Florida Municipal Power Agency

2019 Load Forecast

Final Report

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Power Industry Planners • Analysts • Advisors

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EXECUTIVE SUMMARY

nFront Consulting, LLC (nFront) was retained by Florida Municipal Power Agency (FMPA) to prepare a forecast of peak load and net energy for load for its All-Requirements Power Supply Project (ARP). FMPA is a governmental wholesale power company owned by municipal electric utilities and created to provide economies of scale in power generation and related services. The ARP supplies capacity and energy to 13 municipal utilities in Florida, located throughout the peninsula from the Panhandle to the lower Keys.

A load forecast is a key input to many utility planning functions, including generation resource planning, fuel and purchased power budgeting, transmission planning, financial planning and budgeting, and staffing. In addition, the FMPA load and energy forecast is submitted to the Florida Reliability Coordinating Council as part of the Load and Resource Database as well as to the Florida Public Service Commission as part of the Ten-Year Site Plan. Consequently, a rigorous and detailed process that relies on utility industry standard practices and thorough review of results by various parties is essential to FMPA operations and long-term planning.

The 2019 Load Forecast has been prepared for a 20-year period, beginning 2019 through 2038. The forecast relies on an econometric approach to forecast monthly retail customer counts and sales by major customer classification of the ARP Participants as a function of certain explanatory factors based on an analysis of the influence of these factors generally over 1992 through 2018 (Study Period). Forecasts of system net energy for load (NEL) and coincident and non-coincident peak demand are derived from the total sales forecast based primarily on recent averages of distribution loss factors and load and coincidence factors. The total ARP forecast represents a simple summation across the Participants, taking into account whether or not they are supplied by the ARP in any particular period, where appropriate. All system load determinants presented herein are on a delivered, or "city gate," basis and exclude losses associated with transferring energy across the transmission systems of Florida Power & Light (FPL) and Duke Energy Florida (DEF).

The forecast relies on municipal utility data provided to FMPA by the ARP Participants (Participants), metered load data maintained by FMPA, and historical data regarding Participant load management activity, the ARP Net Metering Program, and the ARP Conservation Program submitted by ARP Participants to FMPA. Historical and projected economic and demographic data were provided by Woods and Poole Economics (Woods & Poole), a nationally-recognized provider of such data, and the University of Florida's Bureau of Economic and Business Research (BEBR), a widely-used resource for Florida utilities, with the projected period reflecting a consensus developed from both providers' data. nFront has also relied on information, provided by FMPA staff and the Participants, regarding local economic developments and other issues specific to each Participant. Weather data was provided by the National Oceanic and Atmospheric Administration (NOAA) for a variety of weather stations in close proximity to the ARP Participants. Finally, projections regarding electricity and competing fuel prices have been obtained from the 2018 Annual Energy Outlook (AEO) Clean Power Plan (CPP) Case, published by the Energy Information Administration (EIA) in February 2018.[1]

Results of the load forecast included herein for the total ARP are presented in the following two ways:

- **Current Participants:** Reflecting the total load requirements of ARP Participants currently served by the ARP (Current Participants) over the entire historical period and forecast horizon irrespective of the fact that certain Participants were not yet supplied by the ARP in certain historical periods and certain Participants are anticipated in the future to receive service under a CROD or to discontinue service from the ARP altogether. This allows for results to reflect a consistent set of ARP Participants and base of customer load over the entire historical and forecasted period, which aids in the comparison of growth rates over the period shown.
- **Supplied Load:** Reflecting in each period the total load of ARP Participants actually supplied by the ARP (the "Supplied" loads), which has varied through time as a result of ARP Participants initiating and discontinuing service from the ARP and is directly used in downstream FMPA planning analyses.[2]

The results of the Forecast reflect that the net energy for load (NEL) of the Current Participants[3], depicted in Figure ES-1 below, is expected to grow at compound annual growth rates of 1.1% per year over fiscal years (FY)[4] 2019-2028 and 0.7% over 2029-2038. As mentioned above, these results reflect the Current ARP Participants and do not account for the initiation or discontinuation of full requirements service by the ARP of certain Participants during the historical period or over the forecast horizon.

