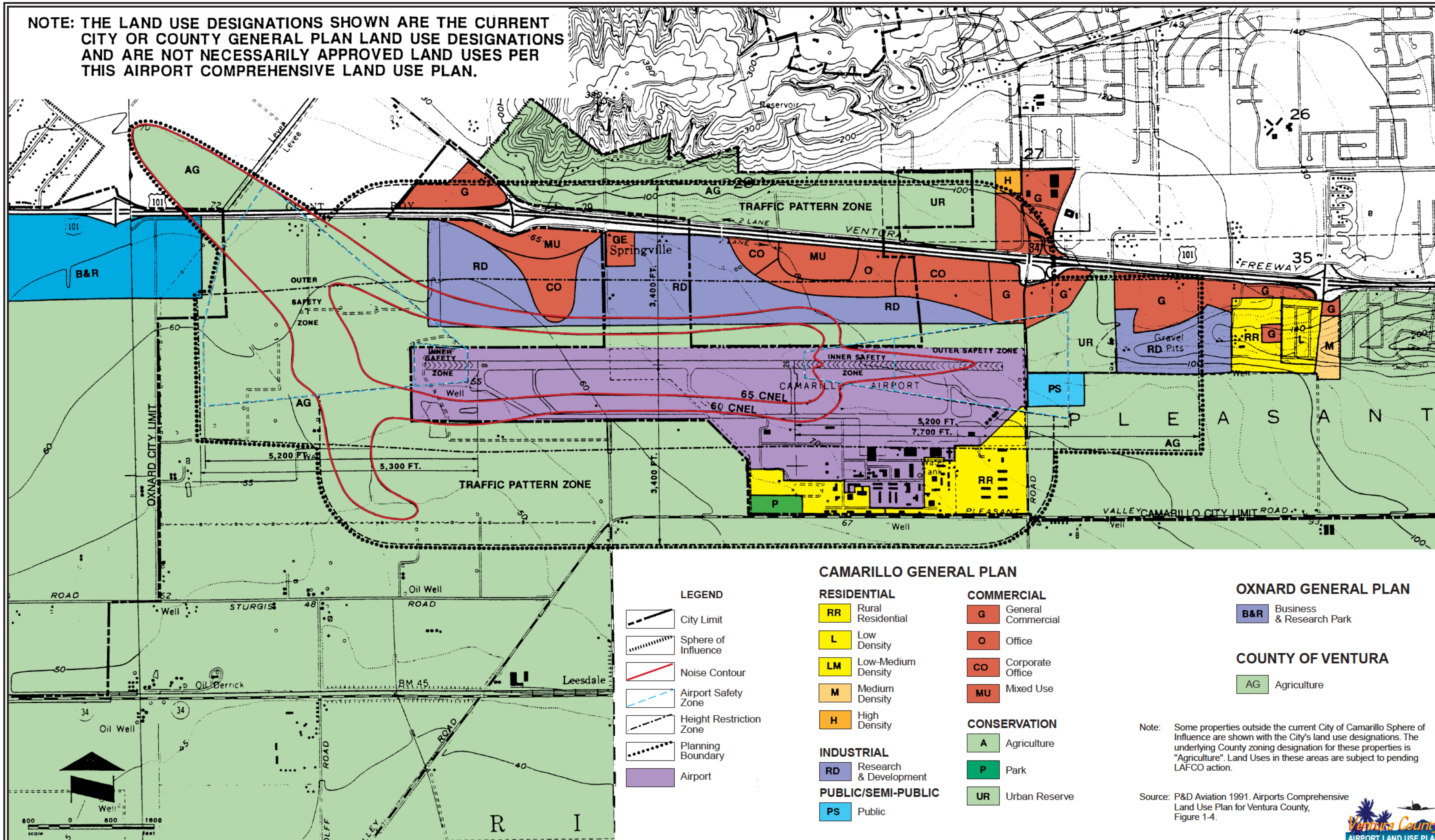


Exhibit A1
1991 COMPREHENSIVE LAND USE PLAN
FOR CAMARILLO AIRPORT

97SP12-A2-9/4/97

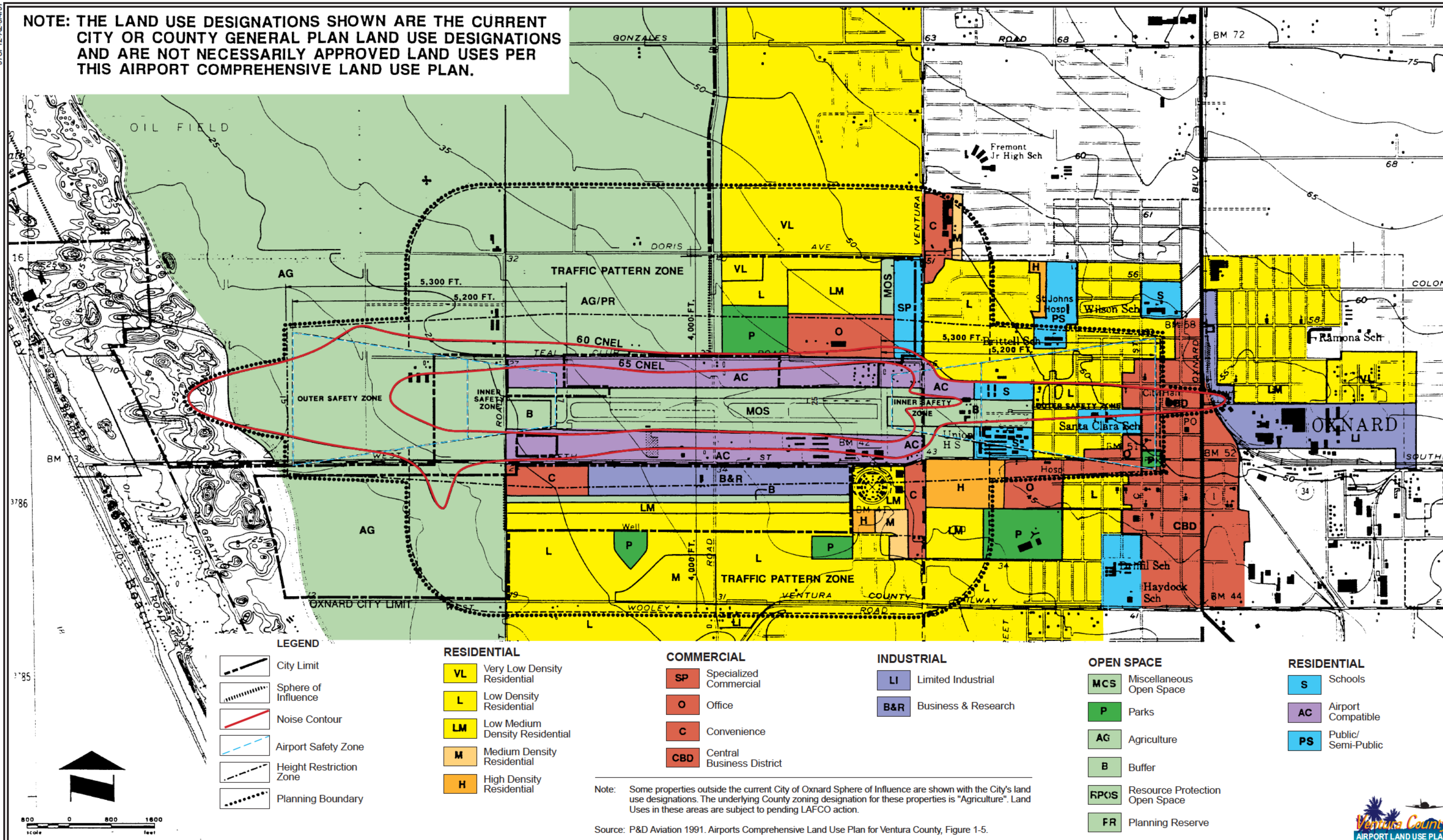


Exhibit A2
1991 COMPREHENSIVE LAND USE PLAN
FOR OXNARD AIRPORT

97SP12-A3-9/4/97

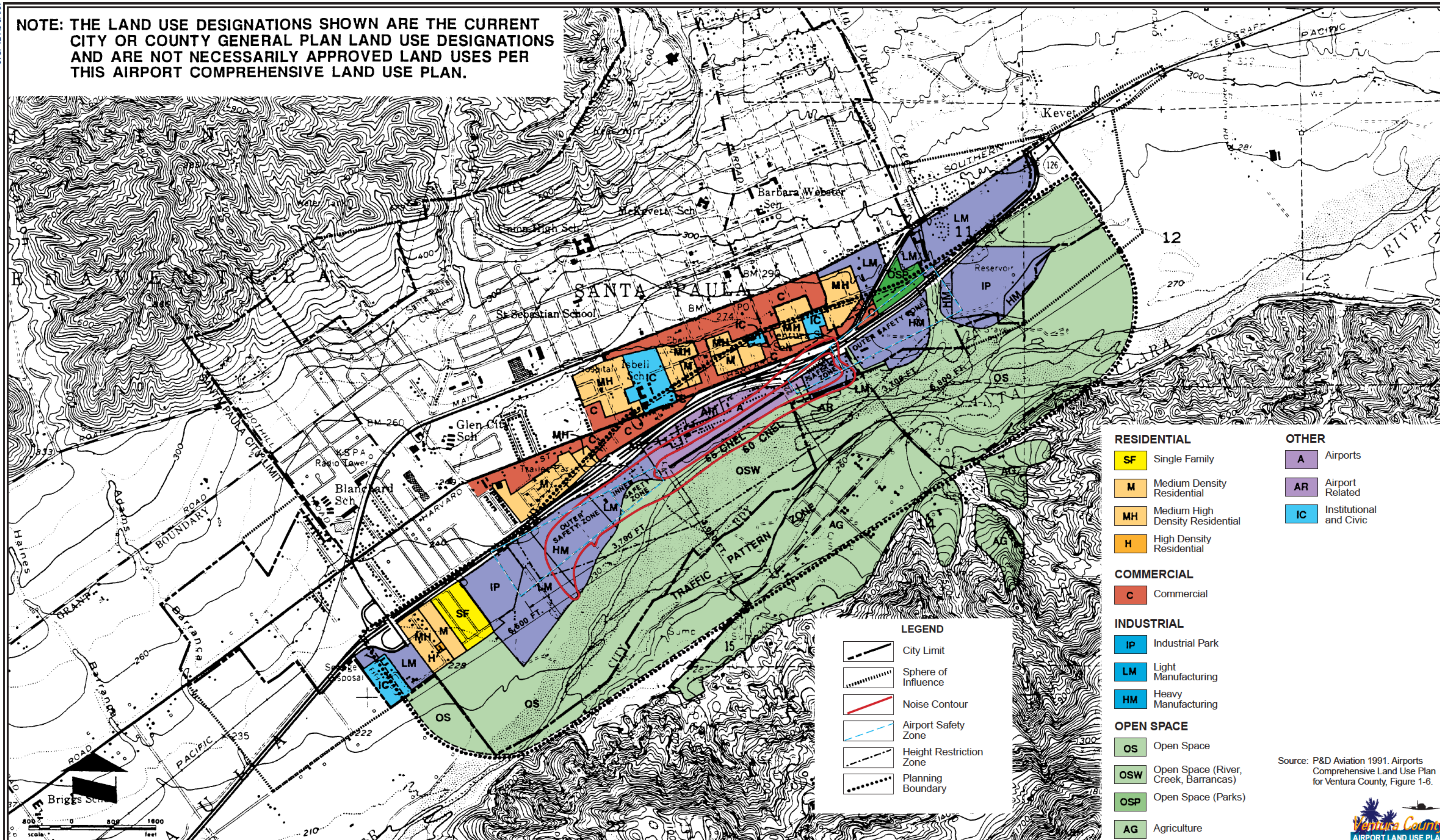


Exhibit A3
1991 COMPREHENSIVE LAND USE PLAN
FOR SANTA PAULA AIRPORT

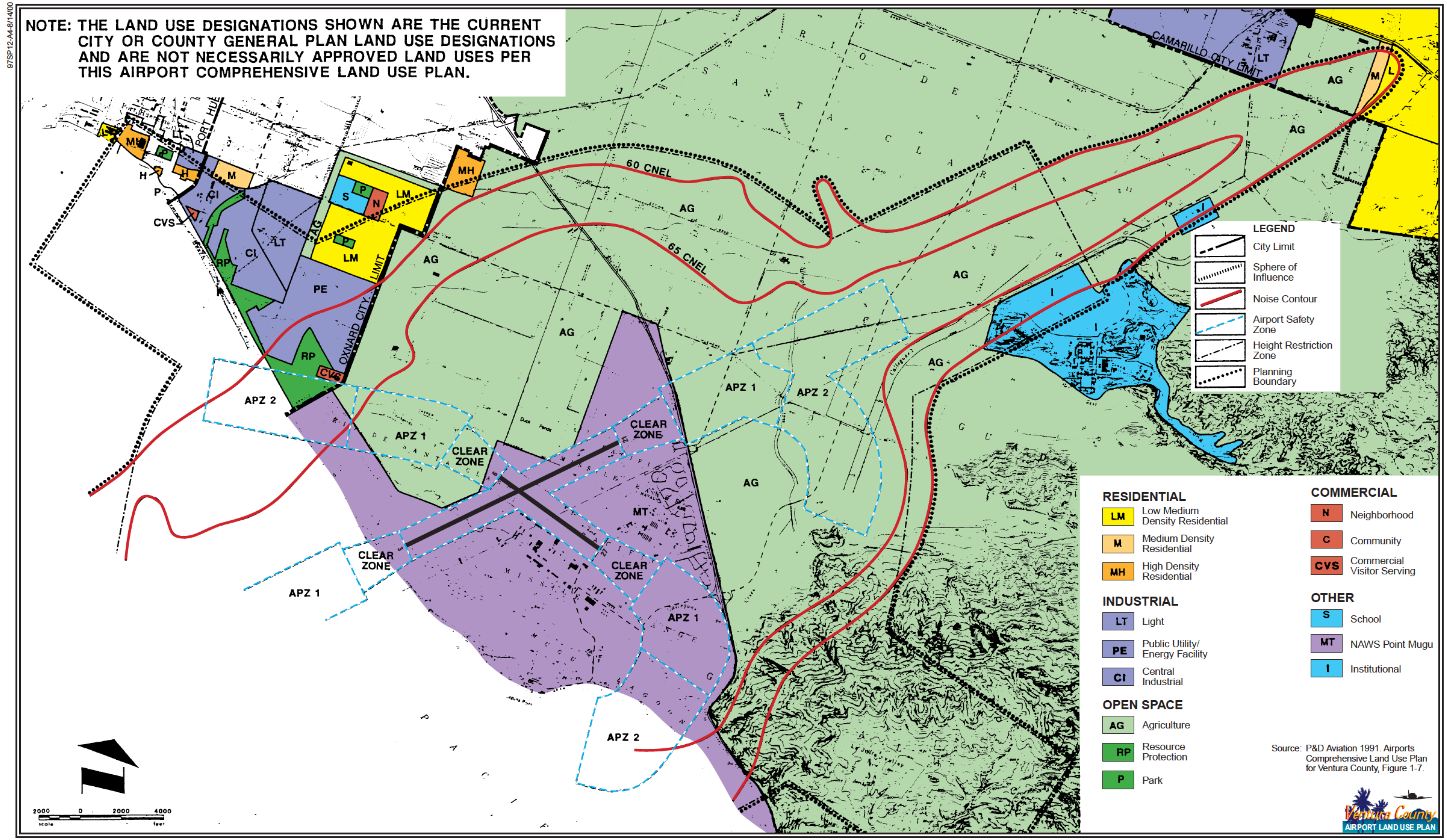


Exhibit A4
1991 COMPREHENSIVE LAND USE PLAN
FOR NAS POINT MUGU

TABLE A1
Recommended Land Use Compatibility Guidelines
Related to Aircraft Noise for Ventura County Airports
Comprehensive Land Use Plan

	CNEL Range (dB)				
Land Use	**60-65**	**65-70**	**70-75**	**75-80**	**Over 80**
Residential [1]					
Single Family	C [a]	U	U	U	U
Multi-Family	C [a]	U	U	U	U
Mobile Home Parks	U	U	U	U	U
Public/Institutional					
Hospitals/Convalescent Homes	C [a]	C [b]	U	U	U
Schools	C [a]	C [b]	U	U	U
Churches/Synagogues	C [a]	C [b]	U	U	U
Auditoriums/Theaters	C [a]	C [b]	C [c]	U	U
Transportation Terminals	A	A	C [d]	C [e]	C [f]
Communication/Utilities	A	A	C [d]	C [e]	C [f]
Automobile Parking	A	A	C [d]	C [e]	C [f]
Commercial					
Hotels and Motels	C [a]	C [b]	C [c]	U	U
Offices and Business/ Professional Services	A	A	C [g]	C [h]	U
Wholesale	A	A	C [d]	C [e]	C [f]
Retail	A	A	C [g]	C [h]	U
Industrial					
Manufacturing-General/ Heavy	A	A	C [d]	C [e]	C [f]
Light Industrial	A	A	C [d]	C [e]	C [e]
Research and Development	A	A	C [d]	C [e]	C [e]
Business Parks/Corporate Offices	A	A	C [d]	C [e]	C [e]
Recreation/Open Space					
Outdoor Sports Arenas	A	C [k]	C [k]	U	U
Outdoor Amphitheaters	U	U	U	U	U
Parks	A	A	A	U	U
Outdoor Amusement	A	A	A	U	U
Resorts and Camps	A	A	A	U	U
Golf Courses and Water Recreation	A	A	A	U	U
Agriculture	A	A	A	A	A

TABLE A1 (Continued)
Recommended Land Use Compatibility Guidelines
Related To Aircraft Noise For Ventura County Airports
Comprehensive Land Use Plan

NOTES

A = Acceptable land use
C = Land use is conditional upon meeting compatibility criteria (see footnotes)
U = Unacceptable land use

[a] New construction or development may be undertaken only after an analysis of noise reduction requirements and necessary noise insulation is included in the design. Noise easements are recommended.

[b] Noise level reduction [NLR] from outdoor to indoor of at least 25 CNEL must be achieved by incorporation of noise attenuation into the design and construction of the structure. Noise easements are recommended.

[c] Noise level reduction [NLR] from outdoor to indoor of at least 30 CNEL must be achieved by incorporation of noise attenuation into the design and construction of the structure. Noise easements are recommended.

[d] Measures to achieve NLR of 25 must be incorporated into the design and construction of portions of these buildings where the public is received, office areas, noise sensitive areas or where the normal noise level is low.

[e] Measures to achieve NLR of 30 must be incorporated into the design and construction of portions of these buildings where the public is received, office areas, noise sensitive areas or where the normal noise level is low.

[f] Measures to achieve NLR of 35 must be incorporated into the design and construction of portions of these buildings where the public is received, office areas, noise sensitive areas or where the normal noise level is low.

[g] Noise level reduction [NLR] of 25 CNEL is required.

[h] Noise level reduction [NLR] of 30 CNEL is required.

[i] Noise level reduction [NLR] of 35 CNEL is required.

[j] Land uses involving concentrations of people are unacceptable.

[k] Sound reinforcement system is required.

[l] For new residential uses in areas below 60 dB CNEL that are within the Traffic Pattern Zone, it is recommended that the local jurisdictions require a review of noise attenuation requirements, a disclosure covenant (notification of proximity to airport prior to sale of property), and an avigation easement.

Source: P&D Aviation 1991.

Finally, the noise standards recommend several measures for new residential uses outside the 60 CNEL contour but inside the "Traffic Pattern Zone." These include a review of noise attenuation requirements, an avigation easement, and a "disclosure covenant" notifying buyers of the proximity of the property to the airport.

A.2.2 SAFETY

A.2.2.a Civilian Airports

The 1991 CLUP establishes three safety zones at each civilian airport. These are the Inner Safety Zone, the Outer Safety Zone, and the Traffic Pattern Zone. The Inner Safety Zone corresponds to the runway protection zone (RPZ) off the runway ends. The Outer Safety Zone corresponds to the Part 77 approach surface extending between the RPZ and the base of the Part 77 horizontal surface. The size of these areas varies depending on the type of approach established or planned for each runway end. At Camarillo, the Outer Safety Zone has been enlarged to cover the area beneath a commonly used right turning flight track used by Runway 26 departures.

At Oxnard and Camarillo, the Traffic Pattern Zone (TPZ) is a roughly rectangular area centered on the airport. It is intended to cover the area subject to frequent low altitude overflights and touch-and-go traffic in the pattern. The dimensions of the TPZ were defined based on the outer edge of the assumed traffic pattern flight tracks. The TPZ extends 4,000 feet either side of the runway centerline at Oxnard and 3,400 feet either side of the runway at Camarillo.

At Santa Paula, the TPZ is asymmetrical. It extends only south of the runway. The TPZ extends 6,800 feet off the ends of the runway and 3,000 feet off the south side of the runway. The TPZ was not established on the north side of the airport because aircraft flying in this area over the city are at higher than typical pattern altitude.

Table A2 shows the land use compatibility standards for the three air safety zones established at the civilian airports in Ventura County. In the Inner Safety Zone, agriculture is the only acceptable land use. Golf courses and water recreation are conditionally acceptable, provided clubhouses are not allowed. Communication, utilities, and auto parking is conditionally acceptable although structures are not permitted. Aboveground utility lines and parking are allowed only if approved by the FAA as not constituting a hazard to air navigation.

In the Outer Safety Zone, communications/utilities, auto parking, golf courses and water recreation and agriculture are all acceptable land uses. Most commercial and industrial uses are conditionally acceptable if the maximum structural coverage is limited to 25 percent of the gross lot area. (This includes land in streets and green belts.) All other uses, including residential, hotels and other gathering places are unacceptable.

In the Traffic Pattern Zone, acceptable land uses include resorts and camps, outdoor amusement, and parks. Residential, commercial, and industrial uses are conditionally acceptable if the maximum structural coverage is limited to 50 percent of the gross lot area. Large gathering places, including hospitals, schools, places of worship, auditoriums and theaters, transportation terminals, and outdoor sports arenas and amphitheaters are unacceptable.

A.2.2.b NAS Point Mugu

At NAS Point Mugu, three safety zones are established. These are taken directly from the 1977 AICUZ Study for the station. (An updated AICUZ Study was published in July 1992, and some of the zone boundaries have changed.) They include the Clear Zone, Accident Potential Zone 1 (APZ-1), and Accident Potential Zone 2 (APZ-2).

The clear zone is a trapezoid-shaped area extending 3,000 feet off the runway end. It is 1,500 feet wide at the runway end and 2,284 feet at the outside end. The APZ-1 is defined immediately beyond the clear zone under flight paths with 5,000 or more annual operations. Typically, the zone is 3,000 feet wide and 5,000 feet long. It may be curved to conform to flight paths. The APZ-2 is an area just beyond APZ-1 where there is a measurable potential for accidents. It is typically 3,000 feet wide and 7,000 feet wide. It may also be curved to follow flight paths. (The Department of Defense AICUZ standards do not define an area analogous to the Traffic Pattern Zone designated around the civilian airports in the County.)

TABLE A2
Recommended Land Use Compatibility Guidelines In Air Safety Zones For Civilian Airports, Ventura County Airports Comprehensive Land Use Plan

Land Use	Inner Safety Zone	Outer Safety Zone	Traffic Pattern Zone
Residential			
Single Family	U	U	C [a]
Multi-Family	U	U	C [a]
Mobile Home Parks	U	U	C [a]
Public/Institutional			
Hospitals/Convalescent Homes	U	U	U
Schools	U	U	U
Churches/Synagogues	U	U	U
Auditoriums/Theaters	U	U	U
Transportation Terminals	U	U	U
Communication/Utilities	C [b]	A	A
Automobile Parking	C [b]	A	A
Commercial			
Hotels and Motels	U	U	C [c]
Offices and Business/Professional Services	U	C [a]	C [c]
Wholesale	U	C [a]	C [c]
Retail	U	C [a]	C [c]
Industrial			
Manufacturing-General/Heavy	U	C [a]	C [c]
Light Industrial	U	C [a]	C [c]
Research and Development	U	C [a]	C [c]
Business Parks/Corporate Offices	U	C [a]	C [c]
Recreation/Open Space			
Outdoor Sports Arenas	U	U	U
Outdoor Amphitheaters	U	U	U
Parks	U	C [a]	A
Outdoor Amusement	U	C [a]	A
Resorts and Camps	U	C [a]	A
Golf Courses and Water Recreation	C [d]	A	A
Agriculture	A	A	A

TABLE A2 (Continued)
Recommended Land Use Compatibility Guidelines In Air Safety Zones For Civilian Airports, Ventura County Airports Comprehensive Land Use Plan

NOTES

A = Acceptable land use
C = Land use is conditional upon meeting established criteria (see footnotes)
U = Unacceptable land use

[a] Maximum structural coverage must be no more than 25 percent. "Structural coverage" is defined as the percent of building footprint area to total land area, including streets and greenbelts.

[b] The placing of structures or buildings in the Inner Safety Zone is unacceptable. Above ground utility lines and parking are allowed only if approved by the FAA as not constituting a hazard to air navigation.

[c] Maximum structural coverage must not exceed 50 percent. "Structural coverage" is defined as the percent of building footprint area to total land area, including streets and greenbelts. Where development is proposed immediately adjacent to the airport property, it is suggested that structures be located as far as practical from the runway.

[d] Clubhouse is unacceptable in this zone.

Source: P&D Aviation 1991.

Table A 3 shows the land use compatibility standards for the three air safety zones established for NAS Point Mugu. In the Clear Zone, most uses are considered unacceptable. Communication/utilities and auto parking are conditionally acceptable, provided that no buildings are built. Aboveground utility lines and auto parking are permitted only if approved by the Department of Defense as not constituting a hazard to air navigation.

In the APZ-1 zone, auto parking is the only acceptable land use. Several uses are conditionally acceptable, including communication/utilities, wholesale, retail, manufacturing, light industrial, parks, golf courses and water recreation, and agriculture. The conditions are somewhat vague. For example, the condition applying to wholesale, retail, and industrial uses requires that "uses must be evaluated separately due to the variation of densities of people and structures." No guidance is offered as to acceptable densities. One of the conditions applying to parks, golf courses, and water recreation is that "facilities must be low intensity." Again, no guidance or definition of "low intensity" is provided.

In the APZ-2 zone, several uses are considered acceptable, including transportation terminals, communication/utilities, auto parking, wholesale, manufacturing, light industrial, golf courses and water recreation, and agriculture. Several other uses are conditionally acceptable, including single family homes, places of worship, offices, retail, research and development, parks, and outdoor amusement. Here again the conditions are vague. Only "low intensity" facilities are permitted, although the term low intensity is not defined. Homes are limited to a density of 1 to 2 dwelling per acre. This may possibly be increased under a Planned Unit Development provided the maximum lot coverage by the building footprint is limited to 20 percent or less.

TABLE A3
Recommended Land Use Compatibility Guidelines In Air Safety Zones For PMTC Point Mugu, Ventura County Airports Comprehensive Land Use Plan

Land Use	Clear Zone	APZ-1	APZ-2
Residential			
Single Family	U	U	C [a]
Multi-Family	U	U	U
Mobile Home Parks	U	U	U
Public/Institutional			
Hospitals/Convalescent Homes	U	U	U
Schools	U	U	U
Churches/Synagogues	U	U	C [b]
Auditoriums/Theaters	U	U	U
Transportation Terminals	U	U	A
Communication/Utilities	C [c]	C [d]	A
Automobile Parking	C [c]	A	A
Commercial			
Hotels and Motels	U	U	U
Offices and Business/Professional Services	U	U	C [e]
Wholesale	U	C [b]	A
Retail	U	C [b]	C [b]
Industrial			
Manufacturing-General/Heavy	U	C [b]	A
Light Industrial	U	C [b]	A
Research and Development	U	U	C [b]
Business Parks/Corporate Offices	U	U	C [b]
Recreation/Open Space			
Outdoor Sports Arenas	U	U	U
Outdoor Amphitheaters	U	U	U
Parks	U	C [f]	C [f]
Outdoor Amusement	U	U	C [f]
Resorts and Camps	U	U	U
Golf Courses and Water Recreation	U	C [f, g]	A
Agriculture	U	C [h]	A

TABLE A3 (Continued)
Recommended Land Use Compatibility Guidelines In
Air Safety Zones For PMTC Point Mugu, Ventura County Airports
Comprehensive Land Use Plan

NOTES

A = Acceptable land use
C = Land use is conditional upon meeting established criteria (see footnotes)
U = Unacceptable land use

[a] Maximum density must be 1-2 dwelling units per acre, possibly increased under a Planned Unit Development (PUD) where maximum lot coverage is less than 20 percent. "Lot coverage" is defined as the average percent of building footprint area to lot area.

[b] Uses must be evaluated separately due to the variation of densities of people and structures.

[c] The placing of structures or buildings in the Clear Zone is unacceptable. Above ground utility lines and parking area allowed only if approved by the DOD as not constituting a hazard to air navigation.

