BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Application of NEVADA POWER COMPANY d/b/a NV Energy and SIERRA PACIFIC POWER COMPANY d/b/a NV Energy, seeking approval of Second Amendment to 2018 Joint Integrated Resource Plan, including a change to the Demand-Side Action Plan to achieve 1.25% annual energy savings target, additions to the generation portion of the Supply-Side Action Plan including a new cooling pond for Tracy Unit 3 and a new agreement with Idaho Power Company for the orderly retirement of the North Valmy Station, updates to the Transmission Action Plan including several new transmission projects needed to serve growing distribution and transmission load.

Docket No. 18-06___

VOLUME 2 OF 4

TECHNICAL APPENDIX
LOAD FORECAST, GENERATION, AND TRANSMISSION

LF-1

NEVADA POWER COMPANY D/B/A NV ENERGY
SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY

2019 INTEGRATED RESOURCE PLAN SECOND AMENDMENT LOAD FORECAST FOR THE PERIOD 2020-2039

I. HISTORICAL DATA AND WEATHER NORMALIZATION

A. Historical Data

Pursuant to Nevada Administrative Code ("NAC") § 704.9281(1)(b) and (c), Tables LF-1 through LF-3 show the historical sales, estimated losses and company use of electricity[1] from 2008-2017 for NV Energy, Nevada Power Company ("Nevada Power") and Sierra Pacific Power Company ("Sierra "and together with Nevada Power, the "Companies"). Weather adjusted values are shown where applicable. The NV Energy columns for retail sales are Nevada sales. Beginning in 2011, the Estimated Losses and Company Use exclude activities in California, so the Nevada jurisdictional values are represented by the NV Energy values. Table LF-4 summarizes the historical sales data for Nevada. Peppermill and Caesars, who transitioned to Distribution Only Service ("DOS") in April and January 2018 respectively, have not been removed from prior history.

TABLE LF-1
NV ENERGY HISTORICAL SALES, LOSSES AND COMPANY USE

	Billed Retail Sales (GWh)			Resale	WN Billed Retail Sales (GWh)			Resale	Estimated Losses (GWh)			Company Use (GWh)		
Year	NVE	NPC	SPPC (1)	SPPC- NV	NVE	NPC	SPPC	SPPC- NV	NVE	NPC	SPPC	NVE	NPC	SPPC
2009	29,375	21,230	8,146	9	29,317	21,195	8,122	9	1,230	779	452	74	28	46
2010	29,081	20,962	8,119	8	29,180	21,062	8,118	8	1,478	824	655	53	21	31
2011	28,269	20,618	7,651	9	28,649	20,987	7,662	9	1,227	820	407	52	23	29
2012	29,534	21,601	7,933	8	29,288	21,374	7,914	8	1,200	739	461	61	34	28
2013	29,179	21,079	8,100	9	29,088	21,056	8,032	9	1,300	797	503	54	26	28
2014	29,224	21,092	8,132	7	29,316	21,167	8,149	7	1,851	1,301	550	59	19	40
2015	29,679	21,507	8,172	8	29,523	21,317	8,206	8	950	490	461	47	20	27
2016	30,007	21,643	8,364	9	29,852	21,436	8,415	9	1,207	709	497	41	23	18
2017	29,214	20,605	8,608	9	28,889	20,382	8,507	9	1,223	647	576	38	21	17
2018	29,369	20,493	8,876	9	28,682	19,869	8,813	9	1,750	1,214	536	39	18	21

Pursuant to NAC § 704.9281(1)(a) and (d), Table LF-2 provides a summary of the historical peak demand, both actual and weather normalized, energy and load factor. The 2018 NV Energy system peak occurred on July 25, 2018 at 6 p.m., the same time as the Nevada Power peak. The Sierra peak occurred on July 19, 2018 at 6 p.m. The weather normalized peak for Sierra at the time of the NVE peak is based on the relationship between temperature deviations from normal and actual temperatures on the Sierra peak day.

[1] "Company Use" is the energy used by the Company at its facilities.

TABLE LF-2
HISTORICAL PEAK DEMAND (MW), ENERGY (GWH) AND LOAD FACTORS

	Recorded Peak (MW) (1)			WN Peak (MW) (2)			Energy (GWh) - Not WN			Load Factor: Recorded Values		
Year	NVE	NPC	SPPC	NVE	NPC	SPPC	NVE	NPC	SPPC	NVE	NPC	SPPC
2009	7,074	5,586	1,554	N/A	5,490	1,566	30,776	22,061	8,716	49.7%	45.1%	64.0%
2010	7,133	5,604	1,611	N/A	5,495	1,606	30,501	21,718	8,783	48.8%	44.2%	62.2%
2011	7,036	5,530	1,513	N/A	5,556	1,543	30,388	21,659	8,728	49.3%	44.7%	65.9%
2012	7,379	5,761	1,676	N/A	5,571	1,643	31,401	22,363	9,038	48.4%	44.2%	61.4%
2013	7,537	5,854	1,720	N/A	5,630	1,702	31,423	22,123	9,300	47.6%	43.1%	61.7%
2014	7,158	5,572	1,761	N/A	5,594	1,698	31,579	22,300	9,278	50.4%	45.7%	60.1%
2015	7,575	5,864	1,711	N/A	5,814	1,696	31,959	22,595	9,365	48.2%	44.0%	62.5%
2016	7,961	6,124	1,842	7,698	5,870	1,833	32,068	22,568	9,500	45.8%	41.9%	58.7%
2017	7,678	5,929	1,824	7,320	5,630	1,800	31,265	21,484	9,781	46.5%	41.4%	61.2%
2018	7,714	5,956	1,860	7,452	5,731	1,825	31,057	21,017	10,040	46.0%	40.3%	61.6%

(1) Coincident peak for the entity. NPC plus SPPC will generally not match NVE as they peak on different days and or hours.

(2) For 2017 and 2018, the Sierra WN peak is the calculated WN peak on the NVE booked peak day. This calculation may not produce reliable WN peaks for all years if peaks occur on days with significantly different weather at each company.

Pursuant to NAC § 704.925(8), Table LF-3 provides a summary of the Nevada Power, Sierra and combined peak demand, both actual and weather normalized, energy and load factor for 2011 through 2017. Metered data for California is only available since January 1, 2011.

TABLE LF-3
NEVADA HISTORICAL PEAK DEMANDS (MW), ENERGY (GWH) AND LOAD FACTORS

	Recorded Peak (MW) (1)			WN Peak (MW)			Energy (GWh) - Not WN			Load Factor: Recorded Values		
Year	NVE	NPC	SPPC	NVE	NPC	SPPC	NVE	NPC	SPPC	NVE	NPC	SPPC
2011	6,970	5,526	1,444	N/A	5,556	1,468	30,161	22,061	8,100	49.4%	45.6%	64.0%
2012	7,310	5,761	1,549	N/A	5,571	1,570	30,144	21,718	8,426	46.9%	42.9%	61.9%
2013	7,463	5,842	1,621	N/A	5,630	1,628	30,342	21,659	8,683	46.4%	42.3%	61.1%
2014	7,089	5,525	1,564	N/A	5,594	1,628	31,048	22,363	8,685	50.0%	46.2%	63.4%
2015	7,511	5,864	1,647	N/A	5,814	1,633	30,911	22,123	8,789	47.0%	43.1%	60.9%
2016	7,890	6,119	1,771	N/A	5,870	1,762	31,179	22,300	8,879	45.0%	41.5%	57.1%
2017	7,613	5,929	1,749	N/A	5,630	1,732	31,755	22,595	9,160	47.6%	43.5%	59.8%
2018	7,650	5,956	1,694	N/A	5,731	1,763	32,017	22,568	9,449	47.8%	43.3%	63.7%

(1) Coincident peak for the entity. NPC plus SPPC-Nevada will generally not match NVE as they peak on different days and or hours.

B. <u>Weather Normalization of Sales</u>

Sales to both Nevada Power's and Sierra's residential ("RES") and small commercial and industrial ("Small C&I") classes are particularly sensitive to weather. Pursuant to NAC § 704.9281(1)(b), sales have been weather normalized. The statistically adjusted engineering ("SAE") models are not well designed for weather normalization as the constructed interactive variables tend to reduce the size of the weather impacts. Less complex model coefficients from non-SAE models were used to weather normalize sales. The following process was followed:

- Derive the difference between the actual and normal degree days for each month;
- Multiply the difference obtained above by the estimated weather coefficient(s) for that month (the slope estimate); and

- Add the value from the step above to the dependent variable in the econometric equation.

Table LF-4 provides an example of the calculation of weather normalized sales using Sierra's residential billed single family sales per customer for July 2018. For the 2019 general rate review proceeding, Sierra WN residential sales were split into single family and multi-family rate groups. All rate groups for both Companies use this same procedure.

TABLE LF-4
EXAMPLE OF RESIDENTIAL BILLED SALES WN

SINGLE FAMILY

	July-18		
Line	Description	Number	Calculation (1)
1	SF Billed Sales w/o OLS (MWh) (2)	182,248	
2	Residential SF Customers	225,022	
3	Sales Per Customer (KWh)	809.91	1 / 2 * 1000
4	Billing Cycle CDD - Base 70	150	
5	Billing Cycle Normal CDD - Base 70	131	
6	Normal Less Actual	-18.4	5 - 4
7	CDD Coefficient (KWh per CDD)	1.30789	
8	KWh Change per Res Cust	-24.03	6 * 7
9	Total MWh Change	-5,406	2 * 8 * 1000
10	WN SF Billed Sales	176,841	1 + 9

(1) All numbers are Line numbers except for 1000 conversions from KWh to MWh and vice-versa.
(2) OLS refers to outdoor lighting services. These sales are not weather sensitive.

C. System Peak Demand Normalization

Pursuant to NAC § 704.9281(1)(a), econometric models were developed for both Companies to weather normalize winter and summer system peaks. Winter seasons were defined as the period from December through February. For example, December 1, 2018 through February 28, 2019 makes up the 2018-2019 winter season. Summer is defined as the period between June and September. The dependent variable for both the summer regression for 2018 and winter regression for 2018-2019 was the daily uninterrupted (demand response reductions added back as necessary) peak per residential customer. Because residential customer counts are only reported monthly, an estimate of the total residential customers for each day was linearly interpolated. For both the summer and winter, individual regression models were developed for each year. In addition to temperature as an independent variable, a weekend dummy variable was included as peaks that occur on a weekend are lower than those for a weekday given identical temperatures.

Table LF-5 is a summary of the model statistics for the 2018 summer and 2018-2019 winter peak demand weather normalizations. Table LF-6 is a summary of the recorded and weather normalized peak demands for Sierra, Table LF-7 provides the same information for Nevada Power and Table LF-8 for the combined companies.

TABLE LF-5
SUMMER AND WINTER PEAK WEATHER NORMALIZATION MODEL STATISTICS

NPC 2018 SUMMER PEAK WN MODEL

	Constant	MaxTemp	MinTemp	Weekend	After June 27	Adj Obs	Adj R-square	F-Stat	MAPE
Coefficient	-6.054	0.099	0.020	-0.106	0.086	113	0.968	841.60	2.22%
T-Stat	-29.257	24.025	3.912	-3.175	2.195				
P-Value	0.00%	0.00%	0.02%	0.20%	3.03%			0.00	

SIERRA 2018 SUMMER PEAK WN MODEL

	Constant	MaxTemp	MinTemp	Weekend	AR(1)	Adj Obs	Adj R-square	F-Stat (a)	MAPE
Coefficient	N/A	0.048	0.013	-0.199	0.876	92	0.952	N/A	2.15%
T-Stat	N/A	19.134	3.561	-6.966	15.414				
P-Value	N/A	0.00%	0.06%	0.00%	0.00%			N/A	

NPC 2018-19 WINTER PEAK WN MODEL

	Constant	MaxTemp	Weekend	Xmas	AR(1)	Adj Obs	Adj R-square	F-Stat (a)	MAPE
Coefficient	N/A	-0.014	-0.117	-0.299	1.000	85	0.814	N/A	1.76%
T-Stat	N/A	-8.337	-9.279	-6.786	534.017				
P-Value	N/A	0.00%	0.00%	0.00%	0.00%			N/A	

SIERRA 2018-19 WINTER PEAK WN MODEL

	Constant	MaxTemp	Weekend	Xmas	AR(1)	Adj Obs	Adj R-square	F-Stat	MAPE
Coefficient	4.943	-0.010	-0.099	-0.264	0.616	84	0.660	43.74	1.86%
T-Stat	50.620	-5.290	-3.876	-2.932	6.599				
P-Value	0.00%	0.00%	0.02%	0.43%	0.00%			0.00	

(a) There is no F-Stat for a model with no Constant.

TABLE LF-6

SIERRA SUMMER AND WINTER SYSTEM PEAK WEATHER, RECORDED AND WN PEAKS

	SIERRA: TOTAL COMPANY							
	SUMMER					WINTER		
	Min Daily Temperature	Max Daily Temperature	System Peak (MW)			Max Daily Temperature	System Peak (MW)	
Year	(Normal: 66.4o)	(Normal: 102.0o)	Actual	Weather Normalized	Winter	(Normal: 33.8o)	Actual	Weather Normalized
2009	66	99	1,554	1,566	2009-10	19	1,347	1,295
2010	67	100	1,611	1,606	2010-11	32	1,323	1,318
2011 (1)	67	97	1,513	1,543	2011-12	39	1,301	1,320
2012 (2)	65	103	1,676	1,643	2012-13	31	1,330	1,323
2013	69	101	1,720	1,702	2013-14	24	1,432	1,400
2014	68	105	1,761	1,698	2014-15	30	1,371	1,362
2015	71	101	1,711	1,696	2015-16	28	1,400	1,388
2016	67	102	1,842	1,833	2016-17	29	1,370	1,359
2017	68	103	1,824	1,800	2017-18 (3)	38	1,432	1,448
2018	68	104	1,860	1,825	2018-19	39	1,470	1,487

(1) The weather was very mild in July. The hourly data was used for WN as the highest hourly temperature was 98 degrees at 6 pm, one hour after the peak load, and 2 degrees less than the instantaneous temperature of 100 degrees.

(2) Includes an adjustment for Hot August Nights.

(3) The actual peak occurred on 12/20/17. The high temperature for this day was 56 degrees. The WN peak for the day was 1,509 MW which did not look reasonable. The peak on 12/21/2017 was 1,432 MW with a high temperature of 38 degrees. This produced a more reasonable WN peak of 1,448 MW.

Note: Normal Temperatures for each year are the 20 year period ending in that year.

TABLE LF-7

NPC SUMMER AND WINTER SYSTEM PEAK WEATHER, RECORDED AND WN PEAKS

	NEVADA POWER							
	SUMMER					WINTER		
Year	Min Daily Temperature (Normal = 87.9)	Max Daily Temperature (Normal = 112.9)	System Peak (MW) Actual	System Peak (MW) Weather Normalized	**Period**	Maximum Temperature (Normal = 45.8)	System Peak (MW) Actual	System Peak (MW) Weather Normalized
2009	90	112	5,586	5,490	2009-10	45	2,705	2,708
2010	93	112	5,604	5,495	2010-11	38	2,776	2,716
2011	86	111	5,530	5,556	2011-12	47	2,652	2,666
2012	87	112	5,761	5,571	2012-13	38	2,907	2,835
2013	90	115	5,854	5,630	2013-14	40	2,907	2,891
2014	87	112	5,572	5,594	2014-15	43	2,811	2,803
2015	93	112	5,864	5,814	2015-16	48	2,690	2,715
2016	91	115	6,124	5,870	2016-17	53	2,510	2,569
2017 (1)	89	116	5,929	5,630	2017-18	51	2,475	2,509
2018	89	115	5,956	5,731	2018-19	48	2,487	2,513

(1) The actual peak occurred on June 20, 2017 at 4 pm. The maximum temperature for that day was 117 degrees and the minimum temperature was 88 degrees. The actual peak on that day was 5,926 MW and the WN peak was 5,585 MW. On 7/7/2017, the actual peak was 5,913 MW with a maximum temperature of 116 degrees and minimum temperature of 89 degrees. The WN peak on that day was 5,630 MW. One large customer transitioned to DOS between the two dates. July 17, 2017 would have been the actual peak day had that customer not gone DOS. However, the maximum temperature difference of 1 degree caused a higher WN peak on 7/17/2017, hence those temperatures and WN peak are in the table.

Note: Normal Temperatures for each year are the 20 year period ending in that year.

TABLE LF-8
NVE TOTAL WINTER PEAK, NEVADA WINTER RECORDED AND WN PEAKS

	Total	Recorded Peak (MW) (1)			WN Peak (MW)			
Year	NVE	NVE	NPC	SPPC	NVE	NPC	SPPC	
2009-10	4,039		2,705		N/A	2,708		
2010-11	4,055		2,776		N/A	2,716		
2011-12	3,884	3,779	2,652	1,184	N/A	2,666	1,201	
2012-13	4,227	4,117	2,907	1,208	N/A	2,835	1,202	
2013-14	4,339	4,222	2,907	1,315	N/A	2,891	1,286	
2014-15	4,171	4,040	2,811	1,237	N/A	2,803	1,229	
2015-16	4,064	3,952	2,690	1,302	N/A	2,715	1,291	
2016-17	3,857	3,753	2,510	1,250	N/A	2,569	1,240	
2017-18	3,907	3,810	2,475	1,335	N/A	2,509	1,320	(2)
2018-19	3,966	3,860	2,487	1,357	N/A	2,513	1,372	(3)

(1) Coincident peak for the entity. NPC plus SPPC-Nevada will generally not equal the NVE peak as the companies peak on different days and/or hours.

(2) As for Sierra System, the winter peak day was shifted to 12/21/2017 from 12/20/2017. The actual Nevada peak on 12/20/2017 was 1,350 MW.

(3) The Sierra Nevada winter peak day occurred on 12/4/2018 while the Sierra System peak occurred on 12/27/18. The Nevada peak on 12/27 was 1,333 MW and the WN peak was 1,352 MW.

Table LF-9 is a summary of the calculations to obtain the Sierra 2018 WN summer peak of 1,825 MW. The summer peak WN for Nevada Power and Companies' winter peak WN use the same methodology.

TABLE LF-9
SIERRA 2018 SUMMER SYSTEM PEAK WN PEAK CALCULATION

Line	Description	Number	Calculation (1)
1	Uninterrupted Peak (MW)	1,868	
2	Residential Customers	299,694	
3	Peak KW per Res. Customer	6.2330	1 / 2 / 1000
4	Maximum Temperature	104.0	
5	Normal Max Temperature	102.0	
6	Normal Less Actual	-2.0	5 - 4
7	Max Temp Coefficient	0.04809	
8	KW Change per Res Cust	-0.0962	6 * 7
9	Total MW change for Max Temp	-28.83	2 * 8 * 1000
10	Minimum Temperature	68	
11	Normal Min Temperature	66	
12	Normal Less Actual	-1.6	11 - 10
13	Min Temp Coefficient	0.01329	
14	KW Change per Res Cust	-0.02	12 * 13
15	Total MW change for Max Temp	-6.37	2 * 14 * 1000
16	Total Reduction for WN Peak	-35.2	9 + 15
17	WN Uninterrupted Peak MW	1,833	1 + 16
18	Demand Response MW	8	
19	WN Peak MW	1,825	17 - 18

(1) All numbers are Line numbers except for 1000 conversions from KW to MW and vice-versa.

II. ASSUMPTIONS AND DATA DEVELOPMENT

A. Introduction

System energy requirements are derived from revenue class sales and customer forecasts that are based on econometric models. Residential and commercial sales models are estimated using a SAE model specification. The SAE modeling approach entails constructing end-use variables that are then used as right-hand variables in monthly average use and sales forecast models. Average use models are estimated for RES and Small C&I classes. A total sales model is estimated for Nevada Power's Large Commercial and Industrial ("Large C&I") class and Sierra's GS-3 (non-mine and other large customers as appropriate) sales. (Per NAC § 704.922 2(b)). Sierra Outdoor Lighting Service models ("OLS") are estimated separately for the residential and Small C&I classes while these sales are included in the RES and Small C&I models for Nevada Power. Forecasts for the Sierra GS-3 mine load, large GS-3, GS-4 NG, GS-4 (large customers served at transmission voltage) and new Nevada Power customers are developed with Major Account Executive input. Forecasts for the Sierra irrigation ("IRR") and Public Street and Highway ("STL") classes at both Companies are developed based on recent history. In summary, forecast models are estimated for the revenue classes listed below:

- Residential for the Companies and a separate Residential OLS model for Sierra;

- Small C&I (excluding irrigation) for the Companies and a separate Small C&I OLS model for Sierra;
- Large C&I model – all load for Nevada Power and GS3-S and GS3-P non-mines/other large loads/standby loads for Sierra.

B. Assumptions and Changes

Per NAC § 704.922(2)(b), Sierra Residential and Small C&I models are estimated from historical monthly billed sales and customer data covering the period January 2008 through December 2018. The Sierra GS3 model uses monthly edited customer billed MWh from January 2009 through December 2018. This provides a consistent series of data with customers for the entire history on their applicable rate in 2018.

For Nevada Power, the Residential customer model was driven by annual customer counts and population estimates. This change was made as both the historical and forecast population values are annual for Nevada Power. The historical data for that model is 1990 through 2018. Historical data for the residential average use, Small C&I customers and average use and the Large C&I sales model were for the period January 2008 through December 2018.

Pursuant to NAC § 704.922(2)(b) the Nevada Power Large C&I monthly historical sales for 2016 through 2018 were developed by adding back the sales of customers transitioning to distribution only service DOS in those three years. For Sierra, sales were added back for both the Small and Large C&I classes for 2018. The model forecasted sales for these classes would not be accurate using as-billed sales due to the large amount of loads transitioning to DOS, especially at Nevada Power. A total of 171 GWh was added back to 2016 and 1,370 GWh to 2017. For Sierra, 18 GWH was added back to the Small C&I class in 2018 and 75 GWh was added back to the Large C&I class. The DOS load of those customers were then subtracted from the model forecast of Large C&I sales.

Historical and projected data sources are described below:

Economic and Demographic Data. Historical and forecasted demographic and economic data are based on Global Insight's ("GI") October 2018 forecasts for the Las Vegas Paradise Nevada less Las Vegas-Paradise Metropolitan Statistical Area ("Clark County") for Nevada Power and Nevada less Clark County designated as northern Nevada ("NN") throughout the rest of this document. Real Household Income and persons per household are used in estimating the residential forecast models. Real Gross Metro Product ("GMP") is used in estimating the Small C&I average use per customer and Large C&I/GS-3 sales forecast models. Hotel rooms counts[2] are also included as a driver variable for the Nevada Power Large C&I model and non-manufacturing employment for the Sierra GS-3 class. Population is the primary driver in the residential customer forecast model and residential customers based on population for the Small C&I customer models.

In the 2019 Second Amendment Forecast ("2019 IRPA 2nd Forecast"), the Nevada Power models include a Clark County population forecast based on the historical population series through 2010

2 *See*, Technical Appendix LF-6 for a summary of the hotel/motel rooms for the year-to-date October, 2018.

(intercensal population series[3]) and the certified series from 2011-2018[4], both prepared by the State Demographer. Annual growth rates are obtained from the June 2018 release of University of Nevada, Las Vegas' Center for Business and Economic Research's ("CBER") long-term forecast.[5] Sierra's models use northern Nevada's population history and forecast (Nevada minus Clark County). In the 2019 IRPA 2nd Forecast takes historical population figures from the State Demographer intercensal series through 2010, the certified series from 2011 through 2014 (State Demographer) and Global Insight ("GI") growth rates for 2015 to 2017 was used to develop the historical series. Growth rates were obtained from the State Demographer's forecast, but were adjusted upward to reflect recent residential customer growth.

Both forecasts used the State Demographer forecast which included Tesla and a onetime housing and land price shock.

Table LF-10 is a summary of the historical and forecasted Clark County population, residential customers and hotel rooms and Table LF-11 shows the NN Population and Residential customers.

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3 *See*, Technical Appendix LF-2 for this information.

4 *See*, Technical Appendix LF-5 for the State Demographer's certified population history.

5 *See*, Technical Appendix LF-2 for the CBER long term population forecast.

TABLE LF-10
SUMMARY OF THE HISTORY AND FORECAST OF CLARK COUNTY NEVADA POPULATION AND RESIDENTIAL CUSTOMERS

Year	Population: State Demographer Intercensual through 2010; certified through 2016 (thousands)	Percent Change	Population: CBER June 2018 Annual Forecast; Clark Cty History (thousands)	Percent Change	Population as used in modeling (thousands)	Percent Change	Residential Customers	Percent Change
2008	1,898	2.8%			1,898	2.8%	726,321	0.8%
2009	1,933	1.9%			1,933	1.9%	726,950	0.1%
2010	1,959	1.4%			1,959	1.4%	729,565	0.4%
2011	1,968	0.4%			1,968	0.4%	737,500	1.1%
2012	1,988	1.0%			1,988	1.0%	748,245	1.5%
2013	2,032	2.2%			2,032	2.2%	756,904	1.2%
2014	2,069	1.9%			2,069	1.9%	768,263	1.5%
2015	2,118	2.4%			2,118	2.4%	781,941	1.8%
2016	2,166	2.3%			2,166	2.3%	796,196	1.8%
2017			2,248		2,209	2.0%	810,294	1.8%
2018			2,296	2.1%	2,255	2.1%	825,345	1.9%
2019			2,344	2.1%	2,303	2.1%	845,547	2.4%
2020			2,389	1.9%	2,347	1.9%	864,129	2.2%
2021			2,423	1.4%	2,380	1.4%	878,351	1.6%
2022			2,452	1.2%	2,409	1.2%	890,462	1.4%
2023			2,482	1.2%	2,438	1.2%	902,705	1.4%
2024			2,507	1.0%	2,463	1.0%	912,918	1.1%
2025			2,530	0.9%	2,485	0.9%	922,233	1.0%
2026			2,550	0.8%	2,505	0.8%	930,308	0.9%
2027			2,568	0.7%	2,523	0.7%	937,532	0.8%
2028			2,585	0.7%	2,539	0.7%	944,291	0.7%
2029			2,600	0.6%	2,554	0.6%	950,234	0.6%
2030			2,615	0.6%	2,569	0.6%	956,106	0.6%
2031			2,628	0.5%	2,581	0.5%	961,185	0.5%
2032			2,640	0.5%	2,593	0.5%	965,849	0.5%
2033			2,651	0.4%	2,604	0.4%	970,104	0.4%
2034			2,662	0.4%	2,615	0.4%	974,323	0.4%
2035			2,672	0.4%	2,625	0.4%	978,146	0.4%
2036			2,682	0.4%	2,635	0.4%	981,945	0.4%
2037			2,692	0.4%	2,644	0.4%	985,721	0.4%
2038			2,701	0.3%	2,653	0.3%	989,114	0.3%
2039			2,710	0.3%	2,662	0.3%	992,492	0.3%

TABLE LF-11
SUMMARY OF THE HISTORY AND FORECAST OF NORTHERN NEVADA POPULATION AND RESIDENTIAL CUSTOMERS

Year	State Demographer (1)	Percent Change	Oct. 2018 Global Insight	Percent Change	Population Used in Forecast (2) (3)	Percent Change	Residential Customers	Percent Change
2008	742,986	1.0%	741,525	1.0%	742,986	1.0%	275,763	0.4%
2009	744,077	0.1%	746,025	0.6%	744,077	0.1%	275,419	-0.1%
2010	746,354	0.3%	750,102	0.5%	746,354	0.3%	276,250	0.3%
2011	754,072	1.0%	752,380	0.3%	754,072	1.0%	277,252	0.4%
2012	762,022	1.1%	756,660	0.6%	762,022	1.1%	279,219	0.7%
2013	769,244	0.9%	761,390	0.6%	769,244	0.9%	281,282	0.7%
2014	773,851	0.6%	767,471	0.8%	775,389	0.8%	284,301	1.1%
2015	779,231	0.7%	774,191	0.9%	782,177	0.9%	287,725	1.2%
2016	787,194	1.0%	784,061	1.3%	792,149	1.3%	291,401	1.3%
2017	792,838	0.7%	795,212	1.4%	803,415	1.4%	294,966	1.2%
2018	799,745	0.9%	804,996	1.2%	815,344	1.5%	299,623	1.6%
2019	806,600	0.9%	813,012	1.0%	826,526	1.4%	304,207	1.5%
2020	815,608	1.1%	819,387	0.8%	836,617	1.2%	307,693	1.1%
2021	823,126	0.9%	824,852	0.7%	844,942	1.0%	310,732	1.0%
2022	829,357	0.8%	829,271	0.5%	851,803	0.8%	313,252	0.8%
2023	834,610	0.6%	833,228	0.5%	857,568	0.7%	315,372	0.7%
2024	839,091	0.5%	836,682	0.4%	862,909	0.6%	317,336	0.6%
2025	842,525	0.4%	840,199	0.4%	867,555	0.5%	319,045	0.5%
2026	845,379	0.3%	843,745	0.4%	871,910	0.5%	320,647	0.5%
2027	847,934	0.3%	847,593	0.5%	876,270	0.5%	322,250	0.5%
2028	850,179	0.3%	851,596	0.5%	880,651	0.5%	323,861	0.5%
2029	852,477	0.3%	855,804	0.5%	885,054	0.5%	325,480	0.5%
2030	854,725	0.3%	860,188	0.5%	889,480	0.5%	327,108	0.5%
2031	856,989	0.3%	864,741	0.5%	893,927	0.5%	328,743	0.5%
2032	859,239	0.3%	869,391	0.5%	898,397	0.5%	330,387	0.5%
2033	861,437	0.3%	874,236	0.6%	902,889	0.5%	332,039	0.5%
2034	863,613	0.3%	879,293	0.6%	907,403	0.5%	333,699	0.5%
2035	865,732	0.2%	884,378	0.6%	911,940	0.5%	335,368	0.5%
2036	867,672	0.2%	889,471	0.6%	916,500	0.5%	337,044	0.5%
2037	869,462	0.2%	894,568	0.6%	921,082	0.5%	338,730	0.5%
2038	N/A		899,576	0.6%	925,688	0.5%	340,423	0.5%
2039	N/A		904,647	0.6%	930,316	0.5%	342,125	0.5%

(1) Intercensal history from 2004 through 2010 and certified estimates from 2011-2017.
2018 through 2036 is from the October 2018 State Demographer population forecast.
(2) The annual growth rates from 2014 through 2018 are from the November 2017 Global Insight Population Forecast.
(3) The growth rates from 2019 through 2026 are an average of the GI and State Demographer growth rates.
The growth rate was flattened after 2026.

The Denton-Chelotte temporal disaggregation statistical technique was used to convert the quarterly history and forecasts of GI economic variables for all but the population used in the Nevada Power Residential customer forecast.[6] As noted above, that forecast used annual historical

[6] *See*, https://journal.r-project.org/archive/2013-2/sax-steiner.pdf for a discussion of this technique as instituted in the R statistical package.

and forecast population data. The residential customer forecast was converted to monthly data using the Denton-Chelotte method. Statistical temporal disaggregation techniques take lower frequency data to higher frequency data (for quarterly or annual to monthly data for example). These techniques are standard practice for the U.S. Bureau of Economic Analysis ("BEA") as well as many foreign statistical agencies.[7]

Tables LF-12 and LF-13 are a summary of the Economic Variables used in the 2019 IRPA 2nd Forecast. Persons per household ("PPH") is calculated by dividing the GI population history and forecast by the GI history and forecast of households. PPH is incorporated in the residential average use model. Real Personal Income ("RPI") is from the GI data and Real Personal Income per Household ("RPI per HH") was developed by dividing GI RPI by GI households.

7 *See*, https://www.bea.gov/scb/pdf/2008/05%20May/0508_methods.pdf for a discussion of the testing and institution of statistical temporal disaggregation at the BEA.

TABLE LF-12
HISTORY AND FORECAST OF CLARK COUNTY ECONOMIC VARIABLES

Year	Real Gross Metro Product (millions of 2009 $)	Real Personal Income (RPI) (millions of 2009 $)	Households (000's)	RPI per Household (2009 $)	Persons Per Household	Hotel/Motel Rooms (1)
2008	95,447	72,831	701	103,960	2.73	136,940
2009	84,960	67,328	712	94,597	2.73	141,778
2010	82,921	68,721	714	96,223	2.74	148,383
2011	83,298	69,953	714	97,977	2.76	149,572
2012	83,378	73,959	728	101,633	2.75	150,524
2013	84,766	73,035	730	99,992	2.78	150,103
2014	85,847	78,346	745	105,183	2.78	150,126
2015	92,305	84,436	759	111,288	2.79	149,612
2016	93,511	86,442	778	111,093	2.78	148,666
2017	96,054	89,779	816	109,999	2.71	147,268
2018	99,895	93,036	839	110,828	2.68	147,500
2019	103,722	96,204	859	111,948	2.66	147,826
2020	106,925	99,739	878	113,657	2.65	147,905
2021	109,890	103,292	895	115,348	2.63	147,905
2022	112,585	106,402	910	116,921	2.62	147,905
2023	114,946	109,083	924	117,994	2.61	147,905
2024	117,635	111,947	939	119,191	2.60	147,905
2025	120,779	115,217	954	120,806	2.60	147,905
2026	124,164	118,791	969	122,652	2.59	147,905
2027	127,648	122,506	983	124,664	2.58	147,905
2028	130,991	126,466	998	126,759	2.57	147,905
2029	134,428	130,568	1,013	128,891	2.56	147,905
2030	137,756	134,622	1,028	130,909	2.55	147,905
2031	141,309	139,018	1,044	133,122	2.54	147,905
2032	144,995	143,766	1,061	135,537	2.53	147,905
2033	148,894	148,564	1,077	137,907	2.53	147,905
2034	152,884	153,552	1,095	140,264	2.52	147,905
2035	157,110	158,709	1,112	142,703	2.51	147,905
2036	161,413	164,064	1,129	145,251	2.50	147,905
2037	165,544	169,406	1,148	147,587	2.48	147,905
2038	169,990	174,802	1,166	149,882	2.47	147,905
2039	174,737	180,118	1,184	152,179	2.47	147,905

(1) Does not include 3000 rooms for Resorts World opening mid-2021.

TABLE LF-13
HISTORY AND FORECAST OF NN ECONOMIC VARIABLES

Year	Real GMP (millions) 2009$	Non-Manf. Employment	Real Pers Inc (RPI) (millions 2009$)	RPI per HH (2009$)	Households (HH) (000's)	Persons per HH
2008	35,339	328,561	29,007	101,152	286.77	2.59
2009	35,243	302,054	29,542	102,048	289.49	2.58
2010	37,616	295,828	30,726	105,783	290.46	2.58
2011	37,820	298,879	30,973	106,968	289.57	2.60
2012	36,034	300,438	30,092	102,769	292.82	2.58
2013	35,261	304,864	30,196	103,337	292.20	2.61
2014	36,072	311,913	31,619	106,949	295.62	2.60
2015	36,577	318,917	34,075	113,293	300.77	2.57
2016	37,162	327,818	34,676	113,928	304.39	2.58
2017	38,612	339,694	36,392	113,700	320.07	2.48
2018	40,174	347,351	37,636	115,103	326.97	2.46
2019	41,264	352,332	38,647	116,388	332.05	2.45
2020	42,254	358,643	39,886	118,577	336.37	2.44
2021	43,099	363,078	41,017	120,567	340.20	2.42
2022	43,723	365,442	41,901	122,216	342.85	2.42
2023	44,423	366,024	42,635	123,527	345.15	2.41
2024	45,071	366,906	43,450	125,140	347.21	2.41
2025	45,821	368,777	44,397	127,140	349.20	2.41
2026	46,674	371,014	45,440	129,369	351.24	2.40
2027	47,551	372,872	46,552	131,829	353.12	2.40
2028	48,370	374,674	47,716	134,328	355.22	2.40
2029	49,231	376,618	48,912	136,852	357.41	2.39
2030	49,984	377,972	50,037	139,124	359.65	2.39
2031	50,744	378,923	51,253	141,596	361.96	2.39
2032	51,615	381,036	52,605	144,352	364.42	2.39
2033	52,518	383,523	53,941	147,033	366.86	2.38
2034	53,431	386,104	55,336	149,751	369.51	2.38
2035	54,382	388,828	56,750	152,521	372.08	2.38
2036	55,295	391,354	58,203	155,394	374.55	2.37
2037	56,172	393,174	59,655	158,116	377.28	2.37
2038	57,171	395,871	61,090	160,769	379.98	2.37
2039	58,230	398,798	62,587	163,731	382.25	2.37

Mining Industry. Mining load in Sierra's territory is expected to increase moderately over the next few years due to expansion at two mines. In 2020, mine load declines significantly due to the transition to DOS of a large mine customer. The percentage of mine sales to total weather normalized sales drops from 20.6 percent in 2019 to 8.9 percent in 2024.

Other large customers. In Sierra's service territory, the 2019 IRPA 2nd Forecast assumed that load at the Tesla Gigafactory will ramp up to [redacted] MW by 2021 and [redacted] GWh by 2022. This will be partially offset by a reduction of [redacted] GWh expected with the completion of a [redacted] MW rooftop solar array ([redacted] GWh total). The 2018 IRP Forecast assumed [redacted] MW and [redacted] GWh by 2022 with an offset of [redacted] GWh from a [redacted] MW solar rooftop array ([redacted] total GWh). Both forecasts assume that Tesla's load remains flat for the remainder of the forecast. The 2019 IRPA 2nd Forecast assumes that as of 2026, load at the Apple data center will be [redacted] MW, and [redacted] GWh. This compares with [redacted] MW and [redacted] GWh by 2022, as assumed in the 2018 IRP Forecast. Both forecasts assume that Apple's load remains flat for the remainder of the forecast. The forecasted increase in Apple's load is based on a High Voltage Distribution agreement signed in May 2018, which provides for a buildout of [redacted] MW of additional facilities, for a total of [redacted] MW. In Nevada Power's service territory, the only large customer added outside the model is Resorts World. Based on a change in the announced opening date for the facility[8], the 2019 IRP 2nd Forecast assumes [redacted] MW and [redacted] GWh by 2022, while the 2018 IRP Forecast assumed [redacted] MW and [redacted] GWh by 2021.

The expected customer load is discounted for two factors:

1. For some new load the customer requested MW is discounted to reflect operation of less than full capacity ("Expected Load");

2. A probability of the large customer becoming operational was assigned to each new customer or expansion based on whether they were a current customer, their size, and whether signed contracts or funds had been paid to Sierra. This probability factor is then multiplied by the expected load to obtain the final forecasted load for that customer.

The ramp-up time for each customer is forecasted individually. Table LF-14 is a summary of the mine and other large customer load forecasted through 2039. Note: the spreadsheet detailing all the calculations for the large customer load forecast will be included with this filing as a confidential work paper.

[8] See Technical Appendix LF-8, LVCVA Tourism and Construction Bulletin, December 5, 2018 for the expected opening date of Resorts World.

TABLE LF-14 [CONFIDENTIAL]
MINE AND NON-MINE LARGE CUSTOMER LOAD

[redacted]

Weather Data. Monthly Heating Degree Days ("HDD") and Cooling Degree Days ("CDD") (actual and normalized) are calculated from historical daily temperature data for Reno-Tahoe International Airport. HDDs and CDDs are defined for a 65 degree base. Cycle-weighted HDD and CDD are constructed to match the monthly sales data billing period. Cycle-weighted degree days are calculated by first computing daily degree-days; the daily degree days are then weighted based on the historical meter read schedule and summed across the revenue month. Calendar HDD and CDD are generated by aggregating the daily degree-days over the calendar month.

For the 2019 IRPA 2nd Forecast, twenty-year normal HDD and CDD are based on daily temperature data from January 1, 1999 through December 31, 2018. Cycle-weighted normal HDD and CDD are calculated by first applying the meter-read cycle weight to the daily normal degree-days and aggregating over the revenue-month and then averaged over the last 20 years for each month. Cycle weighted degree days are used as a driver variable in the billed sales model as they align more closes with billed sales than calendar degree days.

Table LF-15 is a summary of the annual Cycle and calendar degree days and the annual calendar normal degree days. The calendar degree days are used to forecast class sales for planning as we are interested in the calendar month energy forecast, not a billed sales forecast. The calendar month normals were also the average of the 20-year period from January 1999 through December 2018.

TABLE LF-15
CYCLE AND CALENDAR HDD AND CDD

	SIERRA				NEVADA POWER			
	Cycle Degree Days		Calendar Degree Days		Cycle Degree Days		Calendar Degree Days	
Year	CDD	HDD	CDD	HDD	CDD	HDD	CDD	HDD
1999	717	4,903	717	4,822	3,229	1,828	3,217	1,817
2000	849	4,775	849	4,795	3,753	1,913	3,745	1,941
2001	1,043	4,587	1,043	4,579	3,907	2,021	3,894	2,088
2002	986	4,878	986	4,877	3,645	2,102	3,636	2,105
2003	1,186	4,620	1,186	4,592	3,852	1,855	3,838	1,902
2004	1,024	4,600	1,024	4,654	3,730	1,993	3,730	1,993
2005	963	5,085	963	4,930	3,565	1,598	3,565	1,615
2006	1,151	4,748	1,151	4,893	3,734	1,781	3,739	1,876
2007	1,263	4,737	1,263	4,756	4,077	1,676	4,077	1,775
2008	1,132	4,908	1,132	4,923	3,775	1,827	3,775	1,846
2009	1,069	4,886	1,069	5,004	3,790	1,886	3,791	1,889
2010	922	5,093	922	4,868	3,648	2,009	3,648	1,895
2011	964	5,020	964	5,112	3,540	1,873	3,570	1,873
2012	1,272	4,325	1,272	4,352	4,032	1,699	4,032	1,659
2013	1,177	4,873	1,177	5,008	3,773	1,825	3,773	1,882
2014	1,211	3,998	1,211	3,922	3,970	1,344	3,970	1,306
2015	1,194	4,035	1,194	4,122	4,061	1,379	4,061	1,491
2016	1,088	4,213	1,088	4,190	4,002	1,522	4,002	1,508
2017	1,401	4,582	1,401	4,523	4,043	1,364	4,044	1,265
2018	1,290	4,481	1,290	4,450	4,256	1,487	4,255	1,527
20 yr avg	1,095	4,668	1,095	4,669	3,819	1,749	3,818	1,763

Billing Days. As the class sales models are estimated using billed sales it's important to account for the number of billing days in each month. Monthly billed sales can vary significantly across months due to variation in the number of billing days. Billing days are explicitly incorporated into the model through the "XOther" variable. The number of monthly billing days is calculated from historical meter read schedules.

Retail Price. Per NAC § 704.9225(2), an electric price variable is constructed for each revenue class. The price series is defined as a 12-month moving average of the average retail rate. The average retail rate is calculated by dividing billed revenues by billed sales and adjusting the series for inflation. Using a 12-month moving average mitigates the revenue/sales causal relationship (i.e., revenues are up when sales are up), and translates into a more reasonable relationship between price and how customers respond. The Rates and Regulatory and Financial Planning departments provided revenue forecasts through 2027. However, real prices (cents per kWh) are flattened after 2025 for Nevada Power and after 2024 for Sierra due to NV Energy's pledge to keep rates steady or declining for the next decade. Table LF-16 is a summary of the annual average prices per kWh used in the Nevada Power class sales modelling and Table LF-17 is the same information for Sierra.

TABLE LF-16
NEVADA POWER'S CUSTOMER CLASS - REAL AVERAGE PRICE PER KWH

Year	Res Real Dollars per Kwh	% change	Sm C&I Real Dollars per Kwh	% change	Lg C&I Real Dollars per Kwh	% change
2007	$0.0673	5.4%	$0.0535	-9.0%	$0.0613	22.2%
2008	$0.0707	5.0%	$0.0532	-0.7%	$0.0610	-0.6%
2009	$0.0697	-1.4%	$0.0504	-5.3%	$0.0585	-4.0%
2010	$0.0748	7.3%	$0.0507	0.6%	$0.0611	4.4%
2011	$0.0709	-5.2%	$0.0467	-7.8%	$0.0560	-8.4%
2012	$0.0676	-4.6%	$0.0425	-9.0%	$0.0519	-7.3%
2013	$0.0674	-0.3%	$0.0405	-4.6%	$0.0507	-2.3%
2014	$0.0705	4.6%	$0.0438	8.1%	$0.0537	6.0%
2015	$0.0725	2.8%	$0.0455	3.8%	$0.0553	2.8%
2016	$0.0678	-6.4%	$0.0410	-9.9%	$0.0506	-8.4%
2017	$0.0627	-7.6%	$0.0357	-13.0%	$0.0469	-7.3%
2018	$0.0630	0.6%	$0.0376	5.6%	$0.0472	0.6%
2019	$0.0621	-1.5%	$0.0370	-1.6%	$0.0463	-2.0%
2020	$0.0594	-4.3%	$0.0353	-4.8%	$0.0445	-3.9%
2021	$0.0577	-2.8%	$0.0347	-1.7%	$0.0440	-1.3%
2022	$0.0565	-2.1%	$0.0343	-1.1%	$0.0431	-1.9%
2023	$0.0565	0.0%	$0.0343	0.0%	$0.0431	0.0%
2024	$0.0565	0.0%	$0.0343	0.0%	$0.0431	0.0%
2025	$0.0565	0.0%	$0.0343	0.0%	$0.0431	0.0%
2026	$0.0565	0.0%	$0.0343	0.0%	$0.0431	0.0%
2027	$0.0565	0.0%	$0.0343	0.0%	$0.0431	0.0%
2028	$0.0565	0.0%	$0.0343	0.0%	$0.0431	0.0%
2029	$0.0565	0.0%	$0.0343	0.0%	$0.0431	0.0%
2030	$0.0565	0.0%	$0.0343	0.0%	$0.0431	0.0%
2031	$0.0565	0.0%	$0.0343	0.0%	$0.0431	0.0%
2032	$0.0565	0.0%	$0.0343	0.0%	$0.0431	0.0%
2033	$0.0565	0.0%	$0.0343	0.0%	$0.0431	0.0%
2034	$0.0565	0.0%	$0.0343	0.0%	$0.0431	0.0%
2035	$0.0565	0.0%	$0.0343	0.0%	$0.0431	0.0%
2036	$0.0565	0.0%	$0.0343	0.0%	$0.0431	0.0%
2037	$0.0565	0.0%	$0.0343	0.0%	$0.0431	0.0%
2038	$0.0565	0.0%	$0.0343	0.0%	$0.0431	0.0%
2039	$0.0565	0.0%	$0.0343	0.0%	$0.0431	0.0%

TABLE LF-17
SIERRA'S CUSTOMER CLASS - REAL AVERAGE PRICE PER KWH

Year	Res Real Dollars per Kwh	% change	Small C&I Real Dollars per Kwh	% change	Large C&I Real Dollars per Kwh	% change
2008	$0.1356		$0.1244		$0.1117	
2009	$0.1442	6.3%	$0.1299	4.5%	$0.1165	4.2%
2010	$0.1375	-4.6%	$0.1231	-5.3%	$0.1131	-2.9%
2011	$0.1224	-11.0%	$0.1085	-11.8%	$0.0981	-13.2%
2012	$0.1107	-9.5%	$0.0982	-9.5%	$0.0882	-10.1%
2013	$0.1094	-1.2%	$0.0970	-1.3%	$0.0838	-5.0%
2014	$0.1134	3.7%	$0.0968	-0.2%	$0.0795	-5.1%
2015	$0.1160	2.2%	$0.0921	-4.8%	$0.0739	-7.1%
2016	$0.1060	-8.6%	$0.0821	-10.9%	$0.0658	-10.9%
2017	$0.0956	-9.9%	$0.0721	-12.1%	$0.0576	-12.6%
2018	$0.1007	5.3%	$0.0773	7.2%	$0.0600	4.3%
2019	$0.0967	-4.0%	$0.0737	-4.7%	$0.0578	-3.7%
2020	$0.0921	-4.7%	$0.0701	-4.9%	$0.0551	-4.6%
2021	$0.0897	-2.6%	$0.0703	0.3%	$0.0542	-1.7%
2022	$0.0901	0.4%	$0.0712	1.3%	$0.0531	-1.9%
2023	$0.0899	-0.3%	$0.0718	0.8%	$0.0526	-1.0%
2024	$0.0882	-1.9%	$0.0711	-0.9%	$0.0522	-0.7%
2025	$0.0882	0.0%	$0.0711	0.0%	$0.0522	0.0%
2026	$0.0882	0.0%	$0.0711	0.0%	$0.0522	0.0%
2027	$0.0882	0.0%	$0.0711	0.0%	$0.0522	0.0%
2028	$0.0882	0.0%	$0.0711	0.0%	$0.0522	0.0%
2029	$0.0882	0.0%	$0.0711	0.0%	$0.0522	0.0%
2030	$0.0882	0.0%	$0.0711	0.0%	$0.0522	0.0%
2031	$0.0882	0.0%	$0.0711	0.0%	$0.0522	0.0%
2032	$0.0882	0.0%	$0.0711	0.0%	$0.0522	0.0%
2033	$0.0882	0.0%	$0.0711	0.0%	$0.0522	0.0%
2034	$0.0882	0.0%	$0.0711	0.0%	$0.0522	0.0%
2035	$0.0882	0.0%	$0.0711	0.0%	$0.0522	0.0%
2036	$0.0882	0.0%	$0.0711	0.0%	$0.0522	0.0%
2037	$0.0882	0.0%	$0.0711	0.0%	$0.0522	0.0%
2038	$0.0882	0.0%	$0.0711	0.0%	$0.0522	0.0%
2039	$0.0882	0.0%	$0.0717	0.8%	$0.0522	0.0%

Residential Energy Intensities.[9] The energy intensities for the Statistically Adjusted End Use were updated to the 2018 values provided by Itron and then adjusted based on energy intensities ("EI") developed by ADM Associates based on analysis of the customer survey responses from the 2016 Residential Appliance Saturation Survey ("2016 RASS"). These adjusted EI were then reduced by the Demand Side Management ("DSM") as in past forecasts.

[9] The use of the XCool, XHeat and XOther indices for the residential and commercial class sales forecasts satisfies NAC 704.925(4).

As a part of the 2016 RASS project, ADM Associates developed hourly loads for cooling, heating, water heating, lighting pools and residual load using survey responses, individual customer hourly loads, weather data, statistical modeling and third party sources. These intensities are then inserted as the 2015 values in place of the Itron intensities.[10] The Itron growth rates for each end-use are then used to both back cast and forecast the intensities.

As part of a DSM Market Potential Study conducted in 2017 and 2018 by Applied Energy Group ("AEG"), end-use intensities were calculated based on 2016 Sierra sales and other data sources. The results for lighting shown in Table LF-18. The addition of the four lighting intensities from that study is 1,341 annual kWh per customer while the 2017 Itron estimate was 771 kWh per customer for 2016. After discussions with AEG personnel, it was decided to use the 1,341 kWh as the lighting end-use intensity for the baseline year. To be consistent with the ADM intensity data, which was the year ended April 30, 2016, the 1,341 kWh was used for 2015.

TABLE LF-18
SIERRA 2018 AEG LIGHTING INTENSITY ESTIMATES

Electric Market Profiles

End Use	Technology	Saturation	UEC (kWh)
Interior Lighting	General Service Lighting	100.0%	755.6
Interior Lighting	Linear Lighting	100.0%	98.6
Interior Lighting	Exempted Lighting	100.0%	181.7
Exterior Lighting	Screw-in	100.0%	305.5

Commercial Appliance Equipment Indices. Commercial end-use intensities (use per square feet) are incorporated in the commercial sales forecast variables. End-use intensities projections are based on the U.S. Energy Information Administration ("EIA") 2018 Annual Energy Outlook for the Mountain Census Division. End-use energy intensities are calculated for ten end-uses across eleven building types. End-use intensities for the Mountain Census Region are modified to reflect the Nevada Power and Sierra service area building/business mix based on estimates of sales delivered to specific business categories.

In 2017, the EIA updated the 2004 base year historical commercial intensities developed from the 2003 Commercial Buildings Energy Consumption Survey ("CBECS") to 2013 based on the 2012 CBECS data, which significantly changed the historical and forecasted intensities and reduced Sierra's Small C&I average use per customer and to a lesser extent reduced the Nevada Power Small C&I average use per customer. As part of this change, a significant proportion of office equipment was moved from the office end-use to the miscellaneous end-use.

For 2018, Itron created a set of indices that removed an estimate of DSM for the Mountain region. These intensities were used in the Nevada Power forecast. The DSM adjusted intensities were not

[10] The hourly end-use data and calculations to summarize to annual intensities is included in the work papers for both Companies. The ADM report is included as Appendix LF-7.

used at Sierra as initial regression modeling produced lower forecasted sales than in recent forecasts.

Initial use per customer estimates for the Sierra Residential and Small C&I classes were higher than expected using the Itron miscellaneous intensity growth. The residential intensity increased from 2015 through 2019 then began falling. The miscellaneous intensity growth was reduced for 2016 through 2019 and then smoothed across the initial growth declines until 2025, when the intensities are the same. Growth from 2026 on is the same as the Itron growth.

For the commercial class, growth of over 1% per year was reflected in the Itron miscellaneous intensity from 2015 through 2022. The adjusted intensities smoothed the growth through 2019 and then flattened growth at 1% for the remainder of the forecast.

Table LF-19 is a summary of the miscellaneous intensities before and after smoothing.

TABLE LF-19
SIERRA MISCELLANEOUS INTENSITIES

	ANNUAL KWH PER CUSTOMER RESIDENTIAL					ANNUAL KWH PER SQUARE FOOT COMMERCIAL			
Year	Itron	% Change	Adjusted	% Change	Year	Itron	% Change	Adjusted	% Change
2015	3,352		3,352		2012	14,149		14,149	
2016	3,422	2.1%	3,420	2.0%	2013	14,198	0.3%	14,198	0.3%
2017	3,491	2.0%	3,471	1.5%	2014	14,395	1.4%	14,310	0.8%
2018	3,607	3.3%	3,506	1.0%	2015	14,595	1.4%	14,422	0.8%
2019	3,642	1.0%	3,524	0.5%	2016	14,862	1.8%	14,600	1.2%
2020	3,618	-0.7%	3,524	0.0%	2017	15,132	1.8%	14,777	1.2%
2021	3,585	-0.9%	3,506	-0.5%	2018	15,384	1.7%	14,936	1.1%
2022	3,557	-0.8%	3,493	-0.4%	2019	15,624	1.6%	15,078	1.0%
2023	3,525	-0.9%	3,482	-0.3%	2020	15,850	1.4%	15,222	1.0%
2024	3,497	-0.8%	3,475	-0.2%	2021	16,048	1.3%	15,367	1.0%
2025	3,467	-0.9%	3,467	-0.2%	2022	16,210	1.0%	15,514	1.0%
2026	3,461	-0.2%	3,461	-0.2%	2023	16,338	0.8%	15,662	1.0%
2027	3,456	-0.1%	3,456	-0.1%	2024	16,452	0.7%	15,811	1.0%
2028	3,457	0.0%	3,457	0.0%	2025	16,549	0.6%	15,962	1.0%
2029	3,457	0.0%	3,457	0.0%	2026	16,635	0.5%	16,114	1.0%
2030	3,455	-0.1%	3,455	-0.1%	2027	16,702	0.4%	16,268	1.0%
2031	3,452	-0.1%	3,452	-0.1%	2028	16,760	0.3%	16,423	1.0%
2032	3,452	0.0%	3,452	0.0%	2029	16,809	0.3%	16,580	1.0%
2033	3,450	0.0%	3,450	0.0%	2030	16,848	0.2%	16,738	1.0%

C. Adjustments for DSM Program Savings

As noted in the narrative, the incremental annual reductions in load attributed to DSM in the 2019 IRPA 2nd Forecast are based on the 2019 DSM plan filed to be filed June 1, 2019. These forecasted reductions are based on the 1.25 percent of WN sales statewide goal stipulated with intervenors in in the 2018 IRP. The 2018 IRP used a 1 percent of WN sales goal. The 2018 IRP forecast did not exclude Demand Response ("DR") savings from the calculations. Tables LF-20 and LF-21 are a comparison of the 2019 IRPA 2nd Forecast and the 2018 IRP Forecast. The commercial savings increased significantly from 2018 while the residential savings are much less. This is due to using a 50/50 split of savings between classes for the 2018 IRP and for Nevada Power, including the DR in the calculation of savings. More programs are targeted to commercial customers in the 2019 IRPA 2nd Forecast.

TABLE LF-20
NEVADA POWER DSM SAVINGS COMPARISON (GWH)

	RESIDENTIAL			COMMERCIAL			TOTAL		
Year	2019	2018	Diff	2019	2018	Diff	2019	2018	Diff
2019	44	107	-63	180	118	62	225	226	-1
2020	91	215	-124	366	240	126	457	455	2
2021	135	324	-189	558	364	194	693	688	4
2022	179	434	-255	752	490	263	931	924	7
2023	223	545	-322	948	617	331	1,171	1,163	9
2024	268	658	-390	1,145	747	398	1,413	1,404	9
2025	313	771	-457	1,343	878	465	1,656	1,648	8
2026	359	884	-526	1,541	1,010	531	1,900	1,894	5
2027	404	998	-594	1,740	1,144	596	2,144	2,143	2
2028	450	1,113	-663	1,940	1,280	660	2,391	2,393	-3
2029	496	1,229	-733	2,141	1,417	725	2,638	2,645	-8
2030	543	1,345	-802	2,343	1,554	789	2,885	2,899	-13
2031	589	1,461	-872	2,544	1,692	853	3,134	3,153	-19
2032	636	1,578	-942	2,747	1,830	917	3,383	3,408	-25
2033	683	1,695	-1,012	2,950	1,969	980	3,633	3,665	-32
2034	731	1,813	-1,082	3,153	2,110	1,044	3,884	3,922	-39
2035	778	1,931	-1,153	3,358	2,251	1,107	4,136	4,181	-46
2036	826	2,049	-1,223	3,563	2,392	1,170	4,389	4,442	-53
2037	874	2,168	-1,294	3,769	2,535	1,234	4,643	4,703	-60
2038	923	2,287	-1,365	3,976	2,679	1,297	4,898	4,966	-68

Note: 2018 reductions are adjusted to be incremental from 2018.

TABLE LF-21
SIERRA DSM SAVINGS COMPARISON (GWH)

	RESIDENTIAL			COMMERCIAL			TOTAL		
Year	2019	2018	Diff	2019	2018	Diff	2019	2018	Diff
2019	15	19	-4	64	51	13	79	70	9
2020	30	37	-7	133	105	28	164	142	21
2021	45	56	-12	207	161	46	252	217	35
2022	57	75	-18	275	218	57	332	293	39
2023	70	95	-24	343	270	73	413	365	48
2024	84	114	-30	412	319	93	496	433	63
2025	97	133	-36	482	369	114	580	502	78
2026	111	153	-42	553	418	135	664	571	93
2027	124	173	-48	624	469	156	749	641	108
2028	138	192	-54	695	519	176	834	711	122
2029	152	212	-61	767	570	197	919	782	136
2030	165	232	-67	838	621	217	1,004	853	150
2031	179	253	-73	910	672	238	1,089	925	164
2032	193	273	-80	982	723	258	1,175	996	178
2033	207	293	-87	1,054	775	279	1,260	1,068	192
2034	221	314	-93	1,126	826	299	1,346	1,140	206
2035	234	335	-100	1,198	878	320	1,432	1,213	220
2036	248	356	-107	1,271	930	341	1,519	1,285	234
2037	262	377	-115	1,344	982	362	1,606	1,358	247
2038	276	398	-122	1,417	1,034	383	1,693	1,432	261

Note: 2018 reductions are adjusted to be incremental from 2018.

In developing the forecast the Companies recognize that there is significant efficiency embedded in the forecast even before adjusting for future DSM program savings. DSM impacts are captured through the model estimation process and the EIA end-use efficiency projections. First, the forecast models are estimated using actual billed sales data which includes the impact of past DSM activity. As the models are estimated over a period of increasing DSM program activity, the resulting baseline forecast assumes some level of continued DSM activity into the forecast period. Second, each year the EIA calibrates the forecasted end-use intensities to actual sales and appliance shipment data. The calibration process captures the impact DSM has had on both sales and appliance stock efficiency. As a result the end-use intensity forecasts assume “on-going” DSM activity through the forecast period.

With the inclusion DSM activity in the end-use intensity forecast subtracting out all future DSM program savings would result in “double-counting” future program impacts.

As in the past, DSM planning was provided estimated factors to allocate the historical and incremental future DSM savings on an end-use basis. Using this data, embedded DSM is determined for each end-use based on end-use savings over the estimation period relative to forecasted end-use savings. Adjusted DSM savings are calculated using the embedded DSM rates. The baseline end-use intensities projections are then modified to capture the adjusted DSM savings forecasts. The procedure followed in the 2019 IRPA 2nd Forecast is the same as in past forecasts. Table LF-22 is a summary of the Nevada Power historic DSM savings by end-use and Table LF-

23 is the summary for Sierra. The historic DSM is used to adjust the future DSM to avoid double counting future program impacts.[11]

TABLE LF-22 (page 1 of 2)
NEVADA POWER HISTORICAL DSM SAVINGS (MWH)
Residential Annual Savings (Incremental MWH)

Year	Lighting	Cooling	Refrig	Misc	Water Heating	Heating	Total
2005	4,200	12,976	4,176	312	0	0	21,664
2006	22,899	22,024	4,070	598	0	0	49,591
2007	68,403	19,346	6,579	1,486	0	0	95,814
2008	119,050	19,356	11,317	2,738	0	0	152,461
2009	131,560	28,712	13,011	6,680	0	0	179,964
2010	99,547	10,429	9,860	10,839	0	0	130,674
2011	70,955	5,867	6,303	13,364	30	0	96,518
2012	32,269	9,267	5,485	13,763	45	0	60,829
2013	442	9,844	4,942	10,040	27	0	25,294
2014	6,314	9,921	4,894	13,000	22	0	34,150
2015	15,425	7,948	4,932	20,908	6	0	49,220
2016	9,422	8,383	2,630	17,286	2	0	37,723
2017	0	11,795	0	9,080	0	0	20,874
2018	0	12,001	0	9,080	0	0	21,080

TABLE LF-22 (page 2 of 2)
NEVADA POWER HISTORICAL DSM SAVINGS (MWH)
Commercial Annual Savings (Incremental MWH)

Year	Lighting	Cooling	Misc	Total
2005	24,385	10,472	8,762	43,619
2006	29,626	12,698	10,585	52,910
2007	39,667	17,580	13,898	71,145
2008	48,325	23,083	19,000	90,409
2009	73,168	33,241	30,124	136,533
2010	88,670	37,704	33,320	159,695
2011	72,131	31,332	30,073	133,535
2012	64,194	28,630	31,948	124,772
2013	59,959	26,269	26,134	112,361
2014	60,361	26,215	23,785	110,361
2015	64,943	28,006	24,137	117,086
2016	64,510	28,071	25,631	118,212
2017	71,139	31,034	28,329	130,502
2018	69,610	30,232	26,700	126,542

[11] As in past years, the DSM savings used for the history is the realized savings not the first year savings reported in the DSM volumes. The realized savings are 55 percent of the prior year's savings plus 45 percent of the current year's savings. The 45 percent is the approximate amount of savings for measures installed before the July peak of the current year.

TABLE LF-23 (page 1 of 2)
SIERRA HISTORICAL DSM SAVINGS (MWH)[12]
Residential Annual Savings (Incremental MWH)

Year	Lighting	Cooling	Refrig	Misc	Water	Heating	Total
2005	1,219	0	868	9	0	0	2,095
2006	9,941	145	1,896	44	0	0	12,025
2007	23,647	177	2,166	71	0	0	26,061
2008	40,555	0	3,832	656	0	0	45,043
2009	48,395	0	5,482	1,293	0	0	55,170
2010	33,984	0	4,383	1,035	0	0	39,402
2011	20,066	0	2,917	2,177	19	0	25,179
2012	7,940	0	2,548	3,057	37	0	13,582
2013	0	0	1,995	1,174	43	0	3,212
2014	1,752	0	2,133	2,974	39	0	6,898
2015	5,126	0	2,503	7,111	33	0	14,773
2016	0	2,222	0	663	3,820	1,481	8,186
2017	0	1,138	0	340	1,957	759	4,193
2018	0	0	0	0	0	0	-

TABLE LF-23 (page 2 of 2)
SIERRA HISTORICAL DSM SAVINGS (MWH)
Commercial Annual Savings (Incremental MWH)

Year	Lighting	Cooling	Misc	Total
2005	6,759	2,861	2,156	11,776
2006	20,592	8,480	7,650	36,721
2007	21,640	8,684	9,256	39,580
2008	18,634	7,372	8,457	34,463
2009	26,567	10,408	11,283	48,257
2010	25,233	9,993	10,221	45,446
2011	19,834	7,915	7,530	35,279
2012	18,905	7,264	8,081	34,250
2013	17,992	6,367	9,332	33,692
2014	20,877	7,762	8,918	37,557
2015	20,098	8,537	6,746	35,380
2016	21,011	8,919	6,856	36,786
2017	22,482	4,170	16,347	42,999
2018	17,796	3,370	13,446	34,613

The DSM savings forecast was based on the forecasted total sales for each company prior to adjustment for DSM. The residential, small and large C&I model sales were estimated using the baseline intensities. Adjustments for solar PV reductions and EV sales increases were made. The addition of non-modeled sales produced the total WN sales to be used in the calculation of the

12 No residential savings were calculated for 2018.

DSM savings. Table LF-24 is a summary of the sales forecast unadjusted for DSM used to calculate the DSM program savings by the DSM department.

The 2019 IRPA 2nd Forecast used a percentage goal of 1.18 percent for Nevada Power not including DR (1.39 percent with DR) and 0.91 percent for Sierra (0.96 percent with DR). The Sierra sales used to calculate the DSM program savings did not include Street Lighting as Sierra owns those fixtures.

TABLE LF-24
SALES BEFORE DSM (GWH)

	Residential GWH			Non-Residential MWH		
Year	NVE	NPC	SPPC	NVE	NPC	SPPC
2019	12,160	9,692	2,468	23,449	16,820	6,629
2020	12,246	9,757	2,489	23,767	16,880	6,887
2021	12,298	9,804	2,494	24,473	17,325	7,147
2022	12,391	9,897	2,493	23,083	16,720	6,363
2023	12,463	9,969	2,494	23,149	16,776	6,373
2024	12,552	10,044	2,509	23,632	17,047	6,585
2025	12,589	10,081	2,508	23,923	17,215	6,708
2026	12,645	10,130	2,515	24,051	17,301	6,750
2027	12,709	10,185	2,524	24,121	17,357	6,764
2028	12,795	10,254	2,541	24,197	17,414	6,783
2029	12,859	10,311	2,548	24,244	17,449	6,795
2030	12,896	10,348	2,547	24,275	17,470	6,805
2031	12,936	10,387	2,550	24,315	17,499	6,817
2032	12,999	10,440	2,559	24,384	17,548	6,836
2033	13,034	10,473	2,560	24,425	17,577	6,849
2034	13,093	10,522	2,571	24,491	17,624	6,867
2035	13,154	10,571	2,583	24,566	17,680	6,886
2036	13,242	10,640	2,602	24,660	17,750	6,910
2037	13,297	10,688	2,609	24,717	17,792	6,925
2038	13,368	10,746	2,622	24,800	17,854	6,946
2039	13,449	10,812	2,637	24,891	17,922	6,969

(1) Sierra Street Lighting sales are not included as Sierra owns the fixtures.

The next step is to estimate the embedded historical DSM. We make the simplifying assumption, that past DSM savings impact the estimated model coefficients and that the forecast reflects this level of DSM activity through the forecast period. The amount of future DSM savings already captured by the model partly depends on the number years of DSM activity relative to the estimation period, and the amount of past DSM savings. Table LF-25 shows the calculation for the Sierra Commercial embedded lighting DSM programs.

Table LF-25
Calculation of Commercial Embedded Lighting DSM

Years with Lighting Program	14
Percent of years with programs	100.0%
Cumulative Actual Savings (MWh)	278,420
Adjusted for Estimation Period (MWh)	278,420
Savings over the next 10 years (MWh)	357,949
Pct Embedded in model	77.8%
Adjustment for Future DSM	22.2%

There have been active lighting programs for the last 14 years with cumulative savings of 278,420 MWh. We assume that this level of activity is captured in the baseline forecast. DSM projects future cumulative savings of 357,949 MWh over the next 10 years. The percent embedded in the model is then 77.8 percent (278,420 MWh/357,949 MWh). The adjustment factor applied to future DSM savings is then one minus the percent embedded in the forecast or 22.2 percent (1 – 77.8 percent). This adjustment factor is applied to forecasted commercial miscellaneous DSM savings.

This same approach is applied to all the end-uses impacted by DSM programs. Table LF-26 shows the calculated embedded and DSM forecast adjustment factors for each end-use.

Table LF-26
DSM Embedded and DSM Forecasted Adjustment Factors

	RESIDENTIAL			COMMERCIAL		
Company	End-use	Embedded	DSM Adjustment	End-use	Embedded	DSM Adjustment
NPC	Lighting	100.0%	0.0%	Lighting	55.1%	44.9%
	Cooling	100.0%	0.0%	Cooling	94.5%	5.5%
	Refrig	100.0%	0.0%	Misc	94.4%	5.6%
	Misc	100.0%	0.0%			
	Water	0.4%	99.6%			
	Heating	0.0%	100.0%			
SPPC	Lighting	100.0%	0.0%	Lighting	77.8%	22.2%
	Cooling	4.8%	95.2%	Cooling	100.0%	0.0%
	Refrig	100.0%	0.0%	Misc	46.8%	53.2%
	Misc	100.0%	0.0%			
	Water	12.6%	87.4%			
	Heating	12.3%	87.7%			

Due to the heavy program activity over the last 14 years, and the redesign of the residential and commercial DSM programs, there is now more DSM embedded in the history than expected for the future in many end-use categories. For these end-use categories, we assume that all the future program savings are already reflected in the baseline forecast as future savings are relatively small to what is embedded in the historical estimation period.

The next step is to adjust the end-use intensity forecast for future DSM savings. End-use sales are estimated using the model coefficients from the baseline SAE model. End-use sales forecasts are then adjusted downwards to reflect forecasted DSM savings (adjusted DSM savings). New end-use intensities are then calculated based on the DSM adjusted end-use sales forecast. Table LF-27 shows the calculation for the Sierra commercial lighting end-use.

TABLE LF-27
SIERRA COMMERCIAL LIGHTING DSM: EI ADJUSTMENT

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
Year	Cust	Light Sales (MWH)	Light Sales Per Cust (KWH)	Pct Change	DSM Prg Savings (MWH)	Adj DSM Savings (MWH)	Cum DSM Savings (MWH)	Adj Light Sales per customer (KWH)	Adjusted Use per Cust (KWH)	Adj chnge to Sales per Cust (KWH)	Growth rate change to Efficiencies due to DSM	Lighting Baseline EI (KWH)	Chg	Total Adjusted Change	Adj Light EI (KWH)	Total Change
			(C / B)			(0.24* F)	(Σ col G)	(G / A)	(C - H)		(D - J)			(K + M)		
2017	45,491	368,323	8,097	-2.0%					8,097	-2.0%	0.0%	5,493.73	-3.4%		5,493.73	-3.4%
2018	46,085	366,277	7,948	-1.8%					7,948	-1.8%	0.0%	5,346.95	-2.7%	-2.7%	5,346.95	-2.7%
2019	46,502	365,095	7,851	-1.2%	35,828	7,882	7,882	170	7,682	-3.3%	-2.1%	5,234.80	-2.1%	-4.2%	5,120.77	-4.2%
2020	46,851	356,716	7,614	-3.0%	38,109	8,384	16,266	347	7,267	-5.4%	-2.4%	5,017.52	-4.2%	-6.5%	4,786.35	-6.5%
2021	47,136	348,403	7,391	-2.9%	34,802	7,656	23,923	508	6,884	-5.3%	-2.3%	4,837.18	-3.6%	-5.9%	4,502.03	-5.9%
2022	47,371	341,261	7,204	-2.5%	34,835	7,664	31,586	667	6,537	-5.0%	-2.5%	4,683.83	-3.2%	-5.7%	4,246.74	-5.7%
2023	47,568	335,230	7,047	-2.2%	35,776	7,871	39,457	829	6,218	-4.9%	-2.7%	4,553.80	-2.8%	-5.5%	4,013.73	-5.5%
2024	47,748	330,640	6,925	-1.7%	36,277	7,981	47,438	994	5,931	-4.6%	-2.9%	4,442.40	-2.4%	-5.3%	3,800.34	-5.3%
2025	47,906	326,035	6,806	-1.7%	36,471	8,024	55,461	1,158	5,648	-4.8%	-3.1%	4,346.15	-2.2%	-5.2%	3,601.85	-5.2%
2026	48,054	322,740	6,716	-1.3%	36,558	8,043	63,504	1,322	5,395	-4.5%	-3.2%	4,263.02	-1.9%	-5.1%	3,418.78	-5.1%
2027	48,200	320,042	6,640	-1.1%	36,693	8,072	71,577	1,485	5,155	-4.4%	-3.3%	4,191.50	-1.7%	-5.0%	3,248.31	-5.0%
2028	48,347	318,118	6,580	-0.9%	36,759	8,087	79,664	1,648	4,932	-4.3%	-3.4%	4,129.82	-1.5%	-4.9%	3,089.50	-4.9%
2029	48,495	315,988	6,516	-1.0%	-	-	79,664	1,643	4,873	-1.2%	-0.2%	4,076.42	-1.3%	-1.5%	3,052.55	-1.2%
2030	48,643	305,440	6,279	-3.6%	-	-	79,664	1,638	4,642	-4.8%	-1.1%	3,906.85	-4.2%	-5.3%	2,907.44	-4.8%
2031	48,793	296,290	6,072	-3.3%	-	-	79,664	1,633	4,440	-4.3%	-1.1%	3,760.11	-3.8%	-4.8%	2,781.04	-4.3%
2032	48,943	288,809	5,901	-2.8%	-	-	79,664	1,628	4,273	-3.7%	-0.9%	3,632.67	-3.4%	-4.3%	2,676.76	-3.7%
2033	49,093	281,801	5,740	-2.7%	-	-	79,664	1,623	4,117	-3.6%	-0.9%	3,521.89	-3.0%	-4.0%	2,579.17	-3.6%
2034	49,245	276,059	5,606	-2.3%	-	-	79,664	1,618	3,988	-3.1%	-0.8%	3,425.44	-2.7%	-3.5%	2,498.17	-3.1%
2035	49,397	271,155	5,489	-2.1%	-	-	79,664	1,613	3,877	-2.8%	-0.7%	3,341.33	-2.5%	-3.2%	2,428.29	-2.8%
2036	49,550	267,240	5,393	-1.7%	-	-	79,664	1,608	3,786	-2.3%	-0.6%	3,267.89	-2.2%	-2.8%	2,371.30	-2.3%
2037	49,704	263,323	5,298	-1.8%	-	-	79,664	1,603	3,695	-2.4%	-0.6%	3,203.86	-2.0%	-2.6%	2,314.59	-2.4%
2038	49,858	260,395	5,223	-1.4%	-	-	79,664	1,598	3,625	-1.9%	-0.5%	3,147.59	-1.8%	-2.2%	2,270.66	-1.9%
2039	50,013	258,018	5,159	-1.2%												
	Adjustment Factor		**0.22**													

Total lighting sales are expressed on a per customer basis and then used to calculate the annual baseline change in per customer lighting use. Lighting sales are adjusted for DSM program savings (the commercial lighting DSM adjustment factor is 0.22 (see Column F which equals Column E times 0.22) and a new lighting average use is calculated (Column I = (Column B minus Column G) /Column A)). The forecasted lighting intensity is then adjusted based on the difference in expected lighting usage resulting from the program. So for example, the baseline forecast shows commercial lighting use per customer decreasing 1.2 percent in 2019 (Column D). After adjusting for lighting DSM savings, commercial per customer lighting use is expected to decrease 3.3 percent in 2019 (Column J). The impact is to reduce lighting use 2.1 percent more than that in the baseline forecast (Column K). The baseline intensity (Column M) is adjusted down by this percentage to obtain the DSM adjusted EI (Column O).

