Impact of Variations in Renewable Generation on California's Natural Gas Infrastructure

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Introduction

- This presentation documents the development of five renewable generation scenarios aimed at investigating the impacts on California's gas infrastructure prepared by ICF as part of Subcontract #MNG-07-02, CEC#500-02-004, WA# MR-056.
- Earlier modeling work in this study assessed the use and value of gas storage in California.
- In the original work plan, the next set of scenarios was to focus on the impact of LNG imports, disruptions to gas infrastructure, and/or increased gas-fired power generation. However, CIEE/CEC expressed a desire to redirect the effort to focus on the impact of California's increasing use of renewable energy on gas infrastructure, since gas-fired generation serves as a back-up to renewable generation.
- In the revised work plan, the focus for the remaining scenarios has been shifted to the potential impacts of variations in renewable generation on California's natural gas infrastructure, assuming the adoption of a 33% RPS.

Overview of Task

- To explore the impact of variations in renewable generation on California's natural gas infrastructure, ICF has modeled a series of cases based on different scenarios for meeting a 33% Renewable Portfolio Standard (RPS) by 2020.
  - By definition, several technologies can contribute to meeting the 33% RPS, including wind, solar PV, solar thermal, biogas, biomass, geothermal, and small hydroelectric.
  - Each of the RPS scenarios assumes the same total annual renewable generation by 2020, but a different mix of technologies to meet the goal.
  - Some renewable technologies, such as wind, solar PV, and solar thermal, have a variability to their output due to changing weather conditions.
  - The variability of generation from wind and solar technologies is different, so different mixes of technologies result in different degrees of variability in total RPS generation.
- ICF's cases have been based on three 33% RPS scenarios developed by the California Public Utility Commission (CPUC) for the 33% Implementation Analysis Working Group Meeting on January 15, 2009: Reference, High Wind, and High Central Station Solar.
  - While the total annual RPS generation is the same in each scenario, the differences in the technology mix results in different monthly generation patterns and different projections for reduced levels of generation from renewables that could result from variability in weather.

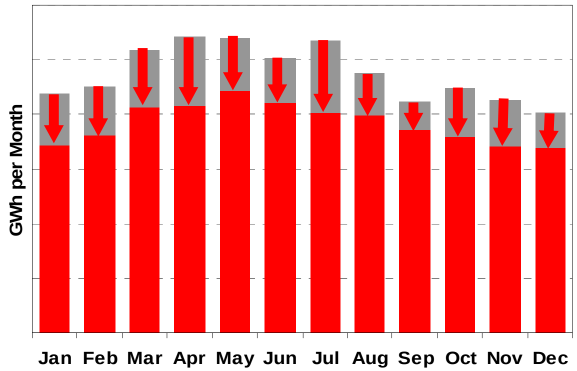
Overview of Modeling Approach

Overview of Modeling Approach

- As with the earlier cases that had examined the impact of weather and hydroelectric generation on gas storage, ICF's analysis is based on a multi-step process that makes use of three different models:
  - **Gas Market Model (GMM)** - creates a monthly projection for the entire North American natural gas market through 2020, including regional supply, demand, storage activity, inter-regional pipeline flows, and gas prices.
  - **Regional Infrastructure Assessment Modeling System (RIAMS)** – RIAMS provides a much more detailed analysis of pipeline flows and storage activity within California for the forecast period 2019-2020 (when the 33% RPS target is met).
  - **Daily Gas Load Model (DGLM)** – DGLM is used to create a daily load profile for January 2020, California's peak gas demand month. The daily load profile is input into RIAMS to project peak-day pipeline flows and storage activity. The results are key to assessing the adequacy of gas infrastructure to satisfy peak day loads.

Modeling of Reduced Renewable Generation Cases

Projected 2020 Renewable Generation for "Reduced Generation" Case



Changes in Renewable Generation

GMM

Solves for regional gas demand, gas prices, inter-regional pipeline flows, and regional storage activity

Reduced renewable generation increases power sector gas consumption

Monthly Gas Load

DGLM

Solves for Daily Gas Load

Reduced renewable generation increases on-peak gas consumption

Gas prices, regional consumption, regional production, and inter-regional pipeline flows

Daily Gas Load

RIAMS (Daily)

Solves for peak day intra-regional pipeline flows, and field-level storage activity

Increased gas consumption increases peak day pipeline flows and storage activity

Peak month storage activity

RIAMS (Monthly)

Solves for monthly average intra-regional pipeline flows and field-level storage activity

Increased gas consumption increases intra-regional pipeline flows and storage activity

Renewable Generation Case Description

1. 33% RPS Reference Scenario, Expected Renewable Generation, Normal Weather	Assumes California's RPS is 33 percent of electricity sales by 2020, that renewable capacity is sufficient to meet this standard, and that renewable generation is at the expected level. The mix of technologies used to meet the RPS is consistent with the CPUC's 33% Reference Scenario.[1] Assumes normal (30-year average) weather conditions.
2. 33% RPS Reference Scenario, Expected Renewable Generation, Adverse Weather	Same total generation from renewable resources as in Case 1; assumes adverse weather conditions (i.e., hot summer and cold winter) and reduced hydroelectric generation. This case is needed to differentiate the impact of weather conditions on gas demand from the impact of changes in renewable generation in Cases 3, 4, and 5.
3. 33% RPS Reference Scenario, Reduced Renewable Generation, Adverse Weather	Same RPS and technology mix as Case 1, but renewable generation is assumed to be below expected levels in 2020, and this deficit is replaced solely with gas-fired generation. Also assumes the same adverse weather/hydroelectric conditions as in Case 2.
4. 33% RPS High Wind Scenario, Reduced Renewable Generation, Adverse Weather	Same RPS, but the mix of technologies used to meet the RPS is consistent with the CPUC's High Wind Scenario.[2] Renewable generation is assumed to be below expected levels in 2020, and this deficit is replaced solely with gas-fired generation. Also assumes same adverse weather/hydroelectric conditions as in Case 2.
5. 33% RPS Solar Scenario, Reduced Renewable Generation, Adverse Weather	Same RPS, but the mix of technologies used to meet the RPS is consistent with the CPUC's High Central Station Solar Scenario.[3] Renewable generation is assumed to be below expected levels in 2020, and this deficit is replaced solely with gas-fired generation. Also assumes same adverse weather/hydroelectric conditions as in Case 2.

1. CPUC 33% Implementation Analysis Working Group Meeting, January 15, 2009 presentation, slide 30, "Reference Case."
2. CPUC 33% Implementation Analysis Working Group Meeting, January 15, 2009 presentation, slide 33, "High Wind Case."
3. CPUC 33% Implementation Analysis Working Group Meeting, January 15, 2009 presentation, slide 34, "High Central Station Solar Case."

Common Assumptions Across All Cases

- The starting point for the analysis is ICF's January 2009 North American Gas Market Base Case.
  - The earlier weather/hydro modeling work used our January 2008 Base Case. The new Base Case projection includes the 2008/09 recession, which reduces near-term demand, and includes ICF's most recent reconnaissance on natural gas pipeline and storage additions throughout North America.
- The ICF January 2009 Base Case has been modified to create a "CIEE Base Case."
  - In the CIEE Base Case, California's electricity demand growth rate is consistent with the CEC's 2007 projection of 1.1% per year growth through 2020.
    - We used the 2007 CEC projection because the updated forecast was not available because it was still being developed when we were conducting this study.
    - Because of the 2008/09 recession, electricity demand in the CIEE Base Case does not match the CEC 2007 projection for every year, but it does match the average long-run growth rate and the total level of demand reached by 2020.
  - Renewable generation growth is consistent with the 33% RPS standard.
  - Using this load projection, ICF estimates retail electricity sales in 2020 are 309 TWh, versus a 2008 level of 268 TWh. With a 33% RPS, renewable generation in 2020 would have to be 103 TWh to meet the standard.
    - If electricity demand growth were reduced though greater efficiency measures, the generation needed to meet the 33% RPS would be lower.

Common Assumptions: Assumed Changes in California's Natural Gas Infrastructure

- Assumptions for gas infrastructure are based on publicly available information.
  - The CEC has reviewed these assumptions and has not provided any information to the contrary.
- Two compression and looping expansions on Kern River Pipeline in 2010 and 2011 will increase capacity on Kern's mainline by a total of 411 MMcfd.
  - These expansions are concentrated on the northern half of Kern's system. While they increase the amount of gas available to the California market, they will not directly increase capacity at the California/Nevada border.
- Ruby Pipeline will provide an additional 1.3 Bcfd of pipeline capacity from Opal to Malin in 2011.
  - A 42-inch line connecting Ruby to PG&E will provide additional capacity crossing the California/Oregon border, but at this time there are no publicly announced plans for additional capacity expansions on PG&E's system.
- The Costa Azul LNG terminal in Baja, Mexico began operation in 2008 with a receipt capacity of 1 Bcfd.
  - Because of an apparent lack of firmly committed supplies, LNG imports at Costa Azul are likely to be far less than the facility's capacity. In the CIEE Base Case, LNG imports at Costa Azul average 0.45 Bcfd in 2020.
  - Costa Azul helps the California gas market mainly by displacing demand for U.S. gas exported to Mexico, but some of the imported gas is also expected to flow north to California.
- Two new storage fields and one field expansion are planned within the next several years.
  - Sacramento Natural Gas Storage is scheduled to begin operation in 2010 with a working gas capacity of 7 Bcf and maximum withdrawal capacity of 200 MMcfd.
  - Gill Ranch is scheduled to begin operation in 2011 with a working gas capacity of 20 Bcf and maximum withdrawal capacity of 300 MMcfd.
  - Kirby Hills is scheduled to expand its working gas capacity by 6.5 Bcf to 12 Bcf in 2011; maximum withdrawal capacity will increase from 50 to 100 MMcfd.

Common Assumptions: Changes in the U.S. Natural Gas Market

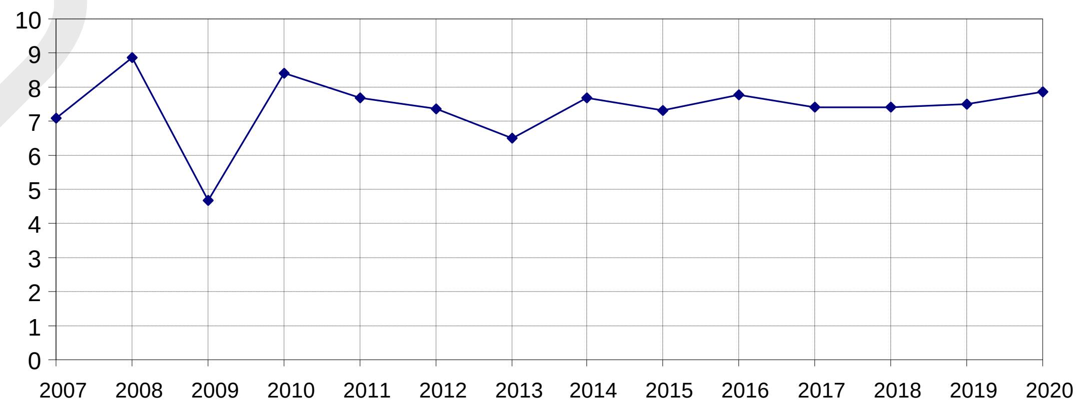
- Under normal weather and hydroelectric conditions, annual demand for gas in the U.S. is expected to increase by about 2.6 Tcf by 2020.
  - Gas consumption is expected to increase by 2.2 Tcf by 2020, primarily due to increased demand in the power sector.
  - Net Exports to Mexico are expected to increase by 0.4 Tcf.
- Most of the increase in gas supply comes from domestic production, which is up by 2.3 Tcf.
  - Production increases are concentrated in the Rockies, Mid-continent shales, and Marcellus Shale.
  - Net LNG imports are also up (+1.2 Tcf), more than offsetting a decline in Net Imports from Canada (-0.9 Tcf).
- After the 2008/09 recession, gas prices are projected to return to between $7 and $8 per MMBtu, similar to pre-recession prices.
  - Robust growth in U.S. production prevents prices from climbing higher.

Case 1: 33% RPS Reference Scenario, Expected Renewable Generation, Normal Weather

U.S. Natural Gas Balance, Bcf per Year	2007	2008	2009	2010	2015	2020	2008-20 Delta	2008-20 CAGR
Total Consumption	23,189	22,996	22,703	22,405	24,675	25,175	2,179	0.8%
+ Net Storage Injections (+) or Withdrawals (-)	(177)	(43)	172	(88)	(153)	87	130	n/a
+ Net Exports to Mexico	277	357	409	298	536	759	402	6.5%
Total Demand	23,289	23,310	23,284	22,615	25,058	26,021	2,711	0.9%
Total Production	19,875	20,503	20,621	19,489	22,331	22,815	2,312	0.9%
+ Net LNG Imports	702	287	324	1,002	1,050	1,524	1,237	14.9%
+ Net Imports from Canada	3,062	2,827	2,588	2,324	1,912	1,890	(937)	-3.3%
Total Supply	23,639	23,617	23,533	22,816	25,293	26,230	2,613	0.9%
Balancing Item /1	350	307	249	201	235	209	(97)	-3.1%

1. Total Supply less Total Demand; i.e., unaccounted for gas.

Projected Henry Hub Natural Gas Price, 2008$/MMBtu



Common Assumptions: Changes in the Western U.S. Natural Gas Market

- Under normal weather and hydroelectric conditions, total demand for gas in the Western U.S. is projected to be relatively flat through 2020.
  - This is largely due to the declining trend in California demand caused by increasing renewable generation.
  - Absent the decline in California's demand, gas demand the rest of the Western U.S. is up by about 0.5 Bcfd.
- As production in the Rockies increases over time, the Western U.S. exports of natural gas grow.
  - In 2008, net exports were only about 0.4 Bcfd.
  - By 2020, net exports are projected to grow to over 2 Bcfd.
  - Most of these exports are out of the Rockies to the Eastern U.S.

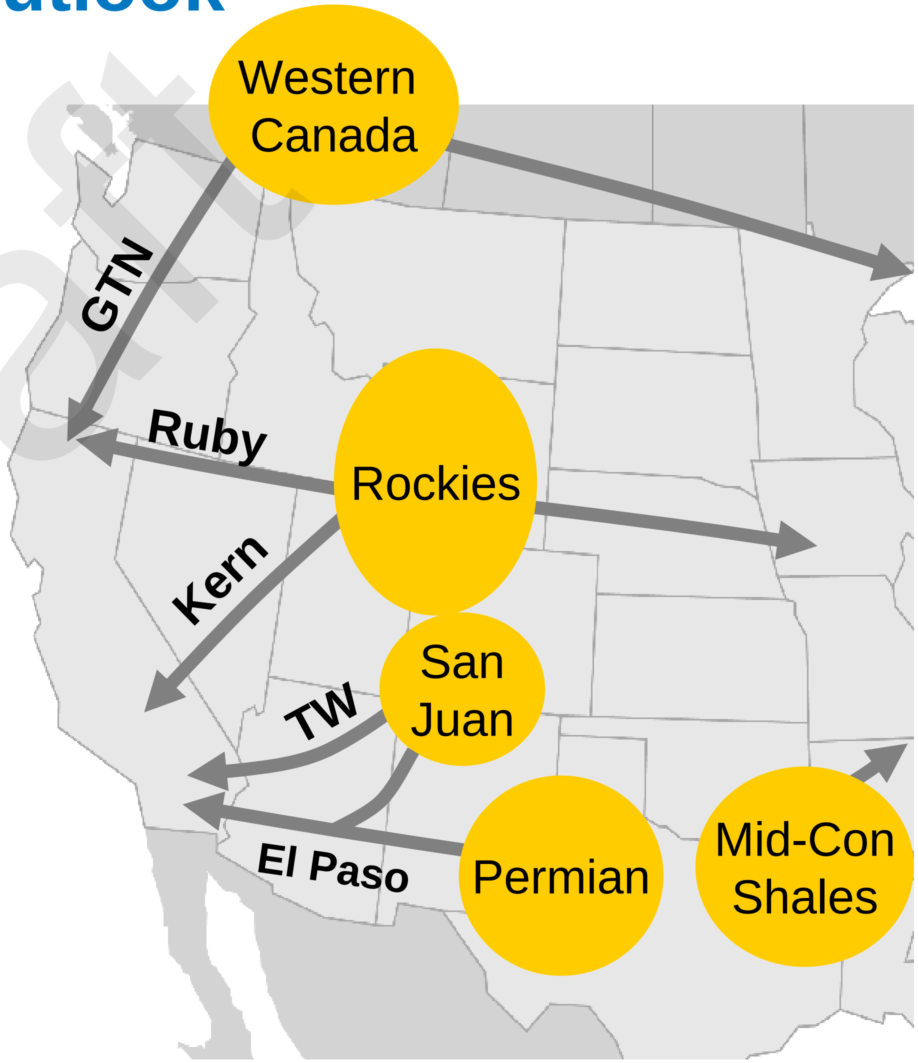
Western U.S. Natural Gas Balance

Case 1: 33% RPS Reference Scenario, Expected Renewable Generation, Normal Weather

Bcfd	2007	2008	2009	2010	2015	2020	2008-20 Delta	2008-20 CAGR
Consumption	**13.27**	**13.38**	**12.06**	**12.17**	**12.95**	**12.90**	**(0.47)**	**-0.3%**
Residential	2.58	2.70	2.54	2.60	2.60	2.64	(0.06)	-0.2%
Commercial	1.43	1.48	1.44	1.47	1.45	1.47	(0.01)	0.0%
Industrial	2.66	2.51	2.29	2.44	2.49	2.55	0.04	0.1%
Power Generation	5.14	5.16	4.32	4.31	4.91	4.76	(0.40)	-0.7%
Other	1.47	1.53	1.46	1.35	1.49	1.49	(0.05)	-0.2%
Pipeline Exports	**3.42**	**4.47**	**4.64**	**3.75**	**5.36**	**5.65**	**1.17**	**2.0%**
Production	**13.11**	**14.09**	**13.66**	**12.65**	**15.00**	**15.15**	**1.05**	**0.6%**
Pipeline Imports	**3.87**	**4.05**	**3.24**	**3.49**	**3.46**	**3.60**	**(0.46)**	**-1.0%**
Storage Net Injections / (Withdrawals)	**(0.01)**	**0.02**	**0.02**	**0.06**	**(0.03)**	**0.03**	**0.02**	**5.3%**
Balancing Item	**0.29**	**0.28**	**0.17**	**0.16**	**0.18**	**0.16**	**(0.12)**	**-4.7%**

Common Assumptions: California's Gas Supply Outlook

- California benefits directly from growing gas production in the Rockies.
  - More gas will be available on Kern River, and the new Ruby Pipeline will allow additional supplies from the Rockies to flow west.
- California also benefits indirectly from increasing production in the Mid-Continent Shales.
  - Increasing production in the Mid-Continent area means more Texas gas could be available to the West.



Common Assumptions: California's Natural Gas Infrastructure

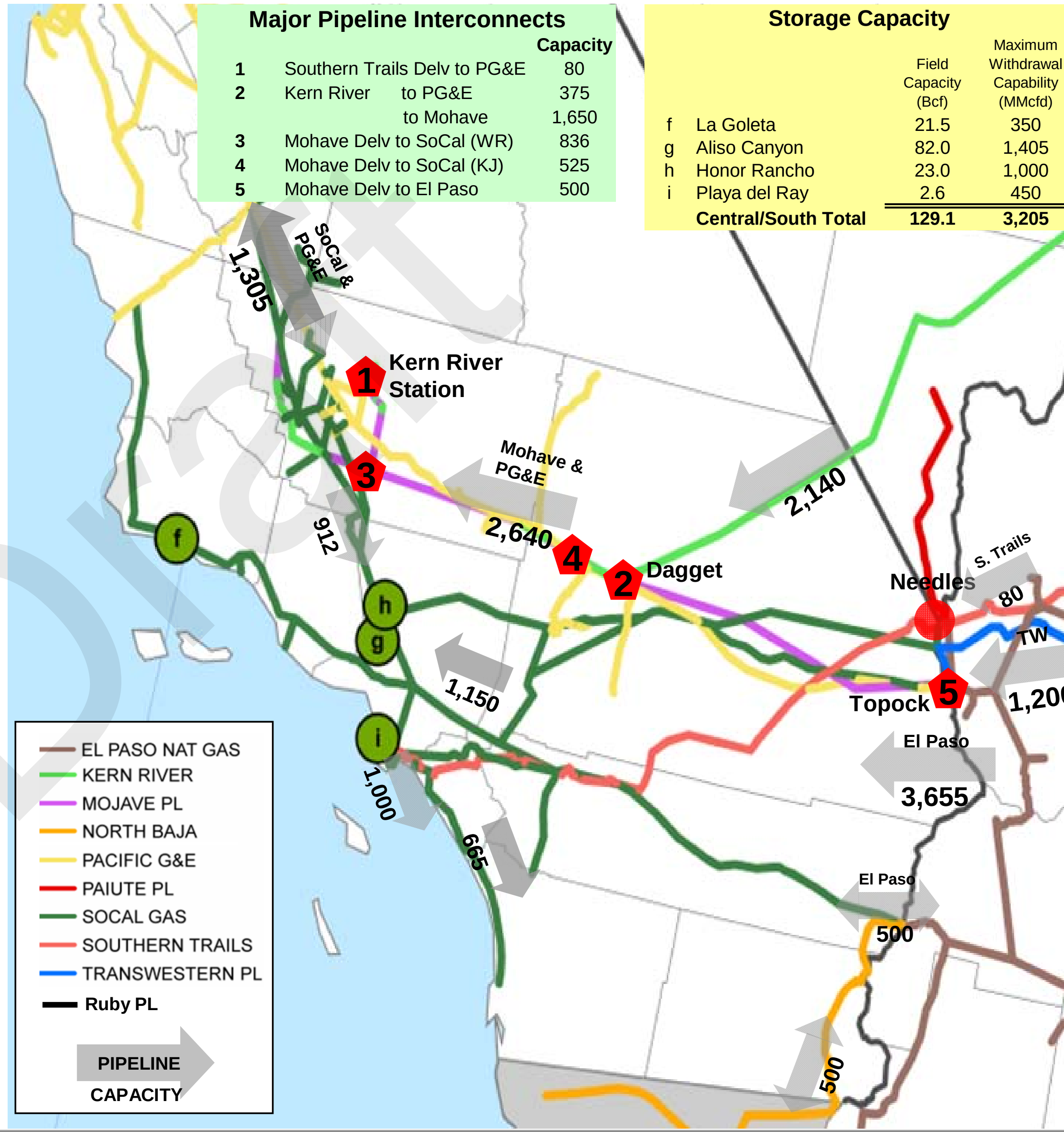
- Southern/Central California has 7.6 Bcfd of in-bound pipeline capacity on interstate pipelines, and about 130 Bcf of storage capacity with a maximum withdrawal capability of 3,200 MMcfd.

Major Pipeline Interconnects

		Capacity
1	Southern Trails Delv to PG&E	80
2	Kern River to PG&E	375
	to Mohave	1,650
3	Mohave Delv to SoCal (WR)	836
4	Mohave Delv to SoCal (KJ)	525
5	Mohave Delv to El Paso	500

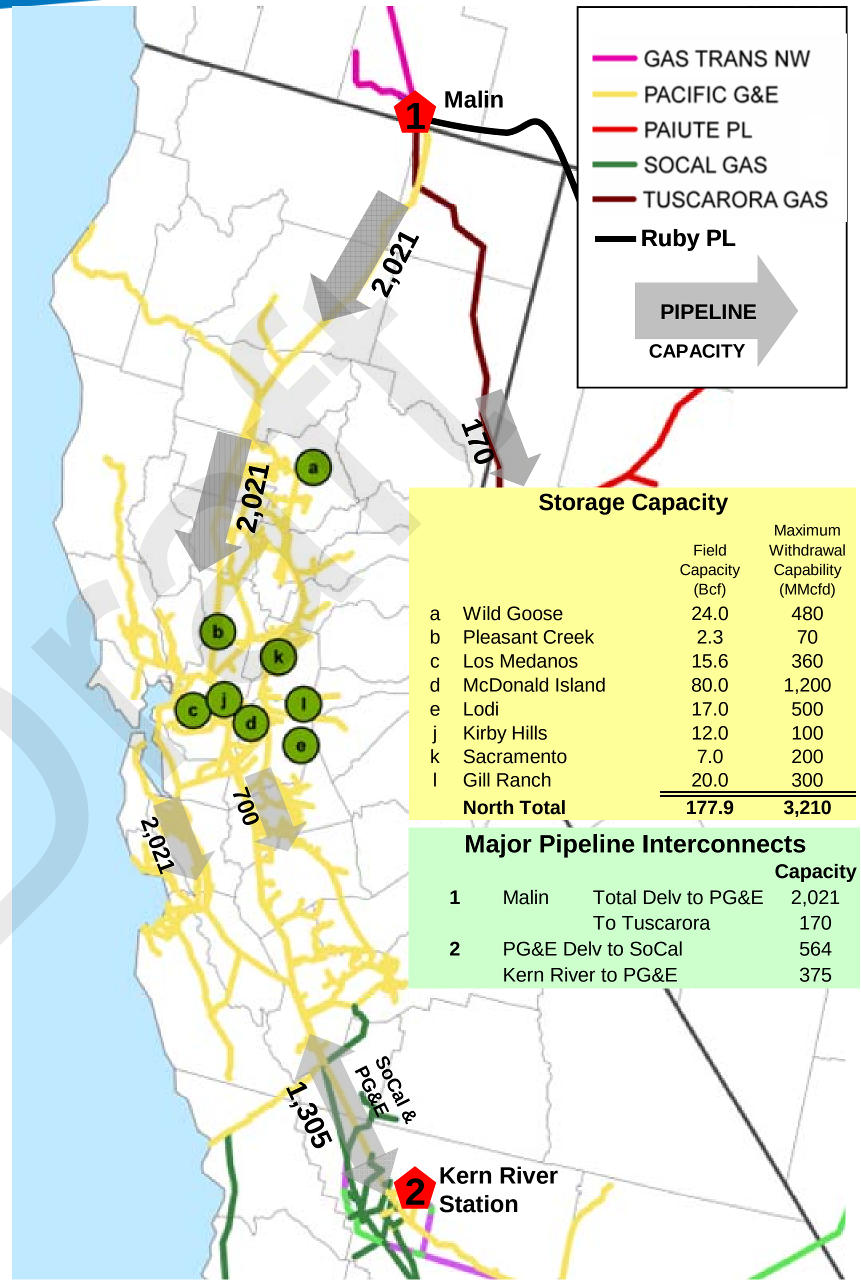
Storage Capacity

		Field Capacity (Bcf)	Maximum Withdrawal Capability (MMcfd)
f	La Goleta	21.5	350
g	Aliso Canyon	82.0	1,405
h	Honor Rancho	23.0	1,000
i	Playa del Ray	2.6	450
	Central/South Total	129.1	3,205



Common Assumptions: California's Natural Gas Infrastructure (continued)

- In the North, PG&E has over 2,000 MMcfd of receipt capacity at Malin.
  - Currently, GTN is the sole supply source at Malin.
  - The addition of Ruby Pipeline in 2011 will add another 1.3 Bcfd of pipeline capacity into Malin.
- Including storage expansions currently underway, Northern California will have nearly 180 Bcf of storage capacity with a maximum withdrawal capability of over 3,200 MMcfd.