The growth rates discussed above can be compared to historical actual growth over 2009-2018 of 0.5% per year. However, as discussed further below, load growth across the Florida peninsula has been depressed as a result of a deep and prolonged recession from which Florida and the ARP Participants have been recovering. The load of the ARP Participants bottomed out in 2012, well after the official end of the recession in late 2009. Since 2012, actual NEL of the Current Participants has grown by approximately 1.3% per year. The forecast results reflect that the FY NEL of the Current Participants is expected to exceed the previous peak level of NEL, which occurred in 2006, for the first time, next year (i.e., in FY 2020).

1 The 2019 AEO, published in January 2019, reflects slightly lower rates of escalation of electricity prices, which would imply higher growth in electricity demand; however, FMPA and nFront jointly determined that the higher price escalation rates reflected in the 2018 AEO CPP Case should be retained for conservatism.

2 Results herein reflect that the load of Green Cove Springs served by the ARP is reduced somewhat as a result of service under a CROD effective January 1, 2020. Subsequent to the preparation of this report, Green Cove Springs executed a supplemental service agreement with FMPA, which results in the ARP serving all load above CROD through at least September 2029.

3 This excludes the load of Lake Worth and Vero Beach, which are no longer supplied by the ARP, effective January 1, 2014 and January 1, 2010, respectively (as discussed in more detail elsewhere below).

4 FMPA's fiscal year represents the twelve month period from October of the preceding year through September of the current year.