This same approach is used for each residential and commercial end-use.

III. <u>MODEL SPECIFICATION</u>

The forecast is based on the SAE modeling framework. The framework entails constructing generalized end-use variables for cooling (XCool), heating (XHeat), and other uses (XOther) and then using these variables as right-hand variables in monthly average use and sales forecast models. The general model specification is:

$$AvgUse_t = b_0 + b_1 * XCool_t + b_2 * XHeat_t + b_3 * XOther_t + e_t$$

The model coefficients are estimated using ordinary least squares. The construction of the end-use variables is presented below.

A. Residential Model Variables

XCool

The cooling variable (XCool) is constructed by combining a variable that reflects cooling saturation and efficiency (CoolIndex) with a variable that captures stock utilization (CoolUse):

$$\text{XCool}_{y,m} = \text{CoolIndex}_y \times \text{CoolUse}_{y,m}$$

The cooling equipment index is defined as a weighted average across cooling equipment types where the weight represents the average technology energy intensity (kWh per household) in the base year. The index changes over time with changes in end-use saturation and end-use efficiency ("EFF"). As cooling saturation increases the index increases, as the end-use efficiency increases the index decreases. A structural index variable also is incorporated into the variable calculation. The structural index (StructuralVar) captures change in housing square footage and thermal shell integrity improvement. As the weights are end-use intensities, the resulting CoolIndex is an estimate of annual cooling energy requirements. Formally, the cooling equipment index is defined as:

$$CoolIndex_y = StructuralVar * \sum_{Type} Weight^{Type} \times \frac{\left(CoolShare_y^{Type} / Eff_y^{Type} \right)}{\left(CoolShare_{base}^{Type} / Eff_{base}^{Type} \right)}$$

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, and prices. Cooling usage is calculated as:[13]

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{NormCDD} \right) \times \left(\frac{HHSize_y}{HHSize_{base}} \right)^{.25} \times \left(\frac{Income_y}{Income_{base}} \right)^{.20} \times \left(\frac{Price_{y,m}}{Price_{base}} \right)^{-.15}$$

Where, *CDD* is the number of cooling degree days in year (y) and month (m),
NormCDD is the normal value for annual cooling degree days,
HHSize is average household size in a year (y),

13 The elasticities shown in the superscripts are default values taken from the Electric Power Research Institute ("EPRI") developed Residential End-Use Energy Planning System model ("REEPS"), a detailed end-use model. The default values have been modified to reflect estimates of these elasticities for the Nevada Power and Sierra service territory. The elasticities used in modeling are -0.15 for price, 0.2 for income and 0.2 for households. These elasticities were applied in developing the XCool, XHeat and XOther variables.

Income is average real income per household in a year (y), and
Price is the average real price of electricity in year (y) and month (m)

By construction, the *CoolUse* variable has an annual sum that is close to one in the base year. The CDD index works to allocate annual cooling index (which is an annual kWh estimate) to months.

The XCool variable is constructed using data specific to Sierra and Nevada Power where data are available. This includes:

1. Modifying the end-use saturation based on the 2008, 2011 and 2016 residential appliance saturation surveys for Sierra and the 2008, 2011 and 2013 single family pricing trial saturations surveys for Nevada Power.
2. Using the 2015 intensities developed from ADM data.
3. Constructing the CoolUse variable with economic drivers including real personal income, population, and number of households.
4. Basing CDDs (actual and normal) from Sierra's historical weather data.
5. Using a price variable that reflects historical revenues and projections of future revenues based on forecasted operating costs.

XHeat

The heating variable (XHeat) construction is similar to XCool. XHeat is defined as:

$$XHeat_{y,m} = HeatIndex_{y} \times HeatUse_{y,m}$$

The heat index (HeatIndex) incorporates residential electric heating saturation and efficiency projections. The utilization variable (HeatUse) is defined like CoolUse but where CDDs are replaced with HDDs. XHeat incorporates Sierra's economic and price projections. The heating saturation rates have been modified to reflect the Sierra Residential Appliance Saturation Survey. The outcome is an initial estimation of average monthly household heating requirements.

XOther

The same logic is used to construct an initial estimate of non-weather sensitive use (XOther). XOther is defined as:

$$\text{XOther}_{y,m} = \text{OtherIndex}_{y,m} \times \text{OtherUse}_{y,m}$$

OtherIndex embodies information about appliance saturation levels and efficiency levels. Seasonal usage patterns are captured by applying monthly usage factors (Mult_m) to the annual end-use energy intensity estimates. OtherIndex is defined as:

$$\text{OtherIndex}_{y,m} = \left[\sum_{\text{Use}} \text{Weight}^{\text{Use}} \times \left(\frac{\dfrac{\text{Sat}_{y}^{\text{Use}}}{\text{Eff}_{y}^{\text{Use}}}}{\dfrac{\text{Sat}_{\text{base}}^{\text{Use}}}{\text{Eff}_{\text{base}}^{\text{Use}}}} \right) \times \text{Mult}_{m}^{\text{use}} \right] + \left[\text{UEC}_{y}^{\text{Light}} \times \text{Mult}_{m}^{\text{Light}} \right] + \left[\text{UEC}_{y}^{\text{Misc}} \times \text{Mult}_{m}^{\text{Misc}} \right]$$

Where, Sat^{Use} represents the fraction of households, who have an appliance type,
$Mult^{use}$ is a monthly multiplier for the Use in month (m),
Weight is the weight for each use, and
UEC is the unit energy consumption for lighting and miscellaneous uses in year (y).

OtherIndex combines information about trends in saturation levels and efficiency levels for the main appliance categories with monthly multipliers for each end-use. Lighting and miscellaneous use are based on EIA's end-use energy projections. As with heating and cooling, the weights are defined as the base year values of energy use per household for each end use.

The impact of price, household size, and household income is captured in OtherUse:

$$OtherUse_{y,m} = \left(\frac{BillingDays_{y,m}}{365}\right) \times \left(\frac{HHSize_{y}}{HHSize_{base}}\right)^{.46} \times \left(\frac{Income_{y}}{Income_{base}}\right)^{.10} \times \left(\frac{Price_{y,m}}{Price_{base}}\right)^{-.15}$$

The end-use elasticities on income, household size, and real price are taken from the REEPS default database. The appliance category includes data for cooking, dishwashers, clothes washers, clothes dryers, and televisions. The main source of month-to-month variation is the number of monthly billing-days.

XOther is constructed using information specific to Sierra where this information is available. Specific service area data included in XOther are:

1. Modifying the end-use saturation based on the 2008, 2011 and 2016 residential appliance saturation surveys.
2. Using the 2015 intensities developed from ADM data and AEG lighting for Sierra.
3. Constructing the OtherUse variable with MSA economic drivers including real personal income, household size, and number of households.
4. Calculating monthly number of billing days from historical meter read schedules.
5. Estimating a price variable that reflects historical revenues and projections of future costs.
6. As detailed above, adjusting the Refrigerator, Water Heating and Miscellaneous EUIs to reflect future DSM program activity.

B. Commercial Model Variables

The Commercial SAE Model is similar to that of the residential model. Cooling (XCool), Heating (XHeat), and Other Use (XOther) combine end-use energy intensity projections and factors that drive utilization of the end-use stock (economic activity, weather, and price). These variables are then used to drive commercial average use in the small commercial revenue class and total sales in the large commercial revenue class.

XCool and XHeat

The cooling variable (XCool) is defined as a product of an annual equipment index and a monthly usage multiplier:

$$XCool_{y,m} = CoolIndex_{y} \times CoolUse_{y,m}$$

Where, $XCool_{y,m}$ is estimated heating energy use in year (y) and month (m),
$CoolIndex_{y}$ is the annual heating stock, and
$CoolUse_{y,m}$ is the monthly usage multiplier.

CoolIndex is designed to capture the trend in commercial cooling saturation and efficiency. Similar to the residential cooling index, the commercial index changes over time with changes in cooling equipment saturations (Cool*Share*) and operating efficiencies (*Eff*). CoolIndex can be defined as:

$$CoolIndex_{y} = CoolSales_{04} \times \frac{\left(CoolShare_{y} / Eff_{y} \right)}{\left(CoolShare_{04} / Eff_{04} \right)}$$

In this expression, 2004 is used as a base year for normalizing the index.[14] The ratio on the right is equal to 1.0 in 2004. Unfortunately, the EIA does not explicitly provide commercial end-use saturation estimates. As a proxy, the index is calculated using end-use energy intensities (use per square foot) by building-type. End-use intensities are derived from EIA's most recent Energy Outlook. As there is effectively a 100 percent cooling saturation, the index generally declines over time as cooling equipment efficiency continues to improve.

The cooling index is calculated as:

$$CoolIndex_{y} = CoolSales_{04} \times \frac{EI_{y}}{EI_{04}}$$

Cooling requirements are driven by weather conditions, economic activity, and price projections. Regional output is the primary economic driver used in the small commercial average use model. For the small commercial revenue class, the utilization variable is defined as:[15]

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[14] 2009 is the base year for the commercial indices used in the Sierra and Nevada Power load forecast models.

[15] The output elasticity for the small C&I customer class model is 0.2. The price elasticity was -0.15 for all C&I classes.

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{CDD_{04}}\right) \times \left(\frac{Output_{y,m}}{Output_{04}}\right)^{0.20} \times \left(\frac{\Pr ice_{y,m}}{\Pr ice_{04}}\right)^{-0.15}$$

Where,

CDD are the number of CDDs in year (y) and month (m) using billing cycle degree days and daily average temperatures.
Output is a real regional output in year (y) and month (m).
Price is the average real price in month (m) and year (y).

XHeat is constructed in a similar manner to the XCool variable. While XHeat is statistically significant in the Small C&I models, the amount of the electric heating is very small. XHeat is not significant in either the Sierra GS-3 or Nevada Power Large C&I model.

XCool and XHeat are constructed to reflect the Nevada Power and Sierra service areas. Specific regional inputs include:

1. Adjusting the building mix and resulting energy intensity to reflect the service area business mix. The calculation of HeatUse (and CoolUse) is an aggregation across eleven different business types. The business-type mix was estimated from the business market survey and estimated MWh sales for each of the eleven business types. Tables LF-28 and LF-29 show the distribution of sales across the business types for Nevada Power and Tables LF-30 and LF-318 are the same data for Sierra.

2. Constructing HeatUse and CoolUse using the Real GMP for the Small C&I classes, Real GMP and Hotel room counts for the Nevada Power Large C&I class and Real GMP and non-manufacturing employment for the Sierra GS-3 class, HDD and CDD are based on Las Vegas and Reno weather data. Output elasticities are calibrated to historical output to sales relationship.

3. As detailed above, adjusting the Cooling EUIs to reflect future DSM program activity.

XOther

The non-weather sensitive variable (XOther) is derived using a similar approach as that used for the cooling and heating variables. XOther is defined as:

$$\mathrm{XOther}_{y,m} = \mathrm{OtherIndex}_{y,m} \times \mathrm{OtherUse}_{y,m}$$

OtherIndex captures the energy intensity projections for the non-weather sensitive end-uses. This includes energy intensities for indoor lighting, outdoor lighting, ventilation, water heating, refrigeration, cooking, office equipment, and miscellaneous use. The intensity index for other uses is defined as:

$$OtherIndex_{y,m} = \sum_{Type} Sales_{04}^{Type} \times \left(\frac{EI_{y}^{Type}}{EI_{04}^{Type}} \right)$$

Where, *Sales* is the estimated end-use sales in 2004,
EI is the energy intensity for the specific end-use

OtherUse captures the impact of factors that effect changes in stock utilization. OtherUse is defined as:

$$OtherUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5} \right) \times \left(\frac{Output_{y}}{Output_{04}} \right)^{0.20} \times \left(\frac{\Pr ice_{y.m}}{\Pr ice_{04}} \right)^{-0.15}$$

Regional non-manufacturing output is used to capture the impact of business activity on average usage. As this is an average use model, the impact of total output on average use is constrained by imposing a 0.2 elasticity on output. Changes in business activity should have a relatively small impact on change in customer average use. The output elasticity is determined by evaluating in-sample and out-of-sample model statistics for small variations in the output elasticity. The output elasticity with respect to small commercial average use is consistent with the income elasticity used in the residential average use model.

As with the constructed XCool and XHeat variables, XOther is constructed using service area specific data where these data are available.

The Sierra Small C&I class MWh distribution across business types was updated as part of the Applied Energy Group ("AEG") DSM Market Potential Study performed in 2017 and 2018. Small C&I premises were classified into the business type categories by AEG. 2016 annual usage was appended to this file. Additional lookup of business types was performed by Sierra until all premises with greater than 99 annual GWH were classified into a business type. Table LF-30 is a summary of the new Sierra Small C&I business type sales.

Large C & I Economic Driver. The Large C&I revenue class forecasts are also derived using the SAE model specification. These models are based on a total sales rather than an average use model. End-use intensities and economic drivers are combined through the XHeat, XCool, and XOther variables. The Sierra GS-3 class MWH are for the period November 2017 through October 2018 with all mine load and other large customer sales subtracted while the Nevada Large C&I class utilizes sales for the year ending May 2008.

TABLE LF-28
NEVADA POWER SMALL C&I BUSINESS TYPE SALES

BUSINESS TYPE	MWH	% MWh
Education	95,004	1.96%
Food Sales	280,389	5.77%
Food Service	639,989	13.18%
Health Care	245,938	5.06%
Lodging	434,553	8.95%
Office	837,377	17.24%
Other	413,380	8.51%
Public Assembly	176,606	3.64%
Retail	412,418	8.49%
Service	746,864	15.38%
Warehouse	574,407	11.83%
Total	4,856,924	100.00%

Note: The MWh data is for the year ending May 2008 and is aggregated from individual customer data.

TABLE LF-29
NEVADA POWER LARGE C&I BUSINESS TYPE SALES

BUSINESS TYPE	MWH	CUSTS		% MWh	% Custs
Education	457,090,111	280		5.85%	17.73%
Food Sales	297,587,492	121		3.81%	7.66%
Food Service	7,086,054	4		0.09%	0.25%
Health Care	229,834,017	46		2.94%	2.91%
Lodging	3,792,219,517	279		48.50%	17.67%
Office	990,293,214	259		12.67%	16.40%
Other	1,212,140,190	303		15.50%	19.19%
Public Assembly	180,617,383	75		2.31%	4.75%
Retail	471,732,908	160		6.03%	10.13%
Service	46,581,932	13		0.60%	0.82%
Warehouse	133,060,028	39		1.70%	2.47%
Total	7,818,242,848	1,579		100.00%	100.00%

Note: The MWh data is for the year ending May 2008 and is aggregated from individual customer data.

TABLE LF-30
SIERRA SMALL C&I BUSINESS TYPE SALES

BUSINESS TYPE	MWH		% MWh
Education	122,873		4.25%
Food Sales or Service	331,438		11.46%
Health Care	194,915		6.74%
Lodging	213,347		7.37%
Office	368,224		12.73%
Other	559,194		19.33%
Public Assembly	236,635		8.18%
Retail	385,871		13.34%
Service	297,859		10.30%
Warehouse	182,628		6.31%
Total	2,892,983		100.00%

Note: The MWh data is for the year ending December 2016 and is aggregated from individual customer data.

TABLE LF-31
SIERRA GS-3 NON-LARGE BUSINESS TYPE SALES

BUSINESS TYPE	MWH		% MWh
Education	67,607		8.06%
Food Sales	0		0.00%
Food Service	0		0.00%
Health Care	95,759		11.41%
Lodging	277,532		33.08%
Office	7,110		0.85%
Other	309,346		36.87%
Public Assembly	52,821		6.30%
Retail	20,173		2.40%
Service	0		0.00%
Warehouse	8,614		1.03%
Total	838,962		100.00%

C. MODEL RESULTS

Pursuant to NAC§ 704.922(2)(g), model documentation, model results are shown in Tables LF-32 through LF-37. A summary of the model statistics is in shown in Table LF-32, while Tables LF-33 through LF-37 summarize model coefficients and significance statistics. Complete output for all models (including the monthly peak forecast models) with all regression statistics is included with the work papers. All Nevada Power models except residential customers us historical data from January 2008 through December 2018.

The Nevada Power residential customer model used historical annual customer counts and population from 1990 through 2018. A longer series was used than for previous monthly models to obtain sufficient observations for the regression model. Since there is no seasonal variation evident in the historical customer counts, and the population history and forecast are annual series, an annual model is reasonable for Nevada Power. Sierra does exhibit seasonality in the residential (and Small C&I) customer counts, so an annual model would not be appropriate.

TABLE LF-32
SUMMARY OF MODEL STATISTICS

SIERRA MODEL STATISTICS

Model Statistic	Residential Customer	Residential Average Use	Small C&I Customer	Small C&I Avg Use	GS-3 (non-large) Sales	RES OLS Sales	Small C&I OLS Sales
Adjusted Observations	131	132	131	132	119	131	131
R-Squared	0.993	0.966	0.912	0.920	0.877	0.956	0.826
Adjusted R-Squared	0.989	0.964	0.910	0.914	0.859	0.954	0.813
Mean Squared Error	491,236	379	51,474	12,304	4.880E+12	2,222,855	29,616,390
Mean Abs. Percentage Error (MAPE)	0.19%	2.04%	0.36%	1.62%	2.34%	0.69%	1.15%
Durbin-Watson Statistic	2.475	2.064	2.341	1.953	1.926	2.500	1.904
Ljung-Box Statistic	37.619	104.250	41.036	29.232	36.444	34.819	19.354

NEVADA POWER MODEL STATISTICS

Model Statistic	Residential Customer	Residential Average Use	Small C&I Customer	Small C&I Avg Use	Large C&I Sales
Adjusted Observations	27	132	131	132	131
R-Squared	0.999	0.986	0.934	0.983	0.937
Adjusted R-Squared	0.999	0.986	0.932	0.983	0.936
Mean Squared Error	3,817	2,522	556,483	6,724	327,913,132
Mean Abs. Percentage Error (MAPE)	0.52%	4.26%	0.49%	1.67%	2.31%
Durbin-Watson Statistic	N/A	1.580	2.046	1.918	2.182
Ljung-Box Statistic	3.501	96.530	49.220	19.100	108.240

TABLE LF-33
NEVADA POWER MODEL COEFFICIENTS AND STATISTICS

RESIDENTIAL CUSTOMERS

Variable	Definition	Coefficient	Standard Error	T-Stat	P-Values
Pop	Population of Clark County	0.373	0.004	84.773	0.00%
AR(1)	1st order autoregressive term	0.842	0.099	8.507	0.34%
MA(1)	1st order moving average autregressive term	0.845	0.109	7.767	0.44%

RESIDENTIAL AVERAGE KWH PER CUSTOMER

Variable	Definition	Coefficient	Standard Error	T-Stat	P-Values
XHeat	Heating Electric Use	2.168	0.099	21.990	0.00%
XCool	Cooling Electric Use	1.300	0.015	85.887	0.00%
XOther	Other Electric Use	0.664	0.019	34.348	0.00%

SMALL C&I CUSTOMERS

Variable	Definition	Coefficient	Standard Error	T-Stat	P-Values
Constant	Intercept	1932.842	1424.73	1.36	17.7%
LagDep(1)	One month lag of the small C&I cust count	0.95	0.03	28.26	0.0%
Cust	Residential Monthly Customer Forecast	0.00	0.00	1.48	14.1%
AR(1)	1st order autoregressive term	-0.20	0.10	-1.91	5.9%
MA(1)	1st order moving average autregressive term	-0.75	0.09	-8.42	0.0%

SMALL C&I AVERAGE KWH PER CUSTOMER

Variable	Definition	Coefficient	Standard Error	T-Stat	P-Values
Constant	Intercept	1207.184	142.23	8.49	0.0%
XHeat	Heating Electric Use	0.60	0.12	4.87	0.0%
XCool	Cooling Electric Use	1.11	0.02	72.44	0.0%
XOther	Other Electric Use	0.56	0.05	11.71	0.0%

LARGE C&I MWH

Variable	Definition	Coefficient	Standard Error	T-Stat	P-Values
Constant	Intercept	489,376	30,719	15.93	0.0%
XCool	Cooling Electric Use	1.02	0.04	27.87	0.0%
XOther	Other Electric Use	0.13	0.05	2.54	1.2%
AR(1)	1st order autoregressive term	0.42	0.08	5.00	0.0%

TABLE LF-34
SIERRA RESIDENTIAL MODEL COEFFICIENTS AND STATISTICS

SIERRA MODEL VARIABLE COEFFICIENTS AND STATISTICS

HISTORY: Jan. 2008 through Dec. 2018

RESIDENTIAL CUSTOMERS (BILLED PLUS UNBILLED CUSTOMERS)

Variable	Definition	Coefficient	Standard Error	T-Stat	P-Values
NN_POP	Population of Northern NV	367.752	0.461	798.563	0.00%
AR(1)	1st order autoregressive term	0.828	0.044	18.996	0.00%

RESIDENTIAL AVERAGE KWH PER CUSTOMER

Variable	Definition	Coefficient	Standard Error	T-Stat	P-Values
XOther	Other Electric Use	0.826	0.010	80.791	0.00%
XCool	Cooling Electric Use	0.943	0.020	47.431	0.00%
XHeat	Heating Electric Use	3.152	0.093	33.955	0.00%
Apr08	Binary for month and year	-71.453	19.009	-3.759	0.03%
Jul08	Binary for month and year	-68.376	20.014	-3.416	0.09%
Aug08	Binary for month and year	98.180	19.706	4.982	0.00%
Sep10	Binary for month and year	97.426	19.528	4.989	0.00%
After 2014	Binary: 1 after 2014, 0 before*	-8.597	4.476	-1.921	5.71%
MA(1)	1st order moving average autregressive term	0.252	0.091	2.770	0.65%

RESIDENTIAL OUTDOOR LIGHTING SERVICE KWH

Variable	Definition	Coefficient	Standard Error	T-Stat	P-Values
Constant	Intercept	166,028.9	1,592.0	104.290	0.00%
TrendVar	Trend variable - increments by one per month	-1,908.8	236.0	-8.089	0.00%
Jun11	Binary for month and year	-4,404.1	1,317.1	-3.344	0.11%
Jul11	Binary for month and year	2,885.8	1,316.9	2.191	3.03%
Oct17	Binary for month and year	39,599.3	1,146.3	34.547	0.00%
May16	Binary for month and year	-8,466.4	1,146.3	-7.386	0.00%
AR(1)	1st order autoregressive term	-4,450.0	1,146.1	-3.883	0.02%

* Average usage is lower after 2014 than before.

TABLE LF-35
SIERRA SMALL C&I MODEL COEFFICIENTS AND STATISTICS

SIERRA MODEL VARIABLE COEFFICIENTS AND STATISTICS

HISTORY: Jan. 2008 through Dec. 2018

SMALL C&I CUSTOMERS

Variable	Definition	Coefficient	Standard Error	T-Stat	P-Values
Constant	Intercept	8738.559	1405.387	6.218	0.00%
May14	Binary for month and year	937.632	228.408	4.105	0.01%
Res Cust Fcst	Residential Monthly Customer Forecast	0.040	0.006	6.985	0.00%
Lag(1) Cust	1 month lag of Small C&I Customers	0.549	0.060	9.107	0.00%

SMALL C&I AVERAGE KWH PER CUSTOMER

Variable	Definition	Coefficient	Standard Error	T-Stat	P-Values
XOther	Other Electric Use	3083.551	284.673	10.832	0.00%
XCool	Cooling Electric Use	0.040	0.012	3.225	0.16%
XHeat	Heating Electric Use	0.021	0.003	6.521	0.00%
XOther	Other Electric Use	0.031	0.005	6.490	0.00%
MBin.Jun	Binary for month	291.877	45.840	6.367	0.00%
MBin.Jul	Binary for month	389.293	86.783	4.486	0.00%
MBin.Aug	Binary for month	468.332	118.038	3.968	0.01%
MBin.Sep	Binary for month	546.550	93.307	5.858	0.00%
MBin.Oct	Binary for month	300.975	53.893	5.585	0.00%
MBin.Yr09Plus	Binary: 1 after 2008, 0 before 2009*	-191.120	46.168	-4.140	0.01%
MBin.Yr10Plus	Binary: 1 after 2009, 0 before 2010*	-87.641	34.956	-2.507	1.35%

SMALL C&I OUTDOOR LIGHTING SERVICE KWH

Variable	Definition	Coefficient	Standard Error	T-Stat	P-Values
Constant	Intercept	300,418.8	988.865	303.802	0.00%
TrendVar	Trend variable - increments by one per month	-3,049.8	154.516	-19.738	0.00%
Feb09	Binary for month and year	-32,506.7	5506.106	-5.904	0.00%
Apr10	Binary for month and year	-33,176.5	5486.818	-6.047	0.00%
Jun10	Binary for month and year	-39,147.2	5484.540	-7.138	0.00%
Dec14	Binary for month and year	-18,879.1	5468.724	-3.452	0.00%
May15	Binary for month and year	-13,805.3	5471.728	-2.523	0.00%
May10	Binary for month and year	-16,496.4	5485.664	-3.007	0.00%
Mar14	Binary for month and year	-39,275.4	5465.223	-7.186	0.00%
Dec15	Binary for month and year	-27,886.3	5477.203	-5.091	0.00%

* Downshift in average usage caused by the recession.

TABLE LF-36
SIERRA GS-3 MODEL COEFFICIENTS AND STATISTICS

SIERRA MODEL VARIABLE COEFFICIENTS AND STATISTICS

HISTORY: Jan. 2009 through Dec. 2018

GS-3 KWH - EXCLUDING GS3-T AND OTHER LARGE CUSTOMERS

Variable	Definition	Coefficient	Standard Error	T-Stat	P-Values
XCool	Cooling Electric Use	274.158	60.806	4.509	0.00%
XOther	Other Electric Use	426.953	104.566	4.083	0.01%
Jan	Binary for month	43,656,885	7,445,118	5.864	0.00%
Feb	Binary for month	42,301,841	6,983,826	6.057	0.00%
Mar	Binary for month	39,416,849	6,747,176	5.842	0.00%
Apr	Binary for month	39,588,973	6,603,045	5.996	0.00%
May	Binary for month	41,305,027	6,341,671	6.513	0.00%
Jun	Binary for month	45,738,461	6,264,616	7.301	0.00%
Jul	Binary for month	47,321,552	6,091,825	7.768	0.00%
Aug	Binary for month	46,965,775	6,366,682	7.377	0.00%
Sep	Binary for month	47,545,469	6,400,329	7.429	0.00%
Oct	Binary for month	45,323,782	6,491,943	6.982	0.00%
Nov	Binary for month	43,044,496	6,710,314	6.415	0.00%
Dec	Binary for month	42,006,529	7,439,006	5.647	0.00%
Yr10Plus	Binary: 0 before 2011, 1 after 2011*	-2,290,179	1,232,284	-1.858	6.60%
AR(1)	1st order autoregressive term	0.447	0.089	5.022	0.00%

* Downshift in average usage caused by the recession.

IV. BASE LOAD FORECAST SUMMARY

A. Sales Forecast Summary

Tables LF-37 and LF-39 are summaries of the sales prior to DSM and DR reductions. Net Metering reductions are included. The sales before DSM and DR in tables LF-37 and LF-39 are calculated by adding the DSM and DR reductions to the final class sales after all reductions. Tables LF-38 and Table LF-40 are summaries of the sales after all reductions. The Sierra resale class does not include California sales. See below for the California Peak and Input to System forecast. Absent the resale, Table LF-39 is the Sierra NV-Only retail sales without DSM and DR and Table LF-40 is the Sierra NV-Only retail sales after DSM and DR reductions.

TABLE LF-37
NEVADA POWER SALES BY CLASS BEFORE DSM AND DR REDUCTIONS BUT AFTER SOLAR PV REDUCTIONS (GWH)

Year	Residential	Small Commercial & Industrial	Large Commercial & Industrial	Public Authority	Street Lighting	Total
2019	9,692	4,723	5,254	58	155	19,882
2020	9,757	4,784	4,995	58	155	19,751
2021	9,804	4,844	5,120	58	155	19,983
2022	9,897	4,901	5,243	58	155	20,255
2023	9,969	4,942	5,248	58	155	20,373
2024	10,044	4,988	5,261	58	155	20,506
2025	10,081	5,020	5,274	58	155	20,589
2026	10,130	5,047	5,289	58	155	20,680
2027	10,185	5,072	5,306	58	155	20,777
2028	10,254	5,097	5,321	58	155	20,886
2029	10,311	5,109	5,332	58	155	20,966
2030	10,348	5,113	5,338	58	155	21,013
2031	10,387	5,120	5,348	58	155	21,069
2032	10,440	5,135	5,363	58	155	21,151
2033	10,473	5,137	5,377	58	155	21,201
2034	10,522	5,148	5,396	58	155	21,279
2035	10,571	5,162	5,418	58	155	21,365
2036	10,640	5,182	5,444	58	155	21,481
2037	10,688	5,190	5,464	58	155	21,556
2038	10,746	5,205	5,489	58	155	21,653
2039	10,812	5,221	5,518	58	155	21,766

TABLE LF-38
NEVADA POWER SALES BY CLASS AFTER ALL REDUCTIONS (GWH)

Year	Residential	Small Commercial & Industrial	Large Commercial & Industrial	Public Authority	Street Lighting	Total
2019	9,645	4,701	5,231	58	155	19,792
2020	9,700	4,739	4,961	58	155	19,614
2021	9,737	4,784	5,077	58	155	19,812
2022	9,821	4,825	5,190	58	155	20,050
2023	9,892	4,851	5,186	58	155	20,142
2024	9,965	4,881	5,188	58	155	20,248
2025	10,002	4,897	5,193	58	155	20,306
2026	10,050	4,910	5,198	58	155	20,372
2027	10,104	4,920	5,206	58	155	20,443
2028	10,173	4,943	5,217	58	155	20,547
2029	10,230	4,953	5,226	58	155	20,623
2030	10,259	4,956	5,231	58	155	20,659
2031	10,288	4,962	5,239	58	155	20,703
2032	10,333	4,975	5,252	58	155	20,773
2033	10,357	4,977	5,264	58	155	20,812
2034	10,397	4,986	5,280	58	155	20,878
2035	10,438	4,998	5,300	58	155	20,950
2036	10,498	5,017	5,323	58	155	21,052
2037	10,538	5,024	5,340	58	155	21,115
2038	10,585	5,037	5,363	58	155	21,199
2039	10,643	5,052	5,389	58	155	21,298

TABLE LF-39
SIERRA NV-ONLY SALES BY CLASS BEFORE DSM AND DR REDUCTIONS BUT AFTER SOLAR PV REDUCTIONS (GWH)

Year	Residential	Small C&I	Large C&I	Street Lighting	Resale	Total
2019	2,498	3,015	3,652	16	9	9,189
2020	2,532	3,075	3,901	16	9	9,532
2021	2,547	3,114	4,190	16	9	9,875
2022	2,557	3,144	3,432	16	9	9,157
2023	2,567	3,171	3,473	16	9	9,236
2024	2,592	3,209	3,706	16	9	9,532
2025	2,602	3,242	3,857	16	9	9,725
2026	2,618	3,277	3,923	16	9	9,843
2027	2,638	3,313	3,960	16	9	9,936
2028	2,665	3,354	3,998	16	9	10,041
2029	2,686	3,392	4,037	16	9	10,140
2030	2,699	3,431	4,076	16	9	10,231
2031	2,716	3,471	4,114	16	9	10,325
2032	2,739	3,515	4,153	16	9	10,432
2033	2,754	3,555	4,195	16	9	10,528
2034	2,779	3,598	4,234	16	9	10,637
2035	2,805	3,643	4,276	16	9	10,749
2036	2,838	3,691	4,318	16	9	10,871
2037	2,860	3,733	4,361	16	9	10,978
2038	2,887	3,779	4,401	16	9	11,092
2039	2,916	3,826	4,444	16	9	11,211

TABLE LF-40
SIERRA NV-ONLY SALES BY CLASS AFTER ALL REDUCTIONS (GWH)

Year	Residential	Small C&I	Large C&I	Street Lighting	Resale	Total
2019	2,479	2,975	3,625	16	9	9,104
2020	2,495	2,997	3,842	16	9	9,360
2021	2,496	2,999	4,093	16	9	9,613
2022	2,491	2,999	3,298	16	9	8,813
2023	2,487	2,998	3,299	16	9	8,809
2024	2,498	3,003	3,495	16	9	9,020
2025	2,493	3,000	3,611	16	9	9,128
2026	2,495	3,000	3,641	16	9	9,160
2027	2,500	3,001	3,643	16	9	9,168
2028	2,512	3,005	3,645	16	9	9,187
2029	2,519	3,008	3,648	16	9	9,199
2030	2,518	3,011	3,651	16	9	9,205
2031	2,520	3,016	3,653	16	9	9,213
2032	2,529	3,024	3,656	16	9	9,234
2033	2,530	3,028	3,661	16	9	9,244
2034	2,541	3,035	3,665	16	9	9,266
2035	2,553	3,044	3,670	16	9	9,292
2036	2,572	3,055	3,676	16	9	9,327
2037	2,580	3,061	3,682	16	9	9,348
2038	2,592	3,071	3,686	16	9	9,374
2039	2,608	3,081	3,692	16	9	9,405

Table LF-41 is a summary of the residential customers and Small C&I customers from 2008-2039 (NV Only). Sierra Small C&I customer counts do not include irrigation customers.

TABLE LF-41
HISTORY AND FORECAST OF RESIDENTIAL AND SMALL C&I CUSTOMERS

	RESIDENTIAL (1)				SMALL C&I		
Year	NPC	SPPC	NVE		NPC	SPPC (2)	NVE
2009	726,950	275,419	1,002,369		99,521	43,841	143,362
2010	729,565	276,250	1,005,816		100,270	44,048	144,318
2011	737,500	277,252	1,014,751		100,716	44,237	144,953
2012	748,245	279,219	1,027,463		101,423	44,320	145,744
2013	756,904	281,282	1,038,186		102,980	44,458	147,438
2014	768,263	284,301	1,052,564		104,428	44,846	149,274
2015	781,941	287,725	1,069,666		104,508	44,960	149,468
2016	797,094	291,401	1,088,495		105,317	45,183	150,499
2017	810,254	294,966	1,105,220		106,463	45,540	152,003
2018	825,345	299,623	1,124,968		107,542	45,974	153,517
2019	845,547	304,207	1,149,754		108,701	46,366	155,067
2020	864,129	307,693	1,171,823		110,216	46,674	156,890
2021	878,351	310,732	1,189,082		111,662	46,950	158,612
2022	890,462	313,252	1,203,714		112,941	47,179	160,120
2023	902,705	315,372	1,218,077		114,111	47,371	161,481
2024	912,918	317,336	1,230,255		115,177	47,547	162,724
2025	922,233	319,045	1,241,278		116,130	47,701	163,831
2026	930,308	320,647	1,250,954		116,983	47,844	164,827
2027	937,532	322,250	1,259,782		117,738	47,987	165,725
2028	944,291	323,861	1,268,152		118,419	48,130	166,549
2029	950,234	325,480	1,275,714		119,032	48,274	167,306
2030	956,106	327,108	1,283,213		119,594	48,418	168,013
2031	961,185	328,743	1,289,929		120,110	48,564	168,674
2032	965,849	330,387	1,296,236		120,577	48,710	169,287
2033	970,104	332,039	1,302,143		121,002	48,857	169,859
2034	974,323	333,699	1,308,022		121,397	49,004	170,402
2035	978,146	335,368	1,313,514		121,767	49,153	170,919
2036	981,945	337,044	1,318,989		122,114	49,302	171,415
2037	985,721	338,730	1,324,451		122,450	49,451	171,901
2038	989,114	340,423	1,329,538		122,770	49,602	172,371
2039	992,492	342,125	1,334,617		123,073	49,753	172,827

(1) Billed plus unbilled for Sierra, billed only for NPC.
(2) Not inculding Irrigation customers.

B. DSM, Solar PV and DR sales reductions

Pursuant to NAC § 704.925(2). Tables LF-42 and LF-43 are summaries of the DSM**,** DR, and net metering reductions. The latter includes net metered and behind the meter Solar PV, both rebated and non-rebated (i.e., outside of the SolarGenerations program) reductions. The reductions for small metered customers on net metered rates were calculated from own load shape data and for net metered customers on large C&I rates from generation load shape data. There were no active wind or hydro projects at the time of forecast completion.

TABLE LF-42
NEVADA POWER DSM, DR AND NET METERING GWH REDUCTIONS BY CLASS

	RESIDENTIAL				SMALL C&I				LARGE C&I				TOTAL NEVADA POWER			
Year	DSM	Solar PV	DR	Total	DSM	Solar PV	DR	Total	DSM	Solar PV	DR	Total	DSM	Solar PV	DR	Total
2019	44	87	38	169	90	1	3.7	95	90	7	3.0	100	225	94	45	364
2020	91	165	42	298	183	2	5.3	190	183	16	3.4	203	457	183	50	691
2021	135	235	46	415	279	3	6.8	288	279	26	3.3	308	693	264	56	1,012
2022	179	276	48	502	376	4	8.3	388	376	36	4.0	416	931	315	60	1,306
2023	223	291	48	563	474	5	9.8	489	474	45	4.8	524	1,171	341	63	1,576
2024	268	302	49	620	572	6	11.4	590	572	55	5.5	633	1,413	363	66	1,842
2025	313	310	50	674	671	7	12.5	691	671	64	5.6	741	1,656	381	68	2,105
2026	359	314	51	723	770	8	13.2	791	770	74	5.7	850	1,900	395	70	2,365
2027	404	316	52	772	870	9	13.8	893	870	84	5.2	959	2,144	408	71	2,624
2028	450	318	52	821	970	10	14.4	994	970	93	5.9	1,069	2,391	421	73	2,884
2029	496	320	53	869	1,071	11	15.0	1,096	1,071	103	6.3	1,180	2,638	434	74	3,146
2030	543	322	53	918	1,171	12	15.7	1,199	1,171	113	6.6	1,291	2,885	447	76	3,408
2031	589	324	54	968	1,272	13	16.3	1,301	1,272	122	6.7	1,401	3,134	459	77	3,670
2032	636	327	54	1,017	1,373	14	16.8	1,404	1,373	132	6.9	1,512	3,383	472	78	3,933
2033	683	329	55	1,067	1,475	15	17.4	1,507	1,475	141	6.5	1,623	3,633	485	79	4,197
2034	731	331	56	1,117	1,577	16	18.0	1,610	1,577	151	6.8	1,735	3,884	498	81	4,462
2035	778	333	56	1,167	1,679	17	18.5	1,714	1,679	161	7.1	1,847	4,136	510	82	4,728
2036	826	335	57	1,218	1,781	18	19.1	1,818	1,781	170	7.2	1,959	4,389	523	83	4,995
2037	874	337	57	1,268	1,884	19	19.6	1,923	1,884	180	7.5	2,072	4,643	536	84	5,263
2038	923	340	58	1,320	1,988	20	20.1	2,028	1,988	190	6.7	2,184	4,898	549	85	5,532
2039	971	342	59	1,371	2,092	21	20.7	2,133	2,092	199	7.3	2,298	5,155	562	86	5,803

Tesla has had a pending Rule 15 application for [redacted] MW of solar rooftop PV since 2018. They have also indicated the possibility that approximately [redacted] MW more will be installed in the near future. For this forecast, Sierra assumes that a [redacted] MW array is installed by January 2020. The annual MWh are included with the Large C&I class in Table LF-43.

TABLE LF-43
SIERRA DSM, DR AND NET METERING GWH REDUCTIONS BY CLASS

	Residential				Small Commercial & Industrial				Large Commercial & Industrial				Total GWH			
	DSM	Solar PV	DR	Total	DSM	Solar PV	DR	Total	DSM	Solar PV	DR	Total	DSM	Solar PV	DR	Total
2019	15	3	4.5	22	38	1	2.0	41	26	0	0.1	27	79	4	7	90
2020	30	5	5.9	41	75	3	2.5	80	58	29	0.3	88	164	37	9	209
2021	45	7	7.2	59	111	5	3.1	119	96	29	0.4	126	252	41	11	303
2022	57	8	8.4	74	141	6	3.5	151	134	30	0.6	164	332	44	13	389
2023	70	9	9.6	89	170	8	3.9	182	173	30	0.7	204	413	47	14	474
2024	84	9	10.7	104	202	10	4.2	216	210	31	0.8	241	496	50	16	561
2025	97	10	11.7	119	238	12	4.5	254	245	31	0.9	277	580	53	17	649
2026	111	10	12.7	134	273	13	4.8	291	281	31	1.0	313	664	55	18	738
2027	124	11	13.6	149	308	15	5.0	328	316	32	1.0	349	749	58	20	826
2028	138	11	14.4	164	343	17	5.2	365	352	32	1.0	385	834	60	21	914
2029	152	12	15.2	179	379	19	5.2	403	388	33	1.1	422	919	63	22	1,003
2030	165	12	16.0	193	414	20	5.3	440	424	33	1.1	458	1,004	65	22	1,092
2031	179	12	16.8	208	450	22	5.4	478	460	33	1.1	494	1,089	68	23	1,180
2032	193	13	17.2	223	486	24	5.4	515	496	34	1.1	531	1,175	70	24	1,269
2033	207	13	17.3	237	522	26	5.5	553	532	34	1.1	567	1,260	73	24	1,357
2034	221	13	17.4	251	557	27	5.6	590	568	35	1.1	604	1,346	76	24	1,446
2035	234	14	17.5	266	593	29	5.6	628	605	35	1.2	641	1,432	78	24	1,535
2036	248	14	17.7	280	630	31	5.7	666	641	35	1.2	678	1,519	81	25	1,624
2037	262	15	17.8	295	666	33	5.8	705	677	36	1.2	714	1,606	83	25	1,714
2038	276	15	17.9	309	703	34	5.8	743	714	36	1.2	751	1,693	86	25	1,804
2039	290	15	18.0	324	740	36	5.9	782	751	37	1.2	788	1,780	88	25	1,894

In previous forecasts, as agreed to with the Commission's Regulatory Operations Staff, the percentage of new EV sales has been capped at 1 percent of total light vehicles sales in Nevada. [16] The 2019 IRPA 2nd Forecast assumes 1 percent of new vehicles on the road are plug-in electric by 2022 and flat thereafter. GI's total new car and truck registrations were extracted from the October 2018 forecast and multiplied by the forecasted percentage of new EV vehicle registrations to derive the EV forecast. Based on prior research, we assume that an EV was driven for 10,000 annual miles and that for each 3.3 miles, one 1 kWh was necessary for charging, for annual use per EV of 3,300 kWh. The total EV sales for Nevada were then split between Sierra and Nevada Power by relative Residential customer forecasts shares. The hourly load shape was based on load shapes contained in "Potential Impacts of Plug-in Hybrid Electric Vehicles on Regional Power Generation," a publication from Oak Ridge National Laboratory, January 2008.[17] However, the load shape was adjusted to ensure that EVs were mainly charging in off-peak hours.

Table LF-44 is a summary of the projected Plug-in Electric Vehicle ("PEV") energy use and peak demand at the meter added to the residential sales for the base load forecast.

As the addition for the base case is small, the same sales and peak demand were added for the low and high load forecasts.

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16 This agreement is included in the Commission's Order for Docket No. 12-08009, Sierra's Second Amendment to the 2010-2029 IRP dated December 24, 2012.

17 *See*, http://www.ornl.gov/info/ornlreview/v41_1_08/regional_phev_analysis.pdf

TABLE LF-44
PEV SALES (GWH – AT THE METER) AND PEAK MW (INCLUDES LOSSES) ADDITIONS TO ALL LOAD FORECAST SCENARIOS (NOT UPDATED)

	MWH		Peak MW	
Year	NPC	SPPC	NPC	SPPC
2019	2,647	958	0.12	0.07
2020	5,601	2,011	0.52	0.14
2021	8,889	3,176	0.39	0.23
2022	12,340	4,391	0.54	0.20
2023	16,042	5,594	1.48	0.53
2024	19,621	6,804	0.85	0.64
2025	23,254	8,022	1.01	0.76
2026	26,918	9,248	2.48	0.41
2027	30,611	10,484	1.33	0.99
2028	34,344	11,731	3.16	1.10
2029	38,075	12,984	1.65	1.65
2030	41,797	14,234	1.82	1.81
2031	45,537	15,500	1.98	1.97
2032	49,314	16,786	2.14	2.13
2033	53,109	18,085	4.89	2.30
2034	56,950	19,404	5.25	2.47
2035	60,835	20,747	2.64	2.64
2036	64,798	22,117	2.82	2.81
2037	68,841	23,517	6.34	3.00
2038	72,950	24,949	3.17	3.18
2039	77,137	26,412	7.10	3.36

V. Peak Demand Forecast Summary

A. Methodology

The monthly peak model builds on the end-use energy estimates from the SAE sales models. We would expect system peak to increase (or decrease) over time with increasing cooling load and other coincident end-use load growth. Similarly winter peak demand will change with changes in heating requirements and other end-use load coincident with the monthly peaks. The impact of summer peak-day temperatures will also change over time with change in cooling load requirements and the impact of winter peak-day temperatures will change with changes in heating load requirements. We can think of peak demand has having three components – weather sensitive heating (HeatVar), weather-sensitive cooling (CoolVar), and other use coincident at the time of the peak (BaseVar). The peak demand model is specified as:

$$Peak_m = a + b_c \times CoolVar_m + b_h \times HeatVar_m + b_o \times BaseVar_m + e_m$$

Where:

$$CoolVar_m = f(PkDayCDD_m, CoolLoad_m)$$

$$HeatVar_m = f(PkDayHDD_m, HeatLoad_m)$$

$$BaseVar_m = f(EndUseCPk_m)$$

m = the specific month and year

$CoolLoad_m$ represents the expected cooling load requirements in month m. CoolLoad is calculated as:

$CoolLoad_m = (WNResCool_m + WNComCool_m) / days / 24$

Where WNResCool and WNComCool are estimates of weather normalized cooling load derived from the SAE sales forecast models.

The impact of peak-day CDD will change with increasing cooling load requirements. To capture this effect, cooling load requirements are indexed and combined with peak-day CDD.

$Cool\_Index_m = CoolLoad_m / CoolLoad_{2005}$

$CoolVar_m = PkDayCDD_m * CoolIndex_m$

The peak model heating variable ($HeatVar_m$) is calculated in a similar manner where an index of heating load requirements ($Heat\_Index_m$) is combined with peak-day heating degree-days ($PkDayHDD_m$):

$HeatVar_m = PkDayHDD_m * CoolIndex_m$

The base load variable (BaseVar) is designed to capture the non-weather sensitive coincident peak load:

$BaseVar_m = ResCP_m + COMCP_m + IndCP_m + OtherCP_m$

$$ResCP_{m,use} = Res\_Other_y \times \frac{EnergySAE_{y,use}}{\sum_u EnergySAE_{y,u}} \times PeakFrac_{use}$$

Estimates of class coincident peak loads are derived by first allocating out the non-weather sensitive load (*XOther*) from the SAE model to end-uses based on the initial end-use intensity estimates and applying a monthly coincident peak factor (*PeakFrac*) to each end-use. The coincident peak factors are based on estimates from Itron’s end-use load library. The calculations are shown below:

$$ComCP_{m,use} = Com\_Other_y \times \frac{EnergySAE_{y,use}}{\sum_u EnergySAE_{y,u}} \times PeakFrac_{use}$$

Where y = the specific year.

For Sierra, the monthly historical peaks exclude the large mining and other large customer load as this load is not weather sensitive. These loads are added to the model results. Peppermill, Atlantis, Grand Sierra and Caesar's DOS loads are subtracted from the forecasted peaks and hourly loads.

For Nevada Power, the historical monthly peaks include the DOS load for MGM, Wynn, Caesars and Switch for the months after they transitioned to DOS. Due to their large load, the drop in the monthly peaks would cause and inconsistency that can result in a biased forecast. That DOS load plus additional load for customers with current 704B applications is then subtracted from the forecasted hourly loads to produce the forecasted monthly peaks. Both models were executed with monthly peaking average temperatures from 1999 through 2018. The weather variables used in the Nevada Power model were converted to CDD base 70 and HDD base 50. For Sierra, the CDD were converted to base 65 and the HDD to base 50. These variables produced the best model fit for the peak model. The normal temperature is the average of the 20 months of CDD or HDD. Table LF-45 shows the summer peak normal weather derivation and Table LF-46 shows the monthly peak normal degree days. Only CDD or HDD were allowed as the normal for each month.

For the 2018 IRP Forecast, peak temperatures for Nevada Power were for the month of July only. Since recent annual peaks have occurred in June, July and August, the 2019 IRPA 2nd Amendment Forecast peaking temperatures for normal calculation were change to the peak day temperature, regardless of which month it occurred. For consistency, Sierra's peak normal was also changed to this calculation. Previously, Sierra normal peak temperature was based on the hottest average

TABLE LF-45
SUMMER PEAK NORMAL WEATHER DERIVATION

	NPC		SPPC	
Year	Avg Temp	CDD70	Avg Temp	CDD65
1999	98.5	28.5	81.5	16.5
2000	96.5	26.5	84.0	19.0
2001	99.5	29.5	80.5	15.5
2002	98.5	28.5	86.0	21.0
2003	99.5	29.5	86.0	21.0
2004	97.0	27.0	81.5	16.5
2005	106.0	36.0	86.0	21.0
2006	102.0	32.0	86.5	21.5
2007	101.0	31.0	87.5	22.5
2008	97.5	27.5	82.5	17.5
2009	101.0	31.0	82.5	17.5
2010	102.5	32.5	83.5	18.5
2011	98.0	28.0	82.5	17.5
2012	102.5	32.5	84.0	19.0
2013	102.5	32.5	83.5	18.5
2014	99.5	29.5	85.5	20.5
2015	96.0	26.0	86.0	21.0
2016	103.0	33.0	84.5	19.5
2017	102.5	32.5	85.0	20.0
2018	102.0	32.0	83.5	18.5
Normal	100.3	30.3	84.1	19.1

TABLE LF-46
MONTHLY PEAK NORMAL DEGREE DAYS – 1999-2018

	NPC		SPPC	
Month	CDD70	HDD50	CDD65	HDD50
1	0.0	8.8	0.0	21.7
2	0.0	5.4	0.0	18.7
3	1.7	0.0	0.0	11.2
4	9.3	0.0	0.0	0.0
5	18.7	0.0	5.6	0.0
6	26.7	0.0	16.4	0.0
7	30.8	0.0	19.1	0.0
8	27.4	0.0	16.2	0.0
9	21.5	0.0	9.8	0.0
10	11.6	0.0	0.0	0.0
11	0.0	0.0	0.0	15.6
12	0.0	9.7	0.0	24.5

The peak model statistics are shown in Table LF-47. The historical data period is January 2008 through December 2018 for Nevada Power and January 2010 through November 2018 for Sierra. Large customer hourly data was only available through November at the time the Sierra peak model was developed.

TABLE LF-47
MONTHLY PEAK MODEL STATISTICS

Model Statistic	Nevada Power	Sierra
Adjusted Observations	120	107
R-Squared	0.989	0.945
Adjusted R-Squared	0.988	0.940
Mean Squared Error	20159	2198
Mean Abs. Percentage Error (MAPE)	0.032	2.98%
Durbin-Watson Statistic	2.038	1.721
Ljung-Box Statistic	33.930	35.697

NEVADA POWER UNINTERRUPTED PEAK MODEL

Variable	Definition	Coefficient	Standard Error	T-Stat	P-Values
HeatVar	Est. of the electric heating equipment (base 50) at the monthly peak	197.456	44.976	4.390	0.00%
CoolVar70	Est. of the electric cooling (base 70) at the monthly peak	1220.084	16.746	72.859	0.00%
Apr10	Binary for month and year	314.212	143.553	2.189	3.07%
May	Binary for month	-250.228	48.743	-5.134	0.00%
Oct	Binary for month	-264.486	48.885	-5.410	0.00%
Jul	Binary for month	115.545	53.899	2.144	3.42%
TotOtherCP	Est. of the non-heating and cooling end-uses at the monthly peak	1.652	0.018	90.950	0.00%

SIERRA UNINTERRUPTED PEAK MODEL

Variable	Definition	Coefficient	Standard Error	T-Stat	P-Values
HeatVar	Est. of the electric heating equipment (base 50) at the monthly peak	45.245	10.936	3.591	0.05%
CoolVar	Est. of the electric cooling (base 65) at the monthly peak	306.125	12.842	25.030	0.00%
ResOtherCP	Est. of the Residential non-heating and cooling end-uses at the monthly peak	0.473	0.167	3.526	0.06%
COMOtherCP	Est. of the C&I non-heating and cooling end-uses at the monthly peak	1.186	0.039	28.272	0.00%
Mar	Binary for month	51.916	17.547	3.110	0.24%
Apr	Binary for month	152.799	15.143	10.147	0.00%
Jul	Binary for month	127.625	16.192	6.403	0.00%
Aug	Binary for month	131.334	15.589	6.941	0.00%
Dec	Binary for month	93.027	15.773	4.450	0.00%
May15	Binary for month and year	-159.085	41.144	-3.788	0.03%

Developing the Hourly Loads

The hourly load development requires the following steps:

1. Develop a monthly forecast of system energy.
2. Create daily normal weather.
3. Apply the daily normal weather to historical hourly system load to create a weather normalized system hourly load shape.
4. Impose the monthly peak and energy forecast and the future annual calendar on the normalized system load shape to produce the forecasted hourly loads.
5. Subtract forecasted hourly loads for net metering, demand response, DOS customers, and add the EV hourly load. For Sierra, add the forecasted hourly loads for the GS-4 class, GS-3 mine load and other large non-mine customers. For Nevada Power, add the load for any new large customers (Resorts World in mid-2021).

The first step is to develop the monthly system peak energy. The monthly system energy is forecasted using the ratio of the historical monthly sales divided by the historical system energy. These ratios are then multiplied by the aggregated monthly class sales forecast to produce the forecasted monthly system energy.

The second step is to develop the daily normal weather. The normal weather used in the peak and hourly forecast is developed using the Rank and Average method. Basically, the daily average temperatures for the 20-year period were ranked from hottest to coldest by season. The average temperatures for the ranked days were then averaged across the 20-years to produce a daily average normal temperature. For example, the 20 hottest temperature days for a season are averaged, then the second 20 hottest days and so on. These daily average temperatures are then assigned to calendar days for the period of the forecast.

Table LF-48 is a summary of the Sierra July 2020 Temperature for Monday through Friday for the week of the peak. The peak for 2020 occurs on July 22nd.

TABLE LF-48
PEAK WEEKDAY AVERAGE TEMPERATURES FOR JULY 2020

Month	Day	Year	AvgTemp	Day of Week
7	20	2020	78.75	Monday
7	21	2020	82.30	Tuesday
7	22	2020	**85.70**	Wednesday
7	23	2020	80.70	Thursday
7	24	2020	80.33	Friday

The third step in the process is to apply the rank and mean weather to the historical system load shape to produce a weather adjusted load shape. This load shape is forecasted by applying future calendars to reflect load differences due to weather and other factors on weekdays, weekends and holidays.

The fourth step in the process is to apply the forecasted system peaks and energy to the weather normalized forecasted system load shape. The forecasted load shape is calibrated to equal the monthly system peak and energy forecast.

The fifth step in the process is to adjust the forecasted hourly loads for net metering, demand response, the GS-3 mining and GS-4 large customer load forecast, new DOS customer load and electric vehicle hourly load shapes.

The process is the same for Nevada Power.

The 2020 Sierra peak load components developed from the process outlined above are shown in Figure LF-49 and Table LF-50.

FIGURE LF-49
JULY 22, 2020 PEAK DAY LOAD COMPONENTS (MW)

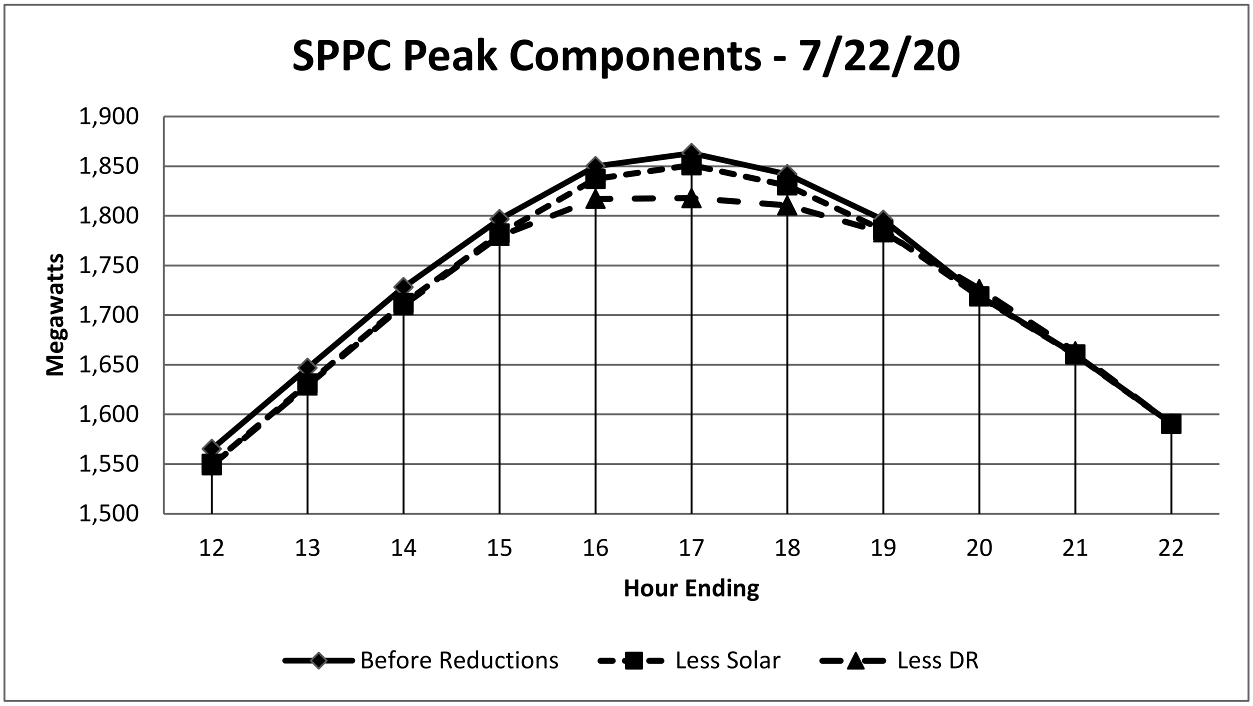

TABLE LF-50
JULY 22, 2020 PEAK DAY LOAD COMPONENTS (MW)

Hour Ending	12	13	14	15	16	17	18	19	20	21	22
Load Less Lg Cust	1,218	1,300	1,380	1,447	1,493	1,501	1,479	1,435	1,355	1,291	1,218
Large Customer (1)	318	317	318	318	326	331	332	330	334	339	343
EV	0	0	0	0	0	0	0	0	0	0	1
Before Reductions	1,536	1,617	1,698	1,766	1,819	1,832	1,811	1,765	1,689	1,630	1,562
Solar PV	-15	-16	-16	-14	-13	-12	-11	-10	-1	0	0
EcoFactor	-1	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2
Unint	1,519	1,600	1,681	1,749	1,805	1,818	1,798	1,753	1,687	1,628	1,560
DR	0	0	0	0	-19	-31	-18	0	9	5	2
Net Peak	1,519	1,600	1,681	1,749	1,786	1,787	1,780	1,753	1,696	1,633	1,562

(1) Includes DOS.

B. <u>Peak Demand Forecast Summary</u>

Pursuant to §§ NAC 704.923(2), (3)(a) and (3)(b), Tables LF-51 and LF-52 are summaries of the peak demand, energy, load factor, losses and company use for 2019-2049. For Sierra, Liberty Energy (California) was removed as it was scheduled to become a balancing authority customer on May 1, 2019. The California energy for 2019 is [redacted] GWh and [redacted] MW at the time of the Sierra winter peak. Sierra losses and company use are not calculated separately for California and Nevada.

Table LF-53 is a summary of the Companies' Nevada jurisdictional energy, peaks and load factor, including the company peaks at the time of the NVE peak.

TABLE LF-51
NEVADA POWER PEAK DEMAND, ENERGY, LOAD FACTOR AND LOSSES & COMPANY USE

Year	Summer Peak MW	Winter Peak MW	Energy GWh	Load Factor	Losses GWh	Company Use GWh
2019	5,701	2,490	20,711	41.5%	898	21
2020	5,696	2,423	20,536	41.2%	901	21
2021	5,778	2,422	20,745	40.9%	913	21
2022	5,825	2,455	20,997	41.1%	926	21
2023	5,853	2,465	21,095	41.1%	933	21
2024	5,891	2,475	21,209	41.1%	939	21
2025	5,923	2,472	21,271	40.9%	944	21
2026	5,953	2,473	21,342	40.9%	949	21
2027	5,998	2,473	21,418	40.8%	953	21
2028	6,023	2,481	21,528	40.8%	960	21
2029	6,064	2,483	21,609	40.6%	965	21
2030	6,101	2,474	21,648	40.5%	967	21
2031	6,140	2,466	21,695	40.3%	970	21
2032	6,178	2,464	21,768	40.2%	973	22
2033	6,209	2,455	21,810	40.0%	976	22
2034	6,246	2,455	21,879	40.0%	980	22
2035	6,286	2,453	21,955	39.9%	984	22
2036	6,341	2,458	22,063	39.7%	989	22
2037	6,385	2,454	22,129	39.5%	993	22
2038	6,430	2,456	22,218	39.4%	997	22
2039	6,465	2,458	22,322	39.4%	1,002	22
2040	6,511	2,467	22,439	39.3%	N/A	N/A
2041	6,563	2,486	22,536	39.1%	N/A	N/A
2042	6,606	2,505	22,632	39.1%	N/A	N/A
2043	6,651	2,525	22,728	39.0%	N/A	N/A
2044	6,692	2,545	22,824	38.9%	N/A	N/A
2045	6,736	2,566	22,923	38.7%	N/A	N/A
2046	6,782	2,587	23,021	38.7%	N/A	N/A
2047	6,838	2,607	23,119	38.6%	N/A	N/A
2048	6,882	2,627	23,218	38.5%	N/A	N/A
2049	6,946	2,653	23,364	38.3%	N/A	N/A

TABLE LF-52
SIERRA PEAK DEMAND, ENERGY, LOAD FACTOR AND LOSSES & COMPANY USE

Year	Energy GWhs	Summer Peak MW	Winter Peak MW	Load Factor	Losses	Company Use
2019	9,938	1,771	1,420	64.1%	606	24
2020	9,969	1,787	1,401	63.7%	581	23
2021	10,215	1,814	1,416	64.3%	586	24
2022	9,386	1,695	1,293	63.2%	578	23
2023	9,390	1,714	1,311	62.5%	551	22
2024	9,620	1,737	1,337	63.2%	558	23
2025	9,723	1,749	1,344	63.5%	576	23
2026	9,759	1,750	1,342	63.7%	571	23
2027	9,770	1,752	1,339	63.7%	576	23
2028	9,802	1,756	1,341	63.7%	579	23
2029	9,813	1,761	1,338	63.6%	592	24
2030	9,822	1,768	1,334	63.4%	590	24
2031	9,828	1,777	1,334	63.1%	593	24
2032	9,867	1,788	1,333	63.0%	591	24
2033	9,872	1,798	1,325	62.7%	608	25
2034	9,911	1,809	1,326	62.5%	603	24
2035	9,945	1,818	1,323	62.4%	620	25
2036	10,000	1,831	1,331	62.3%	628	25
2037	10,015	1,840	1,329	62.1%	647	26
2038	10,053	1,853	1,328	61.9%	642	26
2039	10,094	1,866	1,330	61.7%	652	26
2040	10,138	1,876	1,326	61.7%	662	27
2041	10,149	1,885	1,324	61.5%	678	27
2042	10,180	1,897	1,327	61.3%	682	28
2043	10,217	1,907	1,327	61.2%	690	28
2044	10,278	1,923	1,325	61.0%	698	28
2045	10,303	1,934	1,328	60.8%	718	29
2046	10,348	1,946	1,327	60.7%	716	29
2047	10,394	1,959	1,330	60.6%	726	29
2048	10,459	1,973	1,339	60.5%	733	30
2049	10,485	1,987	1,336	60.2%	753	30

TABLE LF-53
NVE NEVADA PEAK DEMAND, ENERGY LOAD FACTOR

	NVE NEVADA (1)				CO. PEAKS AT THE TIME OF THE NVE PEAK			
Year	Energy GWhs	Summer Peak MW	Winter Peak MW	Load Factor	Date	Hour	NPC	SPPC
2019	30,649	7,459	3,910	46.9%	7/1/2019	16	5,701	1,758
2020	30,505	7,468	3,745	46.6%	7/14/2020	16	5,691	1,777
2021	30,960	7,501	3,756	47.1%	7/5/2021	16	5,778	1,723
2022	30,383	7,404	3,815	46.8%	7/19/2022	16	5,825	1,579
2023	30,485	7,553	3,706	46.1%	7/3/2023	18	5,853	1,700
2024	30,828	7,615	3,722	46.2%	7/1/2024	16	5,891	1,724
2025	30,994	7,662	3,763	46.2%	7/15/2025	16	5,923	1,739
2026	31,101	7,687	3,771	46.2%	7/14/2026	16	5,947	1,740
2027	31,188	7,656	3,756	46.5%	7/5/2027	16	5,998	1,658
2028	31,330	7,769	3,765	46.0%	7/3/2028	16	6,020	1,749
2029	31,422	7,809	3,757	45.9%	7/2/2029	16	6,064	1,745
2030	31,470	7,856	3,782	45.7%	7/1/2030	16	6,101	1,755
2031	31,523	7,903	3,755	45.5%	7/15/2031	16	6,140	1,763
2032	31,635	7,950	3,753	45.4%	7/13/2032	16	6,178	1,772
2033	31,682	7,908	3,728	45.7%	7/4/2033	18	6,209	1,699
2034	31,790	8,037	3,731	45.2%	7/3/2034	18	6,246	1,791
2035	31,900	8,085	3,717	45.0%	7/2/2035	16	6,286	1,799
2036	32,063	8,157	3,760	44.9%	7/15/2036	16	6,341	1,816
2037	32,145	8,200	3,743	44.8%	7/14/2037	18	6,385	1,815
2038	32,270	8,175	3,734	45.1%	7/20/2038	16	6,430	1,745
2039	32,415	8,226	3,739	45.0%	7/4/2039	18	6,465	1,761
2040	32,577	8,366	3,749	44.5%	7/2/2040	16	6,511	1,855
2041	32,685	8,429	3,789	44.3%	7/1/2041	16	6,563	1,866
2042	32,812	8,485	3,794	44.1%	7/15/2042	16	6,606	1,879
2043	32,945	8,527	3,814	44.1%	7/14/2043	18	6,651	1,876
2044	33,101	8,504	3,825	44.4%	7/4/2044	18	6,692	1,812
2045	33,225	8,646	3,851	43.9%	7/3/2045	18	6,736	1,910
2046	33,369	8,705	3,864	43.8%	7/2/2046	16	6,782	1,923
2047	33,514	8,776	3,918	43.6%	7/1/2047	16	6,838	1,938
2048	33,677	8,822	3,929	43.6%	7/14/2048	18	6,882	1,940
2049	33,849	8,756	3,947	44.1%	7/20/2049	16	6,929	1,827

(1) All MW values are at the time of the NVE system peak.
Note: 2019 NVE Nevada hourly loads without California
have not been calculated. The numbers shown include California.

Table LF-54 is a summary of the installed DR and avoided capacity for each company.

TABLE LF-54
DR INSTALLED AND AVOIDED CAPACITY (MW)

	NEVADA POWER MW		SIERRA MW	
Year	Installed*	Avoided Capacity**	Installed*	Avoided Capacity**
2019	215	153	28	25
2020	237	168	36	31
2021	257	192	43	37
2022	268	197	50	42
2023	279	189	57	47
2024	289	191	64	49
2025	294	201	70	52
2026	299	201	75	56
2027	303	215	80	57
2028	308	206	84	59
2029	312	206	88	61
2030	316	204	92	64
2031	320	213	96	65
2032	323	214	97	66
2033	327	227	98	64
2034	330	216	99	65
2035	333	220	100	65
2036	336	226	101	67
2037	339	217	102	67
2038	341	238	103	67
2039	346	239	104	67

* End of year, at the meter.
** At the peak. Includes losses.

Per NAC § 704.925(2). Tables LF-55 and LF-56 summarize the DSM, private generation (solar net metering) and DR effects on the system peak. Table LF-56 includes Sierra Nevada-jurisdictional only, as California load transitions to a balancing authority customer prior to the 2019 Summer peak.

TABLE LF-55
NEVADA POWER PEAK MW BEFORE AND AFTER DSM, NET METERING AND DEMAND RESPONSE ("DR")

Year	Gross Peak (1)	Incremental DSM (2)	Private Generation (incremental Solar PV) (2)	Uninter-rupted Peak (3)	Less: Demand Response (4)	System Peak	System Energy (GWh)	Load Factor
2019	5,929	37	38	5,854	153	5,701	20,711	41.5%
2020	6,008	72	72	5,864	168	5,696	20,536	41.2%
2021	6,181	108	104	5,970	192	5,778	20,745	41.0%
2022	6,288	144	123	6,022	197	5,825	20,997	41.2%
2023	6,354	180	132	6,042	189	5,853	21,095	41.1%
2024	6,437	216	138	6,082	191	5,891	21,209	41.1%
2025	6,522	253	145	6,124	201	5,923	21,271	41.0%
2026	6,593	290	149	6,154	201	5,953	21,342	40.9%
2027	6,693	327	153	6,213	215	5,998	21,418	40.8%
2028	6,749	364	156	6,229	206	6,023	21,528	40.8%
2029	6,832	401	160	6,270	206	6,064	21,609	40.7%
2030	6,908	439	165	6,305	204	6,101	21,648	40.5%
2031	6,998	477	168	6,353	213	6,140	21,695	40.3%
2032	7,078	515	171	6,392	214	6,178	21,768	40.2%
2033	7,164	553	175	6,435	227	6,209	21,810	40.1%
2034	7,232	591	179	6,462	216	6,246	21,879	40.0%
2035	7,318	629	183	6,506	220	6,286	21,955	39.9%
2036	7,421	668	186	6,567	226	6,341	22,063	39.7%
2037	7,499	707	190	6,601	217	6,385	22,129	39.6%
2038	7,608	746	194	6,668	238	6,430	22,218	39.4%
2039	7,687	785	198	6,704	239	6,465	22,322	39.4%

1) Peak at 5 pm without incremental DSM, DR and private generation reductions.
2) Incremental DSM and private generation at 5 pm on the peak day. The DSM incudes the the non-callable DR savings.
3) Peak at 5 pm before demand response effects.
4) This is the avoided capacity of the demand response component. It is calculated by subtracting the system peak at whatever hour it occurs from the uninterrupted peak at 5 pm.

TABLE LF-56
SIERRA PEAK MW BEFORE AND AFTER DSM, NET METERING AND DEMAND RESPONSE ("DR")

Year	Gross Peak (1)	Incremental DSM (2)	Private Generation (Incremental Solar PV) (2)	Uninter-rupted Peak (3)	Less: Demand Response (4)	System Peak
2019	1,809	12	1	1,796	25	1,771
2020	1,846	25	3	1,818	31	1,787
2021	1,893	39	4	1,851	37	1,814
2022	1,793	52	5	1,737	42	1,695
2023	1,831	65	5	1,761	47	1,714
2024	1,871	78	6	1,786	49	1,737
2025	1,899	91	7	1,801	52	1,749
2026	1,917	104	8	1,806	56	1,750
2027	1,935	118	8	1,809	57	1,752
2028	1,956	132	9	1,815	59	1,756
2029	1,978	146	10	1,822	61	1,761
2030	2,002	160	10	1,832	64	1,768
2031	2,027	174	11	1,842	65	1,777
2032	2,054	188	12	1,854	66	1,788
2033	2,077	202	12	1,862	64	1,798
2034	2,103	216	13	1,874	65	1,809
2035	2,126	230	14	1,883	65	1,818
2036	2,156	244	15	1,898	67	1,831
2037	2,181	258	15	1,907	67	1,840
2038	2,208	272	16	1,920	67	1,853
2039	2,235	286	17	1,933	67	1,866

1) Peak at 5 pm without incremental DSM, DR and private generation reductions.
2) Incremental DSM and solar at 5 pm on the peak day. The private generation does not include the estimated 9 MW for Tesla. The DSM includes the non-callable DR savings.
3) Peak at 5 pm before demand response effects.
4) This is the avoided capacity of the demand response component. It is calculated by subtracting the system peak at whatever hour it occurs from the uninterrupted peak at 5 pm.

Several customers have filed 704B applications in the last year. Table LF-57 lists those customers, their annual usage and current status. All have been removed from the 2019 IRPA 2nd Forecast except [redacted] Their application was received by Sierra after the forecast was completed.

TABLE LF-57 {CONFIDENTIAL}
NEW DOS CUSTOMER LOAD REMOVED FROM THE 2019 IRPA 2ND FORECAST

[redacted]

VI. LOAD FORECAST SCENARIOS

A. <u>High and Low Economic Scenarios</u>

Tables LF-58 and LF-59 summarize the energy, summer peak demand, economics, class sales and customers for the Nevada Power and Sierra load forecast scenarios.[18] The high and low scenarios were developed from high and low economic forecasts for NN and the Las Vegas-Paradise MSA, and optimistic and pessimistic large customer load scenarios. No optimistic or pessimistic assumptions of DSM, DR or Solar PV are included in this analysis. However, DSM was calculated for each scenario based on applying the DSM goal percentage to the WN sales before DSM.