Storage Capacity

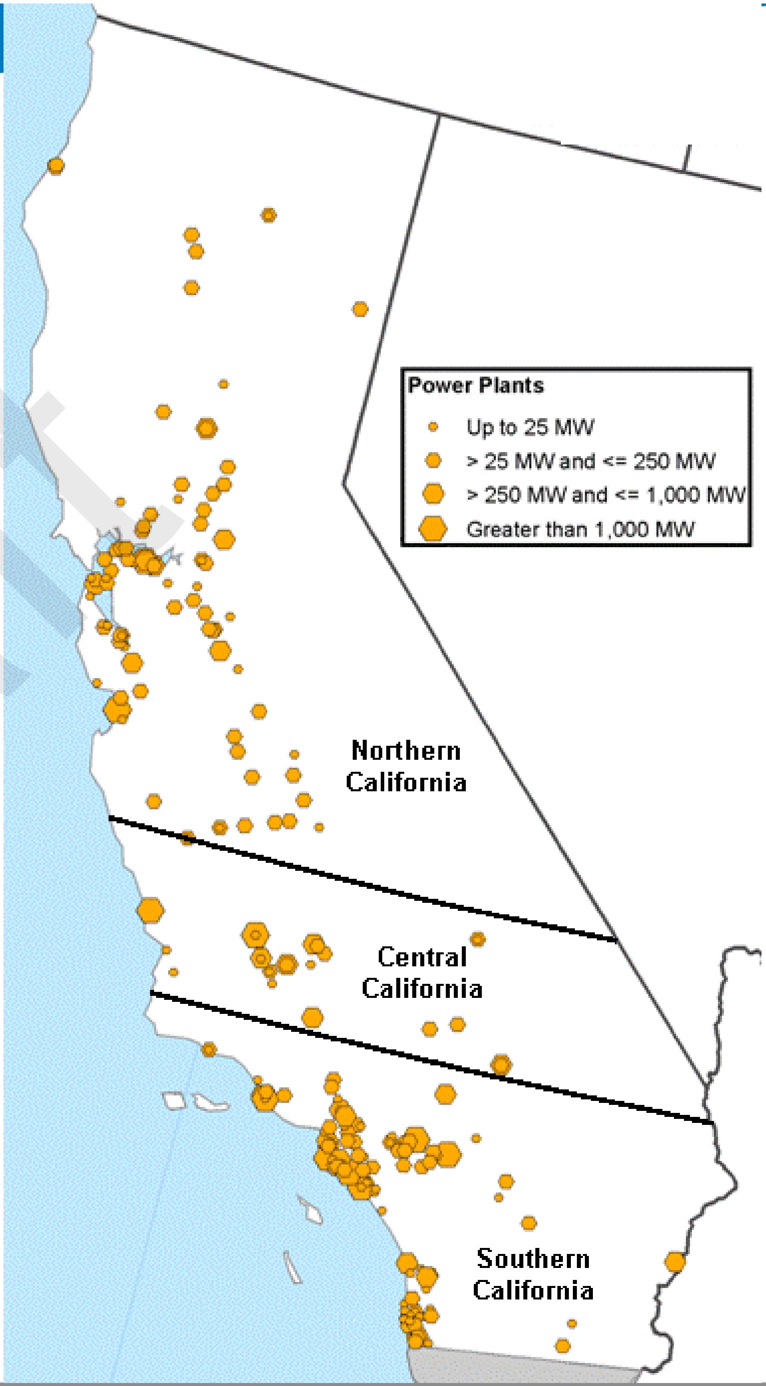
		Field Capacity (Bcf)	Maximum Withdrawal Capability (MMcfd)
a	Wild Goose	24.0	480
b	Pleasant Creek	2.3	70
c	Los Medanos	15.6	360
d	McDonald Island	80.0	1,200
e	Lodi	17.0	500
j	Kirby Hills	12.0	100
k	Sacramento	7.0	200
l	Gill Ranch	20.0	300
	North Total	**177.9**	**3,210**

Major Pipeline Interconnects

			Capacity
1	Malin	Total Delv to PG&E	2,021
		To Tuscarora	170
2	PG&E Delv to SoCal		564
	Kern River to PG&E		375

Common Assumptions:
Gas-fueled Power Plants in California

- As of 2009, California has over 370 gas-fueled electric generating facilities with a total capacity of 40 GW.*
  - 52% of the capacity is located in Southern California, 33% in Northern California, and 15% in Central California.
- Gas-fueled capacity is expected to increase by 3 GW to 43 GW by 2020, with about two-thirds of the new capacity being combustion turbines (peakers).
  - Additions of new capacity are assumed to be distributed within the state roughly in proportion to the location of existing capacity.
- We assume that new regulations on water discharge from plants using once-through cooling will not have any significant impact on power sector gas demand in California.
  - It is unlikely that new regulations would force the retirement of nuclear plants.
  - Any gas-fired plants that may be retired would likely be replaced with new gas-fired capacity, which would cause very little net change in gas consumption.



* Nearly all these units use natural gas exclusively, but a small percentage are dual-fueled (oil and gas) units. New capacity additions are expected to operate on gas only.

Common Assumptions: California's Projected Electric Generation

- In Case 1, California's retail electricity sales increase to 309 TWh in 2020.
  - To meet the 33% RPS, renewable generation and imports are assumed to be 103 TWh.
  - In-state renewable generation increases to 85 TWh, while renewable imports increase to 18 TWh.
- Electricity sales and generation decline from 2008 to 2009 due to the recession.
- Slow load growth and the increase in renewable generation lead to a reduction in gas-fired generation over the projection.
  - By 2020, gas-fired generation is about 25% below the 2008 level.
- In the High Wind and Solar scenarios, the expected annual generation in 2020 is the same, but the seasonal pattern of the generation within the year is slightly different due to the different mixes of renewable technologies.
  - Relative to the Reference Case, the High Wind Case has more renewable generation in the spring, when wind peaks.
  - The Solar Case has relatively more renewable generation in the summer, when solar generation peaks.
  - The annual totals for expected renewable generation are the same in the Reference, High Wind, and Solar cases, so the annual gas-fired generation (and fuel consumption) are also the same.

Case 1:
33% RPS Reference Scenario,
Expected Renewable Generation,
Normal Weather /1

California Electricity Generation, TWh/year	2007	2008	2009	2010	2015	2020	2008-20 Delta	2008-20 CAGR
Gas	117	121	101	100	102	90	(31)	-2.5%
Oil	4	4	4	4	4	4	(0)	-0.4%
Coal	2	3	3	3	3	3	-	0.0%
Large Hydro	25	21	26	31	31	31	10	3.2%
Nuclear	36	35	37	35	38	37	1	0.3%
Renewables	28	31	34	37	61	85	54	8.8%
Total	**213**	**216**	**204**	**210**	**238**	**249**	33	1.2%
Net Electricity Imports	**92**	**93**	**94**	**95**	**100**	**104**	11	0.9%
Renewables Imports	*7*	*8*	*9*	*10*	*14*	*18*	*10*	*7.1%*
Net Energy for Load	**306**	**309**	**298**	**305**	**338**	**353**	44	1.1%
Total Renewables	**36**	**39**	**42**	**47**	**75**	**103**	64	8.5%
Retail Electricity Sales	**263**	**268**	**258**	**261**	**292**	**309**	42	1.2%
Renewables as %	*14%*	*15%*	*16%*	*18%*	*26%*	*33%*		

1. Actual data as reported by EIA and CEC assumed through 2008

33% RPS Scenarios: Expected Generation in 2020

Generation in GWh per Year	2008 Base Generation /1	Reference Incremental Increase	Reference Total Generation	High Wind Incremental Increase	High Wind Total Generation	High Central Station Solar Incremental Increase	High Central Station Solar Total Generation
Wind	5,724	32,685	38,409	42,849	48,573	31,057	36,781
Solar (PV and Thermal)	724	24,815	25,539	11,448	12,172	26,383	27,107
Biomass	5,696	3,050	8,746	4,756	10,452	3,110	8,806
Biogas	-	2,078	2,078	2,078	2,078	2,078	2,078
Geothermal	12,951	11,520	24,471	13,034	25,985	11,520	24,471
Small Hydro	3,761	116	3,877	100	3,861	116	3,877
Total RPS Generation	28,856	74,264	103,120	74,264	103,120	74,264	103,120

1. 2008 Base Generation - http://energyalmanac.ca.gov/electricity/total_system_power.html

- These scenarios are based on assumptions for renewable penetration as provided in the 33% Implementation Analysis Working Group Meeting presentation.
  - Incremental increases in each type of generation have been adjusted slightly so that expected RPS would total exactly 33% of projected retail electricity sales.
- All the scenarios reach 103 TWh of RPS generation by 2020, but with a different mix of technologies.
  - The Reference scenario assumes that wind generation provides about 37% of RPS generation, with 25% coming from solar technologies, and the remaining 38% coming from other technologies (biogas, biomass, geothermal and small hydroelectric).
  - The High Wind scenario assumes that wind makes up 47% of RPS generation, solar technologies 12%, and other technologies 41%.
  - The High Central Station Solar scenario assumes that solar technologies make up 26% of RPS generation, wind 36%, and other technologies 38%.

Methodology for Constructing the Renewable Generation Cases

Methodology for Constructing the Renewable Generation Cases

- At the time of this study, the CEC had not developed any independent estimates for the seasonal patterns in RPS generation and potential reductions in RPS generation due to variability in weather, therefore ICF developed its own estimates.
- ICF provided its estimates to the CEC for review in March 2009.
  - The CEC did not recommend any changes to ICF's estimates.
- All cases assume that there is adequate transmission within California to deliver renewable generation to electric consumers.

Assumptions for Wind Generation

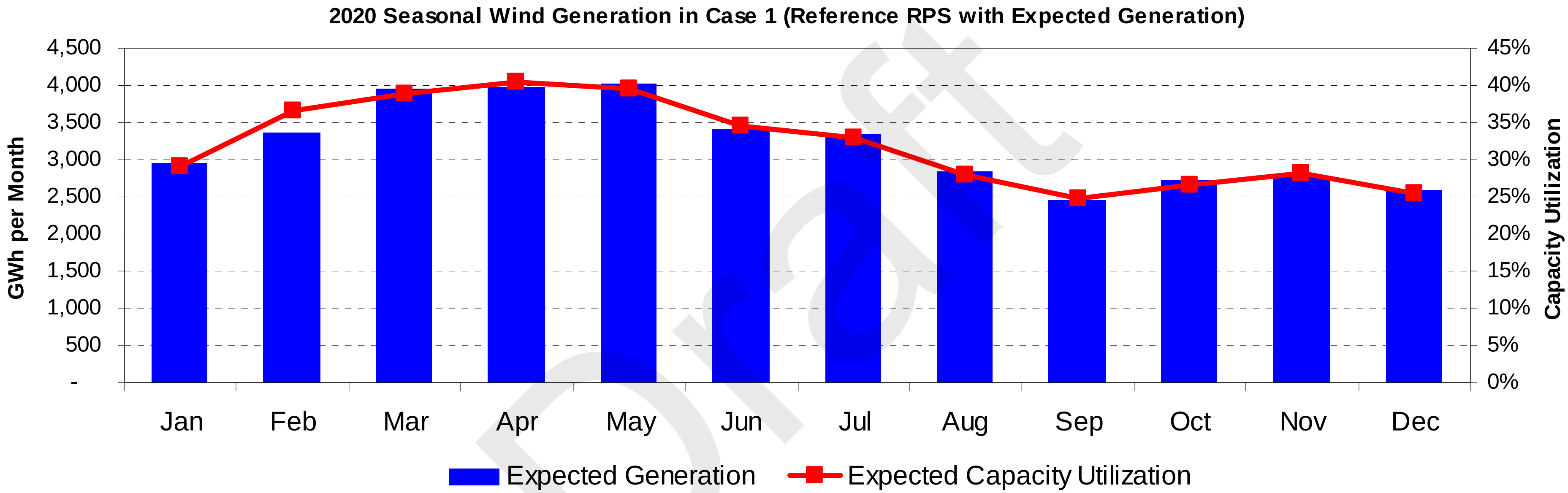
- Monthly wind generation profiles for each RPS scenario are based on NREL wind shape files provided by the CEC.
  - For purposes of determining where wind generation is located, California is divided into three areas: Northern (above 36º latitude), Central (between 34.75º and 36º latitude), and Southern (below 34.75º latitude).
    - These areas roughly correspond to both the GMM's California gas demand regions and regional division in the NREL wind data.
  - The NREL data includes hourly wind generation for each region of California for the years 2004, 2005 and 2006.
  - This data has been used to determine the percentage of the total annual wind generation assigned in each month of the year to each area within California.

Assumptions for Wind Generation (continued)

- The estimates for reduced wind generation are based on 20 to 30 years[1] of daily average wind speed data from NOAA's National Climate Data Center for 12 weather stations throughout California.
  - ICF applied a wind power function to the reported daily average wind speeds to arrive at estimated potential generation for each station.[2]
  - To estimate what the generation would be in a low wind year, we have summed the potential wind generation across all stations for each year and have picked the lowest historical year (the coincidental minimum across all sites).
    - We chose this approach, since summing minimum levels of generation from different years for each area would exaggerate the degree of variability in generation, since low wind speeds in one area of the state may be offset by higher wind speeds in another.

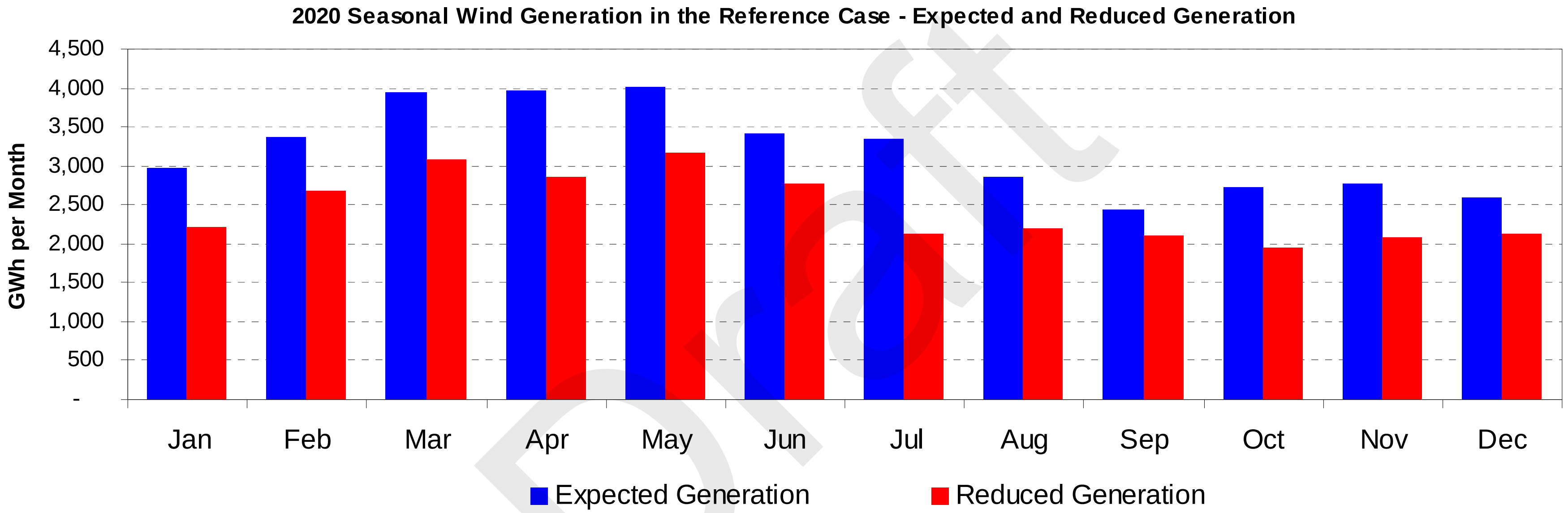
1. The number of years of data available varies by weather station.
2. Weather station anemometers are generally placed at elevations of about 10 meters. The reported wind speeds have been adjusted to arrive at equivalent wind speeds at 100 meter elevations, which represents a typical hub high for a large wind turbine.

Example of Seasonal Wind Generation
Case 1: Reference RPS with Expected Generation



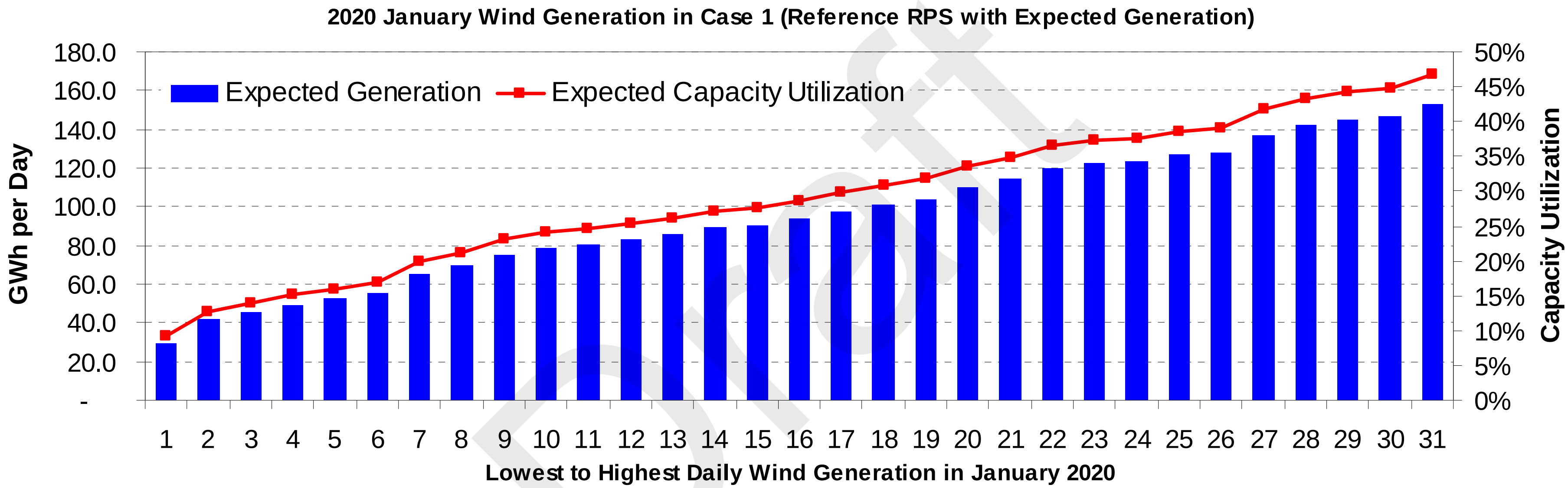
- For California as a whole, wind generation is highest in the spring and lowest in late-summer / early-fall.
- In Case 1 (Reference 33% RPS scenario with expected generation), monthly wind generation ranges from a high of 4 TWh (40% capacity utilization) to a low of 2.5 TWh (25% capacity utilization).

Example of Reduced Monthly Wind Generation Reference RPS, Expected versus Reduced Generation



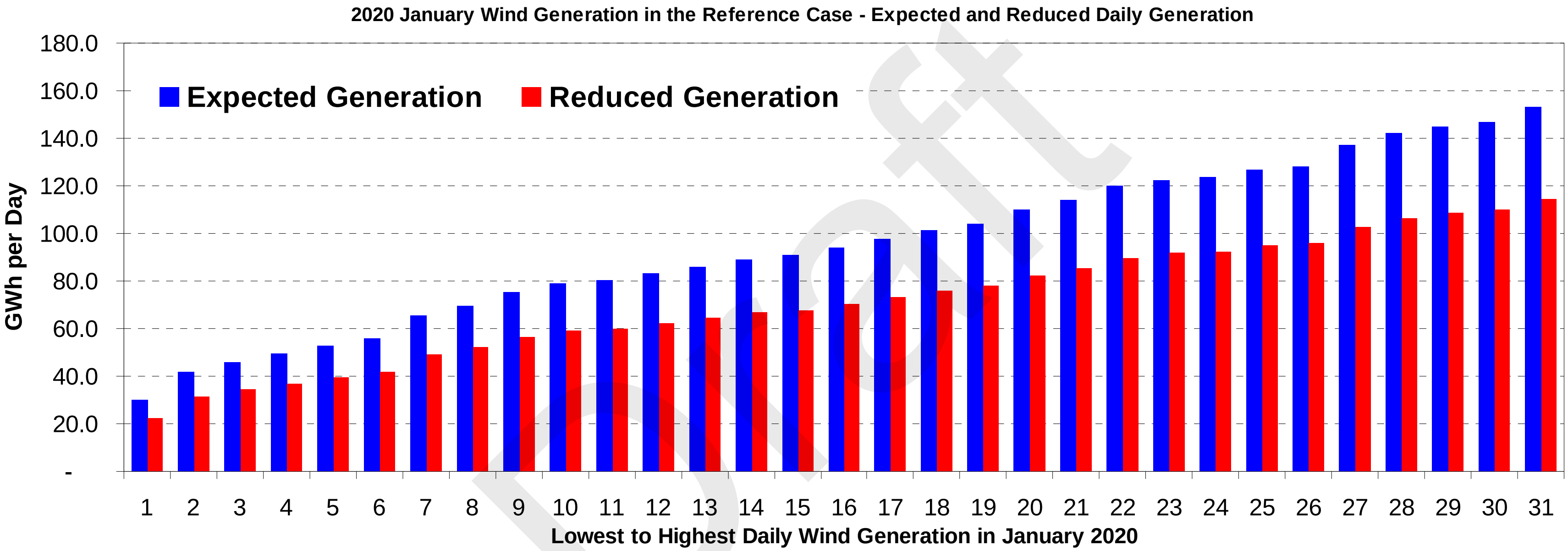
- Based on the historical wind speed data we estimate that in a low wind year, total annual wind generation could be as much as 24% below the expected annual generation.
  - This is based on the lowest observed annual wind speeds across all of California during a 30 year period that ranges from 1975 through 2004.
- July is the most variable month for wind generation, with the estimated low being 37% below the expected level of generation.
  - In the Reference Case with Reduced Generation, wind generation in July 2020 is 1,200 GWh below the expected monthly total.
  - In the High Wind Case with Reduced Generation, wind generation in July 2020 over 1,500 GWh below the expected monthly total.
- In January (the peak month for total gas demand), wind generation in the reduced generation case is 25% below the expected level of generation.

Example of Daily Wind Generation
Case 1: Reference RPS with Expected Generation



- For Case 1, daily wind generation in January 2020 is assumed to range from a low of 30 GWh (9% capacity utilization) to a high of 153 GWh (47% capacity utilization).
  - This is the range of daily values for the State as a whole, summed across all regions for each calendar day. Regionally, daily capacity utilization for January ranges from a low of 6% to a high of 57%.

Example of Reduced Daily Wind Generation
Reference RPS, Expected versus Reduced Generation



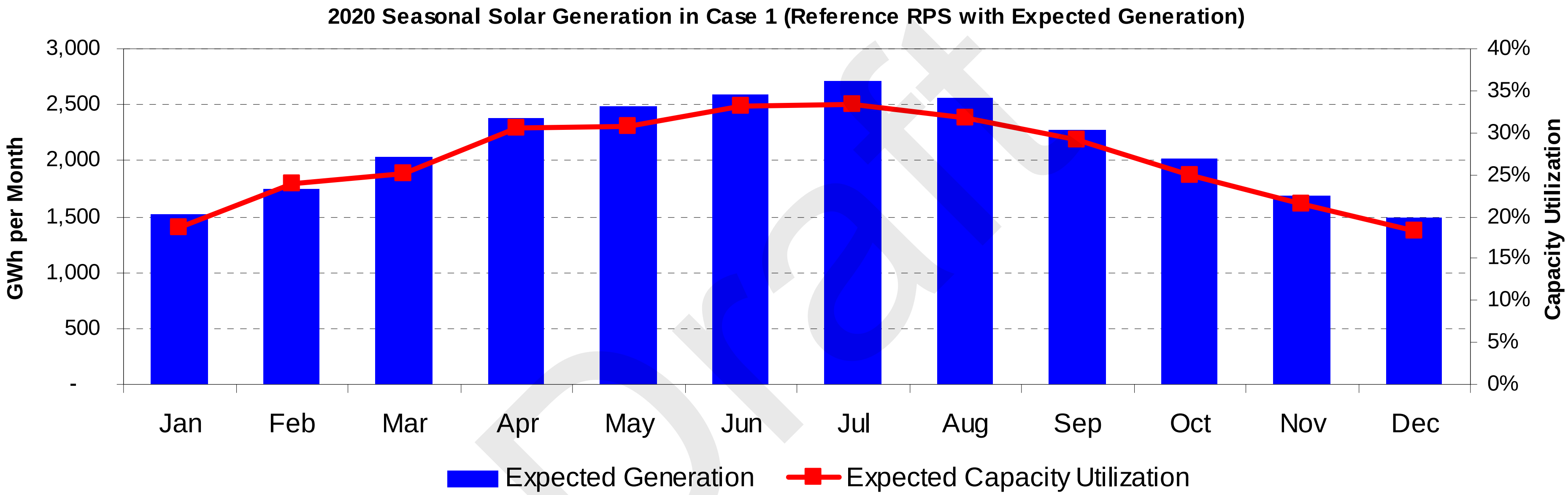
- To arrive at the reduced daily generation values for January, we applied the percentage reduction in monthly generation (-25%) to all days of the month.
  - On the lowest day of the month, wind generation is only 20 GWh, about 20% of the expected average daily generation for January.
- **For the Reduced Generation cases, we assume a "stress" scenario, in which the lowest wind generation day in January occurs on the highest gas demand day in January.**
  - **This increases peak day gas demand during the highest gas demand month of the year.**

Assumptions for Solar Generation

- Since the majority of California's solar resource is located below 34.75° latitude, ICF assumes that the vast solar generation will be located in Southern California.
  - For modeling purposes, we assumed all solar generation is located in Southern California.
- Monthly generation profiles were based on 30 years of NREL data on solar radiation for six weather stations in Southern California.[1]
  - The NREL data is on the average daily solar radiation each month for the years 1961 to 1990; it does not include any data on daily variability within each month.
  - This data has been used to determine how much of the total annual generation should be assigned to each month of the year and the potential reductions in solar generation.
- Solar thermal and PV generation are assumed to have the same seasonal pattern and variability in generation.
- Minimum generation levels have been based on the observed annual minimums in the historical solar radiation data across all six weather stations.
- The daily generation profile for January 2020 is based on the assumption that solar generation is distributed normally within the month.

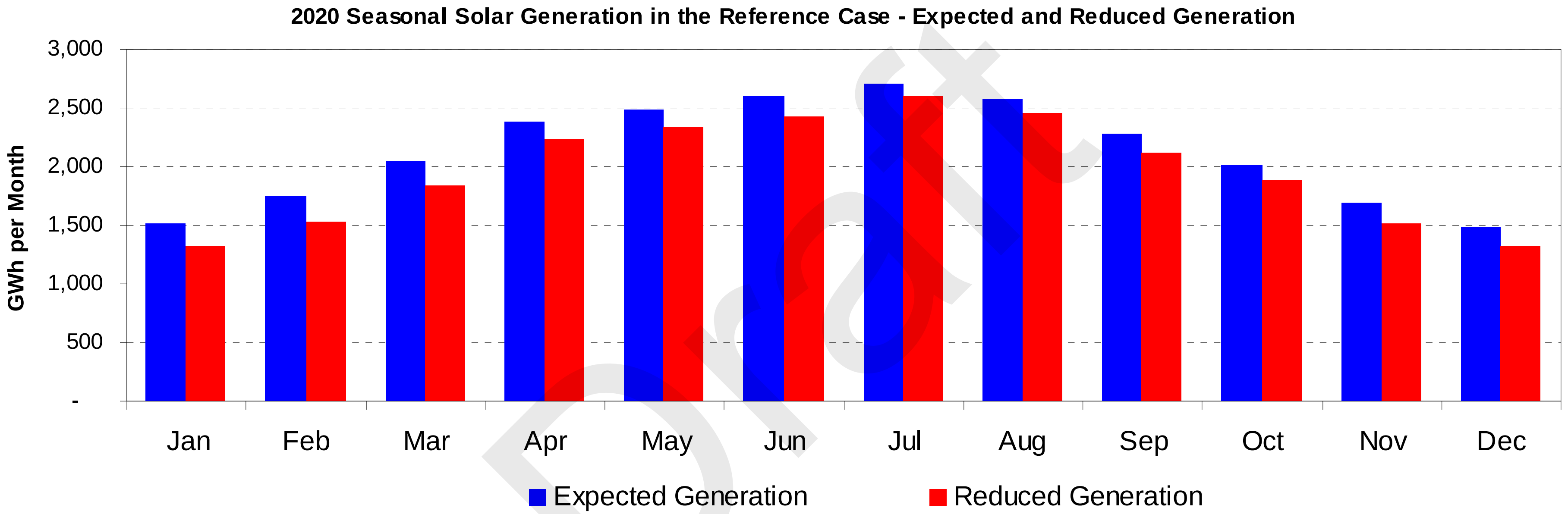
1. Source: http://rredc.nrel.gov/solar/old_data/nsrdb/redbook/mon2/state.html

Example of Seasonal Solar Generation
Case 1: Reference RPS with Expected Generation



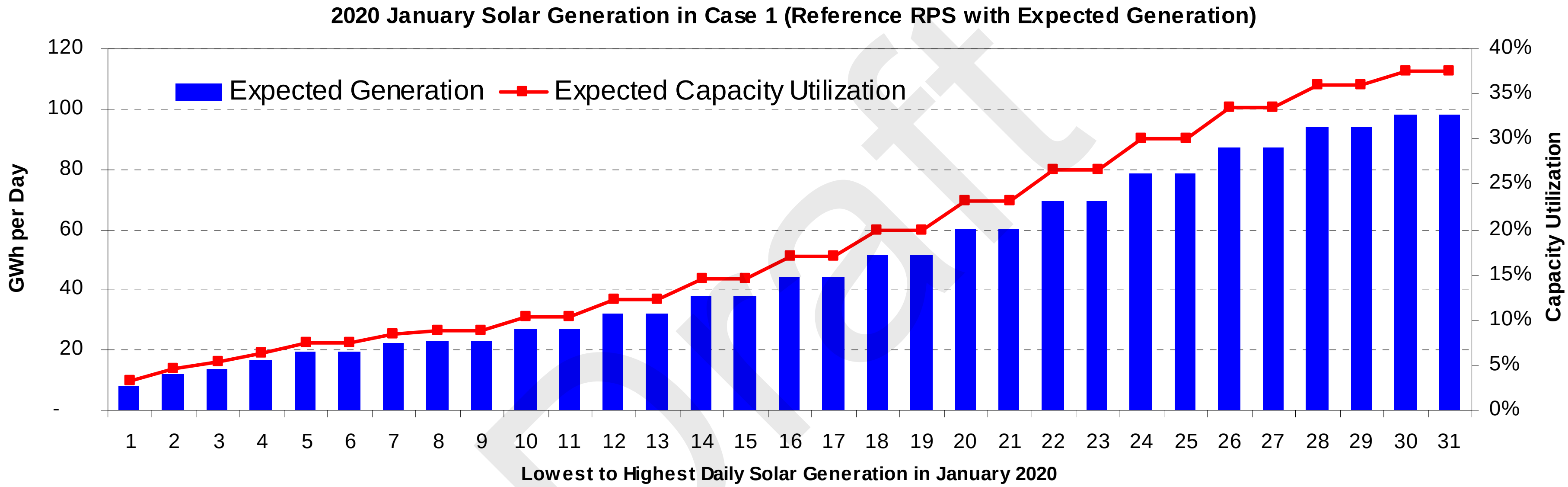
- Solar generation is highest in the summer and lowest in winter.
  - We have assumed that solar thermal and PV generation have the same seasonal variability, based on average solar radiation each month.
  - Since we have assumed all solar generation is located in Southern California, this distribution applies to both the region and the State as a whole.
- In Case 1 (Reference 33% RPS scenario with expected generation), monthly solar generation ranges from a high of 2.7 TWh (33% capacity utilization) to a low of 1.5 TWh (18% capacity utilization).