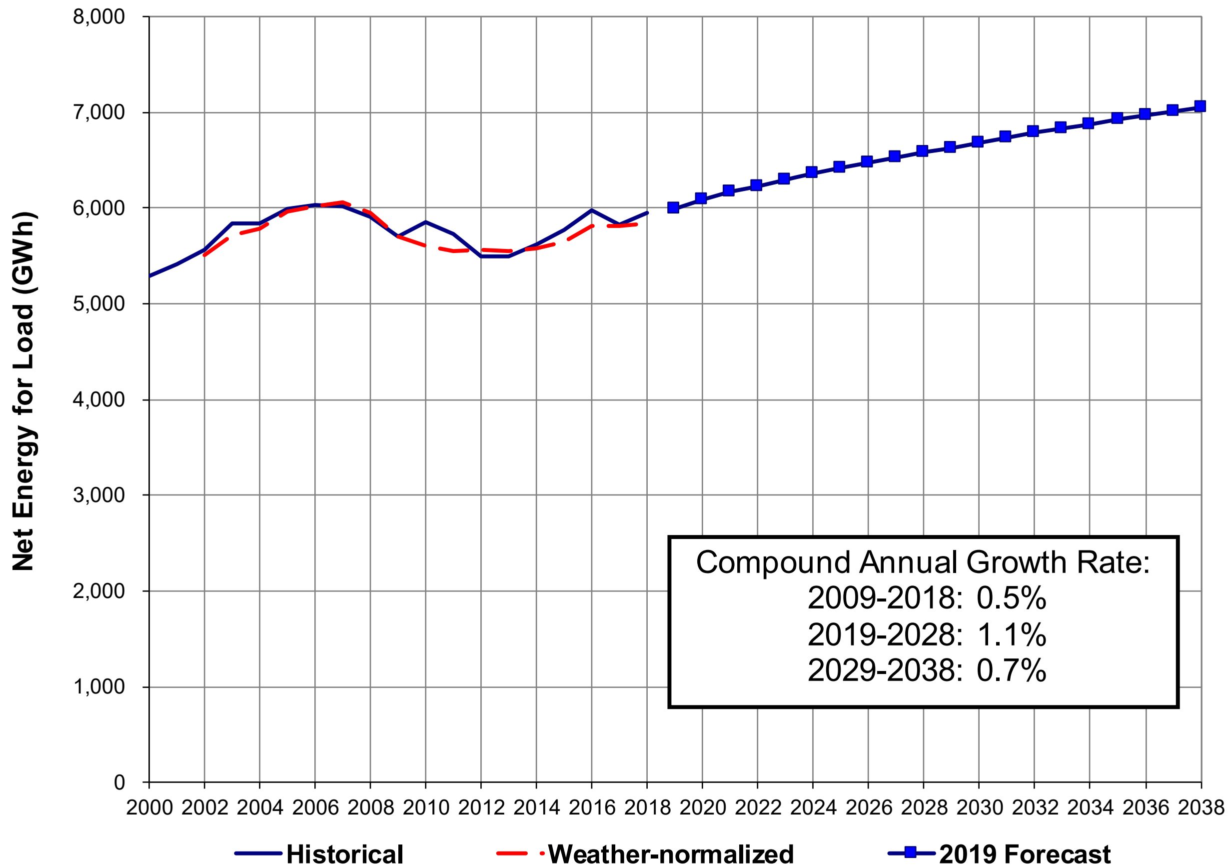

Figure ES-1: Total Net Energy for Load of Current Participants

The Forecast reflects that the coincident peak demand of the Current Participants is expected to grow at compound annual growth rates of 1.1% per year over 2019-2028 and 0.7% over 2029-2038. The Base Case projected 2019 coincident peak of the Current Participants is 1,255.4 MW. The ARP annual coincident peak typically occurs in the summer, and more often in August than other summer months. These growth rates can be compared to weather-normalized compound annual growth rates over 2009-2018 of 0.1% per year and over 2012-2018 of 1.7% per year.

The historical growth rates for both NEL and CP demand are significantly impacted by the recent deep and prolonged recession from which the Florida economy has been recovering. The recent recession had significant negative effects on the housing market, construction and total employment, consumer spending, and visitation by tourists and other seasonal residents. Since 2012, these factors have all improved considerably, as shown in the table below.

Table ES-1
Recent Trends in Florida Economic Indicators

Economic Indicator	2008 Value	2012 Value	2018 Value
Home Price Index (2016$)	213,905	153,928	254,505
Gross State Product (2009$; $M)	764,086	726,372	916,975
Unemployment Rate	6.3%	8.5%	3.7%
Total Employment (Ths)	10,297	10,256	12,406
Construction Employment (Ths)	693	502	743
Tourist Visitation Counts (millions)	82.5	89.7	126.1

Sources: Florida Association of Realtors, Bureau of Economic Analysis, Bureau of Labor Statistics, Woods and Poole Economics, and Visit Florida

This improvement in the economic conditions has been accompanied by a sustained recovery in the demand for electricity in the service areas of the ARP Participants. The economy is anticipated to continue growing at an above-normal pace over the early years of the forecast horizon, which should result in continued growth in the load served by the Participants. The forecasted growth rates in NEL and coincident peak demand for the ARP over 2019-2028 shown above reflect the impact of this above-normal growth.

The load actually served by the ARP historically (Supplied Load) has varied from those depicted in Figure ES-1 as a result of the timing of ARP Participants initiating or discontinuing service from the ARP. For example, Kissimmee Utility Authority and Lake Worth Utilities began taking service from the ARP in October 2002. Conversely, as a result of the establishment of Contract Rate of Demand (CROD) for Vero Beach, effective January 1, 2010, and Lake Worth, effective January 1, 2014, none of the load of these Participants has been served by the ARP beginning the effective date of CROD. Accordingly, the forecast of load supplied by the ARP excludes the load of those two utilities after the respective effective dates of CROD. Furthermore, the forecast of load supplied by the ARP reflects establishment of CROD for Green Cove Springs beginning January 2020, with an estimated CROD value in the Base Case of 25.74 MW. See Section 4 herein for a more detailed discussion of the estimated CROD for Green Cove Springs. Service under a CROD for Ft. Meade was effective January 2015 at a CROD originally established at 10.36 MW. However, as a result of a supplemental service agreement with Ft. Meade, the ARP currently supplies all of Ft. Meade's requirements. This agreement expires in September 2027; hence, the Forecast assumes the ARP will begin serving Ft. Meade on a CROD basis, the agreed CROD level having been reduced to 9.009 MW, effective October 2027.

Figures ES-2 and ES-3 depict the historical, weather-normalized, and projected fiscal year NEL and annual peak demand expected to be <u>supplied from the ARP</u>, reflecting the additions through time of new ARP Participants and the establishment of CROD for Vero Beach, Lake Worth, Ft. Meade, and Green Cove Springs. As shown below, the NEL supplied by the ARP was reduced by approximately 11% over fiscal years 2009 to 2011 and by an additional 7% over fiscal years 2013 to 2015, as a result of establishment of CROD for Vero Beach and Lake Worth, respectively (as the data shown is on a fiscal year basis, and the effective dates of CROD in both cases was January, the impact of CROD is spread over two years each). The historical growth rates are impacted by those changes in the portion of load of ARP Participants that the ARP actually served. The impacts of the initiation of service under a CROD for Ft. Meade and Green Cove Springs are not specifically noted in the Figures below, as it is not sufficiently visible in the charts. Values beyond 2035 are reduced by the anticipated departure from the ARP of Starke, effective October 2035, and Green Cove Springs, effective October 2037.