[d] Passenger terminals and major above-ground transmission lines are unacceptable in APZ-1.

[e} Low-intensity office uses only. Meeting places, etc. are unacceptable.

[f] Facilities must be low intensity.

[g] Clubhouse is unacceptable in this zone.

[h] Factors to be considered: labor intensity, structural coverage, explosive characteristics, air pollution.

Source: P&D Aviation 1991.

A.2.3 HEIGHT LIMITATION

Height limitations in the 1991 CLUP are based on the guidelines provided by Federal Aviation Regulation (F.A.R.) Part 77, *Objects Affecting Navigable Airspace*. These standards are used by the FAA in determining whether objects may obstruct safe air navigation. Part 77 defines a variety of imaginary surfaces around airports. Each surface is defined at a certain altitude around the airport. The dimensions of the Part 77 surfaces vary depending on the type of approach to the runways. Runways with nonprecision approaches have larger surfaces and flatter approach slopes than visual runways. Precision instrument runways have still larger surfaces and flatter approaches.

The FAA uses the Part 77 standards not as absolute height limits, but as elevations above which structures may constitute unsafe obstructions. Any penetrations of the Part 77 surfaces are subject to review by the FAA on a case by case basis. If a safety problem is found, the FAA issues a determination of a hazard to air navigation. The FAA does not have the authority to prevent the encroachment. It is up to the local authorities to implement the FAA's recommendation.

The 1991 CLUP uses the Part 77 guidelines as regulatory height limits that cannot be exceeded by new construction. The CLUP notes that terrain penetrates some of the Part 77 surfaces at Camarillo and Santa Paula Airports and NAS Point Mugu. In these areas, the height limitations would appear to completely prohibit any development above the ground. The CLUP provides no guidance as to whether, and under what conditions, variance should be allowed in these cases.

The 1991 CLUP notes one exception to the Part 77 height restrictions. This applies to Santa Paula Airport. Structures off the east end of the airport may be allowed to penetrate the approach and transitional surfaces "to the extent that such penetrations are 'masked' by the existing penetrations of the Santa Paula Freeway." The term 'masked' means that height penetrations of the Part 77 surface are allowed but only to the degree they are below the approach slope created by the Santa Paula Freeway and its required 17-foot clearance. The masked area consists of the land north of the freeway and east of the end of the primary surface (approximately 10th Street).

A.3 ALTERNATIVE NOISE COMPATIBILITY POLICIES

This section discusses possible alternative noise compatibility policies based on a variety of sources, including Federal guidelines, the State's updated *Airport Land Use Planning Handbook* (Hodges & Shutt 1993), and the CLUPs of other counties in California.

A.3.1 FEDERAL NOISE COMPATIBILITY GUIDELINES

Since the 1960s, many different sets of Federal noise and land use compatibility guidelines have been proposed and used. This section reviews some of the more well known guidelines. These Federal guidelines are based on the DNL metric -- day-night sound level. (In mathematical equations, DNL is referred to as Ldn.) The DNL metric is very similar to the CNEL metric used in California. The only difference is that DNL does not include the weighting penalty for evening noise between 7 and 10 p.m.

A.3.1.a FAA-DOD Guidelines

In 1964, the Federal Aviation Administration (FAA) and the U.S. Department of Defense (DOD) published similar documents setting forth guidelines to assist land use planning in areas subjected to aircraft noise from nearby airports. These are presented in **Table A4**. The guidelines establish three zones, describing the expected responses to aircraft noise from residents of each zone. In Zone 1, corresponding to areas exposed to noise below 65 DNL, essentially no complaints would be expected, although noise could be an occasional nuisance. In Zone 2, corresponding to 65 to 80 DNL, individuals may complain, perhaps vigorously. In Zone 3, corresponding to 80 DNL and above, vigorous complaints would be likely and concerted group action could be expected.

TABLE A4
Chart for Estimating Response of Communities Exposed to Aircraft Noise
1964 FAA-DOD Guidelines

Noise Rating	Zone	Description of Expected Response
Less than 65 Ldn 100 CNR	1	Essentially no complaints would be expected. The noise may, however, interfere occasionally with certain activities of the residents.
65 to 80 Ldn 100 to 115 CNR	2	Individuals may complain, perhaps vigorously. Concerted group action is possible.
Greater than 80 Ldn 115 CNR	3	Individual reactions would likely include repeated, vigorous complaints. Concerted group action might be expected.

Notes: Ldn is the mathematical notation for DNL – day-night sound level. DNL is similar to CNEL except that evening noise (7 to 10 p.m.) is not assigned a weighting penalty.

CNR stands for "community noise rating", a cumulative noise descriptor similar to Ldn which is no longer in general use.

Source: U.S. DOD 1964. Cited in Kryter 1984, p. 616.

A.3.1.b HUD Guidelines

In 1971, the U.S. Department of Housing and Urban Development published noise assessment guidelines for evaluating the acceptability of sites for housing assistance. The guidelines, shown in **Table A5**, establish four classes of noise impact. The first two categories refer to areas outside the 65 DNL contour, the first at a distance exceeding the distance between the 65 and 75 DNL contours, the second at a lesser distance. Housing is considered clearly acceptable in the first category and "normally acceptable" in the second. Housing is considered "normally unacceptable" in the 65 to 75 DNL range and clearly unacceptable inside the 75 DNL contour.

TABLE A5 **Site Exposure to Aircraft Noise** **1971 HUD Guidelines**	
Distance from site to the center of the area covered by the principal runways	**Acceptability category**
Outside the Ldn=65 (NEF=30, CNR=100) contour at a distance greater than or equal to the distance between the contours Ldn=65 and Ldn=75	Clearly acceptable
Outside the Ldn=65 contour, at a distance less than the distance between the Ldn=65 and Ldn=75	Normally acceptable
Between the Ldn=65 and Ldn=75 contours	Normally unacceptable
Within the Ldn=75 contour	Clearly unacceptable

Note: CNR and NEF stand for "community noise rating", and "noise exposure forecast", cumulative noise descriptors which are no longer in general use.

Source: Schultz and McMahon 1971. Cited in Kryter 1984, p. 617.

A.3.1.c EPA Guidelines

The U.S. Environmental Protection Agency published a document in 1974 suggesting maximum noise exposure levels to protect public health with an adequate margin of safety. These are shown in **Table A6**. They note that the risk of hearing loss may become a concern with exposure to noise above 74 DNL. Interference with outdoor activities may become a problem with noise levels above 55 DNL. Interference with indoor residential activities may become a problem with interior noise levels above 45 DNL. If we assume that standard construction attenuates noise by about 20 decibels, with doors and windows closed, a standard estimate, this corresponds to an exterior noise level of 65 DNL.

TABLE A6 Summary of Noise Levels Identified as Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety 1974 EPA Guidelines		
Effect	**Level**	**Area**
Hearing Loss	74 Ldn+	All areas
Outdoor activity interference and annoyance	55 Ldn+	Outdoors in residential areas and farms and other outdoor areas where people spend widely varying amounts of time and other places in which quiet is a basis for use.
	59 Ldn+	Outdoor areas where people spend limited amounts of time, such as school yards, playgrounds, etc.
Indoor activity interference and annoyance	45 Ldn+	Indoor residential areas
	49 Ldn+	Other indoor areas with human activities such as schools, etc.

Note: All Leq values from EPA document converted by FAA to Ldn for ease of comparison (Ldn = Leq(24)+4 dB).

Source: U.S. EPA 1974. Cited in FAA 1977a, p. 26.

A.3.1.d FAA Land Use Guidance System

In 1977, FAA issued an advisory circular on airport land use compatibility planning (FAA 1977b). It describes land use guidance (LUG) zones corresponding to aircraft noise of varying levels as measured by four different noise metrics (**Exhibit A5**). It also includes suggested land use noise sensitivity guidelines (**Exhibit A6**).

In **Exhibit A5**, LUG Chart I, four land use guidance zones are described, corresponding to DNL levels of 55 or less (A), 55 to 65 (B), 65 to 75 (C), and 75 and over (D). LUG Zone A is described as minimal exposure, normally requiring no special noise control considerations. LUG Zone B is described as moderate exposure where land use controls should be considered. LUG Zone C is subject to significant exposure, and various land use controls are recommended. In LUG Zone D, severe exposure, containment of the area within airport property, or other positive control measures, are suggested.

In LUG Chart II, **Exhibit A6**, most noise-sensitive uses are suggested as appropriate only within LUG Zone A. These include single-family and two-family dwellings, mobile homes, cultural activities, places of public assembly, and resorts and group camps. Uses suggested for Zones A and B include multi-family dwellings and group quarters;

LAND USE GUIDANCE ZONES (LUG)	NOISE EXPOSURE CLASS	INPUTS: AIRCRAFT NOISE ESTIMATING METHODOLOGIES				HUD NOISE ASSESSMENT GUIDELINES (1977)	SUGGESTED NOISE CONTROLS
		Ldn DAY-NIGHT AVERAGE SOUND LEVEL	NEF NOISE EXPOSURE FORECAST	CNR COMPOSITE NOISE RATING	CNEL COMMUNITY NOISE EQUIVALENT LEVEL		
A	MINIMAL EXPOSURE	0 TO 55	0 TO 20	0 TO 90	0 TO 55	"CLEARLY ACCEPTABLE"	NORMALLY REQUIRES NO SPECIAL CONSIDERATIONS
B	MODERATE EXPOSURE	55 TO 65	20 TO 30	90 TO 100	55 TO 65	"NORMALLY ACCEPTABLE"	LAND USE CONTROLS SHOULD BE CONSIDERED
C	SIGNIFICANT EXPOSURE	65 TO 75	30 TO 40	100 TO 115	65 TO 75	"NORMALLY UNACCEPTABLE"	NOISE EASEMENTS, LAND USE, AND OTHER COMPATIBILITY CONTROLS RECOMMENDED
D	SEVERE EXPOSURE	75 & HIGHER	40 & HIGHER	115 & HIGHER	75 & HIGHER	"CLEARLY UNACCEPTABLE"	CONTAINMENT WITHIN AIRPORT BOUNDARY OR USE OF POSITIVE COMPATIBILITY CONTROLS RECOMMENDED

Source: FAA 1977b, p. 12.

Ventura County
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Exhibit A5
LAND USE GUIDANCE CHART I:
AIRPORT NOISE INTERPOLATION

financial, personal, business, governmental, and educational services; and manufacturing of precision instruments. In Zones C and D, various manufacturing, trade, service, resource production, and open space uses are suggested.

A.3.1.e Federal Interagency Committee on Urban Noise

In 1979, the Federal Interagency Committee on Urban Noise (FICUN), including representatives of the Environmental Protection Agency, the Department of Transportation, the Housing and Urban Development Department, the Department of Defense, and the Veterans Administration, was established to coordinate various federal programs relating to the promotion of noise-compatible development. In 1980, the Committee published a report which contained detailed land use compatibility guidelines for varying DNL noise levels (FICUN 1980). These are presented in **Table A7**. The work of the Interagency Committee was very important as it brought together for the first time all federal agencies with a direct involvement in noise compatibility issues and forged a general consensus on land use compatibility for noise analysis on federal projects.

The Interagency guidelines describe the 65 DNL contour as the threshold of significant impact for residential land uses and a variety of noise-sensitive institutions (such as hospitals, nursing homes, schools, cultural activities, auditoriums, and outdoor music shells). Within the 55 to 65 DNL contour range, the guidelines note that cost and feasibility factors were considered in defining residential development and several of the institutions as compatible. In other words, the guidelines are based not solely on the effects of noise. They also consider the cost and feasibility of noise control.

LAND USE		LUG ZONE[1]		LAND USE		LUG ZONE[1]	
SLUCM NO.	NAME	SUG-GESTED	STUDY	SLUCM NO.	NAME	SUG-GESTED	STUDY
10	Residential.	A-B		50	Trade.[4]		
11	Household units.			51	Wholesale trade.	C-D	
11,11	Single units--detached.	A		52	Retail trade--building materials, hardware, and farm equipment.	C	
11,12	Single units--semiattached.	A		53	Retail trade--general merchandise.	C	
11,13	Single units--attached row.	B		54	Retail trade--food.	C	
11,21	Two units--side-by-side.	A		55	Retail trade--automotive, marine craft, aircraft, and accessories.	C	
11,22	Two units--one above the other.	A		56	Retail trade--apparel and accessories.	C	
11,31	Apartments--walk up.	B		57	Retail trade--furniture, home furnishings, and equipment.	C	
11,32	Apartments--elevator.	B-C		59	Retail trade--eating and drinking. Other retail trade.	C-D	
12	Group quarters.	A-B					
13	Residential hotels.	B					
14	Mobile home parks or courts.	A		60	Services.[4]		
15	Transient lodgings.	C					
19	Other residential.	A-C		61	Finance, insurance, and real estate services.	B	
				62	Personal services.	B	
20	Manufacturing.[2]	C-D		63	Business services.	B	
				64	Repair services.	C	
21	Food and kindred products--manufacturing.			65	Professional services.	B-C	
22	Textile mill products--manufacturing.	C-D		66	Contract construction services.	C	
23	Apparel and other finished products made from fabrics, leather, and similar materials--manufacturing.	C-D		67	Governmental services.	B	
				68	Educational services.	A-B	
				69	Miscellaneous services.	A-C	
24	Lumber and wood products (except furniture)--manufacturing.	C-D		70	Cultural, entertainment, and recreational.		
25	Furniture and fixtures--manufacturing.	C-D					
26	Paper and allied products--manufacturing.	C-D		71	Cultural activities and nature exhibitions.	A	
27	Printing, publishing, and allied industries.	C-D		72	Public assembly.	A	
28	Chemicals and allied products--manufacturing.	C-D		73	Amusements.	C	
29	Petroleum refining and related industries.[3]	C-D		74	Recreational activities.[5]	B-C	
				75	Resorts and group camps.	A	
30	Manufacturing (Continued).[2]			76	Parks.	A-C	
				79	Other cultural, entertainment, and recreational.[5]	A-B	
31	Rubber and miscellaneous plastic products--manufacturing.	C-D		80	Resource production and extraction.		
32	Stone, clay, and glass products--manufacturing.	C-D					
33	Primary metal industries.	D		81	Agriculture.	C-D	
34	Fabricated metal products--manufacturing.	D		82	Agricultural related activities.	C-D	
35	Professional, scientific, and controlling instruments: photographic and optical goods; watches and clocks--manufacturing.	B		83	Forestry activities and related services.	D	
				84	Fishing activities and related services.	D	
				85	Mining activities and related services.	D	
39	Miscellaneous manufacturing.	C-D		89	Other resource production and extraction.	C-D	
40	Transportation, communication, and utilities.			90	Undeveloped land and water areas.		
41	Railroad, rapid rail transit, and street railway transportation.	D		91	Undeveloped and unused land area (excluding noncommercial forest development).	D	
42	Motor vehicle transportation.	D		92	Noncommercial forest development.	D	
43	Aircraft transportation.	D		93	Water areas.	A-D	
44	Marine craft transportation.	D		94	Vacant floor area.	A-D	
45	Highway and street right-of-way.	D		95	Under construction.	A-D	
46	Automobile parking.	D		99	Other undeveloped land and water areas.	A-D	
47	Communication.	A-D					
48	Utilities.	D					
49	Other transportation communication and utilities.	A-D					

1. Refer to Land Use Guidance Chart I, Exhibit C-1.
2. Zone "C" suggested maximum except where exceeded by self generated noise.
3. Zone "D" for noise purposes; observe normal hazard precautions.
4. If activity is not in substantial, air-conditioned building, go to next higher zone.
5. Requirements likely to vary - individual appraisal recommended.

SLUCM: *Standard Land Use Coding Manual*, U.S. Urban Renewal Administration and Bureau of Public Roads, 1965.

Source: FAA 1977b, p. 14.

Ventura County
AIRPORT LAND USE PLAN

Exhibit A6
LAND USE GUIDANCE CHART II:
LAND USE NOISE SENSITIVITY INTERPOLATION

TABLE A7
Suggested Land Use Compatibility Guidelines
1980 Federal Interagency Committee on Urban Noise

SLUCM No.	Land Use Name	Noise Zones/DNL Levels in Ldn						
		A 0-55	**B 55-65**	**C-1 65-70**	**C-2 70-75**	**D-1 75-80**	**D-2 80-85**	**D-3 85+**
10	**Residential**							
11	Household Units							
11.11	Single Units-detached	Y	Y*	25[1]	30[1]	N	N	N
11.12	Single Units-semi-detached	Y	Y*	25[1]	30[1]	N	N	N
11.13	Single Units-attached row	Y	Y*	25[1]	30[1]	N	N	N
11.21	Two Units-side by side	Y	Y*	25[1]	30[1]	N	N	N
11.22	Two Units-one above the other	Y	Y*	25[1]	30[1]	N	N	N
11.31	Apartments-walk up	Y	Y*	25[1]	30[1]	N	N	N
11.32	Apartments-elevator	Y	Y*	25[1]	30[1]	N	N	N
12	Group Quarters	Y	Y*	25[1]	30[1]	N	N	N
13	Residential Hotels	Y	Y*	25[1]	30[1]	N	N	N
14	Mobile Home Park or Courts	Y	Y*	N	N	N	N	N
15	Transient Lodgings	Y	Y*	25[1]	30[1]	35[1]	N	N
16	Other Residential	Y	Y*	25[1]	30[1]	N	N	N
20	**Manufacturing**	Y	Y	Y	Y[2]	Y[3]	Y[4]	N
21	Food and kindred products-	Y	Y	Y	Y[2]	Y[3]	Y[4]	N
22	manufacturing	Y	Y	Y	Y[2]	Y[3]	Y[4]	N
23	Textile mill products-manufacturing	Y	Y	Y	Y[2]	Y[3]	Y[4]	N
	Apparel and other finished products made from fabrics, leather, and similar							
24	materials-manufacturing	Y	Y	Y	Y[2]	Y[3]	Y[4]	N
	Lumber and wood products (except							
25	furniture)-manufacturing	Y	Y	Y	Y[2]	Y[3]	Y[4]	N
	Furniture and fixtures-							
26	manufacturing	Y	Y	Y	Y[2]	Y[3]	Y[4]	N
27	Paper and allied products-manufacturing	Y	Y	Y	Y[2]	Y[3]	Y[4]	N
28	Printing, publishing, and allied industries	Y	Y	Y	Y[2]	Y[3]	Y[4]	N
29	Chemicals and allied products	Y	Y	Y	Y[2]	Y[3]	Y[4]	N
	manufacturing							
30	Petroleum refining and related industries							
31		Y	Y	Y	Y[2]	Y[3]	Y[4]	N
	Manufacturing (Continued)							
32	Rubber and misc. plastic products-	Y	Y	Y	Y[2]	Y[3]	Y[4]	N
	manufacturing							
33	Stone, clay, and glass products-	Y	Y	Y	Y[2]	Y[3]	Y[4]	N
34	manufacturing	Y	Y	Y	Y[2]	Y[3]	Y[4]	N
35	Primary metal industries	Y	Y	Y	Y[2]	Y[3]	Y[4]	N
	Fabricated metal products- manufacturing							
39	Professional, scientific, and controlling instruments; photographic and optical goods; watches and clocks- manufacturing	Y	Y	Y	25	30	N	N
	Miscellaneous manufacturing							
40	**Transportation, communication, and utilities**							
41	Railroad, rapid rail transit, transit and street railway transportation	Y	Y	Y	Y[2]	Y[3]	Y[4]	N
42	Motor vehicle transportation	Y	Y	Y	Y[2]	Y[3]	Y[4]	N
43	Aircraft transportation	Y	Y	Y	Y[2]	Y[3]	Y[4]	N

TABLE A7 (Continued)
Suggested Land Use Compatibility Guidelines
1980 Federal Interagency Committee on Urban Noise

SLUCM No.	Land Use Name	Noise Zones/DNL Levels in Ldn A 0-55	B 55-65	C-1 65-70	C-2 70-75	D-1 75-80	D-2 80-85	D-3 85+
44	Marine craft transportation	Y	Y	Y	Y[2]	Y[3]	Y[4]	Y
45	Highway and street right-of-way	Y	Y	Y	Y[2]	Y[3]	Y[4]	Y
46	Automobile parking	Y	Y	Y	Y[2]	Y[3]	Y[4]	N
47	Communication	Y	Y	Y	25[5]	30[5]	N	N
48	Utilities	Y	Y	Y	Y[2]	Y[3]	Y[4]	Y
49	Other transportation, communication, and utilities	Y	Y	Y	25[5]	30[5]	N	N
50	**Trade**							
51	Wholesale trade	Y	Y	Y	Y[2]	Y[3]	Y[4]	N
52	Retail trade - building materials, hardware and farm equipment	Y	Y	Y	Y[2]	Y[3]	N	N
53	Retail trade - general merchandise	Y	Y	Y	25	30	N	N
54	Retail trade - food	Y	Y	Y	25	30	N	N
55	Retail trade - automotive, marine craft, aircraft and accessories	Y	Y	Y	25	30	N	N
56	Retail trade - apparel and accessories	Y	Y	Y	25	30	N	N
57	Retail trade - furniture, home furnishings, and equipment	Y	Y	Y	25	30	N	N
58	Retail trade - eating and drinking establishments	Y	Y	Y	25	30	N	N
59	Other retail trade	Y	Y	Y	25	30	N	N
60	**Services**							
61	Finance, insurance, and real estate services	Y	Y	Y	25	30	N	N
62	Personal services	Y	Y	Y	25	30	N	N
62.4	Cemeteries	Y	Y	Y	Y[2]	Y[3]	Y[4,11]	Y[6,11]
63	Business services	Y	Y	Y	25	30	N	N
64	Repair services	Y	Y	Y	Y[2]	Y[3]	Y[4]	N
65	Professional services	Y	Y	Y	25	30	N	N
65.1	Hospitals, nursing homes	Y	Y*	25*	30*	N	N	N
65.2	Other medical facilities	Y	Y	Y	25	30	N	N
66	Contract construction services	Y	Y	Y	25	30	N	N
67	Governmental services	Y	Y*	Y*	25*	30*	N	N
68	Educational services	Y	Y*	25*	30*	N	N	N
69	Miscellaneous	Y	Y	Y	25	30	N	N
70	**Cultural, entertainment, and recreational**							
71	Cultural activities (including churches)	Y	Y*	25*	30*	N	N	N
71.2	Nature exhibits	Y	Y*	Y*	N	N	N	N
72	Public assembly	Y	Y	Y	N	N	N	N
72.1	Auditoriums, concert halls	Y	Y	25	30	N	N	N
72.11	Outdoor music shells, amphitheaters	Y	Y*	N	N	N	N	N
72.2	Outdoor sports arenas, spectator sports	Y	Y	Y[7]	Y[7]	N	N	N
73	Amusements	Y	Y	Y	N	N	N	N
74	Recreational activities (including golf courses, riding stables, water recreation)	Y	Y*	Y*	25*	30*	N	N
75	Resorts and group camps	Y	Y*	Y*	Y*	N	N	N
76	Parks	Y	Y*	Y*	Y*	N	N	N
79	Other cultural, entertainment	Y	Y*	Y*	Y*	N	N	N

TABLE A7 (Continued)
Suggested Land Use Compatibility Guidelines
1980 Federal Interagency Committee on Urban Noise

SLUCM No.	Land Use Name	Noise Zones/DNL Levels in Ldn A 0-55	B 55-65	C-1 65-70	C-2 70-75	D-1 75-80	D-2 80-85	D-3 85+
80	**Resource Production and extraction**							
81	Agriculture (except livestock)	Y	Y	Y[8]	Y[9]	Y[10]	Y[10,11]	Y[10,11]
81.5 to 81.7	Livestock farming and animal breeding	Y	Y	Y[8]	Y[9]	N	N	N
82		Y	Y	Y[8]	Y[9]	Y[10]	Y[10,11]	Y[10,11]
83	Agricultural-related activities	Y	Y	Y[8]	Y[9]	Y[10]	Y[10,11]	Y[10,11]
84	Forestry activities and related services	Y	Y	Y	Y	Y	Y	Y
85	Fishing activities and related services	Y	Y	Y	Y	Y	Y	Y
89	Mining activities and related services	Y	Y	Y	Y	Y	Y	Y
	Other source production and extraction							

NOTES

[1]a) Although local conditions may require residential use, it is discouraged in C-1 and strongly discouraged in C-2. The absence of viable alternative development options should be determined and an evaluation indicating that a demonstrated community need for residential use would not be met if development were prohibited in these zones should be conducted prior to approvals.

b) Where the community determines that residential uses must be allowed measures to achieve outdoor to indoor Noise Level Reduction (NLR) of at least 25 dB (Zone C-1) and 30 dB (Zone C-2) should be incorporated into building codes and be considered in individual approvals. Normal construction can be expected to provide a NLR of 20 dB, thus the reduction requirements are often stated as 5, 10, 15 dB over standard construction and normally assume mechanical ventilation and closed windows year round. Additional consideration should be given to modifying NLR levels based on peak noise levels.

c) NLR criteria will not eliminate outdoor noise problems. However, building location and site planning, design and use of berms and barriers can help mitigate outdoor noise exposure particularly from ground level sources. *Measures that reduce noise at a site should be used wherever practical in preference to measures which only protect interior spaces.*

[2] Measures to achieve NLR of 25 must be incorporated into the design and construction of portions of these buildings where the public is received, office areas, noise sensitive areas or where the normal noise level is low.

[3] Measures to achieve NLR of 30 must be incorporated into the design and construction of portions of these buildings where the public is received, office areas, noise sensitive areas or where the normal noise level is low.

[4] Measures to achieve NLR of 35 must be incorporated into the design and construction of portions of these buildings where the public is received, office areas or where the normal noise level is low.

[5] If noise sensitive use indicated NLR; if not use is compatible.

[6] No buildings.

[7] Land use compatible provided special sound reinforcement systems are installed.

[8] Residential buildings require a NLR of 25.

[9] Residential buildings require a NLR of 30.

[10] Residential buildings not permitted.

[11] Land use not recommended, but if community decides use is necessary, hearing protection devices should be worn by personnel.

TABLE A7 (Continued) Suggested Land Use Compatibility Guidelines 1980 Federal Interagency Committee on Urban Noise	
KEY	
SLUCM	**Standard Land Use Coding Manual**, (U.S. Urban Renewal Administration and Bureau of Public Roads, 1965).
Y (Yes)	Land Use and related structures compatible without restrictions.
N (No)	Land Use and related structures are not compatible and should be prohibited.
NLR (Noise Level Reduction)	Noise Level Reduction (outdoor to indoor) to be achieved through incorporation of noise attenuation into the design and construction of the structure.
Y^x (Yes with restrictions)	Land Use and related structures generally compatible; see notes 2 through 4.
25, 30, or 35	Land Use and related structures generally compatible; measures to achieve NLR of 25, 30, or 35 must be incorporated into design and construction of structure.
25*, 30*, or 35*	Land Use generally compatible with NLR; however, measures to achieve an overall noise reduction do not necessarily solve noise difficulties and additional evaluation is warranted.
Y*	The designation of these uses as "compatible" in this zone reflects individual Federal agencies' consideration of general cost and feasibility factors as well as past community experiences and program objectives. Localities, when evaluating the application of these guidelines to specific situations, may have different concerns or goals to consider....
Source: *Guidelines For Considering Noise In Land Use Planning and Control*, Federal Interagency Committee on Urban Noise, June 1980, p. 6.	

A.3.1.f ANSI Guidelines

In 1980, the American National Standards Institute (ANSI) published recommendations for land use compatibility with respect to noise (ANSI 1980). Kryter (1984, p. 621) notes that no supporting data for the recommended standard is provided.

The ANSI guidelines are shown in **Exhibit A7**. While generally similar to the Federal Interagency guidelines, there are some important differences. First, ANSI's land use classification system is less detailed. Second, the ANSI standard acknowledges the potential for noise effects below the 65 DNL level, describing several uses as "marginally compatible" with noise below 65 DNL. These include single-family residential (from 55 to 65 DNL), multi-family residential, schools, hospitals, and auditoriums (60 to 65 DNL), and music shells (50 to 65 DNL). Other outdoor activities, such as parks, playgrounds, cemeteries, and sports arenas, are described as marginally compatible with noise levels as low as 55 or 60 DNL.