[18] Since the Sierra load forecast is Nevada-only except for January through April of 2019, a separate table for the scenarios for Nevada is not reported.

TABLE LF-58
NEVADA POWER LOW, BASE, AND HIGH SCENARIOS LOAD FORECAST PEAK DEMAND (MW) AND SYSTEM ENERGY (GWH)

	PEAK (MW)					ENERGY (GWH)				
				% Diff to Base					% Diff to Base	
Year	Low	Base	High	Low	High	Low	Base	High	Low	High
2019	5,679	5,701	5,723	-0.4%	0.4%	20,641	20,711	20,711	-0.3%	0.0%
2020	5,618	5,696	5,745	-1.4%	0.9%	20,291	20,536	20,693	-1.2%	0.8%
2021	5,667	5,778	5,879	-1.9%	1.7%	20,389	20,745	21,074	-1.7%	1.6%
2022	5,692	5,825	5,964	-2.3%	2.4%	20,570	20,997	21,509	-2.0%	2.4%
2023	5,700	5,853	6,027	-2.6%	3.0%	20,601	21,095	21,721	-2.3%	3.0%
2024	5,715	5,891	6,097	-3.0%	3.5%	20,640	21,209	21,937	-2.7%	3.4%
2025	5,725	5,923	6,162	-3.4%	4.0%	20,631	21,271	22,106	-3.0%	3.9%
2026	5,734	5,953	6,225	-3.7%	4.6%	20,635	21,342	22,284	-3.3%	4.4%
2027	5,759	5,998	6,304	-4.0%	5.1%	20,646	21,418	22,469	-3.6%	4.9%
2028	5,764	6,023	6,364	-4.3%	5.7%	20,691	21,528	22,687	-3.9%	5.4%
2029	5,786	6,064	6,431	-4.6%	6.0%	20,712	21,609	22,847	-4.1%	5.7%
2030	5,804	6,101	6,485	-4.9%	6.3%	20,693	21,648	22,938	-4.4%	6.0%
2031	5,825	6,140	6,542	-5.1%	6.5%	20,684	21,695	23,037	-4.7%	6.2%
2032	5,846	6,178	6,599	-5.4%	6.8%	20,705	21,768	23,167	-4.9%	6.4%
2033	5,859	6,209	6,649	-5.6%	7.1%	20,692	21,810	23,270	-5.1%	6.7%
2034	5,875	6,246	6,706	-5.9%	7.4%	20,695	21,879	23,394	-5.4%	6.9%
2035	5,891	6,286	6,764	-6.3%	7.6%	20,700	21,955	23,522	-5.7%	7.1%
2036	5,922	6,341	6,839	-6.6%	7.8%	20,735	22,063	23,685	-6.0%	7.4%
2037	5,943	6,385	6,899	-6.9%	8.0%	20,732	22,129	23,805	-6.3%	7.6%
2038	5,967	6,430	6,965	-7.2%	8.3%	20,752	22,218	23,952	-6.6%	7.8%
2039	5,979	6,465	7,021	-7.5%	8.6%	20,789	22,322	24,119	-6.9%	8.1%

TABLE LF-59
SIERRA LOW, BASE AND HIGH SCENARIOS LOAD FORECAST PEAK DEMAND (MW) AND SYSTEM ENERGY (GWH)

	Energy (GWh)					Summer Peak (MW)				
Year	Low	Base	High	Low to Base	High to Base	Low	Base	High	Low to Base	High to Base
2019	9,783	9,938	10,016	-1.6%	0.8%	1,750	1,771	1,783	-1.2%	0.7%
2020	9,598	9,969	10,273	-3.7%	3.0%	1,739	1,787	1,828	-2.7%	2.3%
2021	9,639	10,215	10,953	-5.6%	7.2%	1,739	1,814	1,908	-4.1%	5.2%
2022	8,699	9,386	10,473	-7.3%	11.6%	1,608	1,695	1,832	-5.1%	8.1%
2023	8,601	9,390	10,830	-8.4%	15.3%	1,614	1,714	1,892	-5.8%	10.4%
2024	8,632	9,620	11,328	-10.3%	17.8%	1,613	1,737	1,946	-7.1%	12.0%
2025	8,598	9,723	11,570	-11.6%	19.0%	1,606	1,749	1,976	-8.2%	13.0%
2026	8,584	9,759	11,805	-12.0%	21.0%	1,602	1,750	2,002	-8.5%	14.4%
2027	8,576	9,770	11,861	-12.2%	21.4%	1,600	1,752	2,010	-8.7%	14.7%
2028	8,586	9,802	11,929	-12.4%	21.7%	1,600	1,756	2,016	-8.9%	14.8%
2029	8,581	9,813	11,961	-12.6%	21.9%	1,602	1,761	2,028	-9.0%	15.2%
2030	8,571	9,822	11,987	-12.7%	22.0%	1,604	1,768	2,039	-9.3%	15.3%
2031	8,559	9,828	12,011	-12.9%	22.2%	1,610	1,777	2,053	-9.4%	15.5%
2032	8,577	9,867	12,076	-13.1%	22.4%	1,617	1,788	2,067	-9.6%	15.6%
2033	8,566	9,872	12,097	-13.2%	22.5%	1,623	1,798	2,082	-9.7%	15.8%
2034	8,583	9,911	12,158	-13.4%	22.7%	1,628	1,809	2,097	-10.0%	15.9%
2035	8,593	9,945	12,210	-13.6%	22.8%	1,632	1,818	2,111	-10.2%	16.1%
2036	8,621	10,000	12,292	-13.8%	22.9%	1,640	1,831	2,128	-10.4%	16.2%
2037	8,616	10,015	12,321	-14.0%	23.0%	1,645	1,840	2,141	-10.6%	16.4%
2038	8,631	10,053	12,381	-14.1%	23.2%	1,652	1,853	2,159	-10.8%	16.5%
2039	8,649	10,094	12,445	-14.3%	23.3%	1,661	1,866	2,177	-11.0%	16.7%

Tables LF-60 and LF-61 are summaries of the economic data used for the Base, High and Low load forecast scenarios.

TABLE LF-60 (page 1 of 2)
NEVADA POWER SCENARIO ECONOMIC DATA

	Population (000's)			Real GMP (millions)			Households (000's)		
Year	Low	Base	High	Low	Base	High	Low	Base	High
2019	2,292	2,303	2,309	102,115	103,722	105,614	807	859	812
2020	2,326	2,347	2,364	102,646	106,925	110,119	821	878	834
2021	2,347	2,380	2,410	105,385	109,890	114,331	834	895	857
2022	2,364	2,409	2,450	108,159	112,585	118,382	846	910	879
2023	2,382	2,438	2,490	111,222	114,946	122,495	855	924	898
2024	2,396	2,463	2,524	113,395	117,635	126,200	864	939	916
2025	2,409	2,485	2,556	115,273	120,779	129,520	873	954	934
2026	2,418	2,505	2,585	117,237	124,164	132,735	882	969	951
2027	2,426	2,523	2,611	119,499	127,648	136,218	892	983	969
2028	2,433	2,539	2,637	121,794	130,991	139,744	901	998	987
2029	2,439	2,554	2,661	123,981	134,428	143,390	911	1,013	1,006
2030	2,446	2,569	2,685	126,013	137,756	147,118	920	1,028	1,025
2031	2,449	2,581	2,707	128,036	141,309	151,097	929	1,044	1,046
2032	2,452	2,593	2,728	130,376	144,995	155,451	939	1,061	1,067
2033	2,454	2,604	2,749	132,983	148,894	160,225	948	1,077	1,090
2034	2,455	2,615	2,769	135,739	152,884	165,671	958	1,095	1,113
2035	2,455	2,625	2,788	138,147	157,110	170,899	969	1,112	1,138
2036	2,456	2,635	2,807	140,620	161,413	176,437	980	1,129	1,163
2037	2,456	2,644	2,827	143,185	165,544	182,208	990	1,148	1,188
2038	2,456	2,653	2,845	145,912	169,990	188,123	1,001	1,166	1,214
2039	2,455	2,662	2,863	149,014	174,737	194,739	1,012	1,184	1,240

TABLE LF-60 (page 2 of 2)
NEVADA POWER SCENARIO ECONOMIC DATA

	Persons Per Household			RPI per HH (000's)		
Year	Low	Base	High	Low	Base	High
2019	2.773	2.66	2.767	107.91	111.95	109.36
2020	2.756	2.65	2.741	107.60	113.66	113.09
2021	2.739	2.63	2.719	109.27	115.35	116.35
2022	2.722	2.62	2.699	112.20	116.92	119.26
2023	2.717	2.61	2.690	114.51	117.99	121.54
2024	2.711	2.60	2.682	115.55	119.19	122.85
2025	2.706	2.60	2.674	116.14	120.81	123.81
2026	2.701	2.59	2.667	117.03	122.65	124.87
2027	2.694	2.58	2.657	118.19	124.66	126.13
2028	2.687	2.57	2.648	119.28	126.76	127.48
2029	2.680	2.56	2.636	119.85	128.89	129.07
2030	2.676	2.55	2.624	119.98	130.91	130.85
2031	2.673	2.54	2.611	120.10	133.12	132.48
2032	2.668	2.53	2.596	120.38	135.54	134.35
2033	2.663	2.53	2.581	120.95	137.91	136.44
2034	2.658	2.52	2.565	121.36	140.26	138.68
2035	2.650	2.51	2.548	121.37	142.70	140.74
2036	2.644	2.50	2.532	121.18	145.25	142.63
2037	2.638	2.48	2.516	121.16	147.59	144.81
2038	2.631	2.47	2.498	121.13	149.88	146.78
2039	2.624	2.47	2.481	121.17	152.18	148.81

TABLE LF-61 (page 1 of 2)
SIERRA SCENARIO ECONOMIC DATA

	Population (000's)			Real GMP (millions 09$)			Households (000's)		
Year	Low	Base	High	Low	Base	High	Low	Base	High
2019	815.34	815.34	815.34	40,174	40,174	40,174	326.97	326.97	326.97
2020	822.81	826.53	828.97	41,066	41,264	41,662	330.45	332.05	333.14
2021	829.03	836.62	842.92	40,707	42,254	43,111	332.73	336.37	339.03
2022	833.20	844.94	855.41	40,991	43,099	44,555	334.37	340.20	344.57
2023	836.05	851.80	866.46	41,480	43,723	45,914	335.30	342.85	348.99
2024	837.98	857.57	875.96	42,034	44,423	47,379	336.09	345.15	352.90
2025	839.64	862.91	884.57	42,425	45,071	48,735	336.73	347.21	356.36
2026	840.81	867.56	892.28	42,864	45,821	50,302	337.32	349.20	359.65
2027	841.81	871.91	899.69	43,452	46,674	52,065	337.98	351.24	363.04
2028	842.79	876.27	907.15	44,090	47,551	53,892	338.46	353.12	366.32
2029	843.92	880.65	914.65	44,700	48,370	55,623	339.21	355.22	369.83
2030	845.34	885.05	922.20	45,338	49,231	57,099	339.98	357.41	373.57
2031	846.78	889.48	929.80	45,817	49,984	58,279	340.29	359.65	377.63
2032	848.15	893.93	937.46	46,303	50,744	59,467	340.48	361.96	381.80
2033	849.44	898.40	945.20	46,945	51,615	60,859	340.76	364.42	386.18
2034	850.65	902.89	953.00	47,569	52,518	62,402	340.96	366.86	390.55
2035	851.82	907.40	960.86	48,096	53,431	63,834	341.31	369.51	395.18
2036	853.02	911.94	968.73	48,635	54,382	65,295	341.56	372.08	399.76
2037	854.24	916.50	976.63	49,142	55,295	66,781	341.68	374.55	404.25
2038	855.48	921.08	984.54	49,611	56,172	68,212	342.02	377.28	409.05
2039	856.76	925.69	992.47	50,217	57,171	69,913	342.31	379.98	413.81

TABLE LF-61 (page 2 of 2)
SIERRA SCENARIO ECONOMIC DATA

	Non-Farm Employ. (000's)			Persons per HH		
Year	Low	Base	High	Low	Base	High
2019	347.35	347.35	347.35	2.462	2.462	2.462
2020	350.24	352.33	354.70	2.490	2.448	2.488
2021	347.56	358.64	362.80	2.492	2.436	2.486
2022	345.36	363.08	369.89	2.492	2.425	2.483
2023	347.04	365.44	375.95	2.493	2.419	2.483
2024	348.72	366.02	380.25	2.493	2.414	2.482
2025	348.50	366.91	383.89	2.493	2.410	2.482
2026	348.50	368.78	388.74	2.493	2.406	2.481
2027	349.32	371.01	394.52	2.491	2.402	2.478
2028	350.24	372.87	400.01	2.490	2.400	2.476
2029	351.40	374.67	404.92	2.488	2.397	2.473
2030	353.01	376.62	408.84	2.486	2.394	2.469
2031	353.91	377.97	411.24	2.488	2.392	2.462
2032	354.23	378.92	413.70	2.491	2.389	2.455
2033	355.88	381.04	417.52	2.493	2.386	2.448
2034	357.89	383.52	422.37	2.495	2.383	2.440
2035	359.45	386.10	426.88	2.496	2.380	2.431
2036	360.88	388.83	430.75	2.497	2.377	2.423
2037	362.13	391.35	434.94	2.500	2.375	2.416
2038	362.74	393.17	438.19	2.501	2.371	2.407
2039	364.31	395.87	442.66	2.503	2.367	2.398

Note: Base values higher than High values are caused by anomalies created in subtracting the Las Vegas-Paradise MSA values from the Nevada values.

The high and low scenarios were developed by using the GI percent deviations around the base economic forecast and applying these percentages to the base economic forecast.

Tables LF-62 and LF-63 summarize the class sales for each scenario. There was no change to base Public Authority or Street Lighting sales for either Company.

TABLE LF-62
NEVADA POWER SCENARIO CALENDAR SALES (GWH)

	Residential			Small C&I			Large C&I					Total Sales		
Year	Low	Base	High	Low	Base	High	Low	Base	High	Public Authority	Street Lighting	Low	Base	High
2019	9,593	9,645	9,684	4,696	4,701	4,709	5,223	5,231	5,247	58	155	19,726	19,792	19,854
2020	9,556	9,700	9,798	4,704	4,739	4,762	4,908	4,961	4,988	58	155	19,383	19,614	19,762
2021	9,520	9,737	9,899	4,730	4,784	4,825	5,011	5,077	5,183	58	155	19,475	19,812	20,122
2022	9,558	9,821	10,052	4,755	4,825	4,890	5,119	5,190	5,378	58	155	19,646	20,050	20,534
2023	9,588	9,892	10,186	4,764	4,851	4,940	5,109	5,186	5,394	58	155	19,675	20,142	20,734
2024	9,617	9,965	10,316	4,776	4,881	4,993	5,104	5,188	5,415	58	155	19,711	20,248	20,937
2025	9,613	10,002	10,408	4,774	4,897	5,031	5,100	5,193	5,441	58	155	19,701	20,306	21,094
2026	9,622	10,050	10,514	4,770	4,910	5,066	5,099	5,198	5,469	58	155	19,705	20,372	21,263
2027	9,637	10,104	10,626	4,764	4,920	5,098	5,100	5,206	5,500	58	155	19,715	20,443	21,438
2028	9,666	10,173	10,753	4,772	4,943	5,144	5,105	5,217	5,533	58	155	19,756	20,547	21,644
2029	9,687	10,230	10,851	4,767	4,953	5,172	5,109	5,226	5,557	58	155	19,776	20,623	21,794
2030	9,683	10,259	10,905	4,756	4,956	5,191	5,106	5,231	5,570	58	155	19,758	20,659	21,879
2031	9,681	10,288	10,960	4,747	4,962	5,211	5,108	5,239	5,588	58	155	19,749	20,703	21,973
2032	9,695	10,333	11,030	4,746	4,975	5,241	5,115	5,252	5,611	58	155	19,769	20,773	22,096
2033	9,689	10,357	11,082	4,733	4,977	5,259	5,120	5,264	5,637	58	155	19,757	20,812	22,192
2034	9,693	10,397	11,148	4,727	4,986	5,285	5,126	5,280	5,663	58	155	19,759	20,878	22,309
2035	9,695	10,438	11,210	4,722	4,998	5,313	5,134	5,300	5,693	58	155	19,765	20,950	22,430
2036	9,715	10,498	11,295	4,724	5,017	5,348	5,145	5,323	5,728	58	155	19,798	21,052	22,585
2037	9,716	10,538	11,357	4,714	5,024	5,370	5,152	5,340	5,756	58	155	19,796	21,115	22,697
2038	9,726	10,585	11,429	4,711	5,037	5,401	5,164	5,363	5,794	58	155	19,815	21,199	22,837
2039	9,747	10,643	11,514	4,711	5,052	5,433	5,179	5,389	5,834	58	155	19,850	21,298	22,995

TABLE LF-63
SIERRA SCENARIO CALENDAR SALES (GWH)

	RESIDENTIAL			SMALL C&I (NO IRR)			LARGE C&I			IRRIGA-TION	STREET LIGHTING	TOTAL SALES		
Year	Low	Base	High	Low	Base	High	Low	Base	High			Low	Base	High
2019	2,475	2,479	2,496	2,812	2,819	2,840	3,489	3,625	3,672	156	16	8,948	9,095	9,180
2020	2,469	2,495	2,530	2,818	2,841	2,857	3,551	3,842	4,076	156	16	9,011	9,351	9,635
2021	2,451	2,496	2,547	2,809	2,843	2,869	3,631	4,093	4,716	156	16	9,064	9,604	10,305
2022	2,437	2,491	2,561	2,801	2,843	2,880	2,742	3,298	4,225	156	16	8,153	8,804	9,838
2023	2,426	2,487	2,573	2,793	2,841	2,889	2,661	3,299	4,538	156	16	8,051	8,800	10,173
2024	2,427	2,498	2,599	2,790	2,846	2,902	2,687	3,495	4,964	156	16	8,076	9,011	10,638
2025	2,412	2,493	2,608	2,779	2,843	2,908	2,687	3,611	5,194	156	16	8,051	9,119	10,882
2026	2,406	2,495	2,624	2,772	2,843	2,916	2,685	3,641	5,389	156	16	8,036	9,151	11,102
2027	2,402	2,500	2,644	2,767	2,844	2,926	2,685	3,643	5,409	156	16	8,027	9,159	11,151
2028	2,405	2,512	2,671	2,765	2,849	2,939	2,686	3,645	5,416	156	16	8,029	9,178	11,198
2029	2,403	2,519	2,687	2,762	2,852	2,950	2,688	3,648	5,423	156	16	8,026	9,191	11,233
2030	2,395	2,518	2,692	2,758	2,855	2,960	2,691	3,651	5,430	156	16	8,016	9,196	11,255
2031	2,389	2,520	2,700	2,755	2,859	2,972	2,692	3,653	5,435	156	16	8,008	9,204	11,279
2032	2,391	2,529	2,716	2,757	2,868	2,989	2,693	3,656	5,440	156	16	8,014	9,225	11,316
2033	2,385	2,530	2,724	2,754	2,871	3,000	2,697	3,661	5,448	156	16	8,008	9,235	11,344
2034	2,388	2,541	2,742	2,753	2,879	3,016	2,699	3,665	5,455	156	16	8,012	9,258	11,385
2035	2,390	2,553	2,759	2,753	2,887	3,032	2,702	3,670	5,463	156	16	8,018	9,283	11,426
2036	2,399	2,572	2,784	2,757	2,899	3,052	2,705	3,676	5,471	156	16	8,033	9,319	11,479
2037	2,397	2,580	2,797	2,755	2,905	3,066	2,709	3,682	5,481	156	16	8,034	9,339	11,516
2038	2,401	2,592	2,817	2,757	2,914	3,084	2,711	3,686	5,488	156	16	8,041	9,365	11,560
2039	2,407	2,608	2,839	2,759	2,924	3,102	2,715	3,692	5,498	156	16	8,053	9,396	11,611

Large Customer Load Scenarios

The high and low large customer scenarios assumed the following:

1. High Case: For Sierra, both the Pumpkin Hollow and Hycroft mine load was increased from the base case. Non-mine large customers were assumed to ramp up closer to expected load and some expansions were accelerated. For Nevada Power, assume the Resorts World load increases to [redacted] MW and [redacted] GWh.
2. Low Case: For Sierra, the Pumpkin Hollow and Hycroft mine expansions were removed. Other large customer load is assumed to be lower than the base and slower to ramp up. Nevada Power larger customer assumptions were the same as the base.

Table LF-64 is a summary of the Sierra large customer load under each scenario.

TABLE LF-64
NON-MINE LOAD SCENARIO CALENDAR SALES (GWH) AND BILLING DEMAND (MW)

	MINE LOAD						NON-MINE LOAD					
	December Billing Demand			Annual GWH			December Billing Demand			Annual GWH		
Year	Low	Base	High	Low	Base	High	Low	Base	High	Low	Base	High
2019	220	223	231	1,859	1,868	1,892	149.6	167.5	83.0	913	1,043	1,063
2020	220	227	244	1,859	1,894	1,969	163.6	207.0	119.0	1,001	1,315	1,411
2021	220	236	257	1,859	1,934	2,066	178.6	237.2	140.0	1,085	1,519	1,945
2022	72	88	109	1,859	969	2,101	197.6	258.8	140.0	1,199	1,687	2,411
2023	72	88	109	860	777	1,103	207.6	279.5	140.0	1,310	1,880	2,912
2024	72	88	109	668	777	910	207.6	307.4	140.0	1,336	2,076	3,333
2025	72	88	109	668	777	910	207.6	319.0	140.0	1,336	2,191	3,557
2026	72	88	109	668	777	910	207.6	319.0	140.0	1,336	2,220	3,748
2027	72	88	109	668	777	910	207.6	319.0	140.0	1,336	2,220	3,761
2028	72	88	109	668	777	910	207.6	319.0	140.0	1,336	2,220	3,761
2029	72	88	109	668	777	910	207.6	319.0	140.0	1,336	2,220	3,761
2030	72	88	109	668	777	910	207.6	319.0	140.0	1,336	2,220	3,761
2031	72	88	109	668	777	910	207.6	319.0	140.0	1,336	2,220	3,761
2032	72	88	109	668	777	910	207.6	319.0	140.0	1,336	2,220	3,761
2033	72	88	109	668	777	910	207.6	319.0	140.0	1,336	2,220	3,761
2034	72	88	109	668	777	910	207.6	319.0	140.0	1,336	2,220	3,761
2035	72	88	109	668	777	910	207.6	319.0	140.0	1,336	2,220	3,761
2036	72	88	109	668	777	910	207.6	319.0	140.0	1,336	2,220	3,761
2037	72	88	109	668	777	910	207.6	319.0	140.0	1,336	2,220	3,761
2038	72	88	109	668	777	910	207.6	319.0	140.0	1,336	2,220	3,761
2039	72	88	109	668	777	910	207.6	319.0	140.0	1,336	2,220	3,761

Scenario Probability

In October 2018, the month GI released the economic forecast used in the 2019 IRPA 2nd Forecast, the U.S. low scenario was assigned a probability of 25 percent and the high 15 percent. Given the population derivation, mine load, and other large customer assumptions, it is likely that the probability of the low and high scenarios occurring is less than 25 percent and 15 percent respectively.

VII. ONE-IN-TEN WEATHER TRANSMISSION FORECAST SCENARIO

The models for the 1 in 10 year to develop the transmission reserve percentage have not been updated for the 2019 IRA 2nd Forecast. The model statistics and temperature information used to develop the Sierra the 3.86 percent multiplier and Nevada Power 4.23 percent multiplier to the base system peak can be found in Nevada Power's 3rd Amendment to the 2016-2035 IRP filing, Docket No. 17-11004, Volume 1, pages 202 and 203 of 205, and in Sierra's 2nd Amendment filing to their 2015-2034 IRP filing, Docket No. 17-11003, Volume 2, pages 82 through 84 of 372.

Table LF-65 is a summary of the base peak demand forecasts as developed from the procedure described in Section V. The Transmission Reserve is then calculated by applying the adjustment factor for each company to the 2019 IRPA 2nd base case peak demand forecast. The NVE 1 in 10 peak is calculated by assuming the Nevada Power 1 in 10 peak occurs at the time of the NVE peak. The Sierra contribution to the NVE 1 in 10 peak is then calculated by taking the NVE Base peak less the Nevada Power base peak and multiplying by 1 plus the Sierra transmission reserve percentage of 4.23 percent.

TABLE LF-65
1 IN 10 YEAR PEAK TEMPERATURE PEAK DEMANDS (MW)

South			North			NVE - ADJUSTED FOR DIVERSITY			
		4.23%			3.86%		4.15%		
							(Average from 2019-2028)		
Year	Base	1 in 10	Year	Base	1 in 10	Year	Base	1 in 10	% Diff
2019	5,701	5,942	2019	1,771	1,839	2019	7,459	7,768	4.1%
2020	5,696	5,937	2020	1,787	1,856	2020	7,468	7,778	4.1%
2021	5,778	6,023	2021	1,814	1,884	2021	7,501	7,812	4.2%
2022	5,825	6,072	2022	1,695	1,760	2022	7,404	7,712	4.2%
2023	5,853	6,101	2023	1,714	1,780	2023	7,553	7,867	4.2%
2024	5,891	6,140	2024	1,737	1,804	2024	7,615	7,931	4.1%
2025	5,923	6,174	2025	1,749	1,817	2025	7,662	7,980	4.2%
2026	5,953	6,205	2026	1,750	1,818	2026	7,687	8,006	4.1%
2027	5,998	6,252	2027	1,752	1,820	2027	7,656	7,974	4.2%
2028	6,023	6,278	2028	1,756	1,824	2028	7,769	8,092	4.1%
2029	6,064	6,321	2029	1,761	1,829	2029	7,809	8,134	4.2%
2030	6,101	6,359	2030	1,768	1,836	2030	7,856	8,182	4.1%
2031	6,140	6,400	2031	1,777	1,846	2031	7,903	8,231	4.2%
2032	6,178	6,440	2032	1,788	1,857	2032	7,950	8,280	4.2%
2033	6,209	6,472	2033	1,798	1,867	2033	7,908	8,236	4.2%
2034	6,246	6,510	2034	1,809	1,879	2034	8,037	8,370	4.1%
2035	6,286	6,552	2035	1,818	1,888	2035	8,085	8,421	4.1%
2036	6,341	6,610	2036	1,831	1,902	2036	8,157	8,497	4.2%
2037	6,385	6,655	2037	1,840	1,911	2037	8,200	8,540	4.1%
2038	6,430	6,702	2038	1,853	1,925	2038	8,175	8,514	4.2%
2039	6,465	6,739	2039	1,866	1,938	2039	8,226	8,568	4.2%

VIII. SOLAR PV FORECAST DEVELOPMENT

The private generation (solar PV) incremental monthly MW forecast was created based on installations as of December 31, 2018 and discussions with the renewable department for future PV based on the projected impacts of Assembly Bill 405. Note that the forecast is incremental from July 2018.

The hourly load shapes developed for the Sierra 2016 general rate case and the Nevada Power net metering Docket No. 15-07041 were used to develop the 2019 though 2049 hourly solar PV reductions (on site use). The “Own Load” shape, used for small net metered installations, and the “Generation Load” shape, used for large (> 1 MW) behind the meter installations, were translated to the 2012 calendar to allow for leap day. To avoid using a single day for the solar PV peak load shape, 2-3 high reduction days per month for May through October were averaged to produce the peak day solar PV load shape.

The next step was to create the monthly MWH reductions for the “Own Load” and “Generation Load” energy to impose on the solar PV load shapes. The monthly MWh reduction estimates were calculated by taking the forecasted monthly MW and multiplying by the average MWh per MW calculated from the load shapes. Tables LF-66 and LF-67 summarize the annual MW and MWh forecast at the meter.

TABLE LF-66
NEVADA POWER PRIVATE GENERATION (SOLAR PV) ANNUAL ON-SITE USE FORECAST AT THE METER

	INSTALLED MW		GENERATION		OWN USE	
Year	Small MW	Large MW	Large MWH per MW	Large MWH	Small MWH per MW	Small Own MWH
2019	75.0	2.4	3,148	7,534	1,157	86,739
2020	143.9	5.7	3,177	18,142	1,147	165,056
2021	205.4	9.0	3,185	28,750	1,144	234,923
2022	242.0	12.3	3,189	39,358	1,140	275,775
2023	255.9	15.7	3,191	49,966	1,139	291,413
2024	265.4	19.0	3,193	60,574	1,139	302,237
2025	272.4	22.3	3,193	71,182	1,138	310,067
2026	275.6	25.6	3,194	81,790	1,138	313,690
2027	277.5	28.9	3,195	92,398	1,138	315,856
2028	279.4	32.2	3,195	103,005	1,138	318,023
2029	281.3	35.6	3,196	113,613	1,138	320,189
2030	283.3	38.9	3,196	124,221	1,138	322,356
2031	285.2	42.2	3,196	134,829	1,138	324,523
2032	287.1	45.5	3,196	145,437	1,138	326,689
2033	289.0	48.8	3,196	156,045	1,138	328,856
2034	290.9	52.1	3,197	166,653	1,138	331,022
2035	292.8	55.4	3,197	177,261	1,138	333,189
2036	294.7	58.8	3,197	187,869	1,138	335,355
2037	296.6	62.1	3,197	198,477	1,138	337,522
2038	298.5	65.4	3,197	209,085	1,138	339,688
2039	300.4	68.7	3,197	219,692	1,138	341,855

TABLE LF-67
SIERRA PRIVATE GENERATION (SOLAR PV) ANNUAL ON-SITE USE FORECAST AT THE METER

	INSTALLED MW		GENERATION		OWN USE	
Year	Small MW	Large MW	Large MWH per MW	Large MWH	Small MWH per MW	Small Own MWH
2019	3.6	0.8	1,795	1,350	807	2,875
2020	6.7	2.1	1,681	3,460	785	5,228
2021	9.0	3.4	1,656	5,570	776	7,013
2022	10.5	4.7	1,644	7,679	770	8,106
2023	11.6	6.0	1,638	9,789	770	8,922
2024	12.7	7.3	1,634	11,899	769	9,737
2025	13.5	8.6	1,631	14,009	767	10,327
2026	14.0	9.9	1,629	16,119	767	10,765
2027	14.6	11.2	1,628	18,229	767	11,202
2028	15.2	12.5	1,626	20,339	766	11,640
2029	15.8	13.8	1,625	22,449	766	12,078
2030	16.3	15.1	1,624	24,559	766	12,515
2031	16.9	16.4	1,624	26,669	766	12,953
2032	17.5	17.7	1,623	28,779	766	13,391
2033	18.1	19.0	1,623	30,889	765	13,829
2034	18.6	20.3	1,622	32,998	765	14,266
2035	19.2	21.6	1,622	35,108	765	14,704
2036	19.8	23.0	1,621	37,218	765	15,142
2037	20.4	24.3	1,621	39,328	765	15,579
2038	20.9	25.6	1,621	41,438	765	16,017
2039	21.5	26.9	1,621	43,548	765	16,455

LF-2

Population Forecasts: Long-Term Projections for Clark County, Nevada 2018-2060

2018

Prepared by

Center for Business and Economic Research
University of Nevada, Las Vegas

Prepared for

Regional Transportation Commission of Southern Nevada, Southern Nevada Water Authority, Southern Nevada Regional Planning Coalition, and members of the Forecasting Group

May 31, 2018

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CENTER FOR BUSINESS AND ECONOMIC RESEARCH

Population Forecasts: Long-Term Projections for Clark County, Nevada 2018-2060

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Executive Summary

Each year, the Regional Transportation Commission of Southern Nevada (RTC); the Southern Nevada Water Authority (SNWA); the Southern Nevada Regional Planning Coalition (SNRPC); the Center for Business and Economic Research (CBER) at the University of Nevada, Las Vegas; and a group of community demographers and analysts work together to develop a long-term forecast of Clark County's population growth that is consistent with the structural economic characteristics of the county. Toward this end, we employ a general-equilibrium demographic and economic model developed by Regional Economic Models, Inc. (REMI), specifically for Clark County.

We recalibrate the REMI model to incorporate the most recent available information regarding local employment growth and local public and private investment projects. The resulting long-term forecast predicts positive population growth throughout the range of the forecast. We predict that Clark County's population will reach approximately 2.67 million by 2035 and marginally above 2.90 million by 2060.

Table 1 summarizes the population forecast, showing a gradually declining growth rate of Clark County's population over the forecast horizon. Despite short-term economic uncertainties and modeling difficulties, we note that this forecast is intended for medium- to long-term planning purposes. In the medium term, the population growth rate declines to 1.9 percent by 2020, and in the long term, its growth tapers off as Clark County's maturing economy attracts fewer economic migrants. The rate of growth, which exceeded the national average over the past 50 years, moderates and eventually moves below the national rate of growth. That is, by 2029, the population growth rate falls to 0.58 percent, slightly below the projected[1] long-term national population growth rate of 0.60 percent, and as the Clark County economy continues to mature, it falls further to 0.20 percent by 2060.

As is typical of any forecast, potential risks exist that could lead to either over- or underestimated population growth. Since currently the upside risk to U.S. economic growth exceeds the downside risk, the risk of underestimating population growth exceeds the risk of overestimating it in the near term. The forecast began with the assumption that the local economy will continue to expand in 2018 and 2019. To the extent that the near-term economic outlook differs, the short-run forecasts will differ. Our long-term forecasts exclude business-cycle, seasonal, and irregular events, which respond more to these short-run risks. We believe, however, that these risks arise from short-term uncertainty; whereas, our forecasts primarily provide a long-term planning tool. In other words, our long-term forecast addresses the trend movement in population, excluding the business-cycle, seasonal, and irregular effects.

[1] Source: https://www.census.gov/data/tables/2017/demo/popproj/2017-summary-tables.html.

Table 1: Clark County Final Population Forecast: 2010-2060

Year	Population Forecast	Change in Population Forecast	Growth in Population (Percent)
2010	1,951,269*	-55,078	-2.7%
2011	1,966,630**	15,361	0.8%
2012	2,008,654**	42,024	2.1%
2013	2,062,253**	53,599	2.7%
2014	2,102,238**	39,985	1.9%
2015	2,147,641**	45,403	2.2%
2016	2,205,207**	57,566	2.7%
2017	2,248,391**	43,184	2.0%
2018	2,296,000	47,609	2.1%
2019	2,344,000	48,000	2.1%
2020	2,389,000	45,000	1.9%
2021	2,423,000	34,000	1.4%
2022	2,452,000	29,000	1.2%
2023	2,481,000	29,000	1.2%
2024	2,507,000	26,000	1.0%
2025	2,530,000	23,000	0.9%
2026	2,550,000	20,000	0.8%
2027	2,568,000	18,000	0.7%
2028	2,585,000	17,000	0.7%
2029	2,600,000	15,000	0.6%
2030	2,615,000	15,000	0.6%
2031	2,628,000	13,000	0.5%
2032	2,640,000	12,000	0.5%
2033	2,651,000	11,000	0.4%
2034	2,662,000	11,000	0.4%
2035	2,672,000	10,000	0.4%
2040	2,719,000	9,000	0.3%
2045	2,766,000	10,000	0.4%
2050	2,816,000	10,000	0.4%
2055	2,863,000	9,000	0.3%
2060	2,900,000	6,000	0.2%

* 2010 U.S. Census.
** SNRPC consensus population estimate.

Acknowledgements

CBER thanks the members of the Population Forecasting Group for comments on earlier versions of this report.

I. Introduction

Each year, the Regional Transportation Commission (RTC); the Southern Nevada Water Authority (SNWA); the Southern Nevada Regional Planning Coalition (SNRPC); the Center for Business and Economic Research (CBER) at the University of Nevada, Las Vegas; and a group of community demographers and analysts work together to provide a long-term forecast of economic and demographic variables influencing Clark County. The primary goal is to develop a long-term forecast of the Clark County population growth that is consistent with the structural economic characteristics of the county. Toward this end, we employ a general-equilibrium demographic and economic model developed by Regional Economic Models, Inc. (REMI), specifically for Clark County.

The REMI model is a state-of-the-art econometric forecasting model that accounts for dynamic feedback between economic and demographic variables. Special features allow the user to update the model to include the most current economic information. CBER calibrates the model using information on recent local employment levels, the most recent national Gross Domestic Product (GDP) forecast, and spending on local capital projects.

The model employed divides Nevada into five regions: Clark County; Nye County; Lincoln County; Washoe County; and the remaining counties, which are combined to form a fifth region. These regions are modeled using the U.S. economy as a backdrop. The model contains over 100 economic and demographic relationships that are carefully constructed to represent concisely the Clark County economy. The model includes equations to account for migration and trade between Nevada counties and other states and counties in the country.

The demographic and economic data used to construct the model begin in 2001 and end in 2015. The most important variables include the aggregate totals of employment, the labor force, and population. The economic data for the most recent version of the model (REMI PI+ v2.1) are consistent with the North American Industry Classification System (NAICS). The REMI PI+ v2.1 model was released in 2017. Hence, the model's most recent data are from 2015, since the Bureau of Economic Analysis (BEA) personal-income data only become available with a two-year lag. The availability of the most recent income data sets the last year of history with each release of an updated model.

The REMI model is the best model available for describing how economies interact geographically.[2] These interactions may take place within a single economy (such as the interaction between house-price growth and employment growth in Clark County) or between two economies (such as the interaction between Southern Nevada and Southern California through migration flows). These and over 100 other interactions contained within the model are too complex to consider modeling on our own. Rather, we turn to the REMI model because it has a solid foundation in economic theory and the principles of general-equilibrium-based growth theory and distribution, yet it still offers the flexibility required to model a regional economy like Clark County.

To guarantee that the model incorporates the most recent data, we make a series of adjustments to the model. In this way, we ensure that the forecast model includes the best available information when making the final forecast. First, we update the model's national GDP forecast using the latest available national forecast from the University of Michigan's

[2] See Schwer, R. K. and D. Rickman (1995), "A comparison of the multipliers of IMPLAN, REMI and RIMS II: Benchmarking ready-made models for comparison," *The Annals of Regional Science*, 29(4), 363-374.

Research Seminar in Quantitative Economics (RSQE), since REMI uses the RSQE forecast in its model development. Second, we rebase the population forecast to the most recent population estimate for Clark County available from SNRPC. Third, we update the model with current employment data from the Bureau of Economic Analysis (BEA) and the Nevada Department of Employment, Training and Rehabilitation (DETR). Fourth, we adjust future hotel employment based on the expected number of hotel rooms that will be added in the near future. Fifth, we incorporate the expected direct output produced by the expansion and renovation of the Las Vegas Convention Center District. Sixth, we include the expected economic impact from construction of the Las Vegas Stadium for the Oakland Raiders of the National Football League. Lastly, we include planned new investment in public infrastructure in the model using information from the RTC.

This report proceeds as follows. Section II examines the changes in the REMI model from the prior year's model. Section III presents sequentially the changes made to update the model and tailor it to local information. Section IV reports the population forecast and gives a brief discussion of the economic environment surrounding the forecast. Section V compares the population growth forecast with the previous years' forecast. Section VI discusses the risks to the forecast. Finally, section VII concludes.

II. Comparison of REMI Models: Current and Previous Year

Based on our past practice, we begin by comparing the most recent REMI out-of-the-box benchmark forecast prior to any model recalibrations with the corresponding out-of-the-box forecasts from the REMI models used in prior reports. This gives us the opportunity to examine how the new model differs from previous versions and to explore the basis of these differences.

The most recent data used to develop this year's model end with data from 2015. Thus, we refer to the current model by its last historical year 2015 (LHY2015) and the previous model by its last historical year 2013 (LHY2013).[3]

Each year, the REMI staff and users discuss how the model works and propose adjustments and changes for improvement. The newest REMI model, PI+ v2.1, offers one major improvement: it includes an updated equation for economic migration. Economic migration is one of the important factors for population growth in Southern Nevada, since Southern Nevada population changes largely reflect net domestic migration.[4] Economic migrants emigrate from other regions to improve their living standards and to seek better job opportunities. Three major components attract these interstate migrants according to REMI: relative employment opportunities, relative compensation rates, and amenity values.[5] REMI reestimated the responses (parameters) to the relative employment

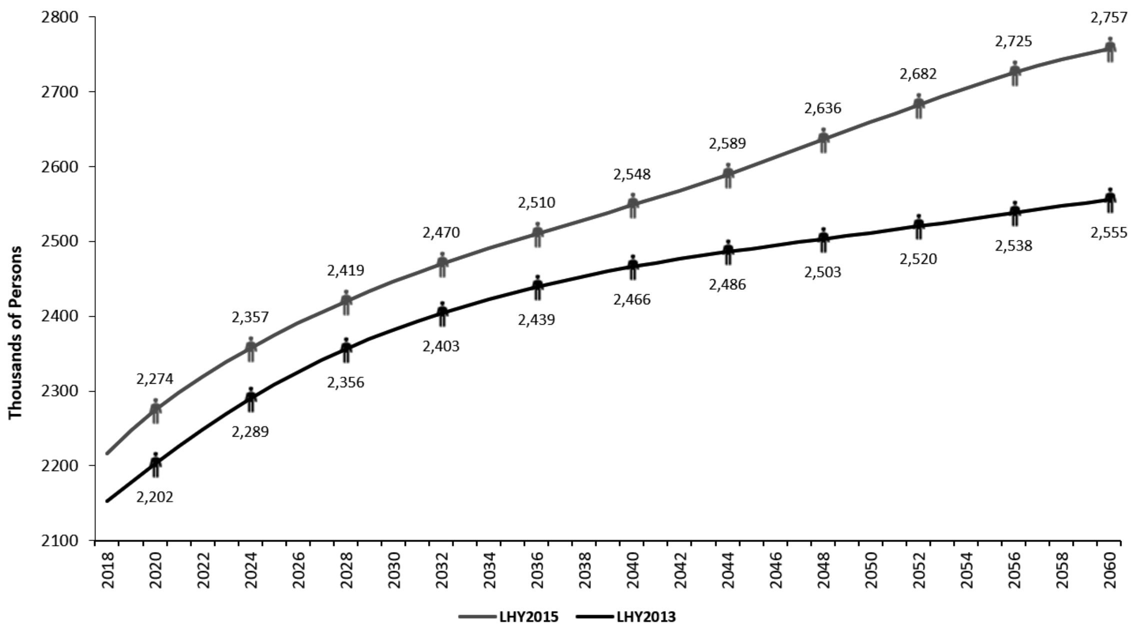
[3] Last year, we used version 1.7 (LHY2013) instead of version 2.0, which was released in 2016 because of some uncertainty about the changes included in version 2.0. We, however, updated version 1.7 with new data history that was contained in version 2.0; therefore, the last year of history in last year's forecast was 2014. Although the last year of history was 2014, we identify the model used last year as LHY2013 to avoid confusion for the reader.

[4] According to the U.S. Census, Clark County added 47,355 residents, including 29,414 net domestic migrants, in 2017.

[5] Relative employment opportunity stands for employment opportunity in the region compared to the U.S. average, the relative compensation rate stands for the real compensation (disposable income) rate compared to the national average level, and amenity values include factors such as climate, community safety,

opportunity and the relative compensation rate based on state and county migration and economic data from 2009 to 2014.[6] Previously, REMI used estimates of the economic migration parameters using data from 2001 through 2008. These model updates and the new history for 2015 lead to the difference in the out-of-the-box population forecasts between the LHY2015 and the LHY2013.

Figure 1: Clark County Population Forecasts: REMI Out-of-the-Box LHY2015 and LHY2013: 2018-2060



Note: Out-of-the-box refers to the model prior to recalibration. These numbers are not the final forecast.

Figures 1 and 2 compare the LHY2015 and LHY2013 population forecasts from the out-of-the-box models (i.e., before any updating for employment, infrastructure projects, the national GDP forecast, and so on).[7] The out-of-the-box population forecast

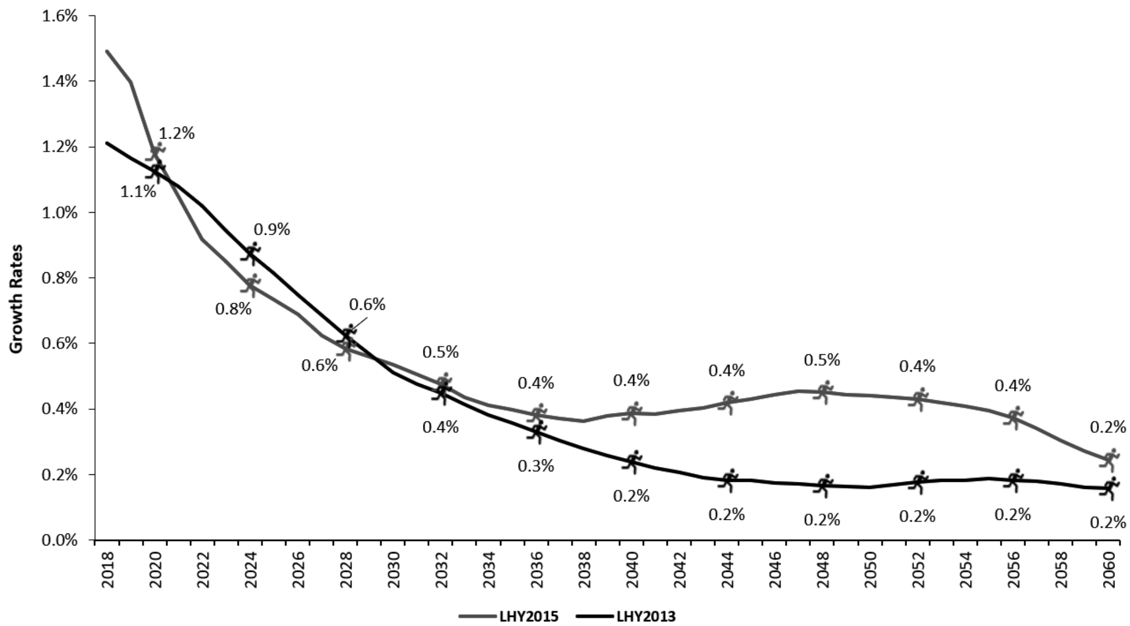
education, and so on. REMI states that economic migrants are of working age who not only contribute to the local human capital resources, but also boost the development of local businesses.

[6] Clark County employment experienced a larger dip during the Great Recession than the national average. Thus, the Clark County economy took more time to recover compared to other counties. Therefore, using migration and economic data from 2009 to 2014 may produce a slightly lower long-term population forecast for Clark County.

[7] The detailed out-of-the-box results through 2060 appear in Table B1 of the appendix.

arising from the LHY2015 model predicts higher population levels than the LHY2013 model through 2060 (Table 2). Regarding population levels, the out-of-the-box model forecasts population in the LHY2015 model for 2018 approximately 64,030 higher than the LHY2013 model. This gap monotonically increases over the entire forecast horizon. By 2060, the out-of-the-box model forecasts population in LHY2015 approximately 201,500 higher than the LHY2013 model.

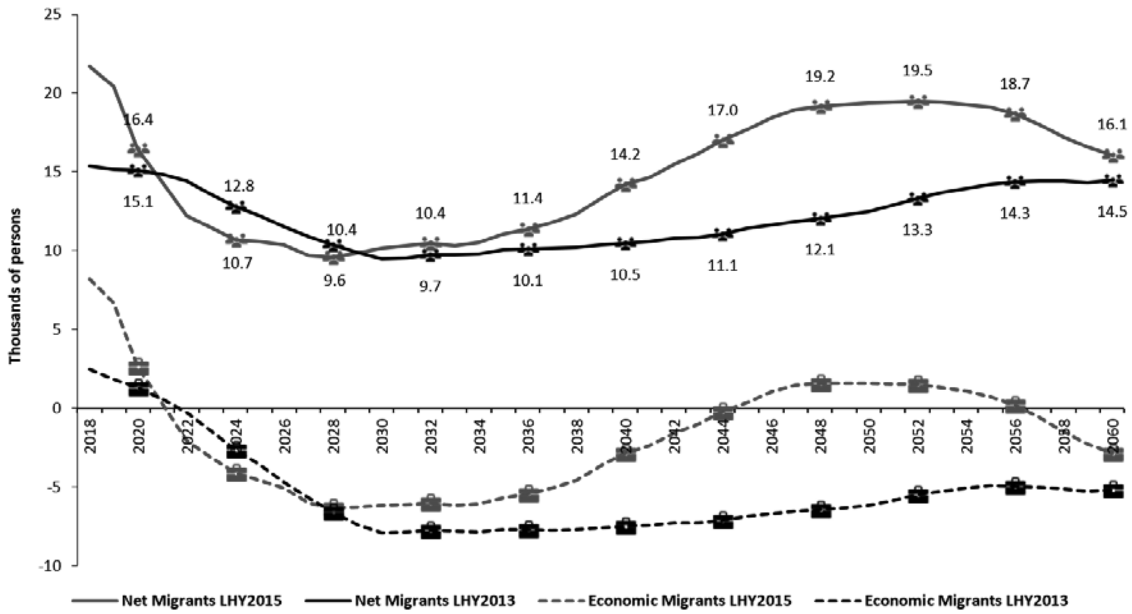
Figure 2: Clark County Population-Growth-Rate Forecasts: REMI Out-of-the-Box LHY2015 and LHY2013: 2018-2060



Note: Out-of-the-box refers to the model prior to recalibration. These numbers are not the final forecast.

The forecasted population growth rate for LHY2015 generally declines over the entire forecast horizon through 2060, except for the period from 2038 to 2047, which shows a slight rise (Figure 2). The LHY2015 model forecasts a growth rate of population that exceeds the growth rate of the LHY2013 model in most of the years, except for the years from 2021 to 2029 where the LHY2015 model forecasts a growth rate of population below the growth rate of the LHY2013 model. These slower growth rates from the LHY2015 model between 2021 and 2029 mainly reflect lower net economic migrants for the LHY2015 model compared to the LHY2013 model (Figure 3). After 2029, a net outflow (inflow) of economic migrants are lower (higher) in the LHY2015 model over the forecast horizon, which results in higher population growth rates as these working-age migrants promote population growth by bringing families to the region.

Figure 3: Clark County Net Migrant and Net Economic Migrant Forecasts: REMI Out-of-the-Box LHY2015 and LHY2013: 2018-2060



Note: Out-of-the-box refers to the model prior to recalibration. These numbers are not the final forecast.

We also notice that the higher out-of-the-box forecasted population level in 2060 from the LHY2015 model uses the out-of-the-box economic and demographic forecasts. Table 2 shows a comparison of the REMI out-of-the-box economic and demographic forecasts from LHY2015 and LHY2013 for the years 2018 and 2060. The LHY2015 out-of-the-box model predicts a stronger Clark County economy in 2060, compared to the LHY2013 model in terms of total population, employment, and real GDP.[8] The LHY2015

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[8] The LHY2015 model predicts a lower real GDP in 2018 compared to the LHY2013 model. We note that the LHY2015 model was updated for an additional two years of history as well as BEA's annual revisions of

out-of-the box model predicts a larger Clark County economy as a percentage of the nation in 2060 compared to LHY2013 model. The stronger out-of-the-box Clark County economic forecast from the LHY2015 model makes the region more attractive relative to the rest of the nation. This creates a lower net outflow of economic migrants from Clark County in 2060.

Table 2: Clark County REMI Out-of-the-Box Forecast Comparison: LHY2015 and LHY2013

	2018			2060		
	LHY2015	**LHY2013**	**Change to Forecast**	**LHY2015**	**LHY2013**	**Change to Forecast**
Population (Thousands)	2,216.26	2,152.23	3.0%	2,756.95	2,555.45	7.9%
Total employment (Thousands)	1,286.60	1,217.54	5.7%	1,566.56	1,370.29	14.3%
Total employment as a percent of nation	0.65	0.63	2.0%	0.60	0.58	2.0%
Gross domestic product (Billions of fixed 2009 dollars)	103.92	105.59	-1.6%	239.85	200.72	19.5%
Gross domestic product as a percent of nation	0.59	0.58	1.0%	0.57	0.52	5.0%
Migrants (Thousands)						
Economic migrants	8.18	2.45	233.9%	-2.84	-5.18	45.2%
Retired migrants	5.14	5.15	-0.2%	8.92	8.91	0.1%
International migrants	8.50	7.98	6.5%	10.06	10.85	-7.3%
Population by age (Thousands)						
Ages 0-14	424.20	414.33	2.4%	419.78	385.63	8.9%
Ages 15-24	272.49	259.12	5.2%	286.04	246.34	16.1%
Ages 25-64	1,181.55	1,141.72	3.5%	1,283.84	1,181.43	8.7%
Ages 64+	338.02	337.06	0.3%	767.29	742.05	3.4%

real GDP. As a result, the LHY2015 model forecasts a slightly lower value for regional GDP in 2018 compared to the LHY2013 model. In 2018, the LHY2015 model predicts more employees relative to the LHY2013 model. More employment, but smaller GDP, may imply that the share of part-time workers increased or that labor productivity per hour decreased. The LHY2015 model actually shows that labor productivity per worker for both the United States and Clark County for 2014 and 2015 were lower than what REMI forecasted in the LHY2013 model.

III. Recalibrating the Model

As noted previously, county-level personal income data only become available with a two-year lag. As a result, the REMI model also imposes a two-year lag on all its data history that ends with 2015 data for the current model, PI+ v2.1, released in 2017. To update the model, we incorporate available pertinent model information, including the most recent national GDP forecast, more recent employment figures, and spending on public and private capital projects to reflect local information in the forecast. We describe each update in sequence.

In the previous two forecasts, we incorporated expected investment and job increases due to Faraday Future at the Apex Industrial Park in Clark County. The project planned to create many new jobs in the region with significant capital investment. Faraday Future cancelled its plans at the Apex Industrial Park last year. Therefore, we did not include the expected investment and job creation from Faraday Future for this year's population forecasts.

A. Adjustment of the national GDP forecast

The REMI model relies on a baseline national GDP forecast from the University of Michigan's RSQE. The REMI model, PI+ v2.1, utilizes the January 2017 GDP forecast from RSQE. We adjust the model's national GDP forecast using both the BEA's most recent data and the March 2018 national GDP forecast from RSQE. Overall, we adjusted the national GDP components downward by about $112 billion in 2018 and $194 billion in 2019. The adjusted national forecast generates a new baseline forecast for Clark County. We, then, use the baseline forecast for the subsequent adjustments.

B. Rebasing the population forecast

We rebase the population forecast using the population update feature in the REMI model. We update the population in 2017 based on the most recent information from the SNRPC. The SNRPC consensus population estimate for Clark County in 2017 is 2.25 million. In addition, we update the population levels in 2018 and 2019 to reflect the population growth-rate forecast from CBER's *2018 Economic Outlook*, which was published in December 2017. The latter adjustment incorporates the views of local economic experts at CBER in the short-term population forecasts. CBER predicts that the Clark County population will grow by 2.1 percent both in 2018 and 2019. These population growth-rate forecasts translate to a forecasted population of 2.30 and 2.34 million, respectively, in 2018 and 2019. We use these forecasted population levels to update the population data in the REMI model, and use the baseline forecast for the subsequent adjustments.

C. Employment adjustment

The county-level employment data in REMI come from the BEA's local area personal income data, which are only provided for 23 sectors. Even though BEA reports the county-level employment data for 23 sectors, BEA supplies the county-level wage data for 70 sectors. This means that REMI calculates employment for 70 sectors by incorporating the county-level wage data. We, therefore, update REMI's employment data with recent BEA data for sectors that do not identify subcategories. Although the most recent historical year in the model's employment data is 2015, BEA employment data are available for 2016. In addition, more recent wage and salary employment data are available from the Nevada DETR for 2016 and 2017. We, therefore, update the model to account for this more recent information.

The latest growth rates for the out-of-the-box REMI-model forecasts as well as recent BEA and DETR estimates appear in Table 3. The actual growth rates from BEA and DETR differ substantially from the REMI out-of-the-box forecasts, suggesting a clear need for adjustment. For example, the growth rate estimates by the BEA and DETR of total employment exceed the REMI forecasts in 2016 and 2017 by 0.23 and 0.77 percentage point, respectively. The employment update proceeds as follows. First, we calculate the annual percentage change using BEA data and apply the percentage changes to generate new estimates for 2016. Second, we compute the annual percentage change using DETR data and apply them to produce new estimates for 2016 and 2017. This procedure implicitly assumes that the proportion of self-employed in each industry classification grows at the same rate as does the ratio between full- and part-time workers.

Table 3: Employment Growth Rates for Clark County before BEA & DETR Adjustment

	REMI Baseline Forecast		BEA & DETR Estimates	
Industrial Classification	**2016**	**2017**	**2016**	**2017**
Construction	4.66%	3.58%	5.85%	8.41%
Wholesale trade	2.96%	2.82%	3.25%	5.09%
Retail trade	4.24%	2.36%	0.82%	0.84%
Transit, ground passenger transportation	0.26%	-0.76%	-5.63%	-6.72%
Monetary authorities, et al.	1.30%	-0.29%	5.76%	4.08%
Ins carriers, related activities	2.43%	0.88%	3.92%	3.77%
Real estate	2.50%	1.08%	6.31%	4.57%
Professional, technical services	3.95%	2.61%	3.64%	3.82%
Management of companies	2.41%	1.89%	8.16%	6.09%
Administrative, support services	2.54%	1.53%	6.48%	2.07%
Ambulatory health care services	6.84%	4.78%	4.51%	5.39%
Hospitals	4.00%	2.65%	8.06%	5.97%
Amusement, gambling, and recreation	2.68%	1.32%	7.30%	4.08%
Accommodation	1.97%	1.05%	-1.48%	-0.42%
Food services, drinking places	2.93%	1.74%	4.99%	3.34%
State & Local government	2.29%	1.04%	2.21%	2.53%
Total	2.94%	1.75%	3.17%	2.52%

Note: BEA estimates are used on the preferential basis if available.

Table 4 reports the updated employment data by category for the model. The Clark County job growth numbers in 2016 and 2017 suggest that general economic conditions continue to improve in the Las Vegas area. While the Southern Nevada economy gained 4.0 percent of its total employment in 2015, the BEA and DETR updated estimates suggest that Clark County employment grew by about 3.2 percent and 2.5 percent in 2016 and 2017, respectively. Most sectors of Southern Nevada's economy experienced positive job growth in 2016. Strong employment gains occurred in key sectors such as health care, gaming, and food services. The construction sector, moreover, continues to experience strong positive job growth in 2016, as the sector continues to recover from the Great Recession. Overall, Southern Nevada's economy gained roughly 38,000 jobs in 2016.

The local economic recovery continued in 2017 with stronger employment growth in key sectors such as construction, management, hospitals, and wholesale trade. Overall, Southern Nevada's economy gained roughly 31,000 jobs in 2017. Accommodation employment for 2016 and 2017 declined as average room inventories fell, which mainly reflected major renovations of the existing rooms on the Las Vegas Strip.

Table 4: Model Job Adjustments (in 000s) for 2016 and 2017

	Baseline	BEA & DETR Growth Rates		Adjusted Job Levels	
Industrial Classification	**History 2015**	**2016**	**2017**	**2016**	**2017**
Forestry et al.	0.31	4.92%	4.47%	0.33	0.34
Agriculture	0.10	3.86%	3.00%	0.10	0.11
Oil, gas extraction	2.06	1.34%	1.92%	2.09	2.13
Mining (except oil, gas)	0.80	0.81%	1.53%	0.81	0.82
Support activities for mining	0.02	0.30%	2.17%	0.02	0.02
Utilities	2.74	3.68%	-0.76%	2.90	2.88
Construction	62.43	5.85%	8.41%	65.93	71.47
Wood product mfg	0.43	1.76%	3.18%	0.44	0.46
Nonmetallic mineral prod mfg	2.14	1.79%	2.07%	2.18	2.22
Primary metal mfg	0.71	-3.63%	4.32%	0.68	0.71
Fabricated metal prod mfg	2.07	0.27%	1.73%	2.07	2.11
Machinery mfg	0.54	-1.67%	0.10%	0.53	0.53
Computer, electronic prod mfg	0.53	2.39%	2.13%	0.55	0.56
Electrical equip, appliance mfg	0.52	-0.69%	1.58%	0.52	0.53
Motor vehicle mfg	0.22	-1.06%	-0.18%	0.22	0.22
Transp equip mfg exc motor veh	0.44	-5.79%	1.03%	0.41	0.41
Furniture, related prod mfg	1.05	1.92%	1.55%	1.07	1.09
Miscellaneous mfg	5.68	-1.78%	-0.97%	5.58	5.53
Food mfg	3.44	3.48%	1.84%	3.56	3.63
Beverage, tobacco prod mfg	0.46	4.07%	3.42%	0.47	0.49
Textile mills; textile prod mills	0.66	1.47%	-0.07%	0.67	0.67
Apparel mfg	0.36	4.29%	-0.08%	0.38	0.38
Paper mfg	0.48	1.67%	1.53%	0.49	0.50
Printing, rel supp act	2.49	0.22%	-0.59%	2.50	2.48
Petroleum, coal prod mfg	0.03	2.27%	0.45%	0.03	0.03
Chemical mfg	1.02	0.77%	-0.48%	1.03	1.02
Plastics, rubber prod mfg	1.67	1.30%	1.24%	1.69	1.72
Wholesale trade	28.04	3.25%	5.09%	29.42	30.92
Retail trade	128.50	0.82%	0.84%	129.81	130.90
Air transportation	6.66	4.92%	3.13%	6.99	7.20
Rail transportation	0.28	-1.72%	1.29%	0.27	0.28
Water transportation	0.09	3.17%	2.92%	0.09	0.09
Truck transportation	5.34	1.81%	1.84%	5.44	5.54
Couriers and messengers	3.66	1.34%	0.74%	3.71	3.74
Transit, ground pass transp	17.77	-5.63%	-6.72%	16.77	15.64
Pipeline transportation	0.04	3.03%	1.86%	0.05	0.05
Scenic, sightseeing transp; supp	6.73	2.93%	2.22%	6.93	7.08
Warehousing, storage	6.59	3.24%	2.05%	6.80	6.94

Table 4: Model Job Adjustments (in 000s) for 2016 and 2017 (continued)

	Baseline	BEA & DETR Growth Rates		Adjusted Job Levels	
Industrial Classification	**History 2015**	**2016**	**2017**	**2016**	**2017**
Publishing, exc Internet	2.69	2.81%	1.92%	2.76	2.81
Motion picture, sound rec	3.73	5.04%	3.99%	3.92	4.07
Internet serv, data proc, other	3.00	4.80%	3.47%	3.15	3.26
Broadcasting, exc Int;	1.70	2.23%	0.91%	1.74	1.76
Telecommunications	4.35	0.00%	3.45%	4.35	4.50
Monetary authorities, et al.	16.69	5.76%	4.08%	17.65	18.37
Sec, comm contracts, inv	31.00	3.92%	3.77%	32.21	33.43
Ins carriers, rel act	13.95	3.92%	3.77%	14.50	15.05
Real estate	64.93	6.31%	4.57%	69.02	72.18
Rental, leasing services	7.17	2.20%	1.93%	7.32	7.47
Prof, tech services	65.04	3.64%	3.82%	68.49	71.10
Mgmt of companies, enterprises	21.90	8.16%	6.09%	23.91	25.37
Administrative, support services	90.31	6.48%	2.07%	96.16	98.16
Waste mgmt, remed services	2.71	2.25%	1.18%	2.77	2.80
Educational services	11.90	4.11%	1.82%	12.19	12.41
Ambulatory health care services	42.92	4.51%	5.39%	44.85	47.27
Hospitals	20.12	8.06%	5.97%	21.75	23.05
Nursing, residential care facilities	9.36	3.73%	2.20%	9.71	9.93
Social assistance	19.81	4.22%	2.36%	20.65	21.13
Performing arts, spectator sports	22.79	2.23%	1.24%	23.30	23.59
Museums et al.	0.41	3.78%	2.31%	0.43	0.44
Amusement, gambling, recreation	16.18	7.30%	4.08%	17.36	18.06
Accommodation	174.48	-1.48%	-0.42%	171.90	171.17
Food services, drinking places	95.34	4.99%	3.34%	100.10	103.44
Repair, maintenance	11.81	2.30%	0.59%	12.08	12.15
Personal, laundry services	30.01	5.34%	3.43%	31.61	32.70
Membership assoc, organ	8.98	4.13%	2.13%	9.35	9.55
Private households	7.19	0.33%	-1.78%	7.21	7.08
State & local government	84.20	2.21%	2.53%	85.83	88.00
Federal civilian	12.69	1.81%	-2.34%	12.98	12.67
Federal military	15.10	0.23%	-0.95%	15.14	15.00
Farm	0.46	0.86%	0.98%	0.47	0.47
Total	1,210.02	3.17%	2.52%	1,248.37	1,279.85

D. Hotel room adjustment

We make an adjustment to future hotel employment based on our expectation of the number of hotel rooms added in each of the next few years. The additional rooms and related employment represent either properties that are under construction with fixed opening dates or properties that have development plans and a high probability of project completion during the specified year. In this way, we ensure that the model includes a good short-term forecast of new hotel investment and employment.

As of April 2018, the Las Vegas Convention and Visitors Authority (LVCVA) projects that hotel/motel construction will add an additional 801 rooms to the local room inventory by the end of 2018 (Table 5). This includes the opening of My Place Hotel, Hilton Garden Inn, Homewood Suites, and Starwood Hotels and Resorts. In 2019, the LVCVA projects an additional 827 hotel/motel rooms will get added to the inventory rooms. This includes the Fairfield Marriott, Fairfield Inn & Suites, TownePlace Suites, SpringHill Suites Marriott, and the Residence Inn Marriott. In 2020, the LVCVA expects to see an additional 9,250 rooms added to the room stock, which includes the opening of the Drew Las Vegas, Paradise Park, and Resorts World Las Vegas. Finally, the LVCVA expects 700 additional hotel/motel rooms will get added to inventory in 2023, with the main addition coming from the Mardi Gras Hotel and Casino.

Table 5: Hotel Construction Adjustment

Year	Total Rooms	New Rooms	New Jobs Implied*	REMI Hotel Employment after DETR Adjustment	REMI New Jobs Implied	Cumulative Additional Jobs after Hotel Adjustment
2017	148,899			171,173		
2018	149,700	801	1,202	172,700	1,527	1,527**
2019	150,527	827	1,241	173,968	1,268	2,795**
2020	159,777	9,250	13,875	173,120	-848	15,822
2023	160,477	700	1,050	172,487	-633	16,239

* Assumes a jobs-to-room multiplier of 1.5.
** The new jobs implied by the room additions are less than the REMI hotel employment.

The model adjustment for new hotel construction uses a jobs-to-room ratio of approximately 1.5, which was obtained in the following manner.[9] First, we expect new

[9] The detailed computation of the jobs-to-room ratio appears in Appendix A.

hotel rooms to create new jobs in hotel services. Using historical information from 2007-2016, we take the historical average ratio of annual accommodation employment from the Bureau of Labor Statistics (BLS) divided by the total number of hotel rooms. From this calculation, we generate a jobs-to-room multiplier of roughly 1.2 for hotel services. New hotel rooms will also generate secondary economic activity and, hence, additional jobs in other sectors. For example, increased tourism activity from new hotel rooms will also increase the demand for food services and other tourism-related industries. We account for these new jobs in the following manner. We use each industry's location quotient[10] to estimate the portion of the industry's employment attributable to tourism activity. We, then, take the historical average ratio of the annual employment in each of these sectors, which is attributable to tourism activity, divided by the total hotel rooms. The sum of the ratios for the food services and other tourism-related industries is approximately 0.3. This, together with the jobs-to-room multiplier of 1.2 for hotel services, produces the overall jobs-to-room ratio of approximately 1.5. The jobs-to-room multiplier is, then, used as the multiplicand times the number of additional rooms *over and above* the rooms and jobs already accounted for in the model. Table 5 reports these results, revealing an increase of about 16,000 jobs by 2023.

E. The Las Vegas Convention Center adjustment

The LVCVA will expand and renovate the current Las Vegas Convention Center (LVCC) by investing $1.4 billion, which is financed by a small portion of the special room tax. The

[10] The Location Quotient (LQ) compares Clark County's employment in a given industry sector to that of the nation. An LQ greater than 1 indicates that the area has proportionately more workers than the nation employed in that specific industry sector. This implies that the area is producing more than is consumed by its residents. Hence, the portion of the LQ that is above 1 represents the proportion of the industry's employment attributable to tourism activity.

LVCVA completed phase one: acquisition and demolition of the Riviera in 2016 and started phase two and three: expansion and renovation in 2017. The construction phase is expected to finish in 2022. The new and renovated LVCC facilities are expected to generate 610,000 additional annual convention attendees.[11] According to LVCVA, the estimated average spending per convention attendee was $869, including gaming expenditure, in 2017.[12] We allocate the total spending of 610,000 additional convention attendees in Las Vegas on the various categories–lodging, food, gaming and so on–based on the *2016 Las Vegas Visitor Profile*,[13] and incorporate the numbers in the REMI model.

F. Las Vegas Stadium adjustment

As the National Football League's (NFL) owners approved the move of the Oakland Raiders to Las Vegas, the new 65,000-seat Las Vegas Stadium is expected to be completed by 2020. The total cost for construction is estimated at $1.33 billion, and funding will come from a portion of the special room tax, the Las Vegas Raiders, and Bank of America, which implies that the investment is fully funded from sources outside of Clark County. Bank of America will lend money to construct the Las Vegas Stadium, and the Raiders organization will pay back the loan. The Las Vegas Stadium is expected to bring 450,000 additional annual visitors to Las Vegas.[14] Visitor economic activity is estimated by multiplying this

[11] Source: Las Vegas Convention and Visitors Authority (2016), *Las Vegas Convention Center District Expansion and Renovation*.

[12] Source: Las Vegas Convention and Visitors Authority (2018), *The Economic Impacts of Southern Nevada's Tourism Industry and Convention Sector*.

[13] Every year, the LVCVA publishes the *Las Vegas Visitor Profile*, which shows visitors' characteristics and expenditure behavior. This report contains information on average spending per visitor in terms of lodging, food and drink, transportation, entertainment, and sightseeing.

[14] Source: http://sntic.org/meeting/17/staff/SNTIC%20Stadium%20Economic%20Impact%20Brief.pdf.

increment (450,000) by average per-visitor, per-trip spending as reported by the LVCVA, for a total of $824 per visitor.[15]

G. Transportation and infrastructure improvements

Clark County continues to invest in transportation infrastructure such as roads, highways, and mass transit. The REMI model assumes that public-infrastructure investment will follow a path consistent with the model history. Thus, some local spending on public infrastructure, such as road building and additional services, is built into the model. One-time monies, however, tend to come from outside the region (e.g., federal transportation funding). We need to incorporate these large, special projects into the forecast process.

The estimated federal funding in transportation-infrastructure investment is about $5.585 billion between 2017 and 2040.[16] We annualize these transportation-infrastructure expenditures and include them in the REMI model as new construction projects. In addition, we assume that federal funding in transportation-infrastructure investment after 2040 will continue with a reasonable expectation that the federal funding will not fall to zero. Rather, we apply the flat amount of federal funding after 2040, where the REMI model adjusts this amount for inflation.

IV. Analysis of the Economic and Demographic Forecast

The forecast predicts moderate rates of population growth for Southern Nevada over the forecast period extending out to 2060. The rate of growth, which decidedly exceeded the

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[15] *The Economic Impacts of Southern Nevada's Tourism Industry and Convention Sector,* which was published by the LVCVA in 2018, addresses the adjusted total spending per visitor. According to the report, an average visitor spent 22.6, 17.4, 16.3, and 11.4 percent of his/her total spending on gaming, shopping, rooms, and food and beverage, respectively.

[16] Source: Regional Transportation Commission (2016), *Access 2040 Enhancing Mobility for Southern Nevada, Residents.*

national average over the past 50 years, moderates and eventually moves below the national rate of growth as the Southern Nevada economy matures. The economic forecast calls for the continuation of the economic expansion in 2018 and steady employment growth through 2020. Tables 6, 7, and 8, respectively, report the population, employment, and real GDP predictions for Clark County from the calibrated model.

A. Population

In the short term, the current forecast predicts moderate rates of population growth in Southern Nevada. The population in Clark County is predicted to grow at rates of 2.1 percent in 2018 and 2019 and 1.9 percent in 2020 (Table 6). The population growth rate declines in the medium term as the Clark County economy matures. By 2029, the population growth rate falls to 0.58 percent, slightly below the projected[17] national population growth rate of 0.60 percent. The population growth rate falls further to 0.2 percent by 2060, which is roughly half the size of the projected national population growth of 2060. This result reflects the cumulative losses of economic migrants that emerge in the long-term forecast for the period from 2022 to 2044 and for the period from 2057 to 2060. This loss occurs because Clark County becomes a less competitive economic destination for economic migrants in the long term relative to the nation. That is, Clark County experiences negative net economic migration. We also stress that the forecasted growth rates experience increasing uncertainty as the forecast extends further into the future that may ultimately lead to higher or lower forecasts. We discuss the potential sources for these uncertainties in section VI, which addresses the risks to the forecast.

[17] Source: https://www.census.gov/data/tables/2017/demo/popproj/2017-summary-tables.html.

Table 6: Population History, REMI Forecast, and Rebased Forecast[18]

Year	Population REMI Forecast*	Population Rebased Forecast	Change in Population Rebased Forecast	Growth in Population Rebased Forecast
2017	2,184,000	2,248,391**		
2018	2,216,000	2,296,000***	47,609	2.1%
2019	2,247,000	2,344,000***	48,000	2.1%
2020	2,274,000	2,389,000	48,000	1.9%
2021	2,298,000	2,423,000	45,000	1.4%
2022	2,319,000	2,452,000	34,000	1.2%
2023	2,338,000	2,481,000	29,000	1.2%
2024	2,357,000	2,507,000	29,000	1.0%
2025	2,374,000	2,530,000	26,000	0.9%
2026	2,390,000	2,550,000	23,000	0.8%
2027	2,405,000	2,568,000	20,000	0.7%
2028	2,419,000	2,585,000	18,000	0.7%
2029	2,433,000	2,600,000	17,000	0.6%
2030	2,446,000	2,615,000	15,000	0.6%
2031	2,458,000	2,628,000	15,000	0.5%
2032	2,470,000	2,640,000	13,000	0.5%
2033	2,481,000	2,651,000	12,000	0.4%
2034	2,491,000	2,662,000	11,000	0.4%
2035	2,501,000	2,672,000	11,000	0.4%
2040	2,548,000	2,719,000	9,000	0.3%
2045	2,600,000	2,766,000	10,000	0.4%
2050	2,659,000	2,816,000	10,000	0.4%
2055	2,715,000	2,863,000	9,000	0.3%
2060	2,757,000	2,900,000	6,000	0.2%

* This forecast refers to the model prior to recalibration.
** Southern Nevada consensus population estimate.
*** CBER 2018 Economic Outlook forecast, December 2017.