Example of Reduced Monthly Solar Generation Reference RPS, Expected versus Reduced Generation



- Based on historical solar radiation data, we estimate that in a low solar year total annual solar generation could be as much as 8% below the expected annual generation.
  - This is based on the lowest observed annual solar radiation levels across Southern California for the 30 years from 1961 through 1990.
- Solar generation is most variable in the winter months, with the estimated low for January being 13% below the expected level of generation.
  - In the Reference Case with Reduced Generation, solar generation in January 2020 is 200 GWh below the expected monthly total.
  - In the Solar Case with Reduced Generation, solar generation in January 2020 is 210 GWh below the expected monthly total.

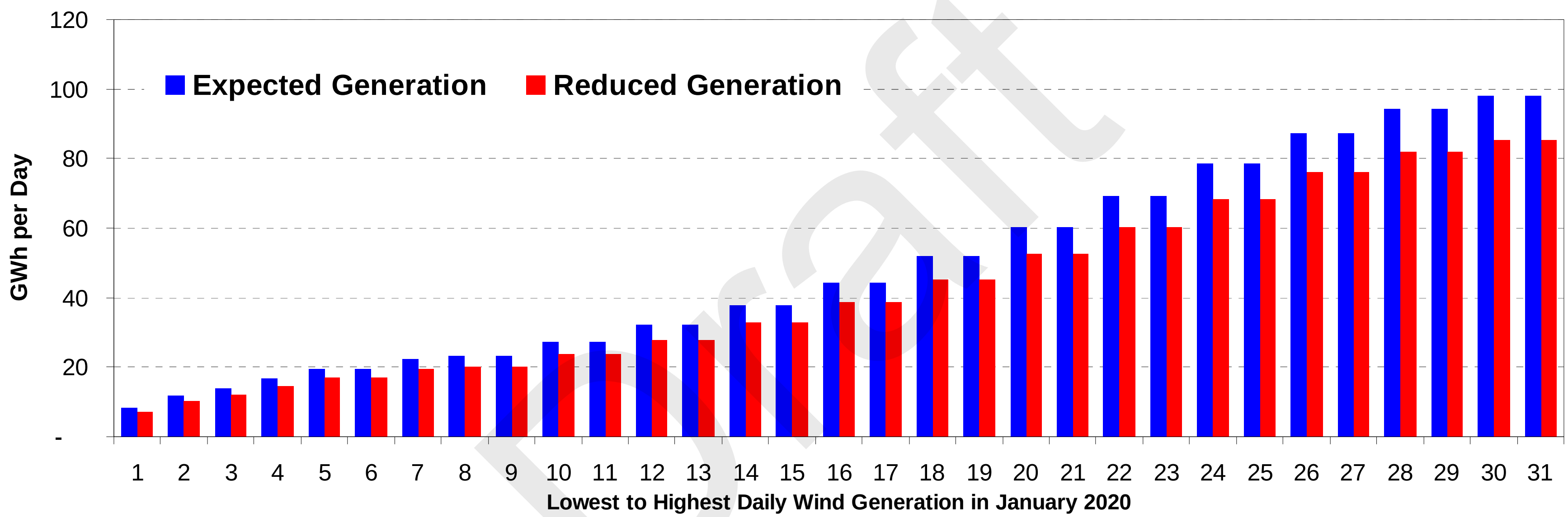
Example of Daily Solar Generation
Case 1: Reference RPS with Expected Generation



- For Case 1, daily solar generation in January 2020 is assumed to range from a low of 8 GWh (3% capacity utilization) to a high of 98 GWh (38% capacity utilization).
  - We assumed that the total generation for January was distributed normally across the days of the month. We also assume that solar thermal and PV have the same daily variability.
  - Since we have assumed all solar generation is located in Southern California, this distribution applies to both the region and the State as a whole.

Example of Reduced Daily Solar Generation Reference RPS, Expected versus Reduced Generation

2020 January Solar Generation in the Reference Case - Expected and Reduced Daily Generation



- To arrive at the reduced daily solar generation values for January, we have applied the percentage reduction in monthly generation (-13%) to all days of the month.
  - On the lowest day of the month, solar generation is only 7 GWh, about 15% of the expected average daily generation for January.
- **For the Reduced Generation cases, we assume a "stress case" scenario, in which the lowest solar generation day in January occurs on the highest gas demand day in January.**
  - **This increases peak day gas demand during the highest gas demand month of the year.**

Assumptions for Biomass, Biogas, Geothermal, and Small Hydroelectric.

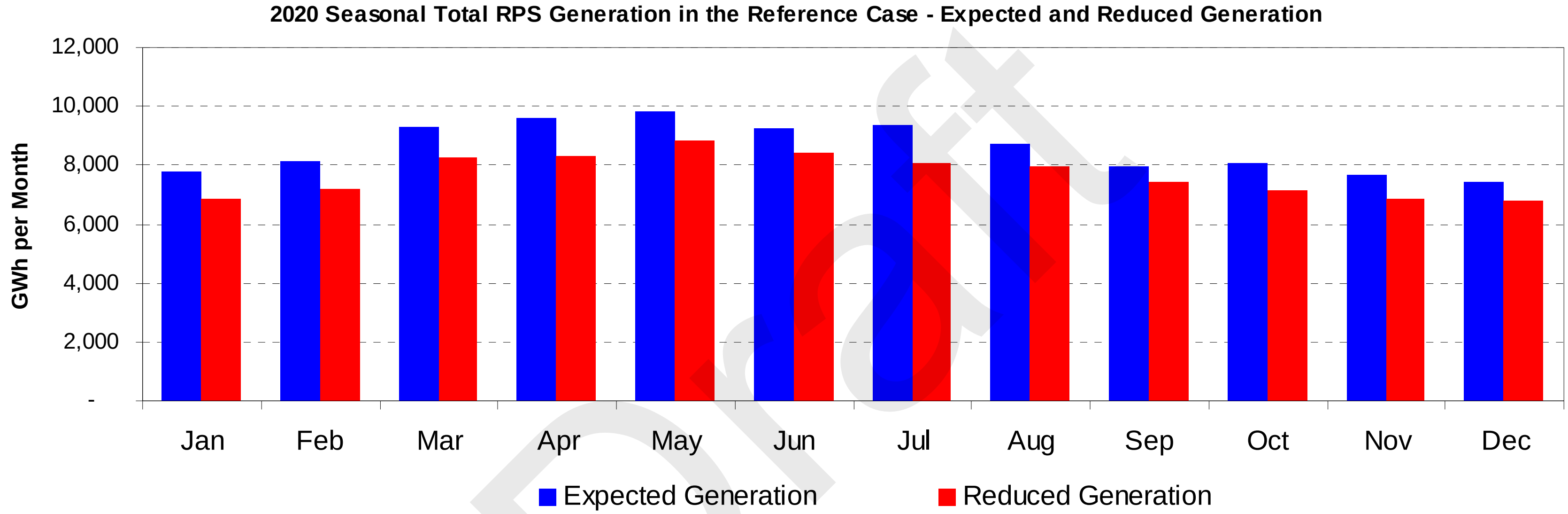
- ICF has assumed that generation from biogas, biomass, and geothermal technologies is constant throughout the year.
- As a simplifying assumption, ICF has also kept small hydroelectric generation constant throughout the year.
  - Small hydroelectric generation comprises only about 4% of the 2020 RPS generation total, and less than 0.3% of the incremental increase in renewable generation through 2020.
  - Variation in large hydroelectric generation, which makes up a much greater percentage of California's total electricity supply, is considered with the assumption of adverse weather/hydroelectric conditions in Cases 2 through 5.

33% RPS Scenarios: Reduced Generation in 2020

	Reference		High Wind		Solar	
	GWh	% Reduction	GWh	% Reduction	GWh	% Reduction
Wind	29,352	-24%	37,119	-24%	28,108	-24%
Solar (PV and Thermal)	23,594	-8%	11,245	-8%	25,043	-8%
Biomass	8,746	0%	10,452	0%	8,806	0%
Biogas	2,078	0%	2,078	0%	2,078	0%
Geothermal	24,471	0%	25,985	0%	24,471	0%
Small Hydro	3,877	0%	3,861	0%	3,877	0%
Total RPS Generation	**92,119**	**-11%**	**90,741**	**-12%**	**92,383**	**-10%**

- For the reduced generation cases, total annual wind generation has been reduced by 24% and total annual solar generation has been reduced by 8%, compared to the expected values for each scenario.
  - Monthly reductions for wind and solar vary based on the observed historical variations in monthly demand. For wind, the monthly reductions range from 14% to 37%. For solar, the monthly reductions range from 4% to 13%.
  - Reductions in wind generation also vary based on region. On an annual basis, the regional adjustments range from 23% to 27%.
  - Biomass, biogas, geothermal, and small hydroelectric generation are all assumed to be the same as the normal levels.
- **In total, annual RPS generation has been reduced by between 10% and 12%, depending on the scenario.**

Example of Reduced Monthly Total RPS Generation Reference RPS, Expected versus Reduced Generation



- Since generation from renewable technologies other than wind and solar are assumed to be constant, all the reductions in RPS generation are due to the assumed reductions in wind and solar generation.
- In all the reduced generation cases, total RPS generation is lowest in the winter, when wind and solar generation are generally at their lowest levels.

Seasonal Impact of Reduced Renewable Generation on Gas Demand and Gas Infrastructure

- Potential reductions in RPS generation are greatest in the summer months.
  - In the reduced generation cases, RPS generation in July 2020 is down by 1,300 to 1,600 GWh (14% to 18%), which creates another 0.3 to 0.4 Bcfd of gas demand for power generation.
  - However, residential/commercial gas demand is 1.8 Bcfd lower in July than in January, so there is more gas supply and pipeline capacity available to meet any increase in power generation gas demand.
  - Gas is normally injected into storage in the summer. Injections could be avoided on peak demand days, and gas could even be withdrawn if needed.
- **Reductions in RPS generation have the greatest impact on gas pipeline loads and storage withdrawals in the winter months.**
  - Due to normal seasonal variations in wind and solar generation, expected levels of RPS generation are lowest in the winter months.
  - California gas demand peaks in January, due to increased residential and commercial loads.
  - Therefore, any reductions in renewable generation in January add additional gas demand at a time when gas demand is already at its highest.

Assumptions for Adverse Weather and Hydroelectric Generation

- In Case 1, it is assumed that seasonal temperatures and hydroelectric generation are "normal" throughout the projection.
  - For temperatures, normal is defined as the average monthly heating and cooling degree days for the past 30 years (1979 to 2008).
  - For hydroelectric generation, normal is the average monthly generation for the 25-year period 1980 to 2004.
  - In the daily analysis, the pattern of peak month (January) temperatures is representative of average variability in January weather.
- Cases 2 through 5 assume adverse weather (hotter summer/colder winter) and reduced hydroelectric generation in the years 2019 and 2020.
  - The assumptions for adverse weather and hydroelectric generation have been based on our earlier analysis of the impact of weather and hydroelectric generation on natural gas storage utilization in California.
  - We have used temperatures from 1957-1958 and hydroelectric generation from 2000-2001, which have the "extreme" case from the weather/hydro analysis. The changes to weather and hydroelectric generation have been applied through the U.S. and Canada.
  - This combination of weather and hydroelectric generation results in end-of-season working gas storage levels similar to those reached during the 2000-2001 California energy crisis.
  - To include the impact of extreme weather on peak day demand, we have chose a temperature pattern for January that includes the coldest day in California from the past 30 years of daily temperature data.

Case Results

Case 1: 33% RPS Reference Scenario with Expected Generation and Normal Weather

- Under normal conditions, as represented in Case 1, gas demand in California is projected to decline by about 0.9 Bcfd by 2020.
  - Most of the decline is in the power sector, where consumption is dropping due to modest load growth and rapidly increased renewable generation to meet the 33% RPS.
  - Residential and commercial gas demands remain relatively flat, as increases in efficiency offset growth due to demographic trends. Industrial demand is also flat.
- California's gas production is expected to decline slightly over the forecast.
- With gas demand decreasing and production relatively stable, loads on the pipelines entering California are generally decreasing over time.

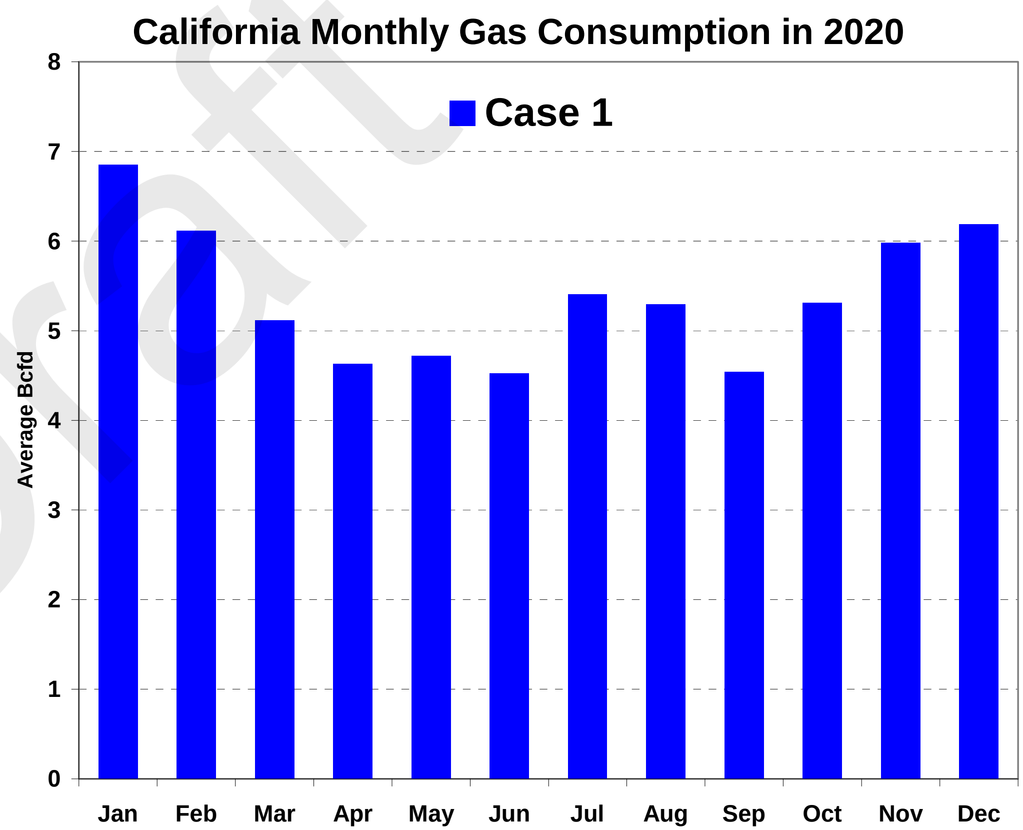
California Natural Gas Balance

Case 1: 33% RPS Reference Case, Expected Renewable Generation, Normal Weather

Bcfd	2008	2009	2010	2015	2019	2020	2008-20 Delta	2008-20 CAGR
Consumption	**6.29**	**5.58**	**5.69**	**5.66**	**5.44**	**5.39**	(0.9)	-1.3%
Residential	1.43	1.31	1.34	1.30	1.29	1.29	(0.1)	-0.8%
Commercial	0.67	0.66	0.66	0.65	0.65	0.66	(0.0)	-0.2%
Industrial	1.48	1.35	1.45	1.48	1.50	1.50	0.0	0.1%
Power Generation	2.58	2.13	2.11	2.10	1.86	1.81	(0.8)	-2.9%
Other	0.13	0.13	0.12	0.13	0.13	0.13	(0.0)	-0.4%
Pipeline Exports	**0.07**	**0.08**	**0.10**	**0.03**	**0.09**	**0.09**	0.0	1.6%
To Northern Nevada	0.07	0.08	0.10	0.02	0.02	0.02	(0.1)	-10.4%
To Mexico	-	-	-	0.02	0.07	0.07	0.1	n/a
Production	**0.88**	**0.87**	**0.84**	**0.83**	**0.85**	**0.85**	(0.0)	-0.4%
Pipeline Imports	**5.61**	**4.94**	**5.03**	**4.91**	**4.72**	**4.67**	(0.9)	-1.5%
via Southern Nevada (Kern River)	1.54	1.52	1.53	1.87	1.87	1.87	0.3	1.7%
via Arizona (El Paso, Transwestern)	2.82	1.93	2.01	1.84	1.60	1.58	(1.2)	-4.7%
via Malin	1.23	1.48	1.45	1.18	1.25	1.21	(0.0)	-0.2%
via Mexico (Costa Azul LNG)	0.02	-	0.04	0.02	0.00	0.01	(0.0)	-7.0%
Storage Net Injections / (Withdrawals)	**0.02**	**0.09**	**0.02**	**-**	**-**	**-**	(0.0)	-100.0%
Balancing Item	**0.11**	**0.07**	**0.06**	**0.05**	**0.04**	**0.04**	(0.1)	-8.8%

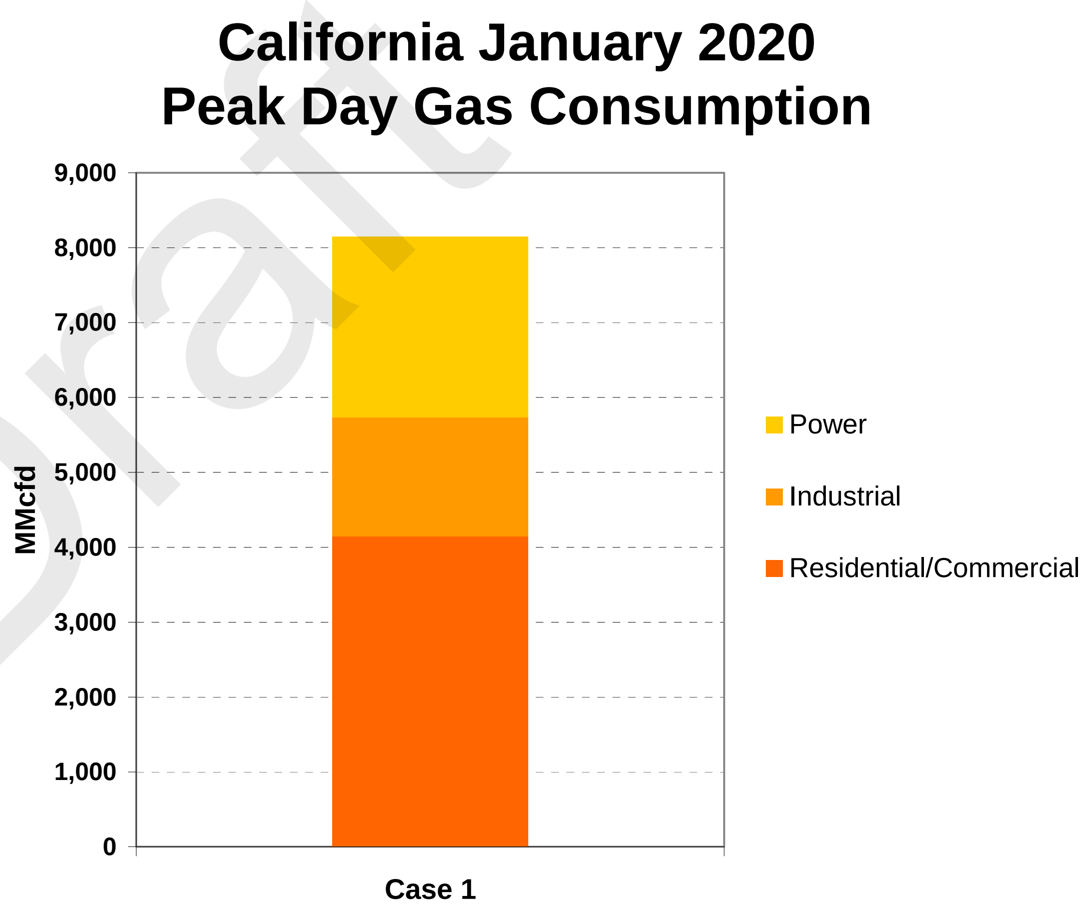
Case 1: 33% RPS Reference Scenario with Expected Generation and Normal Weather (continued)

- Under normal weather conditions and with expected renewable generation, peak month (January) gas consumption is expected to average 6.9 Bcfd.
- Gas demand in July and August averages about 5.3 Bcfd.



Case 1: 33% RPS Reference Scenario with Expected Generation and Normal Weather (continued)

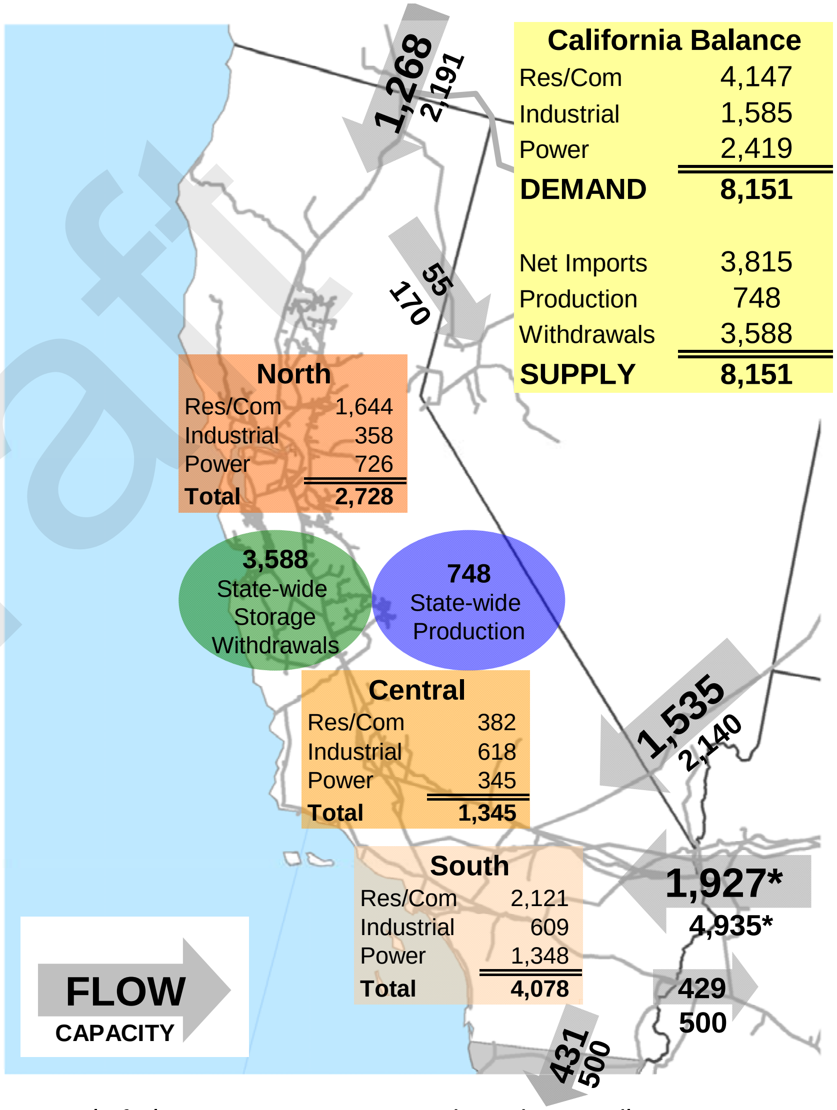
- Under normal weather conditions, peak day gas consumption is projected to be 8.2 Bcf, about 20% greater than the peak month average and over 50% greater than the annual average.
- About 50% of the peak day consumption in the residential and commercial sectors, 30% is for power generation, and 20% is for industrial uses.



Case 1: 33% RPS Reference Scenario with Expected Generation and Normal Weather (continued)

- On the peak gas demand day in January, about 50% of the total demand, and 55% of the power sector demand is in Southern California.
- 47% of peak day demand is met by pipeline imports, 44% by storage withdrawals, and 9% by in-state gas production.

Case 1: January 2020 Peak Day Balance (MMcfd)

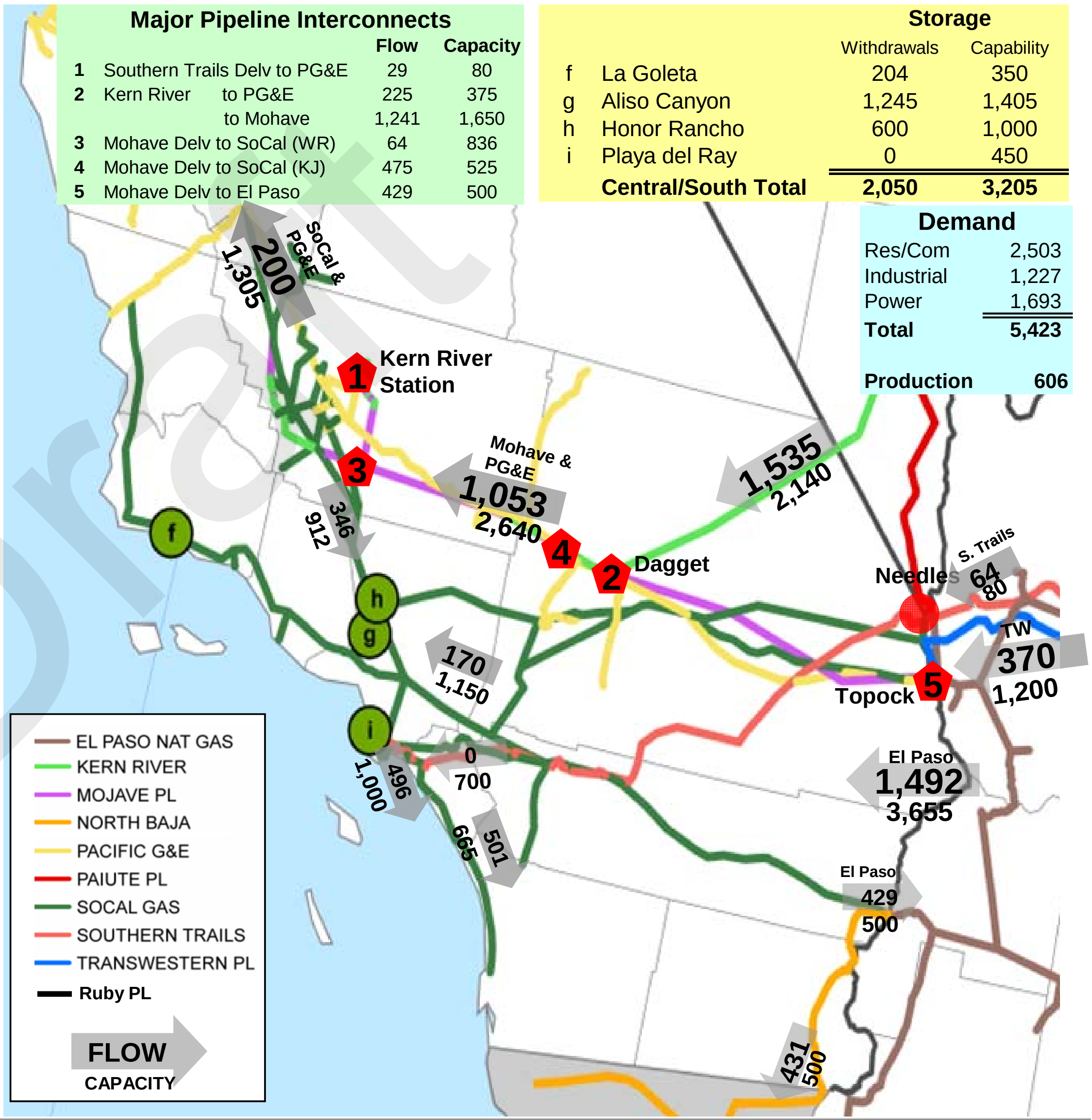


* Total of El Paso, Transwestern, and Southern Trails

Case 1: 33% RPS Reference Scenario with Expected Generation and Normal Weather (continued)

- January peak day pipeline flows into and within Central and Southern California are well under the pipelines' capacities.
- Storage withdrawals are about two-thirds of the maximum withdrawal capability.