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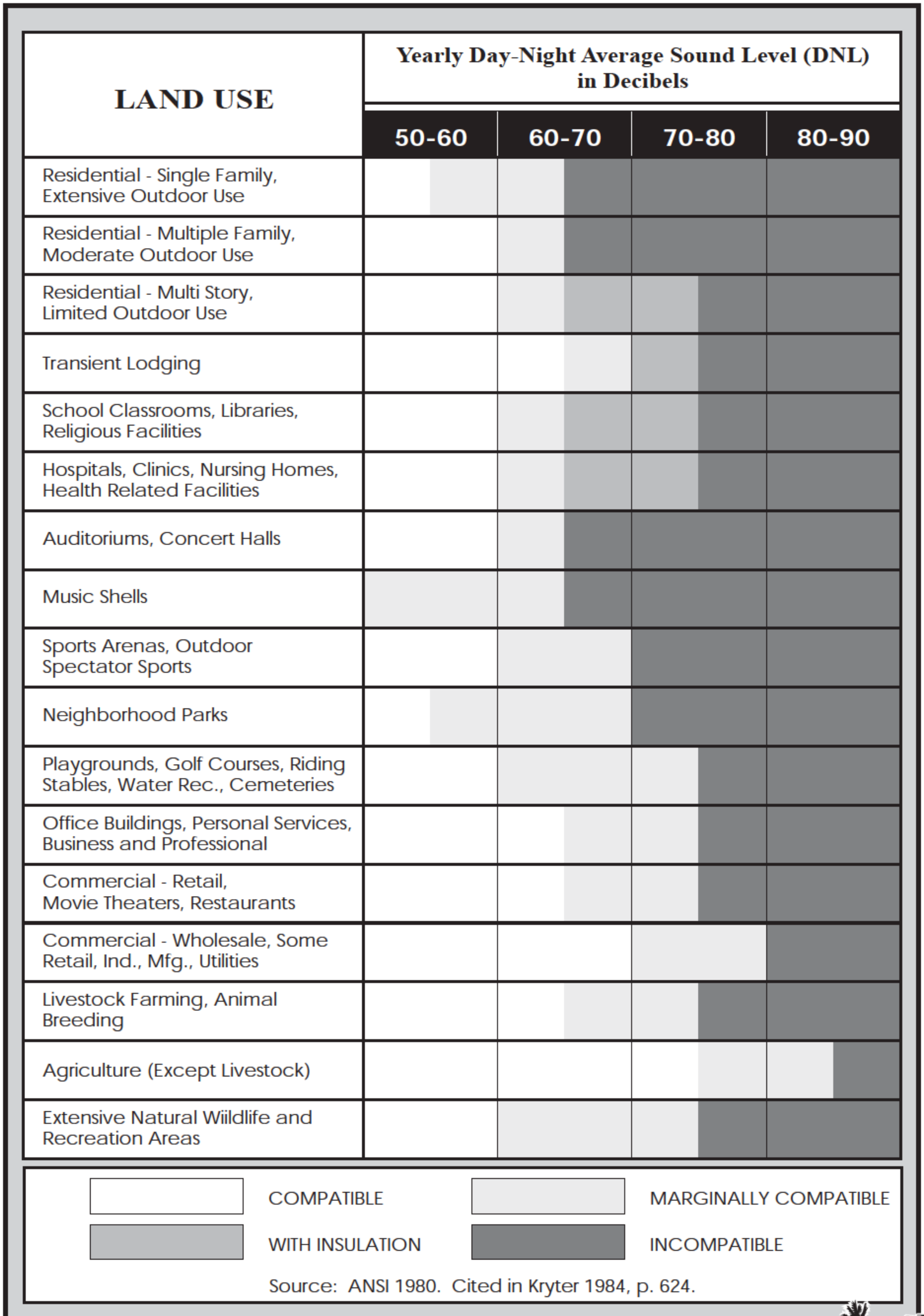

Ventura County
AIRPORT LAND USE PLAN

Exhibit A7
LAND USE COMPATIBILITY WITH YEARLY DAY-NIGHT AVERAGE SOUND LEVEL AT A SITE FOR BUILDINGS AS COMMONLY CONSTRUCTED

A.3.1.g F.A.R. Part 150 Guidelines

The FAA adopted a revised and simplified version of the Federal Interagency guidelines when it promulgated F.A.R. Part 150 in the early 1980s. (The Interim Rule was adopted on January 19, 1981. The final rule was adopted on December 13, 1984, published in the Federal Register on December 18, and became effective on January 18, 1985.) Among the changes made by FAA were the use of a coarser land use classification system and the deletion of any reference to any potential for noise impacts below the 65 DNL level. The determination of the compatibility of various land uses with various noise levels, however, is very similar to the Interagency determinations (FICUN 1980).

Exhibit A8 lists the F.A.R. Part 150 land use compatibility guidelines. These are only guidelines. Part 150 explicitly states that determinations of noise compatibility and regulation of land use are purely local responsibilities. Lacking any specific guidance provided by State law or regulation, local airport sponsors around the country typically use the Part 150 land use guidelines as is when developing noise compatibility studies under F.A.R. Part 150.

A.3.2 CALIFORNIA NOISE COMPATIBILITY REGULATIONS AND GUIDELINES

In California, the CNEL (community noise equivalent level) metric is used instead of the DNL metric. They are actually very similar. DNL accumulates the total noise occurring during a 24-hour period, with a 10 decibel penalty applied to noise occurring between 10:00 p.m. and 7:00 a.m. The CNEL metric is the same except that it also adds a 4.8 decibel penalty for noise occurring between 7:00 p.m. and 10:00 p.m. There is little actual difference between the two metrics in practice. Calculations of CNEL and DNL from the same data generally yield values with less than a 0.7 decibels difference (Caltrans 1983, p. 37).

California law sets the standard for the acceptable level of aircraft noise for persons residing near airports as 65 CNEL (California Code of Regulations, Title 21, Chapter 2.5, Subchapter 6, Sections 5000 et seq.). Four types of land uses are defined as incompatible with noise above 65 CNEL: residences, schools, hospitals and convalescent homes, and places of worship. These land uses are regarded as compatible if they have been insulated to assure an interior sound level, from aircraft noise, of 45 CNEL. They are also to be considered compatible if an avigation easement over the property has been obtained by the airport operator.

California noise insulation standards apply to new hotels, motels, apartment buildings and other dwellings not including detached single family homes. They require that "interior noise levels attributable to outdoor sources shall not exceed 45 decibels (based on the DNL or CNEL metric) in any habitable room." In addition, any of these residential structures proposed within a 60 CNEL noise contour require an acoustical analysis to show that the proposed design will meet the allowable interior noise level standard. (California Code of Regulations, Title 24, Part 2, Appendix Chapter 35.)

In the *1993 Airport Land Use Planning Handbook* (Hodges & Shutt 1993, p. 3-3) land use compatibility guidelines are suggested for use in the preparation of comprehensive airport land use plans. The guidelines suggest that no residential uses should be permitted within the 65 CNEL noise contour. In quiet communities, it is recommended that the 60 CNEL should be used as the maximum permissible noise level for residential uses. At rural airports, it is noted that 55 CNEL may be suitable as a maximum permissible noise level for residential uses.

These guidelines are similar to those proposed in an earlier edition of the *Airport Land Use Planning Handbook* (Metropolitan Transportation Commission 1983, p. 50). The older guidelines had a more detailed list of land use compatibility criteria, although the recommended lowest thresholds for residential land use compatibility were essentially the same.

A.3.3 NOISE COMPATIBILITY STANDARDS IN OTHER COUNTIES

A.3.3.a Imperial County

The noise compatibility standards used by the Imperial County ALUC are shown in **Table A8**. They consider all land uses at least marginally acceptable with noise levels below 60 CNEL. Between 55 and 60 CNEL, single family homes, nursing homes, schools, churches, amphitheaters and similar uses are considered marginally acceptable. The standards note that outdoor activities may be disturbed as will indoor activities with windows open. The standards require that buildings include adequate noise attenuation and be designed to allow windows to remain closed.

Several noise-sensitive uses, including single family homes, nursing homes, schools, and amphitheaters, are considered unacceptable in areas exposed to noise above 60 CNEL. Churches, auditoriums, and concert halls are unacceptable above 65 CNEL. Several other uses, including offices, retail trade, livestock breeding, parks, and outdoor spectator sports are considered unacceptable with noise above 70 CNEL.

A.3.3.b Riverside County

The Riverside County noise compatibility standards are shown in **Table A9**. These were taken directly from the 1983 *Airport Land Use Planning Handbook* (Metropolitan Transportation Commission 1983, p. 50.) With respect to residential compatibility, the County establishes different standards for air carrier/military airports and general aviation airports. The County's concern for land use compatibility begins at the 60 CNEL level.

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LAND USE	Yearly Day-Night Average Sound Level (DNL) in Decibels					
	Below 65	65-70	70-75	75-80	80-85	Over 85
RESIDENTIAL						
Residential, other than mobile homes and transient lodgings	Y	N[1]	N[1]	N	N	N
Mobile home parks	Y	N	N	N	N	N
Transient lodgings	Y	N[1]	N[1]	N[1]	N	N
PUBLIC USE						
Schools	Y	N[1]	N[1]	N	N	N
Hospitals and nursing homes	Y	25	30	N	N	N
Churches, auditoriums, and concert halls	Y	25	30	N	N	N
Government services	Y	Y	25	30	N	N
Transportation	Y	Y	Y[2]	Y[3]	Y[4]	Y[4]
Parking	Y	Y	Y[2]	Y[3]	Y[4]	N
COMMERCIAL USE						
Offices, business and professional	Y	Y	25	30	N	N
Wholesale and retail-building materials, hardware and farm equipment	Y	Y	Y[2]	Y[3]	Y[4]	N
Retail trade-general	Y	Y	25	30	N	N
Utilities	Y	Y	Y[2]	Y[3]	Y[4]	N
Communication	Y	Y	25	30	N	N
MANUFACTURING AND PRODUCTION						
Manufacturing, general	Y	Y	Y[2]	Y[3]	Y[4]	N
Photographic and optical	Y	Y	25	30	N	N
Agriculture (except livestock) and forestry	Y	Y[6]	Y[7]	Y[8]	Y[8]	Y[8]
Livestock farming and breeding	Y	Y[6]	Y[7]	N	N	N
Mining and fishing, resource production and extraction	Y	Y	Y	Y	Y	Y
RECREATIONAL						
Outdoor sports arenas and spectator sports	Y	Y[5]	Y[5]	N	N	N
Outdoor music shells, amphitheaters	Y	N	N	N	N	N
Nature exhibits and zoos	Y	Y	N	N	N	N
Amusements, parks, resorts, and camps	Y	Y	Y	N	N	N
Golf courses, riding stables, and water recreation	Y	Y	25	30	N	N

The designations contained in this table do not constitute a Federal determination that any use of land covered by the program is acceptable under Federal, State, or local law. The responsbility for determining the acceptable and permissible land uses and the relationship between specific properties and specific noise contours rests with the local authorities. FAA determinations under Part 150 are not intended to substitute federally determined land uses for those determined to be appropriate by local authorities in response to locally determined needs and values in achieving noise compatible land uses.

See other side for notes and key to table.

Ventura County
AIRPORT LAND USE PLAN

Exhibit A8
F.A.R. PART 150 LAND USE
COMPATIBILITY GUIDELINES

KEY

Y (Yes)	Land Use and related structures compatible without restrictions.
N (No)	Land Use and related structures are not compatible and should be prohibited.
NLR	Noise Level Reduction (outdoor to indoor) to be achieved through incorporation of noise attenuation into the design and construction of the structure.
25, 30, 35	Land Use and related structures generally compatible; measures to achieve NLR of 25, 30, or 35 dB must be incorporated into design and construction of structure.

NOTES

1 Where the community determines that residential or school uses must be allowed, measures to achieve outdoor to indoor Noise Level Reduction (NLR)of at least 25 dB and 30 dB should be incorporated into building codes and be considered in individual approvals. Normal residential construction can be expected to provide a NLR of 20 dB, thus, the reduction requirements are often stated as 5, 10, or 15 dB over standard construction and normally assume mechanical ventilation and closed windows year round. However, the use of NLR criteria will not eliminate outdoor noise problems.

2 Measures to achieve NLR of 25 dB must be incorporated into the design and construction of portions of these buildings where the public is received, office areas, noise sensitive areas, or where the normal noise level is low.

3 Measures to achieve NLR of 30 dB must be incorporated into the design and construction of portions of these buildings where the public is received, office areas, noise sensitive areas, or where the normal noise level is low.

4 Measures to achieve NLR of 35 dB must be incorporated into the design and construction of portions of these buildings where the public is received, office areas, noise sensitive areas, or where the normal noise level is low.

5 Land use compatible provided special sound reinforcement systems are installed.

6 Residential buildings require a NLR of 25.

7 Residential buildings require a NLR of 30.

8 Residential buildings not permitted.

*Source: **F.A.R. Part 150,** Appendix A, Table 1.*

TABLE A8
Noise Compatibility Criteria
Imperial County Airport Land Use Compatibility Plan

	CNEL, dBA				
LAND USE CATEGORY	**50-55**	**55-60**	**60-65**	**65-70**	**70-75**
Residential					
single family, nursing homes, mobile homes	+	o	-	--	--
multi-family, apartments, condominiums	++	+	o	--	--
Public					
schools, libraries, hospitals	+	o	-	--	--
churches, auditoriums, concert halls	+	o	o	-	--
transportation, parking, cemeteries	++	++	++	+	o
Commercial and Industrial					
offices, retail trade	++	+	o	o	-
service commercial, wholesale trade, warehousing, light industrial	++	++	+	o	o
general manufacturing, utilities, extractive industry	++	++	++	+	+
Agricultural and Recreational					
cropland	++	++	++	++	+
livestock breeding	++	+	o	o	-
parks, playgrounds, zoos	++	+	+	o	-
golf courses, riding stables, water recreation	++	++	+	o	o
outdoor spectator sports	++	+	+	o	-
amphitheaters	+	o	-	--	--

LAND USE AVAILABILITY		INTERPRETATION/COMMENTS
++	Clearly Acceptable	The activities associated with the specified land use can be carried out with essentially no interference from the noise exposure.
+	Normally Acceptable	Noise is a factor to be considered in that slight interference with outdoor activities may occur. Conventional construction methods will eliminate most noise intrusions upon indoor activities.
o	Marginally Acceptable	The indicated noise exposure will cause moderate interference with outdoor activities and with indoor activities when windows are open. The land use is acceptable on the conditions that outdoor activities are minimal and construction features which provide sufficient noise attenuation are used (e.g., installation of air conditioning so that windows can be kept closed). Under other circumstances, the land use should be discouraged.
-	Normally Unacceptable	Noise will create substantial interference with both outdoor and indoor activities. Noise intrusion upon indoor activities can be mitigated by requiring special noise insulation construction. Land uses which have conventionally constructed structures and/or involve outdoor activities which would be disrupted by noise should generally be avoided.
--	Clearly Unacceptable	Unacceptable noise intrusion upon land use activities will occur. Adequate structural noise insulation is not practical under most circumstances. The indicated land use should be avoided unless strong overriding factors prevail and it should be prohibited if outdoor activities are involved.

Source: Hodges & Shutt 1991, p. 2-15.

At air carrier and military airports, new housing is permitted in the 60 to 65 CNEL area, but acoustical reports and noise easements are required. New housing is to be discouraged in the 65 to 70 CNEL range. When permitted, homes should be sound-insulated and noise easements should be required. Mobile homes are prohibited in the 65-70 CNEL area. New homes are prohibited in areas exposed to noise above 70 CNEL. Hotels and motels may be permitted if needed noise insulation is included.

At general aviation airports, the noise compatibility criteria used at air carrier/military airports apply at the next lower CNEL levels. Single family homes are discouraged in the 60 to 65 CNEL area and mobile homes are prohibited. When permitted inside the 60 CNEL contour, homes should be sound-insulated.

At all airports, institutional uses are discouraged in areas exposed to noise above 60 CNEL. Outdoor amphitheaters are prohibited in areas above 65 CNEL. Commercial uses within the 70 CNEL range, and industrial uses within the 75 CNEL range, are permitted only after an analysis of noise reduction requirements.

A.3.3.c San Mateo County

San Mateo County has different noise compatibility criteria at general aviation airports than at its air carrier airport (San Francisco International). At the general aviation airports, the 55 CNEL contour is set as the noise impact boundary, while the 65 CNEL contour is the noise impact boundary at San Francisco International.

At general aviation airports, new housing and institutional development is permitted within the 55 to 60 CNEL contours only after an acoustical analysis is done and needed noise insulation features are included in the building design. New housing and institutions are not permitted within the 60 CNEL contour.

At San Francisco International Airport, housing and institutional uses are considered compatible with noise below 65 CNEL. These uses are not permitted in areas exposed to noise above 70 CNEL. Between 65 and 70 CNEL, these uses are permitted only after an acoustical analysis is conducted and needed noise insulation incorporated into the building design.

At both general aviation airports and San Francisco International, commercial uses, hotels, and outdoor recreational uses are compatible with noise below 70 CNEL. Industrial uses are compatible with noise below 75 CNEL.

A.3.3.d Santa Barbara County

The Santa Barbara County noise compatibility standards address only a few types of land use and are not as comprehensive as the standards in the other counties (Santa

TABLE A9
Land Use Guidelines For Noise Compatibility
Riverside County, California

Type of Airport/ Land Use	60-65 CNEL	65-70 CNEL	70-75 CNEL	75-80 CNEL	80 + CNEL
Air Carrier and Military					
Residential/Lodgings	Potential for annoyance exists; identify high complaint areas Determine whether sound insulation requirements should be established for these areas. Require acoustical reports for all new construction. Noise easements should be required for new construction.	Discourage new single family dwellings. Prohibit mobile homes New construction or development should be undertaken only after an analysis of noise reduction requirements is made and needed noise insulation is included in the design. Noise easements should be required for new construction. Development policies for "infill".	New construction or development of residential uses should not be undertaken. New hotels and motels may be permitted after an analysis of noise reduction requirements is made and needed noise insulation is included in the design	New hotels and motels should be discouraged.	
General Aviation					
Residential/Lodgings	Discourage new single family dwellings Prohibit mobile homes. New construction or development should be undertaken only after an analysis of noise reduction requirements is made and needed noise insulation is included in the design. Noise easements should be required. Develop policies for "infill".	New construction or development of residential uses should not be undertaken. New hotels and motels may be permitted after an analysis of noise reduction requirements is made and needed noise insulation is included in the design.	New hotels and motels should be discouraged.		
All Airports					
Public/Institutional	Satisfactory with little noise impact and requiring no special noise insulation requirements for new construction.	Discourage institutional uses. If no other alternative location is available, new construction or development should be undertaken only after an analysis of noise reduction requirements is made and needed noise insulation is included in the design.	No new institutional uses should be undertaken.		
Commercial		Satisfactory, with little noise impact and requiring no special noise insulation for new construction.	New construction or development should be undertaken only after an analysis of noise reduction requirements is made and needed noise insulation features included in the design. Noise reduction levels of 25-30 dB will be required.	Same as 70-75 CNEL	New construction or development should not be undertaken unless related to airport activities or services. Conventional construction will generally be inadequate and special noise insulation features should be included in the construction.
Industrial			Satisfactory, with little noise impact and requiring no special noise insulation requirements for new construction.	New construction or development should be undertaken only after an analysis of noise reduction requirements is made and needed noise insulation features included in the design. Measures to achieve noise reduction of 25-35 dB must be incorporated in portions of building where the public is received and in office areas.	New construction or development should not be undertaken unless related to airport activities or services. Conventional construction will generally be inadequate and special noise insulation features should be included in the construction.
Recreation/Open Space		Satisfactory, with little noise impact and requiring no special noise insulation requirements for new construction. Outdoor music shells and amphitheater should not be permitted.	Parks, spectator sports, golf courses and agricultural generally satisfactory with little noise impact. Nature areas for wildlife and zoos should not be permitted.	Land uses involving concentrations of people (spectator sports and some recreational facilities) or of animals (livestock farming and animal breeding) should not be permitted.	

Source: Coffman Associates 1992. Reproduced from *Airport Use Planning Handbook: A Reference Guide for Local Agencies*, prepared for California Department of Transportation, Division of Aeronautics by Metropolitan Transportation Commission and Association of Bay Area Governments, 1983, p. 50.

Barbara County ALUC 1993, p. 42). The County prohibits new institutional land uses such as schools, hospitals, convalescent homes, and other in-patient health care facilities within the 65 CNEL noise contour. Multi-family residential development is permitted in areas exposed to noise above 65 CNEL subject to an acoustical analysis showing that structures have been designed to limit interior noise levels to 45 CNEL. In the area between 60 and 65 CNEL, residential uses are permitted subject to an acoustical analysis showing that all structures have been designed to limit interior noise levels to 45 CNEL.

A.4 ALTERNATIVE SAFETY COMPATIBILITY POLICIES

A.4.1 FEDERAL SAFETY STANDARDS AND GUIDELINES

The Federal Aviation Administration has defined areas in the immediate runway environment which must be kept free of obstructions. The largest is the runway protection zone (RPZ), a trapezoidal area off the runway end. The size of the RPZ varies depending on the type of approach to the runway. It is smallest for visual approaches and largest for precision instrument approaches. **Exhibit A9** shows the basic configuration of the RPZ. FAA recommends that the area within the RPZ be kept free of structures and people and advises airport proprietors to secure title to the area.

Exhibit A9 also shows the runway approach area. Within this area, FAA is concerned only that objects not be allowed to penetrate an imaginary surface sloping upward from the runway end. FAA has no official policies regarding the use of the land beneath the approaches, although its policies permit the use of Airport Improvement Program funds for property acquisition up to 5,000 feet off the end of the runway (FAA 1989, Par. 602.b(2), p. 70). This is a clear, although implicit, acknowledgment of the need for compatible use of this property to protect the interests of the airport and the general public.

A.4.2 SAFETY GUIDELINES IN OTHER STATES

This section briefly summarizes safety standards and guidelines used in selected states.

A.4.2.a Arizona--Pima County

Pima County Arizona has adopted airport environs zoning establishing compatible use zones around each airport within its jurisdiction. (See Pima County Code, Chapter 18.57.) The ordinance establishes three zones based on safety concerns: the RSZ runway safety zone, the CUZ-1 compatible use zone, and the CUZ-2 compatible use zone.

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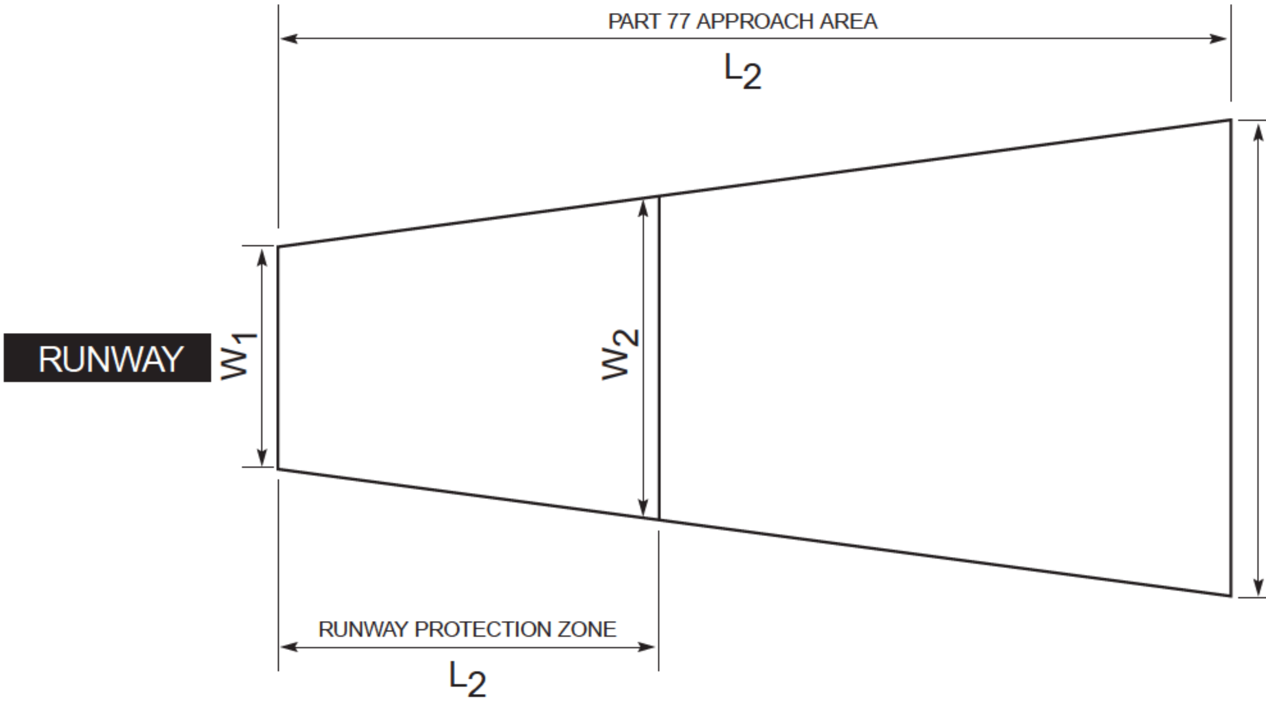

CATEGORY	W_1	W_2	W_3	L_1	L_2
1. Precision instrument	1,000	1,750	16,000	2,500	50,000
2. Nonprecision instrument for larger than utility with visibility minimums as low as 3/4 mi.	1,000	1,510	4,000	1,700	10,000
3. Nonprecision instrument for larger than utility with visibility minimums greater than 3/4 mi.	1,000	1,425	3,500	1,700	10,000
4. Visual approach for larger than utility	1,000	1,100	1,500	1,000	5,000
5. Nonprecision approach for utility	500	800	2,000	1,000	5,000
6. Visual approach utility	250	450	1,250	1,000	5,000

SOURCE: Federal Aviation Administration

Ventura County
AIRPORT LAND USE PLAN

Exhibit A9
RUNWAY PROTECTION ZONES AND
APPROACH AREAS

The RSZ zone is immediately off the runway ends. Development is strictly limited in this zone as the land must remain in open space. At general aviation airports, this area is typically 1,500 feet long and 1,500 feet wide.

The CUZ-1 zone is applied off the end of the RSZ zone at air carrier and military airports. Dimensions of the CUZ-1 zone at air carrier airports are 1,500 feet wide by 2,000 to 3,500 feet long, depending on the runway approach. At military airports, the zone is 3,000 feet wide by 5,000 feet long. Potentially hazardous land uses are prohibited as are uses attracting large numbers of people. Structures are not permitted to occupy over 35% of the lot area.

The CUZ-2 zone is applied off the end of the RSZ zone at smaller general aviation airports. It has similar use restrictions as the CUZ-1 zone, but permits structures to occupy up to 45% of the lot area. Off non-precision runways, it is 2,000 feet long and 1,500 feet wide. Off precision runways, it is 3,500 feet long and 1,500 feet wide.

A.4.2.b. Louisiana

The State of Louisiana has prepared a model airport hazard zoning ordinance for use at larger than utility airports in the state. The ordinance proposes height control standards generally based on F.A.R. Part 77. It also proposes standards for three land use safety zones.

Safety Zone A is defined as the area within the approach zone which extends outward from the primary surface a distance equal to two-thirds of the planned length of the runway. In this area only open space uses are permitted. Structures and above-ground obstructions are not permitted, nor are uses which would attract a group of persons.

Safety Zone B extends outward from the end of Zone A a distance equal to one-third of the planned length of the runway. Certain uses are specifically prohibited, including churches, hospitals, schools, theaters, stadiums, hotels and other places of public assembly. The building and population densities of other uses are restricted.

Safety Zone C is subject only to height limitations. It includes all that area within the horizontal zone. This corresponds to the F.A.R. Part 77 horizontal surface.

A.4.2.c Oregon

The State of Oregon has suggested that local communities use the inner part of the approach area, extending from 2,500 to 5,000 feet off the end of the primary surface, as an area within which land use controls should be considered. The State adds that "local conditions may require additional areas of land use controls...", although it does not provide specific guidance (OrDOT 1981, p. 67).

A.4.2.d Wisconsin--Brown County

Brown County has established airport protection zoning in the vicinity of Austin Straubel Airport near Green Bay (Coons 1989, p. 30). The ordinance establishes three overlay zones. Zone A is referred to as the "noise cone/crash hazard zone". It extends off the end of each runway and includes the 65 Ldn contour area. Residential development is not permitted in the area, nor are hospitals, churches, schools, theaters and other places of public assembly or uses attracting large populations of birds. Zone B is the overflight noise zone. Residential density limits are established and sound insulation is required. Zone C establishes only height limits.

A.4.3 CALIFORNIA SAFETY GUIDELINES

The 1993 *Airport Land Use Planning Handbook* includes suggested safety compatibility criteria (Hodges & Shutt 1993, p. 3-3). The document emphasizes that these are not to be considered state-mandated standards, but are suggestions for consideration by airport land use commissions. The suggested state criteria are listed in **Table A10**. The general configuration of the suggested safety zones is shown in **Exhibit A10**. Six safety zones are suggested: runway protection zones, inner safety zones, inner turning zones, outer safety zones, sideline zones, and a traffic pattern zone.

A.4.3.a Runway Protection Zone

The runway protection zones (RPZ) would correspond to the areas delineated by Federal criteria. According to the suggested guidelines, no structures and no assemblages of people would be permitted in these areas. Airports would be encouraged to own the property in the runway protection zone.