We forecast that Clark County will add roughly 48,000 new residents in 2018. The forecast then predicts that population growth will remain strong in the near term as the local economy continues to experience strong expansion in employment. Population growth, however, will not drive economic growth as it did throughout much of Las Vegas' history. Rather, economic growth will drive population growth in the future. The

[18] A table detailing the rebased population forecast appears in the appendix–Table B2.

population forecast predicts that the Clark County population will increase to roughly 2.90 million by 2060.

B. Employment

The forecast predicts a continuing economic expansion for Southern Nevada in 2018. We forecast that the Las Vegas economy will add an additional 31,000 jobs in 2018, which represents a 2.4 percent growth in employment from 2017. See Table 7.[19] We predict that employment growth will remain stable in 2019 as the economy is predicted to add 17,000 new jobs. The forecast also predicts a continuation of steady employment growth in the near term and then eventually stabilizes at around a 0.5 percent growth rate as the Southern Nevada economy matures.

[19] Unadjusted employment forecasts are shown in Appendix B.

Table 7: Employment History and Forecasts

Year	Employment Forecast	Change in Employment Forecast	Growth in Employment Forecast	Employment-Population Ratio Forecast
2016	1,251,582*			
2017	1,280,000	28,000	2.5%	0.57
2018	1,311,000	31,000	2.4%	0.57
2019	1,328,000	17,000	1.3%	0.57
2020	1,351,000	23,000	1.7%	0.57
2021	1,355,000	4,000	0.3%	0.56
2022	1,355,000	0	0.0%	0.55
2023	1,364,000	9,000	0.7%	0.55
2024	1,366,000	2,000	0.1%	0.54
2025	1,369,000	3,000	0.2%	0.54
2026	1,373,000	4,000	0.3%	0.54
2027	1,375,000	2,000	0.2%	0.54
2028	1,380,000	5,000	0.4%	0.53
2029	1,385,000	5,000	0.3%	0.53
2030	1,390,000	5,000	0.4%	0.53
2031	1,396,000	6,000	0.4%	0.53
2032	1,401,000	5,000	0.4%	0.53
2033	1,405,000	4,000	0.3%	0.53
2034	1,410,000	5,000	0.3%	0.53
2035	1,415,000	5,000	0.3%	0.53
2040	1,442,000	6,000	0.4%	0.53
2045	1,472,000	7,000	0.4%	0.53
2050	1,512,000	8,000	0.6%	0.54
2055	1,555,000	9,000	0.5%	0.54
2060	1,595,000	8,000	0.5%	0.55
* Actual employment, Local Area Personal Income and Employment, BEA.				

C. Gross domestic product

Real gross domestic product (GDP) is defined as the (constant) dollar value of all final goods and services sold in a regional economy over a given time period. As such, it reflects the output of a local economy and avoids double-counting initial and intermediate goods. The forecast for growth in Clark County real GDP, shown in Table 8, basically mirrors the growth pattern of local employment. The real GDP growth forecast starts at 3.6 percent in 2018, but falls below 2 percent by 2024. The real GDP growth forecast finally stabilizes at around 2.0 percent growth rate in 2060 as the Southern Nevada economy reaches maturity.

Table 8: Gross Domestic Product Forecasts

Year	GDP (Billions of Fixed 2018$) REMI Forecast	Change in GDP (Billions of Fixed 2018$) REMI Forecast	Growth in GDP (Billions of Fixed 2018$) REMI Forecast	GDP per Capita (Fixed 2018$) REMI Forecast
2017	118.31	4.83	4.3%	52,619
2018	122.56	4.25	3.6%	53,387
2019	125.78	3.22	2.6%	53,663
2020	129.76	3.99	3.2%	54,310
2021	132.27	2.51	1.9%	54,595
2022	134.98	2.70	2.0%	55,042
2023	138.07	3.10	2.3%	55,648
2024	140.62	2.54	1.8%	56,098
2025	143.15	2.53	1.8%	56,590
2026	145.60	2.45	1.7%	57,097
2027	148.00	2.41	1.7%	57,633
2028	150.90	2.90	2.0%	58,378
2029	153.83	2.93	1.9%	59,156
2030	156.81	2.98	1.9%	59,969
2031	159.81	3.00	1.9%	60,810
2032	162.94	3.13	2.0%	61,713
2033	165.93	3.00	1.8%	62,582
2034	169.03	3.10	1.9%	63,495
2035	172.19	3.16	1.9%	64,433
2040	189.15	3.58	1.9%	69,569
2045	207.95	3.96	1.9%	75,175
2050	230.13	4.66	2.1%	81,732
2055	254.78	5.10	2.0%	89,004
2060	281.29	5.46	2.0%	96,992

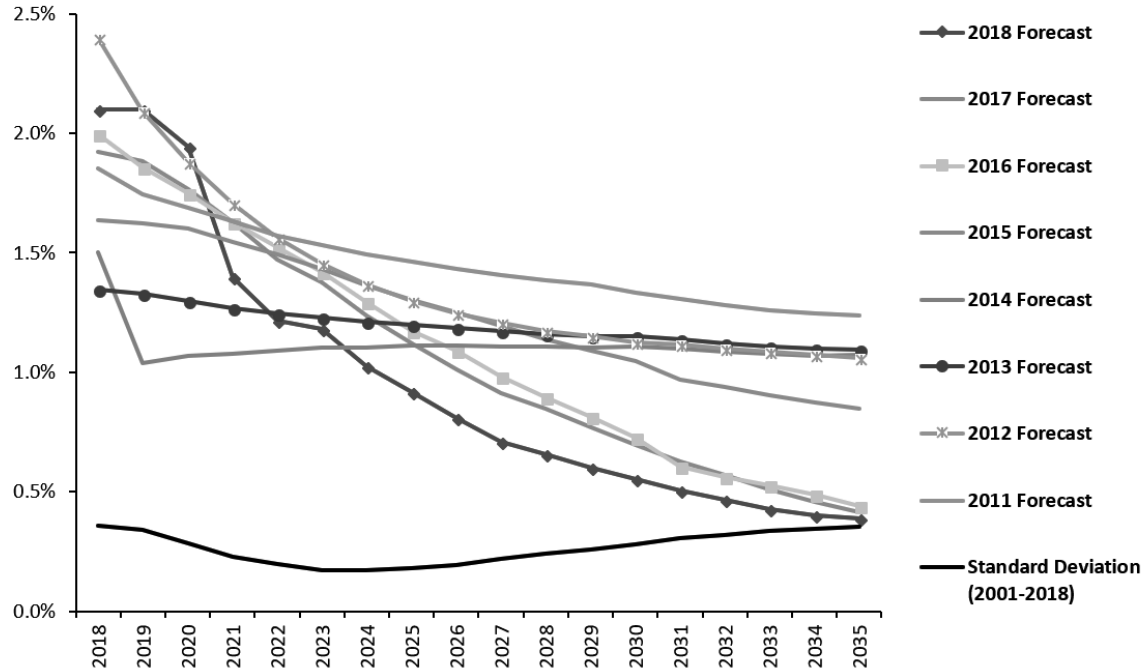
V. Comparing the Current Forecast with Forecasts of Previous Years

This section compares this year's final population growth-rate forecast with the final population growth-rate forecasts from previous years. This exercise assesses the consistency of the forecast methodology and examines the variability in the population growth forecasts over the last eight years.

Figure 4 shows the population growth-rate forecasts generated from the 2011 to 2018 population forecast analyses as well as the standard deviation of the population-growth-rate forecast in the last 18 years (2001-2018).[20] The population growth-rate forecasts exhibit a slightly higher level of variability in the near term as compared to the longer term. The standard deviation of the population growth-rate forecast for the year 2018 is roughly 0.4 percent. This reflects a slightly higher degree of uncertainty in the short-term forecast (see section VI below). The variability among the population growth-rate forecasts falls in the long term. By 2030, the average of the forecasted growth rates converges to about 1.1 percent, with a standard deviation of 0.3 percent. Hence, a larger degree of consistency exists in the long-term growth predictions obtained during the last 18 years, as evidenced by the low standard deviation among the forecasts. This observation further confirms the fact that our forecasts are primarily meant to be long-run planning tools.

[20] The standard deviation measures the variability among data points. For data that follow a normal distribution, 99.7 percent of data points will fall within approximately 3 standard deviations of the mean.

Figure 4: Clark County Historical Population-Growth-Rate Forecasts: 2018-2035



VI. Risks to the Forecast

Our Southern Nevada population forecasts rest on economic and demographic models embedded in the structural model for Clark County as produced by REMI. This structure provides long-term forecasts that exclude the noise that one finds in time-series data–that is, business-cycle, seasonal, and irregular events. In addition, the uncertainty of the forecasts rises the further into the future that the forecasts extend. For example, forecasts of population growth for the next two years see a much smaller range over which the forecast may actually vary than the range for our forecasts 30 years into the future.[21]

[21] The discussions in this and the immediate prior paragraphs may seem inconsistent. The discussion, however, focus on two different issues. In the current paragraph, the uncertainty focuses on the range around an existing forecast within which we can expect the actual value to lie with some probability. For example, a typical range covers 95 percent of actual outcomes. In a statistical sense, the discussion involves confidence bands. The further into the future that the research tries to forecast, the larger the range of the confidence bands needs to be to capture 95 percent of potential outcomes. In the prior paragraph, the standard deviation came from a series of different vintage REMI forecasts. The economic and demographic structure of the REMI model leads to convergence over time. That is, the economic migrants respond to economic incentives. Then, the movement of economic migrants will tend to reduce and eliminate the economic incentive for more

The main risks to the population forecasts arise from short-term fluctuations in both U.S. and Southern Nevada economic conditions. Based on our assessment of national and regional trends, we believe that the Southern Nevada economy will continue to see improvements in 2018 and 2019. In addition, we anticipate that the short-term economic growth in the Southern Nevada economy will generally outperform the national economy, since we started our local recovery later and from a much deeper hole than faced at the national level. Nevertheless, the health of the Southern Nevada economy still depends on national and international economic activity.

The downside risk to U.S. economic growth no longer exceeds, in our view, the upside risk in the near term. With the policies of the current administration, we expect the national economy to strengthen in the short term. Recent economic data show improvement in business investment and consumer confidence, fueled both by a robust labor market and the recently implemented tax cut. A robust U.S. market should benefit the local economy as the majority of Clark County visitors come from the United States, an upside risk to Southern Nevada economic growth as the local economy still largely depends on the tourism sector despite an effort to be a diversified economy. Recent discussion of imposing tariffs on traded goods and services and the possibility of trade wars may produce headwinds for the expanding U.S. economy.

Economic growth in the rest of the world may also influence U.S. economic growth. For example, China became an important player in the world economy because of her aggregate size. China purchases a large share of commodities on international markets, which are the major exports from many emerging market economies. Thus, slower growth

migrants to move in the longer run. That is, excessive growth relative to national growth disappears as the incentives for economic migration diminish.

in China leads to slower growth in emerging market economies. Although the International Monetary Fund's (IMF) projection of economic growth in China was recently revised upward, a downside risk still exists with the continuing growth in its debt.

The Federal Reserve System's (Fed) Federal Open Market Committee (FOMC) ended quantitative easing (QE) and has raised the federal fund rates over last two years. In addition, the FOMC started to lower the size of its balance sheet that ballooned because of the various quantitative easing (QE) programs. Recently, the FOMC raised the federal fund rate to a range of 1.5 to 1.75 and hinted at three more increases in 2018. The pace of the interest rate hikes will largely depend on the degree of success of the tax cut to stimulate the economy. The FOMC's ultimate decision on the number of interest rate increases over the next few years will depend on what the data tell the Fed about the state of the U.S. economy. Fewer interest rate increases could lead to higher inflation, whereas more interest rate increases could lead to slower growth. The U.S. economy currently operates above its potential, which provides a stronger justification for the FOMC to raise interest rates.

The future diversification of the local economy can provide a positive upside risk in terms of long-term population growth. In a Brookings Institution report,[22] Las Vegas ranked 96th out of 100 metropolitan areas based on improvement in prosperity (changes in productivity, average wealth and income, and standard of living). The report emphasizes that high-tech-, research-, and capital-intensive-based economies grow faster than regions that rely on the hospitality and retail sectors for their economic growth. REMI's projections on net outflow of economic migrants may place too much weight on the tourism sector in the local economy. We witnessed the vulnerability of the local economy during the Great

[22] Source: The Brookings Institution (2017), *Metro Monitor*.

Recession because of our tourism-based economy. Approximately 53 percent of the region's gross domestic product currently relies on Southern Nevada's tourism industry, according to the LVCVA.[23]

Finally, the recent tragedy on October 1, 2017, in Southern Nevada could significantly lower future economic growth and, thus, the population forecast. Visitor volume and net immigration to Southern Nevada could fall. The fall in visitor volume would also quickly slow economic growth in Southern Nevada. We have seen some decline in visitor volume, but that may reflect the inventory of rooms under renovation rather than the October 1 shooting. The passage of time will provide a more definitive answer as to the long-term effect of Oct. 1 on the Southern Nevada economy.

In sum, although we feel that the population forecast is sound, risks exist that could lead to either over- or underestimated population growth. Since we think that the downside risk to U.S. economic growth no longer exceeds the upside risk, the risk of overestimating population growth no longer exceeds the risk of its underestimation in the near term. We reiterate that our long-term forecasts exclude business-cycle, seasonal, and irregular events, which respond more to these short-run risks. Our long-term forecasts are designed to aid in the process of long-term planning.

VII. Conclusion

The latest REMI model projects long-term population growth patterns that are consistent with previous population forecasts. In the short term, the population forecast is slightly higher than last year's forecast. By 2025, the population forecast falls below last year's

[23] A report by the LVCVA indicates that the total economic impact of Southern Nevada tourism represents about 53 percent of the region's GDP. More than four out of 10 jobs in Southern Nevada were generated by the Southern Nevada tourism industry, which accounted for 36 percent of regional wages.

forecast through 2048. After 2048, the current population forecast exceeds last year's forecast. These patterns reflect the new data incorporated into the model and major adjustments with current employment and population data. We note that despite short-term economic uncertainties and model difficulties, the long-term population forecast, which is our primary focus in this forecasting exercise, remains consistent with past forecasts. By 2035, we predict that Clark County's population will reach about 2.67 million. In 2060, Clark County is expected to hit slightly above 2.90 million residents.

Appendices:

Appendix A: Computation of the Jobs-to-Room Ratio

The adjustment for new hotel construction uses a ratio of jobs to rooms. Two issues arise in the computation of the jobs-to-room ratio. First, we expect new hotel rooms to create new jobs in hotel services. Second, new hotel rooms will also generate economic activity and, hence, additional jobs in other sectors. Increased tourism activity from new hotel rooms will increase the demand for food services and other tourism-related industries. Hence, we need an approach that accounts for these two issues. We propose the following formula:

$$\text{Jobs} - \text{to} - \text{Room Ratio} \quad \begin{pmatrix} \text{Total} \\ \text{employment} \\ \text{due to tourism} \end{pmatrix} \Big/ \begin{pmatrix} \text{LVCVA} \\ \text{room count} \end{pmatrix},$$

where,

$$\begin{pmatrix} \text{Total} \\ \text{employment} \\ \text{due to tourism} \end{pmatrix} \quad \begin{pmatrix} \text{Accommodation} \\ \text{employment} \end{pmatrix} + \begin{pmatrix} \text{Employment} \\ \text{in tourism -} \\ \text{related} \\ \text{industries} \end{pmatrix} \times \begin{pmatrix} \text{Share of} \\ \text{employment} \\ \text{due to tourism} \end{pmatrix}.$$

Table A1: Computation of the Jobs-to-Room Ratio by Sequence (1) – (5)

(1) Employment (thousands)

Industrial Classification	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Accommodation	179.6	174.1	162.5	163.4	165.7	164.6	164.9	170.6	168.9	166.4
Clothing and clothing accessories	15.7	16.6	15.9	16.8	17.4	18.3	18.5	19.0	19.2	18.5
Transit, ground pass transportation	12.7	12.8	12.2	12.4	12.9	13.3	13.4	14.0	14.2	13.4
Arts, entertainment, and recreation	19.0	18.3	16.4	15.8	16.9	17.5	17.8	18.7	19.3	20.5
Food service and drinking places	74.4	77.1	72.4	74.2	77.0	79.4	84.5	89.3	94.1	98.8

Source: Quarterly Census of Employment and Wages, U.S. Bureau of Labor Statistics.

(2) Proportion of employment due to tourism* (= Location quotient**-1)

Industrial Classification	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Accommodation	1	1	1	1	1	1	1	1	1	1
Clothing and clothing accessories	0.45	0.58	0.73	0.84	0.96	1	1	1	1	0.98
Transit, ground pass transportation	1	1	1	1	1	1	1	1	1	1
Arts, entertainment, and recreation	0.34	0.30	0.26	0.26	0.34	0.36	0.33	0.32	0.30	0.32
Food service and drinking places	0.08	0.13	0.15	0.20	0.23	0.22	0.24	0.24	0.24	0.25

* Maximum value = 1. Minimum value = 0.

** The Location Quotient (LQ) compares Clark County's employment in a given industry sector to that of the nation. An LQ greater than 1 indicates that the area has proportionately more workers than the nation employed in that specific industry sector. This implies that the area is producing more than is consumed by its residents. The portion of the LQ that is above 1 represents the proportion of the industry's employment attributable to tourism activity.

(3) Employment due to tourism (thousands) = (1) x (2)

Industrial Classification	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Accommodation	179.6	174.1	162.5	163.4	165.7	164.6	164.9	170.6	168.9	166.4
Clothing and clothing accessories	15.7	16.6	15.9	16.8	17.4	18.3	18.5	19.0	19.2	18.1
Transit, ground pass transportation	12.7	12.8	12.2	12.4	12.9	13.3	13.4	14.0	14.2	13.4
Arts, entertainment, and recreation	6.4	5.5	4.2	4.0	5.7	6.2	5.8	6.0	5.8	6.5
Food service and drinking places	5.9	10.2	10.6	14.7	17.4	17.4	20.3	21.6	22.9	24.4
Total employment due to tourism*	**211.7**	**212.2**	**201.2**	**208.7**	**218.3**	**219.9**	**223.0**	**231.1**	**231.0**	**228.7**

* The numbers may not sum to the total because of rounding.

(4) LVCVA hotel room count (thousands)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Average room inventory	133.3	136.9	141.8	148.4	149.6	150.5	150.1	150.1	149.6	149.3

(5) Employment due to a hotel room = (3)*/(4)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Average**
Jobs-to-room ratio	1.59	1.55	1.42	1.41	1.46	1.46	1.49	1.54	1.54	1.53	1.50

*Total employment due to tourism.

**Averaged jobs-to-room ratio from 2007 to 2016.

Appendix B: Detailed Report Tables

Table B1: Out-of-the-Box Clark County Population and Population Growth Forecasts from REMI Models LHY2013 and LHY2015

Year	LHY2013 Population (Thousands)	LHY2015 Population (Thousands)	LHY2013 Population Growth	LHY2015 Population Growth
2018	2,152	2,216	1.2%	1.5%
2019	2,177	2,247	1.2%	1.4%
2020	2,202	2,274	1.1%	1.2%
2021	2,226	2,298	1.1%	1.0%
2022	2,248	2,319	1.0%	0.9%
2023	2,270	2,338	0.9%	0.8%
2024	2,289	2,357	0.9%	0.8%
2025	2,308	2,374	0.8%	0.7%
2026	2,325	2,390	0.7%	0.7%
2027	2,341	2,405	0.7%	0.6%
2028	2,356	2,419	0.6%	0.6%
2029	2,369	2,433	0.6%	0.6%
2030	2,381	2,446	0.5%	0.5%
2031	2,393	2,458	0.5%	0.5%
2032	2,403	2,470	0.4%	0.5%
2033	2,413	2,481	0.4%	0.4%
2034	2,423	2,491	0.4%	0.4%
2035	2,431	2,501	0.4%	0.4%
2040	2,466	2,548	0.2%	0.4%
2045	2,490	2,600	0.2%	0.4%
2050	2,511	2,659	0.2%	0.4%
2055	2,534	2,715	0.2%	0.4%
2060	2,555	2,757	0.2%	0.2%

Note: Out-of-the-box refers to the model prior to recalibration. These numbers are not the final forecast.

Table B2: Detailed Final Clark County Population Forecast: 2010 – 2060			
Year	**Population Forecast**	**Change in Population Forecast**	**Growth in Population (Percent)**
2010	1,951,269*	-55,078	-2.7%
2011	1,966,630**	15,361	0.8%
2012	2,008,654**	42,024	2.1%
2013	2,062,253**	53,599	2.7%
2014	2,102,238**	39,985	2.0%
2015	2,147,641**	45,403	2.2%
2016	2,205,207**	57,566	2.7%
2017	2,248,391**	43,184	2.0%
2018	2,296,000	47,609	2.1%
2019	2,344,000	48,000	2.1%
2020	2,389,000	45,000	1.9%
2021	2,423,000	34,000	1.4%
2022	2,452,000	29,000	1.2%
2023	2,481,000	29,000	1.2%
2024	2,507,000	26,000	1.0%
2025	2,530,000	23,000	0.9%
2026	2,550,000	20,000	0.8%
2027	2,568,000	18,000	0.7%
2028	2,585,000	17,000	0.7%
2029	2,600,000	15,000	0.6%
2030	2,615,000	15,000	0.6%
2031	2,628,000	13,000	0.5%
2032	2,640,000	12,000	0.5%
2033	2,651,000	11,000	0.4%
2034	2,662,000	11,000	0.4%
2035	2,672,000	10,000	0.4%
2036	2,682,000	10,000	0.4%
2037	2,692,000	10,000	0.4%
2038	2,701,000	9,000	0.3%
2039	2,710,000	9,000	0.3%
2040	2,719,000	9,000	0.3%
2041	2,728,000	9,000	0.3%
2042	2,737,000	9,000	0.3%
2043	2,747,000	10,000	0.4%
2044	2,756,000	9,000	0.3%
2045	2,766,000	10,000	0.4%
2046	2,776,000	10,000	0.4%
2047	2,786,000	10,000	0.4%
2048	2,796,000	10,000	0.4%
2049	2,806,000	10,000	0.4%
2050	2,816,000	10,000	0.4%
2051	2,825,000	9,000	0.3%
2052	2,835,000	10,000	0.4%
2053	2,844,000	9,000	0.3%
2054	2,854,000	10,000	0.4%
2055	2,863,000	9,000	0.3%
2056	2,871,000	8,000	0.3%
2057	2,879,000	8,000	0.3%
2058	2,886,000	7,000	0.2%
2059	2,894,000	8,000	0.3%
2060	2,900,000	6,000	0.2%

* 2010 U.S. Census.
** SNRPC consensus population estimate.
Note: The average annual forecasted growth rate is 0.6 percent.

Table B3: Economic Forecast

Variable	Unit	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Employment	Thousands (Jobs)	1311.03	1327.67	1350.60	1355.25	1355.45	1364.41	1365.85	1368.88	1372.60
Private Non-Farm Employment	Thousands (Jobs)	1193.89	1209.85	1232.92	1237.85	1238.69	1247.70	1249.38	1252.55	1256.32
Residence-Adjusted Employment	Thousands	1289.78	1306.66	1329.75	1334.90	1335.67	1345.10	1347.09	1350.55	1354.66
Population	Thousands	2295.61	2343.81	2389.34	2422.79	2452.20	2481.17	2506.58	2529.53	2549.97
Labor Force	Thousands	1122.25	1143.67	1170.43	1189.51	1206.78	1219.19	1229.90	1240.01	1249.10
Gross Domestic Product	Billions of Fixed (2018) $	122.56	125.78	129.76	132.27	134.98	138.07	140.62	143.15	145.60
Output	Billions of Fixed (2018) $	196.81	202.06	208.54	212.61	216.97	221.93	225.94	230.34	234.66
Value Added	Billions of Fixed (2018) $	124.20	127.46	131.51	134.04	136.78	139.91	142.50	145.06	147.55
Personal Income	Billions of Fixed (2018) $	102.77	106.02	109.40	111.79	114.66	116.99	118.95	121.44	123.72
Disposable Personal Income	Billions of Fixed (2018) $	92.36	95.46	98.42	100.54	103.11	105.14	106.81	109.01	111.01
PCE-Price Index	2009=100 (Nation)	114.87	117.31	120.20	123.27	126.28	129.36	132.52	135.74	139.02

Table B3: Economic Forecast (continued)

Variable	Unit	2027	2028	2029	2030	2035	2040	2045	2050	2055	2060
Total Employment	Thousands (Jobs)	1374.94	1380.41	1385.22	1390.44	1414.62	1441.65	1471.94	1512.25	1554.60	1594.71
Private Non-Farm Employment	Thousands (Jobs)	1258.87	1264.35	1269.07	1274.03	1298.61	1325.76	1355.86	1394.81	1435.06	1473.49
Residence Adjusted Employment	Thousands	1357.37	1363.12	1368.17	1373.59	1398.65	1426.27	1457.05	1497.69	1540.47	1580.98
Population	Thousands	2568.01	2584.91	2600.45	2614.83	2672.41	2718.90	2766.24	2815.67	2862.56	2900.16
Labor Force	Thousands	1257.90	1266.27	1274.15	1281.30	1319.42	1361.77	1406.13	1445.38	1457.60	1467.00
Gross Domestic Product	Billions of Fixed (2018) $	148.00	150.90	153.83	156.81	172.19	189.15	207.95	230.13	254.78	281.29
Output	Billions of Fixed (2018) $	238.97	244.15	249.41	254.82	283.85	316.79	354.01	398.37	448.67	504.22
Value Added	Billions of Fixed (2018) $	149.99	152.93	155.90	158.91	174.51	191.70	210.74	233.19	258.12	284.91
Personal Income	Billions of Fixed (2018) $	125.97	128.44	130.95	133.56	148.10	165.36	186.03	210.62	239.67	272.24
Disposable Personal Income	Billions of Fixed (2018) $	112.98	115.15	117.35	119.64	132.38	147.47	165.51	186.92	212.11	240.14
PCE-Price Index	2009=100 (Nation)	142.38	145.81	149.35	152.98	172.60	194.74	219.65	247.76	279.48	315.21

Table B4: Employment (in Thousands)

Variable	2018	2019	2020	2021	2022	2023	2024	2025	2026
Private Non-Farm	1193.89	1209.85	1232.92	1237.85	1238.69	1247.70	1249.38	1252.55	1256.32
Forestry, Fishing, Other	0.46	0.47	0.47	0.48	0.47	0.48	0.48	0.48	0.49
Mining	3.03	3.04	3.08	3.07	3.04	3.03	3.00	2.96	2.94
Utilities	2.87	2.84	2.80	2.75	2.70	2.66	2.62	2.55	2.49
Construction	81.42	83.23	85.46	83.58	84.30	82.87	82.79	82.67	82.02
Manufacturing	25.39	25.22	25.02	24.61	24.16	23.87	23.48	23.16	22.96
Wholesale Trade	31.77	32.35	32.94	33.30	33.53	33.82	34.01	34.23	34.46
Retail Trade	133.61	135.45	136.65	137.34	137.16	138.18	138.02	138.50	139.14
Transportation and Warehousing	47.02	47.25	47.39	47.92	47.79	48.58	48.55	48.56	48.63
Information	16.68	16.89	17.06	17.16	17.16	17.20	17.18	17.23	17.27
Finance and Insurance	67.66	67.99	68.59	68.89	69.15	69.91	70.64	71.45	72.29
Real Estate and Rental and Leasing	80.84	81.48	81.79	81.78	81.56	81.79	81.85	81.97	82.13
Professional and Technical Services	73.04	74.51	76.06	77.08	77.61	78.35	78.87	79.36	79.76
Mngmt of Companies and Enterprises	25.76	26.05	26.50	26.62	26.60	26.78	26.81	26.86	26.96
Admin and Waste Services	102.61	103.71	104.87	105.25	105.22	105.85	106.03	106.34	106.73
Educational Services	12.67	12.86	12.96	13.02	13.05	13.13	13.18	13.23	13.30
Health Care and Social Assistance	105.34	108.73	111.23	112.97	114.40	116.20	117.48	118.96	120.63
Arts, Entertainment, and Recreation	42.65	43.01	43.11	44.42	44.30	45.43	45.44	45.49	45.61
Accommodation and Food Services	278.02	280.69	292.10	292.69	291.63	294.56	294.13	293.84	293.83
Other Services, except Govt	63.04	64.08	64.83	64.92	64.84	65.00	64.80	64.69	64.68
Government	116.67	117.35	117.22	116.95	116.31	116.27	116.04	115.90	115.85
State and local	89.42	90.58	91.02	91.23	91.15	91.56	91.75	91.95	92.24
Federal civilian	12.36	12.01	11.78	11.62	11.43	11.29	11.19	11.10	10.99
Federal military	14.89	14.76	14.42	14.09	13.73	13.43	13.10	12.85	12.62
Farm	0.47	0.46	0.46	0.45	0.45	0.44	0.44	0.43	0.43

Table B4: Employment (in Thousands) (continued)

Variable	2027	2028	2029	2030	2035	2040	2045	2050	2055	2060
Private Non-Farm	1258.87	1264.35	1269.07	1274.03	1298.61	1325.76	1355.86	1394.81	1435.06	1473.49
Forestry, Fishing, Other	0.50	0.50	0.51	0.52	0.56	0.62	0.67	0.73	0.79	0.84
Mining	2.91	2.89	2.85	2.83	2.69	2.57	2.44	2.33	2.21	2.07
Utilities	2.42	2.35	2.28	2.21	1.85	1.52	1.24	1.01	0.82	0.66
Construction	81.67	82.58	82.77	83.15	86.89	91.41	97.39	103.86	110.76	117.00
Manufacturing	22.75	22.59	22.38	22.21	21.51	21.08	20.71	20.53	20.33	20.10
Wholesale Trade	34.66	34.95	35.21	35.47	36.85	38.26	39.69	41.23	42.76	44.15
Retail Trade	139.49	140.13	140.84	141.58	145.37	149.58	154.00	159.76	165.42	170.08
Transportation and Warehousing	48.67	48.79	48.90	49.02	49.69	50.54	51.52	52.83	54.28	55.80
Information	17.31	17.40	17.48	17.57	18.11	18.74	19.46	20.35	21.31	22.31
Finance and Insurance	73.04	73.90	74.73	75.52	79.51	83.52	87.97	92.92	97.94	102.70
Real Estate and Rental and Leasing	82.14	82.27	82.39	82.50	82.70	82.90	83.06	83.76	84.34	84.51
Professional and Technical Services	80.25	80.90	81.49	82.11	85.31	88.51	91.98	95.75	99.66	103.61
Mngmt of Companies and Enterprises	27.05	27.17	27.28	27.39	27.96	28.50	28.99	29.61	30.22	30.84
Admin and Waste Services	107.01	107.45	107.89	108.32	110.33	112.40	114.47	117.24	120.19	122.92
Educational Services	13.34	13.39	13.44	13.48	13.59	13.66	13.71	13.89	14.04	14.08
Health Care and Social Assistance	121.95	123.44	124.98	126.49	133.34	140.47	147.87	156.94	166.54	175.88
Arts, Entertainment, and Recreation	45.64	45.74	45.83	45.92	46.15	46.42	46.64	47.15	47.61	47.91
Accommodation and Food Services	293.56	293.46	293.42	293.37	292.40	291.80	291.38	292.33	293.35	296.00
Other Services, except Govt	64.51	64.46	64.41	64.36	63.80	63.26	62.68	62.60	62.48	62.02
Government	115.64	115.64	115.73	115.99	115.61	115.51	115.72	117.10	119.22	120.92
State and local	92.34	92.58	92.90	93.35	94.05	94.73	95.34	97.08	99.41	101.35
Federal civilian	10.91	10.85	10.79	10.74	10.50	10.47	10.75	10.90	11.05	11.13
Federal military	12.39	12.20	12.03	11.90	11.06	10.31	9.62	9.12	8.77	8.44
Farm	0.43	0.42	0.42	0.42	0.40	0.38	0.36	0.34	0.32	0.30

Table B5: Gross Domestic Product (Billions of fixed 2018 $)*

Variable	2018	2019	2020	2021	2022	2023	2024	2025	2026
Personal Consumption Expenditures	86.58	88.85	91.13	92.81	94.88	97.18	99.24	101.40	103.59
Motor vehicles and parts	3.24	3.24	3.28	3.30	3.33	3.38	3.41	3.44	3.48
Furnishings and durable household equipment	2.68	2.83	2.99	3.12	3.25	3.39	3.50	3.62	3.74
Recreational goods and other durable goods	5.69	5.98	6.31	6.58	6.87	7.17	7.44	7.73	8.03
Food and beverages	6.58	6.64	6.68	6.70	6.76	6.83	6.91	6.99	7.07
Clothing and footwear	2.82	2.89	2.97	3.03	3.11	3.19	3.28	3.37	3.44
Motor vehicle fuels, lubricants, and fluids	1.78	1.81	1.82	1.83	1.85	1.86	1.87	1.88	1.89
Fuel oil and other fuels	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.04
Other nondurable goods	9.84	10.15	10.47	10.72	11.00	11.30	11.56	11.84	12.12
Housing	14.95	15.20	15.40	15.54	15.77	16.04	16.31	16.59	16.86
Household utilities	1.90	1.91	1.91	1.91	1.92	1.94	1.96	1.97	1.98
Transportation services	2.14	2.16	2.20	2.21	2.24	2.27	2.29	2.32	2.35
Health care	12.64	13.26	13.81	14.26	14.75	15.23	15.66	16.10	16.55
Recreation and other services	22.28	22.73	23.23	23.55	23.99	24.52	25.00	25.51	26.03
Gross Private Domestic Fixed Investment	25.17	26.27	27.57	28.62	29.43	30.10	30.80	31.42	31.72
Residential	5.54	5.90	6.29	6.47	6.55	6.59	6.59	6.57	6.49
Nonresidential structures	3.77	3.84	4.09	4.25	4.37	4.49	4.60	4.69	4.72
Nonresidential equipment	9.47	9.81	10.19	10.61	10.98	11.31	11.71	12.08	12.33
Nonresidential intellectual property products	6.38	6.73	7.00	7.29	7.53	7.71	7.90	8.08	8.18
Change in Private Inventories	0.13	0.14	0.13	0.13	0.12	0.11	0.10	0.10	0.09
Government Consumption Expenditures	19.55	20.02	20.19	20.32	20.49	20.70	20.85	21.02	21.18
Federal military	6.08	6.21	6.21	6.20	6.20	6.21	6.21	6.21	6.22
Federal civilian	2.44	2.50	2.50	2.50	2.50	2.51	2.51	2.51	2.51
State and local government	11.04	11.30	11.48	11.62	11.79	11.98	12.14	12.30	12.45
Total Exports	67.04	68.58	71.22	72.61	74.16	76.03	77.48	79.07	80.67
Total Imports	77.60	80.02	82.66	84.63	86.75	88.89	90.86	93.07	95.05

*Note: The sum of the components may not add up to the total GDP due to rounding.

Table B5: Gross Domestic Product (Billions of fixed 2018 $) (continued)*

Variable	2027	2028	2029	2030	2035	2040	2045	2050	2055	2060
Personal Consumption Expenditures	105.54	107.82	110.21	112.59	125.06	138.00	153.09	171.85	193.05	215.37
Motor vehicles and parts	3.50	3.54	3.59	3.63	3.85	4.10	4.37	4.73	5.13	5.53
Furnishings and durable household equipment	3.85	3.98	4.12	4.26	5.01	5.88	6.90	8.16	9.64	11.27
Recreational goods and other durable goods	8.32	8.65	9.01	9.37	11.44	13.73	16.59	20.23	24.56	29.47
Food and beverages	7.13	7.21	7.29	7.36	7.69	8.02	8.35	8.80	9.25	9.63
Clothing and footwear	3.51	3.59	3.69	3.78	4.43	4.38	4.75	5.18	5.59	5.92
Motor vehicle fuels, lubricants, and fluids	1.90	1.91	1.92	1.93	1.97	2.01	2.06	2.14	2.24	2.32
Fuel oil and other fuels	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03
Other nondurable goods	12.37	12.67	12.97	13.28	14.91	16.73	18.78	21.33	24.26	27.41
Housing	17.08	17.34	17.61	17.86	19.01	20.17	21.34	22.76	24.14	25.30
Household utilities	1.99	2.00	2.01	2.02	2.04	2.05	2.06	2.09	2.12	2.12
Transportation services	2.37	2.40	2.44	2.48	2.67	2.90	3.17	3.54	3.97	4.46
Health care	16.97	17.43	17.91	18.39	20.80	23.38	26.15	29.38	32.88	36.45
Recreation and other services	26.49	27.04	27.61	28.19	31.20	34.63	38.53	43.49	49.25	55.44
Gross Private Domestic Fixed Investment	32.22	32.88	33.56	34.26	38.55	43.09	48.68	54.80	61.57	68.74
Residential	6.47	6.51	6.58	6.68	7.56	8.67	10.09	11.71	13.53	15.26
Nonresidential structures	4.76	4.82	4.89	4.95	5.39	5.86	6.51	7.23	8.07	9.04
Nonresidential equipment	12.65	13.03	13.40	13.76	15.78	17.83	20.24	22.83	25.63	28.63
Nonresidential intellectual property products	8.34	8.52	8.70	8.87	9.82	10.74	11.84	13.04	14.35	15.80
Change in Private Inventories	0.09	0.09	0.08	0.08	0.07	0.06	0.06	0.06	0.06	0.06
Government Consumption Expenditures	21.33	21.54	21.79	22.09	23.24	24.47	25.76	27.51	29.74	32.09
Federal military	6.23	6.26	6.31	6.36	6.57	6.80	7.04	7.43	7.95	8.55
Federal civilian	2.51	2.52	2.54	2.56	2.63	2.72	2.80	2.93	3.12	3.32
State and local government	12.58	12.75	12.94	13.16	14.04	14.96	15.92	17.15	18.67	20.23
Total Exports	82.33	84.30	86.19	88.09	98.46	110.16	123.09	137.89	154.45	173.49
Total Imports	97.08	99.51	102.02	104.56	118.76	133.73	151.71	173.35	198.30	225.92

*Note: The sum of the components may not add up to the total GDP due to rounding.

Table B6: Income (Billions of fixed 2018 $)

Variable	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total earnings by place of work	71.58	73.09	75.34	76.28	77.53	78.94	80.02	81.08	82.04
Total wage and salary disbursements	53.44	54.61	56.35	57.05	57.97	59.02	59.80	60.53	61.20
Supplements to wages and salaries	13.38	13.72	14.21	14.48	14.80	15.13	15.40	15.68	15.92
Employer contributions for employee pension and insurance funds	9.31	9.57	9.91	10.10	10.33	10.55	10.74	10.94	11.10
Employer contributions for government social insurance	4.07	4.15	4.30	4.38	4.48	4.58	4.66	4.74	4.81
Proprietors' income with inventory valuation and capital consumption adjustments	4.76	4.76	4.78	4.75	4.75	4.78	4.82	4.87	4.92
Less: Contributions for government social insurance	8.24	8.43	8.65	8.77	8.93	9.11	9.22	9.34	9.45
Employee and self-employed contributions for government social insurance	4.17	4.28	4.35	4.39	4.46	4.53	4.56	4.60	4.64
Employer contributions for government social insurance	4.07	4.15	4.30	4.38	4.48	4.58	4.66	4.74	4.81
Plus: Adjustment for residence	-0.29	-0.29	-0.31	-0.30	-0.29	-0.28	-0.27	-0.25	-0.24
Gross in	1.31	1.34	1.36	1.38	1.41	1.43	1.45	1.48	1.50
Gross out	1.60	1.63	1.67	1.68	1.70	1.71	1.72	1.73	1.74
Equals: Net earnings by place of residence	63.04	64.38	66.38	67.21	68.31	69.55	70.54	71.48	72.34
Plus: Rental, personal interest, and personal dividend income	22.39	23.62	24.35	25.23	26.03	26.77	27.40	27.94	28.53
Plus: Personal current transfer receipts	17.33	18.02	18.66	19.35	20.33	20.67	21.01	22.02	22.85
Equals: Personal income	102.77	106.02	109.40	111.79	114.66	116.99	118.95	121.44	123.72
Less: Personal current taxes	10.41	10.57	10.97	11.26	11.55	11.86	12.13	12.43	12.71
Equals: Disposable personal income	92.36	95.46	98.42	100.54	103.11	105.13	106.81	109.01	111.01
Real personal income with housing price (billions of fixed 2009 $)	91.86	94.62	97.50	99.54	102.04	104.06	105.76	107.95	109.95
Real disposable personal income with housing price (billions of fixed 2009 $)	82.55	85.19	87.72	89.52	91.76	93.52	94.97	96.90	98.66
PCE-price index with housing price, 2009=100	111.98	114.53	117.51	120.63	123.64	126.71	129.87	133.05	136.30
Relative housing price	0.83	0.84	0.85	0.85	0.86	0.86	0.86	0.86	0.86

Table B6: Income (Billions of fixed 2018 $) (continued)

Variable	2027	2028	2029	2030	2035	2040	2045	2050	2055	2060
Total earnings by place of work	82.96	84.03	85.09	86.19	92.45	99.72	108.41	118.55	130.46	144.17
Total wage and salary disbursements	61.84	62.59	63.33	64.10	68.46	73.50	79.54	86.57	94.82	104.31
Supplements to wages and salaries	16.15	16.41	16.66	16.92	18.38	20.06	22.08	24.45	27.27	30.53
Employer contributions for employee pension and insurance funds	11.27	11.45	11.62	11.81	12.83	14.00	15.40	17.06	19.02	21.30
Employer contributions for government social insurance	4.88	4.96	5.04	5.12	5.56	6.07	6.68	7.39	8.25	9.23
Proprietors' income with inventory valuation and capital consumption adjustments	4.97	5.03	5.09	5.17	5.61	6.16	6.80	7.53	8.37	9.32
Less: Contributions for government social insurance	9.54	9.65	9.75	9.86	10.45	11.14	11.95	12.91	14.03	15.30
Employee and self-employed contributions for government social insurance	4.66	4.69	4.71	4.74	4.89	5.07	5.28	5.52	5.78	6.07
Employer contributions for government social insurance	4.88	4.96	5.04	5.12	5.56	6.07	6.68	7.39	8.25	9.23
Plus: Adjustment for residence	-0.23	-0.22	-0.22	-0.21	-0.21	-0.23	-0.25	-0.28	-0.28	-0.29
Gross in	1.53	1.55	1.57	1.60	1.73	1.89	2.07	2.28	2.53	2.83
Gross out	1.75	1.77	1.79	1.81	1.94	2.11	2.32	2.56	2.81	3.12
Equals: Net earnings by place of residence	73.19	74.16	75.12	76.12	81.79	88.35	96.20	105.36	116.15	128.58
Plus: Rental, personal interest, and personal dividend income	29.20	29.89	30.60	31.34	35.41	40.24	45.87	52.48	60.18	68.50
Plus: Personal current transfer receipts	23.59	24.40	25.23	26.09	30.90	36.78	43.96	52.78	63.34	75.17
Equals: Personal income	125.97	128.44	130.95	133.56	148.10	165.36	186.03	210.62	239.67	272.24
Less: Personal current taxes	12.99	13.29	13.60	13.92	15.72	17.89	20.52	23.70	27.56	32.10
Equals: Disposable personal income	112.98	115.15	117.35	119.64	132.38	147.47	165.51	186.92	212.11	240.14
Real personal income with housing price (billions of fixed 2009 $)	111.95	114.14	116.37	118.69	131.71	147.18	165.67	187.65	213.64	242.88
Real disposable personal income with housing price (billions of fixed 2009 $)	100.40	102.33	104.29	106.32	117.73	131.26	147.40	166.54	189.07	214.24
PCE-price index with housing price, 2009=100	139.60	142.97	146.44	149.98	169.10	190.64	214.90	242.30	273.19	307.85
Relative housing price	0.86	0.86	0.86	0.86	0.86	0.86	0.85	0.85	0.85	0.84

Table B7: Population and Labor Force (in Thousands)

Variable	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total population	2295.61	2343.81	2389.34	2422.78	2452.20	2481.17	2506.58	2529.53	2549.97
By race and ethnicity									
White	998.88	1011.80	1023.37	1029.30	1033.21	1036.71	1038.45	1038.96	1038.26
Black	245.11	249.84	254.21	257.34	260.07	262.75	265.06	267.11	268.90
Other	327.11	334.55	341.63	346.99	351.77	356.50	360.71	364.55	368.02
Hispanic	724.50	747.63	770.13	789.15	807.14	825.21	842.36	858.90	874.80
By age									
Ages 0-14	439.39	444.14	449.42	451.25	451.44	451.58	451.92	452.07	452.46
Ages 15-24	282.24	288.57	296.59	303.73	308.85	312.28	313.65	313.44	312.51
Ages 25-64	1223.86	1241.54	1256.25	1263.53	1270.87	1279.58	1286.87	1292.77	1297.36
Ages 65 & older	350.12	369.57	387.08	404.28	421.03	437.72	454.13	471.24	487.64
Labor force	1122.25	1143.67	1170.43	1189.51	1206.78	1219.19	1229.90	1240.01	1249.10
Labor force participation rate	0.620	0.618	0.619	0.618	0.618	0.616	0.613	0.611	0.609
Participation rates by gender									
Male (16 & older)	0.683	0.680	0.680	0.679	0.678	0.675	0.672	0.670	0.669
Female (16 & older)	0.559	0.557	0.559	0.560	0.560	0.558	0.556	0.554	0.552

Table B7: Population and Labor Force (in Thousands) (continued)

Variable	2027	2028	2029	2030	2035	2040	2045	2050	2055	2060
Total population	2568.01	2584.91	2600.44	2614.83	2672.41	2718.90	2766.24	2815.67	2862.56	2900.16
By race and ethnicity										
White	1036.39	1033.91	1030.74	1026.99	1000.77	967.69	933.08	899.43	866.89	834.73
Black	270.44	271.86	273.14	274.31	278.74	282.10	285.53	289.03	292.24	294.87
Other	371.13	374.07	376.81	379.39	390.81	401.83	414.12	427.48	440.74	452.26
Hispanic	890.06	905.08	919.76	934.13	1002.09	1067.28	1133.52	1199.74	1262.69	1318.31
By age										
Ages 0-14	453.28	453.76	453.84	453.23	443.43	434.72	431.80	434.06	437.70	438.14
Ages 15-24	310.94	309.34	307.20	305.82	300.32	305.45	303.59	300.73	299.21	298.82
Ages 25-64	1300.37	1302.55	1304.50	1305.71	1315.07	1316.07	1331.21	1342.12	1343.76	1348.47
Ages 65 & older	503.43	519.27	534.91	550.07	613.60	662.66	699.64	738.76	781.89	814.74
Labor force	1257.90	1266.27	1274.15	1281.30	1319.42	1361.77	1406.13	1445.38	1457.60	1467.00
Labor force participation rate	0.608	0.607	0.606	0.606	0.605	0.608	0.614	0.618	0.612	0.607
Participation rates by gender										
Male (16 & older)	0.668	0.667	0.667	0.666	0.664	0.666	0.670	0.673	0.667	0.662
Female (16 & older)	0.550	0.549	0.548	0.548	0.547	0.553	0.561	0.566	0.559	0.554

Table B8: Demographics (in Thousands)

Variable	2018	2019	2020	2021	2022	2023	2024	2025	2026
Starting population	2248.39	2295.61	2343.81	2389.34	2422.78	2452.20	2481.17	2506.58	2529.53
Births	28.714	29.126	29.80	29.87	30.01	30.07	30.10	30.08	30.03
Deaths	17.473	18.179	18.88	19.49	20.12	20.76	21.41	22.08	22.75
Natural growth	11.24	10.94	10.92	10.39	9.89	9.31	8.69	8.00	7.27
Population before migrants	2259.63	2306.55	2354.73	2399.72	2432.67	2461.51	2489.85	2514.58	2536.80
Total migrants	35.98	37.26	34.61	23.06	19.52	19.66	16.72	14.94	13.18
Economic migrants	22.41	23.21	21.25	9.05	5.29	5.10	1.94	-0.19	-2.25
Retired migrants	5.14	5.32	5.52	5.71	5.88	6.05	6.22	6.39	6.55
International migrants	8.50	8.58	8.65	8.73	8.81	8.89	8.98	9.07	9.16
Special pops migrants	-0.07	0.16	-0.80	-0.42	-0.46	-0.39	-0.41	-0.33	-0.29
Total population	2295.61	2343.81	2389.34	2422.78	2452.20	2481.17	2506.58	2529.53	2549.97

Table B8: Demographics (in Thousands) (continued)

Variable	2027	2028	2029	2030	2035	2040	2045	2050	2055	2060
Starting population	2549.97	2568.01	2584.91	2600.44	2662.11	2709.67	2756.38	2806.07	2853.52	2893.51
Births	29.95	29.85	29.72	29.58	28.81	28.45	28.45	28.76	28.88	28.57
Deaths	23.44	24.15	24.87	25.60	29.32	32.57	35.07	36.78	37.89	38.69
Natural growth	6.50	5.70	4.85	3.98	-0.51	-4.12	-6.62	-8.02	-9.01	-10.12
Population before migrants	2556.48	2573.71	2589.77	2604.43	2661.60	2705.55	2749.76	2798.05	2844.51	2883.39
Total migrants	11.54	11.20	10.68	10.40	10.81	13.35	16.47	17.62	18.05	16.78
Economic migrants	-4.11	-4.69	-5.46	-5.91	-5.90	-3.66	-0.81	-0.17	-0.28	-2.12
Retired migrants	6.68	6.80	6.92	7.01	7.22	7.30	7.45	7.82	8.33	8.91
International migrants	9.25	9.34	9.43	9.48	9.70	9.87	10.00	10.07	10.09	10.06
Special pops migrants	-0.29	-0.24	-0.21	-0.17	-0.21	-0.17	-0.16	-0.10	-0.09	-0.08
Total population	2568.01	2584.91	2600.44	2614.83	2672.41	2718.90	2766.24	2815.67	2862.56	2900.16

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Nevada County Population Projections 2018 to 2037

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The full projections by year and county are at the end of this document.

Introduction to the 2018 Population Projections

In keeping with the 2014 projections through this current edition, a baseline projection is presented as well as a projection that includes the Tesla Gigafactory project and the impact of relative housing prices for Clark and Washoe Counties. The projection with the Gigafactory and other factors will still be used as the control total for the age, sex, race, and Hispanic origin estimates and projections.

The 2018 Projections:

The Regional Economics Models, Inc. (REMI) model was used for these projections. The REMI model provides information for all 17 counties by 23 major economic sectors. The REMI model looks at the interaction between the economic and demographic characteristics of a county. It looks at the dynamic economic and demographic relationships between the 17 counties and the United States as a total. The 20 year projections are produced annually and will change as historic data becomes available or is revised and information about future developments becomes available. Because REMI looks at the relationship between changes in the economy and in population, it is a useful tool for looking at how changes in the structure of the population or the economy can impact each other.

The 2018 Projections were prepared using the REMI PI+ 2.2 model, which uses 2016 as the last year of historic data. The 2017 Projections were produced with the REMI PI+ 2.1 model with history through 2015. Since 2014, two projections have been prepared annually. One is the baseline forecast. The other includes the Tesla project and other factors. This project was first modeled in 2014 with information from the Governor's Office of Economic Development. There is still interest in understanding the direct and indirect impact of this project. Modeling it separately from the baseline forecast allows for understanding these impacts. It will become part of the baseline forecast as it progresses and the development becomes part of the economic history in the model.

Changes to the out-of-box model (the model as shipped with no additional information from the user) included the additional years of history for 2016 and any revisions to the data for the earlier years. Both the Census Bureau and the Bureau of Economic Analysis revise their data given new information as well as after reviewing data.

For the baseline forecast, the following alterations were made to the out of the box 2018 (2.2) REMI model:

1.) The current employment in the model was updated from 2016 to 2018. The model uses Bureau of Economic Analysis (BEA) data which covers total employment by sector. Growth rates from the Bureau of Labor Statistics Quarterly Census of Employment and Wages data for the first quarter of 2016 to 2018 were used to estimate what would be the BEA totals for 2017 and 2018..
2.) The Quarterly Census of Employment and Wages data was used to update the counties as well using the first quarter of 2018 data, with the exception of the following: Esmeralda, Eureka, Lincoln, Mineral and Pershing. This was because of data suppression in these counties that is done to protect confidentiality.
3.) Hotel employment for Clark County was based on existing hotels and proposed projects as reported by the Las Vegas Convention and Visitors Authority.
4.) Mining employment again showed job losses over time in the REMI model. This varied by county. It was assumed that employment would still not fall below historic averages, and the model adjusted based on that assumption. Part of the reason that mining employment decreases in the model is that there are projected productivity gains over the next 20 years for that industry.
5.) As in the past, as growth has occurred in the Tahoe Regional Industrial Center in Storey County, it was assumed that those jobs would be filled by commuters from Lyon and Washoe Counties.

For the projection that includes Tesla, the following assumptions were made:

1.) The recent history in the 2.2 model, as well as the information from the employment update, has increased the model's response to manufacturing employment for Northwestern Nevada. The

Governor's Office of Economic Development reports that Tesla continues to meet overall objectives as set forth in 2014. Employment was annualized from 2018 to reach full capacity by 2024 of their original contracted amount of 6,500 employees.

2.) Housing prices were reviewed for Clark and Washoe Counties for how they compare to the U.S. (Zillow.com Market Overviews). The baseline forecast has a 2017 relative housing price for Clark County of 0.82 and Washoe County of 1.06 of the national housing price. The estimate that was derived using Zillow and Census tenure data indicates that the relative housing prices might be 1.07 for Clark County and 1.43 for Washoe County. The REMI housing and land price variable was adjusted for 2018 and 2019 to reflect these relative price levels as a one-time shock to the two counties. While there are a number of things that could be impacting migration, the 2017 One Year ACS from the Census Bureau reported 18,418 out-of-state immigrants to Washoe County and 19,178 persons migrating out of state for a net loss of state-to-state migrants of 760 persons.

3.) The Northeastern Nevada Regional Development Authority and the Governors' Office of Economic Development provided information on probable mining projects for Elko, Eureka, Humboldt, Lander, Pershing and White Pine Counties. The employment from these projects appeared to be accounted for by the assumption that mining employment would not be falling below historic averages. The exception was Humboldt County, where 350 jobs were added above the baseline forecast to account for potential employment from the Barrick, Hycroft and Lithium Nevada projects. Employment was also added in for the Cyanco facility and an expansion of the Humboldt General Hospital.

Table 1 compares the projections for 2030 by the year that they were released. Since 2011, the projections have fluctuated between 3,200,000 and just over 3,380,000 statewide.

Table 1: Comparing Nevada's Annual Population Projections for 2030	
Year Projection Released	**Projection for 2030**
2011	3,363,704
2012	3,338,269
2013	3,222,107
2014	3,251,664
2015	3,204,979
2016	3,257,762
2017	3,240,017
2018	3,387,789

Table 2 compares the last year of the 2017 edition of the projections with the current 2018 projections for the same year by county. The last year of the 2017 projections was 2036, so that is used to compare the two projections for their long-term differences. Both go out 20 years, but this is the last year in common between the two. This provides a summary comparison of the two projections from the 2017 estimate and against each other.

Table 2: Comparison of Projections for 2036 from the final 2017 Projections and the 2018 Projections With Tesla, Housing Cost, and Mining Projects						
	2017 Estimate	**2017 Projection for 2036**	**2017 Projection for 2036 Less 2017 Estimate**	***2018 DRAFT Projection for 2036***	***2018 Projection for 2036 Less 2017 Estimate***	**Difference 2018 DRAFT Projection Less 2017 Projection For 2036**
Carson City	55,438	59,088	3,650	*63,034*	*7,596*	3,946
Churchill	25,387	28,376	2,989	*28,942*	*3,555*	566
Clark	2,193,818	2,398,987	205,169	*2,594,268*	*400,450*	195,281
Douglas	48,300	51,631	3,331	*51,497*	*3,197*	-134
Elko	53,287	58,648	5,361	*56,527*	*3,240*	-2,121
Esmeralda	970	1012	42	*941*	*-29*	-71
Eureka	1,932	2,599	667	*2,027*	*95*	-572

Table 2: Comparison of Projections for 2036 from the final 2017 Projections and the 2018 Projections With Tesla, Housing Cost, and Mining Projects						
	2017 Estimate	**2017 Projection for 2036**	**2017 Projection for 2036 Less 2017 Estimate**	***2018 DRAFT Projection for 2036***	***2018 Projection for 2036 Less 2017 Estimate***	**Difference 2018 DRAFT Projection Less 2017 Projection For 2036**
Humboldt	16,978	17,510	532	*17,466*	*488*	-44
Lander	6,200	6,649	449	*6,016*	*-184*	-633
Lincoln	5,170	4,249	-921	*4,340*	*-830*	91
Lyon	54,657	58,209	3,552	*55,961*	*1,304*	-2,248
Mineral	4,674	4,072	-602	*4,520*	*-154*	448
Nye	46,390	46,677	287	*50,763*	*4,373*	4,086
Pershing	6,743	6,549	-194	*6,318*	*-425*	-231
Storey	4,084	5,424	1,340	*5,730*	*1,646*	306
Washoe	451,923	526,949	75,026	*507,985*	*56,062*	-18,964
White Pine	10,705	10,375	-330	*10,831*	*126*	456
State Total	2,986,656	3,287,004	300,348	*3,467,166*	*480,510*	180,162

Tables 3 and 4 compare the 2017 (2.1) and 2018 (2.2) version of the models for the U.S. and Nevada.

Table 3. Comparison of the Historic and Projected Data for the United States for Selected Years from the 2017 (2.1) and the 2018 (2.2) REMI Models (Bold = Historic Data)				
United States	**Population (in Thousands)**		**Labor Force (in Thousands)**	
	2017 Model	**2018 Model**	**2017 Model**	**2018 Model**
2014	**318,907.41**	**318,563.47**	**156,231.01**	**156,021.79**
2015	**321,418.81**	**320,896.63**	**157,236.30**	**156,933.73**
2016	323,934.47	**323,127.50**	157,669.61	**158,730.28**
2017	326,466.51	*325,377.13*	159,070.40	159,384.53
2022	339,234.92	337,064.15	165,935.87	164,354.72
2027	351,748.25	348,958.55	171,310.28	169,548.64
2032	363,428.36	360,428.46	177,700.32	175,465.68
2036	371,864.71	368,853.67	183,088.31	180,453.76
	16.61%	15.79%	17.19%	15.66%
United States	**Total Employment (in Thousands)**		**Gross Domestic Product (in Billions of Fixed (2009) Dollars)**	
	2017 Model	**2018 Model**	**2017 Model**	**2018 Model**
2014	**186,168.11**	**186,354.80**	**$16,131.43**	**$16,014.21**
2015	**190,195.41**	**190,422.80**	**$16,583.56**	**$16,495.79**
2016	193,442.42	**193,668.39**	$16,885.08	**$16,793.73**
2017	196,478.56	196,796.50	$17,367.03	$17,182.37
2022	200,758.53	201,916.19	$19,054.47	$19,048.68
2027	204,121.46	199,391.28	$20,884.39	$20,635.85
2032	209,948.31	201,896.39	$23,137.31	$22,469.48
2036	213,869.11	206,612.68	$25,008.64	$24,063.22
	14.88%	10.87%	55.03%	50.26%

Table 4. Comparison of the Historic and Projected Data for Nevada for Selected Years from the 2017 (2.2) and the 2018 (2.2) REMI Models (Bold = Historic Data)				
Nevada	**Population (in Thousands)**		**Labor Force (in Thousands)**	
	2017 Model	**2018 Model**	**2017 Model**	**2018 Model**
2014	**2,838.28**	**2,833.01**	**1,401.79**	**1,395.36**
2015	**2,890.85**	**2,883.76**	**1,425.71**	**1,414.70**
2016	2,928.15	**2,940.06**	1,435.72	**1,427.08**
2017	2,959.80	*3,001.57*	1,454.51	1,441.43
2022	3,108.27	3,241.78	1,552.09	1,557.60
2027	3,184.75	3,352.24	1,589.02	1,603.77
2032	3,229.52	3,429.94	1,619.81	1,644.56
2036	3,260.07	3,480.38	1,645.88	1,679.57
	14.86%	22.85%	17.41%	20.37%
Nevada	**Total Employment (in Thousands)**		**Gross Domestic Product (in Billions of Fixed (2009) Dollars)**	
	2017 Model	**2018 Model**	**2017 Model**	**2018 Model**
2014	**1,609.87**	**1,611.52**	**$126.30**	**$125.59**
2015	**1,660.46**	**1,666.53**	**$129.38**	**$130.69**
2016	1,721.48	**1,714.09**	$134.40	**$131.97**
2017	1,780.04	1,773.89	$140.43	$136.77
2022	1,806.53	1,851.59	$154.08	$155.04
2027	1,812.87	1,803.21	$167.07	$165.75
2032	1,836.56	1,813.44	$182.47	$179.18
2036	1,852.21	1,844.31	$195.26	$190.48
	15.05%	14.45%	54.60%	51.67%

Tables 5 A and B show the population age distribution for four major age cohorts for historic data, near-term projections, and the projection for 2035. The population for Nevada in the 2017 DRAFT projection is smaller and slightly older. This is similar to the distribution of the labor force population for 2007 to 2016 discussed in a later section.

Table 5 A and B. Comparing Estimated Age Structure of Nevada's Population for Selected Years for the 2016 and 2017 Projections (Bold=Historic Data)						
Table 5A. Population (In Thousands) By Age For By Selected Cohorts 2017 (2.1) Model						
Age Group	2013	2014	2015	2016	2017	2035
0-14	**548.263**	**551.985**	**556.788**	558.568	560.03	537.425
15-24	**364.603**	**365.112**	**364.91**	362.457	360.967	360.107
25-64	**1496.676**	**1519.599**	**1547.065**	1563.333	1573.342	1592.761
Ages 65+	**380.825**	**401.585**	**422.081**	443.79	465.463	762.072
	2790.367	**2838.281**	**2890.844**	2928.148	2959.802	3252.365
Table 5A. Population (In Thousands) By Age For By Selected Cohorts 2018 (2.1) Model						
Age Group	**2013**	**2014**	**2015**	**2016**	2017	2035
0-14	**548.153**	**551.933**	**557.501**	**564.07**	573.207	586.991
15-24	**363.471**	**363.482**	**362.685**	**363.598**	367.412	391.902
25-64	**1494.206**	**1516.063**	**1541.853**	**1571.289**	1598.893	1731.956
Ages 65+	**380.634**	**401.535**	**421.72**	**441.1**	462.06	758.006
	2786.464	**2833.013**	**2883.758**	**2940.058**	3001.572	3468.855

Table 5 B. Comparing Estimated Age Structure of Nevada's Population for Selected Years for the 2016 and 2017 Projections (Bold=Historic Data)						
Table 5B. Percentage Age Distribution from 2017 (2.1) Model						
Age Group	**2013**	**2014**	**2015**	2016	2017	2035
0-14	**19.60%**	**19.40%**	**19.30%**	19.10%	18.90%	16.50%
15-24	**13.10%**	**12.90%**	**12.60%**	12.40%	12.20%	11.10%
25-64	**53.60%**	**53.50%**	**53.50%**	53.40%	53.20%	49.00%
Ages 65+	**13.60%**	**14.10%**	**14.60%**	15.20%	15.70%	23.40%
Table 5B. Percentage Age Distribution from 2018 (2.2) Model						
Age Group	**2013**	**2014**	**2015**	**2016**	2017	2035
0-14	**19.67%**	**19.48%**	**19.33%**	**19.19%**	**19.10%**	**16.92%**
15-24	**13.04%**	**12.83%**	**12.58%**	**12.37%**	**12.24%**	**11.30%**
25-64	**53.62%**	**53.51%**	**53.47%**	**53.44%**	**53.27%**	**49.93%**
Ages 65+	**13.66%**	**14.17%**	**14.62%**	**15.00%**	**15.39%**	**21.85%**

This concludes the Overview of National and Regional Data section. The following section discussed four main risks to the projections.

Risks to the Projections:

There are three areas of risk to the current projections that could slow Nevada's growth:

1.) Unsettled trends and policy in international migration could impact the projections. The Migration Policy Institute reports that while there was an increase in total migration from 2014 to 2015, the migrant population has been made up of fewer migrants from Mexico, and India and China are now the largest countries of origin. This could lead to new settlement patterns from the immigrant population. Also, with Nevada's sizable unauthorized population, efforts at deportation may lead to a loss of population and lower employment both due to a loss of employees as well as consumer spending. Most recently the Reforming American Immigration for Strong Employment Act or the RAISE Act would limit legal immigration to half of current levels.

2.) Potential impacts from automation could pose a risk to employment over time. A study from the University of Redlands has estimated that up to 65 percent of the jobs in Clark County are at risk of being automated. This is based on work by Frey and Osborne that looked at the likelihood of occupation being automated in total or in part based on the skill set for the occupation. Arntz and Zierahn, in a paper for the Organization for Economic Cooperation and Development, found that up to 9 percent of jobs could be automated for most developed economies. There is no clear consensus on the timing or full impact of automation in the literature.

3.) Climate change could have mixed impacts on Nevada's growth. For instance, work by Matthew Hauer examines sea level rise and potential migration impacts given historic migration trends and found that population would increase for Nevada. In contrast, works by David Albouy (Climate Amenities, Climate Change, and American Quality of Life) and Solomon Hsiang (Estimating economic damage from climate change in the United States) look not at migration impacts but at the economic impact. In the work by Hsiang, the impacts vary by county and some parts of Nevada could benefit and some could be negatively impacted.