Case 1: January 2020Peak Day Flows in Central/Southern California (MMcfd)



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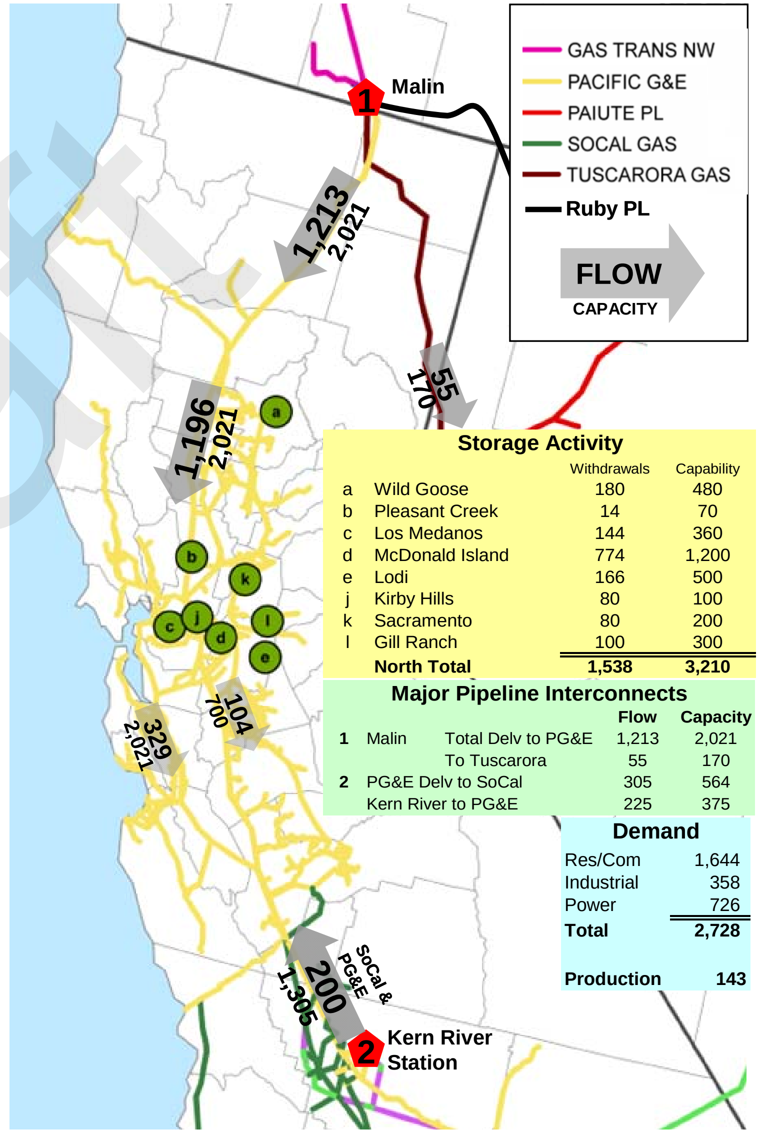
Case 1: 33% RPS Reference Scenario with Expected Generation and Normal Weather (continued)

- January peak day pipeline flows into and within Northern California are well under the pipelines' capacities.
- Storage withdrawals are less than half the maximum withdrawal capability.

Case 1: January 2020 Peak Day Flows in Northern California (MMcfd)



Storage Activity

		Withdrawals	Capability
a	Wild Goose	180	480
b	Pleasant Creek	14	70
c	Los Medanos	144	360
d	McDonald Island	774	1,200
e	Lodi	166	500
j	Kirby Hills	80	100
k	Sacramento	80	200
l	Gill Ranch	100	300
	North Total	**1,538**	**3,210**

Major Pipeline Interconnects

			Flow	Capacity
1	Malin	Total Delv to PG&E	1,213	2,021
		To Tuscarora	55	170
2	PG&E Delv to SoCal		305	564
	Kern River to PG&E		225	375

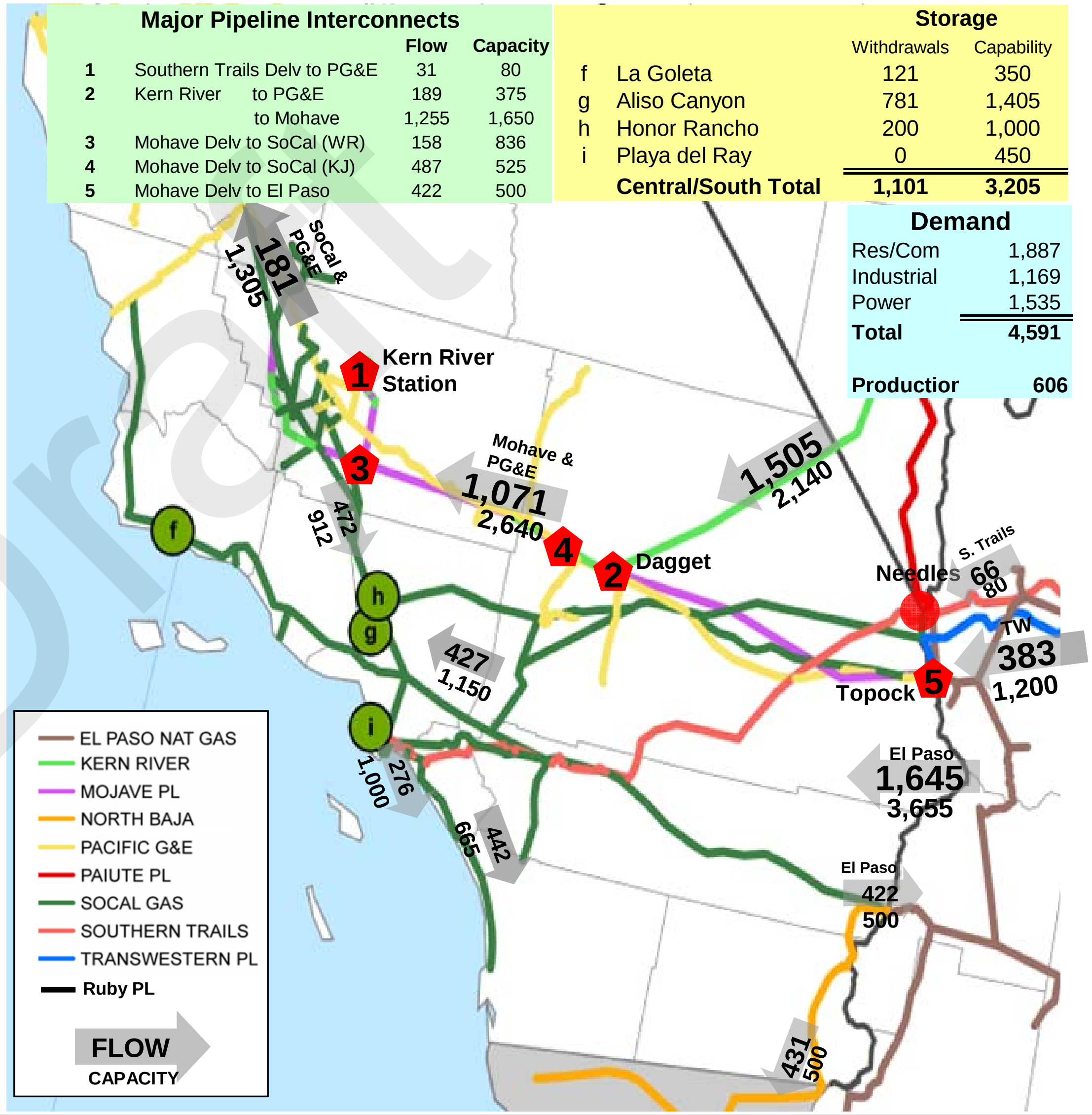
Demand

Res/Com	1,644
Industrial	358
Power	726
Total	**2,728**
Production	**143**

Case 1: 33% RPS Reference Scenario with Expected Generation and Normal Weather (continued)

- The average demand for January in Central/Southern California is about 0.8 Bcf lower than the peak day demand.

Case 1: January 2020 Average Flows in Southern/Central California (MMcfd)



Major Pipeline Interconnects

		Flow	Capacity
1	Southern Trails Delv to PG&E	31	80
2	Kern River to PG&E	189	375
	to Mohave	1,255	1,650
3	Mohave Delv to SoCal (WR)	158	836
4	Mohave Delv to SoCal (KJ)	487	525
5	Mohave Delv to El Paso	422	500

Storage

		Withdrawals	Capability
f	La Goleta	121	350
g	Aliso Canyon	781	1,405
h	Honor Rancho	200	1,000
i	Playa del Ray	0	450
	Central/South Total	**1,101**	**3,205**

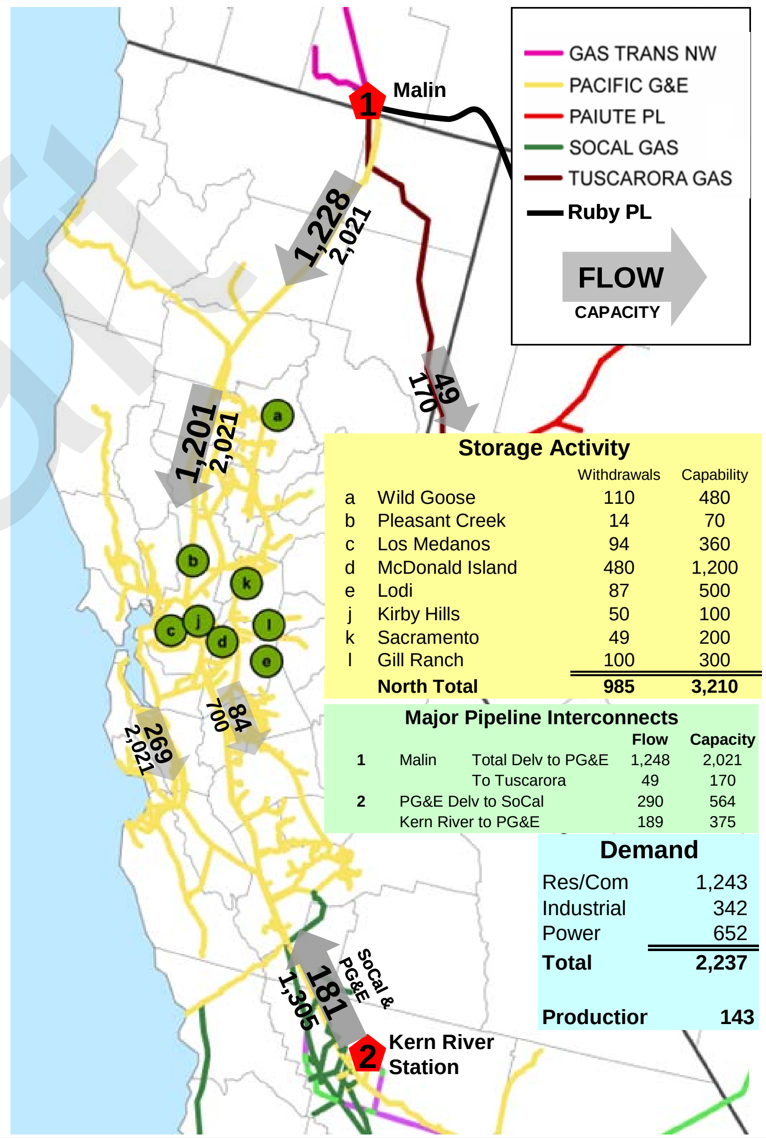
Demand

Res/Com	1,887
Industrial	1,169
Power	1,535
Total	**4,591**
Production	**606**

Case 1: 33% RPS Reference Scenario with Expected Generation and Normal Weather (continued)

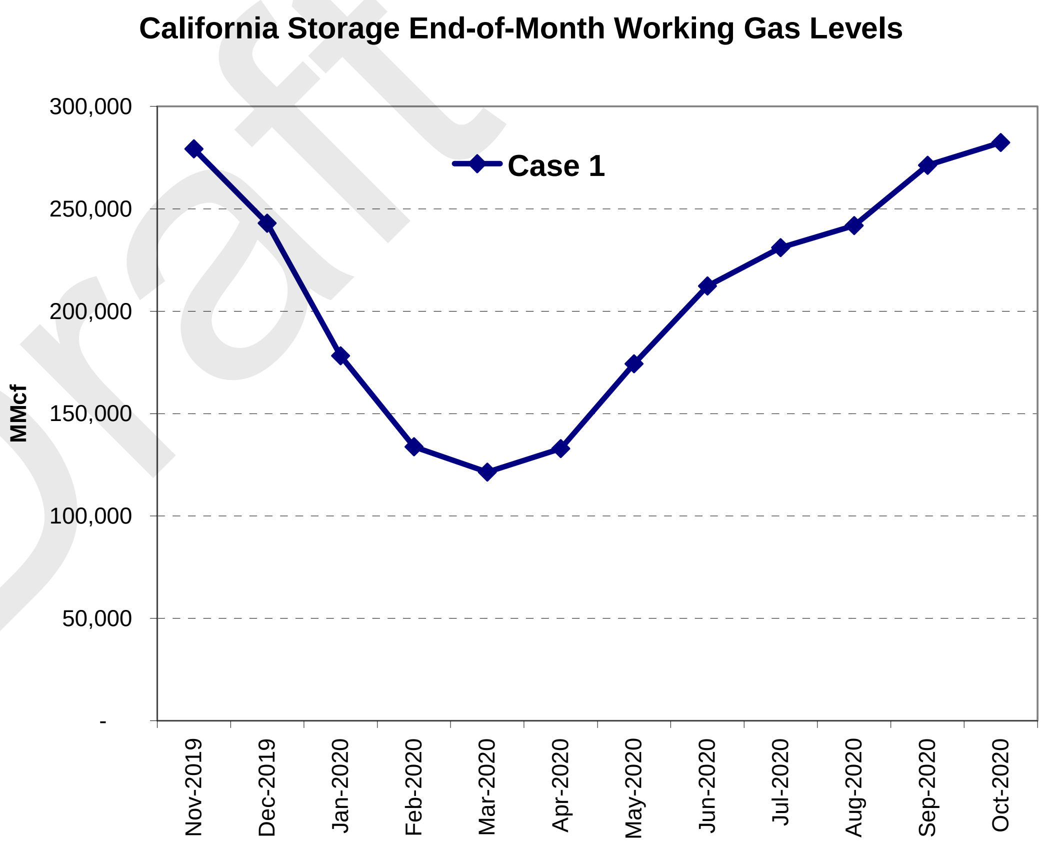
- The average demand for January in Northern California is about 0.5 Bcf lower than the peak day demand.

Case 1: January 2020 Average Flows in Northern California (MMcfd)



Case 1: 33% RPS Reference Scenario with Expected Generation and Normal Weather (continued)

- By 2020, California's total storage working gas capacity is projected to be over 300 Bcf.
- With expected renewable generation and normal weather, the working gas fill level at the end of March (end of the withdrawal season) is about 120 Bcf, or roughly 40% of capacity.



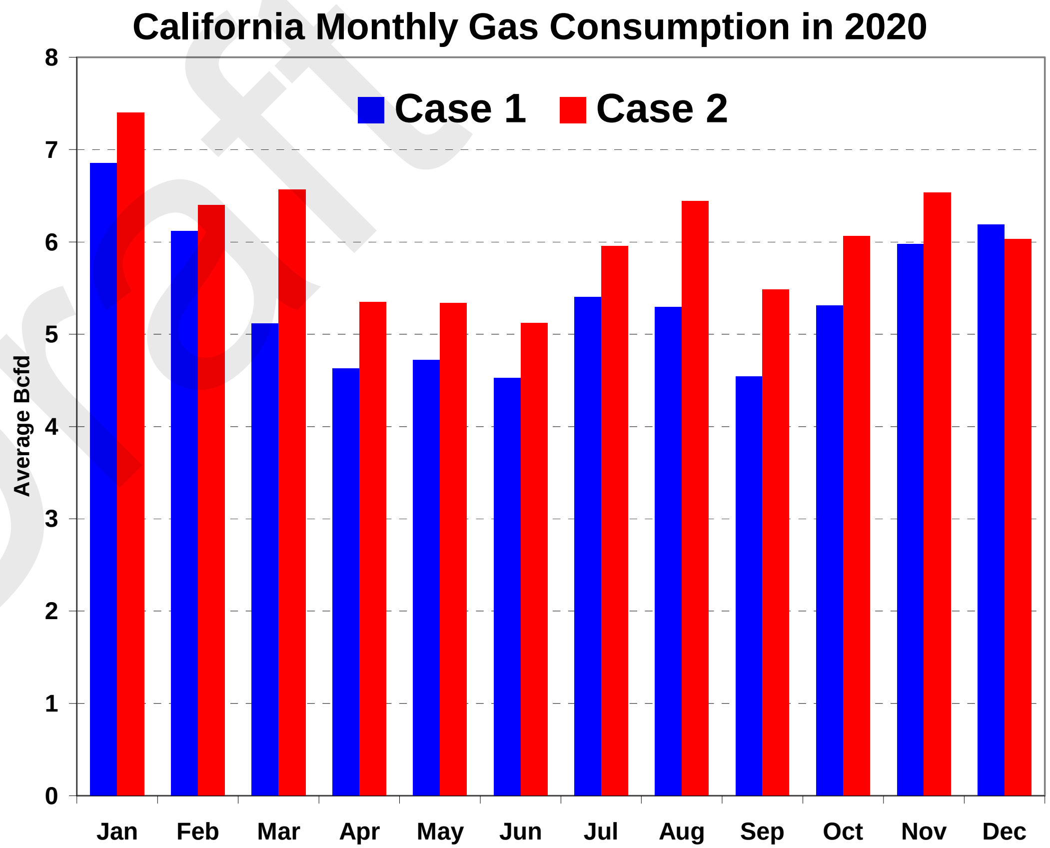
Case 2: The Impact of Adverse Weather on California Gas Demand

- Case 2 assumption are identical to Case 1, except for the addition of adverse weather and hydroelectric conditions in 2019 and 2020.
  - Assuming adverse weather in these years, average daily consumption is up by 0.17 Bcfd in 2019 and 0.67 Bcfd in 2020.
- However, even with adverse conditions, the projected average gas consumption for 2020 is still **below** the 2008 consumption level of about 6.3 Bcfd.

Bcfd	2019 Case 2	2019 *Delta vs Case 1*	2020 Case 2	2020 *Delta vs Case 1*
Consumption	**5.61**	***0.17***	**6.06**	***0.67***
Residential	1.32	*0.03*	1.24	*(0.05)*
Commercial	0.66	*0.00*	0.65	*(0.01)*
Industrial	1.50	*(0.00)*	1.48	*(0.02)*
Power Generation	2.00	*0.14*	2.56	*0.75*
Other	0.13	*0.00*	0.13	*0.00*
Pipeline Exports	**0.08**	***(0.01)***	**0.06**	***(0.03)***
To Northern Nevada	0.02	-	0.01	*(0.01)*
To Mexico	0.06	*(0.01)*	0.05	*(0.02)*
Production	**0.85**	***0.00***	**0.85**	***0.00***
Pipeline Imports	**4.88**	***0.16***	**5.32**	***0.65***
via Southern Nevada (Kern River)	1.85	*(0.02)*	1.79	*(0.09)*
via Arizona (El Paso, Transwestern)	1.75	*0.15*	2.11	*0.53*
via Malin	1.27	*0.02*	1.39	*0.18*
via Mexico (Costa Azul LNG)	0.01	*0.01*	0.04	*0.03*
Storage Net Injections / (Withdrawals)	**-**		**-**	*0*
Balancing Item	**0.04**	***0.00***	**0.04**	***0.01***

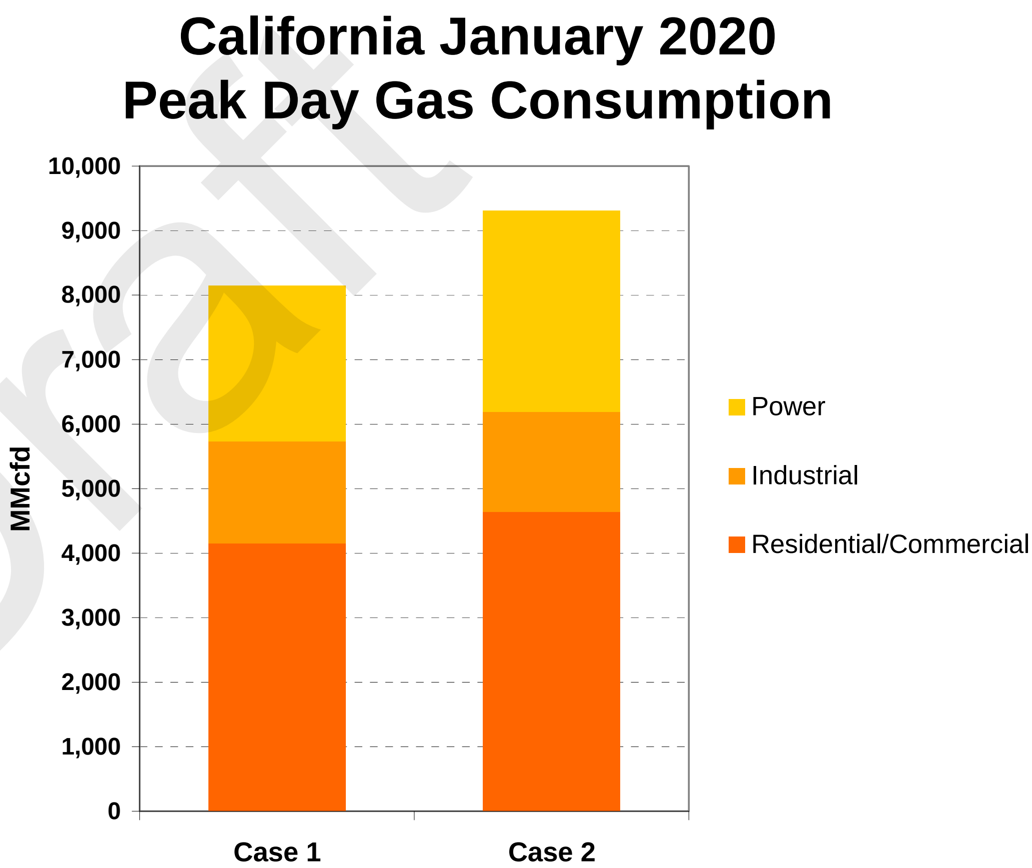
Case 2: The Impact of Adverse Weather on California Gas Demand (continued)

- With the exception of December, average monthly gas demand is up by 0.3 Bcfd to 1.5 Bcfd with the addition of adverse weather/hydro.
- Average demand in the peak month (January) is 7.40 Bcfd, an increase of about 0.5 Bcfd over Case 1.
- Hot weather and low hydro conditions increase gas demand in the power sectors and drive August demand up by over 1 Bcfd.
  - However, total gas demand in January is still about 1 Bcfd greater than the total demand in August.



Case 2: The Impact of Adverse Weather/Hydro on California Gas Demand (continued)

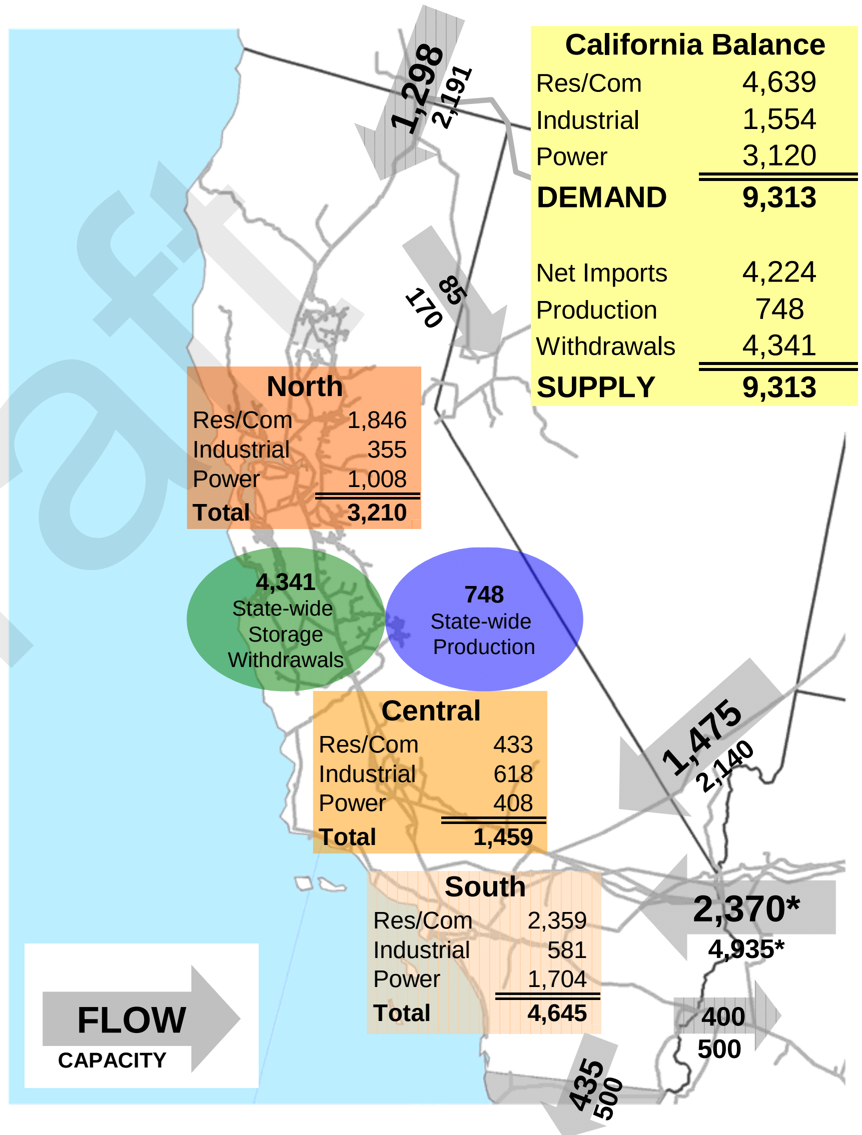
- January peak day gas consumption in 2020 is about 1.2 Bcf greater with adverse weather/hydro conditions than in the normal weather case.
  - Residential/Commercial gas consumption is 0.5 Bcf greater.
  - Power sector gas consumption is 0.7 Bcf greater.
  - Industrial demand is about the same.



Case 2: The Impact of Adverse Weather/Hydro on California Gas Demand (continued)

- January peak-day gas consumption is up throughout the state, but increases are greatest in the south, where most of the gas-fired electric capacity is located.
- The increase in consumption is met by increases in pipeline imports (+0.4 Bcfd) and storage withdrawals (+0.7 Bcfd).
  - Most of the increase in pipeline imports is from the El Paso system into Southern California.
- Both the pipeline flows and storage field withdrawals are well within infrastructure capabilities.

Case 2: January 2020 Peak Day Balance (MMcfd)

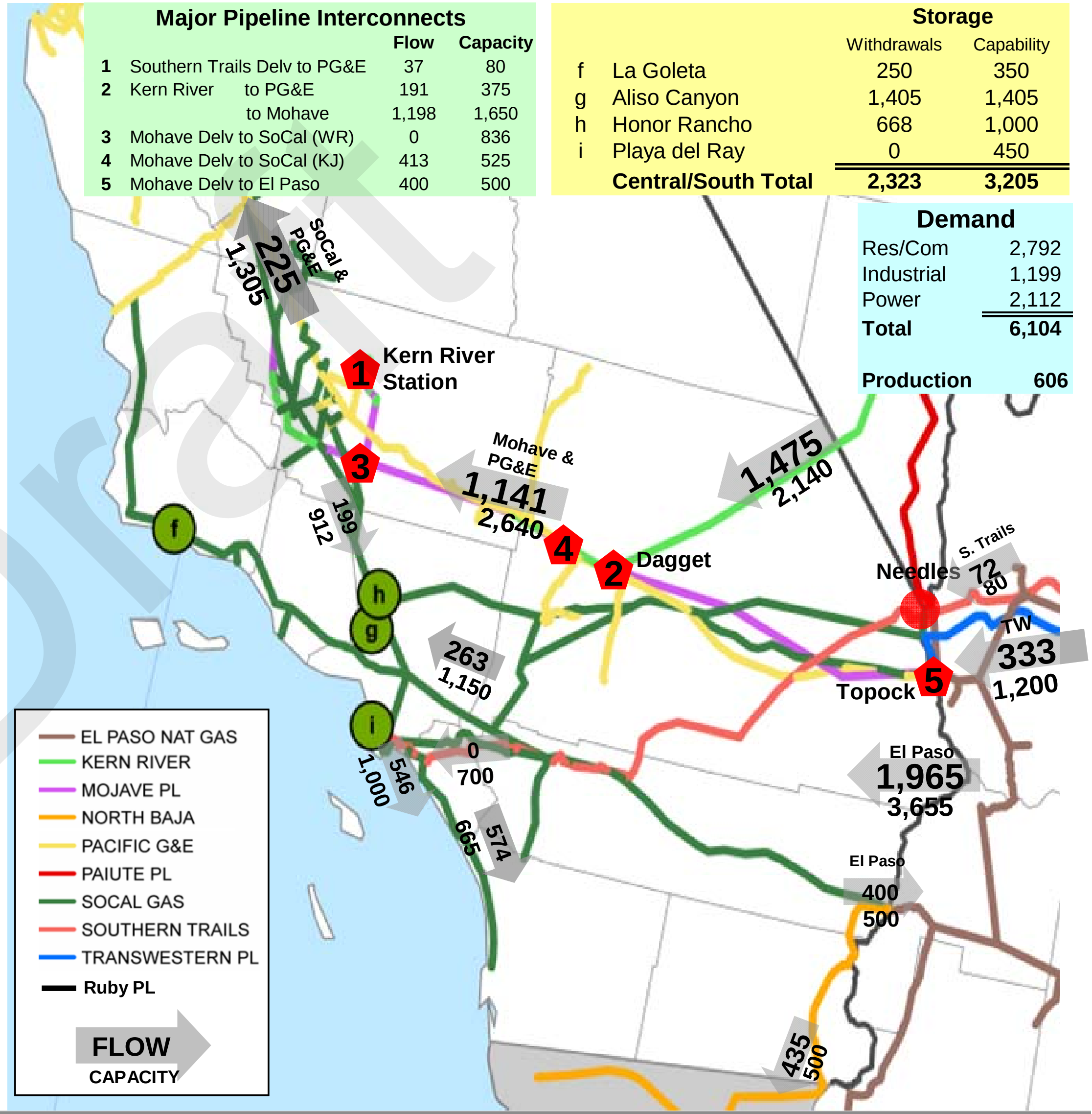


* Total of El Paso, Transwestern, and Southern Trails

Case 2: The Impact of Adverse Weather/Hydro on California Gas Demand (continued)

- Compared to Case 1, the January peak day with adverse weather and hydro has 0.7 Bcf of additional demand in Central/Southern California.
  - In-bound pipeline flows increase by 0.4 bcf.
  - Storage withdrawals increase by 0.3 bcf.
- Pipeline flows and storage withdrawals are well within system constraints.
  - Pipelines into San Diego counties are getting heavily loaded, but they are still capable of meeting demand.
  - In August, when gas demand for power generation peaks, San Diego would be constrained under this scenario due to its lack of storage and limited pipeline options.