A.4.3.b Inner Safety Zones

The inner safety zone (ISZ) is suggested as a rectangular area centered on the extended runway centerline immediately beyond the runway protection zone. It would have a width of 500 to 1,000 feet and a length of 1,500 to 2,500 feet depending on the length of the runway.

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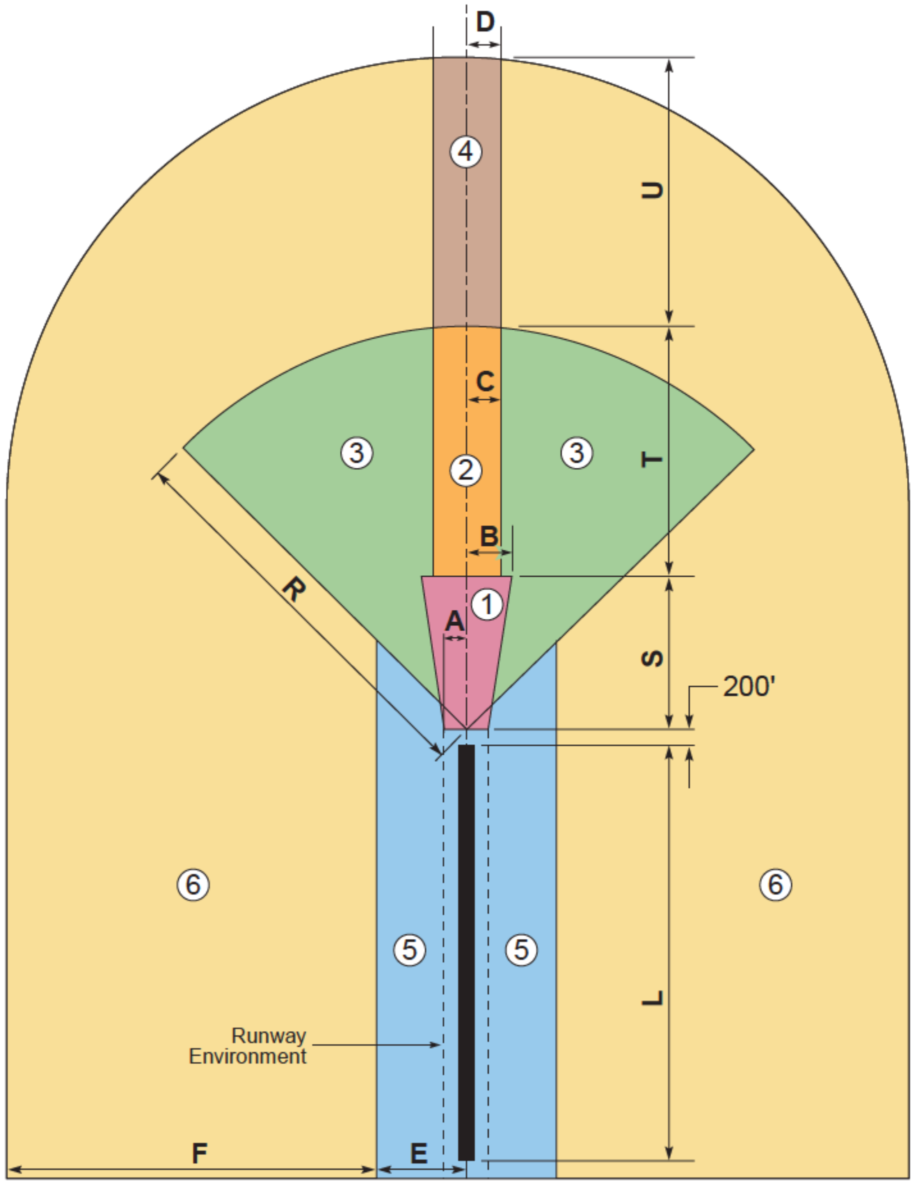

SAFETY ZONE NAMES	
1	Runway Protection Zone
2	Inner Safety Zone
3	Inner Turning Zone
4	Outer Safety Zone
5	Sideline Safety Zone
6	Traffic Pattern Zone

SAFETY ZONE DIMENSIONS (Feet)

	Runway Length Group (L)		
	less than 4,000'	4,000' to 5,999'	6,000' or more
A	125	250	500
B	225	505	875
C	225	500	500
D	225	500	500
E	500	1,000	1,000
F	4,000	5,000	5,000
R	2,500	4,500	5,000
S	1,000	1,700	2,500
T	1,500	2,800	2,500
U	2,500	3,000	5,000

Note: These safety zone shapes and sizes are intended only to illustrate the concepts discussed in the text. They do not represent standards or recommendations.

Source: Hodges & Shutt, Airport Land Use Planning Handbook, Prepared for CALTRANS Division of Aeronautics, (December 1993)

Ventura County
AIRPORT LAND USE PLAN

Exhibit A10
SAFETY ZONE
CONFIGURATION EXAMPLE

TABLE A10
Suggested Safety Compatibility Criteria
State of California

Compatibility Zone Delineation	Suggested Compatibility Criteria
• Up to 6 zones based upon relative risk of aircraft accidents in each area.[1] • Take into account typical flight tracks and areas overflown by aircraft at low altitude. • Consider instrument arrival and departure routes.	• Runway Protection Zones: -- No structures. -- No assemblages of people. -- Encourage airport to own the property. • Inner Safety Zones: -- Preferably no residential uses or, at most, very low density. -- Limit other uses to ones which attract relatively few people and leave substantial areas without structures. -- Prohibit bulk storage of flammable or hazardous materials. -- Prohibit schools, hospitals, nursing homes. -- Maintain as much open land as possible by clustering of development. • Inner Turning Zones: -- Residential uses only at very low density -- Restrictions on other uses similar to Inner Safety Zone. • Outer Safety Zones: -- No urban density residential subdivisions. -- Other uses limited to ones with moderate concentrations of people. -- Avoid schools, hospitals, nursing homes. -- Maintain as much open land as possible by clustering of development. • Sideline Zones (Areas Adjacent to Runways) -- All common aviation-related uses acceptable. -- Limit non-aviation uses, on- or off-airport, to low-intensity activities. -- Prohibit schools, hospital, nursing homes. • Traffic Pattern Zone: -- Avoid high-density residential unless clustered to leave open areas in between. -- Avoid activities with very high concentrations of people. -- Avoid schools, hospitals, nursing homes.

[1] See Exhibit A10 for suggestions regarding safety zone shapes and dimensions.

NOTE: These criteria should be treated as general suggestions for consideration by individual ALUCs, not as state-mandated standards. Economic and technical feasibility may need to be taken into account when setting criteria for individual airports.

Source: Hodges & Shutt 1993, p. 3-3.

Within this area housing would be prohibited if possible. At most, housing would be permitted at very low densities -- ten acres or more per dwelling. Permitted uses would be ones which attract relatively few people and leave substantial open space areas. Maximum concentrations of people should be limited to no more than 40 to 60 per acre. Schools, hospitals, and nursing homes would be prohibited as would bulk storage of flammable or hazardous materials.

Development should be clustered to allow for the preservation of as much open land as possible. At least 50 percent useable open space should be provided within an approximately 500-foot wide strip along the extended runway centerline. An average of 25 to 30 percent of useable open space should be provided throughout the entire ISZ. (Useable open space involves areas of land large enough to provide a possibility for a safe forced landing by an aircraft. Areas as small as 300 by 75 feet (0.5 acre) can be suitable for small aircraft. The areas must be relatively level and be free of objects such as large trees, overhead wires, and poles.)

A.4.3.c Inner Turning Zones

Inner turning zones (ITZ) would be roughly triangular areas on each side of the RPZ and ISZ. Their outside boundaries would be defined by lines drawn at 45-degree angles from the extended runway centerline beginning at the edge of the primary surface. (The primary surface extends 200 feet past the runway end.) They would have a length of 2,500 to 5,000 feet, depending on the length of the runway.

Within the ITZ, residential uses would be permitted only at very low densities, ranging from 2 to 10 acres per dwelling. Concentrations of people should be limited to 40 to 100 people per acre. Other uses would be restricted as suggested for the ISZ. At least 15 to 20 percent of the zone should remain as open space.

A.4.3.d Outer Safety Zones

The outer safety zone (OSZ) would be a rectangular area centered on the extended runway centerline. It would be 500 to 1,000 feet wide and would extend from 2,500 to 5,000 feet beyond the ISZ.

Residential development would be permitted, but only at less than "urban density." Minimum lot sizes should be limited to two to five acres. Other permitted uses would be those with moderate concentrations of people, ranging from 60 to 100 per acre. Schools, hospitals, and nursing homes would be avoided. As much open space as possible would be provided by clustering development. Approximately 25 to 30 percent useable open space would be provided within a 500-foot wide strip along the extended runway centerline, and 10 to 15 percent overall.

A.4.3.e Sideline Zones

Sideline zones (SZ) would be established along the sides of the runways. They would extend from 500 to 1,000 feet from the runway centerline and would terminate at the ITZ boundaries. Common aviation-related uses would be permissible in this area, but non-aviation uses would be limited to "low-intensity" activities. Schools, hospitals, and nursing homes would be prohibited. In general, the criteria for the ITZ or OSZ would be suitable for this area. Adjacent to the runway ends and RPZs, 25 to 30 percent useable open space should be reserved.

A.4.3.f Traffic Pattern Zone

The traffic pattern zone (TPZ) would extend 4,000 to 5,000 feet beyond the sideline zones. Off the runway end, it would extend to the outer boundary of the OSZ. This is an area below the typical traffic patterns. Frequent low altitude overflights can be expected in this area.

Typical residential subdivision densities of 4 to 6 dwellings per acre are considered acceptable in the TPZ. In urban areas, higher density residential uses could be acceptable if the buildings are clustered to leave open space. It is suggested that 10 to 15 percent of the area be reserved as useable open space, or open areas should be provided approximately every 1/4 to 1/2 mile. Schools, hospitals, nursing homes and activities with very high concentrations of people (more than 150 people per acre) should be avoided in this area unless no other feasible alternatives are available.

A.4.4 SAFETY STANDARDS IN OTHER SELECTED CALIFORNIA COUNTIES

A.4.4.a Imperial County

Table A11 shows the safety standards applying at public use airports in Imperial County. The County's Comprehensive Airport Land Use Plan defined five safety zones, shown conceptually in **Exhibit A11**.

Zone A corresponds with the runway protection zone and land within the building restriction lines on the airfield. Only structures with the location set by aeronautical function are allowed in Zone A. As much open land as possible should be reserved in this area.

Zone B1 is the area in an approach/departure zone and includes land off the sides of the runway beyond Zone A. Residential densities are limited to 0.1 dwelling per acre. The maximum occupancy density should be limited to 60 people per acre in Zone B1. At the civilian airports, Zone B1 extends 3,500 feet from the end of the primary surface along the extended runway centerline and, at most airports, 45 degrees either side of the centerline. It also extends 500 feet beyond Zone A off the runway sidelines.

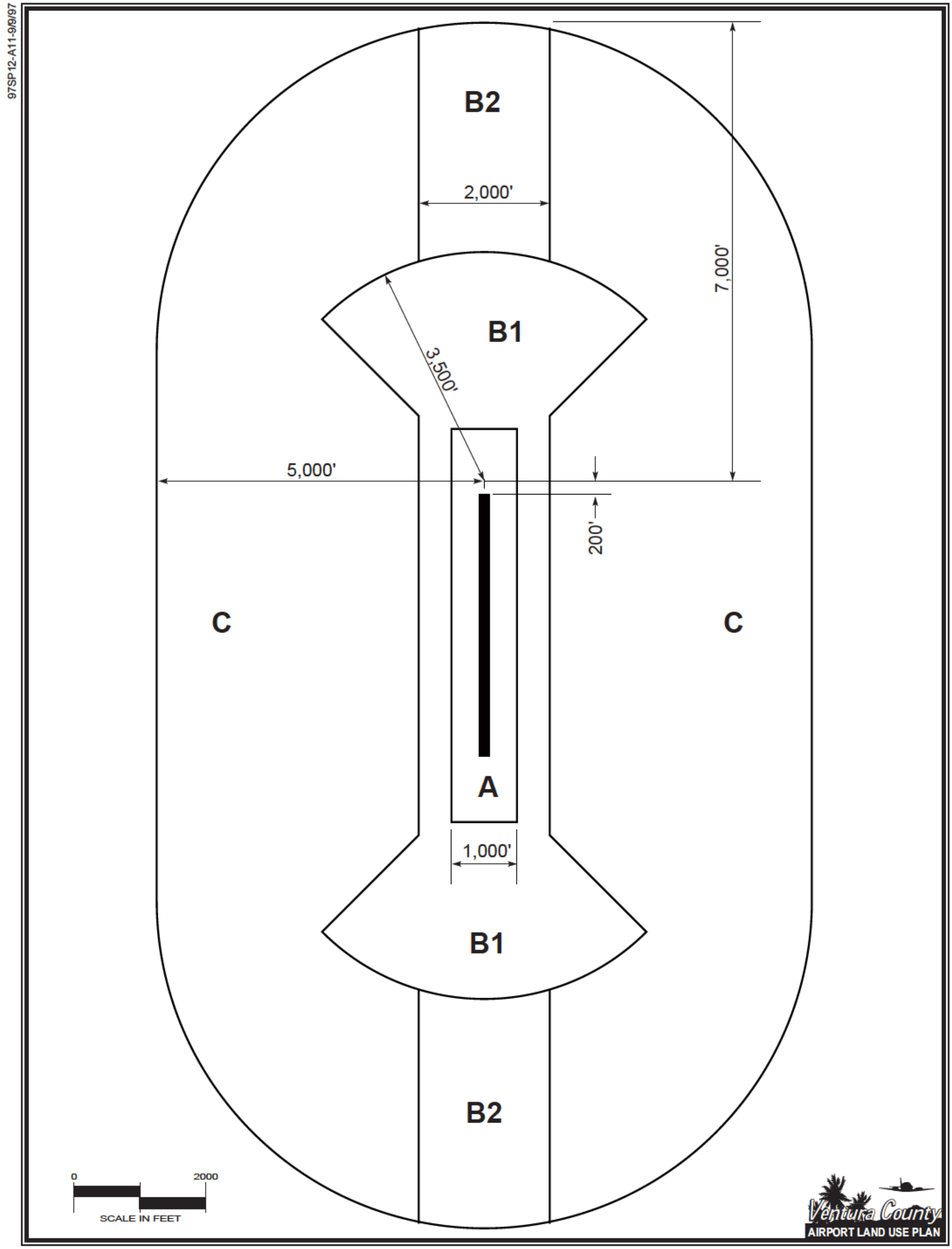

Exhibit A11
IMPERIAL COUNTY AIRPORT
SAFETY AREAS - EXAMPLE

TABLE A11
Safety Compatibility Criteria
Imperial County Airport Land Use Compatibility Plan

Zone	Location	Impact Elements	Maximum Densities: Residential (du/ac)[1]	Maximum Densities: Other Uses (people/ac)[2]	Required Open Land[3]
A	Runway Protection Zone or within Building Restriction Line	• High risk • High noise levels	0	10	All Remaining
B1	Approach/Departure Zone and Adjacent to Runway	• Substantial risk - aircraft commonly below 400 ft. AGL or within 1,000 ft. of runway • Substantial noise	0.1	60	30%
B2	Extended Approach/ Departure Zone	• Significant risk - aircraft commonly below 800 ft. AGL • Significant noise	0.5	60	30%
C	Common Traffic Pattern	• Limited risk - aircraft at or below 1,000 ft. AGL • Frequent noise intrusion	4	150	15%
D	Other Airport Environs	• Negligible risk • Potential for annoyance from overflights	No Limit	No Limit	No Requirement

Zone	Additional Criteria: Prohibited Uses	Additional Criteria: Other Development Conditions	Examples: Normally Acceptable Uses [4]	Examples: Uses Not Normally Acceptable[5]
A	• All structures except ones with location set by aeronautical function • Assemblages of people • Objects exceeding FAR Part 77 height limits • Hazards to flight [6]	• Dedication of aviation easement	• Aircraft tiedown apron • Pastures, field crops, vineyards • Automobile parking	• Heavy poles, signs, large trees, etc.
B1 and B2	• Schools, day care centers, libraries • Hospitals, nursing homes • Highly noise-sensitive uses • Storage of highly flammable materials • Hazards to flight [6]	• Locate structures maximum distance from extended runway centerline • Minimum NLR [7] of 25 dBA in residential and office buildings • Dedication of avigation easement	• Uses in Zone A • Any agricultural use except ones attracting bird flocks • Warehousing, truck terminals • Single-story offices	• Residential subdivisions • Intensive retail uses • Intensive manufacturing or food processing uses • Multiple story offices • Hotels and motels
C	• Schools • Hospitals, nursing homes • Hazards to flight [6]	• Dedication of overflight easement for residential uses	• Uses in Zone B • Parks, playgrounds • Low-intensity retail, offices, etc. • Low-intensity manufacturing, food processing • Two-story motels	• Large shopping malls • Theaters, auditoriums • Large sports stadiums • Hi-rise office buildings
D	• Hazards to flight [6]	• Deed notice required for residential development	• All except ones hazardous to flight	

Source: Hodges & Shutt 1991, p. 2-13.

TABLE A11 (Continued)
Safety Compatibility Criteria
Imperial County Airport Land Use Compatibility Plan

NOTES

1 Residential development should not contain more than the indicated number of dwelling units per gross acre. Clustering of units is encouraged as a means of meeting the Required Open Land requirements.

2 The land use should not attract more than the indicated number of people per acre at any time. This figure should include all individuals who may be on the property (e.g., employees, customers/visitors, etc.). These densities are intended as general planning guidelines to aid in determining the acceptability of proposed land uses.

3 See Policy 3.2.5.

4 These uses typically can be designed to meet the density requirements and other development conditions listed.

5 These uses typically do not meet the density and other development conditions listed. They should be allowed only if a major community objective is served by their location in this zone and no feasible alternative location exists.

6 See Policy 3.3.5.

7 NLR = Noise Level Reduction; i.e., the attenuation of sound level from outside to inside provided by the structure.

BASIS FOR COMPATIBILITY ZONE BOUNDARIES

The following general guidelines are used in establishing the Compatibility Zone boundaries for each civilian airport depicted in Chapter 3. Modifications to the boundaries may be made to reflect specific local conditions such as existing roads, property lines, and land uses. Boundaries for NAF El Centro are modified in recognition of the differences between civilian and military aircraft characteristics and flight tracks.

A. The boundary of this zone for each airport is defined by the runway protection zones (formerly called runway clear zones) and the airfield building restriction lines.

Runway protection zone dimensions and locations are set in accordance with Federal Aviation Administration standards for the proposed future runway location, length, width, and approach type as indicated on an approved Airport Layout Plan. If no such plan exists, the existing runway location, length, width, and approach type are used.

The building restriction line location indicated on an approved Airport Layout Plan is used where such plans exist. For airports not having an approved Airport Layout Plan, the zone boundary is set at the following distance laterally from the runway centerline:

Visual runway for small airplanes	370 feet
Visual runway for large airplanes	500 feet
Nonprecision instrument runway for large airplanes	500 feet
Precision instrument runway	750 feet

B1 The outer boundary of the Approach/Departure Zone is defined as the area where aircraft are commonly below 400 feet above ground level (AGL). For visual runways, this location encompasses the base leg of the traffic pattern as commonly flown. For instrument runways, the altitudes established by approach procedures are used. Zone B1 also includes areas within 1,000 feet laterally from the runway centerline.

B2 The Extended Approach/Departure Zone includes areas where aircraft are commonly below 800 feet AGL on straight-in approach or straight-out departure. It applies to runways with more than 500 operations per year by large aircraft (over 12,500 pounds maximum gross takeoff weight) and/or runway ends with more than 10,000 total annual takeoffs.

C The outer boundary of the Common Traffic Pattern Zone is defined as the area where aircraft are commonly below 1,000 feet AGL (i.e., the traffic pattern and pattern entry points). This area is considered to extend 5,000 to 10,000 feet longitudinally from the end of the runway primary surface. The length depends upon the runway classification (visual versus instrument) and the type and volume of aircraft accommodated. For runways having an established traffic solely on one side, the shape of the zone is modified accordingly.

D The outer boundary of the Other Airport Environs Zone conforms with the adopted Planning Area for each airport.

Zone B2 is the extended approach/departure zone. This zone is defined only off the ends of runways with more than 10,000 annual takeoffs. Residential density in this area is limited to 0.5 dwellings per acre. The maximum occupancy density is 60 people per acre. Zone B2 is a rectangle extending 3,500 feet beyond Zone B1 along the extended runway centerline. It is 2,000 feet wide.

Zone C is the common traffic pattern. It is typically defined as an oval shape with the boundaries extending 5,000 feet off the sides of the runway and 7,000 feet off the end of the primary surface. Residential density in this area is limited to four units per acre. The maximum occupancy is limited to 150 people per acre. Fifteen percent of the area must be reserved as open land.

A.4.4.b Riverside County

Table A12 shows the safety standards applying in Riverside County. These are very similar to the guidelines presented in the State's 1983 *Airport Land Use Planning Handbook* (Metropolitan Transportation Commission 1983). Five safety zones are established. The four zones off the runway ends are shown in **Exhibit A12**.

The Inner Safety Zone (ISZ) is a rectangular area 1,500 feet wide and 1,320 to 2,500 feet long, depending on the classification of the runway approach. (The length is measured from the edge of the primary surface.) Development in this area is severely restricted. No structures and no occupancy of this area is permitted.

The Outer Safety Zone (OSZ) is a rectangular area extending 2,180 to 2,500 feet beyond the ISZ. It is also 1,500 feet wide. A number of land uses including residential and other uses involving large concentrations of people are prohibited in this area. Critical public facilities that could be disabled in the event of an aircraft accident are also prohibited. These include public utility stations and plants and public communication facilities. The maximum occupancy is limited to 25 persons per acre for uses in structures and 50 persons per acre for uses not in structures. Lot coverage by structures is limited to 25 percent of the net area.

The Emergency Touchdown Zone (ETZ) is a rectangular area, 500 feet wide, extending through the middle of the ISZ and the OSZ. Development is strictly limited in this area with no significant obstructions being permitted.

The Extended Runway Centerline Zone (ERC) is defined off the ends of runways with nonprecision or precision instrument approaches. It is 1,000 feet wide and extends 5,000 feet beyond the end of the ETZ and OSZ. Within this area uses involving hazardous materials are prohibited. Residential density is limited to three units per acre. The maximum occupancy for uses in structures is 100 persons per acre. Fifty percent of the gross area, or 65 percent of the net lot area, of the development must be kept in open space.

The Traffic Pattern Zone corresponds to the F.A.R. Part 77 horizontal surface. This area extends 5,000 feet off the sides and ends of the primary surface of runways designated as utility or visual. It extends 10,000 feet off the sides and ends of all other runways (including

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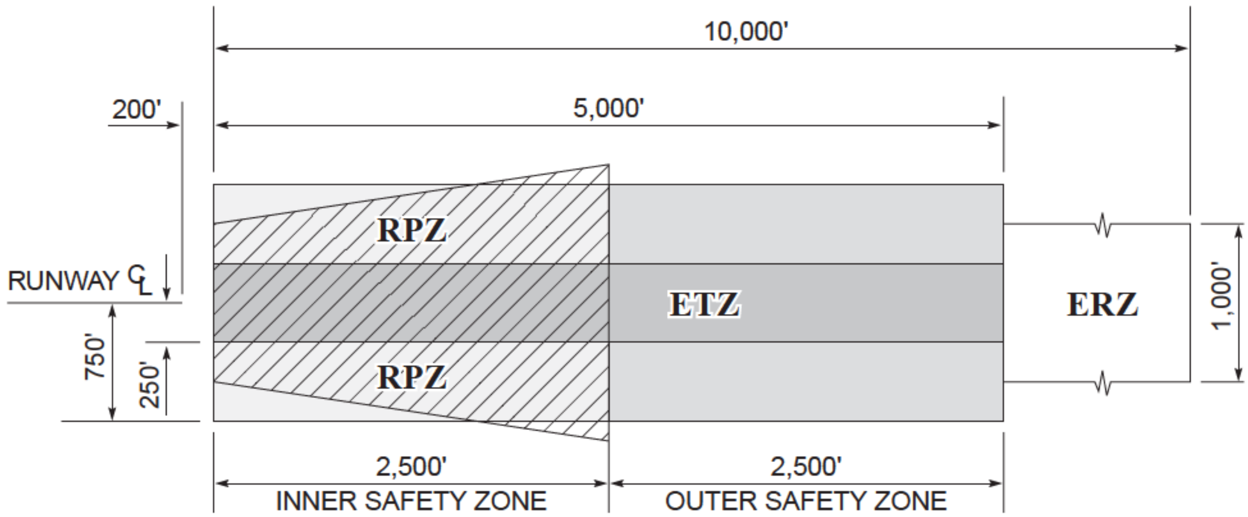
PRECISION AND NON-PRECISION INSTRUMENT RUNWAYS
JET AIRCRAFT



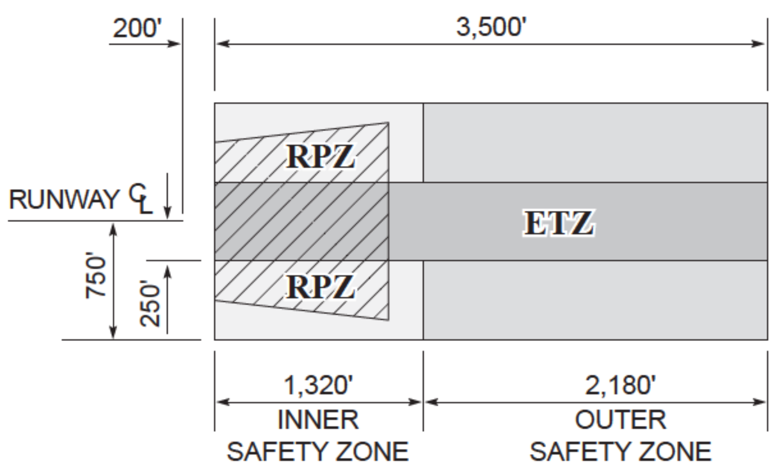
LEGEND

RPZ - Runway Protection Zone

ETZ - Emergency Touchdown Zone

ERC - Extended Runway Centerline

VISUAL APPROACH RUNWAYS
TWIN ENGINE AIRCRAFT



SOURCE: Coffman Associates, 1992. Reproduced from Airport Land Use Planning Handbook: A Reference and Guide for Local Agencies, prepared for California Department of Transportation, Division of Aeronautics, by Metropolitan Transportation Commission and Association of Bay Area Governments, 1983, p. 97.

Ventura County
AIRPORT LAND USE PLAN

Exhibit A12
AIRPORT SAFETY ZONES OFF RUNWAY ENDS
RIVERSIDE COUNTY, CALIFORNIA

TABLE A12
Land Use Compatibility Guidelines for Airport Safety Zones
Riverside County, California

Safety Zone	Dimensions (ft.) Length	Dimensions (ft.) Width[7]	Maximum Pop/DU Density[2]	Maximum Lot Coverage By Structures	Land Use
ISZ-Inner Safety Zone	1,320 to 2,500[3]	1,500	0	0	No petroleum or explosives. No above-grade powerlines.
OSZ-Outer Safety Zones	2,180 to 2,500[4]	1,500	Uses in structures:[9] 25 persons/ac. Uses not in structures: 50 persons/ac.	25% of net area	No residential No hotels, motels No restaurants, bars No schools, hospitals, government services No concert halls, auditoriums No stadiums, arenas No public utility stations, plants No public communication facilities No uses involving, as the primary activity, manufacture, storage, or distribution of explosives or flammable materials
ETZ-Emergency Touchdown Zone	3,500 to 5,000[3]	500	0	0	No significant obstructions[5]
TPZ-Traffic Pattern Zone	F.A.R. Part 77 horizontal surface		----	50% of gross area or 65% of net area	Discourage schools, auditoriums, amphitheaters, stadiums Discourage uses involving, as the primary activity, manufacture, storage, or distribution of explosives or flammable materials[8]
ERC-Extended Runway	5,000[7]	1,000	3 du/net ac. Uses in structures:[9] 100 persons/ac.	50% of gross area or 65% of net area	No uses involving, as the primary activity, manufacture, storage, or distribution of explosives or flammable materials[8]

1 Width of zones is centered on the extended runway centerline
2 Pop/DU - population or dwelling unit.
3 Length is measured from the primary surface. The shorter length is for visual runways serving twin or single engine propeller aircraft, the longer for precision and non-precision instrument runways or runways serving jets.
4 Length is measured from the ISZ. The shorter length is for visual runways serving twin and single engine propeller aircraft, the longer for precision and non-precision instrument runways or runways serving jets.
5 Significant obstructions include but are not limited to large trees, heavy fences and walls, tall and steep berms and retaining walls, non-frangible street light and sign standards, billboards.
6 Applies only to runways with precision or non-precision approaches or serving jet aircraft.
7 Length is measured from the OSZ.
8 This does not apply to service stations involving retail sale of motor vehicle fuel if fuel storage tanks are installed underground.
9 A "structure" includes fully enclosed buildings and other facilities with fixed seating and enclosures limiting the mobility of people, such as sports stadiums, outdoor arenas, and amphitheaters.