2018 Population Projections for Nevada's Counties 2018 to 2037
Based On 2017 Estimate: Includes Tesla as Separate Impact

With Addtional Factors: Tesla, Housing Prices, and Mining Projects	Carson City W/ Additional Factors			Churchill W/ Additional Factors		
	Total Population	Change Previous Year	Percentage Change	Total Population	Change Previous Year	Percentage Change
2017	55,438			25,387		
2018	55,945	507	0.9%	25,816	429	1.7%
2019	56,437	491	0.9%	26,257	442	1.7%
2020	56,891	454	0.8%	26,551	293	1.1%
2021	57,276	385	0.7%	26,780	230	0.9%
2022	57,647	371	0.6%	26,973	193	0.7%
2023	57,988	342	0.6%	27,145	172	0.6%
2024	58,296	308	0.5%	27,301	156	0.6%
2025	58,554	258	0.4%	27,446	145	0.5%
2026	58,792	238	0.4%	27,587	141	0.5%
2027	59,018	227	0.4%	27,731	144	0.5%
2028	59,341	323	0.5%	27,875	144	0.5%
2029	59,717	376	0.6%	28,024	149	0.5%
2030	60,133	416	0.7%	28,169	145	0.5%
2031	60,587	454	0.8%	28,303	134	0.5%
2032	61,069	482	0.8%	28,429	126	0.4%
2033	61,569	499	0.8%	28,549	120	0.4%
2034	62,071	502	0.8%	28,681	132	0.5%
2035	62,561	490	0.8%	28,811	130	0.5%
2036	63,034	473	0.8%	28,942	130	0.5%
2037	63,494	460	0.7%	29,072	130	0.5%

Baseline Without Tesla and Current Housing Costs	Carson City			Churchill		
	Total Population	Change Previous Year	Percentage Change	Total Population	Change Previous Year	Percentage Change
2017	55,438			25,387		
2018	55,974	536	1.0%	25,802	415	1.6%
2019	56,463	488	0.9%	26,229	427	1.7%
2020	56,865	402	0.7%	26,519	290	1.1%
2021	57,186	322	0.6%	26,740	221	0.8%
2022	57,479	293	0.5%	26,921	181	0.7%
2023	57,727	248	0.4%	27,078	157	0.6%
2024	57,929	203	0.4%	27,214	137	0.5%
2025	58,103	173	0.3%	27,345	130	0.5%
2026	58,271	168	0.3%	27,474	129	0.5%
2027	58,444	172	0.3%	27,610	136	0.5%
2028	58,745	302	0.5%	27,748	138	0.5%
2029	59,099	354	0.6%	27,894	146	0.5%
2030	59,493	394	0.7%	28,036	142	0.5%
2031	59,923	430	0.7%	28,169	134	0.5%
2032	60,382	458	0.8%	28,295	125	0.4%
2033	60,858	476	0.8%	28,413	118	0.4%
2034	61,339	481	0.8%	28,541	128	0.5%
2035	61,808	469	0.8%	28,671	130	0.5%
2036	62,261	453	0.7%	28,800	128	0.4%
2037	62,702	441	0.7%	28,929	129	0.4%

2018 Population Projections for Nevada's Counties 2018 to 2037
Based On 2017 Estimate: Includes Tesla as Separate Impact

With Addtional Factors: Tesla, Housing Prices, and Mining Projects	Clark W/ Additional Factors Total Population	Clark W/ Additional Factors Change Previous Year	Clark W/ Additional Factors Percentage Change	Douglas W/ Additional Factors Total Population	Douglas W/ Additional Factors Change Previous Year	Douglas W/ Additional Factors Percentage Change
2017	2,193,818			48,300		
2018	2,232,175	38,357	1.7%	48,915	615	1.3%
2019	2,266,702	34,528	1.5%	49,463	548	1.1%
2020	2,322,042	55,339	2.4%	49,848	385	0.8%
2021	2,369,947	47,906	2.1%	50,169	321	0.6%
2022	2,395,751	25,804	1.1%	50,432	263	0.5%
2023	2,418,693	22,942	1.0%	50,649	216	0.4%
2024	2,438,177	19,483	0.8%	50,824	176	0.3%
2025	2,455,416	17,239	0.7%	50,948	124	0.2%
2026	2,471,509	16,093	0.7%	51,044	96	0.2%
2027	2,486,720	15,211	0.6%	51,137	93	0.2%
2028	2,500,778	14,058	0.6%	51,213	77	0.2%
2029	2,514,516	13,739	0.5%	51,293	80	0.2%
2030	2,527,826	13,309	0.5%	51,360	67	0.1%
2031	2,540,589	12,763	0.5%	51,424	64	0.1%
2032	2,552,576	11,987	0.5%	51,473	49	0.1%
2033	2,563,927	11,351	0.4%	51,511	38	0.1%
2034	2,574,614	10,687	0.4%	51,529	18	0.0%
2035	2,584,759	10,145	0.4%	51,529	0	0.0%
2036	2,594,268	9,509	0.4%	51,497	-32	-0.1%
2037	2,603,007	8,739	0.3%	51,437	-60	-0.1%

Baseline Without Tesla and Current Housing Costs	Clark Total Population	Clark Change Previous Year	Clark Percentage Change	Douglas Total Population	Douglas Change Previous Year	Douglas Percentage Change
2017	2,193,818			48,300		
2018	2,245,141	51,323	2.3%	48,853	553	1.1%
2019	2,291,026	45,885	2.0%	49,348	496	1.0%
2020	2,343,694	52,668	2.3%	49,742	394	0.8%
2021	2,389,438	45,745	2.0%	50,051	309	0.6%
2022	2,413,347	23,909	1.0%	50,293	241	0.5%
2023	2,434,702	21,355	0.9%	50,477	185	0.4%
2024	2,452,824	18,122	0.7%	50,615	138	0.3%
2025	2,468,896	16,072	0.7%	50,707	92	0.2%
2026	2,483,993	15,097	0.6%	50,778	72	0.1%
2027	2,498,339	14,346	0.6%	50,854	76	0.1%
2028	2,511,642	13,304	0.5%	50,920	66	0.1%
2029	2,524,715	13,073	0.5%	50,992	72	0.1%
2030	2,537,432	12,717	0.5%	51,054	62	0.1%
2031	2,549,659	12,227	0.5%	51,115	61	0.1%
2032	2,561,153	11,494	0.5%	51,160	46	0.1%
2033	2,572,042	10,888	0.4%	51,194	34	0.1%
2034	2,582,271	10,230	0.4%	51,210	16	0.0%
2035	2,591,965	9,694	0.4%	51,207	-3	0.0%
2036	2,601,048	9,083	0.4%	51,172	-35	-0.1%
2037	2,609,390	8,342	0.3%	51,112	-61	-0.1%

2018 Population Projections for Nevada's Counties 2018 to 2037
Based On 2017 Estimate: Includes Tesla as Separate Impact

With Addtional Factors: Tesla, Housing Prices, and Mining Projects	Elko W/ Additional Factors Total Population	Change Previous Year	Percentage Change	Esmeralda W/ Additional Factors Total Population	Change Previous Year	Percentage Change
2017	53,287			970		
2018	53,646	359	0.7%	968	-2	-0.3%
2019	54,144	498	0.9%	964	-4	-0.4%
2020	54,468	325	0.6%	959	-5	-0.5%
2021	54,783	314	0.6%	955	-4	-0.4%
2022	55,083	300	0.5%	949	-6	-0.7%
2023	55,421	338	0.6%	941	-7	-0.8%
2024	55,694	274	0.5%	931	-10	-1.1%
2025	55,874	180	0.3%	922	-10	-1.1%
2026	56,007	132	0.2%	915	-6	-0.7%
2027	56,102	96	0.2%	915	0	0.0%
2028	56,160	58	0.1%	919	4	0.4%
2029	56,216	56	0.1%	922	2	0.3%
2030	56,253	37	0.1%	925	4	0.4%
2031	56,277	24	0.0%	928	2	0.3%
2032	56,315	38	0.1%	934	6	0.7%
2033	56,370	55	0.1%	936	2	0.3%
2034	56,425	55	0.1%	938	1	0.1%
2035	56,476	51	0.1%	939	1	0.1%
2036	56,527	51	0.1%	941	2	0.3%
2037	56,568	42	0.1%	943	1	0.1%

Baseline Without Tesla and Current Housing Costs	Elko Total Population	Change Previous Year	Percentage Change	Esmeralda Total Population	Change Previous Year	Percentage Change
2017	53,287			970		
2018	53,540	253	0.5%	966	-4	-0.4%
2019	53,744	203	0.4%	961	-5	-0.5%
2020	53,815	71	0.1%	956	-5	-0.5%
2021	53,777	-38	-0.1%	953	-4	-0.4%
2022	53,668	-110	-0.2%	948	-5	-0.5%
2023	53,551	-117	-0.2%	940	-7	-0.8%
2024	53,448	-103	-0.2%	930	-10	-1.1%
2025	53,329	-119	-0.2%	920	-10	-1.1%
2026	53,228	-101	-0.2%	914	-6	-0.7%
2027	53,145	-83	-0.2%	914	0	0.0%
2028	53,064	-80	-0.2%	918	4	0.4%
2029	53,020	-44	-0.1%	920	2	0.3%
2030	52,987	-34	-0.1%	924	4	0.4%
2031	52,961	-25	0.0%	927	2	0.3%
2032	52,964	3	0.0%	933	6	0.7%
2033	52,999	35	0.1%	936	4	0.4%
2034	53,043	44	0.1%	938	1	0.1%
2035	53,094	51	0.1%	939	1	0.1%
2036	53,153	59	0.1%	940	1	0.1%
2037	53,210	57	0.1%	941	1	0.1%

2018 Population Projections for Nevada's Counties 2018 to 2037
Based On 2017 Estimate: Includes Tesla as Separate Impact

With Addtional Factors: Tesla, Housing Prices, and Mining Projects	Eureka W/ Additional Factors			Humboldt W/ Additional Factors		
	Total Population	Change Previous Year	Percentage Change	Total Population	Change Previous Year	Percentage Change
2017	1,932			16,978		
2018	1,844	-88	-4.5%	16,899	-79	-0.5%
2019	1,759	-86	-4.6%	16,926	26	0.2%
2020	1,788	29	1.7%	16,911	-14	-0.1%
2021	1,798	10	0.6%	16,888	-23	-0.1%
2022	1,809	10	0.6%	16,924	35	0.2%
2023	1,824	16	0.9%	17,012	89	0.5%
2024	1,837	13	0.7%	17,082	70	0.4%
2025	1,847	10	0.6%	17,141	59	0.3%
2026	1,861	14	0.7%	17,187	45	0.3%
2027	1,875	14	0.7%	17,214	27	0.2%
2028	1,891	17	0.9%	17,223	9	0.1%
2029	1,909	18	0.9%	17,242	19	0.1%
2030	1,930	21	1.1%	17,269	27	0.2%
2031	1,946	16	0.8%	17,299	30	0.2%
2032	1,959	14	0.7%	17,333	33	0.2%
2033	1,974	15	0.7%	17,370	37	0.2%
2034	1,992	18	0.9%	17,402	32	0.2%
2035	2,010	19	0.9%	17,435	33	0.2%
2036	2,027	17	0.8%	17,466	30	0.2%
2037	2,043	16	0.8%	17,492	26	0.1%

Baseline Without Tesla and Current Housing Costs	Eureka			Humboldt		
	Total Population	Change Previous Year	Percentage Change	Total Population	Change Previous Year	Percentage Change
2017	1,932			16,978		
2018	1,894	-38	-1.9%	16,891	-87	-0.5%
2019	1,864	-30	-1.6%	16,818	-74	-0.4%
2020	1,846	-18	-1.0%	16,729	-89	-0.5%
2021	1,836	-10	-0.6%	16,640	-89	-0.5%
2022	1,832	-4	-0.2%	16,543	-98	-0.6%
2023	1,838	6	0.3%	16,449	-94	-0.6%
2024	1,846	8	0.5%	16,364	-85	-0.5%
2025	1,857	10	0.6%	16,293	-72	-0.4%
2026	1,875	18	1.0%	16,228	-64	-0.4%
2027	1,896	22	1.2%	16,164	-64	-0.4%
2028	1,922	25	1.3%	16,099	-64	-0.4%
2029	1,950	28	1.5%	16,058	-41	-0.3%
2030	1,980	30	1.6%	16,038	-20	-0.1%
2031	2,005	25	1.3%	16,030	-8	-0.1%
2032	2,028	23	1.1%	16,032	2	0.0%
2033	2,052	24	1.2%	16,046	14	0.1%
2034	2,077	25	1.2%	16,060	14	0.1%
2035	2,103	26	1.3%	16,081	21	0.1%
2036	2,126	23	1.1%	16,101	20	0.1%
2037	2,146	20	0.9%	16,121	19	0.1%

2018 Population Projections for Nevada's Counties 2018 to 2037
Based On 2017 Estimate: Includes Tesla as Separate Impact

With Addtional Factors: Tesla, Housing Prices, and Mining Projects	Lander W/ Additional Factors Total Population	Lander Change Previous Year	Lander Percentage Change	Lincoln W/ Additional Factors Total Population	Lincoln Change Previous Year	Lincoln Percentage Change
2017	6,200			5,170		
2018	6,120	-80	-1.3%	5,078	-92	-1.8%
2019	6,073	-48	-0.8%	4,996	-83	-1.6%
2020	6,050	-22	-0.4%	4,921	-74	-1.5%
2021	6,029	-21	-0.3%	4,847	-74	-1.5%
2022	6,016	-13	-0.2%	4,773	-74	-1.5%
2023	6,012	-4	-0.1%	4,708	-65	-1.4%
2024	6,005	-7	-0.1%	4,638	-70	-1.5%
2025	5,994	-11	-0.2%	4,572	-67	-1.4%
2026	5,975	-19	-0.3%	4,508	-64	-1.4%
2027	5,956	-19	-0.3%	4,454	-54	-1.2%
2028	5,938	-19	-0.3%	4,418	-36	-0.8%
2029	5,928	-10	-0.2%	4,392	-26	-0.6%
2030	5,931	3	0.1%	4,388	-4	-0.1%
2031	5,936	6	0.1%	4,369	-19	-0.4%
2032	5,950	13	0.2%	4,370	1	0.0%
2033	5,964	14	0.2%	4,356	-14	-0.3%
2034	5,980	15	0.3%	4,346	-10	-0.2%
2035	5,997	18	0.3%	4,345	-1	0.0%
2036	6,016	19	0.3%	4,340	-5	-0.1%
2037	6,030	14	0.2%	4,334	-5	-0.1%

Baseline Without Tesla and Current Housing Costs	Lander Total Population	Lander Change Previous Year	Lander Percentage Change	Lincoln Total Population	Lincoln Change Previous Year	Lincoln Percentage Change
2017	6,200			5,170		
2018	6,151	-49	-0.8%	5,080	-90	-1.7%
2019	6,108	-43	-0.7%	5,001	-79	-1.6%
2020	6,048	-60	-1.0%	4,926	-75	-1.5%
2021	5,990	-59	-1.0%	4,851	-74	-1.5%
2022	5,933	-56	-0.9%	4,776	-75	-1.6%
2023	5,884	-49	-0.8%	4,711	-65	-1.4%
2024	5,841	-43	-0.7%	4,642	-70	-1.5%
2025	5,805	-37	-0.6%	4,574	-68	-1.5%
2026	5,767	-38	-0.6%	4,510	-64	-1.4%
2027	5,733	-34	-0.6%	4,456	-54	-1.2%
2028	5,705	-28	-0.5%	4,420	-36	-0.8%
2029	5,690	-15	-0.3%	4,394	-26	-0.6%
2030	5,688	-1	0.0%	4,389	-5	-0.1%
2031	5,692	3	0.1%	4,371	-18	-0.4%
2032	5,703	11	0.2%	4,372	1	0.0%
2033	5,716	13	0.2%	4,357	-15	-0.3%
2034	5,731	14	0.3%	4,347	-10	-0.2%
2035	5,749	19	0.3%	4,346	-1	0.0%
2036	5,768	19	0.3%	4,341	-5	-0.1%
2037	5,784	15	0.3%	4,335	-5	-0.1%

2018 Population Projections for Nevada's Counties 2018 to 2037
Based On 2017 Estimate: Includes Tesla as Separate Impact

With Addtional Factors: Tesla, Housing Prices, and Mining Projects	Lyon W/ Additional Factors Total Population	Change Previous Year	Percentage Change	Mineral W/ Additional Factors Total Population	Change Previous Year	Percentage Change
2017	54,657			4,674		
2018	55,426	769	1.4%	4,612	-62	-1.3%
2019	56,054	628	1.1%	4,569	-43	-0.9%
2020	56,324	270	0.5%	4,534	-34	-0.8%
2021	56,582	258	0.5%	4,508	-27	-0.6%
2022	56,779	198	0.3%	4,494	-14	-0.3%
2023	56,903	123	0.2%	4,486	-8	-0.2%
2024	56,984	81	0.1%	4,489	3	0.1%
2025	57,003	19	0.0%	4,497	8	0.2%
2026	56,970	-34	-0.1%	4,505	9	0.2%
2027	56,900	-70	-0.1%	4,511	5	0.1%
2028	56,816	-83	-0.1%	4,511	0	0.0%
2029	56,723	-93	-0.2%	4,513	2	0.0%
2030	56,618	-105	-0.2%	4,514	1	0.0%
2031	56,530	-89	-0.2%	4,514	0	0.0%
2032	56,430	-100	-0.2%	4,514	0	0.0%
2033	56,318	-112	-0.2%	4,520	6	0.1%
2034	56,203	-115	-0.2%	4,522	1	0.0%
2035	56,087	-116	-0.2%	4,523	1	0.0%
2036	55,961	-126	-0.2%	4,520	-2	0.0%
2037	55,815	-146	-0.3%	4,519	-1	0.0%

Baseline Without Tesla and Current Housing Costs	Lyon Total Population	Change Previous Year	Percentage Change	Mineral Total Population	Change Previous Year	Percentage Change
2017	54,657			4,674		
2018	55,177	519	1.0%	4,611	-63	-1.4%
2019	55,581	404	0.7%	4,567	-44	-1.0%
2020	55,874	293	0.5%	4,533	-33	-0.7%
2021	56,071	197	0.4%	4,505	-28	-0.6%
2022	56,165	95	0.2%	4,490	-15	-0.3%
2023	56,157	-8	0.0%	4,482	-9	-0.2%
2024	56,086	-71	-0.1%	4,484	2	0.0%
2025	55,986	-100	-0.2%	4,491	8	0.2%
2026	55,858	-128	-0.2%	4,498	6	0.1%
2027	55,715	-143	-0.3%	4,503	5	0.1%
2028	55,577	-138	-0.2%	4,503	0	0.0%
2029	55,440	-136	-0.2%	4,505	2	0.0%
2030	55,303	-137	-0.2%	4,505	0	0.0%
2031	55,188	-115	-0.2%	4,505	0	0.0%
2032	55,064	-124	-0.2%	4,505	0	0.0%
2033	54,930	-133	-0.2%	4,512	6	0.1%
2034	54,797	-133	-0.2%	4,513	1	0.0%
2035	54,665	-132	-0.2%	4,514	1	0.0%
2036	54,525	-139	-0.3%	4,512	-2	0.0%
2037	54,369	-156	-0.3%	4,511	-1	0.0%

2018 Population Projections for Nevada's Counties 2018 to 2037
Based On 2017 Estimate: Includes Tesla as Separate Impact

With Addtional Factors: Tesla, Housing Prices, and Mining Projects	Nye W/ Additional Factors Total Population	Change Previous Year	Percentage Change	Pershing W/ Additional Factors Total Population	Change Previous Year	Percentage Change
2017	46,390			6,743		
2018	46,900	510	1.1%	6,654	-88	-1.3%
2019	47,359	458	1.0%	6,632	-22	-0.3%
2020	47,679	320	0.7%	6,591	-41	-0.6%
2021	47,987	308	0.6%	6,559	-33	-0.5%
2022	48,229	242	0.5%	6,527	-32	-0.5%
2023	48,437	207	0.4%	6,498	-29	-0.5%
2024	48,630	194	0.4%	6,479	-19	-0.3%
2025	48,840	209	0.4%	6,462	-17	-0.3%
2026	49,040	200	0.4%	6,440	-22	-0.3%
2027	49,244	204	0.4%	6,423	-17	-0.3%
2028	49,444	200	0.4%	6,404	-19	-0.3%
2029	49,635	191	0.4%	6,387	-17	-0.3%
2030	49,809	173	0.3%	6,373	-14	-0.2%
2031	49,972	164	0.3%	6,369	-4	-0.1%
2032	50,121	149	0.3%	6,356	-13	-0.2%
2033	50,260	139	0.3%	6,344	-13	-0.2%
2034	50,418	157	0.3%	6,334	-9	-0.1%
2035	50,588	170	0.3%	6,326	-8	-0.1%
2036	50,763	175	0.3%	6,318	-8	-0.1%
2037	50,948	185	0.4%	6,311	-6	-0.1%

Baseline Without Tesla and Current Housing Costs	Nye Total Population	Change Previous Year	Percentage Change	Pershing Total Population	Change Previous Year	Percentage Change
2017	46,390			6,743		
2018	46,788	398	0.9%	6,642	-101	-1.5%
2019	47,167	380	0.8%	6,551	-91	-1.4%
2020	47,534	367	0.8%	6,465	-86	-1.3%
2021	47,867	333	0.7%	6,389	-76	-1.2%
2022	48,125	258	0.5%	6,314	-75	-1.2%
2023	48,344	219	0.5%	6,255	-59	-0.9%
2024	48,545	201	0.4%	6,223	-33	-0.5%
2025	48,760	215	0.4%	6,207	-16	-0.3%
2026	48,962	202	0.4%	6,199	-8	-0.1%
2027	49,171	208	0.4%	6,207	8	0.1%
2028	49,373	202	0.4%	6,222	15	0.2%
2029	49,567	195	0.4%	6,243	21	0.3%
2030	49,743	175	0.4%	6,269	26	0.4%
2031	49,910	167	0.3%	6,309	40	0.6%
2032	50,062	152	0.3%	6,341	32	0.5%
2033	50,203	141	0.3%	6,370	29	0.5%
2034	50,363	160	0.3%	6,401	31	0.5%
2035	50,535	172	0.3%	6,432	32	0.5%
2036	50,712	178	0.4%	6,463	31	0.5%
2037	50,900	187	0.4%	6,493	31	0.5%

2018 Population Projections for Nevada's Counties 2018 to 2037
Based On 2017 Estimate: Includes Tesla as Separate Impact

With Addtional Factors: Tesla, Housing Prices, and Mining Projects	Storey W/ Additional Factors			Washoe W/ Additional Factors		
	Total Population	Change Previous Year	Percentage Change	Total Population	Change Previous Year	Percentage Change
2017	4,084			451,923		
2018	4,126	42	1.0%	456,038	4,115	0.9%
2019	4,196	70	1.7%	460,391	4,353	1.0%
2020	4,408	212	5.0%	467,763	7,371	1.6%
2021	4,578	171	3.9%	473,991	6,228	1.3%
2022	4,730	152	3.3%	479,259	5,268	1.1%
2023	4,863	134	2.8%	483,747	4,488	0.9%
2024	4,985	121	2.5%	487,555	3,808	0.8%
2025	5,096	112	2.2%	490,457	2,901	0.6%
2026	5,199	103	2.0%	492,868	2,411	0.5%
2027	5,297	98	1.9%	494,966	2,098	0.4%
2028	5,382	85	1.6%	496,668	1,703	0.3%
2029	5,459	77	1.4%	498,290	1,622	0.3%
2030	5,523	64	1.2%	499,810	1,519	0.3%
2031	5,577	53	1.0%	501,309	1,500	0.3%
2032	5,625	49	0.9%	502,759	1,450	0.3%
2033	5,667	42	0.7%	504,145	1,386	0.3%
2034	5,700	32	0.6%	505,497	1,352	0.3%
2035	5,721	21	0.4%	506,795	1,298	0.3%
2036	5,730	10	0.2%	507,985	1,190	0.2%
2037	5,732	2	0.0%	509,084	1,099	0.2%

Baseline Without Tesla and Current Housing Costs	Storey			Washoe		
	Total Population	Change Previous Year	Percentage Change	Total Population	Change Previous Year	Percentage Change
2017	4,084			451,923		
2018	4,285	200	4.9%	459,608	7,685	1.7%
2019	4,475	191	4.5%	466,758	7,150	1.6%
2020	4,638	163	3.6%	472,862	6,104	1.3%
2021	4,783	145	3.1%	477,826	4,964	1.0%
2022	4,915	132	2.8%	481,732	3,906	0.8%
2023	5,031	116	2.4%	484,795	3,063	0.6%
2024	5,136	105	2.1%	487,149	2,354	0.5%
2025	5,231	94	1.8%	488,884	1,735	0.4%
2026	5,316	86	1.6%	490,359	1,474	0.3%
2027	5,397	80	1.5%	491,721	1,362	0.3%
2028	5,465	69	1.3%	492,854	1,133	0.2%
2029	5,524	59	1.1%	494,045	1,191	0.2%
2030	5,572	48	0.9%	495,234	1,189	0.2%
2031	5,611	39	0.7%	496,458	1,224	0.2%
2032	5,641	30	0.5%	497,658	1,200	0.2%
2033	5,663	22	0.4%	498,814	1,156	0.2%
2034	5,676	13	0.2%	499,941	1,127	0.2%
2035	5,681	5	0.1%	501,023	1,082	0.2%
2036	5,680	-1	0.0%	502,028	1,005	0.2%
2037	5,673	-7	-0.1%	502,968	940	0.2%

2018 Population Projections for Nevada's Counties 2018 to 2037
Based On 2017 Estimate: Includes Tesla as Separate Impact

With Addtional Factors: Tesla, Housing Prices, and Mining Projects	White Pine W/ Additional Factors			State Total W/ Additional Factors		
	Total Population	Change Previous Year	Percentage Change	Total Population	Change Previous Year	Percentage Change
2017	10,705			2,986,656		
2018	10,756	51	0.5%	3,031,920	45,263	1.5%
2019	10,786	30	0.3%	3,073,706	41,786	1.4%
2020	10,796	10	0.1%	3,138,523	64,817	2.1%
2021	10,906	111	1.0%	3,194,584	56,060	1.8%
2022	10,979	72	0.7%	3,227,353	32,770	1.0%
2023	11,016	38	0.3%	3,256,344	28,991	0.9%
2024	11,040	23	0.2%	3,280,948	24,603	0.8%
2025	11,046	7	0.1%	3,302,114	21,167	0.6%
2026	11,033	-13	-0.1%	3,321,438	19,324	0.6%
2027	11,018	-14	-0.1%	3,339,480	18,042	0.5%
2028	10,997	-21	-0.2%	3,355,978	16,498	0.5%
2029	10,979	-19	-0.2%	3,372,146	16,168	0.5%
2030	10,957	-21	-0.2%	3,387,789	15,643	0.5%
2031	10,933	-24	-0.2%	3,402,863	15,074	0.4%
2032	10,908	-26	-0.2%	3,417,122	14,259	0.4%
2033	10,891	-17	-0.2%	3,430,673	13,551	0.4%
2034	10,871	-20	-0.2%	3,443,520	12,848	0.4%
2035	10,853	-18	-0.2%	3,455,755	12,234	0.4%
2036	10,831	-22	-0.2%	3,467,166	11,411	0.3%
2037	10,816	-16	-0.1%	3,477,647	10,481	0.3%

Baseline Without Tesla and Current Housing Costs	White Pine			State Total		
	Total Population	Change Previous Year	Percentage Change	Total Population	Change Previous Year	Percentage Change
2017	10,705			2,986,656		
2018	10,761	57	0.5%	3,048,165	61,509	2.1%
2019	10,796	34	0.3%	3,103,457	55,292	1.8%
2020	10,803	8	0.1%	3,163,850	60,394	1.9%
2021	10,800	-3	0.0%	3,215,705	51,855	1.6%
2022	10,777	-23	-0.2%	3,244,258	28,553	0.9%
2023	10,737	-40	-0.4%	3,269,159	24,901	0.8%
2024	10,697	-40	-0.4%	3,289,975	20,816	0.6%
2025	10,656	-41	-0.4%	3,308,043	18,068	0.5%
2026	10,605	-51	-0.5%	3,324,835	16,792	0.5%
2027	10,559	-45	-0.4%	3,340,827	15,992	0.5%
2028	10,515	-44	-0.4%	3,355,692	14,865	0.4%
2029	10,479	-37	-0.3%	3,370,536	14,844	0.4%
2030	10,443	-35	-0.3%	3,385,091	14,555	0.4%
2031	10,408	-35	-0.3%	3,399,241	14,150	0.4%
2032	10,373	-34	-0.3%	3,412,666	13,424	0.4%
2033	10,349	-24	-0.2%	3,425,454	12,789	0.4%
2034	10,323	-26	-0.2%	3,437,570	12,116	0.4%
2035	10,300	-23	-0.2%	3,449,114	11,544	0.3%
2036	10,275	-26	-0.2%	3,459,905	10,791	0.3%
2037	10,256	-19	-0.2%	3,469,840	9,934	0.3%

2018 Population Projections for Nevada's Counties 2018 to 2037
Based On 2017 Estimate: Includes Tesla as Separate Impact

With Addtional Factors: Tesla, Housing Prices, and Mining Projects	Reno Carson City Fernley Combined Statistical Area W/ Additional Factors		
	Total Population	Change Previous Year	Percentage Change
2017	614,403		
2018	620,451	6,048	1.0%
2019	626,541	6,090	1.0%
2020	635,233	8,692	1.4%
2021	642,596	7,363	1.2%
2022	648,847	6,251	1.0%
2023	654,150	5,303	0.8%
2024	658,644	4,494	0.7%
2025	662,058	3,414	0.5%
2026	664,872	2,814	0.4%
2027	667,317	2,445	0.4%
2028	669,421	2,104	0.3%
2029	671,483	2,063	0.3%
2030	673,444	1,961	0.3%
2031	675,427	1,983	0.3%
2032	677,357	1,930	0.3%
2033	679,210	1,853	0.3%
2034	680,999	1,789	0.3%
2035	682,692	1,693	0.2%
2036	684,207	1,515	0.2%
2037	685,562	1,355	0.2%

Baseline Without Tesla and Current Housing Costs	Reno Carson City Fernley Combined Statistical Area Baseline		
	Total Population	Change Previous Year	Percentage Change
2017	614,403		
2018	623,896	9,493	1.5%
2019	632,625	8,729	1.4%
2020	639,981	7,356	1.2%
2021	645,917	5,936	0.9%
2022	650,584	4,667	0.7%
2023	654,187	3,604	0.6%
2024	656,916	2,728	0.4%
2025	658,911	1,995	0.3%
2026	660,583	1,672	0.3%
2027	662,131	1,548	0.2%
2028	663,562	1,431	0.2%
2029	665,101	1,539	0.2%
2030	666,656	1,555	0.2%
2031	668,295	1,639	0.2%
2032	669,905	1,609	0.2%
2033	671,459	1,554	0.2%
2034	672,963	1,504	0.2%
2035	674,384	1,421	0.2%
2036	675,667	1,283	0.2%
2037	676,824	1,158	0.2%

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NEVADA STATE DEMOGRAPHER
INTERCENSAL POPULATION ESTIMATES

Year	State of Nevada	Clark County
2012	2,750,217	1,988,195
2011	2,721,794	1,967,722
2010	2,705,845	1,959,491
2009	2,677,392	1,933,315
2008	2,641,105	1,898,119
2007	2,582,561	1,847,087
2006	2,504,473	1,783,781
2005	2,418,460	1,715,052
2004	2,334,015	1,650,234
2003	2,243,124	1,577,154
2002	2,169,896	1,516,805
2001	2,098,632	1,457,233
2000	2,023,378	1,394,440
1999	1,946,366	1,327,145
1998	1,870,881	1,261,150

Notes: 2011 and 2012 are post censal estimates; 1986 through 2010 are intercensal estimates produced by the Nevada State Demographer's

LF-5

Governor Certified Population Estimates of Nevada's Counties, Cities and Towns 2010 to 2016

Estimates from NV State Demographer, NV Department of Taxation

	April 1 2000	JULY 1 2000	Percent Change 4/00 - 7/01	Percent Change 7/00 - 7/01	JULY 1 2001	Percent Change 7/01 - 7/02	JULY 1 2002	Percent Change 7/02 - 7/03	JULY 1 2003	Percent Change 7/03 - 7/04
State of Nevada	1,998,257	2,066,831	6.7%	3.2%	2,132,498	3.4%	2,206,022	4.1%	2,296,566	5.0%
Counties										
Cities										
Towns										
Carson City	52,457	53,095	3.3%	2.0%	54,171	1.2%	54,844	0.7%	55,220	1.7%
Churchill County	23,982	26,247	3.9%	-5.0%	24,928	0.8%	25,116	2.8%	25,808	1.2%
Fallon	7,536	8,386	8.3%	-2.7%	8,162	0.2%	8,178	1.5%	8,301	1.2%
Clark County	1,375,765	1,425,723	8.0%	4.2%	1,485,855	4.3%	1,549,657	4.6%	1,620,748	5.8%
Boulder City	14,966	15,519	-1.4%	-4.9%	14,760	0.6%	14,842	0.6%	14,934	0.8%
Henderson	175,381	198,691	12.2%	-1.0%	196,780	6.5%	209,486	3.8%	217,448	5.8%
Las Vegas	478,434	483,448	5.2%	4.1%	503,188	2.3%	514,640	2.7%	528,617	4.0%
Mesquite	9,389	15,605	27.2%	-23.5%	11,940	10.7%	13,216	5.1%	13,895	14.3%
North Las Vegas	115,488	124,936	10.7%	2.4%	127,897	6.3%	135,967	7.4%	146,005	13.0%
Bunkerville	877	909	30.8%	26.2%	1,147	2.9%	1,180	-1.3%	1,165	1.7%
Enterprise	21,138	21,905	60.9%	55.3%	34,017	35.8%	46,193	34.2%	62,001	27.9%
Indian Springs	1,339	1,387	9.9%	6.1%	1,471	5.8%	1,557	4.0%	1,619	2.6%
Laughlin	7,800	8,083	-20.8%	-23.5%	6,181	3.6%	6,403	8.6%	6,952	16.6%
Moapa	711	736	30.1%	25.5%	925	16.3%	1,076	26.8%	1,364	-12.0%
Moapa Valley	8,770	9,088	-35.3%	-37.6%	5,672	10.7%	6,277	0.7%	6,323	3.6%
Mt. Charleston	885	917	-10.5%	-13.6%	792	7.7%	853	2.3%	873	2.4%
Paradise	166,260	172,297	11.2%	7.3%	184,870	1.6%	187,746	-1.3%	185,304	1.9%
Searchlight	741	767	-0.7%	-4.2%	735	11.7%	822	30.6%	1,073	3.1%
Spring Valley	125,607	130,168	6.3%	2.5%	133,469	4.4%	139,290	8.0%	150,402	7.2%
Summerlin	4,675	4,845	64.9%	59.1%	7,708	58.8%	12,239	33.2%	16,300	9.5%
Sunrise Manor	154,616	160,231	11.4%	7.5%	172,237	2.5%	176,587	2.7%	181,354	1.9%
Whitney	14,422	14,946	17.2%	13.1%	16,899	12.3%	18,979	8.8%	20,640	5.3%
Winchester	29,658	30,735	17.2%	13.1%	34,767	-2.2%	33,994	1.1%	34,378	-1.3%

Note: This series represents the estimates as certified by NV's Governor each year. It is not a time series reflecting Census 2010.

Governor Certified Population Estimates of Nevada's Counties, Cities and Towns 2010 to 2016

Estimates from NV State Demographer, NV Department of Taxation

	JULY 1 2004	Percent Change 7/04 - 7/05	JULY 1 2005	Percent Change 7/05 - 7/06	JULY 1 2006	Percent Change 7/06 - 7/07	JULY 1 2007	Percent Change 7/07 - 7/08	JULY 1 2008	Percent Change 7/08 - 7/09
State of Nevada	2,410,768	4.5%	2,518,869	4.1%	2,623,050	3.6%	2,718,337	0.8%	2,738,733	-1.0%
Counties										
Cities										
Towns										
Carson City	56,146	1.7%	57,104	1.0%	57,701	0.0%	57,723	-0.2%	57,600	-1.9%
Churchill County	26,106	1.8%	26,585	3.0%	27,371	-0.7%	27,190	-0.8%	26,981	-0.5%
Fallon	8,398	-0.7%	8,339	-0.5%	8,299	1.8%	8,452	9.5%	9,258	-1.6%
Clark County	1,715,337	4.7%	1,796,380	4.4%	1,874,837	4.2%	1,954,319	0.7%	1,967,716	-0.8%
Boulder City	15,058	1.0%	15,203	1.8%	15,478	2.5%	15,863	5.2%	16,684	-3.7%
Henderson	229,984	4.8%	241,134	4.2%	251,321	3.5%	260,161	3.6%	269,538	-0.7%
Las Vegas	549,571	3.7%	569,838	1.8%	579,840	1.8%	590,321	0.5%	593,528	-0.4%
Mesquite	15,881	3.4%	16,423	7.5%	17,656	6.4%	18,787	5.1%	19,754	4.7%
North Las Vegas	164,971	9.2%	180,219	10.2%	198,516	6.0%	210,472	2.0%	214,661	0.2%
Bunkerville	1,185	1.1%	1,198	-1.6%	1,179	6.5%	1,255	-7.6%	1,160	5.3%
Enterprise	79,299	20.3%	95,377	24.9%	119,100	20.8%	143,917	4.0%	149,713	0.5%
Indian Springs	1,661	1.1%	1,679	13.6%	1,907	-13.0%	1,659	-10.3%	1,488	-2.8%
Laughlin	8,105	1.5%	8,226	2.8%	8,458	4.1%	8,807	-0.5%	8,761	-9.7%
Moapa	1,200	5.1%	1,261	-20.5%	1,003	19.7%	1,201	-16.9%	998	5.4%
Moapa Valley	6,549	2.7%	6,726	1.8%	6,845	18.1%	8,085	-11.8%	7,134	1.9%
Mt. Charleston	894	-1.7%	879	-8.3%	806	46.4%	1,179	-5.2%	1,118	-5.0%
Paradise	188,768	1.5%	191,650	-2.8%	186,370	-0.2%	185,935	-2.0%	182,264	-1.8%
Searchlight	1,106	-1.6%	1,088	-29.8%	764	4.4%	798	-6.1%	750	-4.2%
Spring Valley	161,286	2.5%	165,335	4.1%	172,110	2.7%	176,815	0.1%	176,910	-1.4%
Summerlin	17,841	13.5%	20,256	7.1%	21,692	21.8%	26,415	6.0%	27,992	1.2%
Sunrise Manor	184,801	0.9%	186,511	2.9%	191,858	0.1%	191,966	-3.2%	185,745	-3.2%
Whitney	21,738	24.9%	27,155	22.1%	33,144	9.2%	36,182	0.0%	36,164	4.2%
Winchester	33,917	3.8%	35,208	-0.9%	34,874	7.7%	37,561	-1.1%	37,141	-5.1%

Note: This series represents the estimates as certified by NV's Governor each year. It is not a time series reflecting Census 2010.

Governor Certified Population Estimates of Nevada's Counties, Cities and Towns 2010 to 2016

Estimates from NV State Demographer, NV Department of Taxation

	JULY 1 2009	Percent Change 7/09 - 7/10	April 1 2010	JULY 1 2010	Percent Change 4/10 - 7/11	Percent Change 7/10 - 7/11	JULY 1 2011	Percent Change 7/11 - 7/12	JULY 1 2012	Percent Change 7/12 - 7/13
State of Nevada	2,711,206	0.5%	2,700,551	2,724,634	0.8%	-0.1%	2,721,794	1.0%	2,750,217	1.8%
Counties										
Cities										
Towns										
Carson City	56,506	-1.2%	55,274	55,850	1.4%	0.4%	56,066	-1.1%	55,441	-1.4%
Churchill County	26,859	-1.9%	24,877	26,360	1.0%	-4.6%	25,136	0.4%	25,238	0.3%
Fallon	9,113	-2.3%	8,606	8,903	0.0%	-3.3%	8,609	1.1%	8,706	0.0%
Clark County	1,952,040	0.9%	1,951,269	1,968,831	0.8%	-0.1%	1,967,722	1.0%	1,988,195	2.2%
Boulder City	16,064	-4.4%	15,023	15,359	2.1%	-0.2%	15,335	2.8%	15,759	-0.8%
Henderson	267,687	-0.2%	257,729	267,270	2.8%	-0.9%	264,839	0.8%	266,846	2.8%
Las Vegas	591,422	-0.8%	583,756	586,536	0.8%	0.3%	588,274	0.1%	589,156	1.6%
Mesquite	20,677	-1.1%	15,276	20,440	11.5%	-16.6%	17,038	-1.5%	16,778	4.2%
North Las Vegas	215,022	1.1%	216,961	217,482	3.2%	2.9%	223,873	-0.8%	222,009	1.9%
Bunkerville	1,222	2.7%	1,256	1,255	-4.5%	-4.5%	1,199	-9.6%	1,084	-1.5%
Enterprise	150,473	9.8%	165,435	165,285	-2.9%	-2.8%	160,632	1.4%	162,872	4.8%
Indian Springs	1,447	-6.3%	1,357	1,356	-13.9%	-13.8%	1,169	2.0%	1,192	0.9%
Laughlin	7,914	-0.6%	7,874	7,867	-9.0%	-8.9%	7,166	17.4%	8,414	5.0%
Moapa	1,052	0.8%	1,061	1,060	31.0%	31.1%	1,390	-21.8%	1,086	0.7%
Moapa Valley	7,269	3.1%	7,503	7,496	1.9%	2.0%	7,647	-10.2%	6,868	0.0%
Mt. Charleston	1,061	0.6%	1,069	1,068	-38.7%	-38.7%	655	-1.3%	647	0.7%
Paradise	178,974	3.5%	185,472	185,304	-2.1%	-2.0%	181,635	1.7%	184,745	1.7%
Searchlight	718	3.4%	744	743	-23.2%	-23.1%	571	-30.7%	395	0.3%
Spring Valley	174,458	1.3%	176,872	176,712	-2.5%	-2.4%	172,483	7.2%	184,910	2.1%
Summerlin	28,342	4.7%	29,694	29,667	-15.3%	-15.3%	25,141	0.5%	25,260	6.3%
Sunrise Manor	179,808	-2.6%	175,365	175,206	8.9%	9.0%	191,007	2.9%	196,570	1.6%
Whitney	37,690	-0.2%	37,637	37,603	3.9%	4.0%	39,122	-0.5%	38,910	2.4%
Winchester	35,235	-0.3%	35,174	35,142	-5.2%	-5.2%	33,329	-5.1%	31,634	1.0%

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Governor Certified Population Estimates of Nevada's Counties, Cities and Towns 2010 to 2016

Estimates from NV State Demographer, NV Department of Taxation

	JULY 1 2013	Percent Change 7/13 - 7/14	JULY 1 2014	Percent Change 7/14 - 7/15	JULY 1 2015	Percent Change 7/15 - 7/16	JULY 1 2016	Percent Change 7/16 - 7/17	JULY 1 2017
State of Nevada	2,800,967	1.5%	2,843,301	1.9%	2,897,584	1.9%	2,953,375	1.1%	2,985,723
Counties									
Cities									
Towns									
Carson City	54,668	-1.3%	53,969	0.6%	54,273	1.7%	55,182	-0.1%	55,150
Churchill County	25,322	-0.9%	25,103	0.1%	25,126	0.6%	25,266	0.1%	25,293
Fallon	8,706	-0.7%	8,645	1.4%	8,770	1.2%	8,874	0.8%	8,945
Clark County	2,031,723	1.9%	2,069,450	2.4%	2,118,353	2.3%	2,166,181	1.3%	2,193,818
Boulder City	15,635	0.0%	15,627	1.2%	15,813	3.1%	16,298	-1.1%	16,121
Henderson	274,270	2.4%	280,928	2.5%	287,828	2.3%	294,359	2.2%	300,709
Las Vegas	598,520	2.0%	610,637	1.7%	620,935	1.4%	629,649	0.5%	633,028
Mesquite	17,477	4.5%	18,262	4.4%	19,061	4.9%	19,991	4.2%	20,838
North Las Vegas	226,199	1.9%	230,491	2.1%	235,395	2.3%	240,708	1.1%	243,339
Bunkerville	1,067	-2.7%	1,039	5.7%	1,097	-0.1%	1,096	-5.0%	1,042
Enterprise	170,699	2.0%	174,064	5.6%	183,755	2.6%	188,503	2.7%	193,572
Indian Springs	1,203	1.4%	1,220	1.2%	1,235	1.9%	1,259	0.4%	1,264
Laughlin	8,835	1.4%	8,963	2.5%	9,186	2.1%	9,380	3.1%	9,672
Moapa	1,094	23.6%	1,352	0.8%	1,363	0.6%	1,370	-25.1%	1,026
Moapa Valley	6,871	-0.3%	6,851	0.3%	6,875	1.3%	6,967	2.1%	7,115
Mt. Charleston	651	-2.5%	635	2.9%	653	1.8%	665	0.2%	666
Paradise	187,949	1.6%	191,047	0.9%	192,810	-0.6%	191,705	1.0%	193,712
Searchlight	397	-13.2%	344	0.8%	347	2.6%	356	2.0%	364
Spring Valley	188,818	1.3%	191,342	3.5%	197,958	6.7%	211,232	2.4%	216,228
Summerlin	26,855	1.4%	27,244	3.9%	28,300	6.1%	30,013	1.6%	30,492
Sunrise Manor	199,754	1.5%	202,710	2.0%	206,720	1.6%	209,932	0.1%	210,216
Whitney	39,857	1.8%	40,567	2.7%	41,662	5.9%	44,110	0.8%	44,449
Winchester	31,960	1.4%	32,413	1.1%	32,770	0.6%	32,972	0.3%	33,065

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Governor Certified Population Estimates of Nevada's Counties, Cities and Towns 2010 to 2016

Estimates from NV State Demographer, NV Department of Taxation

	April 1 2000	JULY 1 2000	Percent Change 4/00 - 7/01	Percent Change 7/00 - 7/01	JULY 1 2001	Percent Change 7/01 - 7/02	JULY 1 2002	Percent Change 7/02 - 7/03	JULY 1 2003	Percent Change 7/03 - 7/04
State of Nevada	1,998,257	2,066,831	6.7%	3.2%	2,132,498	3.4%	2,206,022	4.1%	2,296,566	5.0%
Counties										
Cities										
Towns										
Douglas County	41,259	43,101	5.3%	0.8%	43,450	1.8%	44,212	3.1%	45,603	4.8%
Gardnerville	3,377	3,528	14.0%	9.2%	3,851	5.6%	4,065	6.2%	4,316	17.4%
Genoa	235	245	-4.5%	-8.6%	224	1.3%	227	1.0%	229	6.6%
Minden	2,697	2,818	6.1%	1.5%	2,861	-1.1%	2,830	1.4%	2,870	2.6%
Elko County	45,291	50,756	3.0%	-8.1%	46,668	-0.2%	46,577	-1.7%	45,805	1.5%
Carlin	2,161	2,395	2.5%	-7.5%	2,215	-6.4%	2,074	-1.4%	2,045	9.6%
Elko	16,708	18,642	2.3%	-8.3%	17,093	-2.4%	16,690	-2.0%	16,354	4.8%
Wells	1,346	1,563	-11.5%	-23.8%	1,191	16.6%	1,389	-1.1%	1,373	2.4%
West Wendover	4,721	3,867	-2.3%	19.3%	4,614	4.9%	4,839	-2.2%	4,732	2.1%
Jackpot	1,178	1,310	9.3%	-1.7%	1,287	0.1%	1,288	-1.3%	1,271	0.8%
Montello	191	216	-5.1%	-16.3%	181	0.0%	181	0.0%	181	-1.1%
Mountain City	135	150	-2.6%	-12.4%	132	-4.0%	127	-1.6%	125	-1.3%
Esmeralda County	971	1,513	6.9%	-31.4%	1,038	8.4%	1,125	-0.8%	1,116	5.3%
Goldfield	369	574	35.0%	-13.4%	498	-11.9%	438	0.2%	439	3.1%
Silver Peak	148	230	9.8%	-29.6%	162	-20.9%	128	-3.5%	124	2.4%
Eureka County	1,651	1,847	-8.8%	-18.5%	1,506	-8.1%	1,384	2.6%	1,420	4.4%
Crescent Valley	330	369	-9.7%	-19.3%	298	-6.3%	279	7.4%	300	1.4%
Eureka (town)	499	558	-5.8%	-15.8%	470	-7.8%	434	2.9%	446	1.7%
Humboldt County	16,106	18,149	0.4%	-10.9%	16,164	0.9%	16,308	0.9%	16,457	1.4%
Winnemucca	*7,174*	8,884	-2.4%	-21.2%	7,001	3.3%	7,234	0.6%	7,280	-0.4%

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Governor Certified Population Estimates of Nevada's Counties, Cities and Towns 2010 to 2016

Estimates from NV State Demographer, NV Department of Taxation

	JULY 1 2004	Percent Change 7/04 - 7/05	JULY 1 2005	Percent Change 7/05 - 7/06	JULY 1 2006	Percent Change 7/06 - 7/07	JULY 1 2007	Percent Change 7/07 - 7/08	JULY 1 2008	Percent Change 7/08 - 7/09
State of Nevada	2,410,768	4.5%	2,518,869	4.1%	2,623,050	3.6%	2,718,337	0.8%	2,738,733	-1.0%
Counties										
Cities										
Towns										
Douglas County	47,803	4.8%	50,108	3.3%	51,770	1.2%	52,386	-0.5%	52,131	-1.4%
Gardnerville	5,067	1.9%	5,165	7.4%	5,550	-2.8%	5,394	0.3%	5,412	-3.0%
Genoa	244	1.4%	248	1.6%	252	0.2%	252	1.3%	255	0.2%
Minden	2,945	1.3%	2,983	8.4%	3,234	0.2%	3,239	0.7%	3,261	-1.0%
Elko County	46,499	2.3%	47,586	1.6%	48,339	4.3%	50,434	0.3%	50,561	1.5%
Carlin	2,240	1.0%	2,261	0.9%	2,281	0.6%	2,295	1.2%	2,322	1.0%
Elko	17,140	4.1%	17,850	1.9%	18,183	1.3%	18,427	0.0%	18,424	0.0%
Wells	1,406	1.2%	1,423	1.9%	1,449	4.0%	1,508	1.1%	1,524	-0.6%
West Wendover	4,830	0.4%	4,848	0.5%	4,871	1.8%	4,958	0.6%	4,990	-0.9%
Jackpot	1,281	-0.6%	1,273	1.6%	1,293	-5.9%	1,217	0.4%	1,222	-3.1%
Montello	179	1.2%	181	-3.7%	175	-5.7%	165	0.4%	165	1.3%
Mountain City	123	-1.8%	121	3.1%	125	3.5%	129	0.9%	130	-7.0%
Esmeralda County	1,176	8.5%	1,276	-1.1%	1,262	-2.1%	1,236	0.3%	1,240	-4.3%
Goldfield	453	-3.3%	438	-1.7%	430	4.2%	448	-7.5%	415	6.4%
Silver Peak	127	-0.9%	126	-7.1%	117	6.9%	125	45.9%	182	-22.7%
Eureka County	1,484	0.1%	1,485	-1.7%	1,460	-0.1%	1,458	6.5%	1,553	0.6%
Crescent Valley	304	2.2%	311	-5.9%	292	-1.2%	289	-2.2%	283	0.2%
Eureka (town)	454	-2.9%	440	-1.7%	433	-0.4%	431	9.6%	473	2.1%
Humboldt County	16,692	3.6%	17,293	2.6%	17,751	1.7%	18,052	-0.2%	18,014	-1.8%
Winnemucca	7,249	2.1%	7,401	3.3%	7,643	0.0%	7,646	0.2%	7,659	-0.9%

Note: This series represents the estimates as certified by NV's Governor each year. It is not a time series reflecting Census 2010.

Governor Certified Population Estimates of Nevada's Counties, Cities and Towns 2010 to 2016

Estimates from NV State Demographer, NV Department of Taxation

	JULY 1 2009	Percent Change 7/09 - 7/10	April 1 2010	JULY 1 2010	Percent Change 4/10 - 7/11	Percent Change 7/10 - 7/11	JULY 1 2011	Percent Change 7/11 - 7/12	JULY 1 2012	Percent Change 7/12 - 7/13
State of Nevada	2,711,206	0.5%	2,700,551	2,724,634	0.8%	-0.1%	2,721,794	1.0%	2,750,217	1.8%
Counties										
Cities										
Towns										
Douglas County	51,390	-4.2%	46,997	49,242	1.4%	-3.2%	47,661	0.7%	48,015	1.0%
Gardnerville	5,250	-5.1%	4,756	4,983	15.0%	9.8%	5,469	0.5%	5,495	0.8%
Genoa	256	-4.7%	233	244	-7.2%	-11.5%	216	1.3%	219	0.6%
Minden	3,229	-0.5%	3,067	3,213	-2.7%	-7.1%	2,984	0.9%	3,010	-0.6%
Elko County	51,325	1.5%	48,818	52,097	2.1%	-4.3%	49,861	3.8%	51,771	3.1%
Carlin	2,345	1.1%	2,368	2,370	0.3%	0.3%	2,376	0.0%	2,376	20.0%
Elko	18,428	2.2%	18,297	18,842	5.0%	1.9%	19,209	6.2%	20,406	2.7%
Wells	1,515	1.1%	1,292	1,531	-9.1%	-23.3%	1,174	9.0%	1,280	2.1%
West Wendover	4,945	1.1%	4,410	4,999	1.4%	-10.6%	4,470	-2.3%	4,367	2.0%
Jackpot	1,184	1.1%	1,103	1,197	-12.7%	-19.5%	963	-5.1%	914	1.0%
Montello	167	1.0%	156	169	-49.3%	-53.3%	79	-23.5%	60	-0.3%
Mountain City	121	0.9%	112	122	-9.3%	-16.4%	102	7.4%	110	-0.7%
Esmeralda County	1,187	-3.5%	783	1,145	5.4%	-27.9%	825	4.3%	860	-0.2%
Goldfield	441	-9.4%	274	400	5.3%	-28.0%	288	-9.9%	259	12.8%
Silver Peak	141	-8.3%	88	129	32.6%	-9.3%	117	9.4%	128	3.4%
Eureka County	1,562	3.0%	1,987	1,609	0.4%	23.9%	1,994	0.8%	2,011	0.7%
Crescent Valley	283	4.5%	366	296	8.3%	33.8%	396	-6.5%	370	0.2%
Eureka (town)	483	3.3%	616	499	-0.8%	22.4%	611	17.3%	717	0.4%
Humboldt County	17,690	3.8%	16,528	18,364	3.7%	-6.7%	17,135	1.5%	17,384	0.4%
Winnemucca	7,593	4.8%	7,396	7,961	6.0%	-1.5%	7,839	2.0%	7,997	2.4%

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Governor Certified Population Estimates of Nevada's Counties, Cities and Towns 2010 to 2016

Estimates from NV State Demographer, NV Department of Taxation

	JULY 1 2013	Percent Change 7/13 - 7/14	JULY 1 2014	Percent Change 7/14 - 7/15	JULY 1 2015	Percent Change 7/15 - 7/16	JULY 1 2016	Percent Change 7/16 - 7/17	JULY 1 2017
State of Nevada	2,800,967	1.5%	2,843,301	1.9%	2,897,584	1.9%	2,953,375	1.1%	2,985,723
Counties									
Cities									
Towns									
Douglas County	48,478	0.2%	48,553	-0.7%	48,223	0.0%	48,235	0.1%	48,300
Gardnerville	5,541	4.0%	5,760	-0.2%	5,751	0.5%	5,780	-1.5%	5,693
Genoa	220	-1.5%	217	-1.1%	215	-0.5%	213	0.0%	213
Minden	2,993	2.7%	3,072	0.0%	3,072	1.2%	3,110	2.6%	3,191
Elko County	53,384	0.0%	53,358	0.4%	53,551	0.8%	53,997	-1.3%	53,287
Carlin	2,851	-4.2%	2,731	-0.1%	2,727	-1.6%	2,684	-2.5%	2,617
Elko	20,958	-0.4%	20,865	-0.7%	20,714	0.0%	20,704	0.4%	20,789
Wells	1,307	8.0%	1,411	-2.8%	1,371	1.3%	1,388	-5.5%	1,312
West Wendover	4,453	-0.7%	4,420	1.3%	4,478	-0.1%	4,474	-6.1%	4,201
Jackpot	923	-1.8%	907	-1.0%	898	0.0%	897	-4.2%	860
Montello	60	-6.3%	56	-0.9%	56	11.6%	62	0.6%	63
Mountain City	109	-1.6%	107	-7.0%	100	-4.1%	95	-8.4%	87
Esmeralda County	858	7.9%	926	-0.4%	923	4.5%	964	0.6%	970
Goldfield	293	-7.2%	272	-3.7%	262	-0.6%	260	1.2%	263
Silver Peak	132	-3.2%	128	4.0%	133	-7.6%	123	-1.1%	122
Eureka County	2,024	-6.0%	1,903	-2.2%	1,862	5.2%	1,959	-1.4%	1,932
Crescent Valley	371	0.8%	374	0.0%	374	-0.5%	372	2.0%	380
Eureka (town)	720	-3.9%	691	0.8%	697	5.1%	732	-4.3%	701
Humboldt County	17,457	-0.4%	17,388	-1.9%	17,057	-1.2%	16,853	0.7%	16,978
Winnemucca	8,185	-1.8%	8,042	-3.0%	7,802	-0.4%	7,772	2.3%	7,947

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Governor Certified Population Estimates of Nevada's Counties, Cities and Towns 2010 to 2016

Estimates from NV State Demographer, NV Department of Taxation

	April 1 2000	JULY 1 2000	Percent Change 4/00 - 7/01	Percent Change 7/00 - 7/01	JULY 1 2001	Percent Change 7/01 - 7/02	JULY 1 2002	Percent Change 7/02 - 7/03	JULY 1 2003	Percent Change 7/03 - 7/04
State of Nevada	1,998,257	2,066,831	6.7%	3.2%	2,132,498	3.4%	2,206,022	4.1%	2,296,566	5.0%
Counties										
Cities										
Towns										
Lander County	5,794	6,822	-0.6%	-15.5%	5,761	-3.7%	5,547	-4.9%	5,277	1.5%
Austin	305	359	2.3%	-13.1%	312	-5.5%	295	-8.0%	271	8.1%
Battle Mountain	3,453	4,066	-11.5%	-24.8%	3,056	-9.3%	2,770	-5.3%	2,623	0.9%
Kingston	219	258	25.6%	6.7%	275	-6.9%	256	5.7%	271	-11.7%
Lincoln County	4,165	4,420	-7.3%	-12.7%	3,861	0.5%	3,879	-3.3%	3,749	1.9%
Caliente	1,123	1,132	13.6%	12.7%	1,276	-17.0%	1,058	11.8%	1,184	-14.4%
Alamo	478	507	-23.2%	-27.7%	367	20.6%	442	-3.1%	428	3.1%
Panaca	632	671	-12.8%	-17.8%	552	2.2%	564	-4.0%	541	2.1%
Pioche	840	892	-25.3%	-29.6%	628	8.3%	680	-3.0%	659	1.5%
Lyon County	34,501	37,393	8.2%	-0.2%	37,329	3.9%	38,777	6.4%	41,244	8.2%
Fernley	8,830	9,570	7.9%	-0.4%	9,529	9.6%	10,440	12.2%	11,718	17.6%
Yerington	2,883	3,210	0.2%	-10.0%	2,889	-1.0%	2,859	1.5%	2,902	0.3%
Mineral County	5,071	6,270	-6.5%	-24.3%	4,743	-1.0%	4,695	-0.2%	4,687	-0.3%
Hawthorne	3,134	3,875	-3.8%	-22.2%	3,013	-0.6%	2,995	0.0%	2,995	-0.9%
Luning	86	106	3.8%	-16.1%	89	4.4%	93	-1.3%	91	5.6%
Mina	307	380	-1.8%	-20.6%	302	-5.7%	284	-2.2%	278	6.8%
Walker Lake	333	412	-1.0%	-19.9%	330	-1.5%	325	-2.1%	318	0.0%

Note: This series represents the estimates as certified by NV's Governor each year. It is not a time series reflecting Census 2010.

Governor Certified Population Estimates of Nevada's Counties, Cities and Towns 2010 to 2016

Estimates from NV State Demographer, NV Department of Taxation

	JULY 1 2004	Percent Change 7/04 - 7/05	JULY 1 2005	Percent Change 7/05 - 7/06	JULY 1 2006	Percent Change 7/06 - 7/07	JULY 1 2007	Percent Change 7/07 - 7/08	JULY 1 2008	Percent Change 7/08 - 7/09
State of Nevada	2,410,768	4.5%	2,518,869	4.1%	2,623,050	3.6%	2,718,337	0.8%	2,738,733	-1.0%
Counties										
Cities										
Towns										
Lander County	5,357	2.8%	5,509	2.7%	5,655	1.6%	5,747	2.5%	5,891	1.9%
Austin	293	-1.6%	288	-0.3%	287	-4.4%	275	12.4%	309	-1.7%
Battle Mountain	2,645	1.8%	2,692	1.8%	2,740	3.8%	2,845	2.7%	2,922	1.5%
Kingston	239	20.5%	288	6.3%	306	1.0%	309	3.5%	320	3.3%
Lincoln County	3,822	1.7%	3,886	2.6%	3,987	5.0%	4,184	4.0%	4,352	-0.8%
Caliente	1,014	0.2%	1,015	-1.4%	1,002	8.7%	1,089	-1.1%	1,077	2.7%
Alamo	441	-2.9%	428	0.7%	432	-1.0%	427	8.5%	464	-1.9%
Panaca	552	1.8%	562	-0.7%	558	6.7%	**595**	8.4%	645	2.1%
Pioche	669	4.3%	698	0.7%	703	12.6%	791	-0.7%	785	6.6%
Lyon County	44,646	9.4%	48,860	10.6%	54,031	3.5%	55,903	-0.1%	55,820	-3.6%
Fernley	13,775	18.7%	16,357	15.2%	18,850	3.9%	19,585	0.1%	19,609	-3.5%
Yerington	2,912	2.3%	2,980	9.3%	3,257	1.9%	3,319	0.2%	3,324	-5.6%
Mineral County	4,673	-0.9%	4,629	-5.0%	4,399	-0.5%	4,377	0.6%	4,401	1.7%
Hawthorne	2,968	-0.4%	2,956	-0.9%	2,931	1.0%	2,960	0.3%	2,970	1.9%
Luning	97	-9.5%	87	-7.0%	81	-2.4%	79	0.6%	80	-1.4%
Mina	297	-7.0%	276	-21.2%	218	-5.9%	205	1.4%	207	-0.2%
Walker Lake	318	-2.5%	310	2.9%	319	-6.2%	299	1.8%	305	3.8%

Note: This series represents the estimates as certified by NV's Governor each year. It is not a time series reflecting Census 2010.

Governor Certified Population Estimates of Nevada's Counties, Cities and Towns 2010 to 2016

Estimates from NV State Demographer, NV Department of Taxation

	JULY 1 2009	Percent Change 7/09 - 7/10	April 1 2010	JULY 1 2010	Percent Change 4/10 - 7/11	Percent Change 7/10 - 7/11	JULY 1 2011	Percent Change 7/11 - 7/12	JULY 1 2012	Percent Change 7/12 - 7/13
State of Nevada	2,711,206	0.5%	2,700,551	2,724,634	0.8%	-0.1%	2,721,794	1.0%	2,750,217	1.8%
Counties										
Cities										
Towns										
Lander County	6,003	-0.2%	5,775	5,992	3.7%	-0.1%	5,988	3.9%	6,221	2.0%
Austin	304	2.8%	301	312	-43.1%	-45.2%	171	1.0%	173	-2.2%
Battle Mountain	2,967	-1.5%	2,816	2,922	18.1%	13.8%	3,326	2.9%	3,421	6.9%
Kingston	331	-0.8%	316	328	-60.5%	-61.9%	125	-0.9%	124	0.1%
Lincoln County	4,317	7.3%	5,345	4,631	-1.1%	14.1%	5,284	-3.5%	5,100	-1.6%
Caliente	1,106	3.5%	1,130	1,144	-7.3%	-8.5%	1,047	4.0%	1,089	-1.9%
Alamo	455	10.6%	608	503	3.1%	24.7%	627	-7.0%	583	0.0%
Panaca	659	-5.0%	757	626	3.2%	24.8%	781	6.5%	832	-2.5%
Pioche	837	0.3%	1,014	839	-8.0%	11.2%	933	-13.2%	810	-2.5%
Lyon County	53,825	-2.8%	51,980	52,334	0.9%	0.2%	52,443	-0.4%	52,245	1.4%
Fernley	18,929	-2.6%	19,368	18,434	-2.4%	2.5%	18,896	-0.3%	18,831	0.8%
Yerington	3,138	-3.3%	3,048	3,034	3.8%	4.3%	3,165	-2.3%	3,094	0.4%
Mineral County	4,474	-0.1%	4,772	4,471	-3.6%	2.9%	4,601	1.7%	4,679	-0.4%
Hawthorne	3,028	5.5%	3,409	3,194	-11.8%	-5.8%	3,008	2.6%	3,086	-0.3%
Luning	79	-0.8%	83	78	5.7%	12.8%	88	12.3%	99	1.0%
Mina	207	-14.1%	190	178	-32.1%	-27.5%	129	25.3%	162	0.9%
Walker Lake	316	0.6%	339	318	-9.5%	-3.5%	307	13.7%	349	-0.7%

Note: This series represents the estimates as certified by NV's Governor each year. It is not a time series reflecting Census 2010.

Governor Certified Population Estimates of Nevada's Counties, Cities and Towns 2010 to 2016

Estimates from NV State Demographer, NV Department of Taxation

	JULY 1 2013	Percent Change 7/13 - 7/14	JULY 1 2014	Percent Change 7/14 - 7/15	JULY 1 2015	Percent Change 7/15 - 7/16	JULY 1 2016	Percent Change 7/16 - 7/17	JULY 1 2017
State of Nevada	2,800,967	1.5%	2,843,301	1.9%	2,897,584	1.9%	2,953,375	1.1%	2,985,723
Counties									
Cities									
Towns									
Lander County	6,343	3.4%	6,560	-4.8%	6,247	0.2%	6,257	-0.9%	6,200
Austin	169	0.7%	170	-2.6%	166	0.3%	166	0.0%	166
Battle Mountain	3,657	4.0%	3,804	-6.1%	3,573	-0.4%	3,559	-2.4%	3,473
Kingston	124	2.9%	128	-5.9%	120	13.3%	136	-9.5%	123
Lincoln County	5,020	-0.3%	5,004	1.7%	5,088	-0.6%	5,057	2.2%	5,170
Caliente	1,068	-1.1%	1,056	-0.7%	1,049	-1.7%	1,031	3.4%	1,066
Alamo	583	-0.9%	578	0.3%	580	13.8%	660	2.0%	673
Panaca	811	-1.7%	797	-1.8%	783	1.9%	798	-0.2%	797
Pioche	790	-0.7%	784	-5.1%	744	3.9%	773	1.4%	784
Lyon County	52,960	0.7%	53,344	-0.1%	53,277	0.7%	53,644	1.9%	54,657
Fernley	18,987	0.5%	19,077	-0.7%	18,936	0.6%	19,042	1.4%	19,300
Yerington	3,106	-0.4%	3,095	3.1%	3,191	-0.9%	3,162	1.3%	3,202
Mineral County	4,662	-1.7%	4,584	-1.0%	4,539	0.9%	4,578	2.1%	4,674
Hawthorne	3,076	-1.7%	3,023	0.4%	3,035	-5.5%	2,868	6.9%	3,066
Luning	100	-1.8%	98	3.1%	101	22.1%	123	-15.2%	105
Mina	163	-1.6%	160	-4.9%	153	13.6%	173	-0.2%	173
Walker Lake	346	-5.0%	329	14.7%	378	6.8%	403	-20.1%	322

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Governor Certified Population Estimates of Nevada's Counties, Cities and Towns 2010 to 2016

Estimates from NV State Demographer, NV Department of Taxation

	April 1 2000	JULY 1 2000	Percent Change 4/00 - 7/01	Percent Change 7/00 - 7/01	JULY 1 2001	Percent Change 7/01 - 7/02	JULY 1 2002	Percent Change 7/02 - 7/03	JULY 1 2003	Percent Change 7/03 - 7/04
State of Nevada	1,998,257	2,066,831	6.7%	3.2%	2,132,498	3.4%	2,206,022	4.1%	2,296,566	5.0%
Counties										
Cities										
Towns										
Nye County	32,485	35,924	5.8%	-4.3%	34,384	1.9%	35,039	4.6%	36,651	4.2%
Amargosa	1,165	1,271	0.0%	-8.4%	1,164	0.6%	1,171	-0.2%	1,169	3.6%
Beatty	1,150	1,255	-4.0%	-12.0%	1,104	-1.3%	1,089	-0.9%	1,079	-9.1%
Gabbs	318	459	5.0%	-27.3%	334	-4.3%	320	-1.9%	314	0.9%
Manhattan	123	135	-0.7%	-9.2%	123	-0.7%	122	10.7%	135	-4.8%
Pahrump	24,181	26,399	9.5%	0.3%	26,470	4.0%	27,527	4.8%	28,847	5.6%
Round Mountain	1,036	1,131	-16.7%	-23.7%	864	-9.8%	779	0.7%	784	-2.1%
Tonopah	2,827	3,086	-1.7%	-9.9%	2,779	-12.9%	2,422	2.4%	2,481	-5.6%
Pershing County	6,693	7,458	2.7%	-7.8%	6,873	0.9%	6,937	0.4%	6,967	-4.8%
Lovelock	2,003	2,772	7.0%	-22.6%	2,144	5.7%	2,267	6.1%	2,405	-1.0%
Imlay	234	261	4.3%	-6.4%	244	-1.4%	241	-1.1%	238	-5.4%
Storey County	3,399	3,897	9.3%	-4.7%	3,714	-2.0%	3,639	2.7%	3,736	1.6%
Gold Hill	169	194	5.2%	-8.2%	178	-3.3%	172	4.2%	180	5.4%
Virginia City	892	1,023	2.1%	-10.9%	911	-3.1%	882	2.4%	904	-1.8%
Washoe County	339,486	333,566	4.1%	5.9%	353,271	1.7%	359,423	3.8%	373,233	2.7%
Reno	180,480	182,818	3.5%	2.2%	186,883	0.5%	187,834	4.2%	195,727	1.8%
Sparks	66,346	66,420	8.2%	8.0%	71,753	4.9%	75,255	4.2%	78,435	4.1%
White Pine County	9,181	10,650	-4.3%	-17.5%	8,783	0.9%	8,863	-0.2%	8,842	1.4%
Ely	4,041	5,118	-8.6%	-27.8%	3,695	5.2%	3,886	-1.5%	3,829	3.5%
Lund	161	187	-9.3%	-21.8%	146	0.2%	146	0.5%	147	0.0%
McGill	1,184	1,374	-10.6%	-22.9%	1,059	1.1%	1,071	-0.4%	1,066	1.2%
Ruth	404	469	-9.5%	-22.0%	366	1.9%	373	-0.3%	372	1.9%

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Governor Certified Population Estimates of Nevada's Counties, Cities and Towns 2010 to 2016

Estimates from NV State Demographer, NV Department of Taxation

	JULY 1 2004	Percent Change 7/04 - 7/05	JULY 1 2005	Percent Change 7/05 - 7/06	JULY 1 2006	Percent Change 7/06 - 7/07	JULY 1 2007	Percent Change 7/07 - 7/08	JULY 1 2008	Percent Change 7/08 - 7/09
State of Nevada	2,410,768	4.5%	2,518,869	4.1%	2,623,050	3.6%	2,718,337	0.8%	2,738,733	-1.0%
Counties										
Cities										
Towns										
Nye County	38,181	8.2%	41,302	8.5%	44,795	3.4%	46,308	2.3%	47,370	-2.1%
Amargosa	1,211	14.3%	1,383	3.7%	1,435	4.7%	1,503	1.2%	1,521	-8.5%
Beatty	981	5.2%	1,032	-0.7%	1,025	3.3%	1,059	-3.3%	1,024	-14.0%
Gabbs	**316**	-1.4%	**312**	0.4%	313	3.0%	322	3.1%	332	-4.9%
Manhattan	128	-3.2%	124	-1.9%	122	14.5%	140	-1.3%	138	-1.8%
Pahrump	30,465	9.1%	33,241	10.2%	36,645	3.5%	37,928	2.5%	38,882	-1.6%
Round Mountain	767	-3.1%	744	5.9%	787	5.5%	831	2.3%	850	-1.5%
Tonopah	2,341	11.3%	2,607	-0.3%	2,600	0.4%	2,610	0.7%	2,628	-1.8%
Pershing County	6,631	1.6%	6,736	3.2%	6,955	1.7%	7,075	1.6%	7,192	-0.6%
Lovelock	2,381	-0.8%	2,363	2.7%	2,427	1.6%	2,465	-0.3%	2,458	-1.9%
Imlay	225	-1.0%	223	2.5%	228	1.9%	233	4.4%	243	-4.1%
Storey County	3,797	5.7%	4,012	2.4%	4,110	4.4%	4,293	2.1%	4,384	-1.5%
Gold Hill	189	0.7%	191	6.3%	203	3.0%	209	1.6%	212	-2.4%
Virginia City	887	5.7%	938	1.7%	954	5.9%	1,011	1.5%	1,027	-1.5%
Washoe County	383,453	3.5%	396,844	3.1%	409,085	2.2%	418,061	1.4%	423,833	-1.7%
Reno	199,249	3.8%	206,735	3.7%	214,371	2.9%	220,613	1.1%	223,012	-2.2%
Sparks	81,673	4.8%	85,618	2.6%	87,846	1.8%	89,449	2.5%	91,684	-0.5%
White Pine County	8,966	3.4%	9,275	2.9%	9,542	0.5%	9,590	2.5%	9,694	-1.3%
Ely	3,962	5.1%	4,166	3.8%	4,325	-0.7%	4,294	1.3%	4,352	-1.4%
Lund	147	6.1%	156	3.7%	162	1.5%	164	-4.2%	157	0.3%
McGill	1,079	2.8%	1,109	3.2%	1,145	-1.8%	1,125	0.3%	1,128	-1.7%
Ruth	379	3.9%	394	2.9%	405	-1.3%	400	1.8%	407	-1.3%

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Governor Certified Population Estimates of Nevada's Counties, Cities and Towns 2010 to 2016

Estimates from NV State Demographer, NV Department of Taxation

	JULY 1 2009	Percent Change 7/09 - 7/10	April 1 2010	JULY 1 2010	Percent Change 4/10 - 7/11	Percent Change 7/10 - 7/11	JULY 1 2011	Percent Change 7/11 - 7/12	JULY 1 2012	Percent Change 7/12 - 7/13
State of Nevada	2,711,206	0.5%	2,700,551	2,724,634	0.8%	-0.1%	2,721,794	1.0%	2,750,217	1.8%
Counties										
Cities										
Towns										
Nye County	46,360	-1.9%	43,946	45,459	1.3%	-2.1%	44,513	-0.5%	44,292	1.0%
Amargosa	1,392	7.2%	1,442	1,492	-7.7%	-10.8%	1,331	1.7%	1,353	-0.8%
Beatty	880	5.0%	893	924	9.6%	6.0%	979	3.2%	1,011	-4.5%
Gabbs	316	-3.8%	294	304	-4.0%	-7.2%	282	-3.9%	271	-4.4%
Manhattan	135	-1.7%	129	133	-5.9%	-9.0%	121	3.4%	125	-0.7%
Pahrump	38,247	-1.2%	36,538	37,796	1.3%	-2.1%	36,995	-1.1%	36,593	1.2%
Round Mountain	837	-3.7%	779	806	-1.0%	-4.3%	771	4.9%	809	1.6%
Tonopah	2,580	-3.6%	2,405	2,488	-2.5%	-5.7%	2,346	8.8%	2,552	1.6%
Pershing County	7,149	-0.2%	6,753	7,133	1.4%	-4.0%	6,847	2.4%	7,013	-1.9%
Lovelock	2,411	-5.7%	1,894	2,274	14.6%	-4.5%	2,171	-10.8%	1,936	2.6%
Imlay	233	-0.1%	233	233	-31.3%	-31.3%	160	16.1%	186	31.5%
Storey County	4,317	-1.9%	4,010	4,234	2.8%	-2.6%	4,123	-0.5%	4,103	-2.1%
Gold Hill	207	-2.4%	191	202	24.4%	17.8%	238	-14.1%	204	-2.1%
Virginia City	1,011	-1.3%	945	998	-9.1%	-13.9%	859	-3.4%	830	1.3%
Washoe County	416,632	0.2%	421,407	417,379	0.0%	1.0%	421,593	1.4%	427,704	1.1%
Reno	218,143	-0.4%	225,221	217,282	-1.1%	2.5%	222,801	3.2%	229,859	1.0%
Sparks	91,237	1.2%	90,264	92,331	2.3%	0.0%	92,302	-2.3%	90,214	1.5%
White Pine County	9,570	-0.7%	10,030	9,503	-0.3%	5.3%	10,002	-0.6%	9,945	1.5%
Ely	4,291	-1.3%	4,255	4,235	-3.9%	-3.4%	4,089	-0.6%	4,066	0.8%
Lund	158	2.7%	178	162	16.6%	27.8%	207	-0.4%	206	0.2%
McGill	1,109	-0.1%	1,215	1,108	-3.8%	5.4%	1,168	0.6%	1,175	0.2%
Ruth	402	-0.7%	437	399	-4.0%	5.3%	420	-0.5%	418	1.5%

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Governor Certified Population Estimates of Nevada's Counties, Cities and Towns 2010 to 2016

Estimates from NV State Demographer, NV Department of Taxation

	JULY 1 2013	Percent Change 7/13 - 7/14	JULY 1 2014	Percent Change 7/14 - 7/15	JULY 1 2015	Percent Change 7/15 - 7/16	JULY 1 2016	Percent Change 7/16 - 7/17	JULY 1 2017
State of Nevada	2,800,967	1.5%	2,843,301	1.9%	2,897,584	1.9%	2,953,375	1.1%	2,985,723
Counties									
Cities									
Towns									
Nye County	44,749	1.6%	45,456	1.3%	46,050	-0.7%	45,737	1.4%	46,390
Amargosa	1,342	6.2%	1,426	-2.1%	1,396	-0.4%	1,390	-3.3%	1,344
Beatty	966	1.0%	975	-0.2%	973	-2.3%	950	1.2%	961
Gabbs	259	-5.6%	245	-5.6%	231	-2.1%	226	-3.4%	218
Manhattan	124	6.9%	133	0.9%	134	-2.7%	130	-3.3%	126
Pahrump	37,030	1.6%	37,626	2.3%	38,482	-0.6%	38,238	2.1%	39,023
Round Mountain	822	2.9%	846	-1.0%	837	-4.6%	799	-3.3%	772
Tonopah	2,593	-0.6%	2,578	-9.0%	2,345	-2.3%	2,291	0.9%	2,311
Pershing County	6,882	-2.4%	6,714	0.5%	6,750	-0.8%	6,693	0.7%	6,743
Lovelock	1,987	-1.8%	1,952	-3.1%	1,893	1.2%	1,915	0.9%	1,933
Imlay	244	5.4%	257	-23.9%	196	6.0%	208	-0.3%	207
Storey County	4,017	-1.1%	3,974	0.3%	3,984	1.5%	4,043	1.0%	4,084
Gold Hill	200	0.6%	201	0.0%	201	1.2%	204	-0.8%	202
Virginia City	841	-1.1%	832	0.0%	831	1.6%	845	0.6%	850
Washoe County	432,324	1.0%	436,797	1.2%	441,946	1.4%	448,316	0.7%	451,370
Reno	232,243	1.3%	235,371	1.4%	238,615	1.5%	242,158	0.9%	244,313
Sparks	91,551	0.9%	92,396	1.3%	93,581	2.3%	95,726	1.1%	96,810
White Pine County	10,095	1.2%	10,218	1.2%	10,336	0.8%	10,413	2.8%	10,705
Ely	4,100	1.6%	4,165	-2.6%	4,056	0.2%	4,065	4.9%	4,267
Lund	206	0.8%	208	-5.5%	197	2.9%	202	1.2%	205
McGill	1,177	2.0%	1,200	-3.2%	1,161	0.4%	1,166	2.2%	1,191
Ruth	424	1.2%	429	1.2%	434	0.8%	437	2.8%	450

Note: This series represents the estimates as certified by NV's Governor each year. It is not a time series reflecting Census 2010.