Case 2: January 2020 Peak Day Flows in Central/Southern California (MMcfd)



Major Pipeline Interconnects

		Flow	Capacity
1	Southern Trails Delv to PG&E	37	80
2	Kern River to PG&E	191	375
	to Mohave	1,198	1,650
3	Mohave Delv to SoCal (WR)	0	836
4	Mohave Delv to SoCal (KJ)	413	525
5	Mohave Delv to El Paso	400	500

Storage

		Withdrawals	Capability
f	La Goleta	250	350
g	Aliso Canyon	1,405	1,405
h	Honor Rancho	668	1,000
i	Playa del Ray	0	450
	Central/South Total	**2,323**	**3,205**

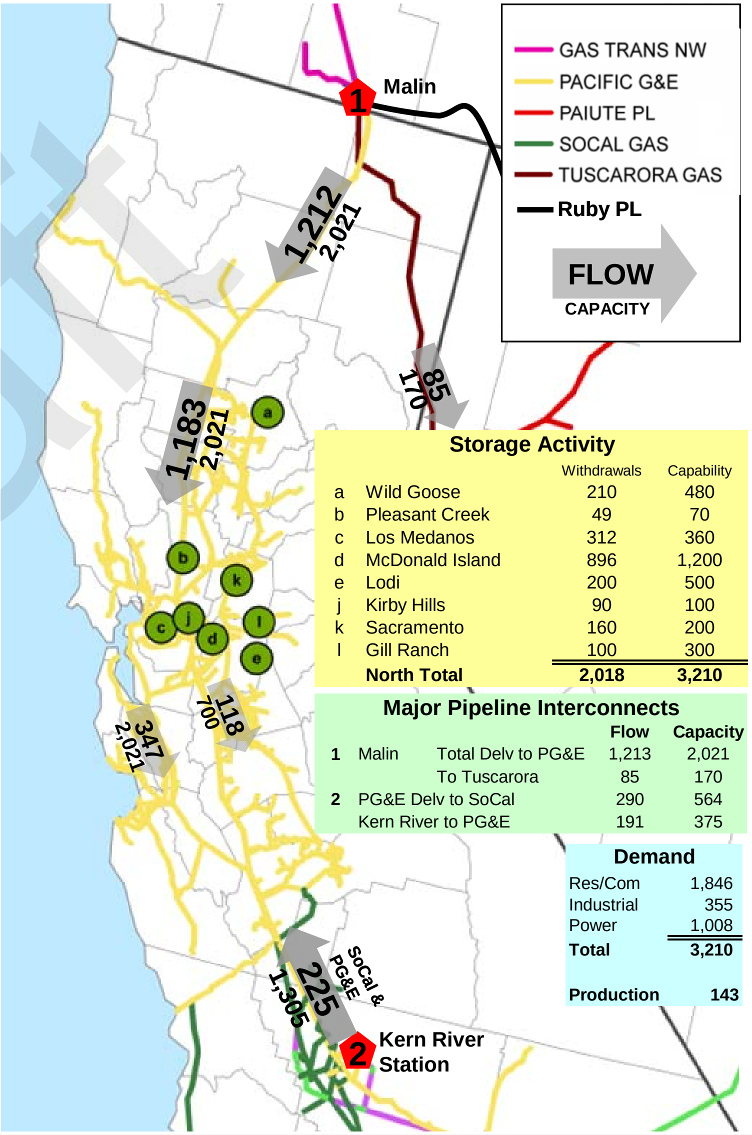
Demand

Res/Com	2,792
Industrial	1,199
Power	2,112
Total	**6,104**
Production	**606**

Case 2: The Impact of Adverse Weather/Hydro on California Gas Demand (continued)

- Compared to Case 1, the January peak day with adverse weather and hydro has 0.5 bcf of additional demand in Northern California.
- The RIAMS model, which uses an inter-temporal optimization, indicates that storage fields in Northern California are capable of meeting all of the increase in peak demand, with negligible changes in pipeline flows.
  - In reality, it is likely that there would be somewhat lower storage withdrawals and an increase in pipeline flows.
  - However, even if storage withdrawals were lower, there is still ample pipeline capacity to meet the peak day demand.

Case 2: January 2020 Peak Day Flows in Northern California (MMcfd)



Storage Activity

		Withdrawals	Capability
a	Wild Goose	210	480
b	Pleasant Creek	49	70
c	Los Medanos	312	360
d	McDonald Island	896	1,200
e	Lodi	200	500
j	Kirby Hills	90	100
k	Sacramento	160	200
l	Gill Ranch	100	300
	North Total	**2,018**	**3,210**

Major Pipeline Interconnects

			Flow	Capacity
1	Malin	Total Delv to PG&E	1,213	2,021
		To Tuscarora	85	170
2	PG&E Delv to SoCal		290	564
	Kern River to PG&E		191	375

Demand

Res/Com	1,846
Industrial	355
Power	1,008
Total	**3,210**
Production	**143**

Case 2: The Impact of Adverse Weather/Hydro on California Gas Demand (continued)

- Average January demand is up about 0.4 bcfd in Central/Southern California, compared to Case 1.
- Pipeline flows are up, but storage withdrawals are very similar to Case 1.
- There is adequate pipeline and storage capacity in Central/Southern California to meet demand throughout the month of January.

Case 2: January 2020 Average Flows in Southern/Central California (MMcfd)

Major Pipeline Interconnects

		Flow	Capacity
1	Southern Trails Delv to PG&E	37	80
2	Kern River to PG&E	166	375
	to Mohave	1,240	1,650
3	Mohave Delv to SoCal (WR)	181	836
4	Mohave Delv to SoCal (KJ)	358	525
5	Mohave Delv to El Paso	377	500

Storage

		Withdrawals	Capability
f	La Goleta	104	350
g	Aliso Canyon	794	1,405
h	Honor Rancho	130	1,000
i	Playa del Ray	0	450
	Central/South Total	**1,028**	**3,205**

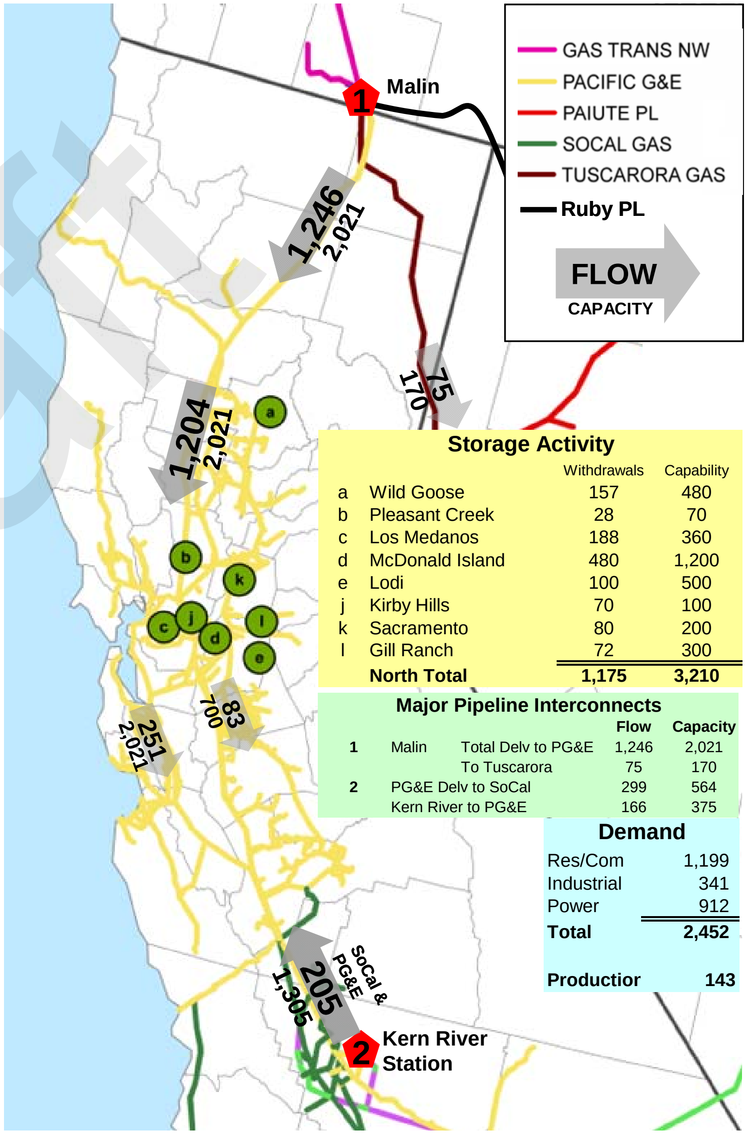
Demand

Res/Com	1,820
Industrial	1,168
Power	1,933
Total	**4,922**
Productior	**606**

Case 2: The Impact of Adverse Weather/Hydro on California Gas Demand (continued)

- Compared to Case 1, average January gas demand is up by 0.2 Bcfd in Northern California.
  - All of the increase in demand is met by increased withdrawals from storage.

Case 2: January 2020 Average Flows in Northern California (MMcfd)



	Storage Activity	Withdrawals	Capability
a	Wild Goose	157	480
b	Pleasant Creek	28	70
c	Los Medanos	188	360
d	McDonald Island	480	1,200
e	Lodi	100	500
j	Kirby Hills	70	100
k	Sacramento	80	200
l	Gill Ranch	72	300
	North Total	**1,175**	**3,210**

Major Pipeline Interconnects

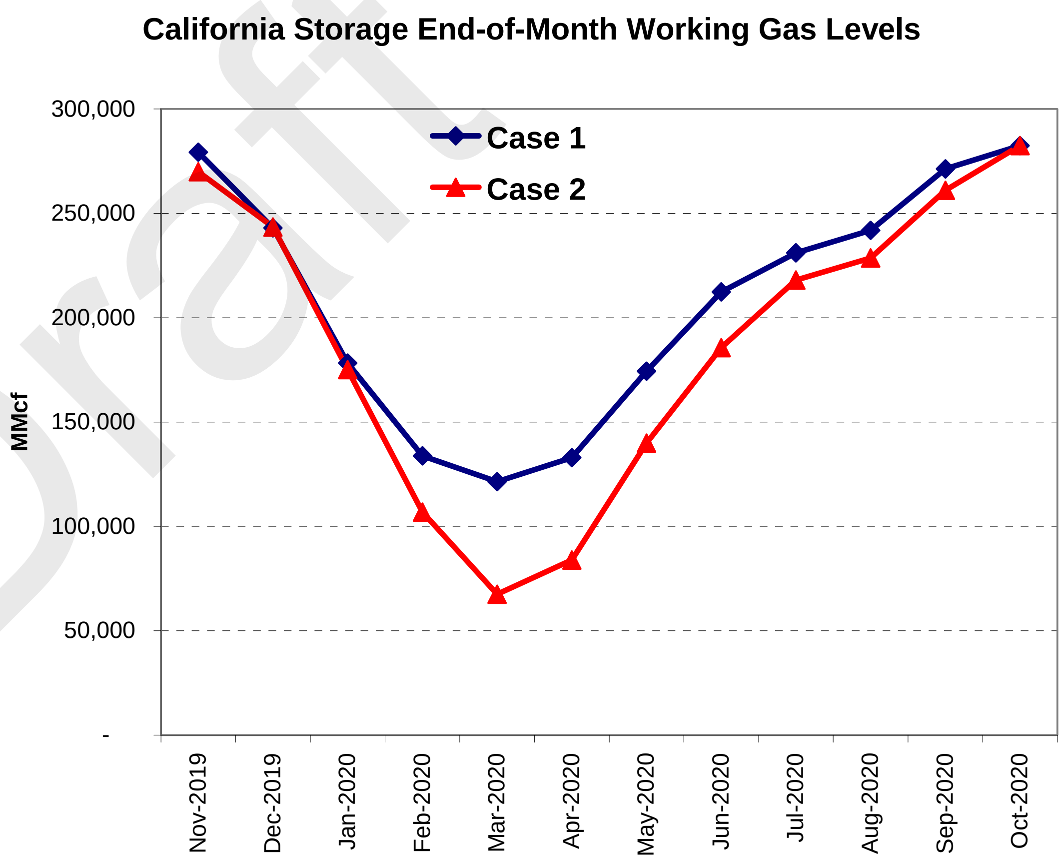
			Flow	Capacity
1	Malin	Total Delv to PG&E	1,246	2,021
		To Tuscarora	75	170
2	PG&E Delv to SoCal		299	564
	Kern River to PG&E		166	375

Demand

Res/Com	1,199
Industrial	341
Power	912
Total	**2,452**
Production	**143**

Case 2: The Impact of Adverse Weather/Hydro on California Gas Demand (continued)

- Under adverse weather/hydro conditions, the January working gas level only slightly lower than in Case 1.
- However, greater withdrawals in February and March drive the end-of-March working gas level to around 70 Bcf, or 22% of total capacity.



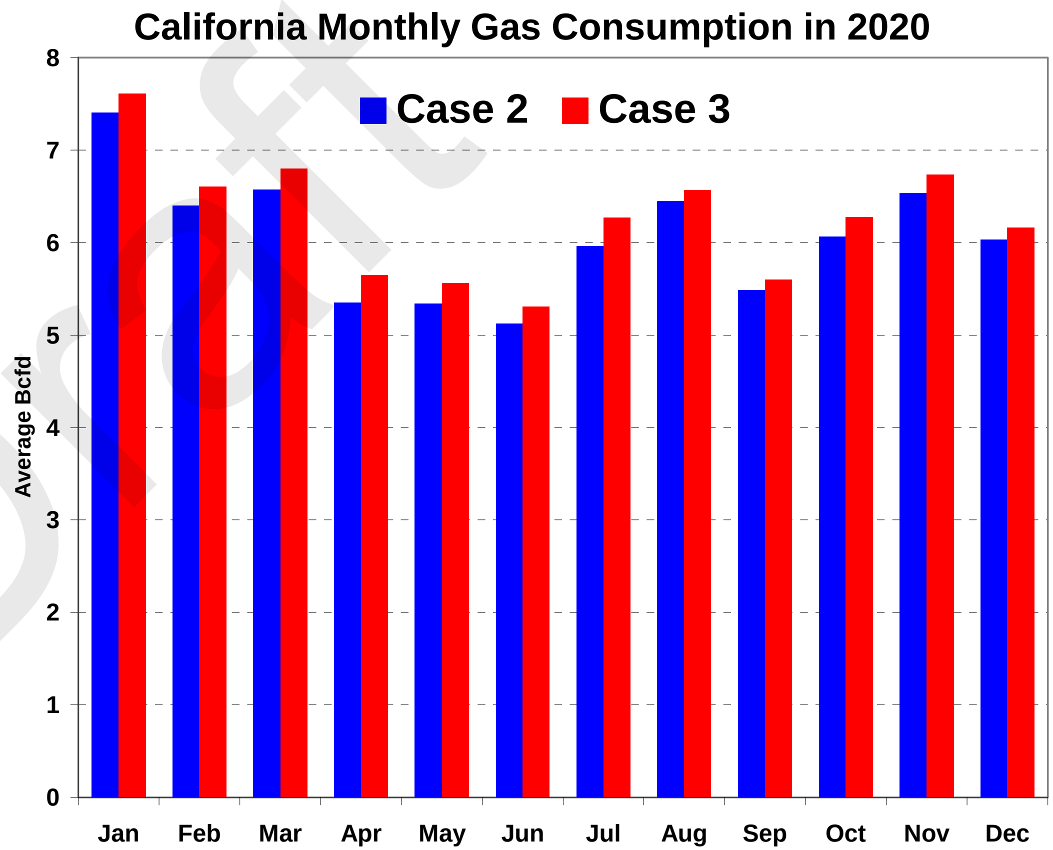
Case 3: The Impact of Reduced Renewable Generation in the 33% RPS Reference Case

- Case 3 reduces annual renewable generation in 2020 by 11 TWh (or about 11%) compared to the expected annual generation.
  - It also used the same adverse weather/hydro conditions as Case 2, so the results are being compared to that case.
  - The difference from Case 2 reflects the impact of reduced renewable generation.
- The reduction in renewable generation lead to an average annual increase in power generation gas demand of 0.2 Bcfd.

Bcfd	2020 Case 3	2020 *Delta vs Case 2*
Consumption	**6.26**	***0.20***
Residential	1.24	*(0.00)*
Commercial	0.65	*(0.00)*
Industrial	1.48	*(0.00)*
Power Generation	2.76	*0.21*
Other	0.13	*0.00*
Pipeline Exports	**0.06**	***(0.00)***
To Northern Nevada	0.01	*0.00*
To Mexico	0.05	*(0.00)*
Production	**0.85**	***0.00***
Pipeline Imports	**5.52**	***0.20***
via Southern Nevada (Kern River)	1.76	*(0.03)*
via Arizona (El Paso, Transwestern)	2.27	*0.16*
via Malin	1.45	*0.06*
via Mexico (Costa Azul LNG)	0.04	*0.01*
Storage Net Injections / (Withdrawals)	**-**	-
Balancing Item	**0.04**	***0.00***

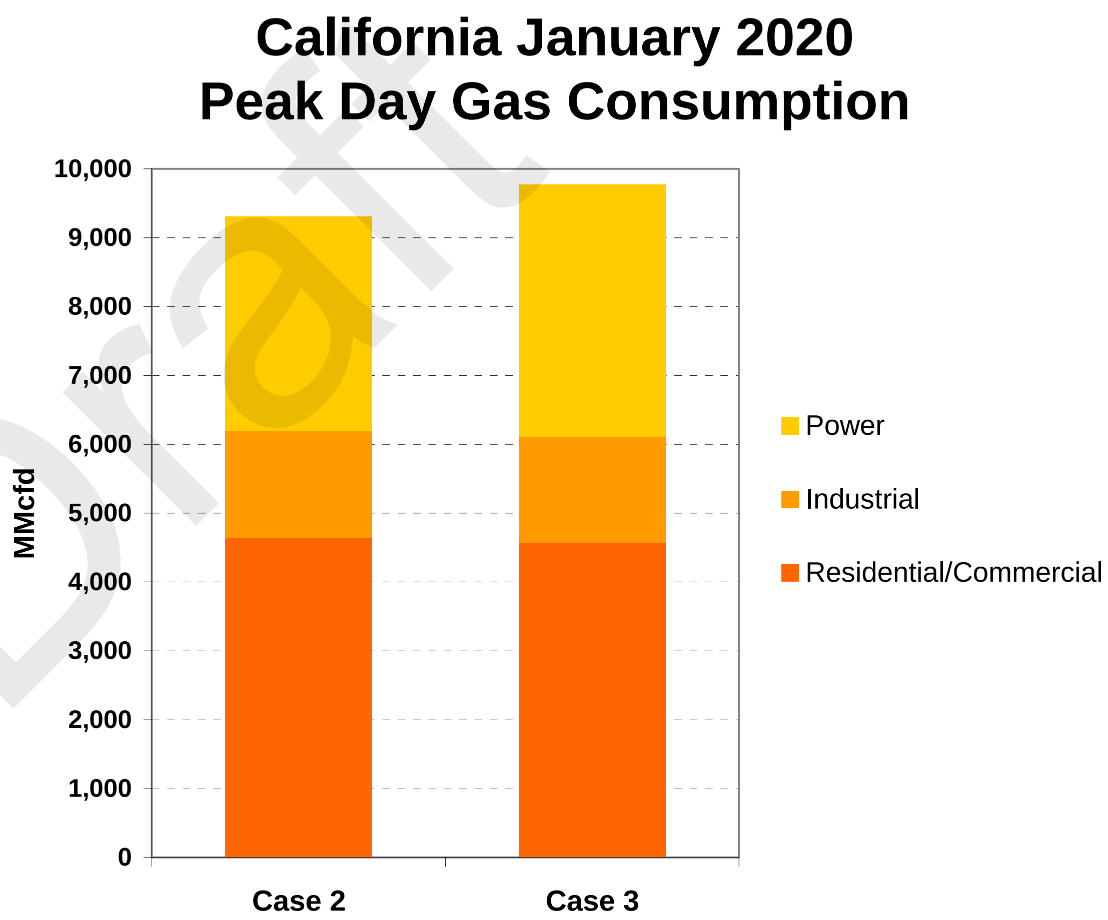
Case 3: The Impact of Reduced Renewable Generation in the 33% RPS Reference Case (continued)

- Compared to Case 2, monthly average gas consumption in Case 3 is up by 0.1 to 0.3 Bcfd.
- Peak month (January) average gas consumption is up by 0.2 Bcfd, about the same as the annual average increase.
- August gas demand is up another 0.1 Bcfd due to reductions in wind and solar generation.



Case 3: The Impact of Reduced Renewable Generation in the 33% RPS Reference Case (continued)

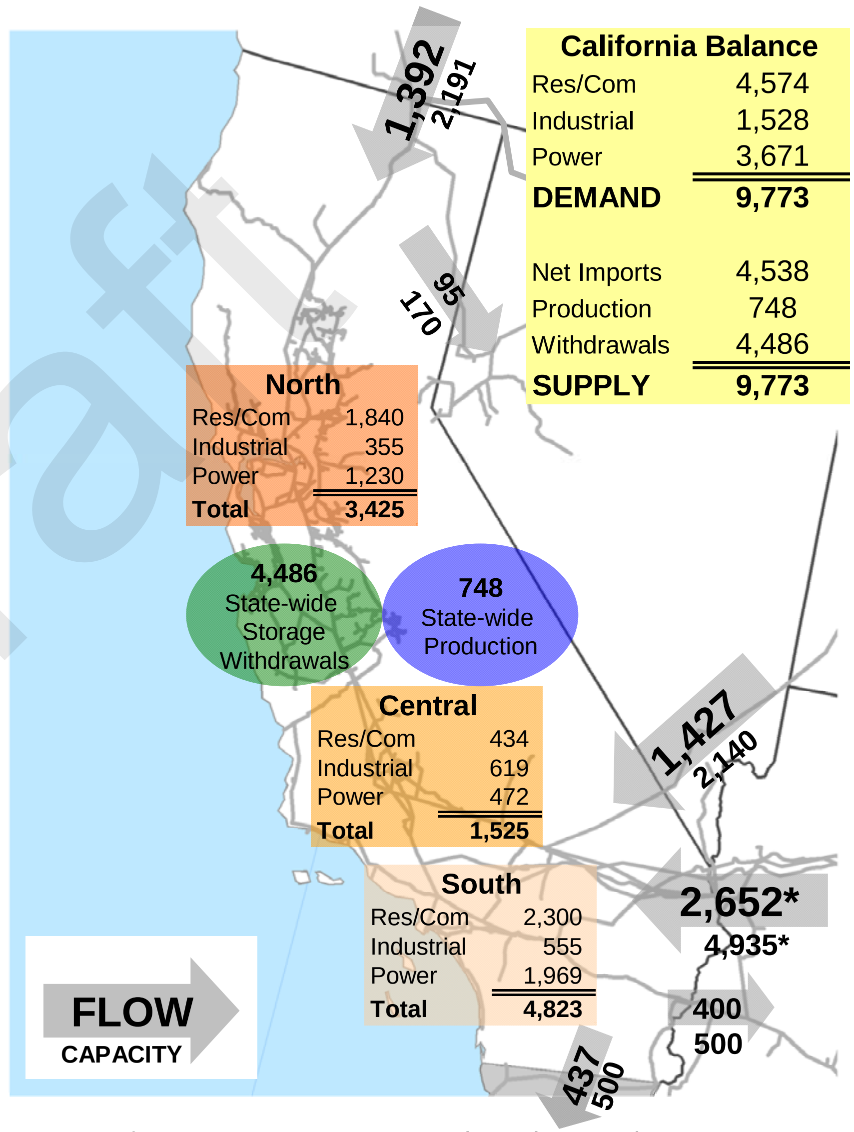
- January peak day gas consumption is about 0.5 Bcfd higher in Case 3, compared to Case 2.
- All of the increase in gas consumption is in the power sector.



Case 3: The Impact of Reduced Generation in the 33% RPS Reference Case (continued)

- January peak day gas consumption for power generation is up throughout the state, with a slightly greater increase in the South.
- The increase in consumption is met by increases in pipeline imports (+0.3 Bcfd) and storage withdrawals (+0.2 Bcfd).
  - Most of the increase in pipeline imports is from the El Paso system into Southern California.
  - Most of the increase in storage withdrawals is concentrated at the Aliso Canyon and Honor Rancho fields near Los Angeles.
- Storage withdrawals are at or near capacity at many fields in California.

Case 3: January 2020 Peak Day Balance (MMcfd)

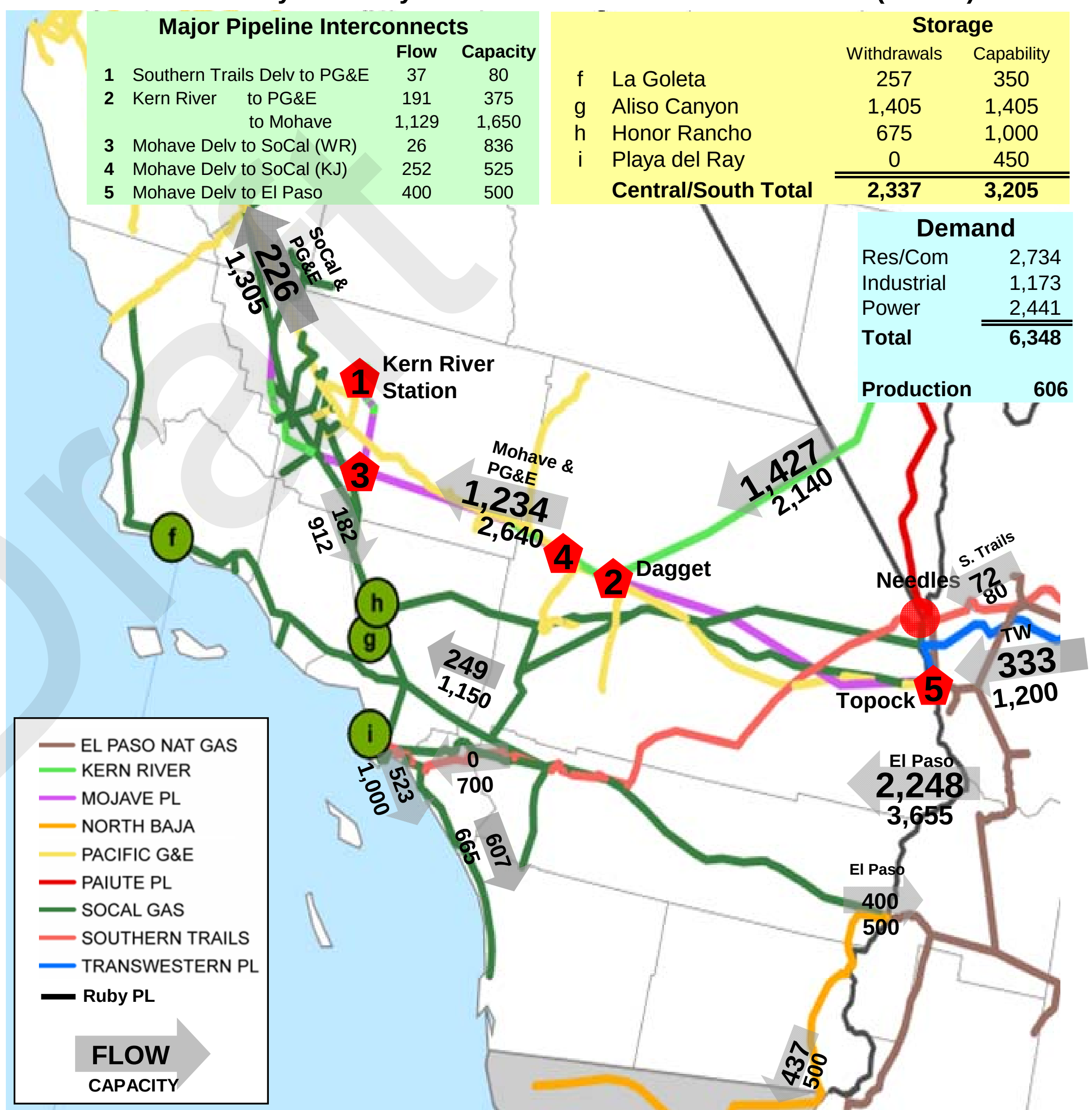


* Total of El Paso, Transwestern, and Southern Trails

Case 3: The Impact of Reduced Generation in the 33% RPS Reference Case (continued)

- The reduction in renewable generation causes a demand increase of about 0.3 bcf in Central/Southern California, compared to Case 2
  - The increased demand is met primarily by increased flows into California on El Paso pipeline.
  - Peak day storage withdrawals are about the same as in Case 2.
- For most of the area, pipeline and storage capacity is adequate to meet demand.
  - Load factors on pipelines serving San Diego county are over 90% - close to constrained, but still adequate.
  - Unlike the L.A. Basin, there is no gas storage in the San Diego area.
  - In August, when gas demand for power generation peaks, San Diego would be constrained under this scenario due to its lack of storage and limited pipeline options.