Source: Coffman Associates 1992, p. 3-4

those with nonprecision or precision instrument approaches). Within this area, maximum lot coverage is limited to 50 percent of the gross area or 65 percent of the net lot area. While no uses are specifically prohibited, schools, auditoriums, amphitheaters, stadiums, and uses involving explosives or flammable materials are discouraged.

A.4.4.c San Mateo County

San Mateo County establishes one safety area for general aviation airports. It is called an "approach zone" and is a rectangular area centered on the extended runway centerline beginning at the end of the primary surface or beginning 200 feet off the ends of displaced runway thresholds. It is 1,000 feet wide and 2,000 feet long. This area is to be kept free of structures. Nonstructural uses are permitted if they do not cause concentrations of people of more than 10 per net acre. Motor vehicle and open storage uses that may, at times, cause concentrations of up to 25 persons per acre are also permitted.

In the vicinity of San Francisco International Airport, no specific safety zones are delineated. Certain types of land uses or activities, however, are considered hazardous to navigation. These include the following:

1. Any use that would direct a steady or flashing light of white, red, green, or amber color toward an aircraft engaged in an initial straight climb following takeoff or toward an aircraft engage in straight final approach toward a landing, other than an FAA approved navigational signal light or visual approach landing aid.

2. Any use that would cause sunlight to be reflected toward an aircraft engaged in an initial straight climb following take-off or toward an aircraft engaged in a straight final approach toward a landing.

3. Any use that would generate smoke or rising columns or air.

4. Any use that would attract large concentrations of birds within approach-climbout areas.

5. Any use that would generate electrical interference that may interfere with aircraft communications or aircraft instrumentation.

A.4.4.d Santa Barbara County

The Santa Barbara County Comprehensive Airport Land Use Plan establishes three safety areas. Safety Area 1 is called the Clear Zone. Its boundaries coincide with the runway protection zone defined using Federal criteria. Safety Area 2 is the Approach Zone. This is a trapezoid-shaped area extending outward from the runway protection zone. The boundaries of this area correspond with the F.A.R. Part 77 approach surface lying between the runway protection zone and the outer edge of the F.A.R. Part 77 horizontal surface. Safety Area 3 is the Airport Traffic Pattern Zone. Its boundaries correspond with the F.A.R. Part 77 horizontal surface.

Table A13 lists the land use compatibility standards applying in each safety area. Within Safety Area 1, the Clear Zone, most development is prohibited. Certain open space uses are permitted. Any activities resulting in concentrations of people must not exceed a density of 25 persons per acre. Above-ground power transmission lines and gas and oil pipelines are prohibited.

TABLE A13
Land Use Guidelines For Safety Compatibility
Santa Barbara County

	Compatibility With Safety Areas		
Land Use Category	**1 (Clear Zone)**	**2 (Approach Zone)**	**3 (General Traffic Pattern Area)**
RESIDENTIAL			
Single Family	No	Yes 1	Yes
Multi-family dwelling	No	No 2	Yes 3
Mobile home parks or courts	No	No 2	Yes 3
Transient lodging, hotels, motels	No	No 2	Yes 3
INDUSTRIAL/MANUFACTURING			
Chemicals and allied products	No	No	Yes 3
Petroleum refining and related industries	No	No	Yes 3
Rubber and misc. plastic	No	No	Yes 3
Misc. manufacturing	No	Yes 3	Yes 3
Warehouse, storage of non-flammables	No 6	Yes 3	Yes
TRANSPORTATION, COMMUNICATIONS, AND UTILITIES			
Railroad, rapid rail transit	No 6	Yes	Yes
Highway and street	No 6	Yes	Yes
Auto parking lots	No 6	Yes	Yes 3
Utilities	Yes 4	Yes	Yes
Other trans, comm, and util.	No 6	Yes	Yes 3
COMMERCIAL/RETAIL TRADE			
Wholesale Trade	No 6	Yes 3	Yes 3
Building materials-retail	No 6	Yes 3	Yes 3
General merchandise-retail	No	No 2	Yes 3
Food-retail	No	No 2	Yes 3
Automotive	No	Yes 3	Yes 3
Eating and drinking	No	No 2	Yes 3
Other retail trade	No	No 2	Yes 3
PERSONAL AND BUSINESS SERVICES	No	Yes 3	Yes 3
PUBLIC AND QUASI-PUBLIC SERVICES			
Cemeteries	No	No	Yes 3
Other public and quasi-public services	No	No	Yes 3

TABLE A13 (Continued) **Land Use Guidelines For Safety Compatibility** **Santa Barbara County**			
	Compatibility With Safety Areas		
Land Use Category	**1 (Clear Zone)**	**2 (Approach Zone)**	**3 (General Traffic Pattern Area)**
OUTDOOR RECREATION			
Playgrounds, neighborhood parks, camps	No	No	Yes 3
Nature exhibits	No	Yes 3	Yes 3
Spectator sports incl. arenas	No	No	Yes 3
Golf course, riding stables	No	Yes 3,5	Yes 3,5
Auditoriums, concert halls	No	No	Yes 3
Outdoor amphitheaters, music shells	No	No	Yes 3
RESOURCE PRODUCTION, EXTRACTION, AND OPEN SPACE			
Agriculture (except livestock)	Yes	Yes	Yes
Livestock farming, animal breeding	No	Yes	Yes
Forestry activities and related services	No	Yes	Yes
Mining activities	No	Yes	Yes
Permanent open space	Yes	Yes	Yes
Water areas	Yes	Yes	Yes

1. Single family residential is a compatible land use within the approach zone only if the population density is less than two single family residences per acre within one mile of the runway end.

2. Use not compatible in approach zone within one mile of the runway end. Use subject to ALUC review if more than one mile from the runway end.

3. Uses subject to ALUC review if they result in large concentrations of people underneath down wind and base legs or departure paths of frequently used airport traffic patterns. The Airport Planning Advisory Committee will provide assistance to the ALUC and its staff in this determination. Threshold for review of "large concentrations" is on the order of 25 people per acre for non-residential uses or more than four units per acre for residential use.

4. No above grade transmission lines, no on or above grade gas or oil pipelines.

5. Equestrian activity, including riding trails, is not compatible with areas overflown by low flying aircraft as horses may be frightened by aircraft.

6. Intensive development in the clear zone is prohibited. All specific development plans must be reviewed by the ALUC to assure that temporary or permanent concentrations of people greater than 25 people per acre are avoided, that storage of concentrations of hazardous materials will not occur, and that the local public safety agency will be able to effectively provide emergency services to the parcel.

In Safety Area 2, the Approach Zone, various uses involving high densities of people or hazardous materials are prohibited within one mile of the runway end. Outside that area, these uses are permitted "subject to ALUC review." (The CLUP does not set any standards to guide the ALUC review.) In essence, Safety Area 2 is effectively divided into inner and outer approach zones with different standards applying to each. Among the uses prohibited in the Inner Approach Zone are apartments, mobile home parks, hotels, retail stores, restaurants, auditoriums, stadiums, and other uses. Single family homes are permitted in the Inner Approach Zone only if the density is less than two dwellings per acre. Some uses which would involve large concentrations of people in the Approach Zone would be subject to ALUC review. The threshold for "large concentrations" is 25 people per acre for non-residential uses and four dwellings per acre for residential uses. Again, the CLUP provides no standards or guidelines for the ALUC to use in its review of these uses.

Safety Area 3, the Traffic Pattern Zone, no uses are prohibited outright. Many uses are subject to ALUC review, however, if they would result in large concentrations of people--more than 25 people per acre or four dwellings per acre.

A.5 CONCLUSION

This discussion paper presents considerable detail about noise and safety compatibility guidelines. While the detail may be bewildering, distinct trends and tendencies emerge. These are particularly clear with respect to noise compatibility standards. While there are many different sets of guidelines for noise and land use compatibility, there is reasonably good agreement among the various approaches. The definition of "noise-sensitive land uses", for example, is generally agreed to be housing, institutions with a residential component, and public gathering places where quiet is essential for the conduct of typical activities. The noise compatibility standards also agree on the use of a cumulative noise dosage metric to define areas of different noise exposure. In most of the United States, the DNL (day-night sound level) metric is used for this purpose, while California State law requires the use of the similar CNEL (community noise equivalent level) metric.

The major point on which various systems of noise compatibility standards differ is the threshold at which aircraft noise should be considered significant for purposes of compatible land use planning. While Federal standards are concerned only with noise exceeding 65 CNEL (or DNL), State guidelines and some local standards are concerned with noise down to 60 or even 55 CNEL (or DNL). This is an issue deserving discussion in the Ventura County CLUP update process.

While there is much agreement among different sets of noise compatibility standards, there is much more variation among safety compatibility standards and guidelines. This is to be expected since the safety standards necessarily require judgements to be made about the risk of rare events -- namely aircraft accidents. The noise standards, on the other hand, are designed to deal with a predictable situation that tends to recur daily.

Specific points of variability among safety area standards include the definition of safety area boundaries and the land use standards that should apply within various safety areas. These standards, however, all recognize the same basic principles. The risk of aircraft accidents becomes greater as distance from the runway and extended runway centerline decreases.

This gives rise to the common requirements that more open space should be preserved and less housing and population density should be permitted in areas near the runway and the extended runway centerline.

Different sets of safety compatibility standards vary in their clarity and ease of implementation. Some, for example, include only a very general list of land uses to which the standards apply. This forces ALUCs and their staffs to interpret whether the standards were meant to apply to various specific development proposals that will arise. Many other standards relate to the density of people permitted at any given land use. If this is to be practical, a clear method for unambiguously calculating this factor must be agreed upon.

One problem which must be addressed for both safety and noise standards is the need for a clear means of defining the boundaries of various noise and safety zones in the field.

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Appendix B
GENERAL PLAN PROVISIONS RELATED TO AIRPORT COMPATIBILITY

Appendix B: GENERAL PLAN PROVISIONS RELATED TO AIRPORT COMPATIBILITY

The State of California requires all local governments to enact a "general plan" establishing framework policies for future development of the city or county. (See Government Code, Sections 65300, *et seq*.) The local general plan is the most important land use regulatory instrument in California. It establishes overall development policy and provides the legal foundation for all other kinds of land use and development regulation in the community. According to California law, the general plan must contain at least seven elements: land use, circulation, housing, conservation, open space, noise, and safety (Curtin 1996, pp. 9-10). Other elements may be prepared as needed and desired.

The policies of the general plan are implemented through specific ordinances regulating development. Chief among these is the zoning ordinance. Zoning regulates the use of land, the density of development, and the height and bulk of buildings. Subdivision regulations are another important land use regulatory tool, regulating the platting of land. Local communities also regulate development through building codes which set detailed standards for construction.

This appendix reviews the general plans of local jurisdictions in Ventura County as they relate to the airports in the County. These jurisdictions include Camarillo, Oxnard, Port Hueneme, Santa Paula, and Ventura County.

CAMARILLO GENERAL PLAN

NOISE ELEMENT

The Noise Element of Camarillo's General Plan was adopted in 1996 (City of Camarillo 1996). It includes a discussion and maps of transportation noise for existing conditions in 1995 and projected conditions for the year 2015. The noise contours for road and highway noise were developed especially for the Noise Element. Noise contours for Camarillo Airport were taken from the *Airports Comprehensive Land Use Plan Update for Ventura County* (P&D Aviation 1991). Noise contours for NAS Point Mugu were taken from the Air Installation Compatible Use Zoning (AICUZ) study (Dames & Moore 1992).

The major source of noise in the community was the Ventura Freeway (U.S. 101). Another significant source was the Southern Pacific Railroad/Fifth Avenue/Lewis Road corridor. Other sources included Camarillo Airport and, in the south part of the planning area, aircraft noise from Point Mugu.

The following goals and policies relating directly or indirectly to airport noise compatibility are included in the Noise Element (City of Camarillo 1996, pp. 417-418).

> **Goal 1:** The City of Camarillo should address the reduction of noise impacts as part of the land use planning process.
>
> *Policy 1.* The City adopt appropriate noise limits for the various land use classifications throughout the community....
>
> *Policy 3.* The City require developers to submit noise assessment reports during the project planning process to identify potential noise impacts to their own developments and on nearby residential and noise sensitive land uses. New developments should be required to incorporate appropriate noise mitigation measures in their project designs, in order to meet the standards contained in this Element, whenever feasible.
>
> *Policy 4.* The City...will require that the State noise insulation standards for exterior-to-interior and for party walls and floor/ceiling noise control be applied to new single-family dwellings as well as multi-family structures.
>
> *Policy 5.* The City...will require that the State noise insulation standards for exterior-to-interior and for party walls and floor/ceiling noise control be applied where legally possible to the conversion of existing apartments into condominiums....
>
> **Goal 2:** The City should require practical measures to reduce noise impacts from transportation system noise sources....

Policy 10. The City should encourage a reduction of engine run ups and flight operations for Camarillo Airport and PMTC Point Mugu which currently impact the community.

The Noise Element also includes several implementation program measures. Those that are related to airport compatibility are listed below (City of Camarillo 1996, p. 420).

Measure 1. The City shall utilize standards that specify acceptable noise compatibilities for various land uses throughout the City. **Exhibit B1** shows guidelines used to assess the compatibility of proposed land uses with the various noise environments.

Measure 2. The City shall require the developers of proposed residential and noise sensitive developments seeking to locate within any area of 60 dB CNEL or greater to submit noise study reports for both exterior and interior living spaces prepared by experienced persons with demonstrated expertise in noise assessment and control.

Measure 3. The City shall enforce the provisions of the State of California Uniform Building Code through the Building Department of the City which specifies that the indoor noise levels for multi-family residential living spaces not exceed 45 dB CNEL due to the combined effect of all exterior and adjacent unit noise sources. The State requires implementation of this standard when the outdoor noise levels exceed 60 dB CNEL.... The City should also, as a matter of policy, apply this standard to single-family dwellings.

LAND USE ELEMENT

The Land Use Element of the Camarillo General Plan establishes the basic pattern for future development of the City (City of Camarillo 1996, p. 28). The main theme of the Land Use Element is the desire to preserve the quality of life that exists through much of the area and specifically to "promote Camarillo as a rural suburban community that has a quality, small town, family atmosphere." It includes sets of principles, standards, and proposals for each of seven land use categories: agricultural, residential, commercial, industrial, urban reserve, public uses, and quasi-public uses. Principles, standards, and proposals that relate indirectly to airport compatibility are summarized in this section.

Agricultural Uses. "The General Plan proposes that the agricultural activities be encouraged to continue both as a source of economic substance to the community and the County and as a physical definition to the urban area of the City.... This land should be conserved but could be converted to other uses if there is a community need or benefit." (See City of Camarillo 1996, p. 33.)

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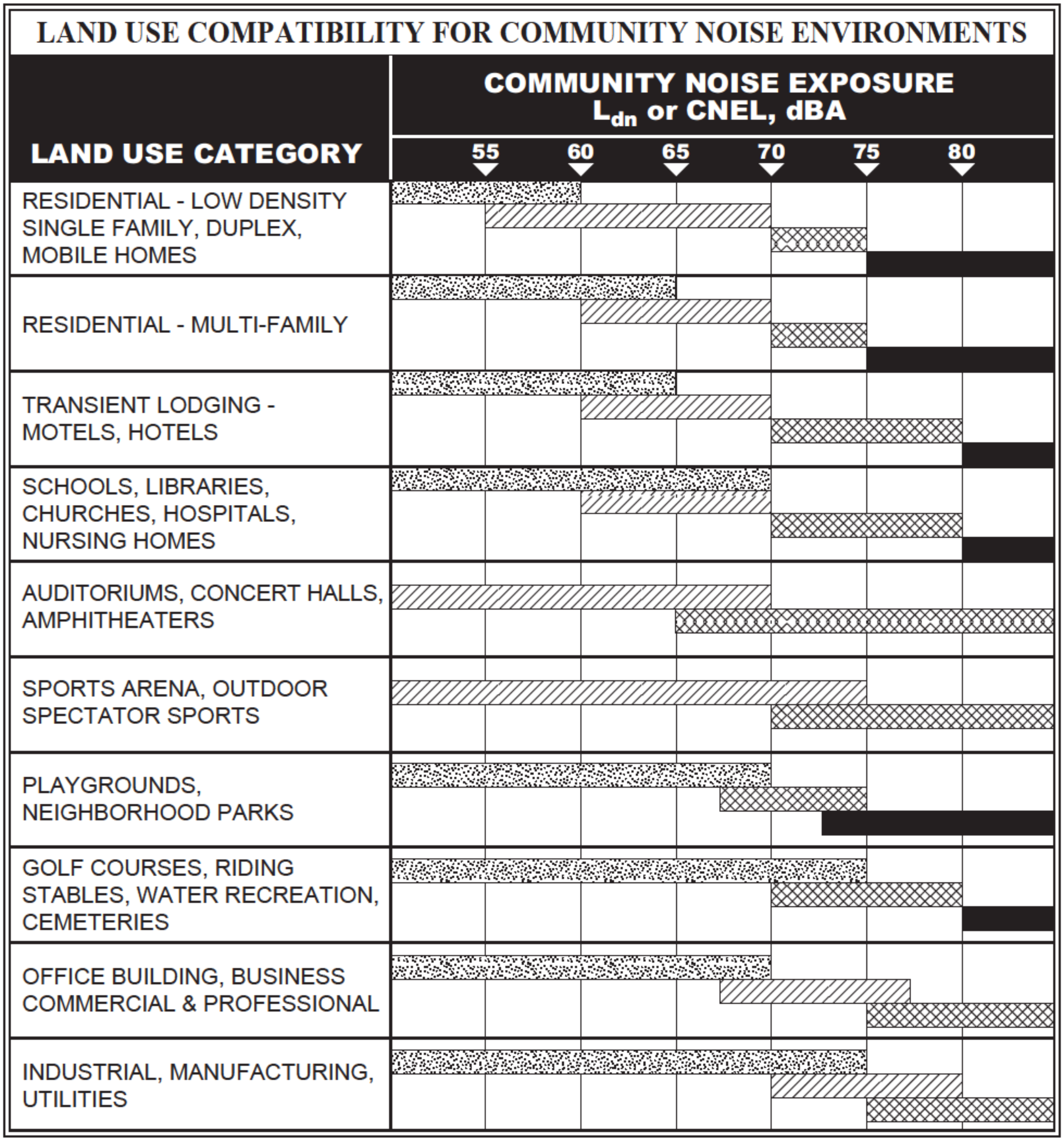

NORMALLY ACCEPTABLE

Specified land use is satisfactory, based upon the assumption that any buildings involved are of normal conventional construction, without any special noise insulation requirements.

CONDITIONALLY ACCEPTABLE

New construction or development should be undertaken only after a detailed analysis of the noise reduction requirement is made and needed noise insulation features are included in the design. Conventional construction, but with closed windows and fresh air supply systems or air conditioning will normally suffice.

NORMALLY UNACCEPTABLE

New construction or development should generally be discouraged. If new construction or development does proceed, a detailed analysis of the noise reduction requirements must be made and needed noise insulation features included in the design.

CLEARLY UNACCEPTABLE

New construction or development should generally not be undertaken.

Source: California State Dept. of Health Services. Cited in City of Camarillo 1996, p. 413.

Ventura County AIRPORT LAND USE PLAN

Exhibit B1
CITY OF CAMARILLO'S LAND USE COMPATIBILITY MATRIX

Residential Uses. This section of the Land Use Element establishes basic residential density classifications that are mapped throughout the City's sphere of influence. The following residential land use objective is established: "To continually improve the areas as places for living by ensuring that those portions of the City which are best suited for residential use will be developed and preserved as healthful, safe, pleasant, attractive neighborhoods where all citizens are served by a full range of appropriate community facilities."

Commercial Uses. The commercial standards and proposals are designed to promote high standards of design for neighborhood and community commercial areas. Large-scale regional shopping centers are not envisioned, as the Plan notes that these needs are currently being met by regional shopping centers in nearby cities.

Industrial Uses. The principles, standards, and proposals for industrial land use emphasize the importance of promoting clean industries with an attractive character and design. For example, "industrial park development concepts" are encouraged. Extensive landscaping and architectural review are also promoted. The Plan notes that the high volume of pollutants which could be generated by certain large industrial operations and related automobile traffic are unacceptable and "cannot be justified by any positive economic benefits which might be enjoyed by the City of Camarillo." (See City of Camarillo 1996, p. 48.)

The Plan also discourages the designation of excessive amounts of industrial land. "This plan also recognizes the danger of premature or overzoning of land for industrial purposes (or other purposes, for that matter) leading to undesirable growth, imbalance and/or 'leapfrogging' which could cause economic hardship on the City." (See City of Camarillo 1996, p. 48.)

General Plan Map. The General Plan Map designates proposed land uses throughout the City's sphere of influence. The "sphere of influence" is an area defined by the Local Agency Formation Commission (LAFCO) which delineates the limits beyond which a city cannot annex territory. It includes the land within the city limits and unincorporated land within the service area of the city.

Exhibit 2C in Chapter Two shows the Camarillo General Plan land use designations within the Camarillo Airport study area. Land in the north part of the study area, north of Ponderosa Drive, is designated for residential use of varying densities. Land at the interchanges of the Ventura Freeway and Las Posas Road and Central Avenue show commercial development. Land off the east end of the airport is designated for a combination of commercial, industrial (research and development), and agriculture.

OXNARD GENERAL PLAN

The Oxnard General Plan was adopted in 1990. It includes eleven planning elements: growth management, land use, circulation, public facilities, open space/conservation, safety, noise, economic development, community design, parks and recreation, and housing. The City also has developed a Coastal Land Use Plan for the coastal zone (City of Oxnard 1982.) Policies and land use designations of the Coastal Land Use Plan have been incorporated into the City's General Plan.

The plan discusses regional plans and policies of significance in the Oxnard planning area. Among the most important are the "Guidelines for Orderly Development." These regional policies were adopted by Ventura County, all municipalities in the County, and the Ventura County Local Agency Formation Commission. These guidelines clarify the relationship between the County and the cities in matters of urban planning and the provision of services. The primary intent of the guidelines is to see that urban development occurs within incorporated areas whenever practical (City of Oxnard 1990, p. III-6).

Growth Management Element. This element of the General Plan has some goals and objectives that indirectly relate to airport compatibility planning (City of Oxnard 1990, p. IV-19).

A. Goals
2. Maintain the quality of life desired by the residents of Oxnard.

B. Objectives
2. Insure that new development avoids or fully mitigates impacts on air quality, traffic congestion, noise and resource protection....

5. Create an appropriate balance between urban development and preservation of agricultural uses within the Planning Area.

The Growth Management Element also includes a number of principles, policies, and implementation measures. The policy with the most direct relevance to the Oxnard Airport Noise Compatibility Study is to cooperate with the City of San Buenaventura (Ventura) and Ventura County in creating an Oxnard/Ventura Greenbelt that would designate land for permanent agriculture/open space. Since the plan was approved, a greenbelt agreement was enacted and the greenbelt established. It is west and northwest of Oxnard Airport as shown in Exhibit 3C in Chapter Three.

Land Use Element. This element includes the following goals and objectives which are indirectly relevant to the airport compatibility planning process (City of Oxnard 1990, p. V-24).

A. Goals
1. A balanced community meeting housing, commercial and employment needs consistent with the holding capacity of the City.

2. Preservation of scenic views, natural topography, natural physical amenities, and air quality.

B. Objectives
1. Limit the urbanized area of the City and facilitate a permanent greenbelt between Oxnard and neighboring cities....

3. Preserve permanent agricultural land within the Oxnard Planning Area.

Exhibit 2C in Chapter Two shows the future land use plan for the Oxnard portion of the Camarillo Airport study area. Exhibit 3C in Chapter Three shows the future land use plan for the Oxnard portion of the Oxnard Airport study area. Exhibit 5C in Chapter Five shows the future land use plan for the NAS Point Mugu study area.

Open Space/Conservation Element. This element includes goal, objectives, and policies for open space for the preservation of natural resources, the managed production of resources, outdoor recreation, and public health and safety. Goals, objectives, and policies with a relationship to airport compatibility planning are quoted below (City of Oxnard 1990, pp. VII-60 to VII-72).

A. Goals
1. Maintenance and enhancement of natural resources and open space.

B. Objectives
3. Protect agricultural lands from premature and unnecessary urbanization....

6. Manage urban development to protect open space areas that provide for public health and safety.

C. Policies
25. The City should provide a mechanism for approval of conservation easements and land banking to establish agricultural open space areas to be managed by either public or private conservation organizations or agencies.

26. The City shall continue the commitment of maintaining the existing Oxnard-Camarillo Greenbelt Agreement, as well as evaluating the possibility of expanding

that agreement and creating a new Greenbelt in the northwest portion of the Planning Area. [This area has since become the San Buenaventura-Oxnard Greenbelt.]

27. The City should encourage the use and formation of Land Conservation Act contracts and other related agreements to offset the costs to property owners of identified agricultural lands....

29. The City should consider adopting a farmland protection program utilizing such land use planning tools as transfer of development rights, purchase of development rights or conservation easements, farmland trusts and greenbelt agreements....

42. Land within the 100-year floodplain is to be designated permanent open space as shown on the Land Use Map.

43. Land within the airport hazard area is to be designated permanent open space as shown on the Land Use Map.

Open space areas are designated on the 2020 Land Use Map in the General Plan. This is shown for the Oxnard Airport study area in Exhibit 3C in Chapter Three. Open space is designated west and northwest of the airport. A narrow band of open space is designated immediately east of the airport.

Noise Element. The Noise Element includes several goals and policies related to noise and land use compatibility planning. Specific goals, objectives, and policies of interest are quoted below (City of Oxnard 1990, p. IX-16).

A. Goals
1. A quiet environment for the residents of Oxnard.

B. Objectives
1. Provide acceptable noise levels for residential and other noise-sensitive land uses consistent with State guidelines.

2. Protect noise sensitive uses from areas with high ambient noise levels.

3. Integrate noise considerations into the community planning process to prevent noise/land use conflicts.

C. Policies
5. Municipal policies shall be consistent with the Ventura County Airport Land Use Commission's adopted land use plan....

7. The City shall prohibit the development of noise-sensitive land uses within the Oxnard Airport 65 dB(A) CNEL contour.

8. The City shall continue to enforce State Noise Insulation Standards for proposed projects in suspected high noise environments. The Planning Division shall notify prospective developers that, as a condition of permit issuance, they must comply with noise mitigation measures, which are designed by an acoustical engineer. No building permits will be issued without City staff approval of the acoustical report/design.

Circulation Element. The Circulation Element includes one goal and several policies relating to Oxnard Airport and the potential civilian use of NAS Pt. Mugu.

A. Goals
3. A regional airport in Ventura County capable of commercial air service....

C. Policies
32. The City should support the location of a regional airport in Ventura County capable of air carrier service.

33. Oxnard Airport should remain as a general aviation facility (operated as a commuter service airport) and operating levels should not be increased.

34. Land uses adjacent to Oxnard Airport should be restricted as set forth in the Land Use Element in order to reduce potential noise and safety problems.

35. If the airport within the Pt. Mugu facility is declared surplus, or made available on a shared basis, the City should promote use of this facility as an air carrier airport.

PORT HUENEME GENERAL PLAN

The Port Hueneme General Plan was adopted in 1997 and establishes policies for a planning period through the year 2015 (Cotton/Beland/Associates, Inc., 1997). It includes seven elements: land use, circulation/infrastructure, housing, conservation/open space /environmental resources, noise, public safety and facilities, and economic development. The Land Use Element is the only element that is directly relevant to this F.A.R. Part 150 Noise Compatibility Study. (According to the Noise Element, the primary source of noise in the City is road noise. The City is not adversely affected by aircraft noise.)

Port Hueneme also has a Local Coastal Program certified by the California Coastal Commission. The updated General Plan reflects the policies of the Local Coastal Program.

"The Land Use Element and Land Use Policy Map are the two most important components of the General Plan. Together, these two parts of the Plan establish the overall policy direction for land use planning decisions in the City." (See Cotton/Beland/Associates, Inc. 1997, p. 1.)

The City of Port Hueneme has very little undeveloped land. Much of the Land Use Element, therefore, is devoted to neighborhood preservation and redevelopment to strengthen the City's economic base. The Land Use Element sets forth six goals:

> Goal 1: Continued development of land uses which will create and sustain a strong, viable economic base for the city.
>
> Goal 2: Creative utilization and responsible conservation of the City's major natural asset -- the beach and harbor environment.
>
> Goal 3: Development and maintenance of a housing stock with a broader range of choice for local residents.
>
> Goal 4: "Fair Share" payment for use of City services and facilities.
>
> Goal 5: Protect the City's interests by continued participation with adjacent and regional jurisdictions to address common issues; including air quality, transportation, water quality and supply, and solid waste disposal.
>
> Goal 6: Create an aesthetically pleasing and efficiently organized city.