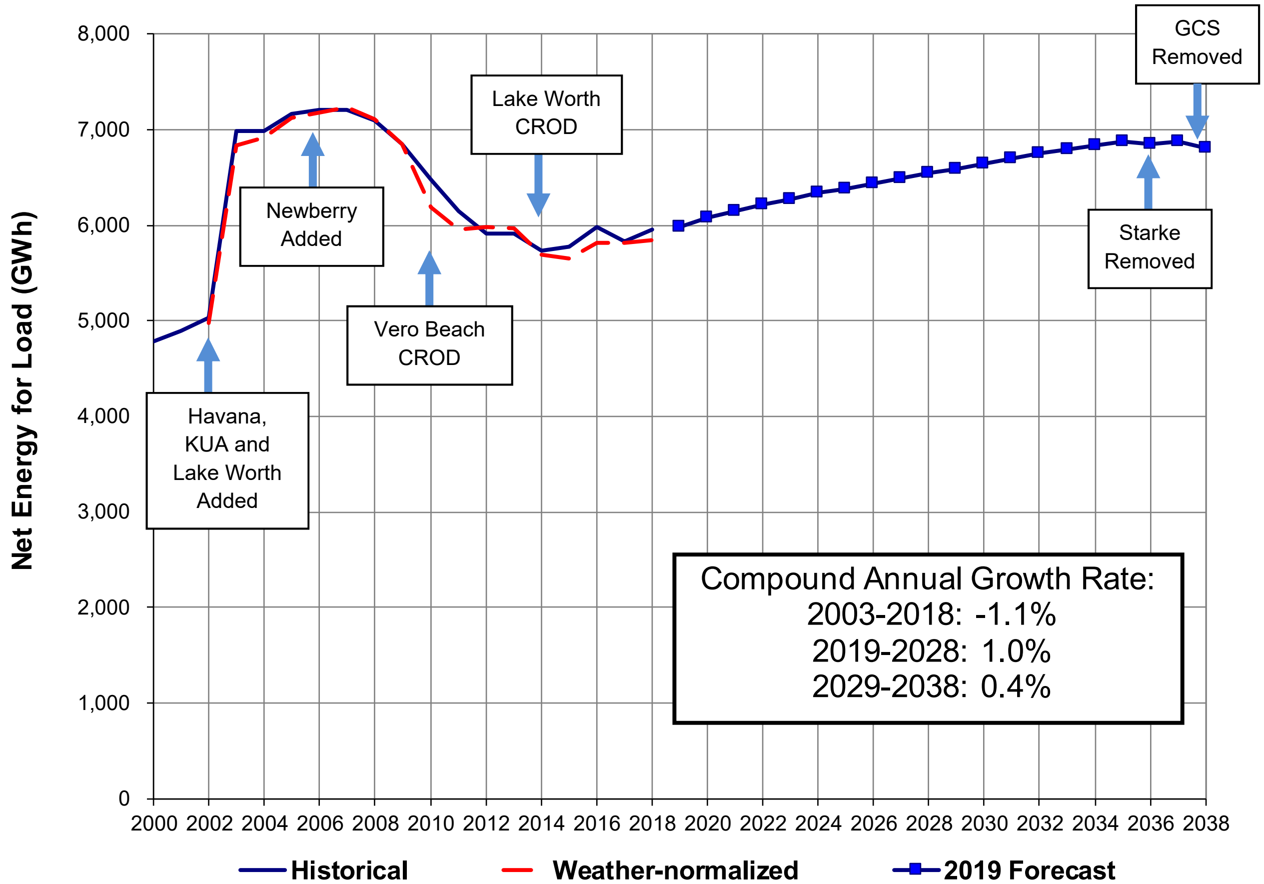

Figure ES-2: Fiscal Year Net Energy for Load Supplied from the ARP

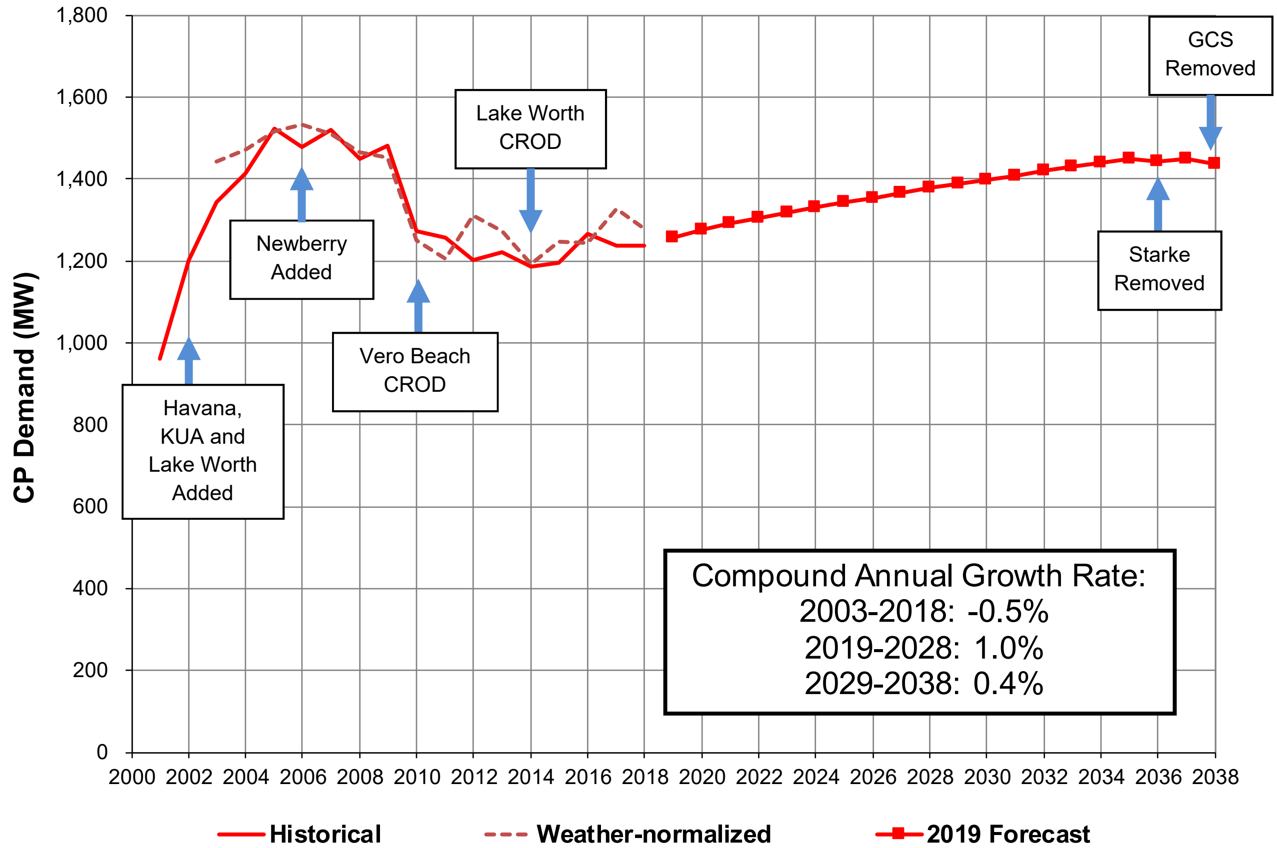

Figure ES-3: Summer Peak Demand Supplied from the ARP

Figure ES-4 compares the currently forecasted peak demand supplied by the ARP and the forecasted peak demand from the 2018 Forecast. This comparison shows that the current Forecast reflects load levels that are 1.3% lower in the early years of the forecast horizon and slightly lower growth over the forecast horizon, resulting in load levels that are as much as 3.8% lower by the end of the forecast horizon. These lower projected load levels are driven primarily from slightly lower projected growth in average income across the ARP Participants and an enhanced representation of future energy efficiency trends across the Participants. However, Figure ES-4 reflects that the current Forecast is very similar to the 2018 Forecast.