Case 3: January Peak Day Flows in Central/Southern California (MMcfd)



Major Pipeline Interconnects

		Flow	Capacity
1	Southern Trails Delv to PG&E	37	80
2	Kern River to PG&E	191	375
	to Mohave	1,129	1,650
3	Mohave Delv to SoCal (WR)	26	836
4	Mohave Delv to SoCal (KJ)	252	525
5	Mohave Delv to El Paso	400	500

Storage

		Withdrawals	Capability
f	La Goleta	257	350
g	Aliso Canyon	1,405	1,405
h	Honor Rancho	675	1,000
i	Playa del Ray	0	450
	Central/South Total	**2,337**	**3,205**

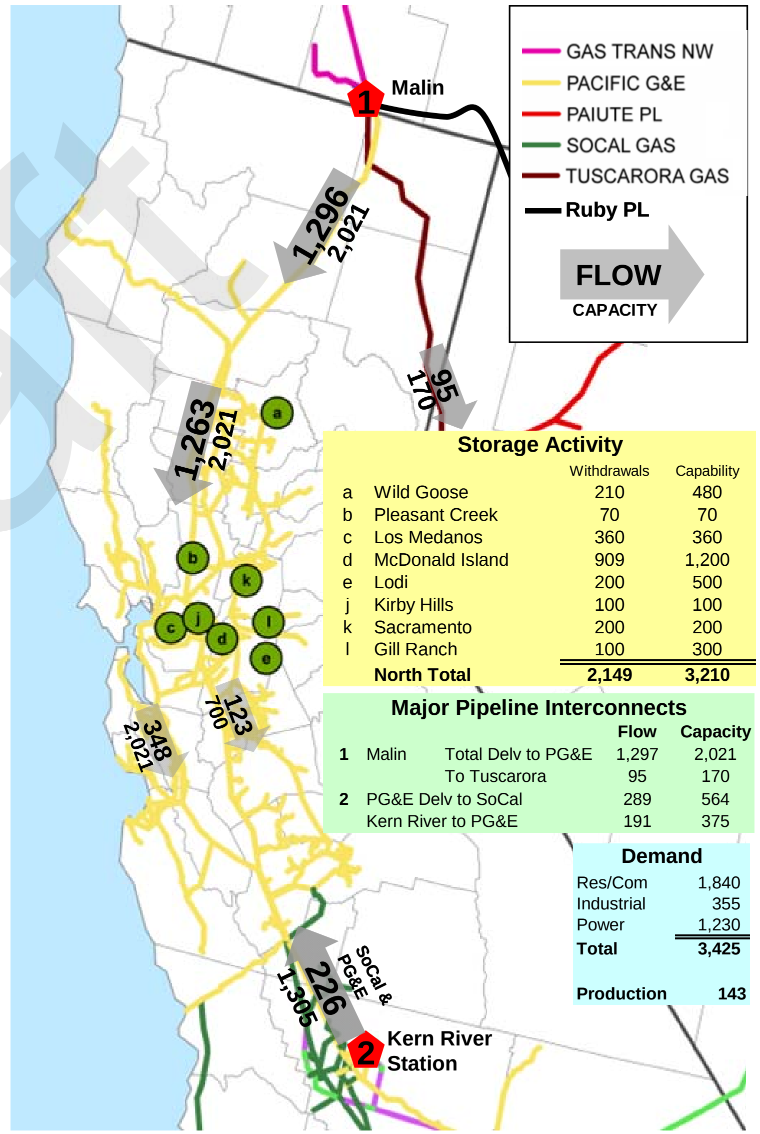
Demand

Res/Com	2,734
Industrial	1,173
Power	2,441
Total	**6,348**
Production	**606**

Case 3: The Impact of Reduced Generation in the 33% RPS Reference Case (continued)

- January peak day demand in Northern California is up by 0.2 Bcf, compared to Case 2.
  - Pipeline flows from Malin increase by 0.08 Bcf, while storage is up by 0.12 Bcf.
- Four storage fields (Pleasant Creek, Los Medanos, Kirby Hills and Sacramento) are withdrawing at full capability.
  - RIAMS optimization method may result in high withdrawals at particular fields because they are close to load centers.
  - However, even if withdrawals at these fields were lower, there is adequate pipeline capacity and storage withdrawal capability at other fields to meet peak day demand.

Case 3: January Peak Day Flows in Northern California (MMcfd)



Storage Activity

		Withdrawals	Capability
a	Wild Goose	210	480
b	Pleasant Creek	70	70
c	Los Medanos	360	360
d	McDonald Island	909	1,200
e	Lodi	200	500
j	Kirby Hills	100	100
k	Sacramento	200	200
l	Gill Ranch	100	300
	North Total	**2,149**	**3,210**

Major Pipeline Interconnects

			Flow	Capacity
1	Malin	Total Delv to PG&E	1,297	2,021
		To Tuscarora	95	170
2	PG&E Delv to SoCal		289	564
	Kern River to PG&E		191	375

Demand

Res/Com	1,840
Industrial	355
Power	1,230
Total	**3,425**
Production	**143**

Case 3: The Impact of Reduced Generation in the 33% RPS Reference Case (continued)

- Average January demand in Central/Southern California is up by 0.1 Bcfd, compared to Case 2.
  - All of the increase in demand is met by increased in-bound flows on El Paso.
- There is adequate pipeline and storage capacity in Central/Southern California to meet demand throughout the month of January.

Case 3: January 2020 Average Flows in Southern/Central California (MMcfd)

Major Pipeline Interconnects

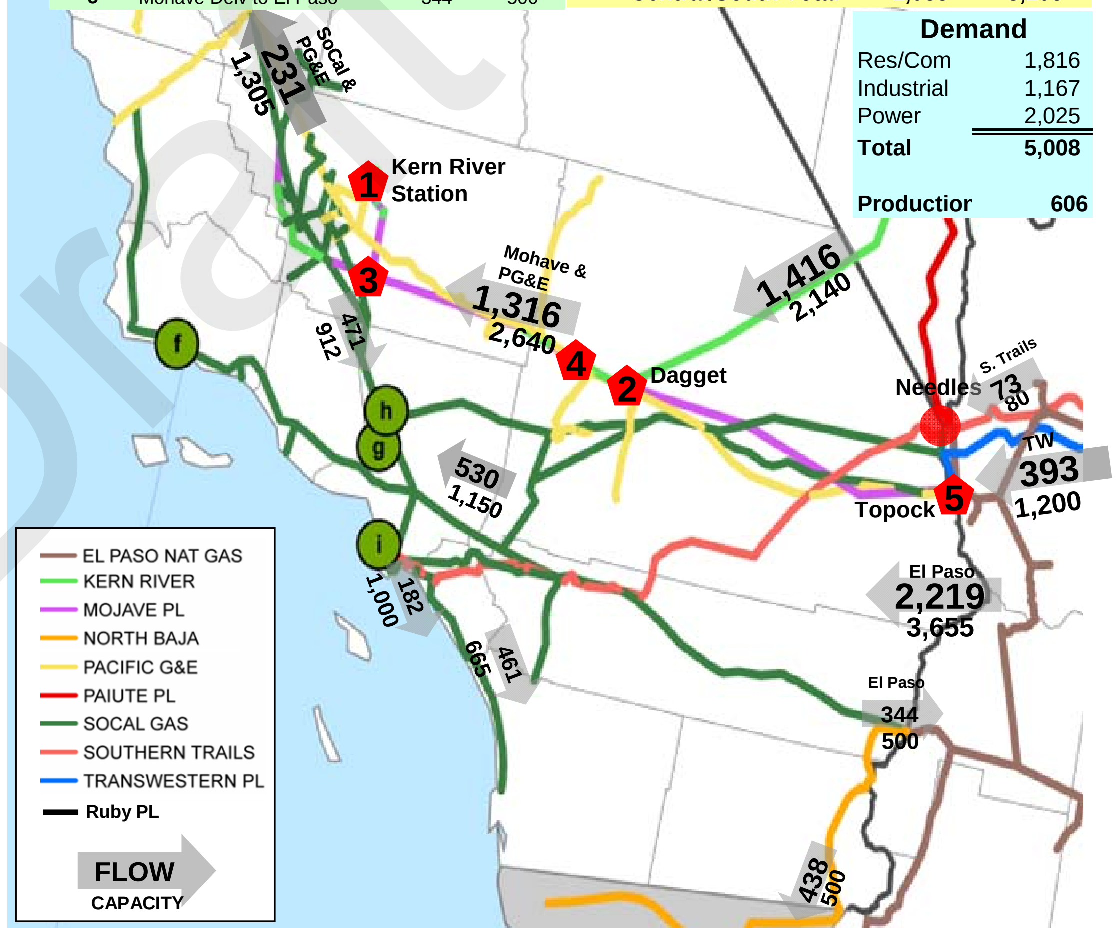
		Flow	Capacity
1	Southern Trails Delv to PG&E	38	80
2	Kern River to PG&E	159	375
	to Mohave	1,175	1,650
3	Mohave Delv to SoCal (WR)	207	836
4	Mohave Delv to SoCal (KJ)	295	525
5	Mohave Delv to El Paso	344	500

Storage

		Withdrawals	Capability
f	La Goleta	73	350
g	Aliso Canyon	854	1,405
h	Honor Rancho	105	1,000
i	Playa del Ray	1	450
	Central/South Total	**1,033**	**3,205**

Demand

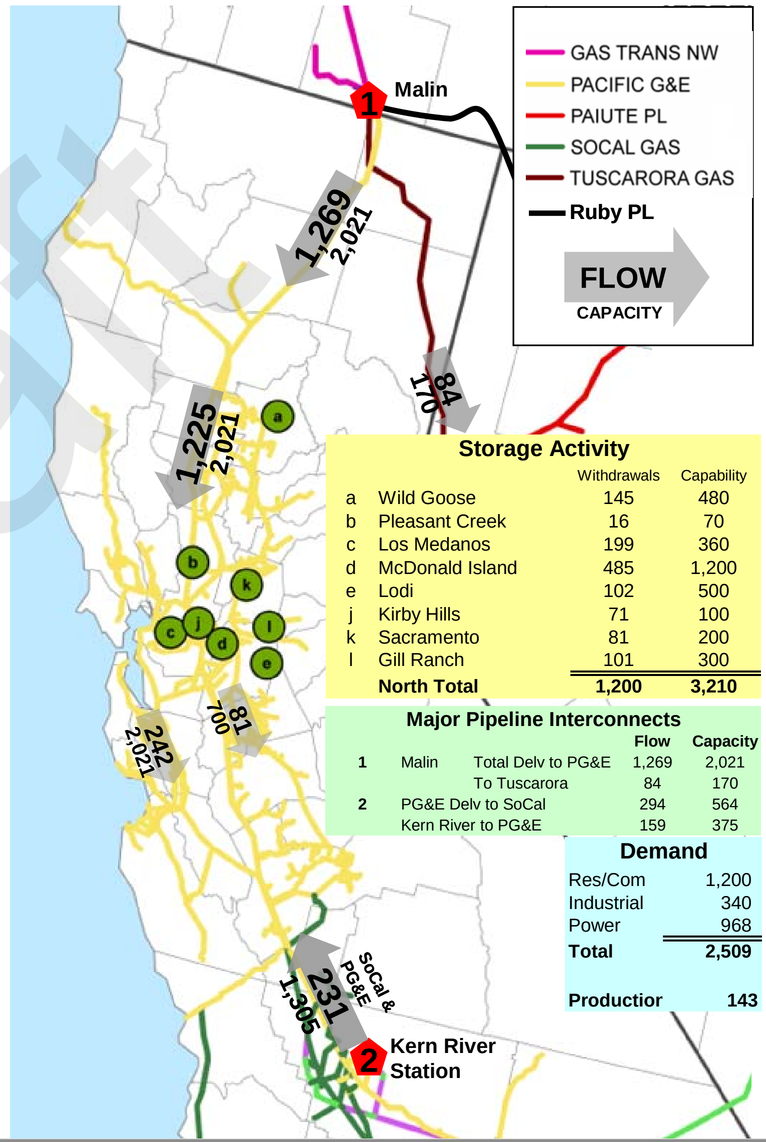
Res/Com	1,816
Industrial	1,167
Power	2,025
Total	**5,008**
Productior	**606**



Case 3: The Impact of Reduced Generation in the 33% RPS Reference Case (continued)

- In Northern California, average January demand is up by just 0.05 Bcfd, compared to Case 2.
  - The increase demand is met by increases in both the pipeline flows from Malin and storage withdrawals.

Case 3: January 2020 Average Flows in Northern California (MMcfd)



Storage Activity

		Withdrawals	Capability
a	Wild Goose	145	480
b	Pleasant Creek	16	70
c	Los Medanos	199	360
d	McDonald Island	485	1,200
e	Lodi	102	500
j	Kirby Hills	71	100
k	Sacramento	81	200
l	Gill Ranch	101	300
	North Total	**1,200**	**3,210**

Major Pipeline Interconnects

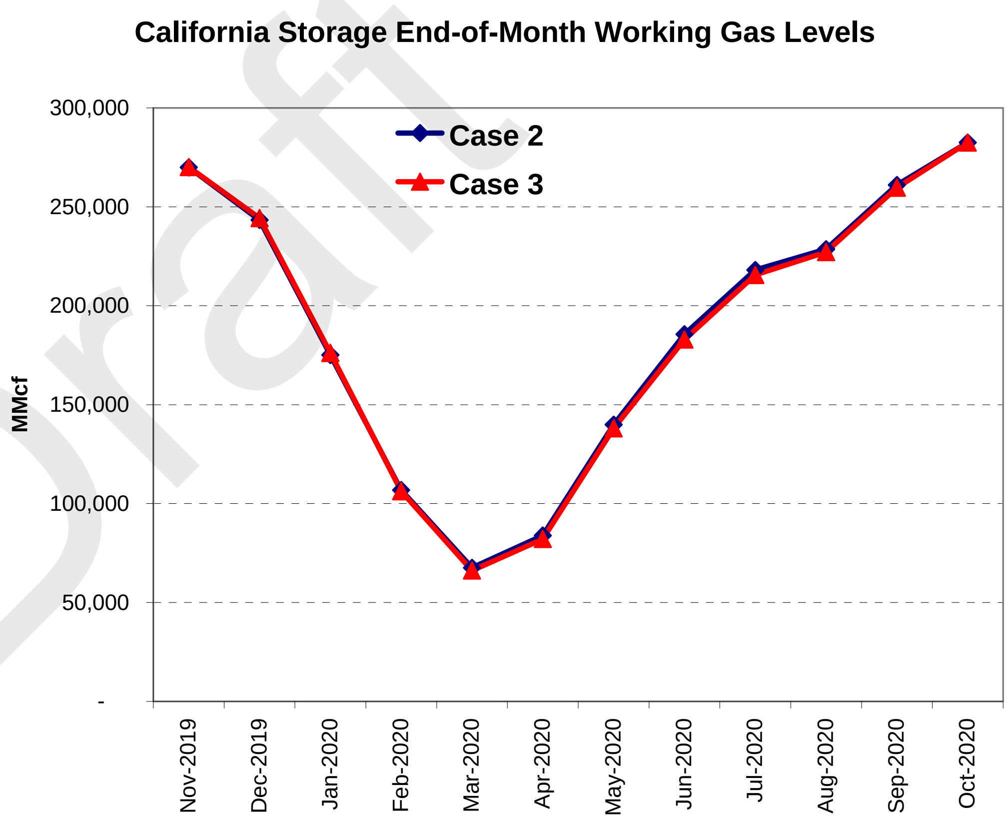
			Flow	Capacity
1	Malin	Total Delv to PG&E	1,269	2,021
		To Tuscarora	84	170
2	PG&E Delv to SoCal		294	564
	Kern River to PG&E		159	375

Demand

Res/Com	1,200
Industrial	340
Power	968
Total	**2,509**
Production	**143**

Case 3: The Impact of Reduced Renewable Generation in the 33% RPS Reference Case (continued)

- While peak day storage withdrawals in Case 3 are higher, the total withdrawals for January are about the same as in Case 2.
- Also, the seasonal injection/withdrawal pattern in Case 3 is nearly identical to Case 2.



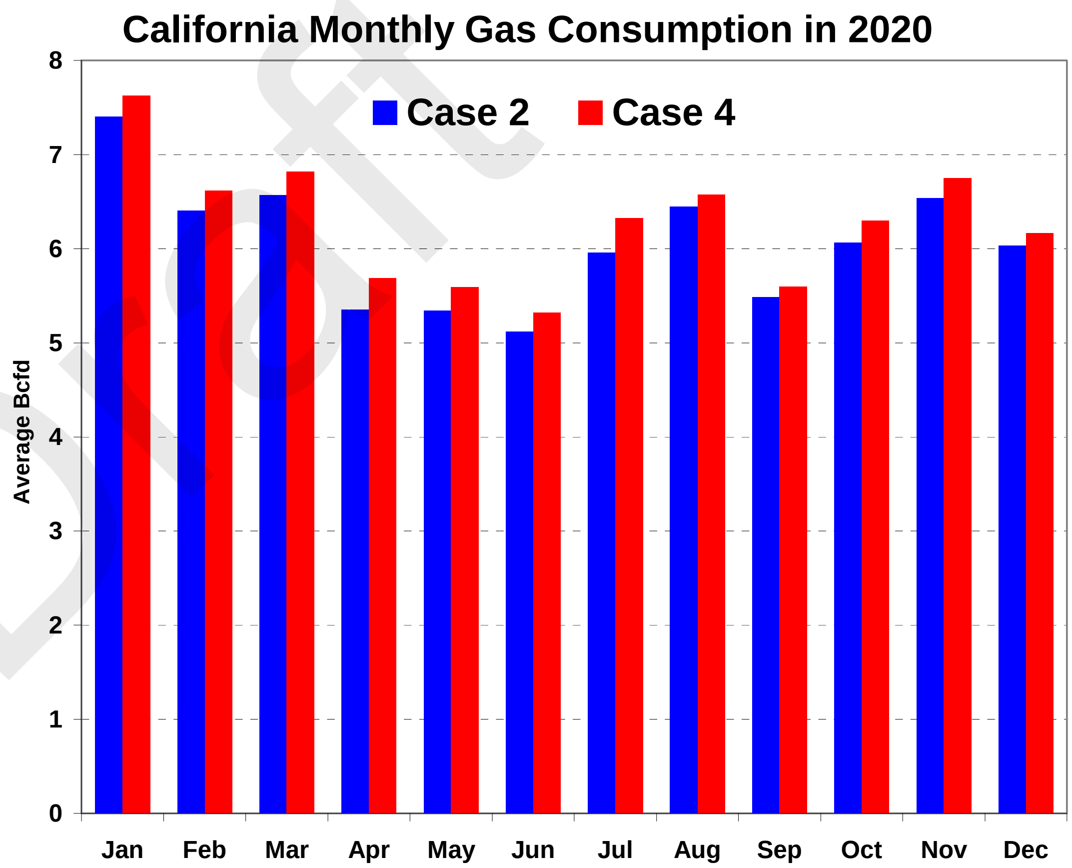
Case 4: The Impact of Reduced Renewable Generation in the 33% RPS High Wind Case

- Case 4 reduces annual renewable generation in 2020 by 12 TWh (or about 12%) compared to the expected annual generation.
  - Of the three reduced renewable generation cases, this case has the greatest reduction in annual generation, but only by 1 TWh.
  - It also used the same adverse weather/hydro conditions as Case 2, so the results are being compared to that case.
- The reduction in renewable generation lead to an average annual increase in power generation gas demand of 0.22 Bcfd, just slightly higher than the increase seen in Case 3.

	2020	
Bcfd	Case 4	*Delta vs Case 2*
Consumption	**6.28**	***0.22***
Residential	1.24	*(0.00)*
Commercial	0.65	*(0.00)*
Industrial	1.48	*(0.00)*
Power Generation	2.78	*0.22*
Other	0.13	*0.00*
Pipeline Exports	**0.06**	***(0.00)***
To Northern Nevada	0.01	*0.00*
To Mexico	0.05	*(0.00)*
Production	**0.85**	***0.00***
Pipeline Imports	**5.54**	***0.22***
via Southern Nevada (Kern River)	1.76	*(0.03)*
via Arizona (El Paso, Transwestern)	2.28	*0.18*
via Malin	1.46	*0.07*
via Mexico (Costa Azul LNG)	0.04	*0.01*
Storage Net Injections / (Withdrawals)	**-**	-
Balancing Item	**0.04**	***0.00***

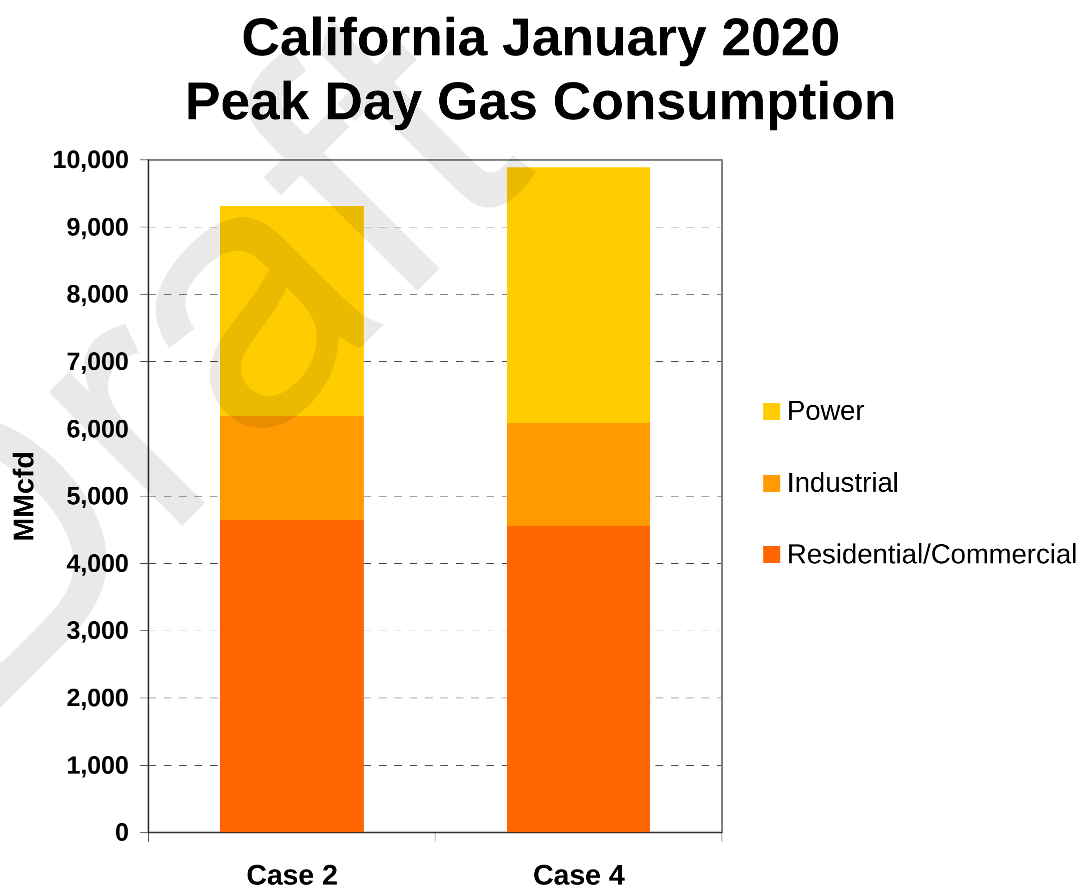
Case 4: The Impact of Reduced Renewable Generation in the 33% RPS High Wind Case (continued)

- Compared to Case 2, monthly average gas consumption in Case 4 is up by 0.1 to 0.4 Bcfd.
    - These increases in monthly average consumption are just slightly higher than in Case 3.
- Peak month (January) average gas consumption is up by 0.22 Bcfd, about the same as the annual average increase.
- August gas consumption is up by 0.1 Bcfd due to reduced wind and solar generation.



Case 4: The Impact of Reduced Renewable Generation in the 33% RPS High Wind Case (continued)

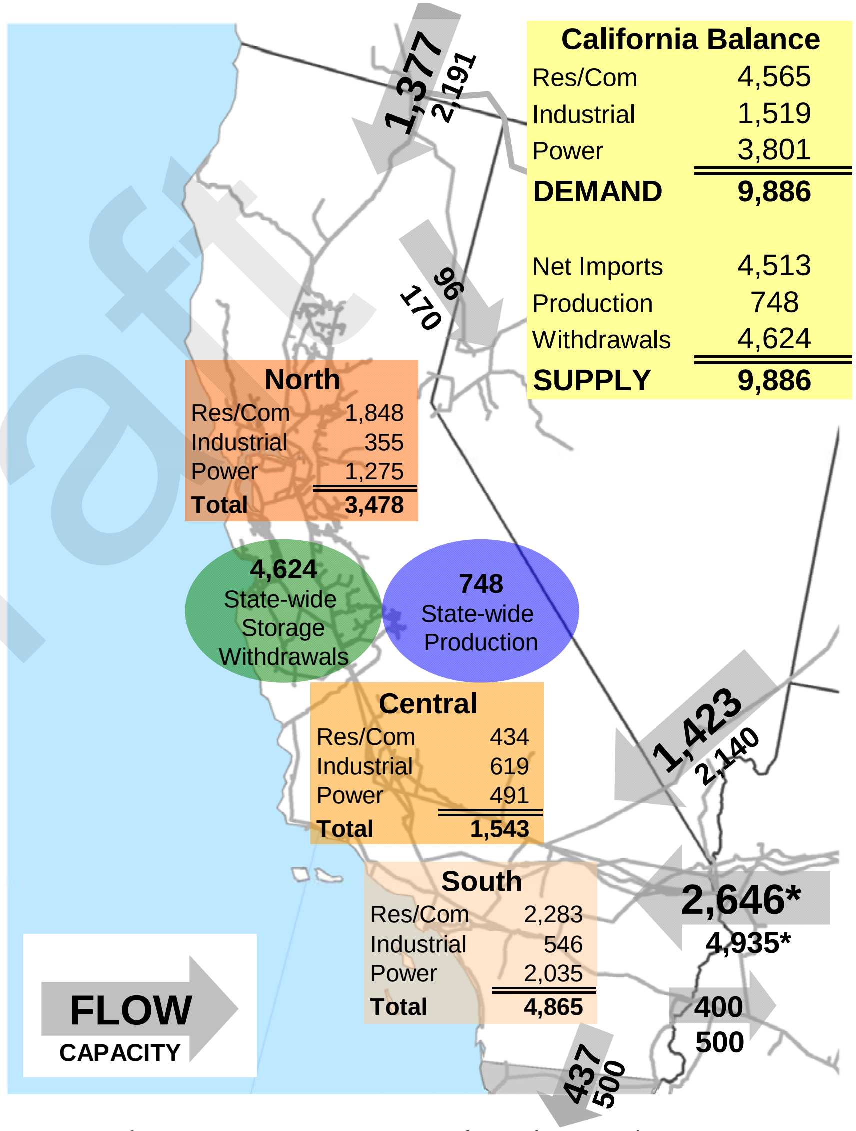
- Peak day consumption is about 0.5 Bcfd higher in Case 4, compared to Case 2.
- All of the increase in gas consumption is in the power sector.



Case 4: The Impact of Reduced Generation in the 33% RPS High Wind Case (continued)

- Compared to Case 2, January peak-day gas consumption for power generation is up throughout the state, with a slightly greater increase in the South.
- The increase in consumption is met by increases in pipeline imports (+0.2 Bcf) and storage withdrawals (+0.3 Bcf).
  - Most of the increase in pipeline imports is from the El Paso system into Southern California.
  - Most of the increase in storage withdrawals is concentrated at the Aliso Canyon and Honor Rancho fields near Los Angeles.
- Storage withdrawals are at or near capacity at many fields in California.