Exhibit 3C in Chapter Three shows the future land use designations in the Oxnard Airport Study Area which includes the northern edge of Port Hueneme. Most of the area north of Channel Islands Boulevard is designated for a mix of residential uses. Commercial use is designated along most of Channel Islands Boulevard. Land south of Channel Islands Boulevard and west of Ventura Road is designated for military use.

SANTA PAULA GENERAL PLAN

The Santa Paula General Plan has recently been updated and all elements of the plan except the Housing Element were adopted on April 13, 1998. The updated Plan includes a Land Use Element, a Circulation Element, a Conservation and Open Space Element, a Safety Element, and a Noise Element. Four of these elements (land use, circulation, safety, and noise) have objectives and policies relating to Santa Paula Airport. Those policies are discussed in this section.

LAND USE ELEMENT

The land use goals, objectives, and policies are classified into several different subject areas, as noted below. The airport is addressed in two subject areas: land use distribution and land use compatibility (City of Santa Paula 1997b, pp. LU-43 to LU-54).

Land Use Distribution

Goals

3.1 A healthy balance of land uses and adequate land for all community needs should be provided.

Objectives

3(a) Adequate land should be provided for all needs and a healthy balance of land uses.

Policies

Airport Land Uses

3ggg. Include airport and airport related land uses in the City's land use plan.

3hhh. Provide for the enhancement of on-site airport facilities and services.

Land Use Compatibility

Goals

6.5 Development should mitigate undue generation of noise and light.

6.6 Development should mitigate undue exposure of citizens to existing noise and light sources.

6.7 Existing exposure of citizens to excessive noise and light sources should be reduced.

Objectives

6(I) Development of properties adjoining or near the airport should be compatible with airport operations and the airport land use plan.

6(j) Aviation related business and industry should be encouraged in the area of the airport.

Policies

6.d.d. Encourage land uses on vacant and underdeveloped land adjacent to the airport that is compatible with the airport as well as adjacent established conforming land uses.

6.e.e. The Santa Paula Airport should be preserved and enhanced as a valuable asset of the community.

6.f.f. Airport activity and its continuing operations should be encouraged.

6.g.g. All new development and uses shall be compatible with the Ventura County Airport Land Use Plan.

The following implementation measures relating to these goals, objectives, and policies are in the Land Use Element (City of Santa Paula 1997b, p. LU-67).

59. Review discretionary projects for consistency with the Airport Land Use Plan.

60. Purchase properties adjacent to the airport that are mapped as clear zones as soon as individual parcels and funds become available.

61. Airport run way overruns should be extended when land becomes available.

CIRCULATION ELEMENT

The circulation goals, objectives, and policies are classified into several different subject areas, including aviation, which addresses Santa Paula Airport (City of Santa Paula 1997a, pp. CI-41 to CI-42).

Goals

9.1 The Santa Paula Airport should be preserved and enhanced as a valuable asset of the community.

9.2 Appropriate uses and development should be maintained and allowed at the airport.

9.3 Existing risks from aviation should be reduced.

9.4 Development should be compatible with existing risks from aviation.

9.5 Existing pollution from aviation should be reduced.

Objectives

9(a) Development of properties adjoining or near the airport should be compatible with airport operations and the airport land use plan.

9(c) The mapped clear zones should be purchased as soon as individual parcels and funds become available.

9(d) Runway overruns should be extended when land becomes available.

9(e) Efforts should continue to reduce the potential for pollution from aircraft fueling and maintenance operations.

9(f) Work with the airport to provide for adequate ground access to the airport in its transportation planning and improvements.

Policies

9.a.a. Properties adjoining or near the airport should be zoned for compatible uses, and aviation related business and industry should be encouraged.

9.b.b. Uses within clear zones should be compatible.

9.c.c. Street system modification should not inhibit the provision for adequate ground access to the airport.

NOISE ELEMENT

The noise goals, objectives, and policies are tied to specific noise sources. Objectives and policies related to aircraft noise are noted below (City of Santa Paula 1997c, pp. N-17).

Objective

2(a) Minimize the effect of air traffic noise generated by the existing and future operations of the Santa Paula Airport on residences and other noise sensitive land uses.

Policies

2.a.a. Coordinate with airport officials to address operational noise as conflicts are identified.

2.a.b. Work with airport officials to address noise concerns from aerobatics and air shows on a case-by-case basis.

2.a.c. Consider the land use/noise compatibility matrix when determining the appropriateness of land uses in the airport vicinity. [Santa Paula's compatibility matrix is virtually identical to Camarillo's matrix shown in Exhibit B1.]

Two implementation measures relating to these objectives and policies are called out in the Noise Element (City of Santa Paula 1997c, pp. N-21 to N-23).

2. Establish exterior land use noise compatibility standards in the Development Code for all new development based on the guidelines shown on Figure N-1 [Exhibit B1] of this Noise Element.

14. The City shall work with the Santa Paula Airport to ensure that local ordinances and state and federal regulations regarding altitudes of departing and arriving aircraft are met.

SAFETY ELEMENT

The goals, objectives, and policies of the Safety Element are tied to specific kinds of hazards. Goals, objectives and policies related to aircraft safety are noted below (City of Santa Paula 1997d, pp. S-43 to S-44).

Goals

6.1 Existing risks from aviation should be reduced.

6.2 Development should be compatible with existing risks from aviation.

Objectives

6(a) Development of properties adjoining or near the airport should be compatible with airport operations and the airport land use plan.

6(b) The mapped clear zones should be purchased as soon as individual parcels and funds become available.

6(c) Runway overruns should be extended when land becomes available.

Policies

6.a.a. The City should work in conjunction with the privately owned Santa Paula Airport to follow the land use guidelines for safety compatibility outlined in the Ventura County Airports Comprehensive Land Use Plan Update.

6.b.b. The City should propose legislation to allow for the City to acquire the property(ies) in the Inner Safety Zones of the airport.

Two implementation measures relating to these goals, objectives, and policies are called out in the Safety Element (City of Santa Paula 1997d, p. S-54).

61. The City of Santa Paula should change the land use designations in the Inner Safety Zone at both ends of the Santa Paula Airport runway to agricultural or other conforming uses.

62. The City should pass legislation which would allow funding by the State for purchase of the property in the Inner Safety Zone.

VENTURA COUNTY GENERAL PLAN

The Ventura County General Plan was adopted in 1988 and has been amended several times since then. The Plan includes several documents. The overall framework of goals and policies is in a document called *Goals, Policies and Programs* (Ventura County 1996a.) Supporting documentation is in a series of technical appendices (Ventura County 1994a, 1994b, 1994c, 1996b). The General Plan also includes several area plans where local issues and concerns are dealt with in greater detail than in the framework document.

The *Goals, Policies and Programs* document is organized into four substantive chapters dealing with different planning issues: resources, hazards, land use, and public facilities and services. The goals, policies, and programs that directly or indirectly relate to airport land use compatibility issues are summarized below.

Resources--Farmland. Agriculture is a major industry in Ventura County. The County General Plan establishes policies to encourage the preservation of prime farmland. Since agriculture is a land use that is compatible with airport noise, the farmland preservation policies can indirectly also promote airport compatibility objectives. Relevant goals and policies are quoted below (Ventura County 1996a, p. 21).

1.6.1 Goals

1. Preserve and protect irrigated agricultural lands as a nonrenewable resource to assure the continued availability of such lands for the production of food, fiber and ornamentals.

1.6.2 Policies

3. Land Conservation Act (LCA) contracts shall be encouraged on irrigated farmlands....

5. The County shall preserve agricultural land by retaining and expanding the existing Greenbelt Agreements and encouraging the formation of additional Greenbelt Agreements.

The LCA (also known as the Williamson Act) was adopted by the State in 1966. It enabled Counties to set up programs allowing farmers to enter into contracts of at least ten years duration to keep their land exclusively in farm use in return for a reduced tax assessment based on the agricultural use of the property. Ventura County entered this program in 1969 (Ventura County 1994c, p. 73).

Greenbelt agreements have been formed between various cities in Ventura County. The agreements delineate areas between the cities which are declared to be off limits to urban development and preserved for agriculture and open space. The cities of Ventura and Oxnard have a greenbelt agreement for the area between the two cities northwest of Oxnard Airport. This is shown in Exhibit 3C in Chapter Three. Camarillo and Oxnard have a greenbelt agreement between their cities, as shown in Exhibit 2C in Chapter Two.

Airport Hazards. The County General Plan includes goals and policies applying to airport hazards, quoted below (Ventura County 1996a, p. 20).

> **2.10.1 Goal**
> Minimize the risk of loss of life, injury, damage to property, and economic and social dislocations resulting from airport hazards.
>
> **2.10.2 Policies**
> To avoid accidents, land in airport approach and departure zones shall be designated Agriculture or Open Space on the General Plan Land Use Map...

Hazards--Flood. Ventura County's flood hazard goals and policies are intended to reduce risks of damage and injury due to floods (Ventura County 1996a, p. 43). In areas of greatest risk, only open space uses are to be permitted. In other areas of flood hazard, development is to be protected from a 100-year flood by being raised above the flood elevation. To the extent that flood hazard areas coincide with airport noise areas, these flood hazard policies also indirectly promote airport compatibility objectives.

Hazards--Noise. The County General Plan declares that the County should attempt to eliminate or avoid the exposure of County residents to adverse noise impacts (Ventura County 1996a, p. 49). It notes that noise-sensitive land uses are considered to be residential, educational and health facilities, research institutions, certain recreational and entertainment facilities, and churches. The Plan sets forth the following policies with respect to development in areas exposed to aircraft noise (Ventura County 1996a, p. 50).

> **2.16.2 Policies**
> 1. (3) Noise sensitive uses proposed to be located near airports:
> a. Shall be prohibited if they are in a CNEL 65 or greater noise contour.

b. Shall be permitted in the CNEL 60 to CNEL 65 noise contour area only if means will be taken to ensure interior noise levels of CNEL 45 or less.

Land Use. The County General Plan includes general land use goals, policies, and programs and sets of specialized goals, policies, and programs in the following policy areas: land use map designations, population and housing, and employment and commerce/industry. One general goal is specifically relevant to airport land use compatibility planning:

3.1.1 Goals
4. Ensure that land uses are appropriate and compatible with each other and guide development in a pattern that will minimize land use conflicts between adjacent land uses.

In the study areas around each airport in Ventura County, the County's future land use designations in most of the unincorporated area outside the city spheres of influence is agriculture, a use that is compatible with aircraft noise. This is shown in Exhibits 2C, 3C, 4C, and 5C in Chapters Two through Five.

Public Facilities and Services -- Transportation/Circulation. The Transportation/Circulation section of the General Plan has two policies related to airport land use compatibility.

4.2.2 Policies
11. Discretionary development which would endanger the efficient, safe operation of an airport or would result in significant land use incompatibility with an airport shall be prohibited.

12. The Ventura County General Plan shall remain consistent with the Ventura County Master Airport Plan for Camarillo Airport and Oxnard Airport, which includes the Airport Noise Control and Land Use Compatibility Study (ANCLUC), for the purpose of ensuring compatible land uses around the Camarillo and Oxnard Airports.

Coastal Area Plan. The County's Coastal Area Plan establishes different land use and conservation policies in the coastal zone (Ventura County 1996c). Most of the area within the County's jurisdiction in the Oxnard Airport study areas and NAS Point Mugu is designated as agriculture. This is reflected in Exhibit 3C in Chapter Three and Exhibit 5C in Chapter Five. Smaller areas are designated as open space, including the McGrath Lake area, the beach west of Channel Islands Harbor, and mountainous areas east of NAS Point Mugu.

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Appendix C
SANTA PAULA AIRPORT NOISE ANALYSIS

Appendix C:
SANTA PAULA AIRPORT NOISE ANALYSIS

AIRCRAFT NOISE ANALYSIS METHODOLOGY

The standard methodology for analyzing the prevailing noise conditions at airports involves the use of a computer simulation model. The Federal Aviation Administration (FAA) has approved two models for use in determining airport noise impacts -- NOISEMAP and the Integrated Noise Model (INM). NOISEMAP is used most often at military airports, while the INM is most commonly used at civilian airports.

Version 5.1 is the most current version of the INM at this time. It is the version used for the noise analysis. The INM works by defining a network of grid points at ground level around the airport. It then selects the shortest distance from each grid point to each flight track and computes the noise exposure for each aircraft operation, by aircraft type and engine thrust level, along each flight track. Corrections are applied for air-to-ground acoustical attenuation, acoustical shielding of the aircraft engines by the aircraft itself, and aircraft speed variations. The noise exposure levels for each aircraft are then summed at each grid location. The cumulative noise exposure levels at all grid points are then used to develop noise exposure contours for selected values (e.g., 65, 70, and 75 CNEL).

In addition to the mathematical procedures defined in the model, the INM has another very important element. This is a database containing tables correlating noise, thrust settings, and flight profiles for most of the civilian aircraft, and many common military aircraft, operating in the United States. This database, often referred to as the noise curve data, has been developed under FAA guidance based on rigorous noise monitoring in controlled settings. In fact, the INM database was developed through more than a decade of research including extensive field measurements of more than 10,000 aircraft operations.

The database also includes performance data for each aircraft to allow for the computation of airport-specific flight profiles (rates of climb and descent).

INM INPUT

A variety of user-supplied input data is required to use the Integrated Noise Model. This includes the airport elevation, a mathematical definition of the airport runways, the mathematical description of ground tracks above which aircraft fly, and the assignment of specific aircraft with specific engine types at specific takeoff weights to individual flight tracks. In addition, aircraft not included in the model's database may be defined for modeling, subject to FAA approval.

Activity Data

For this analysis, current aircraft operations (takeoffs and landings) data were used for noise modeling. CALTRANS operation forecasts from the Southern California Association of Governments General Aviation Study have the same level of operations for 2015. These are briefly summarized in **Table C1**.

TABLE C1
Operations Summary
Santa Paula Airport

Operations	1997[1]
Itinerant	
General Aviation/Fixed Wing	13,200
Helicopter	800
Local	
General Aviation/Fixed Wing	38,000
Total	52,000

[1] Southern California Association of Governments General Aviation Study and AirNav information from the world wide web.

Average daily aircraft operations were calculated by dividing total annual operations by 365 days. The distribution of these operations among various categories, users, and types of aircraft is critical to the development of the input model data.

The selection of individual aircraft types is important to the modeling process because different aircraft types generate different noise levels.

Fleet Mix And Database Selection

The aircraft fleet mix was provided by the airport manager. **Table C2** summarizes the fleet mix data input into the noise analysis by annual aircraft operations.

n order to select the proper aircraft from the INM database, a review of the current fleet mix for Santa Paula Airport was conducted.

The FAA's substitution list indicates that the general aviation single engine variable pitch propeller model, the GASEPV, represents a number of single engine general aviation aircraft. Among others these include the Beech Bonanza, Cessna 177 and 180, Piper Cherokee Arrow, Piper PA-32, and the Mooney. The general aviation single-engine fixed pitch propeller model, the GASEPF, also represents several single-engine general aviation aircraft. These include the Cessna 150 and 172, Piper Archer, Piper PA-28-140 and 180, and the Piper Tomahawk.

TABLE C2
Fleet Mix Data
Santa Paula Airport

	1997
Itinerant Operations	
General Aviation	
Twin Engine	660
Light Single-Variable Pitch Prop.	6,270
Light Single-Fixed Pitch Propeller	6,270
Bell 206 Helicopter	800
Subtotal Itinerant	14,000
Local Operations	
GENERAL AVIATION	
Light Twin	1,900
Light Single-Variable Pitch Prop.	18,050
Light Single-Fixed Pitch Propeller	18,050
Subtotal Itinerant	38,000
Total	52,000

The list recommends the BEC58P, the Beech Baron, to represent the light twin-engine aircraft such as the Piper Navajo, Beech Duke, Cessna 31, and others.

The most common helicopter in the Santa Paula fleet mix is the Bell 206. Helicopter data for this aircraft was extracted from the FAA's Heliport Noise Model (HNM) to simulate the helicopter air taxi and general aviation activity.

These choices are in accordance with the Pre-Approved Substitution List published by the FAA Office of Environment and Energy (AEE) branch in Washington.

Time-Of-Day

The time-of-day at which operations occur is important as input to the INM due to the extra weighting of evening (7:00 p.m. to 10:00 p.m.) and nighttime (10:00 p.m. to 7:00 a.m.) flights. In calculating airport noise exposure, one evening operation has the same noise emission value as three daytime operations by the same aircraft (a weight of 4.8 extra decibels). One nighttime operation has the same noise emission value as 10 daytime operations (a weight of 10 extra decibels).

Evening and nighttime information was not available. Santa Paula Airport is closed during nighttime hours due to the lack of runway lighting. Based on experience at similar airports, ten percent of the itinerant general aviation operations were assumed to occur during evening hours.

Runway Use

Runway usage data is another essential input to the INM.. Runway use was provided by the airport manager. Approximately 90 percent of general aviation arrivals and departures are on Runway 22.

Flight Tracks

Flight track data was derived from the Santa Paula Airport brochure dated June 1996. Arrival, departures, and touch-and-go tracks are depicted on Exhibit 4E in Chapter Four.

INM OUTPUT

Output data selected for calculation by the INM were annual average noise contours in CNEL. The following sections presents the results of the contour analysis for the current condition, as developed from the Integrated Noise Model.

Noise Exposure Contours

Exhibit 4F in Chapter Four presents the plotted results of the INM contour analysis for current conditions using input data described in the preceding pages. These contours represent noise exposure both current conditions and the 2015 forecast. The surface areas within each contour are presented in **Table C3**.

The 60 CNEL noise contour is cigar shaped with a small arrival spike to the northeast of the airport. The 65 CNEL noise contour has a similar shape, but without the arrival spike. The 70 and 75 CNEL noise contours remain close to Runway 4-22 and are elongated about the runway centerline.

TABLE C3
Noise Exposure Area
Santa Paula Airport

	Area in Square Miles
CNEL Contour	**1997/2015**
60	0.34
65	0.13
70	0.05
75	0.02

SUMMARY

The information presented in this report defines the noise patterns for the Santa Paula Airport vicinity. It is stressed that CNEL contour lines drawn on a map do not represent absolute boundaries of acceptability or unacceptability in personal response to noise, nor do they represent the actual noise conditions present on any specific day, but rather the conditions of an average day derived from annual average information.

Appendix D
IMPLEMENTATION MATERIALS

Appendix D: IMPLEMENTATION MATERIALS

The materials in this appendix are for use in implementing the updated Airport Comprehensive Land Use Plan for Ventura County.

- A model agreement for noise disclosure and fair disclosure statement;
- A model noise and avigation easement;
- An excerpt from F.A.R. Part 77 describing Federal requirements for notifying the FAA of proposed construction which may affect navigable airspace.

While care has been taken to ensure accuracy of the model easement and fair disclosure agreement and statement, the form and language of these instruments may need to be altered to conform with local laws and customs. They must be reviewed by attorneys representing local jurisdictions before their use or adoption.

MODEL AGREEMENT FOR NOISE DISCLOSURE

This Agreement made and entered into this _____ day of ___________, 199__, by and between the Ventura County Airport Land Use Commission, hereinafter referred to as "ALUC", the ***[City of _________; OR Ventura County]***, hereinafter referred to as ***"City" [OR "County"]***, ***[Ventura County; OR the United States Navy; OR the Santa Paula Airport Association, Ltd.]***, as proprietor of _______________ Airport, hereinafter referred to as "Airport Proprietor," and _______________________, herein referred to as "Developer."

WITNESS, that

WHEREAS, Developer has an interest in a tract of land generally located at ____ in Ventura County, California, more specifically described in Exhibit "A" which is attached hereto and incorporated herein by reference, to be platted as ____________________, and referred to herein as "Developer's Property"; and

WHEREAS, ____________________ owns and operates a certain airport known as _____________________ Airport located _______________________ of Developer's Property; and

WHEREAS, it is in the best interest of the ALUC, Airport Proprietor, ***[City OR County]***, and Developer to advise all future purchasers and lessees of the presence of the Airport and the potential for low-flying aircraft and noise attributable to aircraft operations at __________________ Airport; and

WHEREAS, this Agreement is entered into for the purpose of advising said purchasers and lessees of the aircraft activity and potential for noise generation;

NOW, THEREFORE, for and in consideration of the mutual covenants and considerations herein contained, it is agreed as follows:

1. ALUC, ***[City OR County]***, Airport Proprietor, and Developer enter into this Agreement for the purpose of advising future purchasers and lessees of the activity and noise attributable to aircraft operations at ___________________ Airport.

2. Developer agrees that in the sales listing information for each lot or separately transferrable property, he will include a notice that the property is in the _____________ Airport Influence Area. The information shall include copies of a map showing the Airport Influence Area and the safety zones and noise contours taken from the most recent version of the ALUC's Airport Comprehensive Land Use Plan.

3. Developer agrees that as a part of closing of any real estate transaction conveying a fee simple interest or any lesser estate including leasehold interest that Developer will provide the transferee copies of the aforementioned map and further that Developer shall secure the acknowledgment on six copies of the Fair Disclosure Statement as set forth in Exhibit "B" attached hereto and incorporated herein by reference.

4. The ALUC shall provide Developer with copies of the most recent, official Airport Influence Area Map for______ ___________Airport at the request of Developer. Any request for said Map shall be in writing to the Ventura County Airport Land Use Commission, in care of the Ventura County Transportation Commission, 950 County Square Drive, Ventura, California, 93003, and shall be made not less than thirty (30) days before the date thereof.

5. After the execution of the Fair Disclosure Statement (Exhibit "B"), Developer shall record one copy at the County Recorder's office, file one copy with the City ***[OR County]*** Planning Department, one copy with the Airport Proprietor, one copy with the ALUC, retain one copy, and deliver the remaining copy to the transferee.

6. Developer further agrees that all transferees shall take subject to the terms of this Agreement and require the execution of the Fair Disclosure Statement as a part of any subsequent conveyance.

7. This Agreement shall be considered a covenant running with the land and be binding on all future transferees, assigns and successors of Developer inasmuch as the potential affects of the Airport operation is associated with the use of the land and indiscriminate of ownership.

8. This Agreement shall not be amended, modified, canceled, or abrogated without the written consent of the parties.

9. Invalidation of any part or parts of this Agreement by judgment or other court action shall in no way affect any of the other provisions which shall remain in full force and effect.

10. This contract shall be construed and enforced in accordance with the laws of the State of California.

11. Upon the effective date of this Agreement, the Agreement shall be recorded in the Office of the Recorder of Deeds, Ventura County, California.

12. This Agreement shall be binding on the parties hereto only after all legal requirements relating to ALUC and ***[City OR County]*** entering into this Agreement have been satisfied.

____________________AIRPORT

By:________________________________
Its Airport Director

ATTESTED TO:

____

Approved as to form and legality:

____
Legal Counsel

DEVELOPER

By:________________________________

ATTEST:

____
Secretary

NOTARY'S CERTIFICATION:

____
Notary Public

[CITY OF ________________ OR VENTURA COUNTY]

By:________________________________
Chief Executive Officer

ATTESTED TO:

____

Approved as to form and legality

____
Legal Counsel

AIRPORTLANDUSECOMMISSION

By:________________________________

Chairman

ATTESTEDTO:

____

Approvedastoformandlegality

____

LegalCounsel

"EXHIBIT B"

MODEL FAIR DISCLOSURE STATEMENT

NOTICE TO PROSPECTIVE BUYERS OF REAL PROPERTY OR LESSEES OF RESIDENTIAL PROPERTY WITHIN ___________ AIRPORT INFLUENCE AREA.

1. An Airport Influence Area exists in the environs of ____________ __ Airport (herein referred to as the Airport). All land within the area is or may be at a future date exposed to low and frequent aircraft overflights or aircraft noise levels of 60 CNEL or higher. Low and frequent aircraft overflights and noise levels of 60 CNEL can be annoying or disturbing.

2. No person who acquires property or an interest therein, or who leases property or an interest therein within the Airport Influence Area after the date on which this statement is signed, shall be entitled to recover damages from the Airport Proprietor, with respect to the noise or activity attributable to aircraft operations at the Airport unless, in addition to any other elements for recovery of damages, such person can show that said damage occurred as a result of one or more of the following, any one or all of which occurred after the date of the acquisition or lease of such property or interest therein:

   A. A major change in the approved Airport Layout Plan or interest therein.

   B. A significant change in flight patterns which were used in producing the noise contours in the attached Airport Influence Area map.

3. The undersigned acknowledges that he or she has been informed that the property being considered for ***[purchase OR lease]*** at:

____
Address

____
City State Zip Code

is within the Airport Influence Area for the Airport. He or she further acknowledges that he or she has been given copies of the Airport Influence Area map (a copy of which is attached hereto).

The undersigned has read and fully understands all of the provisions relating to this Fair Disclosure statement.

IN WITNESS WHEREOF, the parties have executed this Statement as of the day and year written below.

Date:__________________________,19___.

______________________________	______________________________
PRINTNAMEOFBU YERORLESSEE	PRINTNAMEOFSELLER,LESSOR, BROKER
______________________________	______________________________
CurrentAddress	Company
______________________________	______________________________
City State ZipCode	Address
	______________________________
	City State ZipCode
______________________________	______________________________
Signature	Signature

Stateof______________)
)ss
Countyof_____________)

BE IT REMEMBERED that on the _____ dayof__________________, 19___, beforeme, theundersignednotarypublicinandforthecountyandstate aforesaid, came____, tomepersonally known,who beingbymedulysworndidsaythatheisthe____________________________________
__________________________of____,
a corporation,andthatthe sealaffixedtotheforegoinginstrumentisthecorporate sealofsaidcorporationandthatsaidinstrumentwassignedandsealedonbehalfof said corporation by authority of its board of directors and said _________________________
___________________________________acknowledged saidinstrumenttobe thefreeact anddeedofsaidcorporation.

INWITNESSWHEREOF,I havehereunto setmyhandandaffixedmyofficial seal,thedayandyearlastabovewritten.

____
NotaryPublic

Mycommissionexpires:______________________________________

MODEL NOISE AND AVIGATION EASEMENT AND NON-SUIT COVENANT

WHEREAS the grantor is the owner in fee of a certain parcel of land in the [***City OR County***] of ____________, State of California; and

WHEREAS Grantor has been advised and is of the opinion that the subject property is located in the Airport Influence Area for __________ Airport; that this area is subject to low and frequent aircraft overflights and aircraft noise; that these present and future aircraft overflights and noise levels might be annoying to users of the land for its stated purpose and might interfere with the unrestricted use and enjoyment of the property in its intended use; that these aircraft overflights and noise levels might change over time by virtue of greater numbers of aircraft, louder aircraft, seasonal variations, and time-of-day variations; that changes in airport, aircraft, and air traffic control operating procedures or in airport layout could result in increased overflights and noise levels; and that the grantor's or user's own personal perceptions of the aircraft activity and noise could change and that his or her sensitivity to aircraft noise and overflights could increase;

NOW, THEREFORE, KNOW ALL MEN BY THESE PRESENTS:

That for a good and valuable consideration, the receipt of which is hereby acknowledged, that ____ does hereby grant a permanent noise and avigation easement to ***[Ventura County; OR the United States Navy; OR the Santa Paula Airport Association, Ltd.]***, owner and operator of _____________ Airport, for the use of "Navigable Airspace" as defined by the Federal Aviation Act of 1958, over all of the following described real estate, to wit:

By virtue of this agreement, the grantor, for and on behalf of himself and all successors in interest to any and all of the real property above described, waives as to the airport owner and operator or any successor entity legally authorized to operate said airport, any and all claims for damage of any kind whatsoever incurred as a result of aircraft using the "Navigable Airspace" granted herein regardless of any future changes in volume or character of aircraft overflights, or changes in airport design and operating policies, or changes in air traffic control procedures.

The Grantor, for and on behalf of himself and all successors in interest to any and all of the real property above described, does further hereby covenant and agree with the Grantee that it will not from and after the effective date hereof, sue, prosecute, molest, or trouble the Grantee in respect to or on account of the flight of any and all aircraft over or near the said parcel of land or for any effects resulting therefrom including but not limited to noise, air pollution, or any and all other possible damages to or taking of said property resulting from such flights. This easement and non-suit covenant is granted solely to ***[Ventura County; OR the United States Navy; OR the Santa Paula Airport Association, Ltd.]*** as owner and operator of ______________ Airport, and any successor entity, and does not grant any right to private persons or corporations.

"Navigable Airspace" means airspace above the minimum altitudes of flight prescribed by regulations issued under the Federal Aviation Act of 1958, Section 101(24) 49 U.S. Code 1301, and shall include airspace needed to ensure safety in the takeoff and landing of aircraft.

To have and to hold said easement forever.

(Witness, signatures, and dates follow in customary local format.)