LF-6

LVCVA Summary of Monthly Tourism Indicators for Las Vegas, NV

For Calendar Year 2018

As of November 29, 2018

Compiled by the LVCVA Research Center

Tourism Indicators	Jan 2018	Feb 2018	Mar 2018	Apr 2018	May 2018	Jun 2018	Jul 2018	Aug 2018	Sep 2018	Oct 2018	Nov 2018	Dec 2018	2018 YTD
Visitor Volume	3,393,900	3,130,400	3,749,800	3,548,000	3,630,400	3,565,400	3,659,600	3,555,200	3,457,500	3,680,600			35,370,600
Convention Attendance	612,900	690,000	652,400	563,800	489,100	500,600	408,000	646,500	437,800	665,600			5,666,700
Available Room Inventory	146,715	146,672	147,463	147,508	147,963	147,689	147,587	147,244	147,802	147,598			147,598
Citywide Occupancy	83.8%	85.3%	92.7%	91.0%	89.4%	90.6%	90.8%	87.7%	87.4%	91.4%			89.0%
Weekend Occupancy	86.9%	93.9%	96.6%	96.9%	96.0%	95.8%	96.7%	95.5%	95.8%	97.2%			95.1%
Midweek Occupancy	82.6%	81.2%	90.8%	88.8%	86.7%	88.0%	88.8%	84.6%	83.2%	89.4%			86.5%
Strip Occupancy	85.3%	86.5%	93.7%	91.8%	90.5%	91.6%	92.7%	89.5%	88.4%	92.5%			90.3%
Downtown Occupancy	79.6%	83.7%	88.6%	88.2%	84.2%	81.1%	82.3%	79.1%	84.1%	87.9%			83.9%
Average Daily Room Rate (ADR)*	$150.45 r	$119.65	$134.27	$128.90	$133.75	$116.41	$119.08	$115.67	$136.23	$142.43			$129.74
Strip ADR*	$163.50 r	$128.72	$144.45	$139.32	$143.89	$125.94	$127.87	$123.96	$146.75	$153.82			$139.86
Downtown ADR*	$80.17	$64.97	$74.19	$66.61	$72.75	$63.84	$66.84	$61.87	$78.81	$75.41			$70.68
Revenue Per Available Room (RevPAR)*	$126.08 r	$102.06	$124.47	$117.30	$119.57	$105.47	$108.12	$101.44	$119.07	$130.18			$115.38
Strip RevPAR*	$139.47 r	$111.34	$135.35	$127.90	$130.22	$115.36	$118.54	$110.94	$129.73	$142.28			$126.11
Downtown RevPAR*	$63.82	$54.38	$65.73	$58.75	$61.26	$51.77	$55.01	$48.94	$66.28	$66.29			$59.22
Total Room Nights Occupied	3,812,200	3,501,200	4,236,000	4,024,800	4,100,600	4,013,100	4,155,400	4,005,100	3,873,600	4,181,700			39,903,500
Total En/Deplaned Passengers	3,776,299	3,568,662	4,298,358	4,188,246	4,360,117	4,311,292	4,425,670	4,306,334	4,056,591	4,436,756			41,728,325
Avg. Daily Auto Traffic: All Major Highways	104,143 e	106,030 e	121,206 e	118,375 e	122,794 e	125,508 e	130,920 e	126,575 e	117,421 e	120,635 e			119,361 e
Avg. Daily Auto Traffic: I-15 at NV/CA Border	39,003	39,896	44,919	43,878	47,268	49,031	53,033	48,018	44,207	43,631			45,288
Gaming Revenue : Clark County	$892,064,000	$888,773,000	$888,307,000	$825,327,000	$904,582,000	$790,981,000	$839,052,000	$756,098,000	$843,436,000	$926,514,000			$8,555,134,000
Gaming Revenue: Las Vegas Strip	$554,752,000	$603,494,000	$573,944,000	$499,502,000	$581,466,000	$523,921,000	$533,100,000	$477,919,000	$546,025,000	$593,419,000			$5,487,542,000
Gaming Revenue: Downtown	$56,526,000	$53,205,000	$53,991,000	$60,485,000	$53,309,000	$44,015,000	$48,823,000	$46,213,000	$54,990,000	$63,758,000			$535,315,000
Gaming Revenue: Boulder Strip	$90,627,000	$63,825,000	$64,604,000	$78,377,000	$79,825,000	$60,893,000	$78,742,000	$62,171,000	$67,541,000	$78,323,000			$724,928,000
Room Tax / LVCVA's Portion[1]	$27,432,821	$19,404,696	$27,195,042	$24,903,752	$25,720,731	$21,874,205	$23,156,509	$21,687,741	N/A	N/A			N/A

Change from Previous Year	Jan 2018	Feb 2018	Mar 2018	Apr 2018	May 2018	Jun 2018	Jul 2018	Aug 2018	Sep 2018	Oct 2018	Nov 2018	Dec 2018	2018 YTD
Visitor Volume	-3.3%	-0.6%	-0.9%	0.1%	0.8%	-1.1%	-3.4%	-0.2%	-3.1%	2.1%			-1.0%
Convention Attendance	-16.7%	11.2%	-13.9%	11.5%	-5.0%	2.9%	-19.5%	17.9%	-5.6%	-3.1%			-2.7%
Room Inventory	-1.3%	-0.8%	-0.2%	0.0%	0.2%	0.3%	0.4%	0.3%	0.7%	0.7%			0.7%
Citywide Occupancy	-1.9	-0.3	-1.3	0.3	0.3	-2.0	-3.7	-0.9	-3.7	1.4			-1.2
Weekend Occupancy	-5.7	0.9	-1.4	0.5	0.5	-0.3	-1.1	1.0	-0.2	3.0			-0.3
Midweek Occupancy	0.2	-1.0	-1.5	0.5	0.2	-3.0	-4.3	-2.0	-5.1	0.8			-1.5
Strip Occupancy	-1.8	-0.5	-1.1	-0.1	0.1	-2.6	-3.2	-1.6	-3.9	1.2			-1.3
Downtown Occupancy	-1.8	1.0	-0.6	1.6	1.7	-3.9	-4.0	0.0	-1.1	1.9			-0.5
Average Daily Room Rate (ADR)	0.9%	2.5%	-9.6%	4.4%	7.4%	-2.1%	-4.3%	2.1%	-2.2%	2.6%			-0.1%
Strip ADR	0.7%	2.8%	-10.0%	4.8%	7.3%	-1.6%	-4.3%	1.9%	-2.2%	2.3%			-0.1%
Downtown ADR	7.5%	3.3%	-11.7%	1.2%	12.4%	-4.3%	-5.7%	4.1%	-2.2%	1.1%			0.0%
Revenue Per Available Room (RevPAR)	-1.4%	2.1%	-10.9%	4.7%	7.8%	-4.2%	-8.1%	1.1%	-6.2%	4.2%			-1.4%
Strip RevPAR	-1.4%	2.2%	-11.0%	4.7%	7.5%	-4.3%	-7.5%	0.1%	-6.4%	3.7%			-1.6%
Downtown RevPAR	5.1%	4.5%	-12.3%	3.1%	14.7%	-8.7%	-10.0%	4.1%	-3.5%	3.3%			-0.6%
Total Room Nights Occupied	-3.5%	-1.3%	-1.6%	0.2%	0.5%	-1.8%	-3.5%	-0.8%	-3.5%	2.2%			-1.3%
Total En/Deplaned Passengers	2.7%	4.0%	2.2%	3.1%	3.6%	2.8%	2.3%	1.4%	-0.4%	2.2%			2.4%
Avg. Daily Auto Traffic: All Major Highways	4.8%	3.0%	2.9%	-2.8%	2.5%	-0.3%	-1.3%	2.4%	2.4%	7.4%			1.9%
Avg. Daily Auto Traffic: I-15 at NV/CA Border	4.4%	4.5%	4.2%	-5.9%	4.7%	-2.1%	-2.0%	-2.8%	1.0%	7.1%			1.0%
Gaming Revenue : Clark County	-3.7%	7.6%	3.6%	8.1%	5.1%	3.4%	-1.1%	-10.2%	1.5%	8.4%			2.2%
Gaming Revenue: Las Vegas Strip	-8.9%	11.4%	9.1%	5.1%	6.3%	5.4%	-5.7%	-12.4%	-3.7%	12.2%			1.6%
Gaming Revenue: Downtown	1.8%	2.8%	-14.2%	15.6%	-3.5%	-4.4%	8.2%	-4.8%	11.6%	0.3%			1.0%
Gaming Revenue: Boulder Strip	6.8%	-1.0%	-6.0%	22.7%	-0.2%	3.7%	18.5%	-16.3%	27.5%	-0.6%			4.6%
Room Tax / LVCVA's Portion[1]	-1.3%	0.7%	-7.0%	3.5%	7.1%	-4.0%	-7.3%	-0.1%					N/A

Sources: *Las Vegas Convention and Visitors Authority; McCarran International Airport; Nevada Department of Transportation (NDOT); Nevada Gaming Control Board*

For more information, visit www.lvcva.com/stats-and-facts/

[1] Room Tax amounts exclude portions dedicated to Las Vegas Convention Center District (LVCCD) funding from SB-1 legislation.

e - estimate

r - revised

*** NOTE: ADR & RevPAR figures for 2017 have been restated to reflect the implementation of new accounting rules at some properties in 2018. Previously published 2017 ADR and RevPAR figures may reflect former accounting methods.**

LVCVA Summary of Monthly Tourism Indicators for Laughlin, NV

For Calendar Year 2018

As of November 27, 2018

Compiled by the LVCVA Research Center

Tourism Indicators	Jan 2018	Feb 2018	Mar 2018	Apr 2018	May 2018	Jun 2018	Jul 2018	Aug 2018	Sep 2018	Oct 2018	Nov 2018	Dec 2018	2018 YTD
Visitor Volume	148,400	151,700	179,600	168,000 r	160,500	173,100	188,000	159,000	147,900	156,000			1,632,100
Room Inventory	9,862	9,862	9,862	9,862	9,862	9,846	9,846	9,846	9,846	9,896			9,896
Total Occupancy	59.0%	68.1%	73.5%	70.7% r	64.6%	73.3%	77.7%	64.3%	61.4%	62.3%			67.5%
Average Daily Room Rate (ADR)*	$39.95 r	$47.36	$47.91	$55.97	$53.17	$50.20	$55.02	$52.71	$49.27	$45.18			$49.90
Revenue Per Available Room (RevPAR)*	$23.57 r	$32.25	$35.21	$39.57	$34.35	$36.80	$42.75	$33.89	$30.25	$28.15			$33.68
Total Room Nights Occupied	180,400	188,000	224,700	209,200 r	197,500	216,500	236,700	195,400	180,600	191,100			2,020,000
Gross Gaming Revenue	$45,667,000	$45,117,000	$51,796,000	$46,636,000	$44,028,000	$36,356,000	$41,364,000	$38,210,000	$37,746,000	$47,039,000			$433,959,000
Laughlin/Bullhead City En/Deplaned Passengers	21,268	22,907	25,359	23,216	19,998	16,020	17,611	17,773	19,157	25,274			208,583
Avg. Daily Auto Traffic: Highway 163	4,423	4,761	5,295	5,489	4,806	4,884	5,056	4,608	4,403	4,727			4,845

Change from Previous Year	Jan 2018	Feb 2018	Mar 2018	Apr 2018	May 2018	Jun 2018	Jul 2018	Aug 2018	Sep 2018	Oct 2018	Nov 2018	Dec 2018	2018 YTD
Visitor Volume	3.8%	-0.2%	0.7%	-1.5%	-2.2%	1.8%	-4.4%	-1.2%	-6.3%	-6.5%			-1.7%
Room Inventory	-0.6%	-0.6%	-0.6%	-0.6%	-0.6%	-0.7%	-0.7%	-0.7%	-0.7%	-0.2%			-0.2%
Total Occupancy	4.0	1.6	2.4	0.6	0.0	3.4	-1.7	1.1	-2.8	-3.6			0.5
Average Daily Room Rate (ADR)	11.7%	9.6%	20.4%	2.8%	12.0%	4.5%	-0.1%	9.9%	-3.5%	8.8%			6.7%
Revenue Per Available Room (RevPAR)	19.8%	12.2%	24.4%	3.7%	12.0%	9.6%	-2.3%	11.9%	-7.7%	2.8%			7.5%
Total Room Nights Occupied	6.6%	1.8%	2.8%	0.3%	-0.6%	4.1%	-3.0%	0.6%	-5.4%	-5.6%			0.0%
Gross Gaming Revenue	3.5%	4.6%	3.0%	8.7%	1.7%	-1.9%	1.8%	-2.3%	2.4%	12.1%			3.5%
Laughlin/Bullhead City En/Deplaned Passengers	13.8%	5.6%	3.2%	-1.2%	-6.6%	-11.1%	-4.6%	4.7%	5.9%	4.8%			1.5%
Avg. Daily Auto Traffic: Highway 163	8.2%	2.5%	0.4%	0.1%	0.9%	3.5%	-1.3%	-5.8%	-1.0%	4.8%			1.1%

Sources: *Las Vegas Convention and Visitors Authority; Mohave County Airport Authority; Nevada Department of Transportation (NDOT); Nevada Gaming Control Board*

For more information, visit www.lvcva.com/stats-and-facts/

r - revised

*** NOTE: ADR & RevPAR figures for 2017 have been restated to reflect the implementation of new accounting rules at some properties in 2018. Previously published 2017 ADR and RevPAR figures may reflect former accounting methods.**

LF-7

NV Energy Net to Gross Study
Residential Appliance Saturation Survey
Energy End Use Intensity Analysis

Draft Final Report

November 7, 2016

Prepared for:

NVEnergy

Prepared by:

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TABLE OF CONTENTS

1. EXECUTIVE SUMMARY

This report presents the results of ADM Associates Inc.'s (ADM) evaluation of energy end use intensities (EUIs) associated with homes included in the 2016 Residential Appliance Saturation Survey (RASS) conducted as part of the Net to Gross Study.

Hourly energy use load profiles have been developed individually for the southern Nevada service territory (NPC) and northern Nevada service territory (SPPC) for each of the following end uses:

- Overall energy use
- Lighting
- Water Heating
- Pool Pumps
- Space Cooling
- Space Heating
- Clothes Dryers
- Remaining Miscellaneous Loads

Analysis of each load is discussed herein in the order listed above, as this reflects the order in which loads have been disaggregated from the total energy use. The intent of the order of disaggregating loads is to account for loads that exhibit slight seasonal variation (lighting, water heating, pool pumps) prior to utilizing the weather data as the primary factor in determining the heating and cooling energy use.

Load profiles have been developed based upon detailed analysis of the RASS responses, hourly interval meter data for the RASS participants, and incorporation and comparisons against other data sources and references.

The load profiles developed have been included in the attached spreadsheet and are presented based on the most recently available twelve months of data as of the commencement of the analysis, May 1, 2015 to April 30, 2016.

This analysis was conducted using the R programming language. All R code developed in association with the work will be provided to NV Energy.

2. ASSESSOR COMPARISONS AND DATA VALIDATION

The data cleaning and preparation process has not revealed any issues regarding the integrity or feasibility of the interval meter data. A comparison based on the "RDP" identifier indicates that ADM received interval meter data for 988 of the 994 survey respondents (99.4%). Of those 988 respondents for which data was received, it does not appear that there are any extraneous outlier energy demand values in the data that need to be removed.

ADM performed checks of survey responses against available Clark County assessor data. The intent of these checks is not explicitly to determine the accuracy of the survey responses, as there is no *a priori* knowledge that the assessor information does not contain discrepant data. Rather the focus is on gauging the relative alignment of the two data sets.

It is important to note that when merging the survey data with the assessor data, only 57% of the survey respondents were found based upon the "Premise" identifier. The discussion below is based on those 534 respondents for which assessor data was successfully matched.

Two comparisons were made between the survey responses and the assessor data: age of home (year built) and size of home (square footage). Table 2-1 below provides a summary of the year built comparison results.

Table 2-1: Comparison Between Assessor and Survey Response Home Age Information

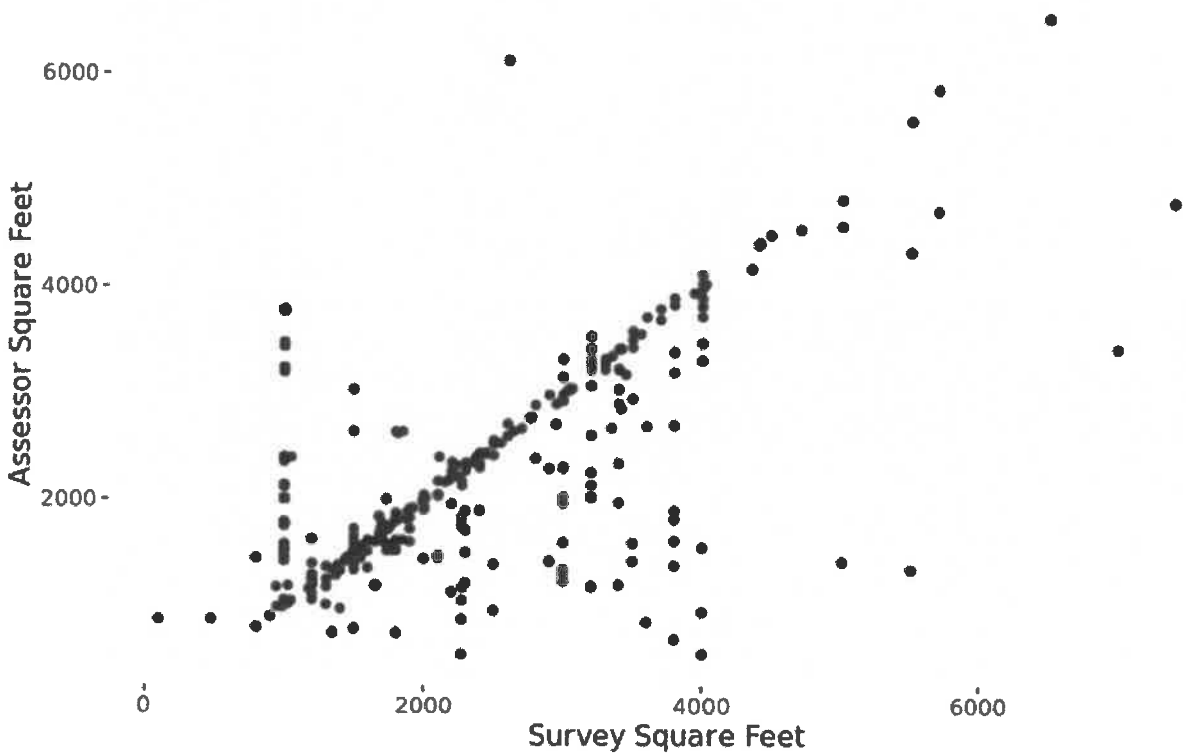
Year Built Survey Response Category	Count	Median Assessor Recorded Year Built	Percent Match
Before 1970	32	1962	78%
1970s	209	1980	15%*
1980s	34	1986	88%
1990-1994	48	1993	65%
1995-1999	51	1996	69%
2000-2004	56	2001	70%
2005-2009	48	2006	69%
2010-2014	14	2008	36%

**Note - It appears there may be an inaccuracy in the assessor data for the 1970s time range as a very high number of homes are reported as being built in 1980. Including the "1980" homes in the 1970s category results in a 57% percent match.*

Excluding the 1970s period, where there appears to be an inaccuracy in the assessor data, there is an imperfect, but general agreement between the two data sets (70% weighted average not including the 1970s).

Figure 2-1 below displays the comparison of the building square footage reported in the survey vs. the assessor data.

Figure 2-1: Assessor vs. Survey Reported Home Square Footage Comparison



There is a clear correlation between the two sets of square footages[1]. It is interesting to note that it appears many respondents are using a default value of 1,000 ft². Of the responses included in the plot above, the median absolute relative difference is 31.7%.

It is important for downstream aspects of the analysis to have a reliable value of square footage assigned to each home. Square footage values were determined in the following order:

1. Use value from survey if valid – 844 homes (non-NA, non-zero, not equal to 1,000, non-outlier).
2. Use value from assessor data if available – 26 homes (Clark County only, ~57% match rate).
3. Impute square footage using a linear regression estimate based on energy use, location (NPC/SPPC), home type, and a flag for pools – 118 homes.

[1] Figure data has been filtered to remove non-responses from survey data, 0 values from assessor data, and one apparent survey outlier response of ~35,000 ft².

3. LIGHTING

Table 3-1 below summarizes the average responses given to questions in Section H of the survey regarding the number of CFLs and LEDs in respondents' homes and how many run for at least three hours per day, categorized by territory and the predominant residence types.

Table 3-1: CFL and LED Average Responses

Territory	Residence Group	Count	Avg. ft²	Avg. No. CFLs		Avg. No. LEDs	
				Total	Run 3+ Hr	Total	Run 3+ Hr
NPC	Single Family w/Pool	123	3,647	12.1	4.9	11.3	4.6
SPPC	Single Family w/Pool	17	3,278	18.4	7.8	13.8	6.5
NPC	Single Family w/o Pool	197	1,966	9.9	3.4	3.4	1.5
SPPC	Single Family w/o Pool	304	2,057	9.5	3.0	5.6	2.0
NPC	Multi-family	141	926	4.9	1.7	1.3	0.3
SPPC	Multi-family	78	980	4.2	1.7	1.7	0.5

The RASS did not ask about the total number of lights in the home, or estimated run times for total number of lights. These quantities will need to be estimated from other sources in order to develop the lighting EUI. The Residential Energy Consumption Survey (RECS) is a national survey similar in nature to the RASS that was most recently conducted in 2009.[2]

The RECS enquires about total number of lights and run time durations. These responses were used to construct a simple linear model of household lights that run for at least one hour per day as a function of conditioned square footage for the 304 homes in the RECS geographical Division 9 (Arizona, New Mexico, Nevada).[3] Table 3-2 on the following page summarizes the results of incorporating the RECS estimate into the categories outlined above.

[2] From http://www.eia.gov/consumption/residential/data/2009/index.cfm?view=microdata: "*First conducted in 1978, the Residential Energy Consumption Survey is a national sample survey that collects energy-related data for housing units occupied as a primary residence and the households that live in them. Data were collected from 12,083 households selected at random using a complex multistage, area-probability sample design.*"

[3] Total lights that run at least 1 hour $\approx 0.73 + 2.7 *$ conditioned area (1,000 ft²)

Table 3-2: Combined RECS + RASS Lighting Run Time Summary

Territory	Residence Group	Count	Avg. ft²	RECS Light 1+	CFLs 3+ Hrs	LEDs 3+ Hrs	Diff* (if > 0)	Demand Est. (W)†
NPC	Single Family w/Pool	123	3,647	10.9	4.9	4.6	1.4	184
SPPC	Single Family w/Pool	17	3,278	9.9	7.8	6.5	0.0	183
NPC	Single Family w/o Pool	197	1,966	6.2	3.4	1.5	1.4	127
SPPC	Single Family w/o Pool	304	2,057	6.5	3.0	2.0	1.5	133
NPC	Multi-family	141	926	3.3	1.7	0.3	1.3	86
SPPC	Multi-family	78	980	3.5	1.7	0.5	1.3	86

*Diff = RECS Estimate - (CFLs + LEDs)

†An estimation of demand associatied with these fixture counts using the average wattages determined as part of ADM's PY 2015 NVE Lighting program analysis (LEDs: 10.2 W, CFLs: 14.9 W, Halogens: 44.8 W)

The objective of incorporating the RECS information is to estimate the number of halogen lights in regular use in each house, based on the difference between the RECS estimated total and the RASS values reported for CFLs and LEDs.

The estimated counts of halogens, CFLs, and LEDs are used to assign an initial lighting demand value to each house. After making comparisons against additional Energy Information Administration (EIA) references[4], it was determined that this initial demand value was a reasonable estimate of the average lighting demand for each home.[5]

The loadshape used to prorate the average lighting energy usage is the one used in the most recent (PY 2015) Measurement & Verification (M&V) report provided to NV Energy by ADM and is based on 2005 and 2010 studies conducted by KEMA[6]. Hourly data from the 2010 KEMA study are not publicly available. The 2005 KEMA study is the most recent and largest (in terms of sampled homes) metering study with published curves at the hourly level.

The mean lighting energy as a percentage of total energy using this approach is estimated to be 13.2%, which represents indoor and outdoor lighting. As a comparison, the EIA references value for *indoor only* lighting as a percentage of total consumption is 11%.[7]

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[4] Energy End-use consumption by fuel, Averages, West homes: https://www.eia.gov/consumption/residential/data/2009/c&e/ce4.10.xlsx

[5] The average lighting demand was capped at a maximum of 50% of average overall energy demand, which only impacted 6% of the homes in the survey.

[6] KEMA, Inc., CFL METERING STUDY, FINAL REPORT, prepared for Pacific Gas & Electric Company, San Francisco, CA, San Diego Gas & Electric Company, San Diego, CA, and Southern California Edison Company, Rosemead, CA. February 25, 2005

[7] https://www.eia.gov/tools/faqs/faq.cfm?id=96&t=3

4. POOL PUMPS AND HEATERS

There are 142 homes that reported having a pool pump. Of these, 125 are in the NPC territory. A little more than half of the homes reporting having a pool pump, 88, also reported having a pool heater. It is likely given the southern Nevada climate that for homes with both pool pumps and heaters that the pool pump energy is significantly larger than pool heater energy. Given the correlation of their usage and the small sample sizes that would be involved in further disaggregation, pool pump and heater energy usage have been analyzed collectively. References below to "pool-related energy" can reasonably be considered predominantly pool pump energy with a likely slight additional contribution from pool heater energy.

To isolate the pool-related energy, two groups of homes with similar characteristics other than having a pool were identified. The groups are drawn from the population of single-family detached homes in NPC with natural gas as the primary heating fuel. There are 69 such homes that have a pool and 98 homes that do not. It is helpful to think of the homes that have a pool as the "treatment" group and the homes that do not have a pool as the "comparison" group in this exercise.

The comparison group was refined to better reflect the distribution of home sizes in the treatment group. Each home in the treatment group was matched with a home in the initial comparison group based on finding the home with the closest square footage value. These closest matches formed the comparison group used downstream in the analysis.[8]

As a final step to normalize the two groups, the energy use in the comparison group was increased by a factor of 11% to make up for remaining differences in average size between the two groups (i.e., the average comparison group home size was found to be 11% less than that of the treatment group following matching).

Following these data preparation steps, energy use was averaged across the homes in each group to determine average load profiles for the two cases. The hypothesis in this approach is that the difference between the two load shapes is due to only pool-related energy.

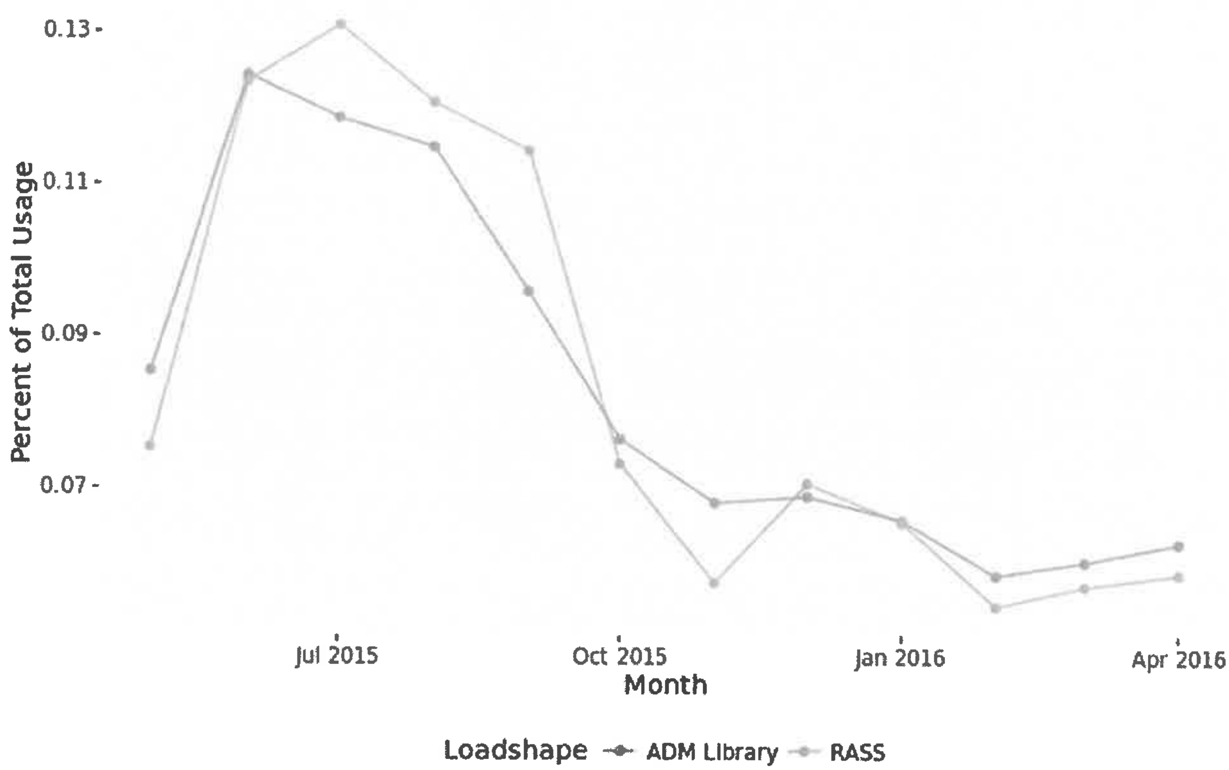
The mean demand value for the treatment group is 2.7 kW and for the comparison group is 1.6 kW. The difference of 1.1 kW corresponds to a 1.5 hp pool pump running year-round, or perhaps as a more reasonable estimate, a 2 hp pool pump running for 9 months out of the year.

While the checks against estimates of what average usage might look like are helpful, in this case another more detailed comparison can be made. ADM has conducted significant prior M&V efforts concerning pool pump efficiency programs conducted by NV Energy in southern Nevada. From those programs, an energy savings curve has been developed based on surveys of program participants. In this instance, the energy savings curve can serve as a proxy for an energy usage

[8] Repeats are allowed and are duplicated in the comparison group.

curve, as the savings is directly proportional to the usage.[9] Figure 4-1 below shows the comparison between the ADM M&V pool pump loadshape[10] and the one developed as described above. For visual clarity, loadshapes have been aggregated to monthly values.

Figure 4-1: Comparison between RASS and ADM Pool Pump Loadshapes



The profiles are a very close match between the two loadshapes, despite being completely independently developed in association with different program analyses, helping to further support the methodology.

To apply these results back to the end use disaggregation efforts, for homes with pools, the mean pool energy has been prorated by the size of the homes in the sample, which works out to 0.37 kW / 1,000 ft², with a cap of 50% of total energy use utilized to eliminate some apparent outliers. This mean value determines the annual usage, which is then converted into hourly usage by the loadshape noted above.

9 This is generally the case, although there are exceptions. For instance, the installation of an air-side economizer on an air handling unit would have an energy savings curve that did not correlate to AHU fan or cooling energy usage.

10 ADM derived this load-shape from 15-minute interval data for the 2015 participants in NV Energy's *Energy Efficient Pools and Spas Program*.

5. WATER HEATING

Numerous exercises like those described in the previous section for pool pumps were attempted in order to isolate the water heating energy end use, primarily by attempting to compare otherwise similar homes that reported having either electric (the treatment group in terms of the methodology used for pool pumps) or gas (the comparison group) water heaters. Unfortunately, no combinations of homes types, locations, treatment/comparison groups, matching efforts, and usage normalization were identified that produced reasonable results (i.e., homes with electric water heaters would be expected to consume somewhere in the neighborhood of 10% more energy than homes without).

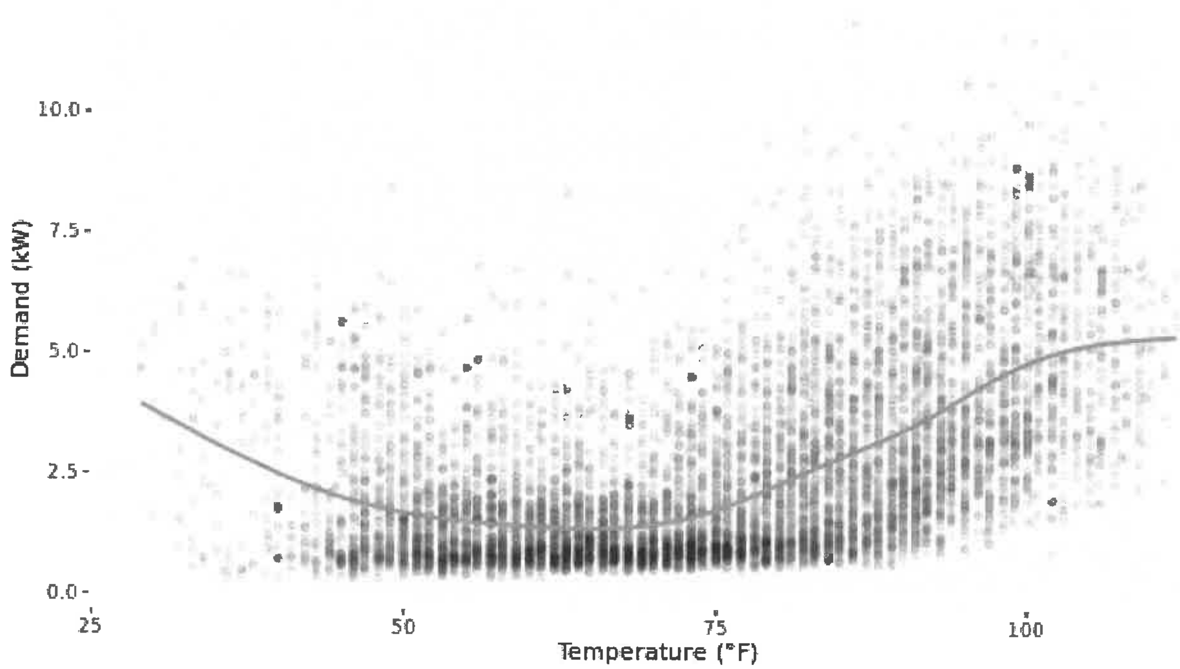
Typically, the comparisons attempted were with homes that reported having natural gas as the primary fuel for space heating, based on the relatively larger sample sizes. It is possible that some survey respondents misreported their water heater type, as it would generally be expected that homes with gas heat would have gas water heating. Typically, in the comparison exercises, no significant difference between average energy use between the treatment and comparison groups was identified, which supports, although not conclusively, this narrative.

As a substitute for a primary source for the water heating energy end use based on the RASS data, for the 311 homes (31% of all respondents) that reported having electric water heaters, 10.8% of their total energy use is attributed to electric water heating. This value is based on the average site end-use consumption data for New Mexico and Nevada based on the 2009 EIA RECS data.

6. SPACE COOLING

The energy usage patterns of each home in the RASS dataset are analyzed as a function of temperature to in order to classify the HVAC regime as either cooling, heating, or dead-band/off (which may still include some fan energy usage). Figure 6-1 below shows a scatterplot of hourly demand vs. temperature for an example home[11]. A local regression (loess)[12] fit is also shown in blue.

Figure 6-1: Example Hourly Demand vs. Temperature + Loess Fit



The loess fit shown in the previous figure is then used as the basis to characterize the HVAC regime. Piecewise linear approximations consisting of heating, mid-band, and cooling regions are made to the loess fit with knots (cutoffs between line segments) ranging over potential temperatures where the home is likely to begin using heating or cooling.[13] The piecewise linear approximation with the minimum normalized root mean squared error is used to determine the heating, mid (HVAC off), and cooling temperature ranges for each

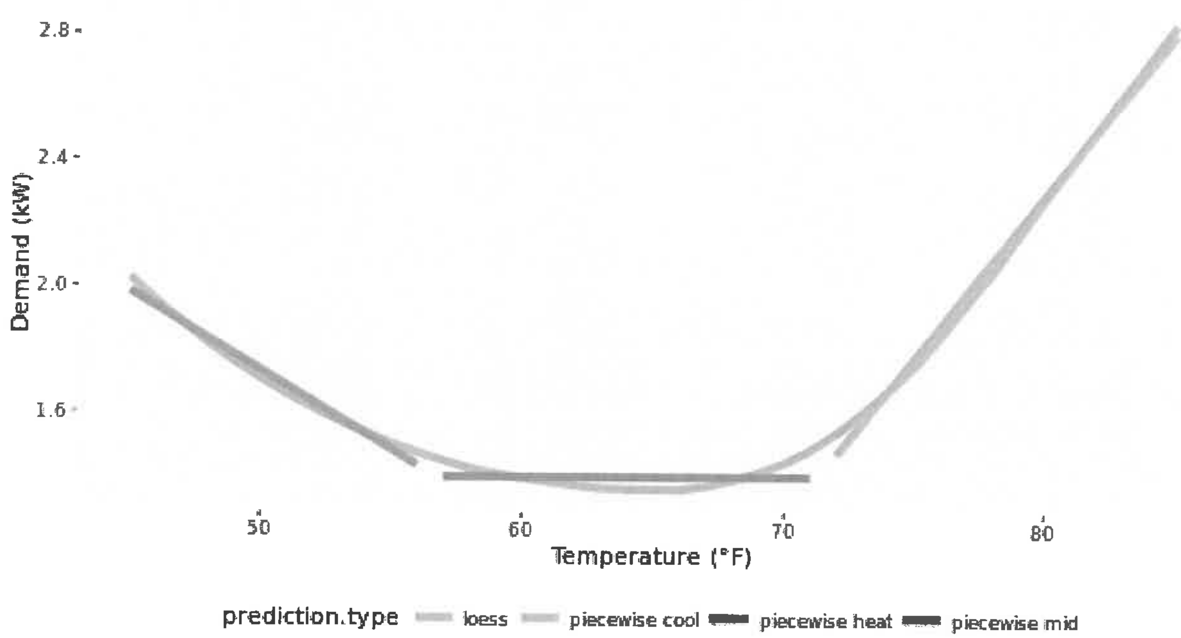
[11] The figures displayed in this section are from the example set of Res. AC homes used at the outset of the analysis.

[12] A loess model is a regression where the functional approximation at each point is a weighted least squares polynomial fit based upon data within a specified span of that point.

[13] Heating temperature cutoffs range from 45°F to 65°F by intervals of 1°F, and cooling temperature cutoffs likewise vary from 65°F to 85°F.

home. Figure 6-2 below shows the loess fit as well as the selected piecewise linear approximation for the same home represented in the figure above.

Figure 6-2: Example Loess with + Piecewise Approximations



The selected heating and cooling regime cutoffs for this particular home are 57°F and 71°F.

Once the HVAC regimes for a given home have been identified, background averaging and subtraction is used to disaggregate the cooling-specific energy from the total energy usage in the cooling regime. For each observation in the cooling regime, a base energy component is determined as the average of the energy use values for that home in the mid regime occurring on the same day type (weekday vs. weekend) and at the same hour of the day. The cooling energy is then estimated as the total energy observed less this base estimate.

In the final loadshape results included with this report, the lighting, pool-related, and water heater energy use were estimated and subtracted from the total energy use prior to conducting the space cooling portion of the analysis. This was done to remove the seasonal variation associated with those end uses that would confound with the temperature variations that are the basis of this approach.

Figures 6-3 and 6-4 on the following pages provides summary plots for average cooling energy estimates as a function of time of day and temperature during the summer (June – September) months for each of the territories.

Figure 6-3: Average Summer (June – Sept.) Cooling Load Profiles by Territory

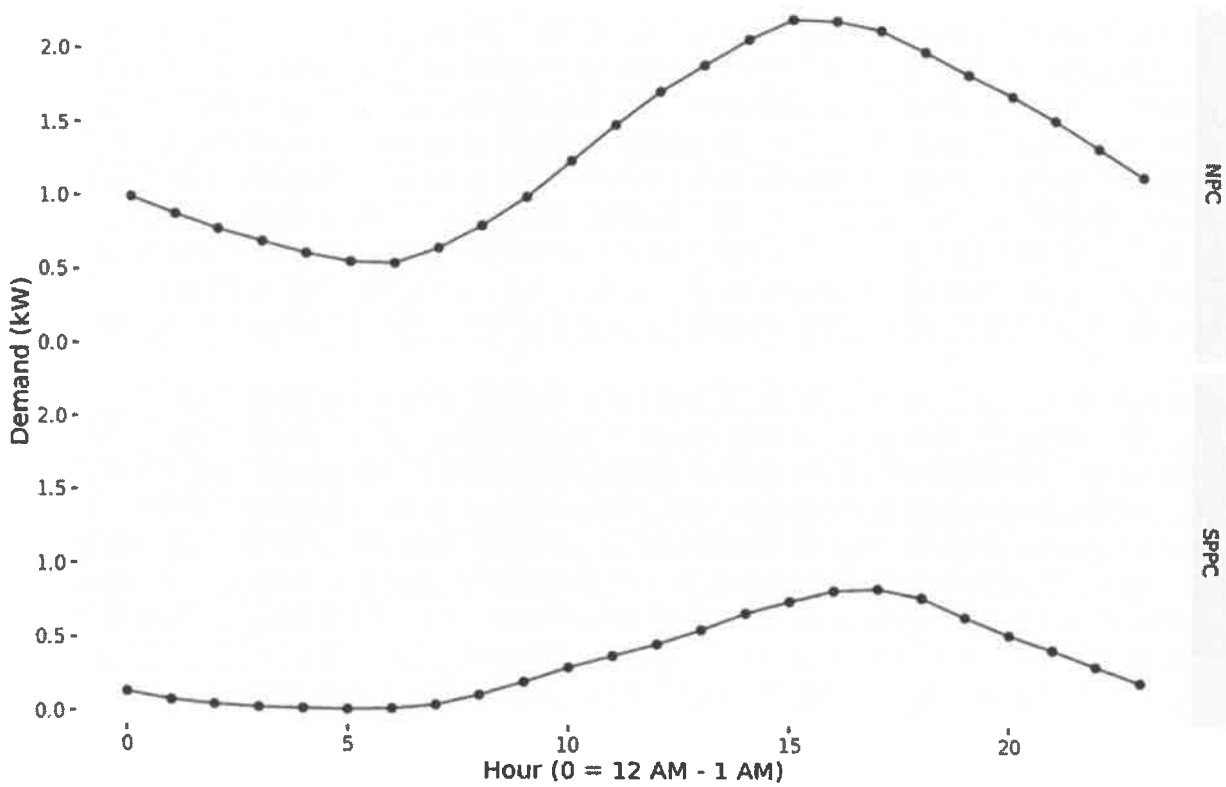
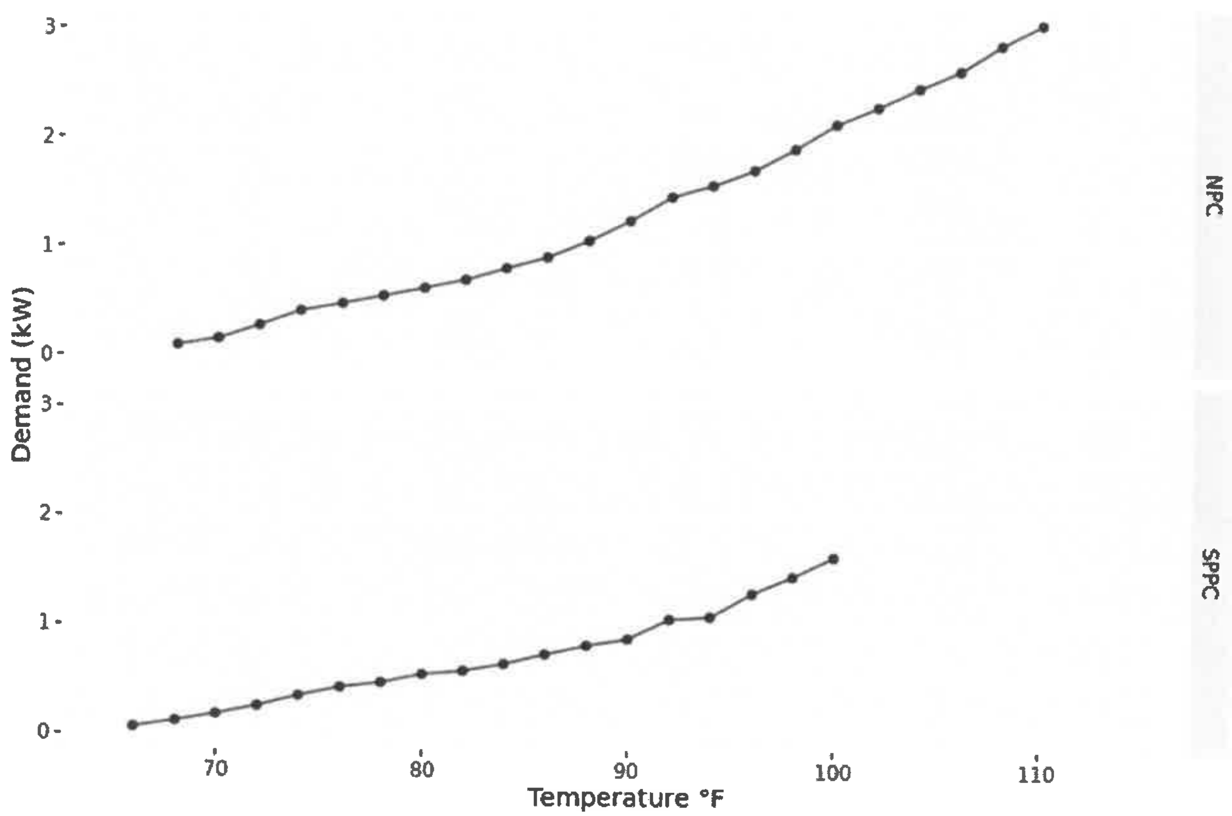


Figure 6-4: Average Summer (June – Sept.) Cooling Temperature Dependence by Territory



7. SPACE HEATING

The space heating disaggregation proceeded simultaneously with the space cooling analysis described above. However, it is worthwhile to detail an important preprocessing step necessary that needs to occur with respect to the heating energy. Table 7-1 below details the response counts to survey question E1 regarding primary heating fuel sources.

Table 7-1: Primary Heating Fuel Response Counts

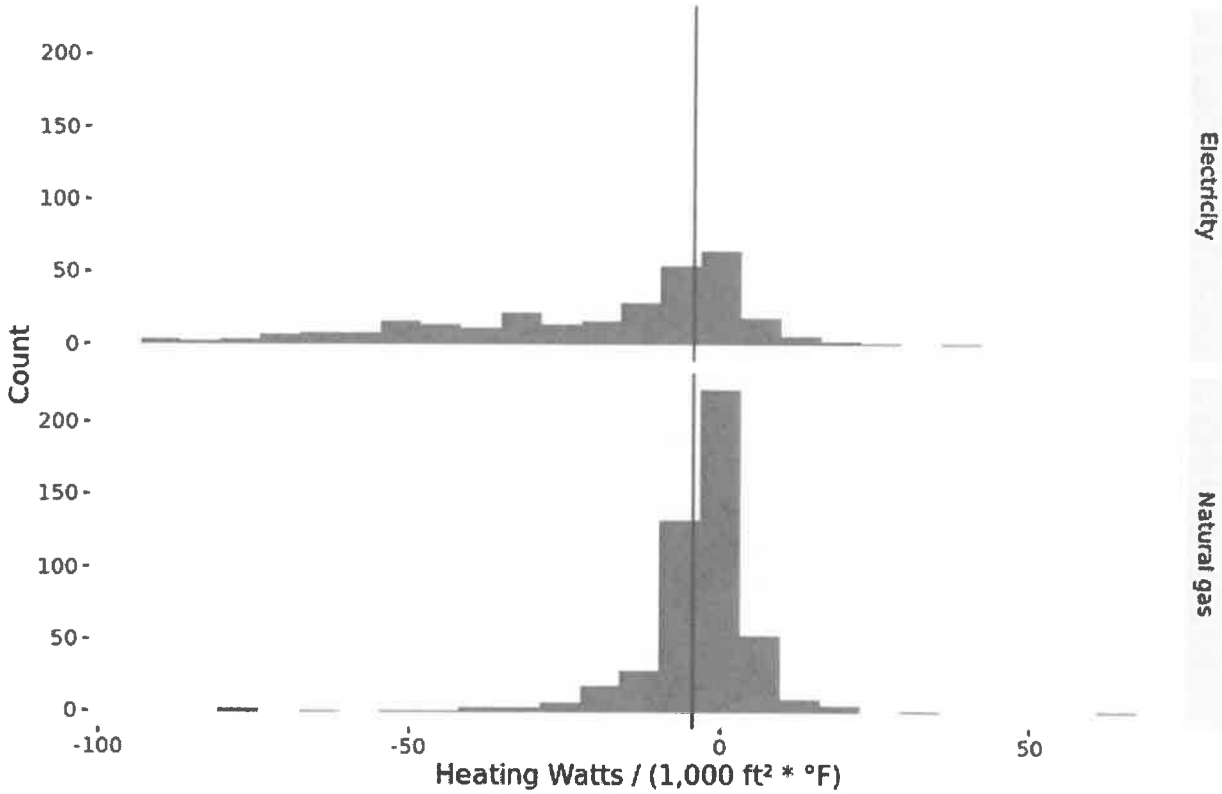
Category	Response	Count
Non-electric	Natural gas	502
	Propane	29
	Fuel oil	12
	Wood/wood pellets	7
	No heating fuel used	2
Electric	Electricity	316
Incomplete	Don't know	98
	Not answered	26
	Other	2

It is straightforward to note that the heating disaggregation algorithm should only be run on the homes that reported having electric heat and not those with natural gas or any of the other non-electric heating sources noted in the table.

For the purposes of developing accurate EUIs, it is important to attempt to classify the primary heating fuel for the homes that provided an incomplete response to this question. Fortunately, the energy use profiles of the homes that provided a detailed response can be used to categorize those that did not. Referring to Figure 6-2, it is apparent that the line segment depicting the heating regime has a negative slope as a function of increasing temperature. This characteristic can be quantified, which in this case is approximately -0.07 kW/°F.

Figure 7-1 on the following page displays histograms of heating slopes normalized by square footage for the sets of homes that reported electricity and natural gas as main fuel sources.

Figure 7-1: Distribution of Normalized Heating Slopes



As would be expected, heating slopes associated with electric heat generally have a larger magnitude than those for natural gas, which are tightly clustered close to 0 W/(1,000 ft² * °F). Statistical summaries of the distributions are provided in Table 7-2 below.

Table 7-2: Heating Slope Summary Statistics

Main Heat Fuel	Avg. Slope	Std. Dev. Slope
Electricity	-19.5	24.5
Natural gas	-3.5	10.3

Avg. and SD in units of W / (1,000 ft² * °F)

The vertical blue line in the figure demarcates the cutoff that is used to classify the homes that did not provide heating fuel type information as having either electric or non-electric heating systems. The line represents the midpoint between the overlapping regions of the distributions based on the average and one standard deviation values of the slopes. The exact cutoff is not critical as there will be minimal difference in the overall aggregated results between classifying an individual home as using very little electricity for heating and none at all.

It is important to also note that efforts were made to rely on the survey data as the primary source for imputing missing heating fuel type responses. These included linear discriminant analysis (LDA), nearest neighbor models, and random forests that attempted to use characteristics such as home age, ZIP code, and latitude/longitude to predict the primary heating fuel source based on the data associated with those respondents who had included heating fuel type responses. However, none of these models were able to outperform the slope-based methodology outlined above in terms of prediction accuracy.

8. CLOTHES DRYERS

A comparison exercise similar to that described for pool-related energy was conducted for clothes dryers. Please note that this result appears to be high based on a rough calculation check but has been left in to demonstrate the limitations in identifying the relatively smaller energy end uses based on whole house meter data.

Table 8-1 below summarizes counts of fuel sources for heating, clothes dryers, and water heaters for different applicable categories for the comparison homes (with natural gas heat and without pools).

Table 8-1: Clothes Dryer Comparison Groups Home Category and Fuel Source Summary

Residential Category	Territory	Main Heat Fuel	Clothes Dryer Fuel	Electric Water Heater	Count	Avg. ft²
Single Family - No Pool	SPPC	Natural gas	Natural gas	No	89	2,211
Single Family - No Pool	SPPC	Natural gas	Electricity	No	102	2,208

The two pairs of rows have sets of similar characteristics except for the clothes dryer fuel source. These two comparison pairs serve as the basis of the clothes dryer analysis with the electric clothes dryer fuel homes serving as the treatment and the natural gas clothes dryer fuel homes serving as the comparison. The steps outlined in the pool-related energy use analysis related to matching based on home size and then energy usage normalization based on remaining discrepancies in homes size have been omitted here given the large sample sizes and the nearly identical square footage between the two groups.

For this comparison, the difference in normalized base[14] energy use between the two single family groups is 23.6 Watt-hours / (week * ft²).

As a rough check, for the homes with electric clothes dryers in the sample indicated above, the normalized value corresponds to 52.1 kWh / week. A typical amperage for a new clothes dryer is 30 Amps. At 240 Volts, assuming an 80% power factor and an amperage oversizing factor of 10%, this corresponds to a demand of approximately 5 kW. Running the dryer for 4-5 hours per week would consume 20 -25 kWh /week.

Given that this comparison does not match between the analysis and the check, the load shape associated with the clothes dryer has not been included in the final deliverables.

[14] Remaining energy after subtracting the previously accounted-for heating, cooling, lighting, water heating and pool pump energy.

9. ADDITIONAL LOADS

The remaining additional loads consist of a combination of refrigeration, personal electronics such as TVs and computers, clothes washers, dishwashers, and other miscellaneous loads.

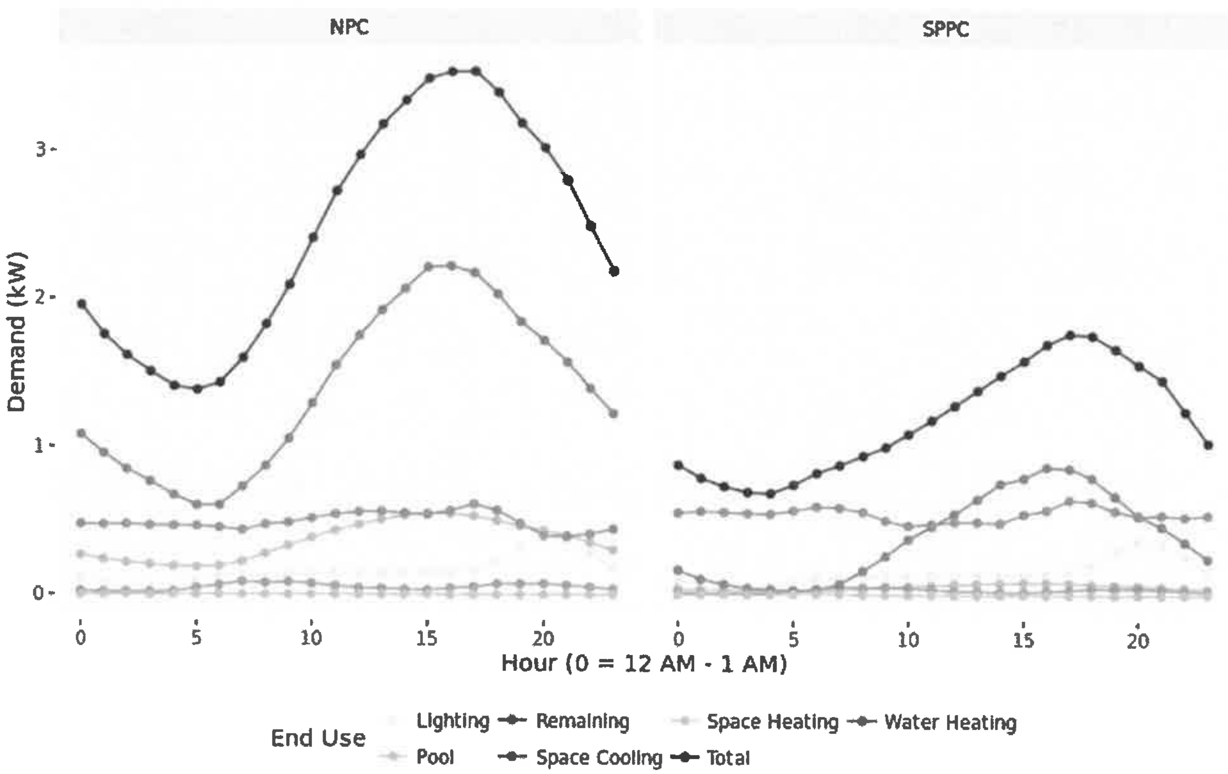
Efforts were made to distill these energy end uses. As noted in the clothes dryer discussion, there are challenges when attempting to disaggregate smaller end uses. In this case, the remaining loads are each relatively small contributors to total energy end use and they tend not to fit into the primary frameworks utilized in the analysis. There is not a strong temperature or seasonal dependence associated with any of these loads, nor do they lend themselves to the treatment vs. comparison pseudo experiment setup that was used successfully in the case of pool-related energy.

10. CONCLUSION AND RESULTS SUMMARY

The hourly loadshapes provided as an attachment to this document have been categorized currently by territory. However, ADM can additionally provide loadshapes in more detailed categorizations per direction from NV Energy.

Figure 10-1 below provides a sample graphical output of the loadshapes for an example set of homes and time frame.

Figure 10-1: Example Hourly Loadshapes in July for Homes in SPPC and NPC



ADM can generate additional sample graphical outputs per direction from NV Energy. ADM can also provide the data file with hourly energy end use values assigned on a home-by-home basis. The file is effectively too large to be analyzed in Excel (~8.5 million rows of data) and is much better suited for statistical software packages such as the R language used in these efforts. Sample code for filtering, slicing, and aggregating the data can be provided along with the primary data file.

LF-8

CONVENTION AND VISITORS AUTHORITY

LAS VEGAS TOURISM CONSTRUCTION BULLETIN
Resort & Other Destination Amenities*

Condensed Summary

(As of: December 5, 2018)

	Construction Cost (Millions)	Convention Space (Sq Ft)	Timeshare Units	Add'l Hotel Rooms	Est. Year-End Room Count
Las Vegas Room Inventory (as of June 30, 2018)					**148,842**
Projects scheduled to open in *2018*	**$1,409**	**553,100**	**68**	**78**	**148,920**
Projects scheduled to open in *2019*	**$1,057**	**126,000**	**-**	**1,017**	**149,937**
Projects scheduled to open in 2020	**$3,388**	**1,951,351**	**-**	**1,068**	**151,005**
Projects scheduled to open in 2021	**$7,108**	**50,000**	**-**	**3,859**	**154,864**
Projects scheduled to open in *2022 and Beyond*	**$3,258**	**975,500**	**-**	**9,355**	**164,219**
Combined Total (2018 and Beyond)	**$16,220**	**3,655,951**	**68**	**15,377**	

*NOTE: The above recap reflects significant projects, room closures, expansions and additions to the room inventory, but is not a comprehensive list of development.

ConstructionBulletin-120518

LAS VEGAS TOURISM CONSTRUCTION BULLETIN
Resort & Other Destination Amenities*
Current & Future Projects
(As of: December 5, 2018)

2018 Name of Property	Location	Completion Date	Cost (Millions)	Changes and/or New Amenities	Convention Space (Sq Ft)	Time-Share Units	Hotel Rooms
The Palazzo Resort - Hotel - Casino	3325 Las Vegas Blvd S	Jan 2018	N/A	Room Renovations			
Park MGM (rebrand Monte Carlo Resort and Casino)	3770 Las Vegas Blvd S	Jan 2018	N/A	Phase I - New Convention Space	77,000		
The Westin Las Vegas Hotel & Spa	160 E Flamingo Rd	Jan 2018	N/A	Property-Wide Renovations Transformed into Non-Gaming/Non-Smoking			
ARIA Resort & Casino	3730 Las Vegas Blvd S	Feb 2018	$165	Add'l 200,000 sf of Meeting Space/ 4-stories	200,000		
Hilton Garden Inn Las Vegas City Center	4655 Dean Martin Dr	Mar 7, 2018	N/A	New Property	1,200		172
Esports Arena Las Vegas	3900 Las Vegas Blvd S	Mar 22, 2018	$9	Allied eSports Gaming Facility 30,500+ sf / Two-Levels			
Las Vegas Motor Speedway	7000 Las Vegas Blvd N	Mar 2018	N/A	Clubhouse Areas and Seating Renovations, Loge-Box Seats, Social Pavilion and Sports Lounge			
Luxor Hotel and Casino	3900 Las Vegas Blvd S	Mar 2018	N/A	Room Renovations and Additional Convention Space	20,000		
The Berkley Corporation @ Silverton Hotel and Casino	8280 Dean Martin Dr	Mar 2018	N/A	New Rooms		68	
Home2 Suites by Hilton Las Vegas Strip South	7740 Las Vegas Blvd S	Apr 2, 2018	N/A	New Property	1,400		120
My Place Hotel	1440 E Craig Rd	Apr 13, 2018	N/A	New Property			63
Park MGM (rebrand Monte Carlo Resort and Casino)	3770 Las Vegas Blvd S	Apr 30, 2018	$450	Rebrand/Redesign, Renovation and Phase II - Executive Media Center (EMC)			
Bally's Las Vegas	3645 Las Vegas Blvd S	May 2018	$125	Room Renovations			
ESP Gaming eSports/Poker Studio (ARIA Resort & Casino)	3730 Las Vegas Blvd S	May 2018	N/A	10,000 sf eSports Gaming Facility/Poker Studio			
The Palazzo Resort - Hotel - Casino	3325 Las Vegas Blvd S	May 2018	$15	Casino Floor Remodel Multiple Phases			
Palms Casino Resort (Phase 1)	4321 W Flamingo Rd	May 2018	N/A	Property-Wide Renovations Restaurants/Casino Floor/Conv Space/Nightclub			
Flamingo Las Vegas	3555 Las Vegas Blvd S	Spring 2018	$90	Room Renovations Fab Rooms / Towers 5-6			
Mob Museum	300 Stewart Ave	Spring 2018	$7	New Interactive Exhibitions New F&B/Exhibit Space/Expand Retail	3,500		
America's Best Value Inn	167 E Tropicana Ave	Jul 2018	N/A	Property Closed			(257)
Motel 8	3961 Las Vegas Blvd S	Jul 2018	N/A	Property Closed			(24)
The Cosmopolitan of Las Vegas	3708 Las Vegas Blvd S	Aug 31, 2018	$152	Boulevard and Chelsea Tower / Room Renovations 3,160 sf Multi-Level Dining Concept			
Waldorf Astoria (rebrand Mandarin Oriental)	3752 Las Vegas Blvd S	Aug 31, 2018	N/A	Property Rebrand			
The Retreat on Charleston Peak (rebrand Resort on Mount Charleston)	2275 Kyle Canyon Rd	Aug 2018	N/A	Rebrand / Renovation			
Stratosphere Casino and Hotel (Phase 1)	2000 Las Vegas Blvd S	Aug 2018	$32	Property-Wide Multi-Phase Renovations			
Treasure Island - TI Hotel & Casino	3300 Las Vegas Blvd S	Aug 2018	$4	Buffet and Sports Bar Renovations			
The Wall eGaming Lounge (Rio All-Suite Hotel & Casino)	3700 W Flamingo Rd	Aug 2018	N/A	25,000 sf eSports Gaming Facility			
Palace Station Hotel & Casino	2411 W Sahara Ave	Sep 1, 2018	$192	Property-Wide Remodel: Restaurants/Poker Room-Bingo-Race & Sports/Theater/Parking/Facade			
Siegel Suites Swenson	4055 Swenson St	Sep 8, 2018	N/A	New Rooms			96
South Point Hotel Casino & Spa (Phase 1)	9777 Las Vegas Blvd S	Sep 2018	N/A	Room Renovations			
Lucky Dragon Hotel & Casino	300 W Sahara Ave	Oct 2, 2018	N/A	Property Closed			(203)
NoMad Las Vegas (rebrand Hotel32 @ Monte Carlo Resort and Casino)	3770 Las Vegas Blvd S	Oct 12, 2018	N/A	Rebrand/Redesign and Renovation			
El Cortez Hotel and Casino	600 E Fremont St	Oct 2018	N/A	Tower Room Renovations			
Terrible's Hotel and Casino (rebrand Gold Strike Hotel and Gambling Hall)	1 Main St - Jean	Nov 8, 2018	N/A	Property Rebrand			
Fly LINQ	3545 Las Vegas Blvd S	Nov 9, 2018	$20	Zip line Experience at The LINQ Promenade 10 side-by-side zip lines			
Park MGM	3770 Las Vegas Blvd S	Dec 27, 2018	N/A	Eataly Las Vegas Eat-Shop-Learn			
On The Record (OTR) @ Park MGM	3770 Las Vegas Blvd S	Dec 31, 2018	N/A	11,000 sf - Nightlife Venue			
MGM Grand Hotel and Casino	3799 Las Vegas Blvd S	Dec 2018	$130	Conference Center Expansion	250,000		
Plaza Hotel & Casino	1 Main St	Dec 2018	N/A	Equestrian Center Two Arenas 30,000sf & 12,500sf			
TownePlace Suites City Center	4920 Dean Martin Dr	Dec 2018	N/A	New Property			111
Ellis Island Hotel, Casino & Brewery (rebrand of Super 8-Koval)	4250 Koval Ln	Fall 2018	$20	Upgrade to Rooms, Suites and Lobby			
2018 TOTAL			**$1,409**		**553,100**	**68**	**78**

*NOTE: The above recap reflects significant projects, room closures, expansions and additions to the room inventory, but is not a comprehensive list of development.

ConstructionBulletin-120518

LAS VEGAS TOURISM CONSTRUCTION BULLETIN
Resort & Other Destination Amenities*
Current & Future Projects
(As of: December 5, 2018)

Las Vegas Convention and Visitors Authority

2019 Name of Property	Location	Completion Date	Cost (Millions)	Changes and/or New Amenities	Convention Space (Sq Ft)	Time-Share Units	Hotel Rooms
Home2 Suites	4940 Dean Martin Dr	Jan 2019	N/A	New Property			135
Fairfield Inn & Suites Airport South	Bermuda & Warm Springs	Apr 2019	N/A	New Property			106
TownePlace Suites Airport South	Bermuda & Warm Springs	May 2019	N/A	New Property			114
The Venetian Resort Hotel Casino	3355 Las Vegas Blvd S	May 2019	$50	Pool Redesign			
Palms Casino Resort (Phase 2)	4321 W Flamingo Rd	Spring 2019	N/A	Property-Wide Renovations Restaurants/Casino Floor/Conv Space/Nightclub			60
Pedestrian Overpass	Las Vegas Blvd & Park Ave	July 2019	N/A	New Pedestrian Bridge			
Kind Heaven (The LINQ Promenade)	3545 Las Vegas Blvd S	Aug 2019	$100	Four-Story Entertainment Venue Virtual and Augmented Reality Experience			
Residence Inn	3225 St Rose Pkwy	Oct 2019	N/A	New Property			115
AREA 15	Sirius Ave & Rancho Dr	Fall 2019	N/A	Art / Recreation Attraction	126,000		
Fairfield Inn by Marriott	5701 Sky Pointe Dr	Fall 2019	N/A	New Property			87
Palms Casino Resort (Phase 3)	4321 W Flamingo Rd	Fall 2019	$690	Property-Wide Renovations Restaurants/Casino Floor/Conv Space/Nightclub			
South Point Hotel Casino & Spa (Phase 2)	9777 Las Vegas Blvd S	Fall 2019	N/A	Room Renovations			
Virgin Hotels Las Vegas (rebrand of Hard Rock Hotel & Casino)	4455 Paradise Rd	Fall 2019	N/A	Property-Wide Renovations			
Wynn Las Vegas	3131 Las Vegas Blvd S	Fall 2019	N/A	Revamped 18-hole Wynn Gold Club			
Hyatt Place (Silverton Village)	8350 Dean Martin Dr	CY 2019	$60	New Property & Retail Project			150
Las Vegas Ballpark	S Pavilion Center Dr	CY 2019	$150	10,000-seat Ballpark			
Name TBD (CAI Investments)	3883 W Flamingo Rd	CY 2019	N/A	New Property			250
Paris Las Vegas	3655 Las Vegas Blvd S	CY 2019	N/A	Room Renovations			
Showcase Mall	3785 Las Vegas Blvd S	CY 2019	N/A	Expansion Four-Story/145,000 sf Bldg			
Treehouse Las Vegas	1022 Main St	CY 2019	$7	22,000 sf Entertainment Venue			
2019 TOTAL			**$1,057**		**126,000**	**-**	**1,017**

2020 Name of Property	Location	Completion Date	Cost (Millions)	Changes and/or New Amenities	Convention Space (Sq Ft)	Time-Share Units	Hotel Rooms
Wynn Las Vegas	3131 Las Vegas Blvd S	Mar 2020	N/A	Expanded Convention and Meeting Space	300,000		
Hampton Inn & Suites	Sierra Vista & Swenson	Apr 2020	$55	New Property			150
Home2 Suites	Sierra Vista & Swenson	Apr 2020	N/A	New Property	1,351		100
CAESARS FORUM Conference Center	3900 Block of Koval Ln	Spring 2020	$375	New Convention Center	550,000		
Corporate Headquarters and Practice Facility (NFL - Raiders)	St Rose Pkwy / Exec Airport Dr	Spring 2020	$75	55-acre Practice Facility and Corporate Headquarters			
Skyline Hotel & Casino	1741 N Boulder Hwy	Spring 2020	$7	Additional Rooms/Pool/Other Amenities			41
Las Vegas Stadium (NFL - Raiders)	Russell Rd / Polaris Ave	Jul 2020	$1,800	65,000-seat Stadium			
South Point Hotel Casino & Spa (Phase 3)	9777 Las Vegas Blvd S	Sep 2020	$40	Room Renovations			
Las Vegas Convention Center District (Phase 2)	3150 Paradise Rd	Dec 2020	$860	Expansion including 600K sf Exhibit Space & 150K sf Meeting Space	750,000		
Expo Center (International Market Centers)	445 S Grand Central Pkwy	CY 2020	$76	350,000 sf Expo Center	350,000		
MSG Sphere Arena (Las Vegas Sands & Madison Square Garden Company)	Sands Ave	CY 2020	N/A	18,500-seat Arena / 600,000 sf			
Name TBD (formerly Las Vegas Club)	18 E Fremont St	CY 2020	N/A	New Property			777
Target	3767 Las Vegas Blvd S	CY 2020	N/A	20,000 sf Store			
SLS Las Vegas	2535 Las Vegas Blvd S	CY 2020	$100	Room Renovations / Pool Redesign and Casino Floor Remodel			
2020 TOTAL			**$3,388**		**1,951,351**	**-**	**1,068**

*NOTE: The above recap reflects significant projects, room closures, expansions and additions to the room inventory, but is not a comprehensive list of development.

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LAS VEGAS TOURISM CONSTRUCTION BULLETIN
Resort & Other Destination Amenities*
Current & Future Projects
(As of: December 5, 2018)

LAS Vegas CONVENTION AND VISITORS AUTHORITY

2021 Name of Property	Location	Completion Date	Cost (Millions)	Changes and/or New Amenities	Convention Space (Sq Ft)	Time-Share Units	Hotel Rooms
SpringHill Suites Marriott	Tropicana Ave & Kelch Dr	Apr 2021	N/A	New Property			170
Fremont Hotel and Casino	200 Fremont St	CY 2021	N/A	New 320 ft / 509 Room Hotel Tower			289
Resorts World Las Vegas	3000 Las Vegas Blvd S	CY 2021	$7,000	New Property Multiple Phases			3,400
Stratosphere Casino and Hotel (Phase 3)	2000 Las Vegas Blvd S	CY 2021	$108	Property-Wide Multi-Phase Renovations	50,000		
2021 TOTAL			**$7,108**		**50,000**	**-**	**3,859**

2022 and Beyond Name of Property	Location	Completion Date	Cost (Millions)	Changes and/or New Amenities	Convention Space (Sq Ft)	Time-Share Units	Hotel Rooms
The Drew Las Vegas (formerly Fontainebleau)	2755 Las Vegas Blvd S	CY 2022	N/A	Redeveloped Property w/3 Hotels, Casino, Restaurants, Mtg Space, Entertainment & Retail	500,000		3,780
Las Vegas Convention Center District (Phase 3)	3150 Paradise Rd	CY 2022	$540	Renovation to the existing Convention Center Including 200K sf Meeting Space	200,000		
Residence Inn	Paradise Rd	June 2023	N/A	New Property			500
Mardi Gras Hotel and Casino	3500 Paradise Rd	CY 2023	N/A	Property-Wide Redevelopment 40,000 sf Casino			700
All Net Resort & Arena	2601 Las Vegas Blvd S	TBD	$2,700	22,000-Seat Arena/Two Hotel Towers/ Conference Center/Movie Theater/Retail Space	240,000		2,500
Aloft Hotel	6605 Las Vegas Blvd S	TBD	N/A	New Property			132
Delta Hotels by Marriott	TBD	TBD	N/A	New Property			260
Downtown Grand Las Vegas	206 N 3rd St	TBD	N/A	New Eight-Story Hotel Tower-The Quad Urban Park/Mtg Space/Café/Tavern	27,000		495
The Element Hotel by Westin	6605 Las Vegas Blvd S	TBD	N/A	New Property			121
Lorenzo Doumani Parcel (formerly Clarion Hotel & Casino)	305 Convention Center Dr	TBD	N/A	New Property			
Name TBD (Aspen Heights)	Symphony Park	TBD	N/A	New Property			300
Name TBD (CAI Investments)	Speedway Blvd & I-15	TBD	$18	New Property			125
Name TBD (Howard Hughes Properties)	Pavilion Ctr Dr & Oval Park Dr	TBD	N/A	New Property	8,500		267
Name TBD (Lyon Living)	9265 W Russell	TBD	N/A	New Property			175
Name TBD (Triple Five)	Las Vegas Blvd & Conv Ctr Dr	TBD	N/A	New Property			
Wynn Resorts parcel (formerly Frontier site)	3120 Las Vegas Blvd S	TBD	N/A	New Property			TBD
2022 and Beyond TOTAL			**$3,258**		**975,500**	**-**	**9,355**

*NOTE: The above recap reflects significant projects, room closures, expansions and additions to the room inventory, but is not a comprehensive list of development.

ConstructionBulletin-120518

GEN-1

Life Span Analysis Process

Frank A. Tracy Generating Station, Unit 3

Sparks, Nevada

2019 Update

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1.0 EXECUTIVE SUMMARY

The recommendation of this Life Span Analysis Process ("LSAP") is to plan for the continued operation of Frank A. Tracy Unit 3 through 2028 and investing approximately $12.9 million in the Tracy 3 New Pond Project. This recommendation would result in continuing the operation of this unit to at least its currently assigned depreciation retirement date. This recommendation is based primarily on the following factors: the investment is in the pond and water treatment equipment is the most economical alternative, there are no other known approved or pending environmental regulations that would materially affect this unit, this unit is currently operating reliably and is expected to continue to operate in a manner similar to its historic operation. The Tracy Station maintenance team conducts annual inspections of the unit to monitor the condition of the boiler and turbine components. Repairs are made as necessary and planned maintenance outages are taken based on the Original Equipment Manufacturer ("OEM") recommended intervals and based on good utility practices. Based on these inspections and repairs, this unit is in good working condition and is expected to meet its expected mode of operation in the future. Based on the reviews that were completed in developing this LSAP, Sierra recommends investing in the new pond and water treatment equipment and maintaining the depreciation planning retirement date of 2028.

2.0 UNIT DESCRIPTION

Frank A. Tracy Generating Station is located outside of Reno in Sparks, Nevada and is owned and operated by Sierra Pacific Power Company (SPPC) doing business as NV Energy (NVE).

Tracy Unit 3 is rated at a net dependable capacity of 108 MW. Currently, Tracy 3 may fire only pipeline quality natural gas. The unit optimally operates at an approximate 10,000 BTU/kw-hr heat rate.

Tracy Unit 3 has been in operation for 44 years and has a current approved retirement date of December 2028.

Tracy Unit 3 is equipped with Low NOx burners for nitrogen oxide emission control and is also equipped with a Continuous Emissions Monitoring System ("CEMS").

Over the past few years, the dispatch of Tracy 3 has been reduced with upgrades to the NVE transmission system and the installation of a new combined cycle block at Tracy Station. Also, an interconnection to the southern NVE distribution system (called the One Nevada Line, or ON-Line) has made low heat rate power from the southern fleet available to the northern system, which has further reduced the power generation demand from Tracy Station. Recent mining and data center developments in the load pocket could reverse this trend requiring additional energy supply from Tracy 3. Additionally, integration of proposed variable renewable generation could require Tracy 3 to run in stand-by mode to support the reliability of the grid. With these changes in NVE's transmission and generation system, the Tracy 3, originally designed for base load, has been operating in a seasonal cycling mode.

With the increase of variable renewable energy to the northern grid and the commissioning of the ON-Line transmission interconnection, there is some question as to how the unit will be dispatched to support load and transmission stability. This uncertainty could dramatically change both the scope and estimates presented in this document.