Case 4: January 2020 Peak Day Balance (MMcfd)

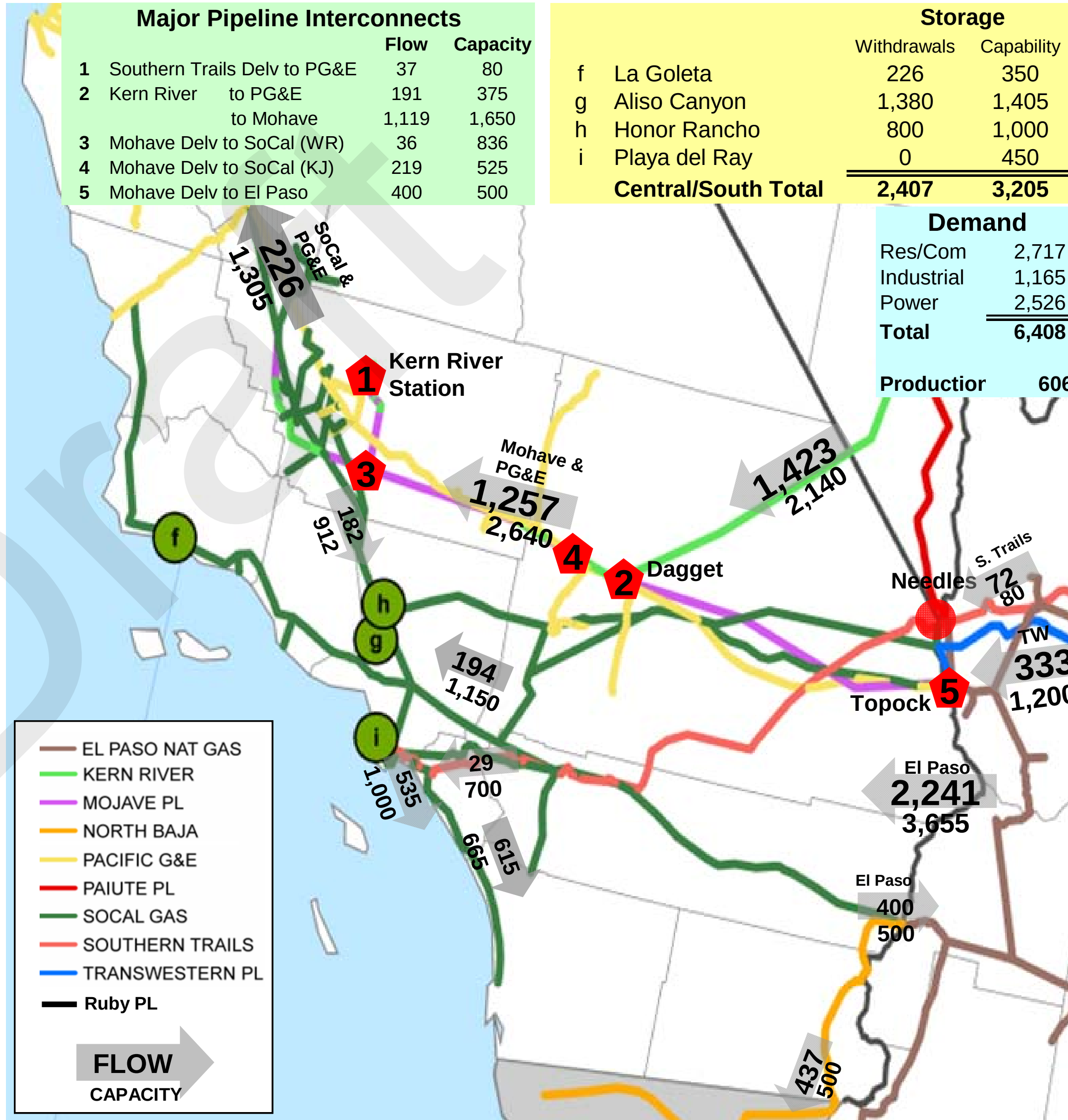


* Total of El Paso, Transwestern, and Southern Trails

Case 4: The Impact of Reduced Generation in the 33% RPS High Wind Case (continued)

- The reduction in renewable generation causes a demand increase of about 0.3 Bcf in Central/Southern California, compared to Case 2
  - Most of the increase in demand is met primarily by increased flows into California on El Paso pipeline, with a small increase in storage withdrawals.
- Generally, pipeline and storage capacity is adequate to meet demand within this area.
  - Again, the January peak day load factors on pipelines serving San Diego county are over 90% - close to constrained, but still adequate.
  - In August, when gas demand for power generation peaks, San Diego would be constrained under this scenario due to its lack of storage and limited pipeline options.

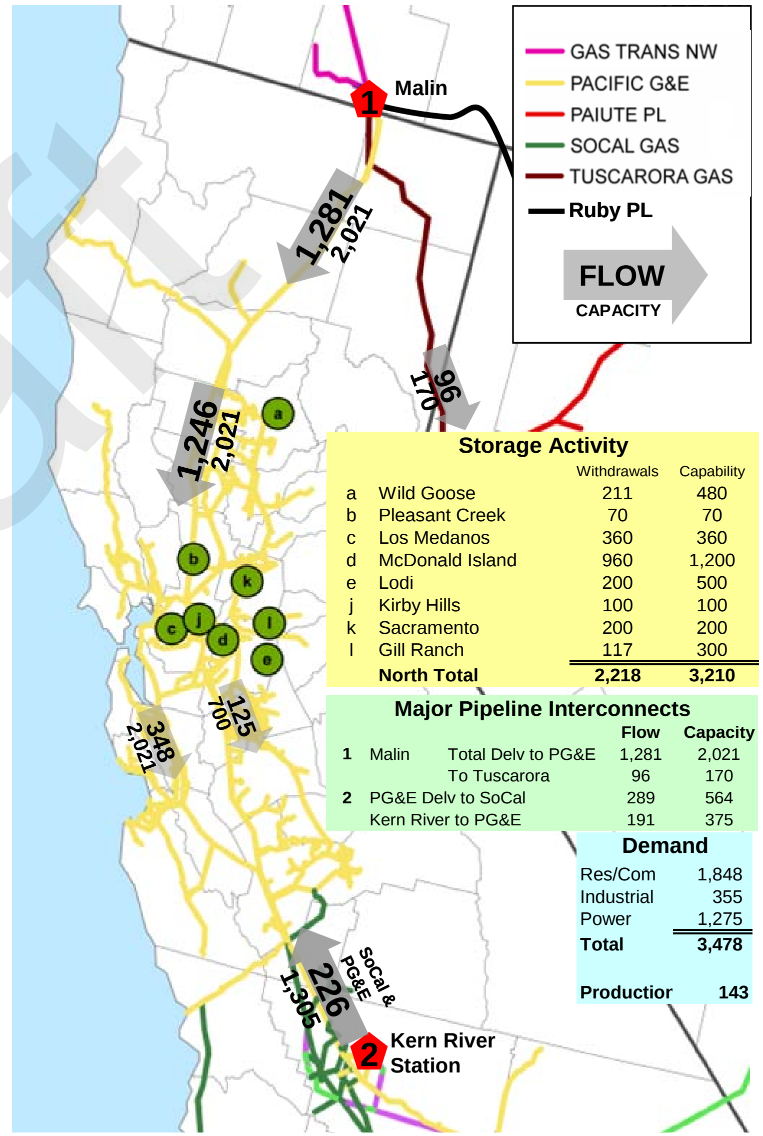
Case 4: January 2020 Peak Day Flows in Central/Southern California (MMcfd)



Case 4: The Impact of Reduced Generation in the 33% RPS High Wind Case (continued)

- January peak day demand in Northern California is up by 0.25 Bcf, compared to Case 2.
  - Storage withdrawals are up by 0.2 Bcf, and the rest of the increased demand is met by increased flows from Malin.
- As in Case 3, four of the eight storage fields in Northern California are withdrawing at their full capability.
  - Even if withdrawals at these fields were lower, there is adequate pipeline capacity and storage withdrawal capability at other fields to meet peak day demand.

Case 4: January 2020 Peak Day Flows in Northern California (MMcfd)



Storage Activity

		Withdrawals	Capability
a	Wild Goose	211	480
b	Pleasant Creek	70	70
c	Los Medanos	360	360
d	McDonald Island	960	1,200
e	Lodi	200	500
j	Kirby Hills	100	100
k	Sacramento	200	200
l	Gill Ranch	117	300
	North Total	**2,218**	**3,210**

Major Pipeline Interconnects

			Flow	Capacity
1	Malin	Total Delv to PG&E	1,281	2,021
		To Tuscarora	96	170
2	PG&E Delv to SoCal		289	564
	Kern River to PG&E		191	375

Demand

Res/Com	1,848
Industrial	355
Power	1,275
Total	**3,478**
Productior	**143**

Case 4: The Impact of Reduced Generation in the 33% RPS High Wind Case (continued)

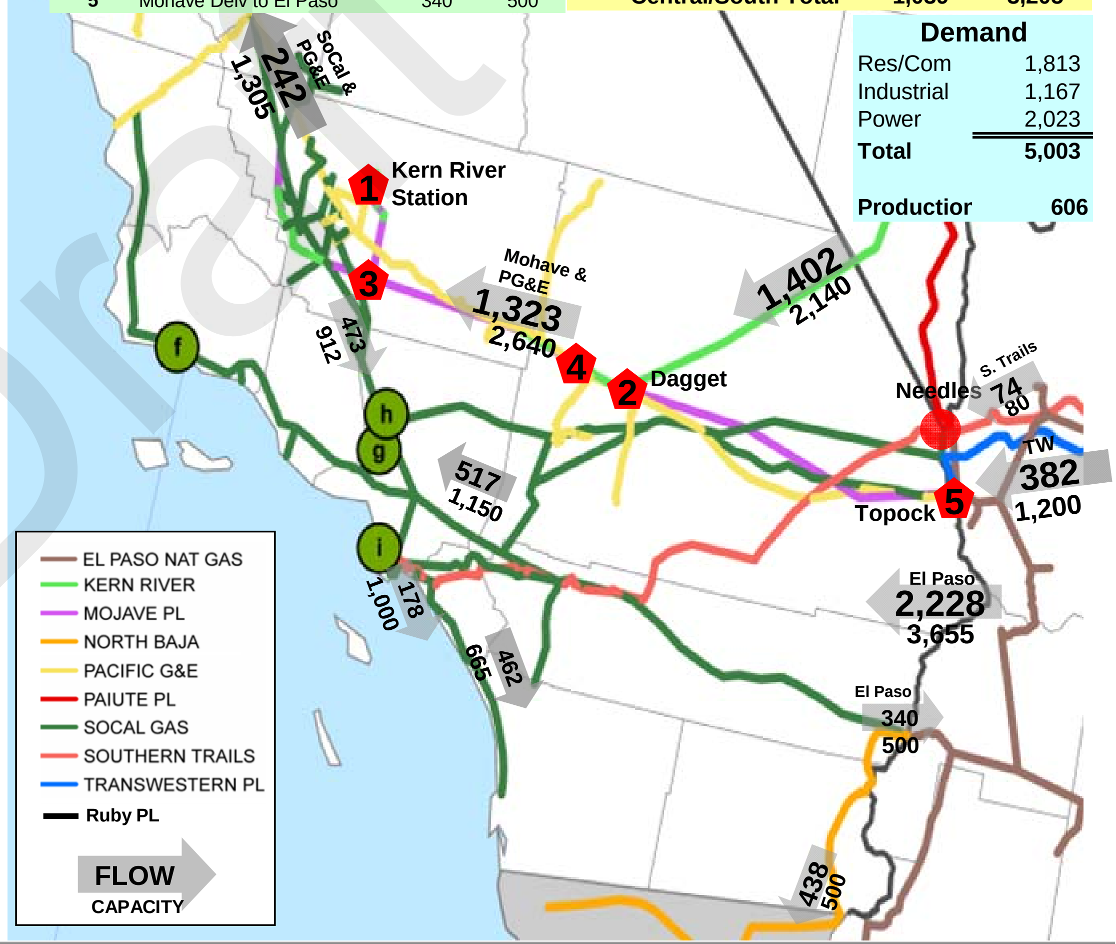
- The average January results for Central/Southern California in Case 4 are very similar to those in Case 3.
  - The reduction in renewable generation causes a demand increase of about 0.1 bcf in Central/Southern California, compared to Case 2
  - The increased demand is met primarily by increased flows into California on El Paso pipeline.
  - Peak day storage withdrawals are about the same as in Case 2.
- There is adequate pipeline and storage capacity in Central/Southern California to meet demand throughout the month of January.

Case 4: January 2020 Average Flows in Southern/Central California (MMcfd)

	Major Pipeline Interconnects		Flow	Capacity
1	Southern Trails Delv to PG&E		39	80
2	Kern River	to PG&E	156	375
		to Mohave	1,163	1,650
3	Mohave Delv to SoCal (WR)		218	836
4	Mohave Delv to SoCal (KJ)		288	525
5	Mohave Delv to El Paso		340	500

	Storage	Withdrawals	Capability
f	La Goleta	74	350
g	Aliso Canyon	772	1,405
h	Honor Rancho	184	1,000
i	Playa del Ray	10	450
	Central/South Total	1,039	3,205

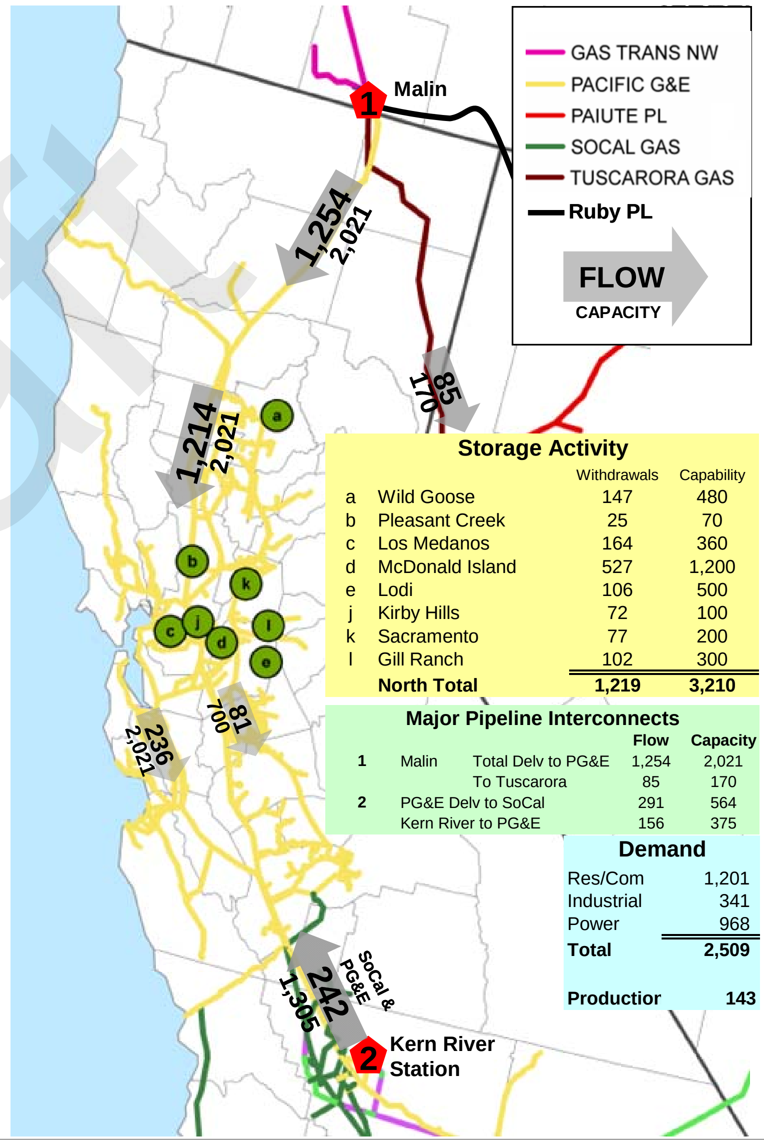
Demand	
Res/Com	1,813
Industrial	1,167
Power	2,023
Total	5,003
Productior	606



Case 4: The Impact of Reduced Generation in the 33% RPS High Wind Case (continued)

- The average January results for Northern California in Case 4 are very similar to those in Case 3.
  - In Northern California, average January demand is about 0.05 Bcfd higher due to the reduction in renewable generation.
  - The increase demand is met by slight increases in both pipeline flows and storage withdrawals.

Case 4: January 2020 Average Flows in Northern California (MMcfd)



Storage Activity

		Withdrawals	Capability
a	Wild Goose	147	480
b	Pleasant Creek	25	70
c	Los Medanos	164	360
d	McDonald Island	527	1,200
e	Lodi	106	500
j	Kirby Hills	72	100
k	Sacramento	77	200
l	Gill Ranch	102	300
	North Total	**1,219**	**3,210**

Major Pipeline Interconnects

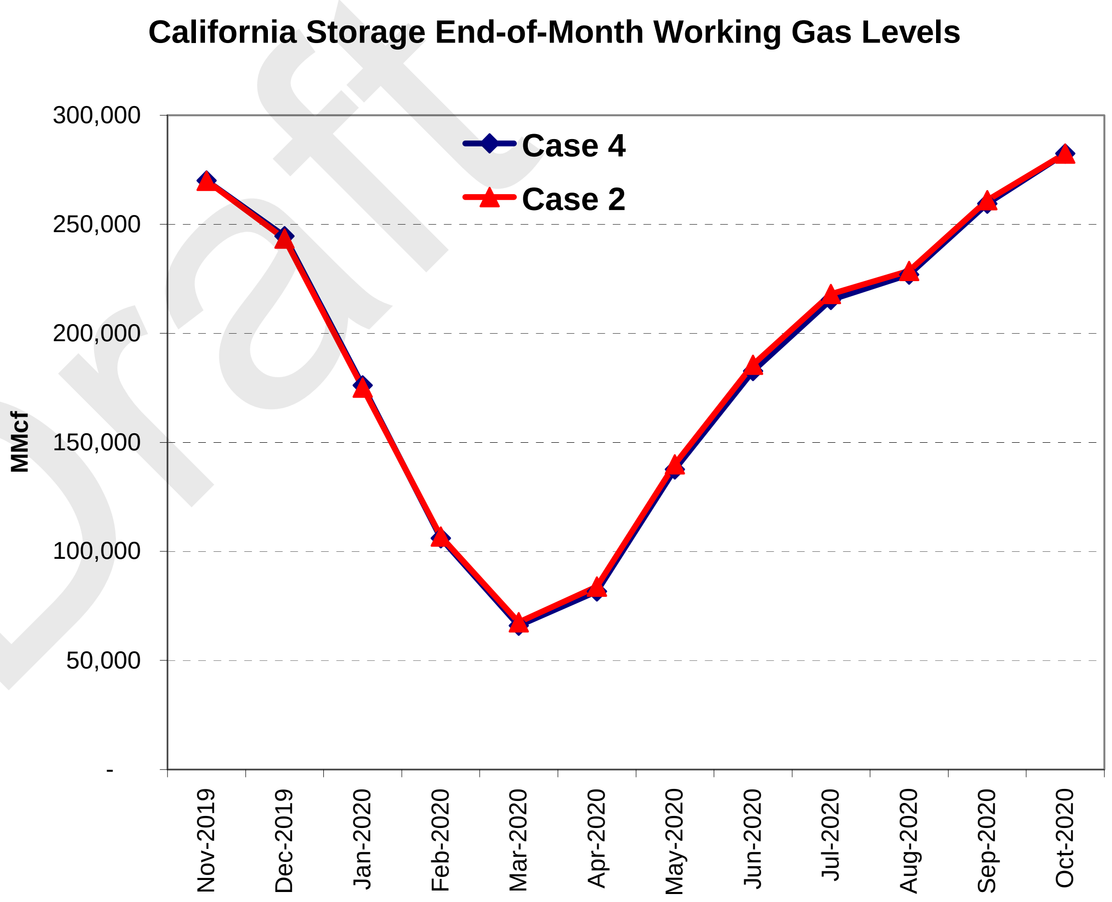
			Flow	Capacity
1	Malin	Total Delv to PG&E	1,254	2,021
		To Tuscarora	85	170
2	PG&E Delv to SoCal		291	564
	Kern River to PG&E		156	375

Demand

Res/Com	1,201
Industrial	341
Power	968
Total	**2,509**
Production	**143**

Case 4: The Impact of Reduced Renewable Generation in the 33% RPS High Wind Case (continued)

- While peak day storage withdrawals in Case 4 are higher, the total withdrawals for January are about the same as in Case 2.
- Also, the seasonal injection/withdrawal pattern in Case 4 is nearly identical to Case 2.



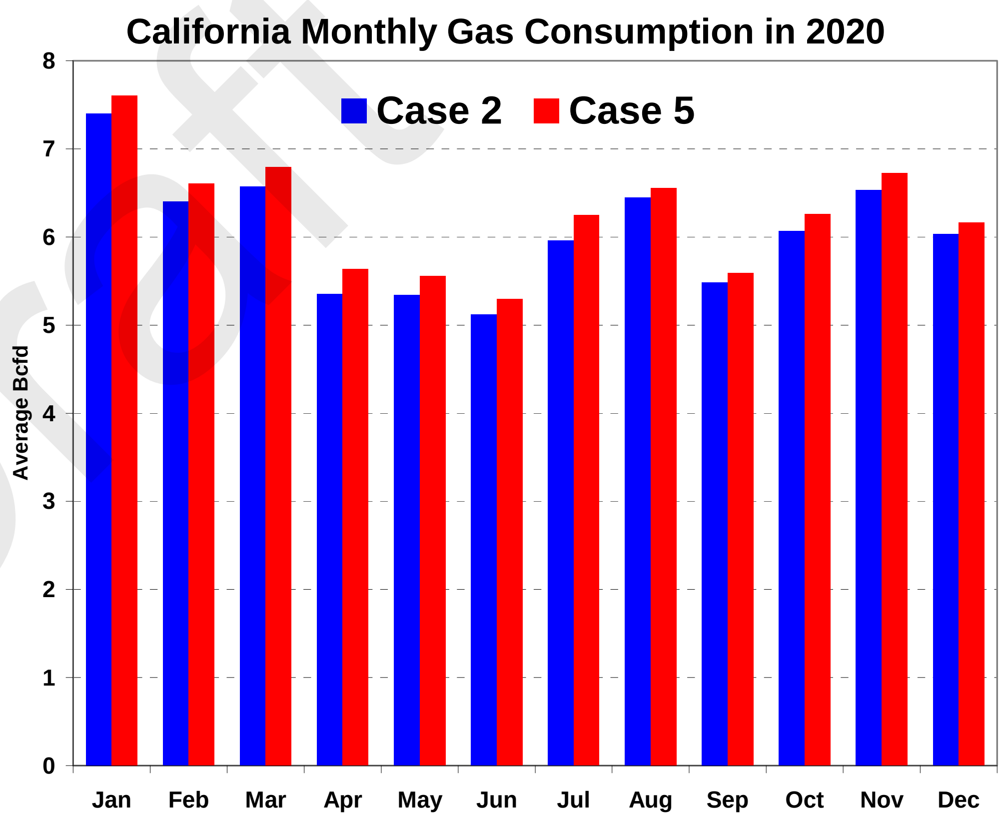
Case 5: The Impact of Reduced Renewable Generation in the 33% RPS Solar Case

- Case 5 reduces annual renewable generation in 2020 by 10 TWh (or about 10%) compared to the expected annual generation.
  - Of the three reduced renewable generation cases, this case has the smallest reduction in annual generation, though it differs from Case 3 by only 0.2 TWh.
  - It also used the same adverse weather/hydro conditions as Case 2, so the results are being compared to that case.
- The reductions in renewable generation lead to an average annual increase in power generation gas demand of 0.19 Bcfd.

	2020	
Bcfd	Case 5	*Delta vs Case 2*
Consumption	**6.26**	***0.19***
Residential	1.24	*(0.00)*
Commercial	0.65	*(0.00)*
Industrial	1.48	*(0.00)*
Power Generation	2.76	*0.20*
Other	0.13	*0.00*
Pipeline Exports	**0.06**	***(0.00)***
To Northern Nevada	0.01	*0.00*
To Mexico	0.05	*(0.00)*
Production	**0.85**	***0.00***
Pipeline Imports	**5.51**	***0.19***
via Southern Nevada (Kern River)	1.76	*(0.02)*
via Arizona (El Paso, Transwestern)	2.26	*0.15*
via Malin	1.45	*0.06*
via Mexico (Costa Azul LNG)	0.04	*0.00*
Storage Net Injections / (Withdrawals)	**-**	-
Balancing Item	**0.04**	***0.00***

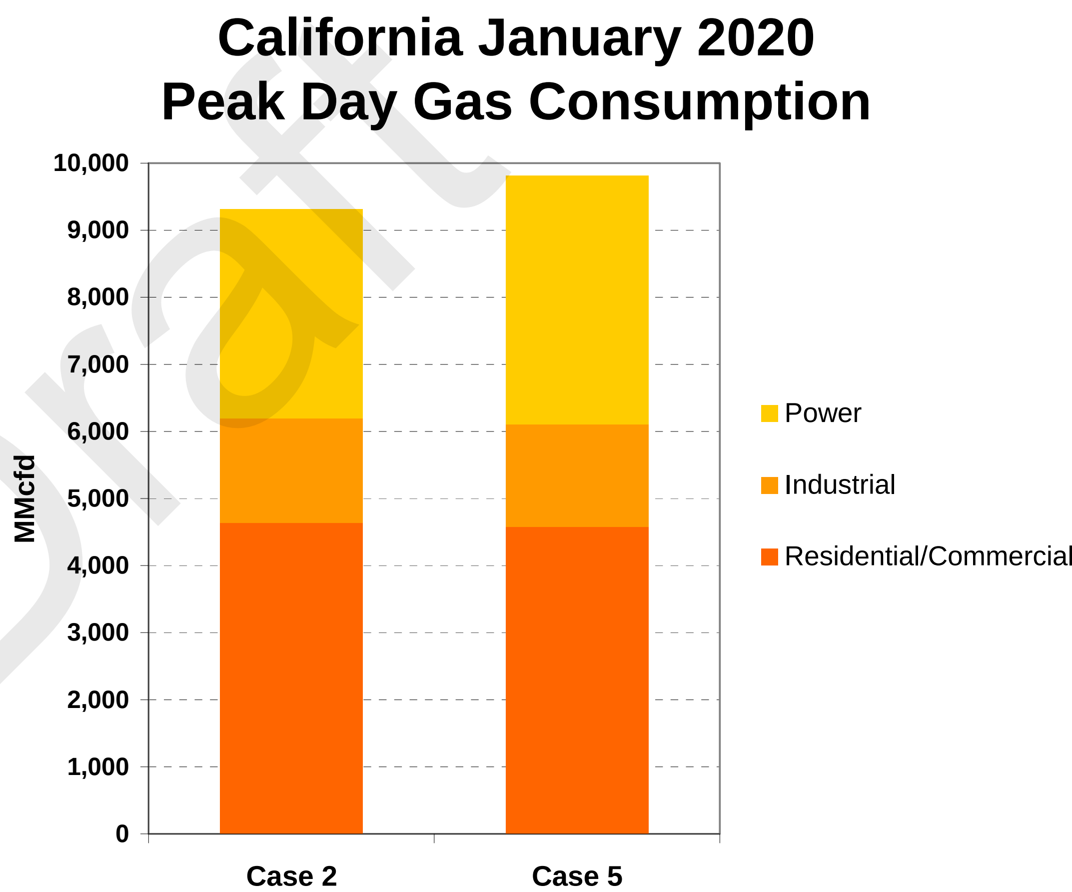
Case 5: The Impact of Reduced Renewable Generation in the 33% RPS Solar Case (continued)

- Compared to Case 2, monthly average gas consumption in Case 5 is up by 0.1 to 0.3 Bcfd.
  - There is very little difference from Case 3 in the renewable generation reductions, so the changes in gas consumption are very similar.
- Peak month (January) average gas consumption is up by 0.2 Bcfd, about the same as the annual average increase.
- August gas consumption is up by 0.1 Bcfd due to reduced wind and solar generation.