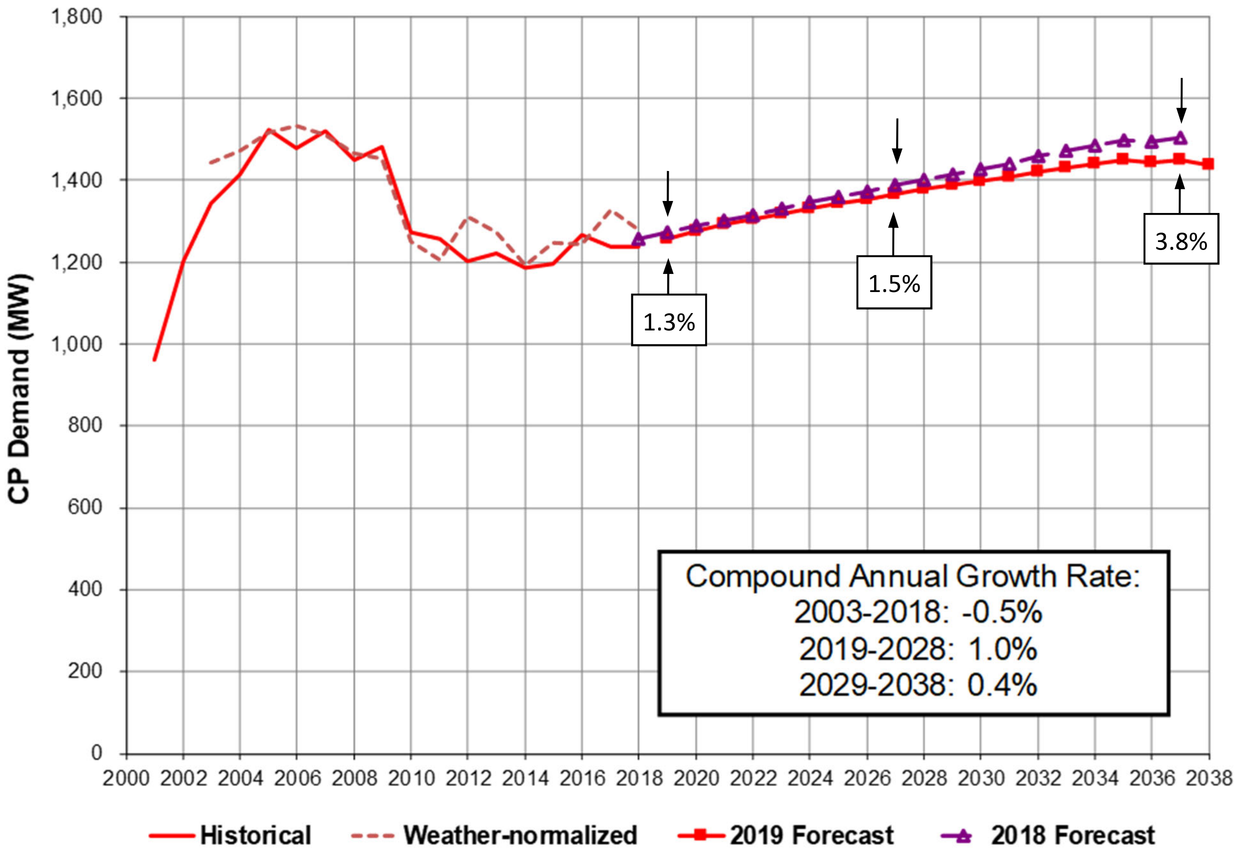

Figure ES-4: Annual ARP Demand Supplied by the ARP

The 2019 Forecast results are strongly influenced by the return of strong population growth to the Florida peninsula and the rebound in growth in residential customer counts and economic activity that this growth in population entails. Importantly, residential average use is projected to be relatively flat over the forecast horizon and is not a growth driver. Figure ES-5 below depicts the comparative growth rates in residential customer counts over 2019-2039 across the ARP Participants ordered in descending compound average growth rate (CAGR) order, with the line across the chart representing the ARP average growth rate. Bushnell reflects the highest growth rate by far due to the assumed acquisition of additional service area and customers of a bordering utility. Kissimmee reflects the next highest growth, reflecting its location in a prime growth corridor in central Florida. KUA's residential growth also significantly affects the overall ARP, as it is the largest ARP member and has by far the largest base of residential customers.