Figure 1 – Frank A. Tracy Station

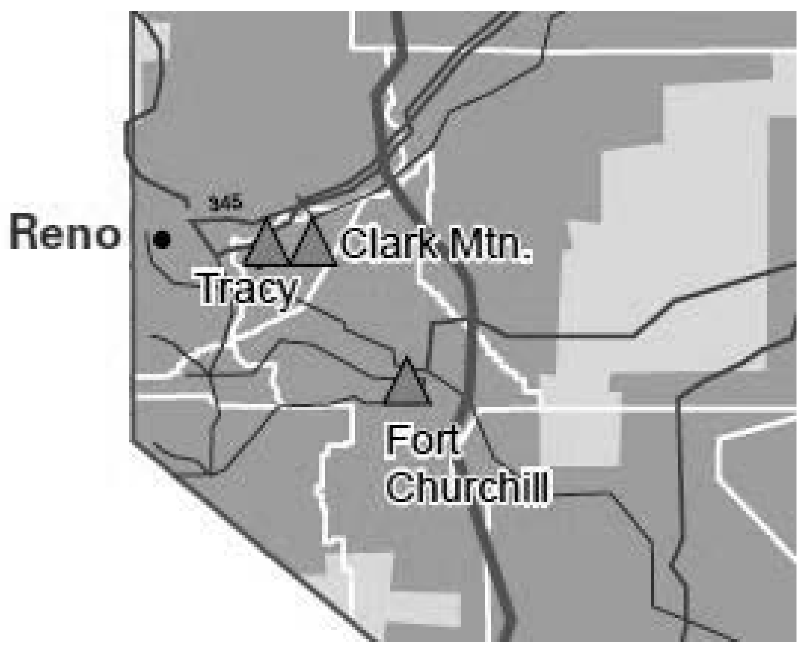


Figure 2 – Tracy/Clark Mountain Plant Location

2.1 Projected Operation

The following table presents the projected operations through 2028. Under the currently projected operations scenario, Tracy 3 would continue to operate primarily as a peaking unit, only operating on an as needed basis.

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Tracy 3	62,662	68,395	75,038	40,632	9,540	13,686	11,294	904	336	13,313

Figure 3 - Projected Operations – Annual MWhs

2.2 Projected O&M Budget

The Operations and Maintenance ("O&M") budget for Tracy Unit 3 includes $75K per year for boiler inspections. The only major maintenance activity that has been budgeted is a valve outage in 2028 for $500K if the plant continues operations.

2.3 Projected Capital Budget

The current capital budget for Tracy Unit 3 is limited to replacement of failed parts. The total capital expense for this site is $150,000.00 through the 2028 retirement of Tracy Unit 3.

3.0 LSAP REASSESSMENT CRITERIA

The LSAP provides an initial life span estimate based on a unit's design and intended mode of operation. This initial life span is established when the unit is first put in service, or in the case of older units when the LSAP was approved by the PUCN[1], the Reassessment Protocol was used to set an initial life.

After a Unit is commissioned and has been in operation, the life span may be reassessed to ensure that the Initial Life Span Assessment is still valid or to determine a new plan that is more appropriate for the Unit. The reassessment of Unit life span can be undertaken for any of the following **Reassessment Criteria**:

- Annual Business Plan Review
- Last Decade of Unit Life Span
- Environmental Compliance
- Infrastructure
- Significant Event
- PUCN Ordered Reassessment.

When a reassessment is undertaken, it can range from cursory to detailed, dependent on the nature of the revisit. For example, during the initial years of operation, the reassessment due to an Annual Business Plan Review may result in a business decision to maintain the Initial Life Span Assessment. The other end of the spectrum would be a Unit entering its planned last decade of operations where operations, maintenance, environmental and infrastructure issues could dictate a detailed review to assess the remaining life span. No matter the nature of the review, the key steps of the **Reassessment Protocol** are as follows:

- Unit Assessment
- Environmental Assessment
- Infrastructure Assessment
- Development of Options
- Options Input to Resource Planning and Financial Analysis
- Final Decision on Life Span Assessment and Implementation Plan

Per the approved LSAP, the following reassessment criteria have been met, triggering an evaluation of the operating life for the Tracy 3.

- Unit is within 10 years of last approved retirement date
- Environmental Compliance: Cease discharge to the cooling pond by 12/31/2020

The following provides a brief explanation of the above triggers and determines the

[1] The Life Span Analysis Process ("LSAP") was approved by the Public Utilities Commission of Nevada in Docket Number 08-08002

criticality of each trigger for the LSAP analysis.

Unit Is Within 10 Years of Last Approved Retirement Date

The latest Integrated Resource Plan filing for Sierra shows a retirement date of 12/31/2028 for Tracy Unit 3. Since replacement capacity would take a number of years to permit, design and construct, and investments in replacement units would be required within the next Action Plan Period to ensure replacement capacity is available if the units are planned to retire in 2028.

Environmental Compliance: Cease discharge to the cooling pond by 12/31/2020

The unlined Tracy cooling pond is currently used for water storage and as a discharge point for plant blowdown and drains. Due to regulatory changes which have been incorporated into the current environmental permit, the unlined cooling pond will not be permitted/used as a discharge point for process water on or after December 31, 2020. Without a solution, Tracy 3 will not be able to operate beyond December 31, 2020.

3.1 Unit Condition Considerations

Tracy Unit 3 is 44 years old and nearing the end of its design life. The unit was designed to be a base loaded unit. The unit is within 10 Years of the current PUCN approved retirement date. The Commission approved retirement date for Fort Tracy Unit 3 is of 12/31/2028.

The last overhauls on the unit were completed in 2005. A steam turbine major was performed in 2005. The turbine is in good condition. The boiler was examined by the original equipment manufacturer Riley Power Inc. in 2005 and the boiler is in an acceptable condition. The boiler feed pumps and condensate pumps were overhauled in 2005.

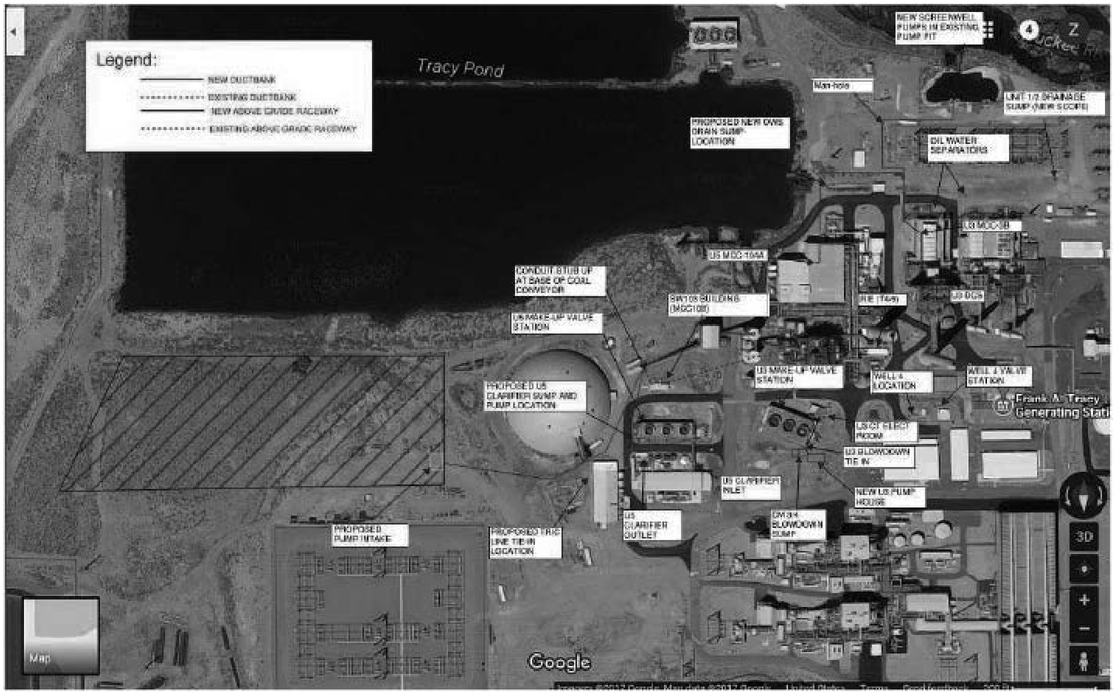
To meet Best Available Retrofit Technology ("BART") environmental regulations, in 2014, a new low NOx combustion system was installed on Tracy Unit 3. All of the existing burners were replaced with Babcock & Wilcox XCL-S gas burners and new sidewall NOx ports were installed. The secondary fuel oil firing system was also decommissioned during the installation of the new low NOx combustion system.

Sierra believes the unit is in good working condition and is currently being used to serve load and is ready to operate on an as needed basis.

3.2 Environmental Considerations

Tracy 3 is currently in compliance with all environmental agency issued permits and associated emissions limits. With the exception of those specifically addressed below associated with the Tracy cooling pond, no other specific environmental regulations are known at this time that would directly impact the operations of Frank A. Tracy Unit 3.

Tracy Cooling Pond Project



The unlined Tracy cooling pond is currently used for water storage and as a discharge point for plant blowdown and drains. Due to regulatory changes which have been incorporated into the current environmental permit, the unlined cooling pond will not be permitted/used as a discharge point for process water on or after December 31, 2020.

NV Energy was required to make the decision to modify the existing processed water discharge infrastructure from Tracy 3 Cooling Tower Blowdown, Clark Mountain Evaporative Cooler blowdown and other smaller stream that discharge into Tracy cooling pond.

An engineering analysis was conducted to understand the needs of all process water users, the capabilities of the existing equipment, and capabilities of available technologies. Safety and reliability problems of the existing waste water treatment plant, clarifier, and reverse osmosis units were reconsidered and addressed in the comprehensive solution.

In consideration of this engineering analysis, a recommendation for construction of a new Tracy pond for equalization and retention of cooling tower 3 and Clark Mountain 3&4 evaporative cooling blowdown and modernizing or upgrading of the existing water treatment equipment to reduce discharge into the existing evaporation ponds to maintain a sustainable operation was approved by NV Energy’s management.

The Key Decision Report and capital project business case for the Tracy 3 Pond Project is included in Appendix A of this LSAP.

3.3 Infrastructure Considerations

Infrastructure for a Unit includes all those support systems that allow a Unit to generate and deliver power to the customer. They include land, roads, railways, fuel supply, water supply, transmission access and other features.

The LSAP focuses on current and forecasted changes to the Infrastructure elements. There are contracts on many of these Infrastructure components and at any time during the life span of the Unit, the renewal, expiration or negotiation of these contracts may result in impacts to the economic viability of the Unit. Similarly, market conditions are associated with some Infrastructure components, with fuel being a prime example.

There are currently no infrastructure concerns for Tracy 3.

4.0 OPTION DEVELOPMENT

The alternatives identified for the future utilization of Tracy Unit 3 represent different options of capital investments in the facility to allow safe and reliable operation of the unit in accordance with environmental regulations.

Since Sierra is operating at a capacity deficit, no early retirement option was identified.

4.1 Base Case, Retire Tracy Unit 3 12/31/2028

This alternative assumes that Tracy Unit 3 will operate until the eve of December 31, 2028 as planned. This alternative includes the investment in capital for the New Tracy 3 Pond Project, but no other extraordinary capital investments for the remaining life of the unit, other than normal turbine maintenance based on operating hours and unit starts. The unit can be expected to continue operating on an as needed basis to support the transmission grid as necessary in addition to providing energy until its retirement. At retirement on December 31, 2028 Sierra would retire its interests in the plant.

4.2 Option A – Retire Tracy Unit 3 12/31/2020 – Replace with Market

This alternative assumes that Tracy Unit 3 will operate until the eve of December 31, 2020. This alternative does not include the investment in the New Tracy Unit 3 Pond Project. At retirement on December 31, 2030 Sierra would retire its interests in the plant and Tracy Unit 3's capacity would be replaced with market purchases. It should be noted that since Sierra is already operating at a capacity deficit, replacement capacity may not be readily available in the near term to replace the unit.

4.3 Option B – Retire Tracy Unit 3 12/31/2020 – Replace with Battery

This alternative assumes that Tracy Unit 3 will operate until the eve of December 31, 2020. This alternative does not include the investment in the New Tracy Unit 3 Pond Project. At retirement on December 31, 2030 Sierra would retire its interests in the plant and Tracy Unit 3's capacity would be replaced with an 8-hour battery asset.

5.0 PLANNING ASSUMPTIONS

The following Planning Assumptions are used in the ProMod analysis and are used in Sierra's business planning.

5.1 Labor

The Tracy plant currently budgets 2.5 full time employees (FTEs) for the operation of Tracy Unit 3. This is expected to remain constant through the planning period. If unit 3 was retired those FTEs reallocated to other plant operations.

5.2 Expected Operations Strategy:

Tracy 3 is typically dispatched to meet peak loads during the summer and winter months. The unit is also used to meet capacity reserve margins throughout the year. This operations strategy is expected to continue through the planning period.

6.0 OPTION ANALYSIS

6.1 Economic Analysis

Currently, Sierra relies on the market to provide a portion of its capacity needs. When Tracy 3 retires, its capacity must be replaced – either by another unit or by acquiring even more capacity from the market. This analysis will compare the fixed and variable costs of continuing the operation of Tracy 3 to the end of 2028 with the cost of purchasing an equivalent amount of capacity from the market for the same time period.

Another case was run of replacing the Tracy Unit 3 capacity with a batter resource that would provide approximately 100MW of capacity for 8 hours

Over the period 2024-2028, Tracy 3 is expected to have a capacity factor of approximately 12%. The analysis will also subtract the fuel costs of continuing operation of Tracy 3 to the end of 2028.

Tracy LSAP

	5 Year PWRR 2019-2023 (million $)	10 Year PWRR 2019-2028 (million $)	20 Year PWRR 2019-2038 (million $)	30 Year PWRR 2019-2048 (million $)	5 Year PWRR Increase vs Least Cost (million $)	10 Year PWRR Increase vs Least Cost (million $)	20 Year PWRR Increase vs Least Cost (million $)	30 Year PWRR Increase vs Least Cost (million $)
2019 Tracy LSAP Base	$ 5,972	$ 10,812	$ 18,446	$ 24,317	$ -	$ -	$ -	$ -
2019 Tracy LSAP retire 2020	$ 5,985	$ 10,844	$ 18,486	$ 24,361	$ 12	$ 32	$ 41	$ 44
2019 Tracy LSAP retire2020wBat	$ 6,060	$ 11,011	$ 18,722	$ 24,597	$ 88	$ 200	$ 276	$ 279

Figure 4 – Economic Analysis Results

The table shows continued operation of Tracy 3 saves between $2.4 and $17.6 million per year, with the 5 year PWRR.

7.0 LSAP RETIREMENT DATE RECOMMENDATION

The recommendation of this LSAP is to plan for the continued operation of Tracy Unit 3 through at least 2028, including making the investment in the new pond and water treatment equipment. No other extraordinary capital investments are required for the continued operation of Tracy Unit 3 through 2028. The PWRR analysis shows that continued operation of the Unit is the most economic management of the asset. Continued operation of the unit provides a ready capacity and energy resource for Sierra's system and reduces the capacity deficit at peak, compared to retiring the unit. Though there are no other known approved or pending environmental regulations that would materially affect Tracy Unit 3, the Company currently believes there would be a high level of uncertainty forecasting environmental capital requirements to operate this unit beyond 2030. However, there are also no known or approved environmental regulations that would necessitate the retirement of the Tracy Unit 3 in 2028. Based on this analysis, Sierra recommends maintaining the depreciation planning retirement date of the Tracy Unit 3 as December 31, 2028.

APPENDIX A

TRACY 3 POND PROJECT KEY DECISION REPORT AND BUSINESS CASE

TRACY 3 POND PROJECT KEY DECISION REPORT AND BUSINESS CASE are included as Confidential Technical Appendix GEN-2 in this filing

GEN-2

NVEnergy

Authorization For Expenditures

1 - General Information

AFE TYPE	Supplemental	Date	1/25/2019
Project Title	T3 Evaporation Pond	Proj. Code	TR2027
Business Unit Name	Energy Supply	BU Code	8
Department Name	Charles Lenzie Plant	Dept. Code	D175
FERC Account Name	WASTE WATER TREATMENT / POND LINER#100.00%	Acct. Code	311
Project Start Date	9/1/2017	Complete Date	1/1/2021
In-Service Date	11/30/2020		
Project Mgr	Ross, Dennis B	AFE Index Number	TR2027-2
Company	North		
Outage Required (Yes/No):	No	Is there a risk this project will extend the outage? (Yes/No):	No

Description and purpose of expenditure (Attach supporting details. See Authorization for Expenditures Procedures.)

The original AFE was written in order to provide funding to complete the Preliminary Engineering for the new Tracy 3 pond. This Supplemental AFE will provide funding to complete the detailed design, permitting, procurement and construction of the new pond and associated balance of plant improvements as identified and outlined in the Key Decision Report (KDR) Scenario #16 dated December 7, 2018.

The unlined Tracy cooling pond is currently used for water storage and as a discharge point for plant blowdown and drains. The largest user of the pond is Tracy Unit 3. In the future, the cooling pond will not be permitted/used as a discharge point for process water unless lined. NV Energy must invest in either water treatment, line the existing cooling pond, build a new lined discharge pond or decommission Tracy Unit 3 early in order to meet future environmental permit requirements. The associated risk profiles of additional water treatment or an attempt to line the existing cooling pond is much higher than building a new lined discharge pond.

2 - AFE Cost Information

Labor (10, 11, 12)
Stores (50, 59)
Non-stock goods (51)
Outside services (40)
Purchases (54, 55, 56, 70)
Expenses (75)
Other (81, 82, 97, 99)
Labor overheads (30, 31)
Transportation (60)
Material overheads (52, 53)
A&G and Capital surcharge (32,
Partnership Billing
CIAC (85, 86)*
Subtotal (@ Net)
Financing (80) AFUDC
Contingency
CIAC Reversal (if required)
Total AFE Approval Cost

[redacted]

3 - Budget Information

AFE
Original AFE
Supplemental additions
Total AFE Approval Cost

BUDGET
Current year approved capital plan (Fall 2018 Approved
Reallocated Amount
Other years capital plan
AFUDC

Total Approved Budget

AFE (Over)/Under Budget

[redacted]

Allocated Amount
Please indicate BID being transferred from and the total dollars transferred

Budget ID	Amt Transferred
	$ -
	$ -
	$ -
Total Transferred	**$ -**

4 - Expenditure Schedule (excludes contingency and CIAC reversal)

Year	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr
Prior	$ [redacted]			
2017	$			
2018	$			
2019	$			
Beyond	$			

	Total Capital	Total Expense
	[redacted]	
Tota		

NVEnergy

Standard Project Proposal

Business Unit: Energy Supply **Proposed Date:** 1/25/2019

Title: T3 Evaporation Pond

Proj. Code TR2027

Objective: The unlined Tracy cooling pond is currently used for water storage and as a discharge point for plant blowdown and drains. The largest user of the pond is Tracy Unit 3. In the future, the cooling pond will not be permitted/used as a discharge point for process water unless lined. NV Energy must invest in either water treatment, line the existing cooling pond, build a new lined discharge pond or decommission Tracy Unit 3 early in order to meet future environmental permit requirements. The associated risk profiles of additional water treatment or an attempt to line the existing cooling pond is much higher than building a new lined discharge pond. The scope of work includes the construction of a new evaporation pond to support opertations of Tracy 3. The scope of work will also include all necesary infrastructure to re-direct waste streams currently be routed to the Tracy Cooling Pond to the new Tracy 3 Evaporation Pond.

Decisions Required: The Supplemental AFE is to provide funding for the detailed design engineering, permitting, procurement, construction and supervision necessary to construct a new waste water pond and associated balance of plant improvements.

Executive Summary: The original AFE was written in order to provide funding to complete the Preliminary Engineering for the new Tracy 3 pond. This Supplemental AFE will provide funding to complete the detailed design, permitting, procurement and construction of the new pond and associated balance of plant improvements as identified and outlined in the Key Decision Report (KDR) Scenario #16 dated December 7, 2018.

The unlined Tracy cooling pond is currently used for water storage and as a discharge point for plant blowdown and drains. The largest user of the pond is Tracy Unit 3. In the future, the cooling pond will not be permitted/used as a discharge point for process water unless lined. NV Energy must invest in either water treatment, line the existing cooling pond, build a new lined discharge pond or decommission Tracy Unit 3 early in order to meet future environmental permit requirements. The associated risk profiles of additional water treatment or an attempt to line the existing cooling pond is much higher than building a new lined discharge pond.

Key Issues for Discussion:

- Coordination with NVE Substation Group. The West Tracy Substation additon will be constructed adjacent to the new pond and will share the same site.
- Applying for and receiving a UEPA permit.
- Completion of the project by the end of 2020.

Investment Request:
(in $ Thousands)

Direct
Indirect
CIAC
Subtotal Capital Plan
AFUDC
CIAC Reversal
Contingency
Total AFE (@ 100%)

PWRR:

Budget Status: Budgeted in the 2016, 2017 and 2018 Fall plans.

Business Unit Sponsor:

Project Manager: Ross, Dennis B

1. **Background** *(Provide background and state if project is discretionary or required and describe the source and reason for the requirement)*
   The unlined Tracy Cooling Pond was built in the 1960s to supply the Station with once-through cooling water withdrawn from the Truckee River.Thispond wasused for cooling, which discharged back to the river. The pond was identified in the Nevada Administrative Code (NAC), which NDEP interprets as Waters of the United States, unless proven otherwise. In approximately 1974, cooling towers were constructed at the station and the pond was changed to its current configuration. Since then, the pond has been used to supply station cooling water, service water and some water for dust control and fire protection. The pond currently receives non-contact cooling water, cooling tower blowdown, incidental storm water and other minor wastewaters from the station, as well as makeup water from the river.
2. **Benefits** *(Include categories as appropriate for the project and describe benefits)*
   - **Customer Service -- Will allow for the contiued operation of Tracy 3.**
   - **Reliability -- Will replace the existing Tracy Cooloing Pond as the waste water discharge pond**
3. **Alternatives Considered** *(What other alternatives were considered)*
   1) Install additional water treatment equipment. 2) Transition to an ACC. 3) Discharge to the river. 4) Line the existing cooling pond. 5) Invest in a brine concentrator. 6) Injection well.
4. **Project Risk Factors** *(What are primary risk factors and what risk mitigation has been done)*
   This proejct hs been scheudled to be completed by the end of 2020 to allow for the continued operation of Tracy 3.
5. **Financial Analysis**

Project Economics (unleveraged)	Before Regulatory Recovery	With Regulatory Recovery
Project NPV (in $ Thousands)	($1,801,432.0)	($565,298.9)
Project IRR	4.94%	6.06%
Discount Rate Used	6.65%	6.65%
Business Unit Cost of Capital	6.65%	6.65%
Capital Productivity Ratio	0.835	0.948
Payback Period (years)	17.47 Yrs	15.60 Yrs

6. **Regulatory Recovery Strategy** *(Indicate if there are any special ratemaking or legislative activities required as part of the project)*
   This projectshall be including the Sierra Pacific Power Company General Rate Case filing in 2022.
7. **Procurement Strategy** *(Describe any special considerations to minimize procurement cost)*
   The project will be competiviely bid using the low price technically acceptable criteria. The detailed design shall be competiviely bid upon completion of
8. **Project Management** *(What major dependencies are there from other business unit operations or contractors)*
   The project shall be managed by the NV Energy Generation Capital Projects Management team per the NV Energy Capital Projects Process.
9. **Project Milestones** *(Include projected start, in-service, and completion dates)*
   - Project Start Date: September 13, 2017
   - Project Construction Start Date: September 30, 2019
   - Project In-Service Date: December 11, 2020
   - Project Completion Date: March 5, 2021
   -

Appendices *(As applicable; list in bullet form each appendix name and attach detailed appendix info)*
-
-

REDACTED PUBLIC VERSION

NVEnergy PPM ▸ Project Proposal Document: T3 Evaporation Pond

Budget ID: TR2027 **Project Name: T3 Evaporation Pond** Edit Refresh

Project Proposal Document | Environmental | Reference Documents | Variance | Close Out Forms | Project Close Out

Expand All | Collapse All

Project Type*	MOC Number	Budget ID	Project Name*	PPD Workflow Status	
Modification	MOC-TR-2017-003	TR2027	T3 Evaporation Pond	Approved	Create P6 Schedule

Project Group*	Plant*	Operational Technology	Information Technology	Planning In Service*	Forecast In Service	In Service
GEN-CP	Tracy	☐	☐	07/31/2020	10/19/2020	☐

Business Unit*	Budget Priority*	Sub-Priority	Outage	Outage ID	Project Proposal Owner*
SPPC	3		☐		Ross, Dennis

- PROJECT ATTRIBUTES

Budget Type	Budget Group	Investment Reason	Investment Reason Subcategory	Project Status	Billable To Partners	10 Year Plan	AFE Status
Operating	Regulated generation - Natural Gas	CORE	None	Unapproved	☐	YES	Not Approved

Project Manager	Project Control	Project Owner At Facility	Contingency	Gas Allocation %*	AFUDC Type	AFUDC Rate	Flag Executive Reporting	Program
Ross, Dennis	Hoover, Amy	Aboumrad, Nicholas	$ 0	0	N/A	6.65	☐	☐

- ◉ SINGLE SCOPE ◯ MULTI SCOPE

Budget Area Code*	Unit*	Division Code	Project Category	Budget ID Status	Billing Percentage	Product Code
TR	Tracy 3	E	TR	ACTIVE	0	687

Scope*

This project will create a lined disposal pond for the Tracy Unit 3 cooling tower. Additional waste streams currently directed to the existing cooling pond will be routed to the new pond.

Scope Change	Scope Change Counter	Scope Change Remarks
☐	1	Original plan was to re-line a portion of the existing cooling pond. The original concept had too high of an environmental risk associated profile.

Link to Scope Document

- PROJECT SUMMARY

Metric:* Reliability (EFOR); Environmental;

Primary Driver:* Environmental

Identify Problem

In 2016, the Nevada Department of Environmental Protection (NDEP) received formal notification that NV Energy would end the practice of process water discharge into the Tracy cooling pond by 12/31/2020. The Tracy cooling pond is identified in the Nevada Administrative Code (NAC). NDEP has determined that they cannot continue to issue a permit for discharge to a waterbody identified in the NAC without addressing the pollutant limits listed in the NAC for that water. NDEP has indicated that all discharges into this pond henceforth will be required to meet the standards listed in the NAC. Discharges to the pond do not currently meet these standards. The pond does not meet standards for discharge into the river.

An investment is required to keep Tracy Unit 3 operational. Approximately eight viable scenarios were evaluated that would allow continued operation of Tracy Unit 3. Based on the forward capacity curve, supplied by resource planning, the value of replacement capacity from 2021-2028 is [redacted]

Executive Summary

The unlined Tracy cooling pond is currently used for water storage and as a discharge point for plant blowdown and drains. The largest user of the pond is Tracy Unit 3. In the future, the cooling pond will not be permitted/used as a discharge point for process water unless lined. NV Energy must invest in either water treatment, line the existing cooling pond, build a new lined discharge pond or decommission Tracy Unit 3 early in order to meet future environmental permit requirements. The associated risk profiles of additional water treatment or an attempt to line the existing cooling pond is much higher than building a new lined discharge pond.

Background

The unlined Tracy Cooling Pond was built in the 1960s to supply the Station with once-through cooling water withdrawn from the Truckee River. This pond was used for cooling, which discharged back to the river. The pond was identified in the Nevada Administrative Code (NAC), which NDEP interprets as Waters of the United States, unless proven otherwise. In approximately 1974, cooling towers were constructed at the station and the pond was changed to its current configuration. Since then, the pond has been used to supply station cooling water, service water and some water for dust control and fire protection. The pond currently receives non-contact cooling water, cooling tower blowdown, incidental storm water and other minor wastewaters from the station, as well as makeup water from the river.

REDACTED PUBLIC VERSION

Project Benefits (Outcome)

This project will allow Tracy Unit 3 the ability to continue operation after 12/31/2020. Based on forward capacity estimates from resource planning, if the unit was retired early (2020) the company would need to replace approximately [redacted] in capacity from 2021-2028. The investment required to keep Tracy Unit 3 operational through this window is approximately [redacted].

Alternatives

1) Install additional water treatment equipment. 2) Transition to an ACC. 3) Discharge to the river. 4) Line the existing cooling pond. 5) Invest in a brine concentrator. 6) Injection well.

Justification For Preferred Alternative

The preferred alternative has the highest probability of success while being one of the lowest cost options.

Project Risks

Sensitivity Analysis

- STANDARD PROJECT PROPOSAL (SPP) DETAILS

Objective

The unlined Tracy cooling pond is currently used for water storage and as a discharge point for plant blowdown and drains. The largest user of the pond is Tracy Unit 3. In the future, the cooling pond will not be permitted/used as a discharge point for process water unless lined. NV Energy must invest in either water treatment, line the existing cooling pond, build a new lined discharge pond or decommission Tracy Unit 3 early in order to meet future environmental permit requirements. The associated risk profiles of additional water treatment or an attempt to line the existing cooling pond is much higher than building a new lined discharge pond. The scope of work includes the construction of a new evaporation pond to support opertations of Tracy 3. The scope of work will also include all necesary infrastructure to re-direct waste streams currently be routed to the Tracy Cooling Pond to the new Tracy 3 Evaporation Pond.

Regulatory Recovery Strategy

This project shall be including the Sierra Pacific Power Company General Rate Case filing in 2022.

Procurement Strategy

The project will be competiviely bid using the low price technically acceptable criteria. The detailed design shall be competiviely bid upon completion of the preliminary engineering. Once detailed design engineering is completed the construction phase of the project shall be competiviely bid. All bids shall be conducted per the NV Energy Procurment policy and practices.

Project Management

The project shall be managed by the NV Energy Generation Capital Projects Management team per the NV Energy Capital Projects Process.

- VERSION HISTORY

Modified	Version Number	Modified By
1/28/2019 8:14:10 AM	23.0	Hoover, Amy
3/22/2018 7:48:25 AM	22.0	Laichter, Jaclyn
3/21/2018 8:57:45 AM	21.0	Daghlian, Jimmy
3/21/2018 8:43:35 AM	20.0	Daghlian, Jimmy
2/12/2018 8:49:56 AM	19.0	Ross, Dennis
1/24/2018 2:57:50 PM	18.0	Hale, Corinna
1/18/2018 2:42:06 PM	17.0	Hale, Corinna
12/22/2017 12:32:45 PM	16.0	Hale, Corinna
12/22/2017 12:22:21 PM	15.0	Hale, Corinna
12/6/2017 11:43:48 AM	14.0	Mungi, Aswinikumar
9/12/2017 11:08:18 AM	13.0	Richardson, Shaun
9/8/2017 1:45:44 PM	12.0	Walker, Kristen
8/22/2017 1:10:29 PM	11.0	Richardson, Shaun
8/22/2017 10:55:19 AM	10.0	Richardson, Shaun
7/28/2017 2:03:11 PM	9.0	Walker, Kristen
7/28/2017 1:56:10 PM	8.0	Ghisletta, Alan
5/25/2017 11:58:51 AM	7.0	Walker, Kristen
5/25/2017 7:49:48 AM	6.0	Richardson, Shaun
5/25/2017 7:22:14 AM	5.0	Richardson, Shaun
5/24/2017 2:58:34 PM	4.0	Walker, Kristen
5/24/2017 11:39:48 AM	3.0	Berryman, Sean
5/24/2017 10:07:08 AM	2.0	Berryman, Sean
5/23/2017 9:32:49 AM	1.0	Richardson, Shaun

PPM ▸ Project Proposal Document: T3 Evaporation Pond

Budget ID: TR2027 **Project Name: T3 Evaporation Pond**

Edit | Refresh

Project Proposal Document	Environmental	Reference Documents	Variance	Close Out Forms	Project Close Out

Expand All | Collapse All

Download and Fill Out the Environmental Evaluation File

- ENVIRONMENTAL

Environmental Support Team

Plant Environmental Advisor	Corporate Environmental Advisor
Broadhead, Bruce	Heintz, Christopher

Is New Source Review (NSR) CheckList Required?

○ YES ◉ NO

If NSR Checklist is required, Please attach the NSR Checklist File.

Environmental Impact	Environmental Permit Required	Title V Permit	Asbestos Abatement	Hazardous Material	Environmental Remediation	Air Pollution Control Equipment	Water Pollution Control Equipment
☐	☑	☐	☐	☐	☐	☐	☐

Environmental Comments. Explain any items that are checked.

Various construction related environmental permits will be needed along with a discharge permit revision (a discharge permit renewal is due during this time frame). Follow the dust control plan measures during construction phase. No further NSR is needed for the pond lining. If operational changes are made to T3 due to the capacity of the pond, this discussion may require its own NSR evaluation.

Plant Environmental Certified	Plant Environmental Certified By	Corporate Environmental Certified	Corporate Environmental Certified By
☑	Clevenger, Dawn	☑	Klimek, Christene

- ENVIRONMENTAL ATTACHMENTS

Document Name
Environmental Review for AFEs ssedits (5-5-17) cooling pond lining-201706050928534126.docx

Annual Cost by Budget ID, Activity

T3 Evaporation Pond

Project / Budget ID / Activity ID	Description	Total Cost	Prior	2018	2019	2020	2021	2022	Post
TR2027	**T3 Evaporation Pond**								
TR2027	**TR2027.TR2027 TR2027 Tracy Cooling Pond Liner_TR**								
TR2027A300	A300-TR2027 Actual Cost Activity	[redacted]							$0.00
TR2027A304	A304-TR2027 Actual Cost Activity								$0.00
TR2027A309	Project Management Effort								$0.00
TR2027A301	Preliminary Engineering								$0.00
TR2027A303	Detailed Design								$0.00
TR2027A306	Permitting UEPA - Legal Dept Handling								$0.00
TR2027A380	Material Received								$0.00
TR2027A357	Construction Implementation								$0.00
TR2027A604	Removal / Decomissioning								$0.00
TR2027A601	Construction Mgt								$0.00
TR2027	**Subtotal**								**$0.00**
TR2027	**Total**								**$0.00**
Grand Total									**$0.00**

28-Jan-19

NV ENERGY - ENERGY SUPPLY
Project Estimate

Project Name: T3 Evaporation Pond, Install

Estimate Date:	25-Sep-18	**In-Service YEAR:**	2020	**Note 4**
Estimator:	Dennis Ross	**Level of Accuracy:**	Design	
Unit:	**Tracy 3**	**Max Risk to Apply:**	15%	
Business Unit:	SPPCO	**Risk Applied:**	0%	**Note 1**
Plant:	**Tracy**	**Product:**	687	
		Category:	C112	**Note 8**
Budget ID:	TR2027			
Work Order No/Project ID:	9842698101	**Partner Billing %:**	0%	
Link Code (if used):		**Short Budget ID:**	TR2027	

Work Breakdown Structure				Direct Costs						
WBS Level	Note	WBS Activity	WBS Element	Labor Role	NV Energy Labor (Hours)	Contractor Labor and Outside Services (40) ($ Direct)	Stock Material (50)	Non-Stock Material (51)	Purchases (70)	Expenses (Travel & Meals) (75)
1		A309000	Project Management	PM	5,200					
2	7	A308000	NVE Prior Studies							
3		A301000	Preliminary Engineering	ENG						
4		A303000	Detailed Design	ENG						
5		A306000	Permitting	ENV						
6		A380000	NVE Procurement					$ 500,000		
7		A357000	Construction/Implementation	CREW	1,040					
11		A601000	Construction Management	CNMGT	5,200					
8		A376000	Startup/Preoperational Test	WRITR						
9		A415000	Capitalized Spares (New)							
10	7	A605000	Salvage							
12	6	A604000	Removal (Retirmt - No Regl Asset)	CREW						
13	2,6	A610000	ARO - Regulatory Asset	PM						
14	2,6	A611000	ARO - No Regulatory Asset	PM						
15	6	A612000	Retirement - Regulatory Asset	PM						
			TOTAL Project		11,440		-	500,000	-	-

Enter data in cells with this fill color.

Will existing equipment be retired as a result of this project?	No
Is the equipment being removed from original construction?	No
Estimated date when the retired equipment was originally installed: (known as the Retirement Unit Vintage Date) Format:1/1/1900	
Will existing equipment be salvaged and the project receive a credit?	No

Cost Benefit Summary	
Profitability Index (PI)	5.37
Payback Period (yrs)	2.75

Template Version 3/15/2018

Enter data in cells with this fill color.

Estimator's Comment Log (add date and comment):

(KDR Option #16)

Note 1

Risk	Direct Costs with Risk Applied						Overheads						TOTAL EAC	Partner	Net EAC
Applied Risk	NVEnergy Labor (10)	Contractor Labor and Outside Services (40)	Stock Material (50)	Non-Stock Material (51)	Purchases (70)	Expenses (Travel & Meals) (75)	Labor Load (30)	Stock Material Load (52)	Non-Stock Material Load (53)	Transportation Load (60)	A&G Load (32)	Project Supervision (33)	TOTAL Estimate At Completion (EAC)	Partner Billing	Net EAC including Partner Billing
0%	$ 286,000		$ -	$ -	$ -	$ -	$ 204,147	$ -	$ -	$ -					
	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
0%	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
0%	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
0%	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
0%	$ -		$ -	$ 500,000	$ -	$ -	$ -	$ -	$ 5,000	$ -					
0%	$ 57,200		$ -	$ -	$ -	$ -	$ 40,829	$ -	$ -	$ -					
0%	$ 286,000		$ -	$ -	$ -	$ -	$ 204,147	$ -	$ -	$ -					
0%	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
0%	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
0%	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
0%	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
0%	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
0%	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
0.0%	629,200		-	500,000	-	-	449,123	-	5,000	-					

Average
Note 5

Property Unit Details	Acct	Property Unit Title
Primary Property Unit	311	WASTE WATER TREATMENT / POND LINER

NVEnergy - Generation
COSTS AND BENEFITS
COST BENEFITS CALCULATIONS

Proj Title:	**T3 Evaporation Pond, Install**		
Plant / Unit:	**Tracy 3**	**Level of Accuracy**	**Design**
Budget ID:	**TR2027**	**In-Service YEAR:**	**2020**
Estimator:	**Dennis Ross**	**Estimate Date**	**25-Sep-18**

10 Year Average Inflation Rate (GDP Price Deflator) 2.00%

Plant Retirement Date 2028

Year #	0	1	2	3	4	5	6	7	8		
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**		
O&M Savings											
Labor	[redacted]										
Incremental Labor Savings \ man-hr											
Average Wage \ $/man-hr											
Labor Overhead											
= Labor Savings(inflation adjusted)											
Non-Labor											
Replacement Capacity of Tracy 3 (Present Value)											
Description #2											
Description #3											
Residual Value											
Obsolete Inventory Write Off (one time cost. Should be n											
= Annual non-labor Savings(Inflation adj.)											
Heat Rate Improvements											
Projected Heat Rate Improvement \ Btu/kW											
Modeled Net Unit Output \ MW											
Total Available Hours / year											
Cost of Fuel \ $/MM Btu											
=Heat Rate Savings											
Avoided Derates/Outages											
Unit Derate \ MW											
Duration of Derate \ hr											
Facility Capacity Factor											
Probability of occurrence											
Incremental Production Loss \ MWh											
Replacement Power Margin \ $/MWh											
= Avoided Derate Savings											
Savings (Pre Tax)											
Capital Costs											
- Capital Costs											
= Pre Tax Cash Flow											
= NV Energy (WACC) **6.65%**											
Payback Period in Years											
Profitability Index (Pre Tax)											

		Net Cash Flow
Proj Title:	**T3 Evaporatio**	**Payback**
Plant / Unit:	**Tracy 3**	
Budget ID:	**TR2027**	
Estimator:	**Dennis Ross**	

ASSUMPTIONS REGARDING TANGIBLES / BASIS FOR SAVINGS / COMMENTS:
O&M Savings - Labor
O&M Savings - Non-Labor
Replacement capacity of Tracy 3 is baased on the Forward Capacity Curve from Resource Planning. Unless this project is implemented or alternative improvements are made Tracy 3 will require early decommissioning after December 31, 2020 due to discharge permit limitations.
Heat Rate Improvements
Avoided Derates/Outages
Other Comments

NVEnergy

Inventory Analysis

Estimated Obsolete Inventory					
Passport Catalog ID	Description	Disposal Date	Quantity	Average Unit Price	Total Price
			0	$ -	$ -
			0	$ -	$ -
			0	$ -	$ -
			0	$ -	$ -
			0	$ -	$ -
			0	$ -	$ -
			0	$ -	$ -
			0	$ -	$ -
			0	$ -	$ -
			0	$ -	$ -
			0	$ -	$ -
			0	$ -	$ -
				Total	$0.00

New Inventory Items					
Description	Manufacturer	Man. Part #	Quantity	Quoted Price	Total Price
			0	$ -	$ -
			0	$ -	$ -
			0	$ -	$ -
			0	$ -	$ -
			0	$ -	$ -
			0	$ -	$ -
			0	$ -	$ -
			0	$ -	$ -
			0	$ -	$ -
			0	$ -	$ -
			0	$ -	$ -
			0	$ -	$ -
				Total	$0.00

Property Unit Summary

Project Name:	**T3 Evaporation Pond, Install**		
Unit:	**Tracy 3**	**Level of Accuracy**	**Design**
Budget ID:	**TR2027**		
Estimator:	**Dennis Ross**	**Estimate Date**	**25-Sep-18**

Enter data in cells with this fill color.

Estimated Cost of Additions

	Account Selection	Account #	Quantity	Property Unit Title	Percentage of Total Addition (List highest % to smallest)	Allocated Cost of Addition
1						
2	311 - STRUCTURES & IMPROVEMENTS	311	1	WASTE WATER TREATMENT / POND LINER	100%	$ [redacted]
3	0 - NEED RETIREMENT UNIT INFORMATION	0			0%	$
4	0 - NEED RETIREMENT UNIT INFORMATION	0			0%	$
5	0 - NEED RETIREMENT UNIT INFORMATION	0			0%	$
6	0 - NEED RETIREMENT UNIT INFORMATION	0			0%	$
7	0 - NEED RETIREMENT UNIT INFORMATION	0			0%	$
8	0 - NEED RETIREMENT UNIT INFORMATION	0			0%	$
9	0 - NEED RETIREMENT UNIT INFORMATION	0			0%	$
10	0 - NEED RETIREMENT UNIT INFORMATION	0			0%	$
	0 - NEED RETIREMENT UNIT INFORMATION	0			0%	$
				Subtotal	**100%**	**$**

Property Units being Removed

	Account Selection	Account #	Quantity	Property Unit Title
1				
2	0 - NEED RETIREMENT UNIT INFORMATION	**0**		
3	0 - NEED RETIREMENT UNIT INFORMATION	**0**		
4	0 - NEED RETIREMENT UNIT INFORMATION	**0**		
5	0 - NEED RETIREMENT UNIT INFORMATION	**0**		
6	0 - NEED RETIREMENT UNIT INFORMATION	**0**		
7	0 - NEED RETIREMENT UNIT INFORMATION	**0**		
8	0 - NEED RETIREMENT UNIT INFORMATION	**0**		
9	0 - NEED RETIREMENT UNIT INFORMATION	**0**		
	0 - NEED RETIREMENT UNIT INFORMATION	**0**		
10	0 - NEED RETIREMENT UNIT INFORMATION	**0**		

TRACY UNIT 3 WASTEWATER MODIFICATION
Key Decision Report

Owner: **Brian Lawson**
Description: Tracy Wastewater Modification
Date: December 7, 2018

Executive Summary:

The unlined Tracy cooling pond is currently used for water storage and as a discharge point for plant blowdown and drains. Due to regulatory changes which have been incorporated into the current environmental permit, the unlined cooling pond will not be permitted/used as a discharge point for process water on or after December 31, 2020.

NV Energy must make the decision to modify the existing processed water discharge infrastructure from Tracy 3 Cooling Tower Blowdown, Clark Mountain Evaporative Cooler blowdown and other smaller stream that discharge into Tracy cooling pond. If capital investments are made to modify the existing process water discharge infrastructure, NV Energy must determine the best investment possible to minimize costs and risk.

An engineering analysis was conducted to understand the needs of all process water users, the capabilities of the existing equipment, and capabilities of available technologies. Safety and reliability problems of the existing waste water treatment plant, clarifier, and reverse osmosis units were reconsidered and addressed in the comprehensive solution.

In consideration of this engineering analysis, this Key Decision Report recommends contruction of a new Tracy pond for equalization and retention of cooling tower 3 and Clark Mountain 3&4 evaporative cooling blowdown and modernizing or upgrading of the existing water treatment equipment to reduce discharge into the existing evaporation ponds to maintain a sustainable operation.

Recommendation and Discussion:

In 2015, the Nevada Division of Environmental Protection (NDEP), Bureau of Water Pollution Control (BWPC) received formal notification[1] from NV Energy that it would end the practice of process water discharge into the unlined Tracy cooling pond by a future date, which was established in the subsequently issued discharge permit as December 31, 2020. The decision to stop discharging to the Tracy cooling pond impacts two NV Energy stakeholders: Power Generation and Environmental Services. Two external stakeholders were also identified: the Army Corp of Engineers, and NDEP. The key decision elements to end process water discharge into the cooling pond were:

- The Tracy cooling pond is identified as a jurisdictional waterbody in the Nevada Administrative Code (NAC). NDEP determined in 2015 that they cannot continue to issue a Groundwater Discharge permit for discharge to a jurisdictional waterbody identified in the NAC without addressing the pollutant limits listed in the NAC for that water.
- NDEP indicated in 2015 that all discharges into this unlined cooling pond in the future would be required to meet the standards listed in the NAC. Discharges to the unlined cooling pond do not currently meet these water quality standards. In addition, discharges into the unlined cooling pond in the future may be subject to a US Environmental Protection Agency (EPA) National Pollutant Discharge Elimination System permit. The EPA federal permit would be administered by the NDEP.
- The cooling pond is unlined and hydraulic communication between this pond and the Truckee River cannot be ruled out. The discharge into the pond does not meet standards for discharge into the river. When the pond was designed, it met the codes and standards applicable at the time.
- NV Energy informed the NDEP by letter[1] dated April 10, 2015 its intent to cease discharge into the unlined cooling pond at some future date.
- NDEP agreed to renew the groundwater discharge permit and issued a renewal on July 1, 2016, that requires NV Energy to cease discharge into the unlined cooling pond by December 31, 2020.

Current operation of Tracy Unit 3 cooling tower and Clark Mountain peaking units evaporative cooling is dependent upon discharging all process cooling water directly into the unlined cooling pond. All other units are partially dependent on discharging process water directly or indirectly to the cooling pond.

[1] NV Energy. (2015, April 10). Renewal of Permit to Discharge NEV97023 Tracy Generating Station.

Without an alternative location to send the process water, Tracy Unit 3 would need to be decommissioned eight years earlier than planned, the gas turbines may not be able to use evaporative cooling, Tracy 5 would need to reduce use of cooling water, and Tracy 8/9 would need to reduce use of evaporative cooling and cooling water. An engineering investigation determined several process water disposal alternatives to continue operation of Tracy Unit 3, evaporative cooling for all gas turbines, use of cooling water in Tracy 5 and Tracy 8/9.

NV Energy submitted a plan[2] to the NDEP on December 20, 2017, detailing process changes and cooling pond modifications that will be implemented to support the decision to stop discharges to the unlined cooling pond. Final implementation of the plan must be finished by December 31, 2020. Based on the review by the key stakeholders, the recommendation is to contruct a new Tracy pond for equalization and retention of cooling tower 3 blowdown and clark mountain 3&4 evaporative cooling blowdown and modification or upgrade of the water treatment equipment to reduce discharge into the existing evaporation ponds to maintain a sustainable operation. This recommendation is economically justified, based on the forward capacity value of the unit.

Work streams Impacted:

Energy Supply:

- Tracy 10-year Budget Plan
- Tracy Operating Procedures
- Tracy Maintenance Procedures
- Tracy Unit Characteristic Data

Environmental Services:

- Environmental Construction Permit
- Environmental Operation Permit

---

[2] NV Energy. (2017, December 20). Letter to NDEP - Tracy Generating Station - Authorization to Discharge Permit #NS0097023 Plan for Ceasing Discharge to Current Cooling Water Pond (Outfall PWC).

Recommendations Coordinated & Agreed With:

Corporate Chemist:	Doug Guillaume	
Manager, Environmental Services:	Tony Garcia	
Manager, Maintenance Tracy:	Nicholas Aboumrad	
Director, Generation Support:	Jimmy Daghlian	
VP, Environmental Services:	Starla Lacy	
Tracy Plant Director:	Brian Lawson	

Recommendation Approval By:

Executive, Generation:	Dariusz Rekowski	
SVP, Energy Operations:	Kevin Geraghty	

Table of Contents

LIST OF ABBREVIATIONS

ACC	Air Cooled Condenser
BWPC	Bureau of Water Pollution Control
CCRO	Closed Circuit Reverse Osmosis
CM	Clark Mountain Peaking Units 3 & 4
CWT	Cooling Water Tower
DCS	Distributed Control System
EDR	ElectroDialysis Reversal
EPA	Environmental Protection Agency
gpm	gallons per minute
HDPE	high density polyethylene
HERO	High Efficiency Reverse Osmosis
M	Million (10^6)
NAC	Nevada Administrative Code
NDEP	Nevada Division of Environmental Protection
NPDES	National Pollutant Discharge Elimination System
OMAG	Operations, Maintenance, Administration, & General
RO	Reverse Osmosis
TDS	Total Dissolved Solids
TRIC	Tahoe Reno Industrial Complex
TSS	Total Suspended Solids
UIC	Underground Injection Control
WSAC	Wet Surface Air Cooler
WOTUS	Waters Of The United States
WWRO	Waste Water Reverse Osmosis

Attachment A

Stakeholders:

Energy Supply and Environmental Services

Description: Tracy cooling Pond

Background

The unlined Tracy cooling Pond was built in the 1960s to supply the Tracy plant with once-through cooling water withdrawn from the Truckee River. After the water was used for cooling, it was discharged back to the cooling pond which discharged back to the river. The pond was later identified as a jurisdictional waterbody in the Nevada Administrative Code (NAC), which NDEP interprets as Waters of the State unless documented otherwise. In approximately 1974, cooling towers were constructed at the Tracy plant and the pond was changed to its current configuration. Since then, the cooling pond has been used to supply station cooling water, service water, and some water for dust control and fire protection. The cooling pond currently receives non-contact cooling water, Tracy 3 cooling tower blowdown, evaporative cooler blowdown from the Clark Mountain peakers, incidental storm water, and other minor process wastewaters from the Station Tracy plant as well as makeup water from the river. This pond does not discharge directly to the river; however since it is unlined, communication between this pond and the Truckee River cannot be ruled out.

Identify Problem

NDEP, acting as the discharge permitting authority, determined in 2015 that it could not continue to issue a permit for discharge to a jurisdictional waterbody identified in the NAC without addressing the pollutant limits listed in the NAC for that water, and that the form of permit issued for such a jurisdictional waterbody may require a federal National Pollutant Discharge Elimination System (NPDES) permit, administered by the NDEP, not a state groundwater discharge permit. Unlike a state groundwater discharge permit, issuance of an NPDES permit would require EPA oversight and approval. NDEP communicated to NV Energy environmental staff, if NV Energy wished to continue discharging into the unlined cooling pond, an NPDES permit would be required and that all discharges into this unlined cooling pond henceforth would be required to meet the listed standards in the NAC. If the facility ceases discharge into the unlined cooling pond, the standards identified in the NAC will not apply to the discharge and an NPDES permit would not be required. Therefore, the decision was made by the company to cease discharge into the unlined cooling pond on or before December 31, 2020. Given that the Tracy Unit 3 cooling tower discharge and all other cooling tower/evaporative cooler discharge will not meet the water quality standard listed in the NAC and any discharge will violate the discharge permit requirement to cease discharge into the unlined cooling pond, an investment must be made to provide an alternative for the process water stream in order to keep Tracy Unit 3 operational beyond that date and also provide a discharge or treatment option for the other cooling towers, evaporative coolers oily water separators.

Current Uses

The Tracy cooling pond was originally installed to meet the cooling needs of Tracy Units 1-3. With the retirement of Units 1 and 2, the cooling pond is used for:

1) Blowdown from the Tracy Unit 3 cooling tower is discharged to the cooling pond (200-600 gallons per minute – (gpm)).
2) Blowdown from the Tracy Unit 5 “Pinon Pine” Cooling Tower is discharged to the cooling pond (100-200 gpm).
3) Blowdown from Clark Mountain Units 3 and 4 evaporative coolers are discharged to the cooling pond (these are relatively small flows 25-50 gpm).
4) Make up for the Tracy Units 3 and 4/5 cooling towers is supplied from the cooling pond (200-1500 gpm).
5) Service water for Tracy Units 8/9/10 is supplied from the cooling pond. The primary use of this water is for the wet surface air condenser (WSAC) in the summer months (100-120 gpm) and evaporative cooling (100-150 gpm).

Description of Impacts

Multiple scenarios were evaluated to address the newly established environmental requirements associated with the Tracy cooling pond. The scenarios are summarized below along with the recommendation for the preferred alternative.

The business case for the preferred alternative is primarily driven by the capacity values of Tracy Unit 3 from 2021 thru 2028 (Table 1). If no investment is made, the unit will be retired at the end of 2020 and the operation of the other units will be reduced to fit within the existing infrastructure. The capacity values were provided by NV Energy's Resource Planning Department. Table 1 shows that the net present value of the capacity is approximately [redacted] assuming 6.65% discount rate from 2021 thru 2028.

Table 1: Forward Capacity Values for Tracy 3

Year	Capacity Cost ($/kW-year)	Replacement Capacity $	Present Value Total $
2018	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

No. Scenario Description

1 **Scenario 1: Do Nothing**

If Tracy Unit 3 was retired the replacement capacity cost would be [redacted] No physical changes would be made to the cooling pond. All other outflows to the cooling pond would be routed to existing plant equipment for treatment. This would require an investment in a new piping network, which is expected to cost [redacted] The cooling pond could continue to be used as a makeup water source only. This option was deemed not economically viable because of the [redacted] capacity replacement cost would significantly exceed the costs to continue to operate Unit 3 with new pond configuration and changes to water treatment equipment.

2 **Scenario 2: Retire Unit 3 and Replace with Quick Start Generation**

Retire Unit 3 and replace with equivalent quick start capacity partially at Tracy station and partially at Fort Churchill station. This will reduce OMAG and CAPEX associated with modifying the waste water handling. The cost to replace the capacity of Unit 3 with new generation would exceed $100 M. Replacement costs ($100M) would significantly exceed the costs to continue to operate Unit 3 with new pond configuration and changes to water treatment equipment. This option was not considered economically viable.

3 **Scenario 3: Discharge to River**

The possibility of direct discharge of process cooling water into the Truckee River was investigated. Direct discharge to the Truckee River would require obtaining an NPDES permit from NDEP and would require EPA oversight and approval. Additionally, an NPDES permit would require meeting federal effluent limitation guidelines for discharges to the Truckee River. Cooling pond chemical composition already exceeds the concentration limits of the river. Currently, the cooling pond is unlined and communication with the Truckee River cannot be ruled out. The cooling pond does not meet standards for discharge into the river, and cooling pond water quality is better than untreated process cooling water quality. Therefore, process cooling water would not meet NPDES water quality standards for discharge into the river. Direct discharge was determined to not be technically viable due to water quality restraints by NDEP.

The process water could be treated to meet NPDES water quality standards, but treated water is then suitable for re-use within the facility. It is not economically viable to treat and purify water

[3] Table *1*: Forward Capacity Values for Tracy 3
[4] Black & Veatch, *Tracy Station Unit 3 Pond Project Preliminary Engineering Report*, (2017) Project 197247, 30

No.	Scenario Description
	for discharge when the water could be reused. Treating and reusing the water is considered in subsequent scenarios.
4	**Scenario 4: Cooling Water 3 Blowdown Effluent Transfer to the Tahoe Reno Industrial Complex (TRIC)**

TRIC currently maintains a non-potable water source throughout the complex. A possible tie-in would allow the direct transfer of waste Tracy cooling water into the TRIC system. The concept would be to establish a mutually beneficial agreement where TRIC could expand their non-potable water supply capacity, and NV Energy could dispose of used cooling water. NV Energy met with TRIC in June 2016 to discuss a mutually beneficial arrangement where TRIC would take Tracy process water for reuse by other users in the TRIC reservoir. Water samples were collected from the Unit 3 CWT basin and Unit 8/9/10 service water tank for analysis. The laboratory analyses[5,6] were presented to TRIC. TRIC reviewed the analyses, indicated that TDS exceeded their limits, and stated that the water could not exceed 500 ppm TDS. This limit was non-negotiable and advised that NV Energy consider using reverse osmosis to reduce TDS prior to sending to TRIC.

If Tracy station implemented reverse osmosis water treatment then the water would be suitable for re-use within Tracy station. NV Energy would still need to manage the brine and solids removed from the water. In this case it would not be a mutually beneficial relationship to discharge purified water to TRIC and it was concluded[7] that NV Energy would not pursue discharging water to TRIC.

In 2018 TRIC began expanding the reservoir to meet the water needs of new users without water rights. As part of the expansion TRIC also considered building a water treatment plant to reduce TDS for water recovery.

NV Energy and TRIC met again on August 1, 2018 to reconsider discharging the Tracy station process water to TRIC. During the meeting TRIC stated the 500 ppm TDS limit was still in effect to discharge to the TRIC reservoir.

TRIC was working on a treatment plant to potentially accept water with higher TDS water, but TRIC could not evaluate and commit to NV Energy to accept the water at a higher TDS typical of cooling tower blowdown by the deadline of this project December 31, 2020. The TRIC pipeline and connection to Tracy station would not be available by December 31, 2020.

[5] Nalco Company. (2015, March). NV Energy Tracy CWT 3 Basin Water Analysis 1386895.
[6] Nalco Company. (2015, March). NV Energy Tracy Unit 8/9/10 Service Water Analysis 1386896.
[7] NV Energy. (2016, June 10). Minutes of Meeting Tracy Water Strategies.

No.	Scenario Description
	Given project execution uncertainty and water quality contraints by TRIC, this option was determined to not be viable.
5	**Scenario 5: Injection Well[8] for Cooling Tower 3 & CM 3/4 Blowdown** Injection wells have been used successfully in the power generation industry, specifically geothermal industry, for the past 35 years. A feasibility study was commissioned to identify the likelihood of a permeable and deep reservoir that could be used as an injection well. Schlumberger (consulting engineer) was commissioned to complete the review. They reviewed all the drilling, geologic, geochemical and hydrological data within a six mile radius of the Tracy plant. The reports indicated there is likely a deep reservoir beneath the groundwater aquifer, however, there is no geochemical data to prove, with certainty, the deep reservoir could be used as an injection well. If NV Energy was to pursue an injection well, the company would need to drill exploration wells to develop a full injection well target. The company would then need to be successful in hitting the target. An exploration program would be approximately \$1.285 M[9] ± 25% in cost per well. In addition to the technical/ecnomical risk, there is a significant regulatory risk with obtaining an Underground Injection Control (UIC) permit. There are no injection permits for this basin and obtaining one would require additional monitoring wells and a testing program. This option was determined to not be viable due to the technical/economical and regulatory risk.
6	**Scenario 6: Utilize Existing Tracy Unit 4/5 clarifier for Cooling Tower 3 Blowdown[10]** Cooling tower 3 blowdown and Clark Mountain evaporative cooler blowdown would be treated through the existing Unit 4/5 clarifier side stream softening system. It was assumed that Unit 3 cooling tower would operate near the permit limit of 7090 mg/L TDS, 6-8 cycles. The side stream softening system was designed to soften blowdown from Unit 4/5 and demineralizer neutralized regeneration water. This system included a 27,000 gallon equalization tank that provides about 20 minutes of surge to respond to chemistry changes. Recently the performance of the clarifier has required additional operators to respond to the chemistry changes. Adding cooling tower 3 blowdown and Clark Mountain evaporative cooler blowdown would further increase the variability in the chemistry feed.

[8] Schlumberger Water Services. (2015). *Injection Well Feasibility Analysis 055436.R*.
[9] Schlumberger. (2015). *NV Energy Tracy Injection Well Budgetary Costing*
[10] Burns & McDonnell, *Frank A. Tracy Water Balance Study*, (2017) Project No. 95050, Rev. 2, Option 2A, 4-5

No.	Scenario Description
	This scenario was deemed technically not viable without other modifications to increase equalization time, storage, and mixing. These modifications were considered in subsequent scenarios.
7	**Scenario 7: Use Existing Clarifier and Add Waste Concentration Tower for Tracy Cooling Tower 3 & CM 3&4 Blowdowns** A waste concentration tower was evaluated to treat Unit 3 cooling water tower blowdown and Clark Mountain 3&4 evaporative cooler blowdown. Unit 4/5 cooling water tower blowdown treatment would remain unchanged. It was assumed that Unit 3 cooling tower would operate near the permit limit of 7090 mg/L TDS, 6-8 cycles. Blowdown water from Unit 3 cooling tower (150-250gpm) and Clark Mountain evaporative coolers (25 gpm) would need to be softened by the clarifier to reduce the hardness and silica before sending to a waste concentration tower. The (175-275 gpm) additional flow to the clarifier would exceed the current normal operating capability of the clarifier side stream softening system as built. The waste concentration tower would receive 175 – 275 gpm, operate at 5 – 7.2 cycles, and blowdown 24 - 55 gpm. This amount of discharge water would approach or exceed the 30 gpm evaporation rate of the existing evaporation ponds. A waste concentration tower to replace the original unit was considered in 2012 . It was designed to accept 80 gpm of water from the clarifier, operate at 7.2 cycles, and blowdown discharge 11 gpm. The project cost was 11 M in 2012[11]. The chemical costs were estimated at $50,000 per year[12]. A larger tower would treat three times the amount of water and require three times the amount of chemicals thus the chemical costs would be $150,000 per year. Considering that a significantly larger tower would be required to concentrate 175 – 275 gpm, the cost would be significantly higher than 11 M, and the clarifier would not operate reliably given the additional flow without additional revisions. This option was not considered technically or economically viable.

[11] Burns & McDonnell, *NV Energy Tracy Station – Water/Wastewater Management Systems Evaluation Report*, (2012) Project No. 67335, 43
[12] Burns & McDonnell, *NV Energy Tracy Station – Water/Wastewater Management Systems Evaluation Report*, (2012) Project No. 67335, 2-4

No.	Scenario Description
8	**Scenario 8: Transition to an Air Cooled Condenser (ACC) or to a Hybrid Type Cooling**

A feasibility study was not conducted for the construction of a full ACC system. However, a hybrid type ACC system feasibility study was conducted in 2006[13]. This hybrid system would have replaced 80% of the existing water cooling with air cooling.

When ambient temperatures exceeded 95°F it required using the cooling tower in series with the ACC to maintain the steam turbine exhaust pressure less than the alarm levels. This hybrid option reduced Unit 3 cooling water tower make-up usage by 219 gpm.

The 2006 initial hybrid feasibility study estimated $15.31 M in capital investment for Unit 3. Assuming 3.0% annual adjustment for inflation, capital investment costs would now exceed $22.4 M for this hybrid cooling system. Since a full ACC would be even larger in scale, installation expenses would also be larger.

This hybrid alternative was determined to be not technically viable. The non-hybrid ACC may be technically viable, but has been determined to be not economically viable.

9 **Scenario 9: Brine Concentrator for Unit 3 Cooling Tower Water 3 Blowdown**

A brine concentrator would significantly reduce process cooling water blowdown. This would allow Tracy Unit 3 the ability to discharge to the existing evaporation ponds directly. The cooling water would need to be concentrated to 6-8 cycles to minimize the size of the brine concentrator.

The cost to rent a 30-60 gpm brine concentrator is $ 164,919 – 266,480 per month[14]. Estimated rental costs could exceed $800,000 per month to treat 180 gpm of Unit 3 CWT blowdown with three (3) rental 60-gpm brine concentrators. Summer seasonal 4-month annualized rental cost is estimated at $3.2M.

The purchase cost of an 80 gpm brine concentrator is approximately $10.0 M[15]. A fully cycled Tracy Unit 3 cooling tower would require at least three (3) brine concentrators. Purchased units would require a capital investment of over $35 M, assuming 3% inflation.

This alternative was determined to be not economically viable.

[13] CH2M HILL. (2006, November 13). Tracy Cooling System Study Project 351606.
[14] Purestream Co. *AVARA Pricing Scenarios NV Energy* (2018)
[15] Burns & McDonald. *Tracy Water Systems Evaluation* (2013) Project 70722, 4-21

No. **Scenario Description**

10 **Scenario 10: High Efficiency Waste Water Treatment for Tracy 3 Cooling Tower 3 Blowdown**[16]

More advanced closed circuit reverse osmosis technology was considered to individually treat Tracy 3 cooling tower blowdown. High Efficiency waster water treatment reject is routed to existing evaporation ponds. This strategy would require additional dedicated infrastructure to support the chosen technology and the project costs were $24.1 M. Blowdown from Clark Mountain 3&4 evaporative coolers and any excess blowdown from the Unit 8/9 evaporative coolers and wet surface air coolers was treated by existing reverse osmosis units.

This option was deemed not economically viable.

11 **Scenario 11: Line the Tracy Cooling Pond**

This scenario was intended to line the existing cooling pond so that all users can continue to use the cooling pond similar to historical operation with makeup and recycle to a pond. No additional water treatment equipment was considered consistent with the historical operation of the facility.

The entire Tracy pond would be lined to confirm that no communication with the Truckee River according to BWPC guidance[17]. The cost was estimated at [redacted] per acre[18] or [redacted] This cost estimate does not consider dewatering and subgrade work for the existing pond.

Geo-Logic advised NV Energy that the cost for dewatering the existing pond and earthwork to establish a suitable subgrade would be significantly higher than the cost to build a new pond.

In consideration of very high costs to line the entire pond it was determined to stop this cost estimate and began evaluating a smaller new pond in combination with other options such as using water treatment.

This option was deemed technically questionable and economically not viable.

12 **Scenario 12: Build New Cooling Pond to Replace the Tracy Cooling Pond**

Use of the Tracy cooling pond has contributed to a sustainable process for Tracy Unit 3, Unit 4/5, Clark Mountain peaking units, and Unit 8/9/10 for many years. Replacing the 33 acre Tracy

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[16] Burns & McDonnell, *NV Energy Tracy Station – Water Balance Revisions*, (2018) Project No. 108247, Option 3, 3-8

[17] Department of Conservation and Natural Resources. (2017, May). WTS-37 Guidance Document for the Design of a Lined Wastewater Holding Pond (Surface Impoundment). Carson City, Nevada: Division of Environmental Protection Bureau of Water Pollution Control.

[18] Burns & McDonnell, *Frank A. Tracy Water Balance Study*, (2017) Project No. 95050, Rev. 2, 4-7

No. Scenario Description

cooling pond was considered. It was assumed that Unit 3 cooling tower would operate at the permit limit of 7090 mg/L TDS, 6 cycles, 16% blowdown with a 27% capacity factor, 2365 hours per year and generate 32,214,024 gallons of waste water. Clark Mountain evaporative coolers would blowdown 25 gpm and generate 2,365,200 gallons of waste water with 18% capacity factor 1577 operating hours per year. The combined waste water flow from Unit 3 cooling tower blowdown and Clark Mountain evaporative cooler blowdown produces 66 gpm per year.

The existing waste water ponds evaporate approximately 1.25 – 2.5 gpm per acre. To evaporate all of the blowdown waste water would require a new cooling pond of 26 - 53 acres. The facility does not have an additional 26 - 53 acres of land to accommodate this scenario. If land were available the cost for a new cooling pond would be [redacted] This is based on a cost of [redacted] $ per acre based on actual costs by Black & Veatch[19] to build a pond.

Solids did concentrate in the Tracy cooling pond over the many years of operation. Additional equipment costs would be required later to the remove the solids.

Considering that a new pond would require a significant amount of land and costs this scenario was deemed technically and economically not viable. Solids removal equipment and costs were not investigated because it would further increase the cost.

13 **Scenario 13: New Water Treatment and Evaporation Pond for Unit 3 Cooling Tower 3 Blowdown[20]**

A new water treatment and evaporation pond for Unit 3 cooling tower blowdown was considered with Clark Mountain evaporative cooler blowdown sent to the waste water equalization tank, TK-2900. This scenario was to evaluate the impact to other parts of the plant if Unit 3 cooling water blowdown was sent to a separate new evaporation pond. This scenario included a new filter, new 2-pass RO, and offsite regeneration of demineralizers. If this scenario proved successful then sizing for a Unit 3 cooling water blowdown evaporation pond would be estimated.

The waste water flow from the other units (4,5,8,9,10,CM3/4) would generate 95 gpm under summer conditions which is significantly higher than the typical evaporation rate of 30 gpm. The existing evaporation ponds would fill within one (1) year under typical operating conditions. If Unit 3 was only operated during the summer this would delay the evaporation ponds from filling for five years. This scenario was deemed technically not viable.

[19] Black & Veatch, *Tracy Station Unit 3 Pond Project Preliminary Engineering Report*, (2017) Project 197247, 34
[20] Burns & McDonnell, *Frank A. Tracy Water Balance Study*, (2017) Project No. 95050, Rev. 2, Option 6, 4-11

No.	Scenario Description
	Since this scenario was not technically viable for the other units (4,5,8,9,10,CM3/4) it was not useful to estimate the size of the pond required to evaporate Unit 3 cooling water blowdown.
14	**Scenario 14: Line 1-5 acres of the Tracy Cooling Pond and New Water Treatment equipment[21] for Unit 3 Cooling Tower Blowdown** A smaller portion of the cooling pond, 1-5 acres, would be lined according to BWPC guidance[22]. This scenario included new filtration, new 2-pass RO, operating the Unit 4/5 clarifier, and offsite regeneration of the mixed bed demineralizers to reduce waste water flow. This scenario was intended to operate Unit 3 CWT at two cycles without chemical treatment similar to historical operation with makeup and recycle to a lined portion of the pond. Clark Mountain peaking units 3 and 4 would discharge to the lined portion of the pond. This scenario generated 80 gpm waste water flow in the summer and could fill the evaporation ponds in 9.7 years. Cooling tower 3 cycles as calcium or silica exceeded the target of 2 cycles and would require chemical treatment or foul the condenser. In this scenario Unit 3 operation was partially dependent on Unit 4/5 and the clarifier operating. Lining a portion of the cooling pond would be technically questionable because of the difficulty in establishing the subgrade and dewatering. This scenario was deemed technically not viable without chemistry or process changes and the difficulty of lining any portion of the existing pond. Scenarios below considered changes to minimize Unit 3 dependence on Unit 4/5 and changes to water treatment for sustainable operation., and included Clark Mountain evaporative cooler blowdown.
15	**Scenario 15: New Equalization Tanks, Clarifier, and Filtration for Cooling Tower 3 Blowdown[23]** Cooling tower 3 blowdown would be treated with a new equalization tank, new clarifier, and new filter to support cooling tower 3 blowdown only. This scenario included additional tanks, filters, 2-pass RO, and offsite mixed bed regeneration for the entire plant.

[21] Burns & McDonnell, *Frank A. Tracy Water Balance Study*, (2017) Project No. 95050, Rev. 2, Option 2B, 4-5
[22] Department of Conservation and Natural Resources. (2017, May). WTS-37 Guidance Document for the Design of a Lined Wastewater Holding Pond (Surface Impoundment). Carson City, Nevada: Division of Environmental Protection Bureau of Water Pollution Control.
[23] Burns & McDonnell, *Frank A. Tracy Water Balance Study*, (2017) Project No. 95050, Rev. 2, Option 1, 4-4

No.	Scenario Description
	This scenario was not technically viable because it would fill the evaporation ponds within 4 years and also generate over 100 gpm of waste water at typical summer conditions.
16	**Scenario 16: Construct a New Pond for Cooling Tower 3 & CM3/4 Blowdown and Recover Water through Existing Clarifier and Reverse Osmosis Unit[24]** The scenario would construct a new pond for Unit 3 CWT blowdown, Unit 4/5 CWT blowdown, Clark Mountain evaporative cooler blowdown, demineralizer regeneration water, recovered oily water, Unit 8/9 overflow, and all other waste streams. This scenario would require construction of a new pond according to BWPC guidance[25] with a capacity of 22.8 M gallons. The maximum available pond area is approximately 3.9 acres. The cooling towers and other users would continue to draw makeup water from the Tracy pond, but discharge the blowdown to the new pond. The new pond could mix and equalize flow to provide stable flow, TDS and TSS for the Tracy 4/5 clarifier. This would address the problem of the small equalization tank. The pond would increase the detention time from less than one (1) hour to 10-30 days. Additional explanation of the relevance of mixing and detention time was discussed in previous scenarios. The clarifier treatment chemical dosages would require less frequent adjustments and the overall clarifier performance would be more predictable. The clarified softened water would be sent to a reverse osmosis unit to remove dissolved solids. RO permeate would be used in the evaporative coolers. Any excess RO permeate could be sent to the demineralizer units for re-use in the steam cycle. Most of the reject from the waste water reverse osmosis unit will be recycled to the new pond. A portion of the RO reject will be sent to the waste water evaporation ponds when the TDS is approaching the osmotic pressure limit of the RO membranes. Current operational philosophy of Tracy Unit 3 would not require significant modification. The existing Tracy Unit 4/5 clarifier equipment, pumps, and piping will continue to be used. Only Tracy Unit 4/5 cooling tower blowdown will flow to the equalization tank. Tracy 4/5 cooling water makeup would come from the pond or from Tracy 3 cooling tower blowdown.

[24] Burns & McDonnell, *NV Energy Tracy Station – Water Balance Revisions, Revision 3*, (2019) Project No. 108247, 3-6.
[25] Department of Conservation and Natural Resources. (2017, May). WTS-37 Guidance Document for the Design of a Lined Wastewater Holding Pond (Surface Impoundment). Carson City, Nevada: Division of Environmental Protection Bureau of Water Pollution Control.

No.	Scenario Description
	Engineering, Procurement and Construction costs are estimated at [redacted]M. The cost of the pond is [redacted] New infrastructure of piping, pumps, and electrical equipment will be required for the new pond. Additional waste streams currently directly to the Tracy cooling pond, unrelated to Unit 3, would need to be modified. Permits will be required to construct and discharge into a new lined pond. The cost of the additional piping is [redacted] The cost to modernize and automate the clarifier and reverse osmosis units is estimated at [redacted] The expected operations and maintenance costs are estimated at [redacted] including under [redacted] annually to cover additional permitting and cooling pond monitoring, [redacted] for clarifier chemicals, and [redacted] for cooling water chemicals. No additional incremental labor costs for clarifier side stream softening operation. This option was deemed technically viable because it reduces waste water flow to less than 33 gpm under summer conditions while remaining within the design conditions for the existing equipment. This option is the lowest cost technically viable option.

Recommendation and Discussion:

The preferred solution is scenario 16 contruction of a new Tracy pond for equalization and retention of cooling tower 3 blowdown and modification or upgrade of the water treatment equipment to reduce discharge into the existing evaporation ponds. It represents the lowest cost technically viable alternative. A summary of the scenarios and costs are summarized in Table 2 Scenario Cost Summary.