Case 5: The Impact of Reduced Renewable Generation in the 33% RPS Solar Case (continued)

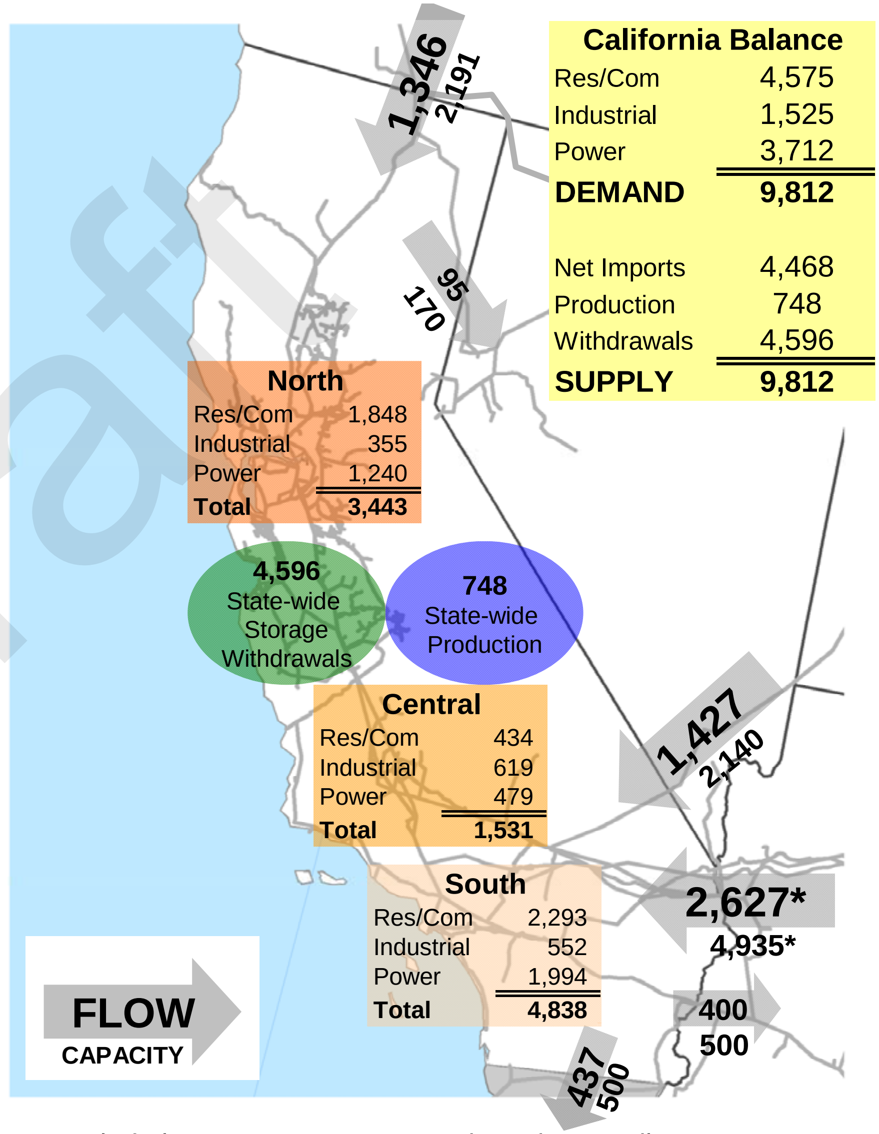
- January peak day gas consumption in the power sector is about 0.5 Bcfd higher in Case 5, compared to Case 2.
  - Again, since the change in generation is similar to Case 3, the change in peak day consumption is very similar.



Case 5: The Impact of Reduced Generation in the 33% RPS Solar Case (continued)

- January peak day gas consumption for power generation is up throughout the state, with a slightly greater increase in the South, compared to Case 2.
- The increase in consumption is met by increases in pipeline imports (+0.25 Bcfd) and storage withdrawals (+0.25 Bcfd).
  - Most of the increase in pipeline imports is from the El Paso system into Southern California.
  - Most of the increase in storage withdrawals is concentrated at the Aliso Canyon and Honor Rancho fields near Los Angeles.
- Storage withdrawals are at or near capacity at many fields in California.

Case 5: January 2020 Peak Day Balance (MMcfd)



* Total of El Paso, Transwestern, and Southern Trails

Case 5: The Impact of Reduced Generation in the 33% RPS Solar Case (continued)

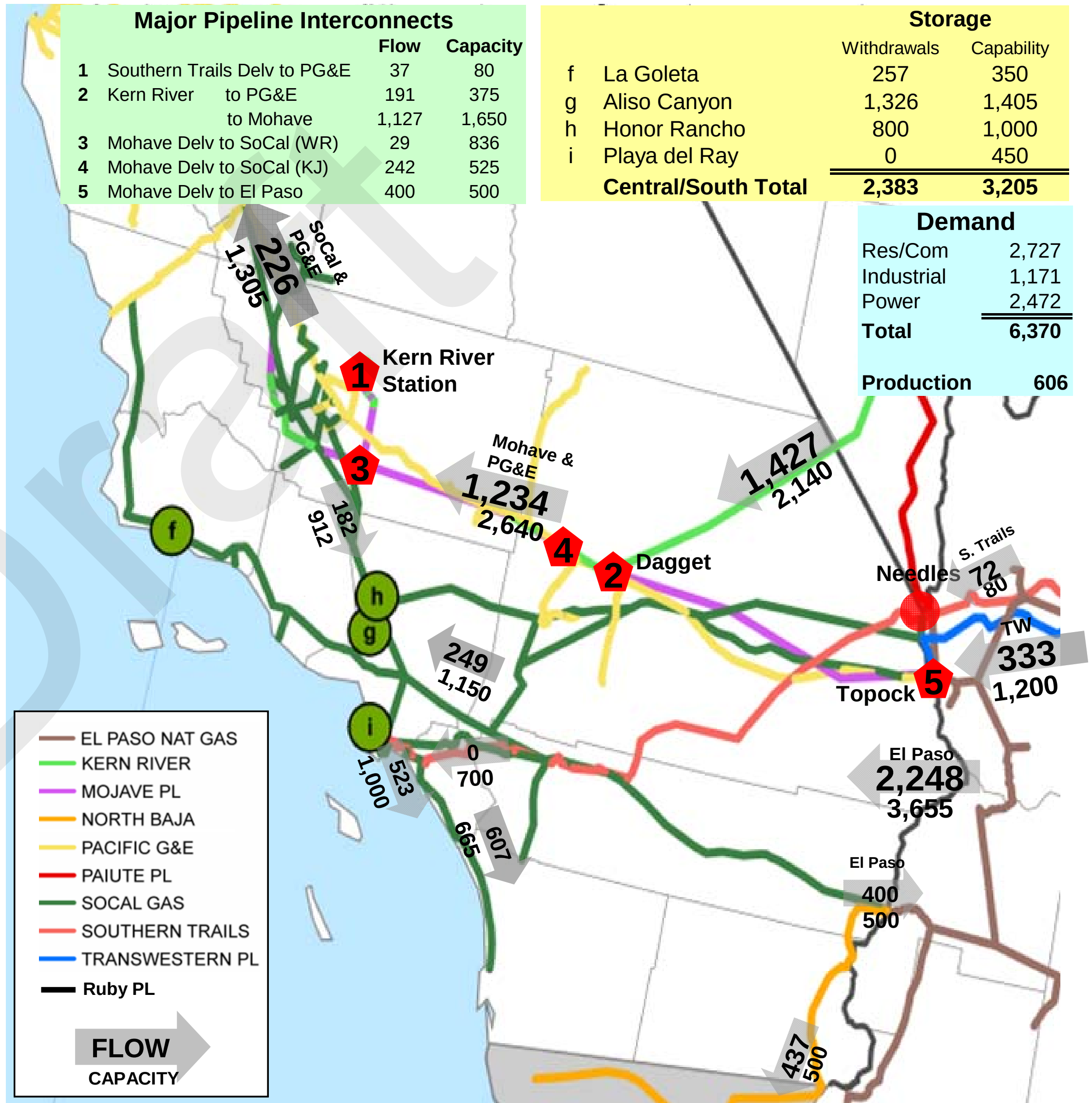
- The reduction in renewable generation causes a demand increase of about 0.4 Bcf in Central/Southern California, compared to Case 2
  - Most of the increase in demand is met primarily by increased flows into California on El Paso pipeline, with a small increase in storage withdrawals.
- Generally, pipeline and storage capacity is adequate to meet demand within this area.
  - As in the other reduced renewable generation cases, load factors on pipelines serving San Diego county are over 90% - close to constrained, but still adequate to meet the January peak day demand.
  - In August, when gas demand for power generation peaks, San Diego would be constrained under this scenario due to its lack of storage and limited pipeline options.

Case 5: January 2020 Peak Day Flows in Central/Southern California (MMcfd)

Major Pipeline Interconnects		Flow	Capacity
1	Southern Trails Delv to PG&E	37	80
2	Kern River to PG&E	191	375
	to Mohave	1,127	1,650
3	Mohave Delv to SoCal (WR)	29	836
4	Mohave Delv to SoCal (KJ)	242	525
5	Mohave Delv to El Paso	400	500

Storage		Withdrawals	Capability
f	La Goleta	257	350
g	Aliso Canyon	1,326	1,405
h	Honor Rancho	800	1,000
i	Playa del Ray	0	450
	Central/South Total	2,383	3,205

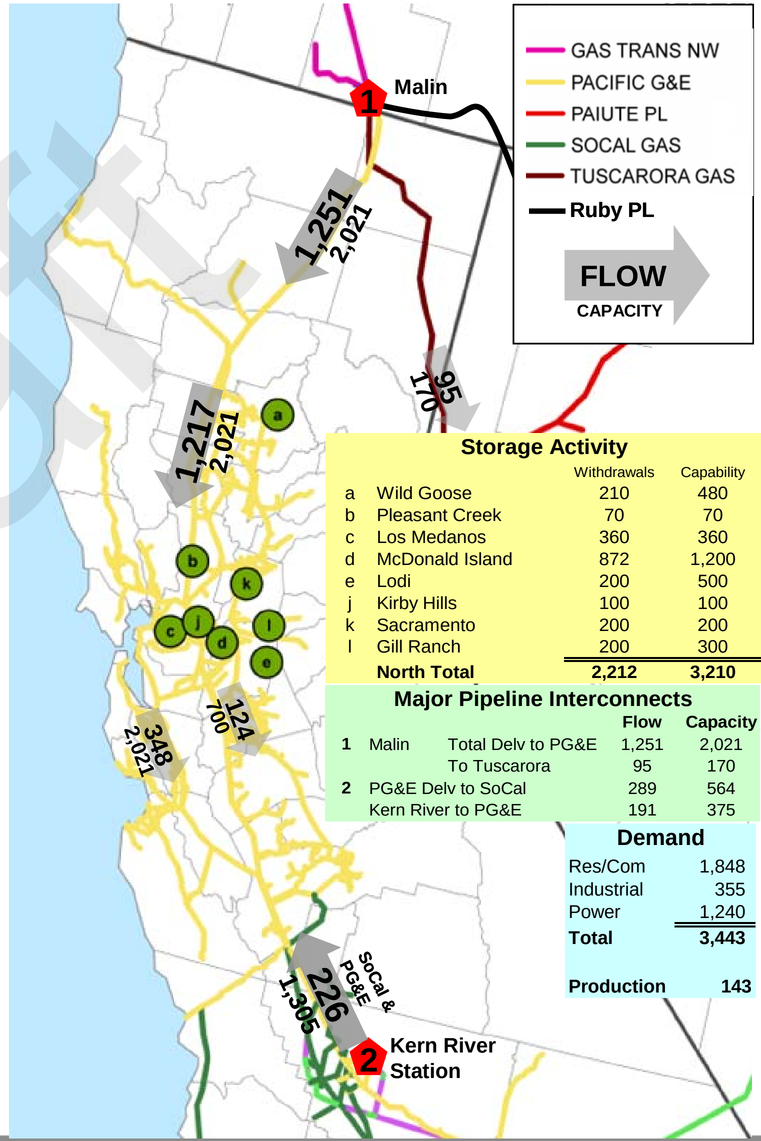
Demand	
Res/Com	2,727
Industrial	1,171
Power	2,472
Total	6,370
Production	606



Case 5: The Impact of Reduced Generation in the 33% RPS Solar Case (continued)

- Peak day demand in Northern California is up by 0.2 Bcf, compared to Case 2.
  - Pipeline flows from Malin increase by 0.04 Bcf, while storage is up by 0.19 Bcf.
- As in the other reduced renewable generation cases, four of the eight storage fields in Northern California are withdrawing at full capability.
  - Even if withdrawals at these fields were lower, there is adequate pipeline capacity and storage withdrawal capability at other fields to meet peak day demand.

Case 5: January 2020 Peak Day Flows in Northern California (MMcfd)



Case 5: The Impact of Reduced Generation in the 33% RPS Solar Case (continued)

- Average January demand in Central/Southern California is up by 0.1 Bcfd, compared to Case 2.
  - All of the increase in demand is met by increased in-bound flows on El Paso.
  - There is adequate pipeline and storage capacity in Central/Southern California to meet demand throughout the month of January.

Case 5: January 2020 Average Flows in Southern/Central California (MMcfd)

Major Pipeline Interconnects

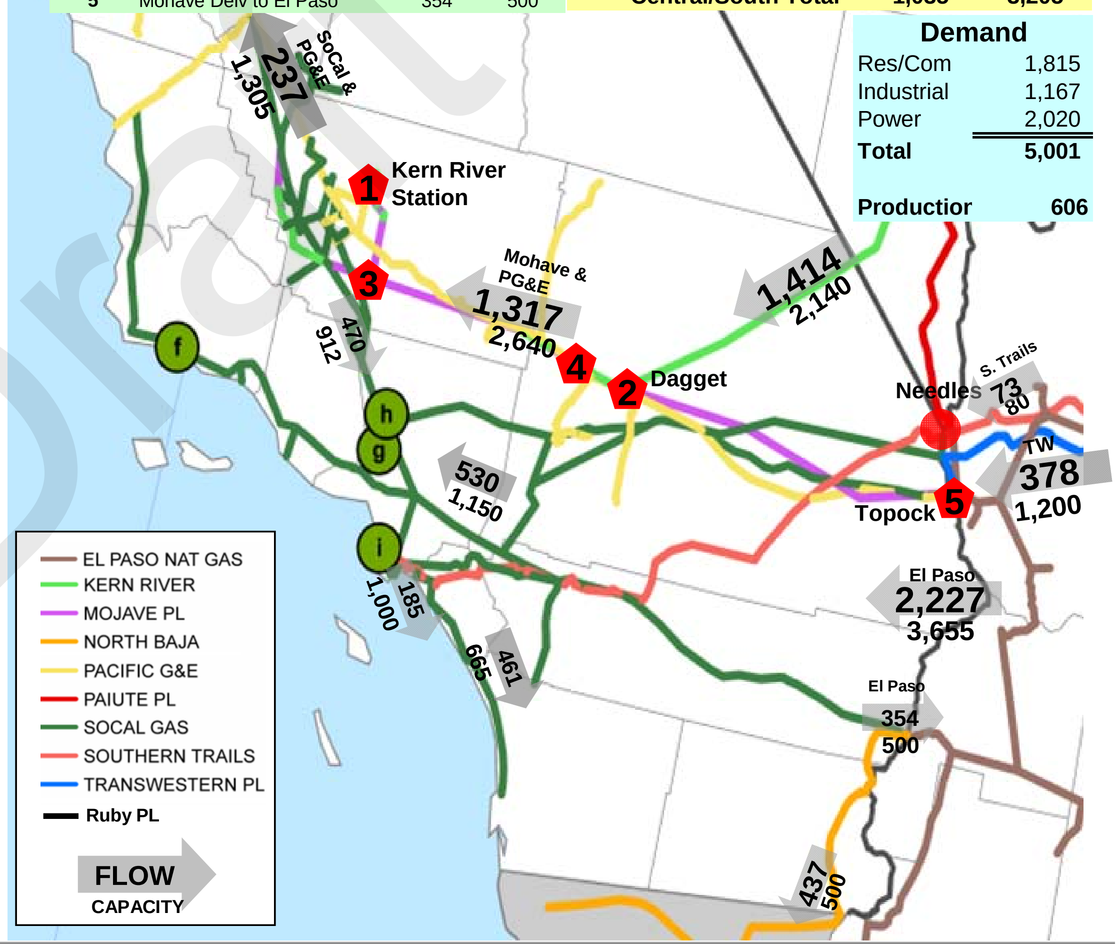
		Flow	Capacity
1	Southern Trails Delv to PG&E	38	80
2	Kern River to PG&E	158	375
	to Mohave	1,174	1,650
3	Mohave Delv to SoCal (WR)	210	836
4	Mohave Delv to SoCal (KJ)	288	525
5	Mohave Delv to El Paso	354	500

Storage

		Withdrawals	Capability
f	La Goleta	143	350
g	Aliso Canyon	742	1,405
h	Honor Rancho	149	1,000
i	Playa del Ray	1	450
	Central/South Total	**1,035**	**3,205**

Demand

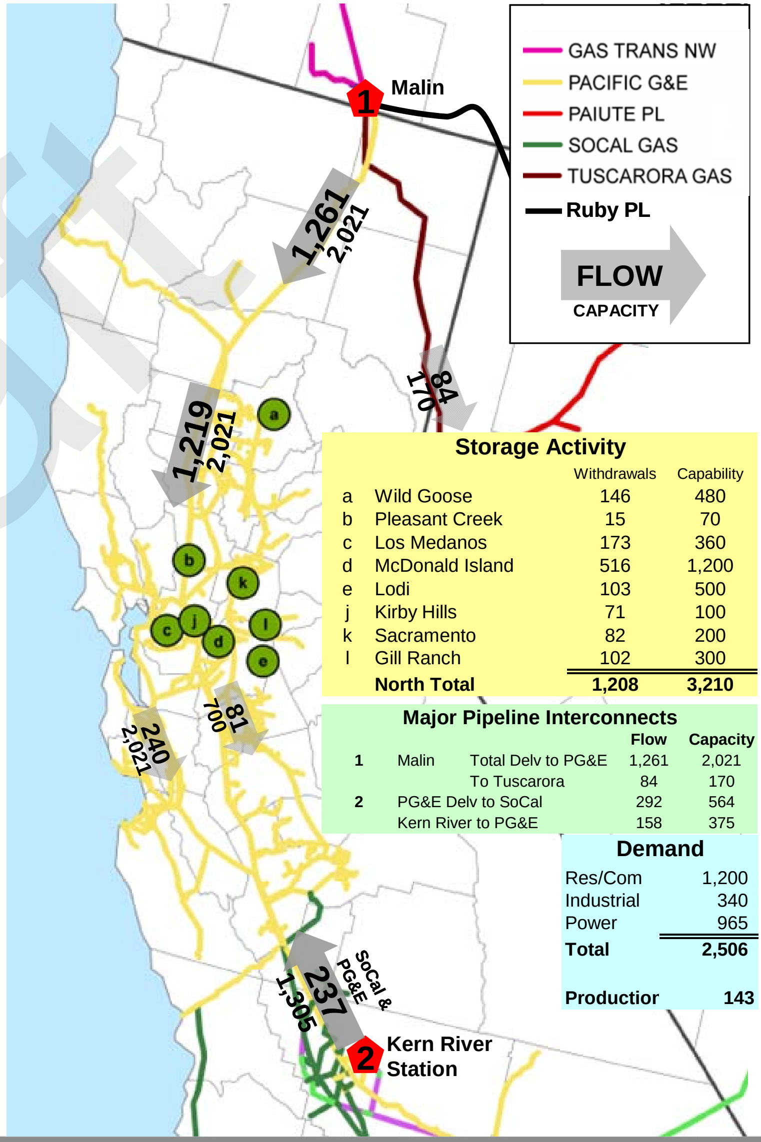
Res/Com	1,815
Industrial	1,167
Power	2,020
Total	**5,001**
Productior	**606**



Case 5: The Impact of Reduced Generation in the 33% RPS Solar Case (continued)

- In Northern California, average January demand is up only slightly compared to Case 2.
  - The increase demand is met by increases in both the pipeline flows from Malin and storage withdrawals.
  - Pipeline and storage capacity in Northern California is adequate to meet demand throughout the month of January.

Case 5: January 2020 Average Flows in Northern California (MMcfd)



Storage Activity

		Withdrawals	Capability
a	Wild Goose	146	480
b	Pleasant Creek	15	70
c	Los Medanos	173	360
d	McDonald Island	516	1,200
e	Lodi	103	500
j	Kirby Hills	71	100
k	Sacramento	82	200
l	Gill Ranch	102	300
	North Total	**1,208**	**3,210**

Major Pipeline Interconnects

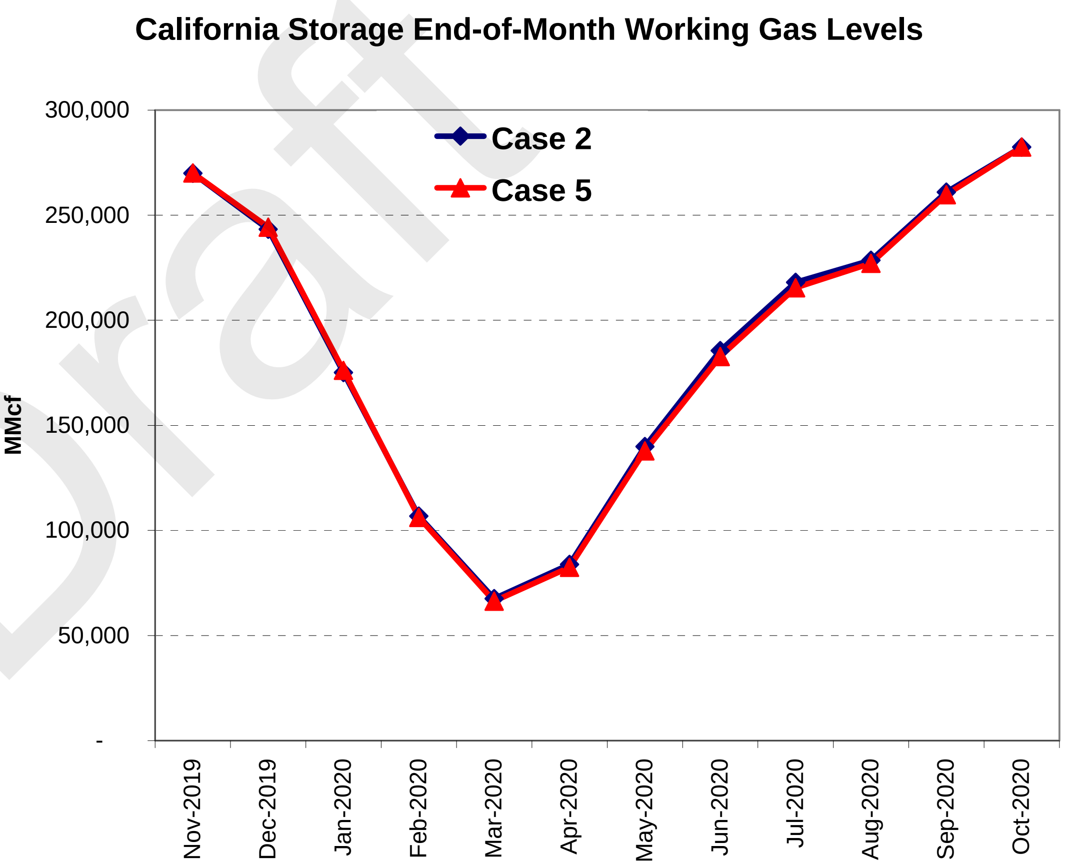
			Flow	Capacity
1	Malin	Total Delv to PG&E	1,261	2,021
		To Tuscarora	84	170
2	PG&E Delv to SoCal		292	564
	Kern River to PG&E		158	375

Demand

Res/Com	1,200
Industrial	340
Power	965
Total	**2,506**
Productior	**143**

Case 5: The Impact of Reduced Renewable Generation in the 33% RPS Solar Case (continued)

- While peak day storage withdrawals in Case 5 are higher, the total withdrawals for January are about the same as in Case 2.
- Also, the seasonal injection/withdrawal pattern in Case 5 is nearly identical to Case 2.



Summary and Conclusions

Summary of Results

- A 33% RPS leads to an incremental decrease in California's power sector gas consumption.
  - As renewable generation increases, gas-fired generation is displaced.
  - With expected levels of renewable generation and normal weather and hydroelectric conditions, California's power sector gas consumption is expected to decline by 0.8 Bcfd by 2020.
  - Even assuming adverse weather and hydroelectric conditions in 2020, total gas consumption is still projected to be lower in 2020 than it was in 2008.
- All the reduced renewable generation cases resulted in an incremental increase in peak day gas demand of about 0.5 Bcfd (or 6%), but this is not enough to cause significant problems for the State's gas pipeline or gas storage infrastructure.
  - There is ample pipeline capacity entering the state meet the increase load on a peak demand day.
  - While high, gas storage withdrawals are estimated to be within the operational limits at all fields, and working gas in storage is not pushed to unreliably low levels.
  - Gas infrastructure within the State is generally adequate to meet the increased January peak day gas demand in all the reduced generation cases.
    - One possible exception is the San Diego area, where congestion on distribution lines occurs in both winter and summer peak gas demand periods. Additional pipeline and/or storage infrastructure may be required in this area to ensure system reliability.
  - All the reduced generation cases show similar results. The High Wind scenario (Case 4) has the greatest generation reductions in the peak demand period, but still shows no signs of demand curtailments, pipeline congestion, or storage constraints on the January peak gas demand day.

Caveats

- This analysis is based on the CEC's 2007 projection of 1.1% per year growth in California's electric load.
  - Many factors, such as the rate of economic growth and the impacts of energy efficiency and DSM programs, can effect the rate of growth in electricity demand.
- The estimates for wind and solar variability are based on a limited amount of data, so the potential variability in generation may be more or less than represented in this study.
  - Historical data on actual wind and solar generation is very limited.
  - Historical wind speed and solar radiation data is more extensive, but still has limitations.
- This analysis assumes that reductions in RPS generation within an area (Northern, Central, or Southern California) will be met with increased gas-fired generation in the same area.
  - This study does not include a detailed analysis of the electric transmission network or intra-regional flows of electricity.
  - Limitations on the ability to transmit electricity within each region could result in a different dispatch pattern for gas-fired power plants.
- The pipeline analysis is based on a county-level assessment of mainline capacities, storage field locations, and gas demand.
  - There could be potential constraints within counties and in local distribution system that are not apparent in this analysis.
- This analysis focuses on seasonal and daily variations in renewable generation; the impact of hourly variations has not been assessed.
  - Hourly variations in wind and solar generation could create additional variability in demand for gas-fired generation.
  - But, on the other hand, pipeline and distribution companies have flexibility in their infrastructure (through line pack and storage) to respond to hourly variability in gas use.
- The RIAMS model, used to project intra-state pipeline flows and storage activity, optimizes the use of storage to meet peak day demands.
  - It is possible that on peak gas demand days, actual pipeline flows would be higher and storage withdrawals would be lower than RIAMS projects.
  - However, the results still suggest that there is ample inter- and intra-state pipeline capacity available on peak days.

Conclusion:
A 33% RPS Leads to Declining Gas Demand in California

- Under all the 33% RPS scenario's, California's power sector gas demand is projected to decline by 0.8 Bcfd (or 30%) by 2020.
  - Hydroelectric and nuclear generation are assumed to be stable at average historic levels; other sources of generation (coal and oil) are relatively small but also assumed to be stable.
  - Under a 33% RPS, growth in renewable generation far out-paces the growth in electric load, so renewables gradually displace gas-fired generation.
- Other demand sectors are flat to slightly down, so California's total gas demand is projected to be down by 0.9 Bcfd by 2020.
- Even with adverse weather/hydro conditions, projected gas demand in 2020 would be less than in 2008.
- Gas-fired capacity is expected to increase to 43 GW by 2020, but gas-fired generation is expected to decline as it is displaced by renewables.
  - Retirement due to new regulation affecting plants using once-through cooling is not expected to have a significant impact on California's power sector gas consumption.

Conclusion:
California's Gas Supply Options Improve over Time

- U.S. gas supplies are expected to increase by over 7 Bcfd by 2020, mainly due to increases in domestic production.
  - Increases in production throughout the U.S. can have a positive impact on California's gas supply outlook.
- Several planned projects will expand the supply of natural gas available to California.
  - Ruby Pipeline will provide an addition 1.3 Bcfd of pipeline capacity from the Rockies to Malin.
  - Additional compression and looping on Kern River Pipeline will allow for additional flows on that system.
  - While the Costa Azul LNG terminal may not receive enough gas to become a significant supply source for Southern California, those imports will displace the need for some U.S. exports to Mexico, and therefore make more gas available to the California market.
- New storage capacity in California provides additional flexibility for meeting peak demand.
  - Two new storage fields and one field expansion are planned within the next several years, adding over 33 Bcf of storage capacity and 550 MMcfd of maximum withdrawal capability.

Conclusion:
Technology Mix and Geographic Diversity in Renewables Minimizes the Potential Impact of Reduced Renewable Generation

- Since a large portion of the projected RPS generation is from non-intermittent renewables (biomass, biogas and geothermal), potential variability in renewable generation is dampened.
  - All the scenarios assume between 38% and 41% of the RPS generation comes from these non-intermittent sources.
- Seasonally, both wind and solar generation tend to be lowest in the winter months, but that is also when California's electric load is lowest.
  - In the summer months, when electric load is highest, residential and commercial gas demand are low. This means gas supplies and pipeline capacity are available to meet increased power sector gas demand should renewable generation fall short of expected values in the summer.
- Wind generation can be highly variable at any particular site, but having many wind farms at different locations throughout the state reduces the variability in state-wide wind generation.
  - Based on historic weather data, it appears unlikely that there would be unfavorable wind conditions simultaneously throughout the State.
- The "High Central Station Solar" scenario from the 33% Implementation Analysis Working Group Meeting had only a minor increase in solar generation compared to the Reference scenario, so we did not see a large impact on Southern California gas demand in the Solar Case with Reduced Renewable Generation (Case 5).
  - Since solar generation is likely to be concentrated in Southern California, a alternate scenario in which solar generation provides a much higher proportion of total RPS generation would have had a much greater impact on Southern California gas demand.

Impact of Variations in Renewable Generation on California's Natural Gas Infrastructure

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