Appendix E
AIRPORT LAND USE COMPATIBILITY POLICIES ALTERNATIVES

Appendix E
AIRPORT LAND USE COMPATIBILITY POLICY ALTERNATIVES

This Appendix discusses airport compatibility framework policies at Ventura County airports. They are compared with the existing airport compatibility policies established in the existing Airport s Comprehensive Land Use Plan (the 1991 CLUP). It was used by the Project Advisory Committee and the Airport Land Use Commission in developing the adopted policies in Chapter 6.

The policy alternatives are based on guidance provided by the updated *Airport Land Use Planning Handbook* (Hodges & Shutt 1993.)

E.1 SAFETY COMPATIBILITY

E.1.1 1991 CLUP STANDARDS AT CIVILIAN AIRPORTS

The 1991 safety compatibility standards for Ventura County civilian airports are shown in **Table E 1**. Three zones are established: the Inner Safety Zone, the Outer Safety Zone, and the Traffic Pattern Zone. The standards become less restrictive as distance from the airport and runway center line increases. The strictest standards are in the Inner Safety Zone, an area corresponding with the runway protection zone defined by FAA airport planning criteria. Less restrictive standards apply in the Outer Safety Zone. The least restrictive standards apply in the Traffic Pattern Zone, the area beneath the most commonly used traffic pattern.

TABLE E1
Land Use Compatibility Guidelines in
Air Safety Zones for Civilian Airports--1991 CLUP

Land Use	Inner Safety Zone	Outer Safety Zone	Traffic Pattern Zone
Residential			
Single Family	U	U	C [a]
Multi-Family	U	U	C [a]
Mobile Home Parks	U	U	C [a]
Public/Institutional			
Hospitals/Convalescent Homes	U	U	U
Schools	U	U	U
Churches/Synagogues	U	U	U
Auditoriums/Theaters	U	U	U
Transportation Terminals	U	U	U
Communication/Utilities	C [b]	A	A
Automobile Parking	C [b]	A	A
Commercial			
Hotels and Motels	U	U	C [c]
Offices and Business/Professional Services	U	C [a]	C [c]
Wholesale	U	C [a]	C [c]
Retail	U	C [a]	C [c]
Industrial			
Manufacturing-General/Heavy	U	C [a]	C [c]
Light Industrial	U	C [a]	C [c]
Research and Development	U	C [a]	C [c]
Business Parks/Corporate Offices	U	C [a]	C [c]
Recreation/Open Space			
Outdoor Sports Arenas	U	U	U
Outdoor Amphitheaters	U	U	U
Parks	U	C [a]	A
Outdoor Amusement	U	C [a]	A
Resorts and Camps	U	C [a]	A
Golf Courses and Water Recreation	C [d]	A	A
Agriculture	A	A	A

TABLE E1 (Continued) Land Use Compatibility Guidelines in Air Safety Zones for Civilian Airports -- 1991 CLUP
NOTES
A = Acceptable land use C = Land use is conditional upon meeting established criteria (see footnotes) U = Unacceptable land use
[a] Maximum structural coverage must be no more than 25 percent. "Structural coverage" is defined as the percent of building footprint area to total land area, including streets and greenbelts.
[b] The placing of structures or buildings in the Inner Safety Zone is unacceptable. Above ground utility lines and parking are allowed only if approved by the FAA as not constituting a hazard to air navigation.
[c] Maximum structural coverage must not exceed 50 percent. "Structural coverage" is defined as the percent of building footprint area to total land area, including streets and greenbelts. Where development is proposed immediately adjacent to the airport property, it is suggested that structures be located as far as practical from the runway.
[d] Clubhouse is unacceptable in this zone.
Source: P&D Aviation 1991.

E.1.2 ALTERNATIVE SAFETY ZONES AT CIVILIAN AIRPORTS

Since the preparation of the 1991 CLUP, the State Aeronautics Program has released an updated version of the *Airport Land Use Planning Handbook* (Hodges & Shutt 1993). The Handbook does not provide standards or official recommendations, but it does suggest a reasonable configuration of safety zones, as shown in **Exhibit E1**. These differ from the safety zones in the 1991 CLUP in the following respects.

The safety zone example from the Handbook establishes a runway sideline zone, recognizing the potential accident risks in this area.

The example in the Handbook advises increasing attention along the extended runway centerline by designating two zones, the Inner and Outer Safety Zones.

The Handbook also advises attention be given to departure turns by designating an Inner Turning Zone. (This concept was used in the 1991 CLUP at Camarillo Airport for the right departure turn off Runway 26.)

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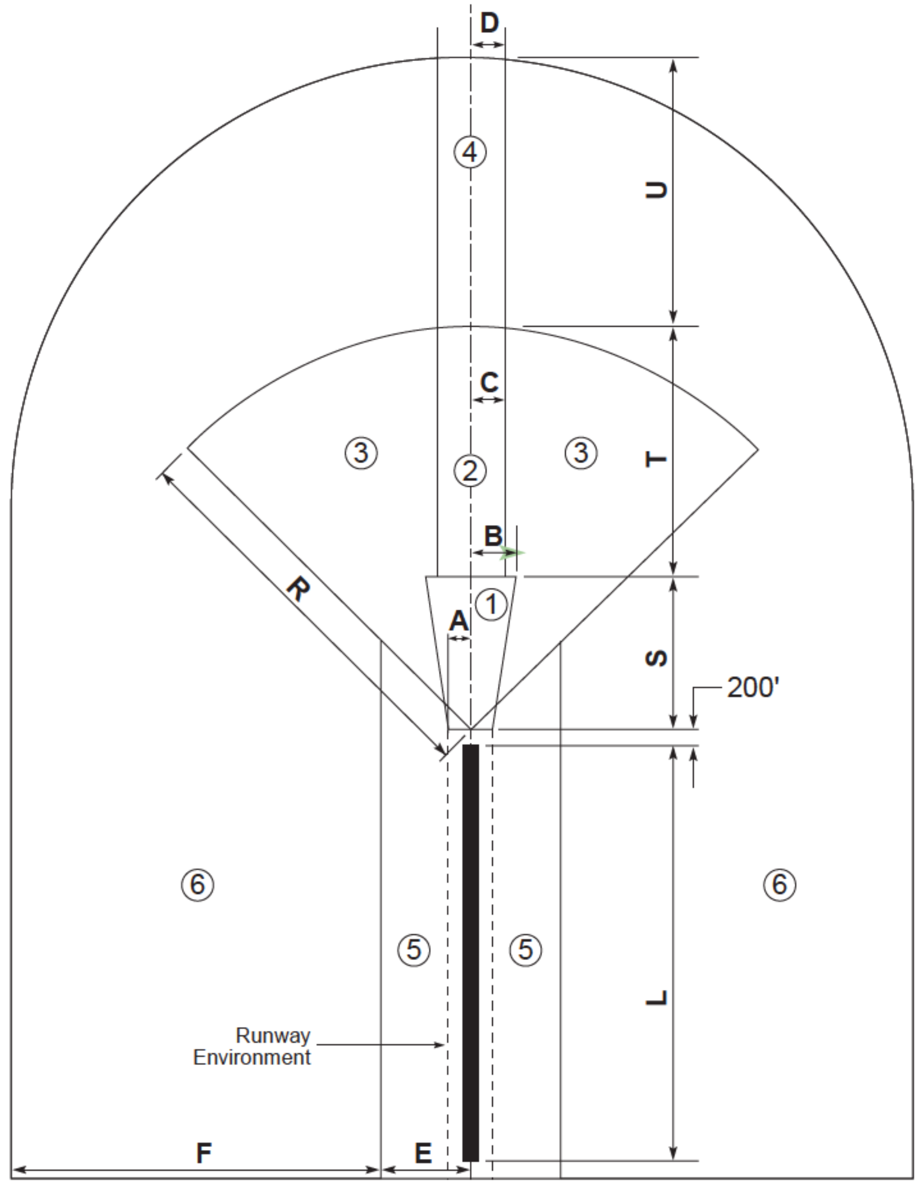

SAFETY ZONE NAMES	
1	Runway Protection Zone
2	Inner Safety Zone
3	Inner Turning Zone
4	Outer Safety Zone
5	Sideline Safety Zone
6	Traffic Pattern Zone

SAFETY ZONE DIMENSIONS (Feet)

	Runway Length Group (L)		
	less than 4,000'	4,000' to 5,999'	6,000' or more
A	125	250	500
B	225	505	875
C	225	500	500
D	225	500	500
E	500	1,000	1,000
F	4,000	5,000	5,000
R	2,500	4,500	5,000
S	1,000	1,700	2,500
T	1,500	2,800	2,500
U	2,500	3,000	5,000

Note: These safety zone shapes and sizes are intended only to illustrate the concepts discussed in the text. They do not represent standards or recommendations.

Source: Hodges & Shutt, *Airport Land Use Planning Handbook*, page 9-16. Prepared for CALTRANS Division of Aeronautics, (December 1993)

Ventura County
AIRPORT LAND USE PLAN

Exhibit E1
SAFETY ZONE
CONFIGURATION EXAMPLE

Like the 1991 CLUP, the 1993 Handbook advises the establishment of a Traffic Pattern Zone. It provides dimensional criteria for drawing the boundaries of the zone. In actual airport settings, the traffic pattern can vary greatly in size depending on the type and volume of aircraft at any given time. It makes sense to define the size of a traffic pattern zone based on the actual experience at airports, provided that reasonably good data on traffic pattern flight tracks is available.

The safety zones in the 1993 *Handbook* could be considered at the civilian airports in Ventura County. In the next section, the 1991 CLUP safety zone boundaries at each civilian airport are compared with alternative boundaries that could be established based on the criteria in the 1993 *Handbook*.

E.1.3 SAFETY ZONE BOUNDARIES AT CIVILIAN AIRPORTS

E.1.3.a Camarillo Airport

Exhibit E2 shows the 1991 CLUP safety zones at Camarillo Airport. The Inner Safety Zone (ISZ) is a small trapezoid-shaped area off each runway end remaining on airport property. The Outer Safety Zone (OSZ) off the east end of the runway is a larger trapezoid which extends about 600 feet east of Las Posas Road off airport property. It extends into area designated in the General Plan for commercial, public and quasi-public, and agriculture. Off the west end of the airport, the OSZ has a large fan shape extending 5,000 feet off the end of the primary surface (which ends 200 feet past the runway end). It follows the approach surface and a nominal departure flight track.

The Traffic Pattern Zone extends about 3,400 feet north and south of the runway centerline and 3,000 feet off the west end of the runway and about 4,800 feet off the east runway end. The TPZ is rather misleadingly named since the actual traffic pattern at the airport often extends well outside the area.

Exhibit E3 shows potential alternative airport safety zones based on the criteria in the 1993 *Airport Land Use Planning Handbook*. The Runway Protection Zones (RPZ) are larger than the current ISZ boundaries because they are drawn based on the assumption of a future precision instrument approach at the airport. The "new" ISZ extends about as far off each runway end as the current OSZ shown in **Exhibit E2**. The new ISZ is rectangular, however, rather than trapezoid-shaped. The "new" OSZ is a rectangular area extending 10,000 feet off the primary surface at each runway end.

"The potential alternative safety zones in **Exhibit E3** include those for the potential parallel runway. They should be considered here as being for information only as the potential runway would not be developed until further feasibility studies/environmental analyses were completed and it was determined through a public review process that its construction would benefit the community."

Inner Turning Zones (ITZ) are designated off both runway ends covering areas where aircraft make departure turns. The "new" TPZ is considerably larger than the existing TPZ. It covers the area where the traffic pattern most frequently lies. (Compare this with Exhibits 2E, 2F, and 2G in Chapter Two of the Phase I Report.)

E.1.3.b Oxnard Airport

Exhibit E4 shows the 1991 CLUP safety zones at Oxnard Airport. The Inner Safety Zone (ISZ) is a trapezoid-shaped area off each runway end. The Outer Safety Zones (OSZ) are larger trapezoids extending 5,000 feet off the end of the primary surfaces at each runway end.

The Oxnard Master Plan has not been adopted yet, therefore, no new safety zones proposed as of this update. The safety zones in the 1991 CLUP, shown on **Exhibit E4**, shall remain in place as part of the CLUP update.

E.1.3.c Santa Paula Airport

Exhibit E5 shows the 1991 CLUP safety zones at Santa Paula Airport. The Inner Safety Zone (ISZ) is a small trapezoid-shaped area off each runway end. The Outer Safety Zone (OSZ) off the east end of the runway is a larger trapezoid which extends about 3,400 feet off the ends of the primary surface at each runway end. Most of the land within the ISZ and the OSZ is designated for industrial use. A small area at the west end is designated for residential (mobile home park).

The 1991 CLUP Traffic Pattern Zone (TPZ) is shown on the southeast side of the airport only. This is because the traffic pattern is confined to that side of the airport. It extends about 3,000 feet off the runway centerline and about 6,300 feet off each end of the primary surface.

Exhibit E6 shows potential alternative airport safety zones based on the criteria in the 1993 *Airport Land Use Planning Handbook*. The Runway Protection Zones (RPZ) are the same size as the current ISZ boundaries. The "new" ISZ extends 2,500 feet off the ends of the primary surface, covering less area than the current Outer Safety Zone. The new ISZ is also rectangular, so it covers significantly less area than the current OSZ.

The "new" OSZ is a rectangular area extending 5,000 feet off the primary surface at each runway end, well beyond the outside boundary of the current OSZ.

Inner Turning Zones (ITZ) are designated off both runway ends covering areas where aircraft make departure turns.

The "new" TPZ is similar in size to the existing TPZ. It extends about the same distance southeast of the runway end, and about 1,300 feet less off each runway end. It extends about 1,770 feet northwest of the runway centerline.

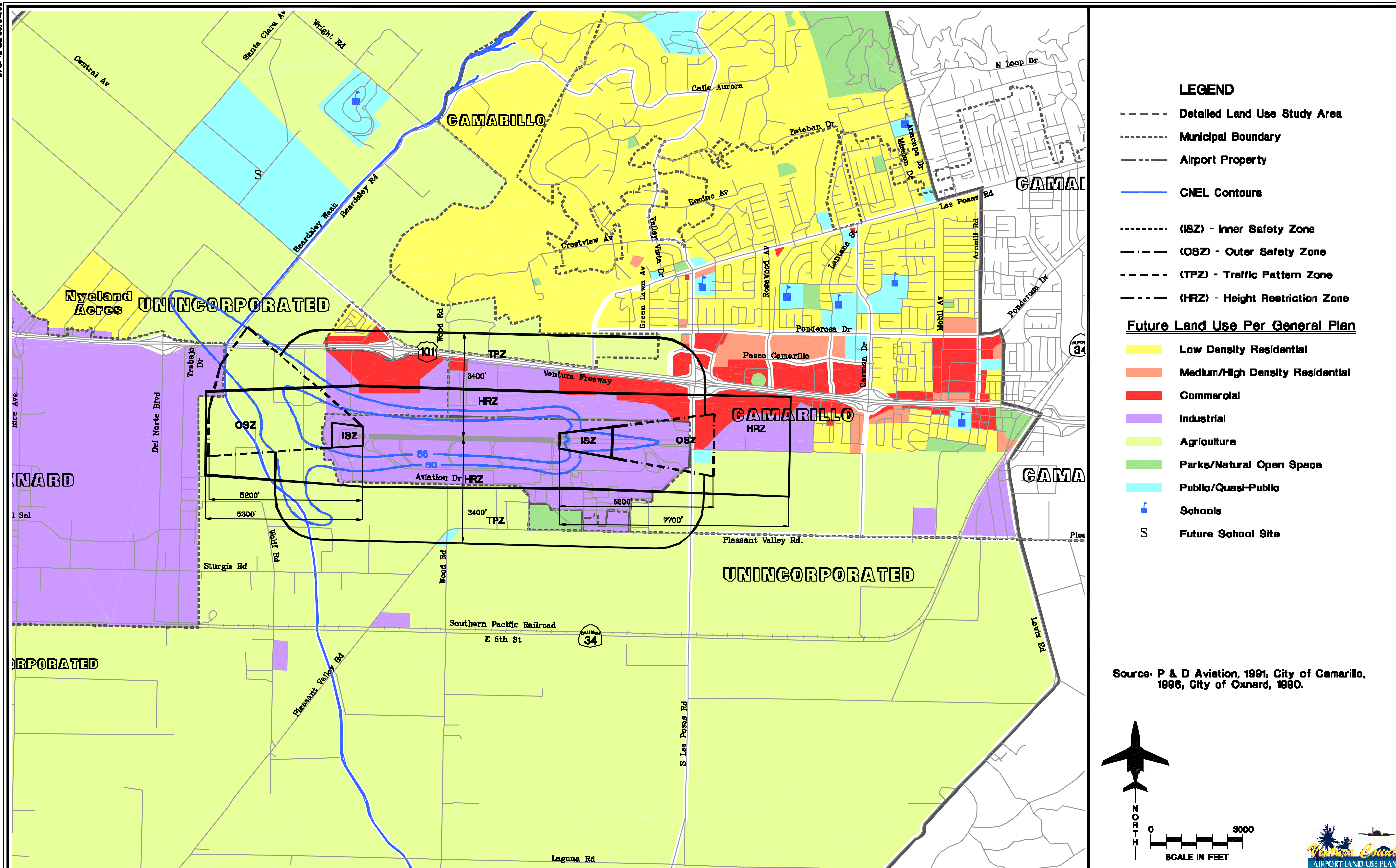

Exhibit E2
1991 AIRPORT COMPREHENSIVE LAND USE PLAN
FOR CAMARILLO AIRPORT

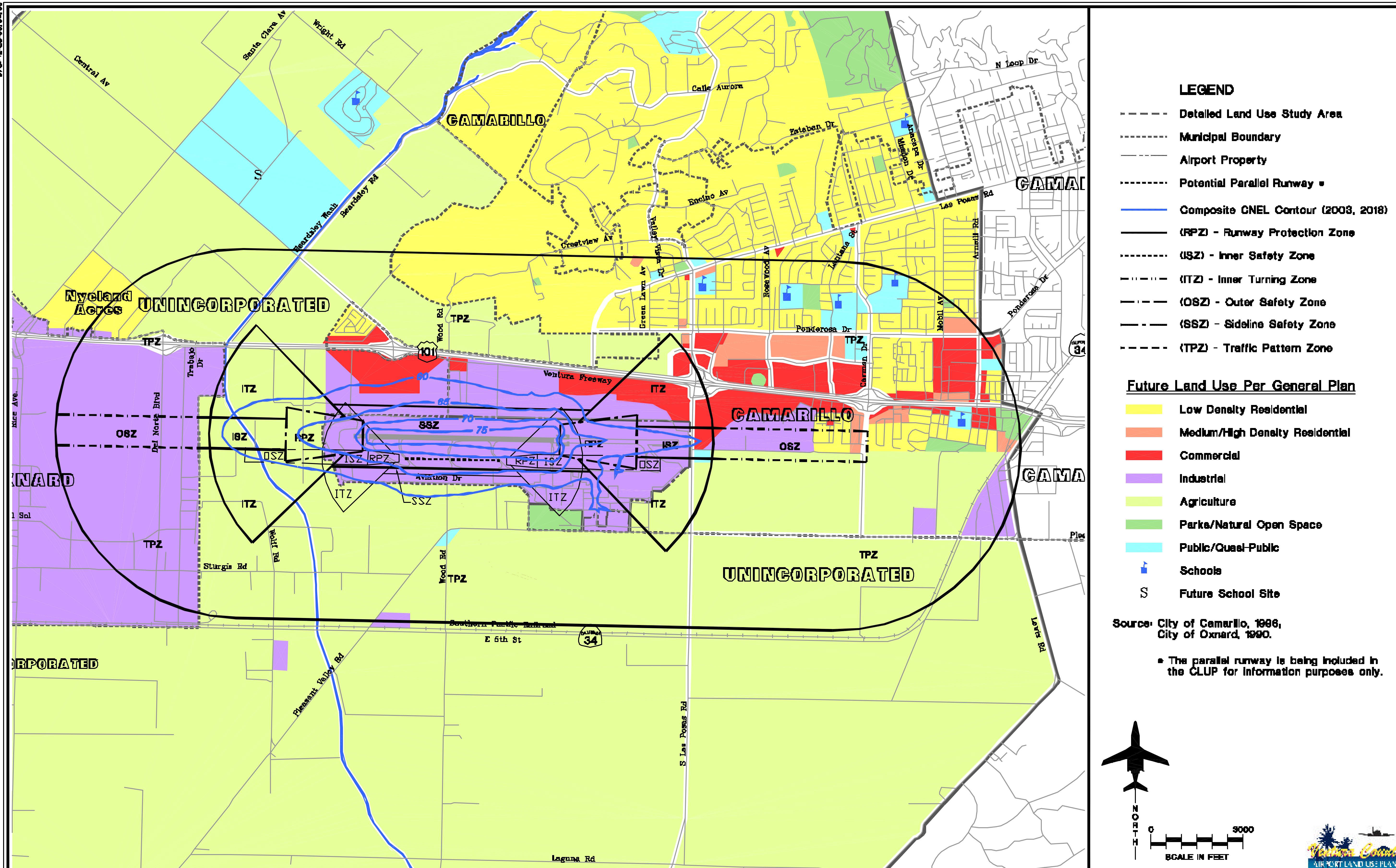

Exhibit B3
POTENTIAL NOISE AND SAFETY ZONES
FOR CAMARILLO AIRPORT

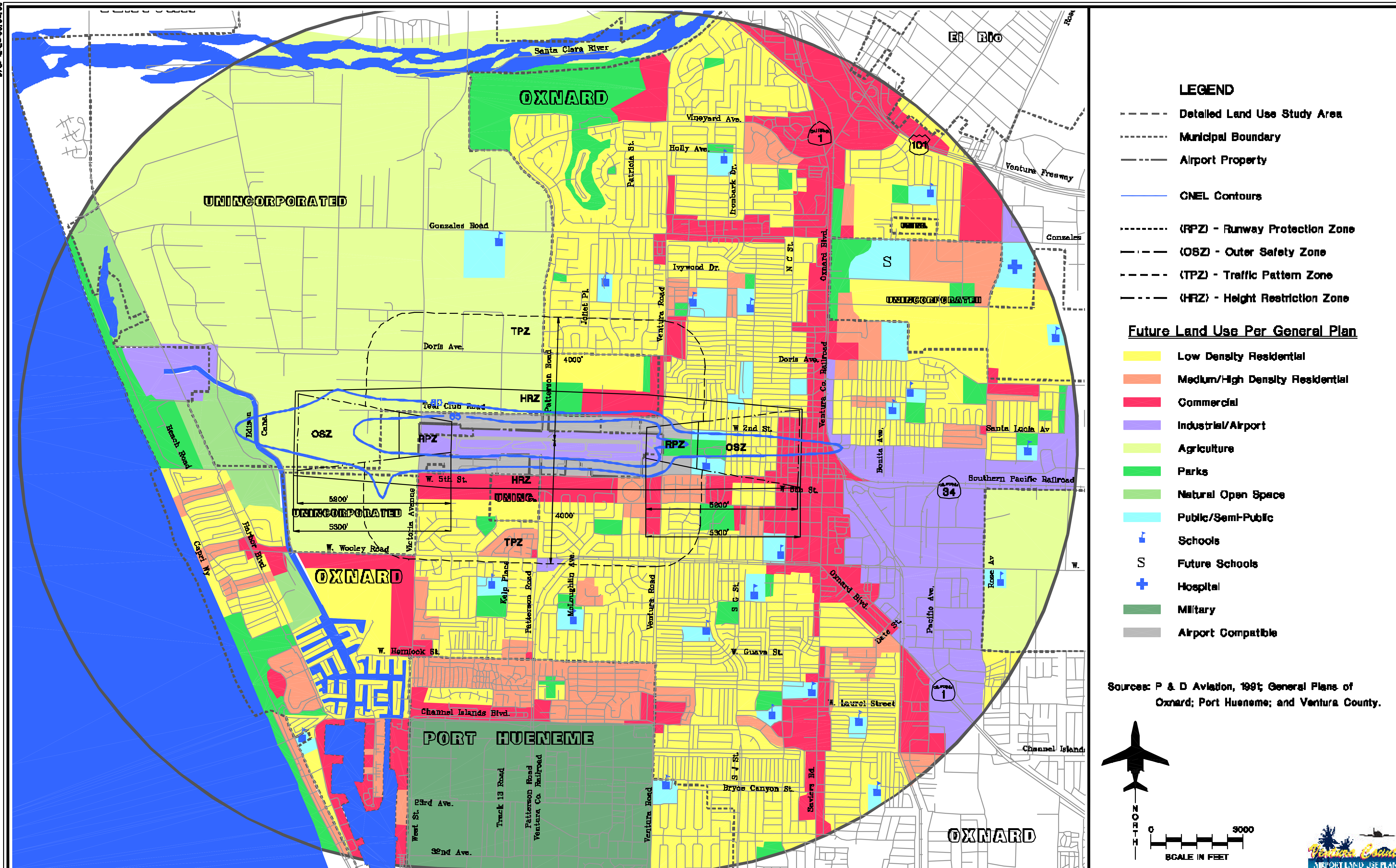

Exhibit E4
1991 AIRPORT COMPREHENSIVE LAND USE PLAN
FOR OXNARD AIRPORT

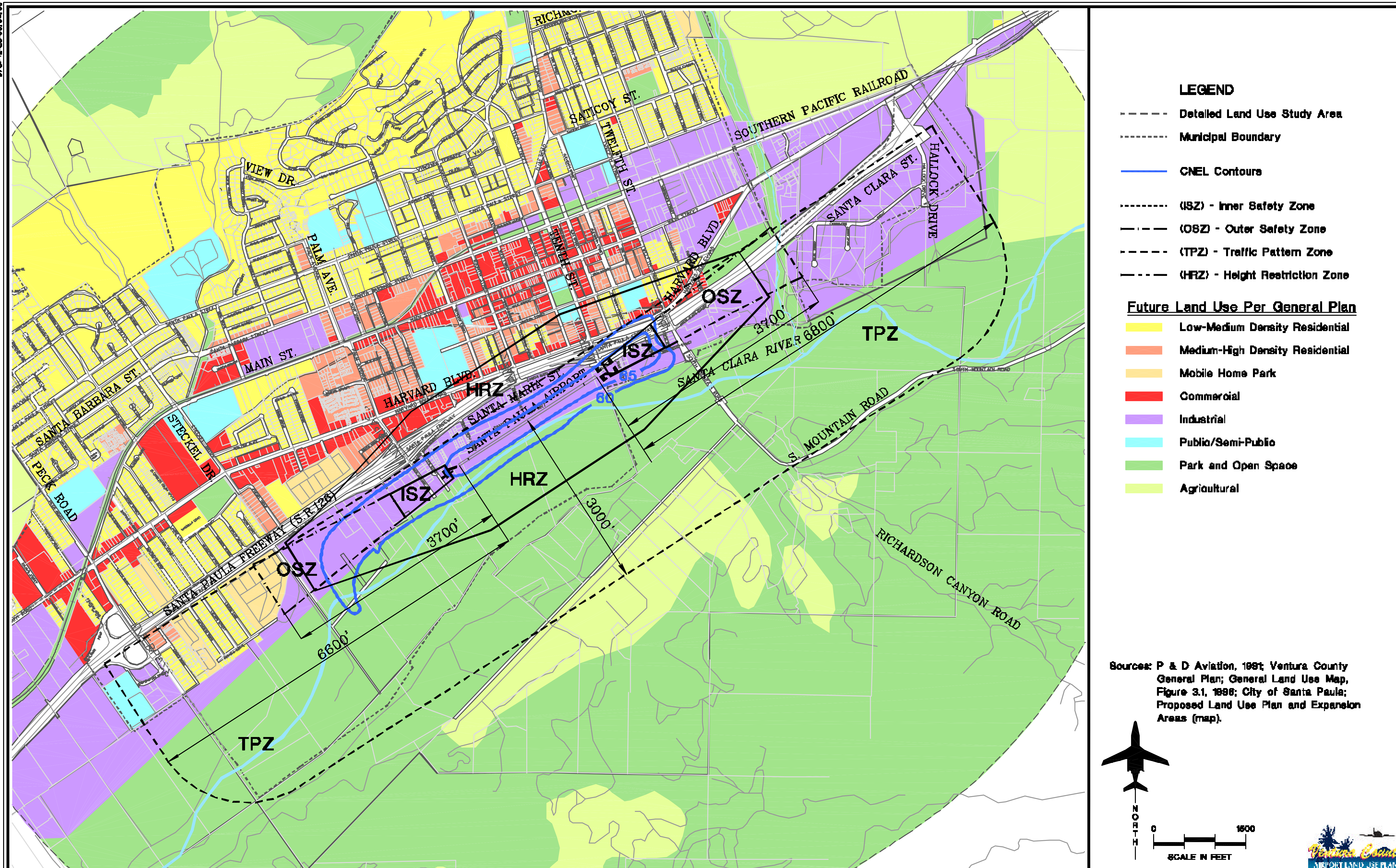

Exhibit B5
1991 AIRPORT COMPREHENSIVE LAND USE PLAN
FOR SANTA PAULA AIRPORT

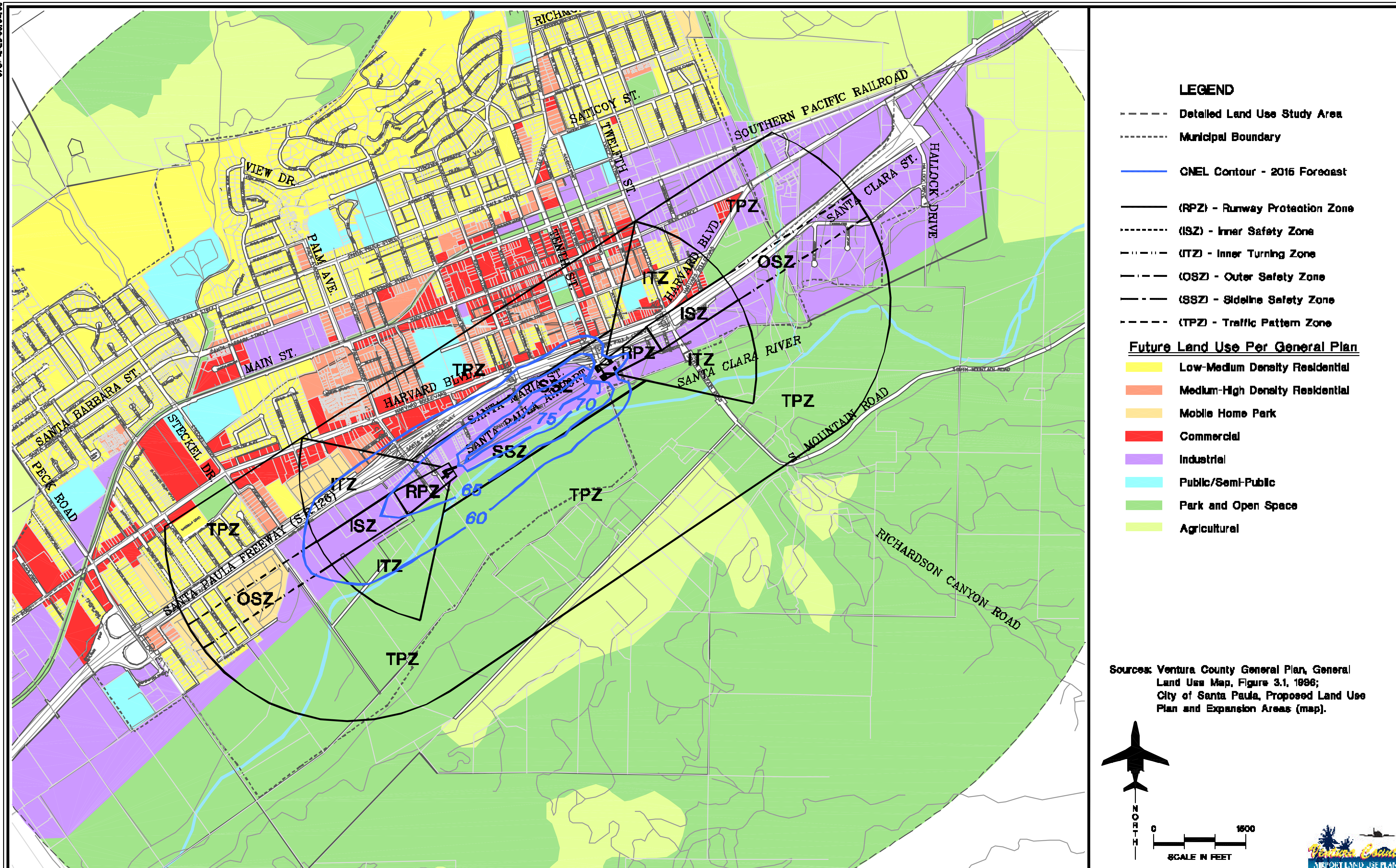

Exhibit E6
POTENTIAL NOISE AND SAFETY ZONES
FOR SANTA PAULA AIRPORT

It is important to note that most of the land northwest of the Santa Paula Freeway within the prospective new safety zones is developed, so any new land use compatibility standards would have no effect in that area.