Table 2 Scenario Cost Summary

No.	Scenario	Technically Viable	Project Cost $ M	OMAG $ M	Capacity $ M	Total Cost to 2028 Retirement $ M
1	**Do Nothing**	Yes	[redacted]			
2	**Retire Unit 3 and Replace with Quick Start Generation**	Yes	[redacted]			
3	**Discharge to River**	No	[redacted]			
4	**TRIC Discharge**	No	[redacted]			
5	**Injection Well**	No	[redacted]			
6	**Utilize Existing Clarifier**	No	[redacted]			
7	**Use Existing Clarifier and Waste Concentration Tower for Tracy 3 & CM3/4 Blowdowns**	No	[redacted]			
8	**Air Cooled Condenser/ Hybrid Cooling**	No	[redacted]			
9	**Brine Concentrator for Cooling Tower 3 Blowdown**	Yes	[redacted]			
10	**High Efficiency Equipment for Cooling Tower 3 Blowdown**	No	[redacted]			
11	**Line Tracy Cooling Pond**	Maybe	[redacted]			

12	**Build New Cooling Pond to Replace Tracy Cooling Pond**	No	[redacted]
13	**New Water Treatment and Evaporation Pond for Unit 3 CWT Blowdown**	No	
14	**Line 1-5 acres of Tracy Cooling Pond and New Water Treatment for Unit 3 CWT Blowdown**	No	
15	**New Tanks, Clarifier, Filtration, and 2-Pass Reverse Osmosis for Unit 3 CWT Blowdown**	No	
16	**Construct New Pond for Unit 3 CWT and CM 3/4 Blowdowns and Recover Water through Existing Clarifier and Reverse Osmosis Unit**	Yes	

** Scenarios that were not technically viable were not* [redacted]
+ Additional OMAG cost not estimtated.

Attachment B

Tracy 3 New Pond Project and Funding Schedule

Description: Tracy cooling Pond

Tracy 3 New Pond Project Schedule

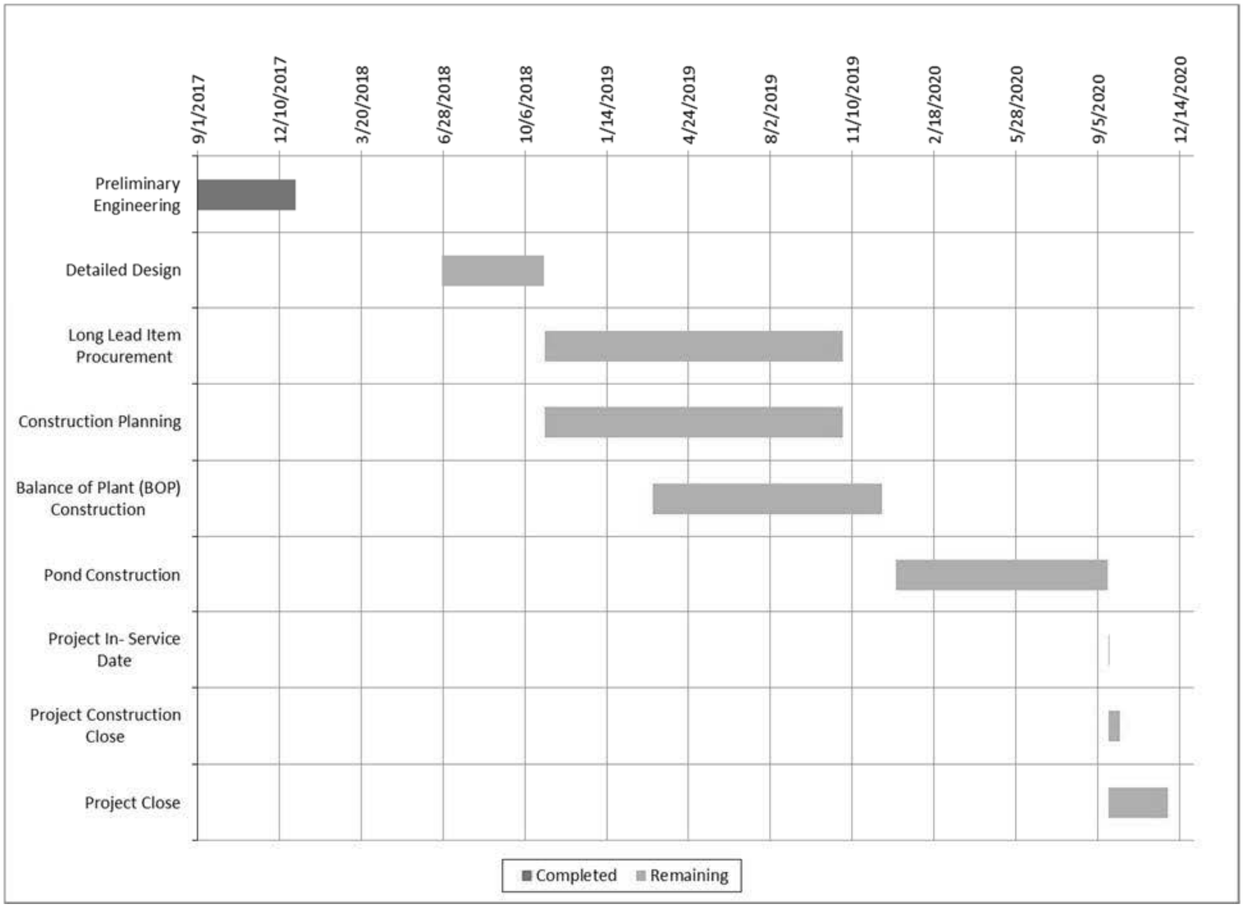

Table 3. New Pond Project Schedule

	Start Date	Completed	Remaining	Completion Date
Preliminary Engineering	9/1/2017	120	0	12/30/2017
Detailed Design	2/1/2019	0	124	8/1/2019
Long Lead Item Procurement	9/2/2019	0	365	3/6/2020
Construction Planning	2/1/2019	0	365	9/30/2019
Balance of Plant (BOP) Construction	2/3/2020	0	280	10/16/2020
Pond Construction	10/1/2019	0	259	9/18/2020
Project In- Service Date	10/16/2020	0	1	10/16/2020
Project Construction Close	10/19/2020	0	14	11/6/2020
Project Close	10/19/2020	0	73	4/16/2021

Tracy 3 New Pond Funding Schedule

Table 4. Tracy 3 New Pond Funding Schedule

	2017	2018	2019	2020
Proposed Funding Schedule	[redacted]			

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GEN-3

GEN-3

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TRAN-1

NV Energy Northern Import Limit Re-assessment

Contents

Introduction

The northern Nevada import limit was identified at 1275 MW after the energization of the ON Line Transmission project on January 1, 2014, a 275 MW increase over the pre ON Line transmission system. The 1275 MW limit was based off of a study that determined a voltage deviation of 4.7% at several busses in the Reno and Valmy areas when contingencies on the Robinson to Falcon 345 kV line were observed and either the Valmy to Tracy 345 kV lines or one Valmy generating unit was lost. At the time this analysis was performed, the North American Electric Reliability Corporation ("NERC") Transmission Planning standards allowed for voltage deviations of up to 5%. NERC TPL-001-4 was approved on January 1, 2016 and modified the maximum voltage deviation for a single contingency to 8%. The updated analysis in this study reflects the latest reliability criteria as well as discusses other system limitations associated with the northern system import limit.

Several factors are taken into account when establishing and/or confirming the system import limit. These factors include updated system facility ratings, historical system imports, historical reliability issues, system maintenance, generation dispatch, variable flow conditions and Transmission Reliability Margin. Under a single theoretical maximum import case using generation that is owned and dispatchable by NV Energy resulted in a best import case scenario of 1360 MW. This level of import assumed the completion of several existing system upgrades as well as future planned transmission projects.

Modeling, Simulation and Methodology

Reliability Criteria

For transmission system planning purposes, analysis is performed based on the NERC standard TPL-001-4. NERC TPL-001-4 provides classification and allowable performance criteria of all contingencies for transmission planning purposes. NV Energy adheres to NERC TPL-001-04 as well as WECC Criterion TPL-001-WECC-CRT-3 in its "NV Energy Reliability Criteria for Transmission System Planning" (with some caveats pertaining to system specifics). The Criteria is included in the company's FERC No. 715 annual filing.

Base Cases

NV Energy uses WECC Base-cases as well as an in-house developed system master case to simulate various scenarios in the transmission system. General Electric's Positive Sequence Load Flow ("PSLF") software was used for the study.

The WECC 2024 summer peak ("24HS2") case was used as a starting point for the case development. Since this case incorporates NV Energy's latest master case, as represented by the model of NV Energy's controlled "areas" (#64 for "North" & #18 for "South"), the load forecast for Nevada and known transmission and generation projects were adequately represented. Two time frames were considered to be of interest as impacting the import capabilities:

a) Current system
b) System after facility ratings are improved per NERC FAC-008 and completion of near-term transmission upgrade projects.

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List and Description of Study Cases

A total of 12 cases were assessed; the import results are summarized in Table 1. The study was performed based on both the major P1 contingencies and critical P6 (N-2 outage of Tracy – Valmy 345 kV lines and N-1-1 Humboldt – Midpoint and Falcon – Robinson). It can be noted that in order to be able to withstand the second contingency of Falcon – Robinson line, after the Humboldt – Midpoint line is out of service, the import needs to be reduced to 740-750 MW, which number is consistent with other assessments, including by the system operations department.

The comprehensive list and description of the study cases, based on the "Base Maximum Import Case" are described in Table 1 below.

TABLE: DESCRIPTION of IMPORT STUDY CASES														
Case Description			SPPC, [MW]				Gen Retirement, in service [MW]		System Upgrade Projects [Y/N]					
#	PSLF name	Description	BA Load (with losses)	Genera-tion	Inter-change	TRIC Load*	Valmy	New-mont	BOR - CAL Project	W Tracy XF	FAC-008	Bell Creek 120kV Cap 48MVAR	Comments	SOL
2020HS BASE CASE														
1	20HS_no_Nmnt_Imp=1360_v1.sav	2020 Heavy Summer Maximum Import	2494.6	1163.3	-1360.2	48.4	285.0	0.0	N	N	N	N	ETY XF OL, IROL_3419_3428; FAC-008 issues.	P1#3428:BOR PST@99.1%; P1#3429:ETY-XF@96.4%
2	20HS_no_Nmnt_Imp=1360_v2.sav	Avoid P6_IROL [20HS + redispatch TCY G3-5 +CM3]	2523.53	1163.3	-1360.2	48.4	285.0	0.0	N	N	N	N	Still FAC-008 issues at: HBT, NVY, MIR, #141/142;	P1#3428:BOR PST@99.1%; P1#3429:ETY-XF@96.4%
3	20HS_no_Nmnt_Imp=1220_v3.sav	Avoid HBT137 [v2+reduce SI by redispatch WTY CC (from ar 30&40)]	2504.34	1284	-1220.2	48.4	285.0	0.0	N	N	N	N	SI reduced until HBT137 OL does not appear (HBT137/RAS-0139 fix)	P0:HTP-XF, BOR-PS, FTC-PS; P1#3423: #137@99.9%. P1#3428:FTCPS@99%, BOR PST@97.6%; P1#3429:ETY-XF@95.6%
4	20HS_no_Nmnt_Imp=1150_v3.sav	Avoid all FAC-008 [#3 + reduce SI by redispatch WTY CC (from ar 24&30)]	2498.0	1348.0	-1150.0	48.4	285.0	0.0	N	N	N	N	SI reduced until NVY XF#2 OL does not appear; + dispatched TCY G3-5 to Max	P0:(HTP-XF, BOR-PS, FTC-PS); P1#NVY-XF1: NVY-XF2#99.9%. P1#3428:FTCPS@95.6%, BOR PST@95.4%.
5	20HS_no_Nmnt_Imp=750_3419-oos_gen-IROL.sav	Post-HBT-MPT OOS [#4+reduce SI by redispatch to work for P1#3428]	2485.43	1735.4	-750.0	48.4	285.0	0.0	N	N	N	N	Works for all P1s; avoids IROL_#3419+#3428 (re-dispatch: WTY,TCYG3-G5+CMT, FTC2 @ max)	P0:HTP-XF, BOR-PS; P1#3428:BOR PST@99.7%, FTC PST@90%
6	20HS_no_Nmnt_Vlmy_noBOR-CAL_ET-XF#1_Imp=1240.sav	2020HS without Valmy & Newmont [SI reduced from ar 30&40].	2499.82	1260.5	1239.4	48.4	0.0	0.0	N	N	N	N	Works OK for P1 & P6_IROL (re-dispatch: TCYG3-G5 @ max + CMT3@100; WTY @420).	P0:HTP-XF, BOR-PS; P1#3428:BOR PST@98.7%, HTP XF@97.7%; Voltages near HBT120kV
7	20HS_no_Nmnt_Vlmy_BCK-cap_Imp=1300.sav	2020HS without Valmy & Newmont with Bell Cr. Cap.	2504.9	1204.7	1300.3	48.4	0.0	0.0	N	N	N	Y	Works OK for P1 & P6_IROL (re-dispatch: TCYG3-G5 @ max + CMT3@100; WTY @420).	P0:HTP-XF, BOR-PS; P1#3428:BOR PST@99.3%, HTP XF@98.4%; Vdrop=8% @ 64044 QUEENSTAKE 120kV
2024HS BASE CASE														
8	24HS_no_Nmnt_Imp=1360_v1.sav	2024 Heavy Summer Maximum Import	2522.33	1161.9	-1360.5	48.4	285.0	0.0	Y	Y	Y	N	Works for P1s, but P6 (IROL) would require generation re-dispatch in Reno/Tracy area	P0:HTP-XF, BOR-PS. P1#3428:FTCPS@98.8%, BOR PST@97.9%. Voltages near HBT120kV
9	24HS_no_Nmnt_Imp=1360_v2.sav	Avoid P6_IROL [24HS + redispatch TCY G3-5 +CM3]	2521.59	1161.7	-1359.9	48.4	285.0	0.0	Y	Y	Y	N	Works OK for P1 & P6_IROL (re-dispatch: TCYG3-G5 @ 100 + CMT3@50; WTY@min=181).	P0:HTP-XF, BOR-PS. P1#3428:BOR PST@99.4%, HTPXF@98.3%. Voltages near HBT120kV
10	24HS_no_Nmnt_Imp=750_3419-oos_gen-IROL.sav	Post-HBT-MPT OOS [#9+reduce SI by redispatch to work for P1#3428]	2484.2	1743.7	-750.0	48.4	285.0	0.0	N	N	N	N	Works for all P1s; avoids IROL for #3419+#3428 (same dispatch as #5)	P0:HTP-XF, BOR-PS; P1#3428:BOR PST@99.9%, HTP XF@98.8%, FTC PST@98.2%
11	1.0_24HS2a_Pre-af-rctrs.sav	2024HS Max SI with Economic Dispatch	2504.34	1379.4	-1113.9	48.4	0.0	80.0	Y	Y	Y	N	Works OK for P1 & P6_IROL (re-dispatch: TCYG3-G5 @ 100 + CMT3@50; WTY@min=181).	P0: flow on Midpoint – Humboldt 345 kV line (P16=500 MW). P1#3428: voltage (0.9 p.u., Δ= 8%) near Humboldt 120kV.
12	1.0_24HS2a_Pre-af-rctrs_#3419-oos_SI=740.sav	Post-HBT-MPT OOS [#11+reduce SI by redispatch to work for P1#3428]	2490.72	1739.5	-740.0	48.4	0.0	80.0	Y	Y	Y	N	Works for all P1s; avoids IROL for #3419+#3428 (similar dispatch to #5)	P0: HTP-XF, BOR-PS; P1#3428: FTC-PS 99.5%, BORPS 98.1%. Voltage on Alturas (Δ= 8%@ FT SAGE 345)

Notes, color code & abbreviations:	
***** - TRIC Load includes: Pah Rah (Apple), Red Rock (Tesla), Patrick, Wild Horse & Meadows	
OOS - facility out of service	
SI - System Import	
#3420-Valmy-Coyote	#3423-Humboldt-Coyote
#3428-Robinson-Falcon	#3429-W.Tracy-Mira Loma
	- case that passed reliability testing
	- case with reliability violations
	- notable cell (with changes comparing to previous cases)

***Table 1**: List and Description of Study Cases.*

This 1360 MW import limit assumed that the proposed West Tracy 345/120 kV transformer was installed and the Bordertown – California project was implemented, as well as the completion of several upgrades that are currently in progress to increase facility ratings. Details on the planned future projects are provided below:

Planned Future Projects:

a) West Tracy 345/120 kV transformer: is an ongoing NV Energy transmission project (planned to be in service in 2021) consisting of a new 120 kV switchyard and a 345/120 kV transformer at the West Tracy substation. This project is the subject of the Second Amendment to the 2018 Joint Integrated Resource Plan. The project is designed to accommodate load growth in the Reno/Tahoe area. The high import conditions would add more stress on the existing 345/120kV SPPC transformers potentially causing reliability issues (e.g., multiple overloads of 345/120 kV transformers and 120 kV lines, specifically for critical outage of #3429 West Tracy – Mira Loma 345kV line), which during load peak conditions could be mitigated by running all the 120 kV Tracy generation (including two "peaking" units) at maximum and the West Tracy CC at reduced output. Such scenario is not economic, not reliable and does not sufficient generation reserve in Sierra. Therefore, completion of this project is required for achieving higher import.

b) Bordertown – California project: is an ongoing NV Energy transmission project (planned to be in service in 2021) consisting of a 345/120 kV transformer and a 120kV line between Bordertown and California substations. This project is also the subject of the Second Amendment to the 2018 Joint Integrated Resource Plan. The project is designed to mitigate the reliability issues caused by load growth in "Reno West" zone. Since high import conditions add more stress on the critical 120 kV lines, completion of this project is required for achieving higher import.

These reduced facility ratings were identified in late 2016 during a NERC self-report and overhaul of all of NV Energy's facility ratings. Examples of issues identified are 600A switches that were in line with 900A conductor, 250 MVA switches that were in line with 280 MVA transformers, circuit breakers rated 2000A, but limited by a CT with a 900:5 ratio. Some of the issues identified were easy fixes that just required field checks or CT ratio setting changes. Others are more complicated as they may require the removal or replacement of substation switches and breakers. While these limiting facilities are being addressed, the parameters and flexibility of operating the transmission system have been tightened. Without these facility rating issues addressed, it's not possible to maintain the existing 1275 MW import limit. NV Energy has been operating around the constraints associated with reduced facility ratings to maintain system reliability. The specific projects associated with reduced facility ratings are identified below:

FAC-008 Issues:

c) Restore thermal ratings of the 2x345/120 kV transformers at North Valmy substation by upgrading CTs and switches at the 120 kV bus.

d) Restore thermal rating of 120 kV line #137 (Humboldt-Eight Mile) by replacing switch HBT137 at Humboldt; modify RAS-0139 to include the overload monitoring of line #137.

e) Restore thermal rating of the 345/120 kV transformer #2 (280 MVA) at Humboldt substation by upgrading CTs and switches at the 120 kV bus.

f) Restore thermal rating of the 2x345/120 kV transformers at Mira Loma substation by upgrading CTs and switches at the 120 kV bus.

g) Restore thermal rating of the 345/120 kV transformer #2 at North Valley Road substation and North Valley Road - Valley Road 120 kV bus-tie by upgrading the 120 kV bus (jumper replacement and the associated bus work).

Best Import Case - 1360 MW

Starting from the base summer peak 24HS case, the generation in area 64 was reduced by 1422.6 MW as shown in Table 2. The choice of the specific units followed the normal operating practices, curtailing mainly gas and coal generation (82%, including Valmy #1 and Newmont) and then approximately 18 % of solar, wind and geothermal which is contractually bound must-take generation (see tables 2 & 3). Finally, the reliability or core-supporting units were properly dispatched for this case, including their voltage schedule to provide sufficient reactive support: West Tracy and Tracy G5 @ 255 MW, Valmy #2 @ 285 MW and Ft. Churchill #2 at 50 MW. Also, all the additional available reactive support in northern Nevada (NVEN) including appropriate switching of the shunt reactors and capacitors, was utilized to create adequate system voltages for the maximum import case. The additional import was brought from the adjacent WECC "Balancing Areas" (i.e., areas 18 – Southern Nevada, 24 – Southern California, 30 – PG&E, 40 - Northwest & 60 – Idaho Power).

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TABLE: NVEN GENERATION ADJUSTMENT to MAXIMIZE IMPORT in AREA 64						
	with BREAKDOWN BY TYPE OF GENERATION					
	WECC Case 24hs2a		Maximum Import (1360) Case		Change	
TYPE	MW	%	MW	%	MW	%
GEOTHERMAL	440.0	17.0	424.0	36.5	-16.0	1.1
SOLAR/WIND	290.0	11.2	47.0	4.0	-243	17.1
FOSSIL	1854.5	71.8	690.9	59.5	-1163.6	81.8
TOTAL	2584.5	100.0	1161.9	100.0	-1422.6	100.0

TABLE: Load and Generation in NV Energy's BA in Maximum Import Case							
[20HS_no_Nmnt_Imp=1360_v1.sav] with 1360 MW Import							
Area		BA Load, MW			Generation		Interchange
#	Name	Load	Losses	Total	Capacity	On-line	MW
18	Nevada Power (NVES)	6752	157.3	6909.3	6325.7	5699.0	-1367.7
64	Sierra Pacific (NVEN)	2290.87	115.73	2406.6	3212.6	1161.9	-1360.5

Table 2*: Adjustment of NVEN Generation (starting from WECC base-case) to Maximize Import and Load, Generation, Losses & Interchange of the "Maximum Import" case.*

TABLE: Generation Dispatch in NV Energy's BA in Maximum Import Case										
[20HS_no_Nmnt_Imp=1360_v1.sav] with 1360 MW Import										
NAME1	KV1	ID	ST	BL	AR	ZON	PGEN	PMAX	PMIN	QGEN
APPLE PV G	0.69	1	1	2	64	648	8	19.9	2	-5.8
BEOWAWE	4.16	1	1	2	64	640	8	11	7.5	0
BEOWAWE	4.16	2	1	2	64	640	1	1.7	0	0
CAITHNES	12.3	2	0	2	64	646	0	5.5	1	3.5
CAITHNES	12.3	1	1	2	64	646	10	13.5	2	3.3
CAITHNES	12.3	3	1	2	64	646	13	14.5	2	3.3
CLARKMT3	13.8	1	0	0	64	646	0	70	28	-8.3
CLARKMT4	13.8	1	0	0	64	646	0	70	28	-8.4
CRSNT DUNE	13.8	1	0	2	64	642	0	114.5	48	9.7
DESRT P2	13.8	1	1	2	64	649	6	15	4	1.3
DESRT P2	13.8	2	1	2	64	649	6	11	2	1.3
DIXIE M P1	13.8	1	1	2	64	640	15	22.5	0	0.1
DIXIE M P1	13.8	2	1	2	64	640	15	22.5	0	0.1
DOVEGEN1	13.8	7	0	0	64	646	0	8.3	3.3	1.4
DOVEGEN1	13.8	6	0	0	64	646	0	8.3	3.3	1.4
DOVEGEN1	13.8	5	0	0	64	646	0	8.3	3.3	1.4
DOVEGEN1	13.8	4	0	0	64	646	0	8.3	3.3	1.4
DOVEGEN1	13.8	3	0	0	64	646	0	8.3	3.3	1.4
DOVEGEN1	13.8	2	0	0	64	646	0	8.3	3.3	1.4
DOVEGEN1	13.8	1	0	0	64	646	0	8.3	3.3	1.4
DOVEGEN2	13.8	2	0	0	64	646	0	8.3	3.3	1.4
DOVEGEN2	13.8	3	0	0	64	646	0	8.3	3.3	1.4
DOVEGEN2	13.8	4	0	0	64	646	0	8.3	3.3	1.4
DOVEGEN2	13.8	5	0	0	64	646	0	8.3	3.3	1.4
DOVEGEN2	13.8	6	0	0	64	646	0	8.3	3.3	1.4
DOVEGEN2	13.8	7	0	0	64	646	0	8.3	3.3	1.4
DOVEGEN2	13.8	1	0	0	64	646	0	8.3	3.3	1.4
FAR WST1	4.16	1	1	2	64	646	7	10.3	3	0.6
FAR WST1	4.16	2	1	2	64	646	7	10.3	3	0.6
FAR WST2	4.16	3	1	2	64	646	7	10.3	3	0.7
FAR WST2	4.16	4	1	2	64	646	7	10.3	3	0.7
FT CH G1	13.8	1	0	0	64	648	0	113	47	28.4
FT CH G2	13.8	1	1	0	64	648	50	113	47	23.2
GALENA	13.8	2	1	2	64	646	11	15	2	3.5
GALENA	13.8	1	1	2	64	646	11	15	2	3.5
GALENA3	13.8	2	1	2	64	646	11	15	2	-0.2
GALENA3	13.8	1	1	2	64	646	11	15	2	-0.2
JERSEYV	13.2	1	1	2	64	640	10	15	2	-4
JERSEYV	13.2	2	1	2	64	640	5	7.5	1	-2.7
LUNING G	0.55	1	1	2	64	642	14	50	0	-10.8
MCGINESS	12.47	1	1	2	64	642	9	25	3	-0.4
MCGINESS	12.47	2	1	2	64	642	9	25	3	-0.4
MCGINESS	12.47	3	1	2	64	642	5	15	2	-0.4
MCGINESS2	12.47	1	1	2	64	642	15.5	25	3	0.1
MCGINESS2	12.47	2	1	2	64	642	15.5	25	3	0.1
MCGINESS2	12.47	3	1	2	64	642	9.5	15	2	0.1
NEWMONT	18	1	0	0	64	645	0	226	80	33.6
NGPPGEN	12.47	1	1	2	64	649	4	8	3.2	1.3
NGPPGEN	12.47	2	1	2	64	649	4	8	3.2	1.3
NGPPGEN	12.47	3	1	2	64	649	4	8	3.2	1.3
NGPPGEN	12.47	4	0	1	64	649	0	6.5	2	0.8
NVGEOG1	12.47	1	1	2	64	640	7.5	14.2	3.4	1.8
NVGEOG1	12.47	2	1	2	64	640	7.5	13.8	6.3	1.8
NVGEOG1	12.47	3	1	2	64	640	7.5	11.7	4.6	1.8
PATUA	12.47	1	1	2	64	649	9	12	4.8	2.7
PATUA	12.47	2	1	2	64	649	9	12	4.8	2.7
PATUA	12.47	3	1	2	64	649	9	12	4.8	2.7
SALTWELL	4.16	1	1	2	64	642	17	31	12.4	3.5
SODAPH2	13.8	1	1	2	64	649	8	12	4.8	1
SPRING VAL G	0.69	1	1	2	64	642	15	150	15	-69.7
STILLWTR-GEO	13.8	1	1	2	64	649	8	11.2	4.5	2.2
STILLWTR-GEO	13.8	2	1	2	64	649	8	11.2	4.5	2.2
STILLWTR-GEO	13.8	3	1	2	64	649	8	11.2	4.5	2.2
STILLWTR-GEO	13.8	4	1	2	64	649	8	11.2	4.5	2.2
STILLWTR-PV	13.8	1	1	2	64	649	10	22	2.2	-1
TRACY G3	13.8	1	0	0	64	646	0	113	45	-0.9
TRACY G4	13.8	1	0	0	64	646	0	66	26	29.7
TRACY G5	13.8	1	1	0	64	646	25	46.2	18	21.4
TRACY W8	18	1	1	0	64	646	90	168	67	106.2
TRACY W9	18	1	1	0	64	646	90	168	67	107.1
TRACYW10	18	1	1	0	64	646	150.9	275	46	1.5
TUNGSTEN P1	12.47	1	1	2	64	642	18	43.5	0	-6.1
TURQ_GEN	0.41	1	1	0	64	646	20	61	0	-12.9
TUSCARORA	12.47	1	1	2	64	645	6	16	3	4
TUSCARORA	12.47	2	1	2	64	645	6	16	3	4
USGEMPR1	12.47	1	1	2	64	649	7	12.4	5.5	2
VALMY G1	22	1	0	0	64	640	0	273	103.5	47.4
VALMY G2	18	1	1	0	64	640	285	285	100.9	99
WILDROSE	12.47	1	1	2	64	642	12	20	5	-1.7
WILDROSE2	12.47	2	1	2	64	642	12	20	5	-2
TOTAL:							1161.9			

***Table 3**: Generation Dispatch in NVEN in Maximum Import Case.*

The most limiting contingency for the import case was loss of Robinson Summit – Falcon 345 kV line, which was associated simultaneously with several system reliability limits as follows:

a. Thermal loading of the Hilltop 345/230 kV transformer and 345 kV Bordertown PST.
b. Low voltage and voltage deviation limits at Humboldt 345 kV and 120 kV and nearby 120 kV load buses.
c. Thermal loading of Ft. Churchill 230/120 kV transformer and 120 kV phase-shifting transformer (PST).
d. Thermal loading of California 120 kV PST and thermal loading of the transmission lines comprising WECC path #24 ("PG & E – Sierra"). These lines (2×115kV Drum – Summit & 60 kV Spaulding – Summit) are monitored by PG&E RAS, which if triggered would separate Sierra & PG&E. Therefore the system must be operated in a way that avoids overloading of any of these lines and RAS operation for any next anticipated contingency.

<u>Other "critical" contingencies limiting import are:</u>

- Loss of Valley Road – Reno 120 kV line loading of Penney – Northwest 120 kV line to its thermal limit. This is a known pre-existing issue that will be mitigated by new Bordertown –California project (is planned to enter service in 2021). The "Reno West" zone load growth is the major contributing factor to this overload. However, the high import conditions add additional stress on these 120 kV lines.
- Loss of WECC path # 76 (Hilltop 345/230 kV transformer or Hilltop – Ft Sage – Bordertown 345 kV line) causing low voltage and voltage deviation issues at Humboldt 345 kV and 120 kV and nearby 120 kV load buses.
- Loss of WECC path # 16 (Humboldt - Midpoint 345 kV line) loading Hilltop 345/230 kV transformer and 345 kV Bordertown 345 kV PST to its thermal limits.
- Loss of 120 kV line # 186 (Valmy – Winnemucca) loading 120 kV line # 117 (Winnemucca – Kramer Hill) to its thermal capacity.
- Consecutive loss of Robinson – Falcon and Humboldt – Midpoint 345 kV lines which may result in potential Interconnection Reliability Operating Limit (IROL) due to voltage collapse in the Reno load area. Even though simultaneous or closely timed loss of these two lines is highly unlikely, the NERC Reliability operating requirements direct NV Energy to always operate at such operating points that would allow, if the first contingency to occur, to restore within 30 minutes to system import levels that would avoid the IROL conditions for the second anticipated contingency. To accommodate this requirement, the available generating unit ramp rates should be taken into account.

Variable Flow Conditions

Transmission schedules, unscheduled loop flow, load pocket density and phase shifter angle all have a significant impact on import conditions. The 1360 MW scenario case had a precise generation dispatch, balanced schedules and exact tuning of system phase shifters. True operation of the transmission grid requires flexibility within all the noted variables.

Transmission Schedules

A scenario was analyzed where all existing firm transmission reservations were scheduled into the northern Nevada system. As the import was increased, generation was turned off based on "quasi-economic" dispatch. The case was 24HS, with the previously noted facility rating violations assumed to be mitigated; both Valmy units were offline and Newmont at its minimum of 80 MW. Under this system condition, the maximum import limit was reached at 1114 MW. The reliability constraints limiting the system import for this case were:

Loss of the Falcon – Robinson 345 kV line and minimum voltage 0.9 p.u. and voltage deviation of 8% near Humboldt. The case was also limited by the pre-contingency flow on the Midpoint – Humboldt 345 kV line reaching the WECC rating of Path # 16 currently set at 500 MW.

Modifications in generation dispatch and or schedules could result in an increased import limit, but these modifications would be moving the analysis away from actual operations and into a theoretical analysis.

Phase Shifter Angles & Flows

A Phase shifting transformer (PST) is a type of equipment used in power systems to control the amount and direction of real power flow in MW by changing the voltage angle between the transformer's input and the output terminals. This equipment has upper bound and lower bound of its "load-tap-changer", and its regulation steps correspond to specific upper and lower angle limits; depending on a PST location inside a power system, the range of MW-power transfer and possibly direction can be controlled by the operator. All NV Energy's PSTs are manually controlled by the operator, which may require a 20-30 min window post-contingency to implement a PST adjustment Each step is performed through initiation of a manual control button and the PST tap movement takes up to 30 sec per step. These units can be used to push energy against the natural flow for reliability or transactional purposes. The phase shifters in NV Energy's system are typically used for reliability purposes.

NV Energy's northern system has the following phase shifting transformers at or near intertie points:

1. 345 kV PS at Bordertown Substation – Controls power flow on the Alturas tie in and out of the BPA intertie (300 MW Capacity)
2. 120 kV PS at California Substation – Controls power flow into and out of the 120 kV PG&E intertie (150 MW Capacity)
3. 120 kV PS at Ft. Churchill Substation – Controls power flows on the 230 kV interties to PacifiCorp and IPP (Intermountain Power Plant) into the Carson and Reno load pockets. (150 MW Capacity)
4. 2×55 kV PS at Silver Peak Substation – Controls power flow into and out of the 55 kV interties to SCE's system (17 MW Capacity)

Certain phase shifting transformers in NV Energy's system need to be tuned to a specific flow and angle in order to accomplish the maximum import capability of 1360 MW. Specifically the Bordertown phase shifter needs to be set to near maximum inbound flow pre-contingency (260-270 MW range) in order to maintain the interties flow within the rating limit (pre-contingency), as well as avoid overload and severe voltage issues in the Carlin Trend in northeastern Nevada and overloads in the Fort Churchill area in central Nevada for the loss of the Falcon – Robinson 345 kV line. The California phase shifter needs to be set to a minimum of 50 MW outbound to avoid inbound overloads of the 120 kV interties to PG&E for the loss of either the Falcon to Robinson 345 kV line or the Humboldt to Midpoint 345 kV line. Inbound overloads on the PG&E tie can result in the existing Drum remedial action scheme activating which would disconnect NV Energy from PG&E. This RAS operating after the loss of one or both of the 345 kV lines noted has shown voltage collapse across the northern system. The Ft. Churchill 120 kV phase shifter needs to be set to a 110-120 MW schedule into the Carson load pocket, leaving little room for adjustments.

If either the Bordertown or Ft. Churchill PST cannot be scheduled to the abovementioned flows due to internal NV Energy operating conditions, WECC system conditions, or events potentially limiting their regulating ranges, the system import capability is significantly affected.

Specifically, the settings of the Bordertown phase shifter can result in overloads under single contingencies and import levels well below 1360 MW or even 1275 MW. For example, one condition was previously studied[1] with a pre-scheduled inbound flow of only 73 MW on the Bordertown phase shifter. This results in increased flows on the remaining interties in northern Nevada to accommodate the same amount of import. For such case, the loss of Falcon to Robinson or Humboldt to Midpoint lines resulted in overloads in the Ft Churchill area, low voltages and possibly voltage collapse in Humboldt/Carlin area at an import levels of only 769 MW. In the same case, if the Bordertown PST is scheduled at approximately 265 MW, the system import could be increased up to 1240 MW, which correlates with the similar result for a 2020HS case without Valmy and Newmont that was created in 2019.

Modifying the California phase shifter to draw rather than deliver power from PG&E can result in overloading of the 120 kV PG&E interties for losses of 345 kV lines. A remedial action scheme exists that disconnects NV Energy from PG&E under and an overload of the PG&E interties. Under this scenario, possibility of voltage collapse in all of northern Nevada has been observed even under moderate import conditions. Therefore per the company's Reliability Coordinator, PeakRC's direction NV Energy must monitor this condition and operate the phase shifter in a way that prevents the Drum RAS operation.

Although control of power flow exists with all phase shifters, they are used for reliability purposes and it's not possible to predict exactly when and why they'll be needed. For this reason, there is some uncertainty between a theoretical maximum import limit and limit that allows for operational flexibility.

Impact of the Out of NV Energy System and Unscheduled Flow

Utilization of ON Line

After the Harry Allen – Robinson 500 kV line (ON Line) was placed in service, the Northern Nevada system essentially enhanced its intertie import capability due to better ability to distribute the in-bound flows between its three major "unregulated paths" (those without PSTs): path 16 (Idaho tie), path 32 (Intermountain – Gonder/Pavant-Gonder) and ON Line. Therefore, as studies showed, to achieve the maximum import it's necessary to "source" ON Line at approximately 400 MW flow from South to North.

[1] A case (7-3R) without both Valmy units and the Newmont plant availability and without additional voltage support in Carlin Trend area was studied during the Valmy LSAP study in 2017.

Prior studies showed that ON Line, being a major path within the WECC system, is subject to unscheduled flows interacting with other major WECC transmission lines. For example, California-Oregon Intertie (COI, #66) and Path "C" (#20) & "TOT 2" ("B" & "C" paths) are two major WECC cut-planes with which the ON Line interactions were observed. As the result, even though ON Line is impacted the most by power interchange between northern and southern Nevada, it also would carry a certain amount of flow that is being shared with COI and TOT. For example up to 400 MW of unscheduled N-S flow that added to the ON Line scheduled flow, mainly from COI, once had been determined by prior NV Energy studies.

Another tool that can be utilized for purpose of controlling ON Line flows are NV Energy's phase-shifters in the Southern system, as well as some PSTs outside of NV Energy may have noticeable impact on ON Line flow. The most effective phase shifters for this purpose are:

a) NV Energy's 2×345 kV PSTs at Harry Allen (WECC path 35 or "TOT 2C");
b) PacifiCorp's four PSTs that control combined WECC path "TOT 2B" as follows:
    - 3×345 kV PSTs at Pinto
    - 230 kV PST at Sigurd.

In order to most effectively support the desired flows on ON Line all the above PSTs need to be scheduled in the north to south direction, within their thermal and angular capabilities and WECC paths ratings. While NV Energy's Harry Allen PST is under NV Energy's control the other PSTs are under PacifiCorp's control and all are participants in the WECC "Unscheduled Flow Administration Subcommittee (UFAS) Procedure" as described below.

Unscheduled Flow Mitigation in WECC

The WECC "UFAS" Procedure designates a number of PSTs in different BAs that can be used in a coordinated fashion to alleviate operating conditions in the Western Interconnection. The most common use of this procedure is to alleviate COI conditions by adjusting the participating phase shifters. For example, when COI flow reaches high amount in the north to south direction (approaching its 4800 MW rating) the operator of the listed above TOT 2B and TOT 2C PSTs will receive a signal from the UFAS system requiring to increase their schedule in N- S direction. This condition is reasonably represented in the base import case developed for this study, where COI is at > 4000MW N-S while path "C" is at 970MW (N-S), TOT 2B is at 833 MW (N-S) and TOT 2C is at 293 MW N-S (see Table below).

Table: Path Flows in WECC				
Maximum Import Case [20HS_no_Nmnt_Imp=1360_v1.sav] with 1360 MW Import				
Path		**Flow**		**Limit**
#	**Name**	**MW**	**Direction**	**MW**
15	Midway – Los Banos	76 MW	S-N	2000-3265
16	Idaho - Sierra	445 MW	N-S	500
20	Path "C"	971 MW	N-S	1600
26	Northern-Southern California	2284	N-S	4000
32	Intermountain-Gonder/Pavant-Gonder	281MW	E-W	500
34	TOT 2B (2B1 + 2B2)	833	N-S	912
35	TOT 2C (Red Butte - H Allen)	293	N-S	600
66	COI	4060	N-S	4800
NA	ON Line (Robinson - H Allen)	363	S-N	600

***Table 4**: Path Flows through the Major WECC Cut-Planes.*

The major WECC flows shown above represent a "typical" summer case scenario with North – to – South flows. In this scenario, with relatively high COI flow, UFAS could have been already activated to unload COI. There's still some room on TOT 2C that is possible to use (~250MW) for further COI "unload" if needed. If this would be done, ON Line flow also would increase S-N.

Summary for Out of NV Energy System and Unscheduled Flow

a. There's a strong interaction between different BAs inside Western Interconnection (WECC), which may be critical in determining the feasible amount of import into SPPC. SPPC is an electrically weak system (substantially weaker than for example Southern Nevada) and therefore is protected and controlled be several phase-shifting transformers.

b. Major WECC subsystems and paths, such as COI, Path "C", TOT 2B and TOT 2C can have critical impact on SPPC import due to the fluctuating flow conditions to which NV Energy has no control. One of the concerns is that due to these conditions some of the NV Energy's phase-shifters may become limited in their regulating ability. Another aspect impacting SPPC is the amount of "unscheduled flows", which appear on its ties and Robinson- H Allen 500 kV line due to outside conditions. These factors could make the "perfect import" case unachievable and significantly reduce the available import capability.

c. The base case for this study was based on a typical WECC Heavy Summer case and reasonably favorable assumptions for the outside of the NV Energy system.

System Reliability and Maintenance

Maximum system import is typically performed through the analysis of single contingencies. While the import limit is determined in a non-conservative manner, the planning and operation of the system is a much more complex and requires the analysis of several unexpected circumstances. For transmission system planning purposes, analysis is performed based on the North American Electric Reliability Corporation (NERC) standard TPL-001-4. This standard requires NV Energy to run several different types of contingencies, classified as P0 to P7 events depending on the specific type of tripping being simulated such as single element tripping (N-1), breaker failures, bus faults, communication failures, and double contingencies. NERC TPL-001-4 provides classification and allowable performance criteria of all contingencies for transmission planning purposes the standard.

Previous power flow analysis has identified that under the loss of two major 345 kV lines into the system, the maximum import into northern Nevada would have to be reduced from 1275 MW to 800 MW. The loss of two lines simultaneously is an unrealistic condition, but the loss of one line followed by another is not and has occurred in the past. Regardless of whether the next worst contingency occurs, NERC standard TOP-001-4 requires that the next worst contingency be pre-mitigated within 30 minutes of the first contingency. This mitigation may require phase shifter adjustment, ramping up available generation, turning on fast start peaking generation and as a last resort, shedding load. When it comes to planned or unplanned loss of any one of the major interties in northern Nevada, high imports are severely detrimental on system reliability. Simply because when these lines are heavily loaded, the loss of anyone of them disconnects that resource from the system and those transfers are reverted to the remaining interties. NV Energy transmission operations was contacted by our designated Reliability Coordinator, PEAKRC in late 2018 regarding system reliability violations that their real time contingency calculator had identified. They brought the following three examples to NV Energy's attention:

March 1st – 24th 2018 – The Humboldt to Midpoint 345 kV line was out for maintenance during this period and the simulated loss of the Robinson to Falcon 345 kV line was resulting in operation of the Drum remedial action scheme and eventual voltage collapse in northern Nevada. Under this condition, the northern system was operating at an import level of 510 MW.

January 11th, 2016 – The Humboldt to Midpoint 345 kV line was out for maintenance and the West Tracy Combined Cycle had incurred a forced outage. The simulated loss of the Robinson to Falcon 345 kV line was resulting in operation of the Drum remedial action scheme and eventual voltage collapse in northern Nevada. Under this condition, the northern system was operating at an import level of 721 MW.

December 19th – 21st 2016 – The Robinson to Falcon 345 kV line incurred a forced outage and the simulated loss of the Humboldt to Midpoint 345 kV line was resulting in voltage collapse in northern Nevada. Under this condition, the northern system was operating at an import level of 604 MW.

The loss of both the Humboldt - Midpoint 345 kV line and the Robinson - Falcon 345 kV line at any given time is an extreme contingency and has a strong potential to result in system instability in northern Nevada. As a result of recent unsolvable events of these 345 kV lines, NV Energy has developed Operating Procedure that provides guidance on what actions need to be taken in the event one of these lines is or will be out of service in order to prepare for the loss of the other.

The actions specified in this procedure are in the simplest sense, system import must be reduced in order to alleviate tie line flows. This can be achieved by increasing available generation in the northern Nevada system. Additionally, the capability of the NV Energy's phase shifters controlling the flow on the ties with PG&E (Summit – Drum lines) and with BPA (Alturas line to Hilltop) can be utilized to avoid possible violations of the system limits.

PEAKRC was initially planning to declare an IROL for the particular condition. It is a system condition that a NERC Reliability Coordinator feels has the potential to have widespread and cascading effects on an interconnection such as the western grid. At this time, only three IROL's are declared in the entire western grid. When an IROL is declared, all substations that are defined as critical to the derivation of the IROL event must be considered CIP2 Medium Impact or upgraded to meet CIP medium impact requirements. The draft IROL provided by PEAK RC identified nine NV Energy substations. It's estimated that upgrading to CIP medium impact status would cost approximately $150k - $200k per substation. In addition to CIP requirements, several new internal procedures would be required as well as additional compliance exposure would be created. It could also be argued that a publicly declared IROL within NV Energy's system could have a negative reputational impact as well.

After several conversation and analyses of how NV Energy could have mitigated the conditions on the specified dates, PEAKRC decided not to declare the IROL. Alternatively, they have proposed a specific real time contingency simulation. This real time analysis would simulate the real time contingency of the two 345 kV lines every five minutes in PEAK RC's real time contingency calculator. After the contingency simulation, the PG&E intertie would be monitored for overload to determine if the Drum RAS would operate. If this RAS would operate under the current condition, NV Energy will be required to take action to pre-mitigate the problem. The mitigation can be accomplished by adjusting the California Sub phase shifter and or by raising generation in northern Nevada. Load drop would be a mitigation of last resort.

The IROL and reliability violations identified by PEAKRC were provided in this import analysis to better describe the sensitivity of operating the transmission grid. General import analysis assumes every element in the system is intact before outages are simulated. Due to the age, condition, required maintenance and growth occurring in northern Nevada, it is very rare for the entire transmission grid to be completely intact. These situations are operated around by NV Energy to ensure consistent reliability to customers. The system import level that these reliability issues were identified under ranged from 510 MW to 721 MW, significantly below the existing system import limit.

While these situations can be considered extreme and rare, the requirements to pre-mitigate before the next worst contingency are a significant burden. This pre-mitigation can require the running of generation for reliability out of economic order as well as dropping of system load even if the next worst contingency never occurs. As expected, in all three situations identified by PEAKRC, the alternative 345 kV line never actually tripped. When it comes to regional grid stability and potential cascading blackouts, no risk level is acceptable.

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[2] NERC Compliance term meaning Critical Infrastructure Protection. Specific physical and cyber security upgrades are required at substations considered CIP medium impact

Historical Imports

Maximum simultaneous import analysis makes the assumption that there are no offsetting exports or counter schedules occurring. In reality, export transactions directly offset import transactions. In order to understand the limitations of the system, both historical imports as well as simulated imports are analyzed. The graph in Table 5 displays the import into northern Nevada over the three year period from January 1st, 2016 through January 1st, 2019. Negative values are imports, positive values are exports.

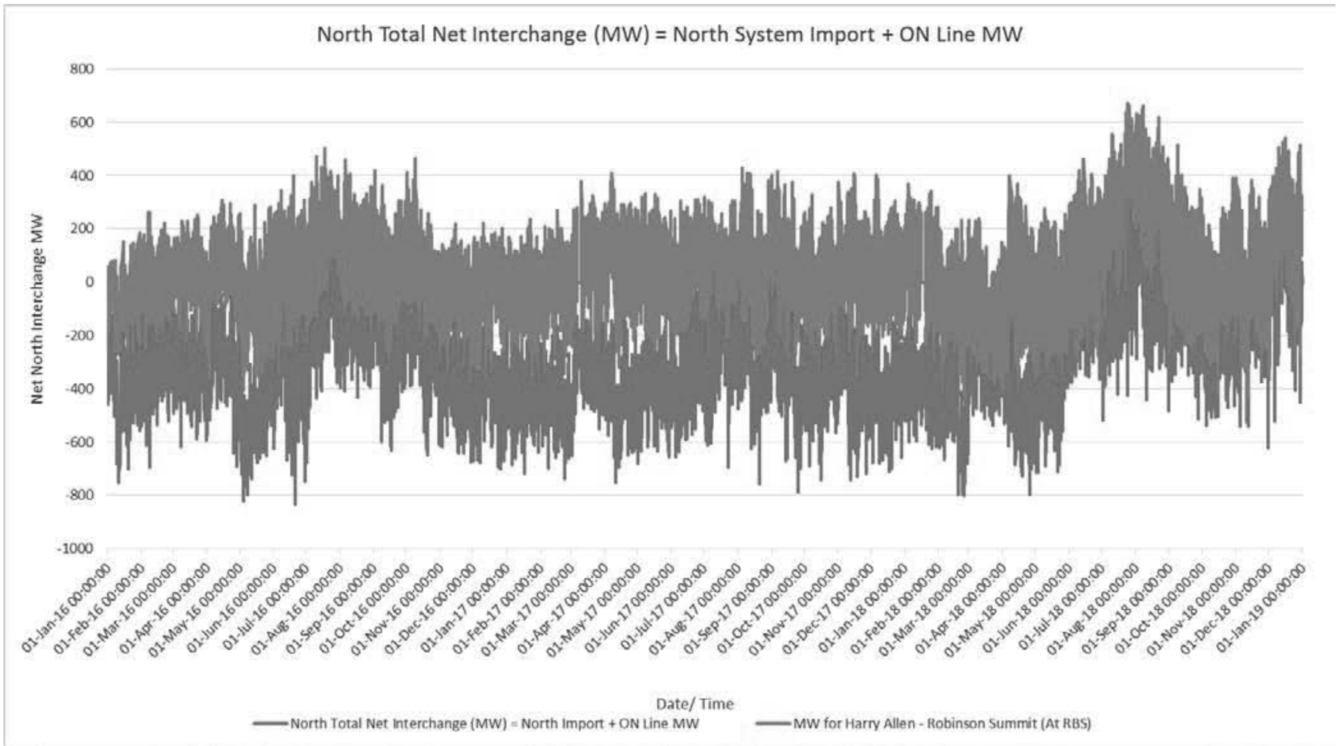

***Table 5**: Three Year Import Export into Northern Nevada*

The historical import over the three year period reached a maximum of 835 MW on June 21, 2016. FERC requires SIL or Simultaneous Import Limit studies to be performed for market power analysis. While these studies have explicit direction and are used for different purposes than maximum import analysis, the commission states that SIL studies are intended to provide a reasonable simulation of historical conditions and are not a theoretical maximum import capability or best import case scenario.

Generation Dispatch

Particular generators in NV Energy's system can have an impact on import conditions: specifically Valmy and TS Power Plant in northeastern Nevada, Ft. Churchill in central Nevada and the Tracy 120 kV generation in the Reno area.

Without any Valmy generation available, the maximum system import limit is reduced to approximately 1240 MW. Under variable conditions such as different flow schedules and phase shifter controls, this limit can be further reduced. For example, the Valmy Life Span Analysis Process study[3] identified an import limit of 1147 MW without Valmy generation available. This particular case assumed the availability of the TS Power Plant. However, the TS Power Plant is not owned or dispatched by NV Energy and Valmy unit 1 is conditionally planned for retirement in 2021. For the import analysis performed to identify the 1360 MW limit, only Valmy unit 2 was made available. Valmy unit 2 is planned for retirement 2025. Currently, NV Energy does not run Valmy on a year around basis. Under normal circumstances, both units are only running from April through October.

With the uncertainty surrounded by both current and future operation of the Valmy generating plant, its impact on the northern system's import limit must be accounted for.

Transmission Reliability Margin

NV Energy is a participant in the Northwest Power Pool (NWPP) reserve sharing program. This program allows NV Energy to import reserves during situations where NV Energy does not have sufficient internal reserves to rebalance the system following a qualifying event or contingency.

In order to call upon NWPP reserves, NV Energy must experience a qualifying event. There are four types of qualifying events[4].

A. Sudden Loss of Generation
B. Sudden Loss of Import
C. Sudden Restoration of a Demand
D. Energy Emergency Alert

Following a qualifying event, the amount of reserves that can be imported from NWPP is calculated using the Most Severe Single Contingency (MSSC) and Contingency Reserve Obligation (CRO) with the equation below.

$$Available\ NWPP\ Reserves\ Import = MSSC - CRO$$

The CRO is dynamically calculated using current Balancing Authority Area (BAA) load and generation with the equation below.

$$CRO = (0.03 * Generation) + (0.03 * Load)$$

For NV Energy, the CRO typically ranges from 180 MW to 450 MW and is calculated dynamically based on current system conditions.

[3] Filed February 16, 2018 in PUCN Docket No. 16-07001.
[4] http://www.nwpp.org/documents/RSGC/NWPP-RSG-Program-Documentation-RSG-Approved-Nov-8-2018.pdf

For Sierra, the MSSC is loss of Midpoint 345 kV with an import rating of 500 MW which is a qualifying event that falls under category B, above. For maximum Midpoint 345 kV import with minimum CRO, the maximum NWPP Reserves are calculated below.

$$NWPP\ Reserves = 500\ MW - 180\ MW \rightarrow NWPP\ Reserves = \ 320\ MW$$

In order to preserve the ability to import up to 320 MW of NWPP Reserves, NV Energy has allocated 325 MW of TRM for import. 150 MW of TRM is allocated to SPPC to be imported from a combination of Midpoint 345 kV, Gonder - IPP, and Gonder - Pavant. 175 MW of TRM is allocated to Nevada Power Company (NPC) to be imported from Red Butte 345 kV.

In order to preserve the ability to import NWPP Reserves during a qualifying event, 150 MW TRM for SPPC must be reserved out of SPPC's total import capacity.

Summary & Conclusions

This study has determined a theoretical maximum import limit for the northern Nevada System as well as identified several major factors that have to be taken into account for the Import limit determination. The theoretical maximum import limit of 1360 MW was determined with the assumption that several system upgrades have been implemented, under a favorable generation dispatch and perfect tuning of system phase shifters. While a single study case can determine this theoretical limit, actual system limitations for every day of every year must have a balance between the theoretical limit and true system operation.

Two major issues exist in the typical approach to the system import analysis. Import analysis is typically performed on a peak system case and only single contingencies are analyzed. A peak system case is used with the assumption that this would be the most stressed condition and that the highest import is generally achievable under peak system load. For example the northern Nevada system has a peak load of approximately 2200 MW and a 1275 MW import limit. In the shoulder months, assuming light loading, the entire northern system load could be 1300 – 1400 MW. If 1275 MW of system load was required to be imported in to the system, the northern system would be operating 25 MW to 125 MW generation over several hundred square miles. Due to the rural nature of the system and length of the transmission lines sourcing the system, it would be impossible to maintain system voltage and operate the system. The assumption is that both native and non-native loads will be tracking together and be overall reduced in the shoulder months. Generally, this is the case but some of northern Nevada's existing and proposed transmission only loads are winter peaking and can skew the overall trend between on and off peak loading.

The import analysis approach does not take into account the likely potential that more than one system facility is out at a time. As discussed in the System Reliability and Maintenance section of this document, the next worst contingency must always be mitigated regardless of the state of the current system. Due to the age of the northern system and the amount of growth the system is experiencing, transmission facilities are out of service on a regular basis. There is no way around taking facilities out of service, both for safety and required maintenance. Certain facilities being out of service have no effect on system import capacity while others drastically effect it. The two 345 kV line previously discussed are perfect examples. The Idaho intertie and the main outlet of the ON Line transmission line are the highest capacity and strongest transmission ties into the northern Nevada system. In the event either of one of these lines incurs a sustained outage, the northern system import must be reduced to around 750 MW in order to sustain the next outage. This requires rapid increase of system generation within a 30 minute time frame. Enough generation must be spinning and available and the ramp rate must be fast enough to bring the generation up quickly. This amount of generation may not always be available. This is yet another complexity of issues that can come up in real time operations versus theoretical power flow analysis.

An alternative to raising generation and decreasing import is the dropping of system load in strategic locations in order to mitigate a potential reliability violation. This is a recognized action for WECC and NERC, as long as actions are within defined standards and regional system reliability is maintained. On the other hand, it is a major concern to the company and dropping of any system load is always a last resort. The first issue gears towards single contingency maximum import analysis under peak conditions not being conservative enough. It could be argued that the import limit must be set lower to account for all the potential variations and system conditions that can occur during actual system operation.

A second issue is that maximum import analysis does not take into account any normal exports that occur off the system. This analysis has to be performed in this manner because the energy cannot be scheduled into a system in excess of what can physically flow reliably. The import limit identifies what can flow reliably and schedules into the system are capped based of that capability. It is extremely rare for all schedules to be inbound and zero outbound schedules. Identifying the physical import limit ensures that counter scheduling cannot be commenced beyond a systems actual capability. This limits the amount of unscheduled flow that is incurred by surrounding utilities. For example, if the company were to schedule 500 MW through a path that can only flow 100 MW, the additional 400 MW would still be dispatched, but would flow on parallel paths creating unscheduled congestion. The historical import section identified that the northern system has not seen a physical maximum import of more than 835 MW over the past three years. Even though the capability existed for energy to be scheduled even above the 1275 MW limit due to the OASIS algorithm error. It could be argued that the import analysis approach is too conservative and is leaving transmission import capacity on the table.

The identified maximum import into the northern system needs to be balance of these two issues. The actual limit is set between the two since analysis attempts to answer a black and white question with an answer that is dependent upon several variable conditions. While the question inquires for a single number, several numbers exist under complex, variable and unpredictable conditions. Based on the analysis performed, the company will maintain the northern Nevada import limit at 1275 MW. For the company, reliability to the system and to its customers is paramount. Increasing this import limit to accommodate more inbound transactions of any level further increases system reliability risk. Based on this updated analysis, further increase to the northern import limit cannot be accommodated without a major transmission interconnection that either adds a new system intertie or strengthens an existing one. The company will continue to review and pursue transmission and generation projects that are in the best interest to its customers and system reliability. The 1275 MW import limit will be reassessed as needed.

TRAN-2

Northern Nevada Export Limit

February 2019

Executive Summary

The purpose of this report is to describe and document Northern Nevada Export Limit.

Following the ATC mapping update in January 2019, the Northern Nevada export limit was re-evaluated. Significant transmission improvements were implemented since previous export limit studies were completed. This report details the export limit considering those infrastructure additions and any new element capabilities detailed in the "Transmission Facility Ratings" spreadsheet maintained by Transmission Planning.

The studies used the Transmission Planning-created master base case modelling the Northern Nevada maximum load day. The export limit studies base case accurately depicts the various facility ratings.

This study followed the NV Energy procedure "1514 - Rated System Path Methodology" (developed in response to the NERC standard "MOD-029-2a Rated System Path Methodology"), and the Peak Reliability policy "System Operating Limits Methodology for the Operations Horizon".

After applying the methodologies, the Northern Nevada Export Limit is **1125 MW** based upon an outage of the Valmy/Coyote Creek 345kV line resulting in the California substation phase shifter (i.e., the jumpers from the bus to the transformer) and the Hilltop 345/230kV transformer at their respective emergency ratings.

After the California substation upgrades, applying the methodologies, the Northern Nevada Export Limit is **1330 MW** based upon many outages causing certain elements to be at their emergency ratings:

- An outage of the Valmy/Coyote Creek 345kV line results in lines between the PG&E Drum and Rio Oso stations to be at their emergency rating.
- An outage of the East Tracy/West Tracy 345kV line results in the Mt. Rose/Steamboat and Mt. Rose/Washoe 120kV line to be at their emergency rating.
- An outage of the Frontier/Gonder 230kV line outage results in the Silver Peak phase shifters at their emergency rating.

The Northern Nevada export rating is resource constrained; insufficient generation limits export capability. In order to calculate the export rating, almost all Northern Nevada generation was turned on at each unit's maximum output except for Apple Solar and Crescent Dunes. Addition of Apple Solar causes other 120kV line overloads in the Reno area and an overload of the East Tracy 345/120kV transformer. Addition of Crescent Dunes above 50 MW causes overloads of the Silver Peak and Ft. Churchill phase shifters at lower net export values. In other words, export values are very sensitive to the generation location. Generation added outside the Reno and 230kV areas may allow more export capability.

The 1125 MW export rating is for the northern zone (i.e., all interties to other utilities and ON Line). The northern interties (i.e., all interties to other utilities without ON Line) export rating is the northern zone export rating less the simultaneous ON Line flow: 1125 MW minus 350 MW for a northern interties rating of 775 MW.

The 1330 MW export rating is for the northern zone (i.e., all interties to other utilities and ON Line). The northern interties (i.e., all interties to other utilities without ON Line) export rating is the northern zone export rating less the simultaneous ON Line flow: 1330 MW minus 452 MW for a northern interties rating of 878 MW.

CONTENTS

STUDY METHODOLOGY

STUDY MODEL

As required by "1514 - Rated System Path Methodology" and the WECC RC policy "System Operating Limits Methodology for the Operations Horizon". Four base cases were used, all modelling the northern Nevada system on it peak day, July 9, 2018.

SOL Methodology Requirement Number	Study Requirement Text	Action Completed	Comments
1.a	Beginning WECC seasonal base case used, utilizing data and assumptions consistent with the time period being studied. Original base case: "Master.sav" created on 1/7/2019 Modified base cases: Existing System: "Export_19HW3a-1105_CAL_PST_CAL30_BOR253_FTC105.sav" (1105 MW export case).; After California upgrades: "Export_19HW3a-1330_CAL_PST_CAL34_BOR208_FTC88.sav" (1330 MW export case).	☒	
1.b	The model used full loop representation with the entire WECC system modeled. Equivalent representation of radial lines and facilities 100kV and below was not used.	☒	
1.c	All system elements were in-service for the assumed initial conditions.	☒	
1.d	The base case modeled all generation (may be either a single generator or multiple generators) that are greater than 20 MVA at the point of interconnection in the studied area.	☒	
1.e	Phase shifting transformers were operated to control the actual power flow without negatively impacting an associated neighbor. Pre-contingency, phase shifting transformers were used in regulating mode. Post-contingency, phase shifting transformers were operated in non-regulating mode.	☒	
1.f	Updated the base cases to reflect the most accurate system line configuration, generation, and load representation for the study time period.	☒	The base cases describe the NVE system at the northern Nevada area at maximum load.
1.g	All Special Protection Schemes (SPS) required for a SOL rating were modeled as they will be applied in operation.	☒	Applied the following: For the #3426 line outage apply the Airport/Mira Loma SPS tripping the North Valley Rd.-to-Rusty Spike line; For the #3425 line outage

			apply the West Tracy generation SPS tripping the West Tracy steam unit; For the #3423 line outage apply the Falcon Transformer SPS tripping the two Falcon 345/120kV transformers
1.h	Models series compensation for each line at the expected operating level.	☒	
1.l	Uses Facility Ratings as provided by the Transmission Owner and Generator Owner	☒	The "Master.sav" case reflects the facility ratings described in the most recent Transmission Planning spreadsheet "Transmission Facility Ratings.xlsx".

STUDY PROCESS---STEADY STATE ANALYSIS

Study Process (MOD-029-2a, R2): Power flow studies should be performed utilizing the following requirement: Adjust the base cases' generation and load levels to determine the maximum SOL (maximum flow or reliability limit) while at the same time satisfying all planning criteria:

<table>
<tr><th>SOL Methodology Requirement Number</th><th>System Performance Criteria</th><th>Action Completed</th><th>Comments</th></tr>
<tr><td>1.i and 3</td><td>Voltage criteria should be applied in accordance with the voltage criteria described in "NV Energy Reliability Criteria":
<table>
<tr><th colspan="9">POST TRANSIENT VOLTAGE CRITERIA</th></tr>
<tr><th rowspan="2">Base kV</th><th colspan="6">PU Voltage Range (Min/Max)</th><th colspan="2">ΔV</th></tr>
<tr><th colspan="2">P0</th><th colspan="2">P1</th><th colspan="2">P2-P7</th><th>P1</th><th>P2-P7</th></tr>
<tr><td>525</td><td>0.95</td><td>1.05</td><td>0.93</td><td>1.05</td><td>0.93</td><td>1.05</td><td>8%</td><td>N/A</td></tr>
<tr><td>345</td><td>0.95</td><td>1.05</td><td>0.9</td><td>1.05</td><td>0.9</td><td>1.05</td><td>8%</td><td>N/A</td></tr>
<tr><td>230</td><td>0.95</td><td>1.05</td><td>0.9</td><td>1.05</td><td>0.9</td><td>1.05</td><td>8%</td><td>N/A</td></tr>
<tr><td>138</td><td>0.95</td><td>1.05</td><td>0.9</td><td>1.05</td><td>0.9</td><td>1.05</td><td>8%</td><td>N/A</td></tr>
<tr><td>120</td><td>0.95</td><td>1.05</td><td>0.9</td><td>1.05</td><td>0.9</td><td>1.05</td><td>8%</td><td>N/A</td></tr>
<tr><td>69</td><td>0.95</td><td>1.05</td><td>0.9</td><td>1.05</td><td>0.85</td><td>1.05</td><td>10%</td><td>N/A</td></tr>
<tr><td>63</td><td>0.95</td><td>1.05</td><td>0.9</td><td>1.05</td><td>0.85</td><td>1.05</td><td>10%</td><td>N/A</td></tr>
<tr><td>57.5</td><td>0.95</td><td>1.05</td><td>0.9</td><td>1.05</td><td>0.85</td><td>1.05</td><td>10%</td><td>N/A</td></tr>
<tr><td colspan="9">Applicable criteria less stringent than TPL-001-WECC-CRT-3.1</td></tr>
<tr><td colspan="9">Applicable criteria more stringent than TPL-001-WECC-CRT-3.1</td></tr>
<tr><td colspan="9">See Note 2 below</td></tr>
<tr><td colspan="9">Non- BES Voltages</td></tr>
</table>
</td><td>☒</td><td></td></tr>
<tr><td>2.a.i and 3</td><td>No transmission element loaded above 100% of its continuous rating under normal conditions</td><td>☒</td><td></td></tr>
<tr><td>2.a.ii and 3</td><td>Following a single contingency or a reasonable double contingency, no transmission element loaded above its emergency rating.</td><td>☒</td><td>After applying the methodologies, the Northern Nevada zone export limit is 1125 MW.After California upgrades, after applying the</td></tr>
</table>

SOL Methodology Requirement Number	System Performance Criteria	Action Completed	Comments
			methodologies, the Northern Nevada zone export limit is 1330 MW.
2.a.iii and 3	No uncontrolled separation	☒	

All facilities are within their Facility Ratings and within their thermal, voltage and stability limits.

STUDY CRITERIA---VOLTAGE STABILITY ANALYSIS

These studies are not needed. Other studies performed by Transmission Planning have not identified a voltage instability concern for n-1 outages.

PATH RATING/STUDY RESULTS

STEADY STATE ANALYSIS RESULTS

After applying the methodologies, the Northern Nevada Export Limit is **1125 MW** based upon an outage of the Valmy/Coyote Creek 345kV line resulting in the California substation phase shifter (i.e., the jumpers from the bus to the transformer) and the Hilltop 345/230kV transformer at their respective emergency ratings.

The powerflow plots below show the California phase shifter almost overloaded at 1105 MW export and an overload at 1150 MW export (based upon its emergency rating). An export of 1125 MW is between the two conditions.

After the California substation upgrades, after applying the methodologies, the Northern Nevada Export Limit is 1330 MW based upon many outages causing certain elements to be at their emergency ratings:

- An outage of the Valmy/Coyote Creek 345kV line results in lines between the PG&E Drum and Rio Oso stations to be at their emergency rating.
- An outage of the East Tracy/West Tracy 345kV line results in the Mira Loma/Airport 120kV line to be at its emergency rating.
- An outage of the Frontier/Gonder 230kV line outage results in the Silver Peak phase shifters at their emergency rating.

VOLTAGE STABILITY ANALYSIS RESULTS

Studies performed by Transmission Planning have not shown a reactive margin deficiency for the Reno area. Therefore, MVAr margin (i.e., voltage stability) analysis is not necessary.

SUMMARY

The Northern Nevada Export Limit is 1330 MW based upon many outages causing certain elements to be at their emergency ratings.

SYSTEM OUTAGES

The following north outages were studied:

All 120kV and 345kV lines in the Reno area.

All 230kV lines in northern Nevada.

All 345kV lines in northern Nevada.

On Line

POWERFLOW PLOTS

TRAN-3

TRAN-3

FILED UNDER CONFIDENTIAL SEAL

TRAN-4

West Tracy 345/120 kV Transformer Addition

Introduction

Transmission Planning performed a load addition study to serve 300 MW of new load at [redacted] facility requiring multiple line rebuilds, a bus expansion at Patrick, bus upgrades at Tracy substation, and 2-120 kV terminal additions at Pah Rah substations. A revised study was performed to determine if project upgrades required for [redacted] as well as other recommended projects for the Tracy area could be combined to achieve a more economical and robust transmission plan. This KDR outlines the benefits of constructing a West Tracy 120 kV substation as alternate to serve new load at [redacted] and integrate additional projects in the Tracy area.

Executive Summary

The Tracy Area has become the most rapidly emerging load pocket in northern Nevada, with most recent load projections of an additional 300 MW of load by the end of 2030. This load pocket is located approximately 20 miles east of Reno with most of the emerging load centered near two industrial parks, the Reno Technology Park and the Tahoe Regional Industrial Center. The load at the Reno Technology Park is primarily comprised of the rapidly expanding [redacted] The Tahoe Regional Industrial Center is the largest regional commercial and industrial center in Northern Nevada. The load is projected to grow in several phases. On a transmission level, these loads are currently served on the 120 kV system which will require upgrades in order to appropriately and reliably serve the forecasted load.

In order to serve this growing load, the amount of transfer required through the existing East Tracy 345/120 kV transformer causes thermal overloads, first on the existing #179 line between East Tracy and Dove, which is scheduled to be upgraded in 2019, and then through the East Tracy 345/120 kV transformer itself. This overload resulted in a recommendation for a second 345/120 kV transformer to be installed at East Tracy. This project has been approved both internally and through an Integrated Resource Plan filing, and it presently has an in-service date of June 2020. The addition of a second transformer at East Tracy also triggered the need to replace underrated breakers at Pah Rah and Dove substations. Additional projects required to serve load in the Tracy area includes folding the #108 line into Dove substation, which requires multiple line re-terminations at Dove substation. This project creates a second strong source between East Tracy and Dove for TRI-Center load. Additionally, Tracy substation also has six 120 kV underrated breakers which are required to be replaced. These projects were identified as necessary without the new load additions at Apple.

The 300 MW load study at [redacted] identified several upgrades at Tracy, Pah Rah and Patrick substations in order to serve the new load. These upgrades are scheduled to occur around the same time that work at East Tracy was to begin for the transformer installation as well as work at Tracy, Pah Rah and Dove substations to upgrade underrated breakers and relays as part of the transformer upgrade addition. Difficulties in the design process for East Tracy as well as construction scheduling issues triggered a re-study for [redacted] which identified a West Tracy 120 kV substation as an alternative for the East Tracy second transformer as well as upgrades required for [redacted] at Patrick and Tracy substations, and eliminated the need for replacing underrated breakers at Pah Rah. The proposal of the West Tracy 120 kV plan is based on a combined assessment for all associated projects. While individual projects may address system reliability issues separately, a comprehensive plan is required to ensure the system is planned efficiently and effectively for both planned and future expansion.

West Tracy Transformer and 120 kV Substation Benefits

Construction of a West Tracy 120 kV substation would allow for the proposed East Tracy 345/120 kV transformer to be moved to West Tracy. Moving this transformer would eliminate the need for the #108 line fold project and underrated breakers at Pah Rah. Additionally, the placement of the transformer at West Tracy would be easier to construct, allows for the addition of a future third 345/120 kV transformer in the Tracy area[1], and creates additional future 120 kV terminals accommodating more flexibility for future expansion.

The original service plan for [redacted] along with the East Tracy transformer uses all remaining terminals at East Tracy. Expanding Patrick substation in the original Apple service plan does not accommodate the addition of a third transformer anywhere in the Tracy area. The construction of West Tracy has an overall lower cost for integrating all projects compared to costs of each individual project.

Tracy Substation Configuration

Tracy substation currently has six 120 kV breakers with an interrupting rating that is lower than the available fault duty. These breakers (1000, 1001BT, 1003G, 1009BT, 1010BT, STA3) are scheduled to be replaced by May 2020 before the new transformer is installed at East Tracy. As part of the project, a new control building was required along with new control cable and new breaker relays. Tracy substation is considerably aged in both equipment condition and configuration.

The West Tracy 120 kV plan for Tracy mitigates the underrated breakers by re-terminating all lines out of Tracy allowing for the removal of breakers at Tracy. This option will effectively remove most of Tracy substation from service. The #177 Patrick – Tracy line will fold into West Tracy with the portion of the line between Tracy and West Tracy being reconductored to 1949 ACCC. The majority of bus work at Tracy would be removed so that Unit 3 and Pinion Pine generation collects on the remaining bus and is directed to West Tracy through the #177 line. The 183 terminal will be re-terminated at Pah Rah substation. The 146 terminal will be re-terminated at East Tracy. The 120/60 kV transformer will be terminated at East Tracy using the existing East Tracy – Tracy bus tie and the remaining bus work at Tracy. This will allow for eight of the existing 120 kV breakers at Tracy to be removed and possibly used for other projects. This new configuration will remove enough relay racks in the existing control building to avoid the significant cost of new control building.

Construction Estimates

Exhibit F provides estimates for installing the transformer at East Tracy and at West Tracy. For the transformer installation at West Tracy, estimates are provided for the proposed Tracy configuration

[1] Several studies for customer-driven projects in the Tracy area have identified the need for a future third 345/120 kV transformer as area loads materialize.

as well. The estimates provided for the East Tracy option include the estimates for replacing the underrated breakers at Tracy and the #108 line fold project. These estimates are provided as these projects are associated with the transformer addition to serve load in the Tracy area. Placing the transformer at West Tracy would eliminate the need for these projects. The total estimates for all projects include estimates for various phases to compare total costs for all projects.

Comparing the costs of installing the transformer at East Tracy (and associated projects) versus installing the transformer at West Tracy, the East Tracy option is lower by approximately $1M. When the cost of the [redacted] service plan is added to the East Tracy estimate, installing the transformer at West Tracy, building a West Tracy 120 kV substation and the proposed Tracy 120 kV changes reduces the overall cost by approximately $1.78M

<u>Conclusion</u>

It is recommended that NV Energy move forward with the construction of West Tracy substation. Transmission System Planning has coordinated this plan and decision with all functional experts and have determined that it is the best system approach for the proposed loads and future expansions.

It is also recommended to integrate Tracy substation work with West Tracy. This plan reduces the overall cost by $1.78M and eliminates the complexities associated with the aged Tracy substation and interconnects existing crucial 120 kV transmission lines into upgraded breaker and a half substations at East and West Tracy.

[redacted]

EXHIBIT C – Project Estimates

West Tracy Estimate Comparisons

Link	Description	East Tracy Transformer and [redacted] Service Plan	West Tracy Transformer and [redacted] Plan
			Breaker and a Half
[redacted]	[redacted]	$ 22,828,000	$ 17,090,000
7T	East Tracy 2nd Transformer	$ 10,628,000	$ -
WJ	West Tracy Substation	$ -	$ 18,959,000
A27	Tracy Underrated Breakers	$ 5,234,000	$ 5,722,000
A22	108 Line Fold	$ 4,861,000	$ -
	Total	**$ 43,551,000**	**$ 41,771,000**
	Cost difference between West Tracy Transformer and [redacted] and East Tracy Transformer with the [redacted]	[redacted]	

REDACTED