E.1.4 ALTERNATIVE COMPATIBILITY STANDARDS

As shown previously in **Table E1**, the safety compatibility standards of the 1991 CLUP are presented in the form of a matrix of permitted, conditionally permitted, and prohibited land uses. In some CLUPs of other counties and in the 1993 Handbook, as noted in Appendix A of the Phase I Report, a different approach is taken. The prohibited uses are specifically called out as are the development conditions applying in each zone. This may be a fairly subtle difference, but it can provide more detail and potentially more precision in administering the regulations.

Table E2 presents a comparison of the 1991 CLUP safety compatibility standards with the criteria contained in the 1993 *Airport Land Use Planning Handbook*. The format of the table is based on the *Handbook* criteria. The current CLUP standards have been reformatted to fit the table. The table contains six sections, each corresponding to one of the *Handbook's* safety zones. The existing safety zone from the 1991 CLUP which most closely corresponds to the *Handbook's* zone is paired with it.

Table E2 shows that in the *Handbook's* RPZ, virtually no structures and no development would be permitted. If at all possible, these areas should be owned by the airport operator. These standards are very similar to the 1991 CLUP standards for the current Inner Safety Zone. Rather than setting a maximum population density as the *Handbook* does, the 1991 CLUP has a much more extensive list of prohibited land uses.

In the *Handbook's* ISZ, no residential uses or other high density uses would be permitted. A maximum population density of 40 to 60 persons per acre would be established for permitted uses in the area. (A formula for computing "population density" is provided in the 1983 State Handbook and could be used if this kind of standard is desired in Ventura County.) From 25 to 50 percent of the gross area involved in the project must be set aside for "useable open space." Useable open space is land of sufficient size and configuration to serve as an emergency crash landing site. The 1993 *Handbook* suggests that areas as small as 300 by 75 feet can be suitable for small aircraft (Hodges & Shutt 1993, p 3-3). In the ITZ, generally the same land use prohibitions would apply as in the ISZ, although very low density residential use could be allowed on minimum lot sizes of 10 acres.

The current Outer Safety Zone from the 1991 CLUP has similar land use standards as the 1993 *Handbook*. Residential use, however, is prohibited in the current OSZ. The current standards have no provision for "useable open space", but they set a maximum structural coverage requirement of 25 percent of the gross development area.

In "new" OSZ from the 1983 *Handbook*, less stringent land use prohibitions would apply than in the current OSZ. Places of public assembly would be prohibited, but very low density residential uses would be allowed (0.2 to 0.5 units per net acre, corresponding to minimum lots sizes of two to five acres). The useable open space requirement would be from 10 to 30 percent of the gross area of the development project.

TABLE E2
Comparison of Compatibility Standards for Alternative Safety Zones
1993 State Handbook vs. 1991 Ventura County CLUP

Safety Zone	Maximum Population Density	Maximum Dwelling Unit (DU) Density	Minimum Amount of Useable Open Space	Maximum Structural Coverage	Prohibited Land Uses
RUNWAY PROTECTION ZONE					
1993 Handbook	0 to 10 persons/ac.	0	100%	0	Residential, Schools, Hospitals, Nursing homes, Aboveground storage of flammable materials or other hazardous substances.
"Inner Safety Zone" 1991 CLUP	N.A.	0	N.A.	0	Residential, Hospitals and convalescent homes, Schools, Churches, Auditoriums and theaters, Transportation terminals, Commercial, Industrial, Outdoor sports arenas, Amphitheaters, Parks, Outdoor amusement, Resorts and camps.

TABLE E2 (Continued)
Comparison of Compatibility Standards for Alternative Safety Zones
1993 State Handbook vs. 1991 Ventura County CLUP

Safety Zone	Maximum Population Density	Maximum Dwelling Unit (DU) Density	Minimum Amount of Useable Open Space	Maximum Structural Coverage	Prohibited Land Uses
INNER SAFETY ZONE					
1993 Handbook	40 to 60 persons/ac.	0 to 0.1 du/ac.	25 to 50% of gross area. (25% overall, 50% in 500-foot wide center strip.)	N.A.	Permit only uses which attract relatively few people. Prohibited examples include: Shopping centers; Eating establishments; Meeting halls; Multi-story office buildings; Labor-intensive manufacturing plants. Schools, hospitals, nursing homes. Uses involving, as the primary activity, manufacture, storage, or distribution of explosives or flammable materials.
"Outer Safety Zone" 1991 CLUP	N.A.	0	N.A.	25% of gross area	Residential, Hospitals and convalescent homes, Schools, Churches, Auditoriums and theaters, Transportation terminals, Hotels and motels, Outdoor sports arenas, Amphitheaters, Parks, Outdoor amusement, Resorts and camps.

TABLE E2 (Continued)
Comparison of Compatibility Standards for Alternative Safety Zones
1993 State Handbook vs. 1991 Ventura County CLUP

Safety Zone	Maximum Population Density	Maximum Dwelling Unit (DU) Density	Minimum Amount of Useable Open Space	Maximum Structural Coverage	Prohibited Land Uses
OUTER SAFETY ZONE					
1993 Handbook	60 to 100 persons/ac.	0.2 to 0.5 du/net ac.	10 to 30% of gross area. (10% overall, 30% in 500-foot wide center strip.)	N.A.	No schools, hospitals, nursing homes. No uses involving, as the primary activity, manufacture, storage, or distribution of explosives or flammable materials.
"Outer Safety Zone" 1991 CLUP	As noted above.	As noted above.	As noted above.	As noted above.	As noted above.
TRAFFIC PATTERN ZONE					
1993 Handbook	150 persons/ac.	4 to 6 du/ac.	10 to 15% of gross area	N.A.	Discourage schools, hospitals, nursing homes.
"Traffic Pattern Zone" 1991 CLUP	N.A.	no limit	N.A.	25 to 50% of gross area.	Prohibit: Hospitals and convalescent homes, Schools, Churches, Auditoriums and theaters, Transportation terminals, outdoor sports arenas, Amphitheaters.
INNER TURNING ZONE					
1993 Handbook	40 to 100 persons/ac.	0.1 to 0.5 du/ac.	15 to 20% of gross area	N.A.	Schools, Hospitals, Nursing homes.
"Traffic Pattern Zone" 1991 CLUP	As noted above.	As noted above.	As noted above.	As noted above.	As noted above.

TABLE E2 (Continued)
Comparison of Compatibility Standards for Alternative Safety Zones
1993 State Handbook vs. 1991 Ventura County CLUP

Safety Zone	Maximum Population Density	Maximum Dwelling Unit (DU) Density	Minimum Amount of Useable Open Space	Maximum Structural Coverage	Prohibited Land Uses
SIDELINE SAFETY ZONE					
1993 Handbook	Same as OSZ	0 to 0.5 du/net ac.	25 to 30% of gross area.	N.A.	Same as OSZ.
"Traffic Pattern Zone" 1991 CLUP	As noted above.	As noted above.	As noted above.	As noted above.	As noted above.

N.A.–not applicable.

In the "new" TPZ, a maximum population density of 150 persons per acre would be established. Housing would be limited to four to six units per acre. The useable open space requirement would be set at 10 to 15 percent of the gross development area. The 1991 CLUP TPZ has none of these requirements. The land use requirements of the "new" TPZ are much less stringent, however, than the requirements of the current TPZ. They would only "discourage" schools, hospitals and nursing homes. No land uses would be prohibited. (Briefly, for "discouraged" land uses, the developer would have to show that alternative sites were considered and found to be unacceptable.) In the current TPZ, various institutional uses and places of public assembly are prohibited.

The "new" Inner Turning Zone, which would primarily lie within area now covered by the current TPZ, much stricter standards would apply than at present. Population density would be limited to 40 to 100 persons per acre. Housing density would be limited to 0.1 to 0.5 units per acre (minimum lots sizes of two to ten acres). Fewer land use prohibitions, however, would apply within the "new" ITZ than now apply in the 1991 CLUP TPZ. Only schools, hospitals, and nursing homes would be prohibited.

In the "new" Sideline Safety Zone (SSZ), similar land use prohibitions and density restrictions would apply as in the "new" OSZ. Again, the population and residential density standards would be stricter than for the 1991 CLUP TPZ. The land use prohibitions, however, are somewhat less restrictive than the 1991 CLUP TPZ standards.

Rather than adopting or rejecting the criteria of the 1993 *Handbook* in total, it would be possible to blend some ideas from the *Handbook* with the currently established policies. Since the current standards have been in place for several years and are generally reasonable, there is a case to be made for keeping them.

Regardless of whether the existing safety zones are preserved, one potential revision needs serious consideration. That is the designation of Traffic Pattern Zones at Oxnard and Camarillo Airports. The current TPZs are far smaller than the actual areas covered by the traffic patterns. At the same time, considerable developed land lies beneath the enlarged TPZs which would be created if the criteria shown in **Exhibits E3** and **E5** were used. One option would be to rename the current TPZs and keep them in place. They could be labeled "sideline safety zones" or "inner over flight zones". A new Traffic Pattern Zone could be established based on the 1993 *Handbook* criteria as shown in **Exhibits E3** and **E5**. An important purpose of designating this enlarged TPZ would be to define an airport influence area for purposes of public disclosure. The safety risks are not necessarily great enough in this area to justify strict land use regulations. The presence of aircraft overflights in this area, however, will be enough to motivate concerns among some prospective residents of those areas.

E.1.5 SAFETY ZONE BOUNDARIES AT NAS POINT MUGU

The 1991 CLUP has a different set of safety standards for NAS Point Mugu than for the civilian airport. The Point Mugu standards were established for three safety zones as defined in the AICUZ Study for the facility. The three zones are called the Clear Zone, Accident Potential Zone-1 (APZ-1), and APZ-2. The Clear Zone corresponds with the civilian Inner Safety Zone. The APZ-1 zone roughly corresponds to the Outer Safety Zone. The APZ-2 zone has no direct equivalent in the civilian scheme. It is an area beneath commonly used flight tracks extending beyond the APZ-1 zone. The military safety zone system at Point Mugu has no equivalent for the Traffic Pattern Zone used at the civilian airports.

Since special studies and Defense Department policies were used in defining the safety areas around NAS Point Mugu, it is reasonable to continue using the AICUZ safety boundaries for safety compatibility around the facility. Up-to-date information, however, should be used. In 1992, the Navy updated the AICUZ Study for NAS Point Mugu. The updated study revised the location and configuration of some of the Accident Potential Zones. These changes should be reflected in the updated CLUP for Ventura County. The updated boundaries are shown in **Exhibit E7**.

E.1.5.a Potential Revisions to NAS Point Mugu Safety Standards

One potential shortcoming of the AICUZ system of safety zones, in light of State guidelines and Ventura County planning tradition, is the lack of a traffic pattern zone. It would be reasonable to consider defining a Traffic Pattern Zone around Point Mugu. The size and shape of the area should be based on the concentration of low altitude flight tracks around the airfield. An area based on the Part 77 horizontal surface, extending 7,500 feet from the edge of the primary surfaces

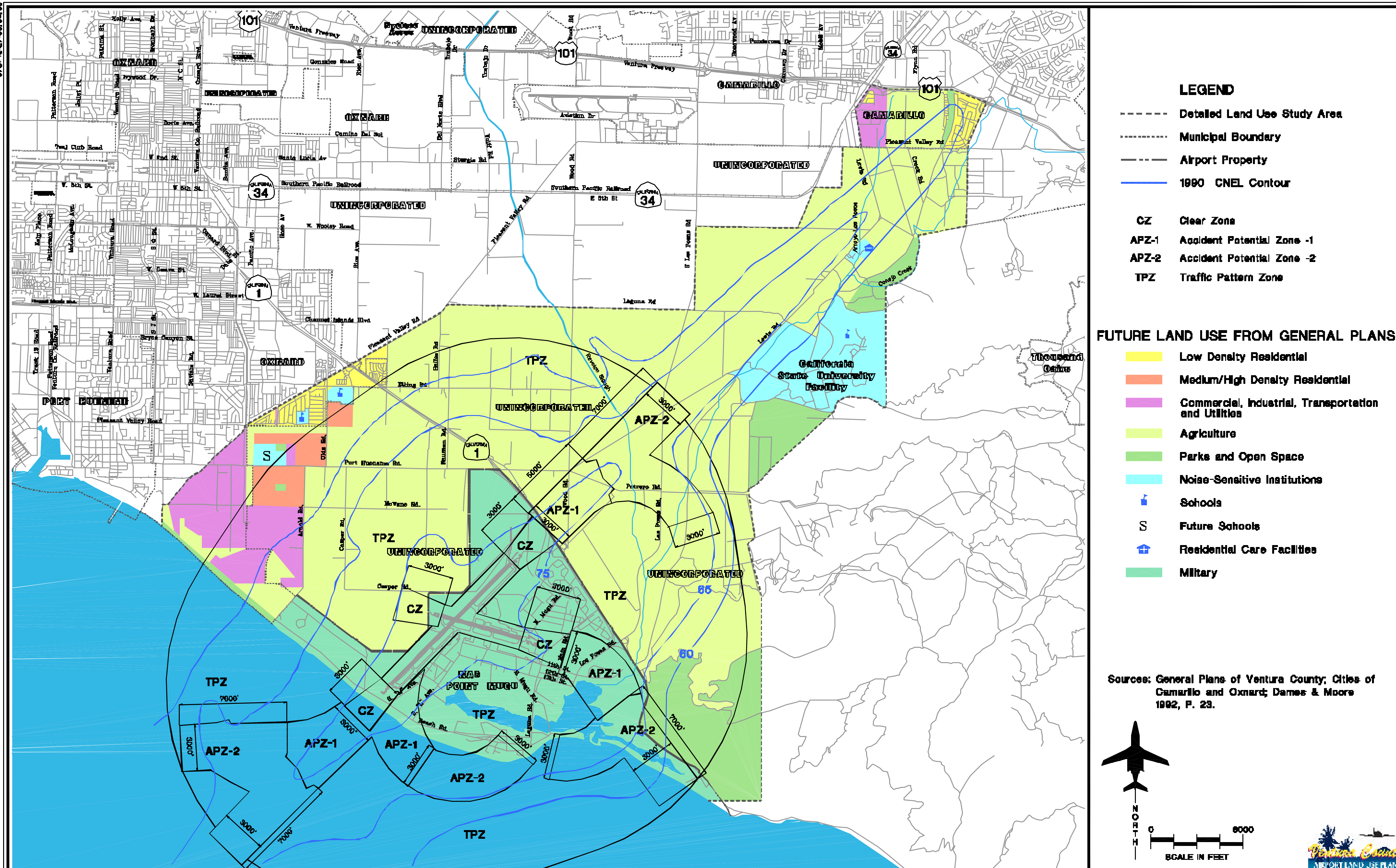

Exhibit E7
POTENTIAL NOISE AND SAFETY AREAS
FOR NAS POINT MUGU

around each runway, would be a reasonable boundary given the pattern of flight tracks around the airport. This area is shown as the TPZ in **Exhibit E7**.

As was suggested for the civilian airports, the "new" TPZ could be part of the basis for defining an airport influence area. It would be used to promote fair disclosure of potential airport impacts including loud single events and low aircraft overflights.

If the County ALUC desires to change its safety compatibility standards based on the criteria in the updated *Handbook*, it would be reasonable to use these within the corresponding Point Mugu safety zones. The following relationships would apply:

> In the CZ, Clear Zone - Same standards as RPZ.
>
> In the APZ-1 - Same standards as ISZ.
>
> In the APZ-2 - Same standards as OSZ.

E.2 NOISE COMPATIBILITY

E.2.1 1991 NOISE COMPATIBILITY STANDARDS

The noise compatibility standards in the 1991 CLUP establish 60 CNEL as the threshold above which aircraft noise becomes a consideration in land use planning. Outdoor amphitheaters and mobile homes are unacceptable in areas exposed to noise above 60 CNEL. Other types of housing, noise-sensitive institutions, and hotels are acceptable in the 60 to 65 CNEL range if an analysis of noise reduction requirements is undertaken and necessary sound insulation installed.

Within the 65 to 70 CNEL range, housing is prohibited and noise-sensitive institutions and hotels are required to be sound-insulated to achieve an outdoor to indoor noise level reduction of 25 CNEL. Within the 70 to 75 CNEL range, most noise-sensitive institutions are prohibited. Auditoriums, theaters and motels are permitted if a noise level reduction of 30 CNEL is incorporated into the structure.

The noise contours within which these requirements apply are shown for each airport in **Exhibit E2** (Camarillo), **Exhibit E4** (Oxnard), **Exhibit E6** (Santa Paula), and **Exhibit E7** (NAS Point Mugu).

E.2.2 POTENTIAL ALTERNATIVE NOISE COMPATIBILITY STANDARDS

E.2.2.a Set 60 CNEL as Compatibility Threshold

Potential revisions would prohibit all housing and noise-sensitive institutions in areas exposed to noise above 60 CNEL. Hotels would be permitted in areas exposed to noise up to 75 CNEL provided they incorporated noise attenuation to achieve a noise level reduction of 25 to 35 CNEL.

These potential policy revisions reflect guidance provided in the updated *Airport Land Use Planning Handbook* (Hodges & Shutt 1993, p. 3-3). Those guidelines recommend that, in quiet communities, 60 CNEL should be the maximum permissible noise level for residential uses. Based on the consultant's experience and the complaint history at the County's airports, noise concerns are frequently registered by people residing in areas far from the 65 CNEL noise contours. Structural sound insulation is of only a very limited benefit. However, state law and local ordinances and elements are based on a 65 CNEL threshold and a change in the CLUP would create an inconsistency and could create confusion in its application.

A comment frequently heard from Southern California residents is the value they place on outdoor living in this mild climate. For sound insulation to be effective, all windows and doors must be closed. This forces the need to use a mechanical ventilation system or air conditioning. If residential development is allowed in areas exposed to noise above 60 CNEL, serious concerns from residents can be expected.

If it is decided to use the 60 CNEL contour as the threshold for permitting residential uses, some special consideration should be given to the Point Mugu area. The 60 CNEL contour covers an enormous area around that facility. A special policy for existing lots of record may deserve consideration in that area. Such a policy could permit a dwelling to be built on a lot of record existing as of the date of adoption of the updated CLUP. Sound insulation and a noise easement could be required as conditions of granting a permit.

E.2.2.b Set 60 CNEL as Threshold for Small Airports Only

One option which has been used in some counties is to establish different noise compatibility threshold levels depending on the class of airport. This approach was suggested in the 1983 *Airport Land Use Planning Handbook* (Metropolitan Transportation Commission 1983). At large air carrier and military airports, the noise compatibility threshold would be set at 65 CNEL. At small airports, a lower threshold would be used. The thinking was that at small airports, many of the noise concerns registered by local residents relate to bothersome overflights and single events. One way of capturing the affected area would be to use a lower CNEL threshold. The lower threshold was variously suggested as 55 or 60 CNEL.

E.2.2c Noise Easements and Disclosure Covenants

Regardless of whether any changes are made in the CNEL threshold for noise compatibility, two other policy refinements deserve discussion.

These refined policies relate to the dedication of noise easements for any noise-sensitive land uses permitted within the 60 CNEL contour and the recording of a fair disclosure covenant with the plat or deed. The covenant would require the property owner to disclose prospective buyers the location of the property with respect to the airport and the airport noise contours and safety zones.

The 1991 CLUP recommended the dedication of easements and the recordation of disclosure covenants. The option exists for requiring both or either of these. Concerns have been raised that VCTC, as the ALUC, does not have the authority, nor should it seek such authority, to require easements. However, no such concern has been raised with regard to disclosure covenants, and requiring recordation of such would afford some measure of additional protection to the current airports in Ventura County."

E.2.3 REGULATORY NOISE CONTOURS

The 1991 CLUP used sets of noise contours at each airport that represented a reasonable worst case of noise exposure over the long term future. The largest set of noise contours developed for each airport were used as the regulatory noise contours. At Santa Paula, the 2010 contours were the largest and were used for regulatory purposes (**Exhibit E5**). At NAS Point Mugu the current and forecast 2010 contours were the same. At Camarillo and Oxnard Airports, special composite sets of noise contours were produced by combining the 1990 and 2010 contours. (See **Exhibits E2** and **E4**.) This is because the 1990 contours were larger in some areas and the 2010 contours larger in other areas. This is a prudent way to approach the question of land use regulation based on a variable factor such as noise. The purpose is to designate an area exposed to long term noise exposure risk, not simply to define an area exposed by noise at any one point in time.

An alternative to continuing this approach would be to select as the regulatory noise contours an updated set of contours for a single year. It would be reasonable to use the generally largest set of updated contours for purposes of noise regulation. These would be either the 2003 or 2018 forecasts at Camarillo (Exhibits 2J and 2K in the Phase I Report), the 2018 forecast at Oxnard (Exhibit 3K in the Phase I Report), the 2015 forecast at Santa Paula (Exhibit 4F in the Phase I Report), and the 1990 contours at NAS Point Mugu (Exhibit 5L).

If the 1991 CLUP approach of defining a reasonable worst case noise exposure area is continued, composite noise contours would be defined for Camarillo and Oxnard Airports. The other two would use noise contours for a single year. The specific contours to use each airport would be as follows:

Camarillo Airport - a combination of the 2003 and 2018 contours developed in the F.A.R. Part 150 Noise Compatibility Study (Coffman Associates 1997a). See **Exhibit E3**.

Oxnard Airport - a combination of the 1990 and 2010 contours developed in the 1991 CLUP. See **Exhibit E4**.

Santa Paula Airport - 2015 noise contours developed in this CLUP update. See **Exhibit E6**.

NAS Point Mugu - 1990 noise contours developed for the 1992 AICUZ Study (Dames & Moore 1992). See **Exhibit E7**.

The rest of this section discusses the implications of these updated noise contours on noise compatibility planning at each airport.

E.2.3.a Camarillo Airport Noise Contours

The updated noise contours at Camarillo Airport, shown in **Exhibit E3** are broader than the contours used in the 1991 CLUP (**Exhibit E2**). The updated contours also extend further east. On the west side of the airport, the updated contours are generally smaller than the older contours. Most of the land within the updated 60 CNEL noise contour is designated in the General Plan for industrial use. Smaller areas are designated for agriculture and commercial use. All these land use designations are compatible with aircraft noise.

The updated 65 CNEL contour lies almost completely over industrial-designated land, most of which is on the airport property. The updated 65 CNEL contour extends off airport property to the west over an area designated for agricultural use. The updated 65 CNEL contour, however, is smaller in this area than the contour used in the 1991 CLUP.

If the 1991 CLUP noise compatibility standards are continued, use of the updated noise contours will generally reduce the size of the regulated area.

E.2.3.b Oxnard Airport Noise Contours

As noted earlier, because the Oxnard Master Plan has not yet been adopted, there are no new noise contours proposed as part of this update. The contours in the 1991 CLUP, shown on **Exhibit E4**, shall remain in place as part of the CLUP update.

E.2.3.c Santa Paula Airport Noise Contours

The updated noise contours at Santa Paula Airport, shown in **Exhibit E6** are much broader than the contours used in the 1991 CLUP (**Exhibit E7**). The updated contours also extend further west off the end of the airport. Most of the land within the updated 60 CNEL noise contour is designated in the General Plan for industrial or open space use, both of which are compatible with aircraft noise. The 60 CNEL noise contour just barely crosses the Santa Paula Freeway over areas designated for commercial and residential use.

The updated 65 CNEL contour lies almost completely over land designated as industrial. The rest of the area within the 65 CNEL contour is designated for open space.

It the current noise compatibility standards are continued, use of the updated noise contours will generally reduce the size of the regulated area because the updated contours are larger than the old contours.

E.2.3.d NAS Point Mugu Noise Contours

The most recent set of noise contours at NAS Point Mugu are shown in **Exhibit E7**. Most of the land within the 60 CNEL contour is designated in the General Plans for agricultural use. Smaller areas are designated for industrial, and open space use. All these categories are considered noise-compatible. Small area are designated for residential and noise-sensitive institutions. These are existing developments. All of the area within the 65 CNEL contour and off the Point Mugu property is designated for agriculture.

It the current noise compatibility standards are continued, there would be no change in land use policies in the Point Mugu area.

If the noise compatibility standards are revised according to the guidance provided in the updated *Airport Land Use Planning Handbook*, as shown in **Table E1**, the area affected by the prohibition of housing and noise-sensitive land uses would increase. The area would be designated by the updated 60 CNEL contour rather than the 65 CNEL contour. According to the land use designations of the General Plan, most of the affected area is designated for compatible land use. Relatively small areas are designated for noise-sensitive uses. These include the old Camarillo State Hospital facility, now planned as a future University of California State University facility, a residential care facility on Lewis Road, and a residential neighborhood in Camarillo and the far end of the 60 CNEL contour.

E.3 CONCLUSION

This chapter has proposed various alternative airport compatibility policies for discussion by the Project Advisory Committee. Based on committee discussions, final, updated compatibility policies will be selected for purposes of preparing a draft Airport Compatibility Land Use Plan for each airport in the County.

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