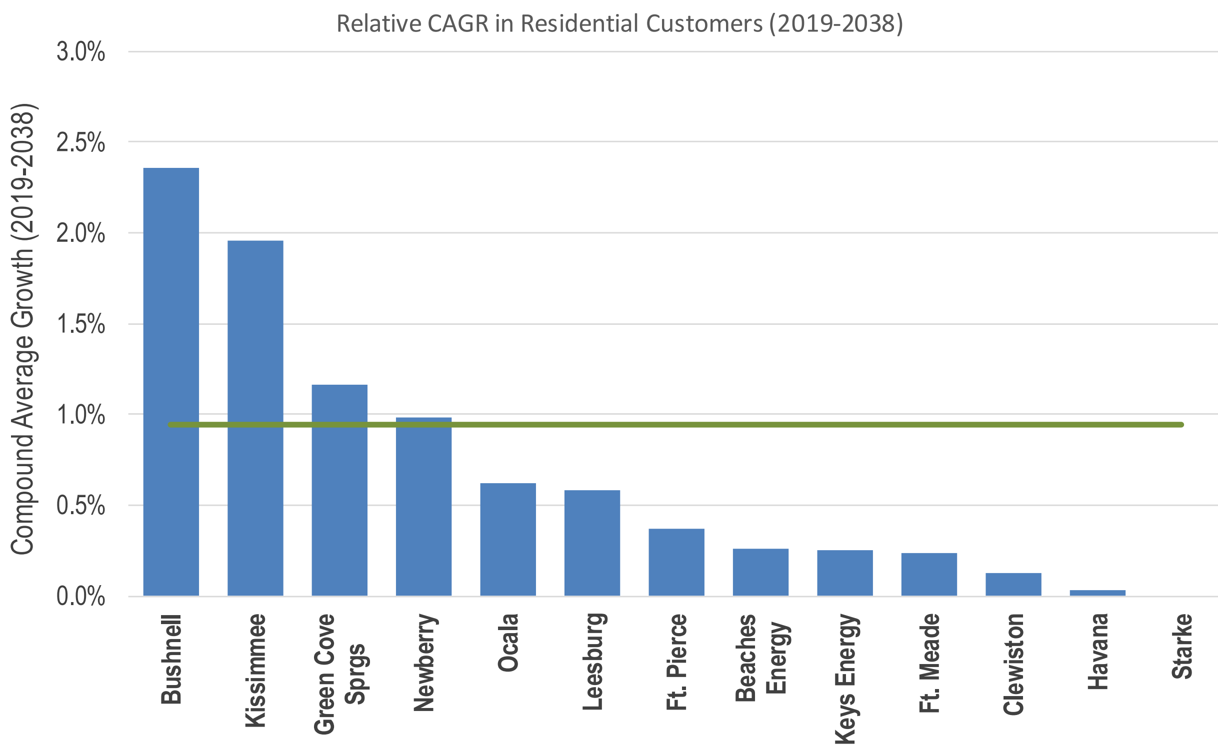

Figure ES-5: Compound Average Growth in Residential Customers over the Forecast Horizon

In addition to the Base Case Forecast, several scenarios were prepared to capture the uncertainty in the primary driving variables. These scenarios separately capture the uncertainty of the trend of economic activity (High and Low Economic Cases) and the uncertainty of weather (Severe and Mild Weather Cases). The high and low forecasts are intended to encompass 90% of the uncertainty in the driving variables. The Low and High Economic Cases result in growth rates for the net energy for load and summer coincident peak <u>of the Current Participants</u> that range from 0.2% to 1.8% over 2019 to 2028 and from 0.2% to 1.1% over 2029 to 2038 (as compared to the projected growth of the Base Case of 1.1% over 2019 to 2028 and 0.7% over 2029 to 2038).

The scenarios related to weather uncertainty are intended to represent the range of potential weather experienced in the summer and winter seasons, encompassing June through September and December through February, respectively, and are essentially aimed at capturing the uncertainty of seasonal NEL. Net energy for load for the summer season in any particular year in the Severe Case was higher than the Base Case by approximately 4.2% and lower in the Mild Case by 3.8%. Winter NEL was higher in the Severe Case by 8.9% and lower in the Mild Case by 7.1% than the Base Case results.

Figure ES-6 below depicts the forecast of summer CP demand resulting from these scenarios as compared to historical and weather-normalized data and the Base Case forecast.

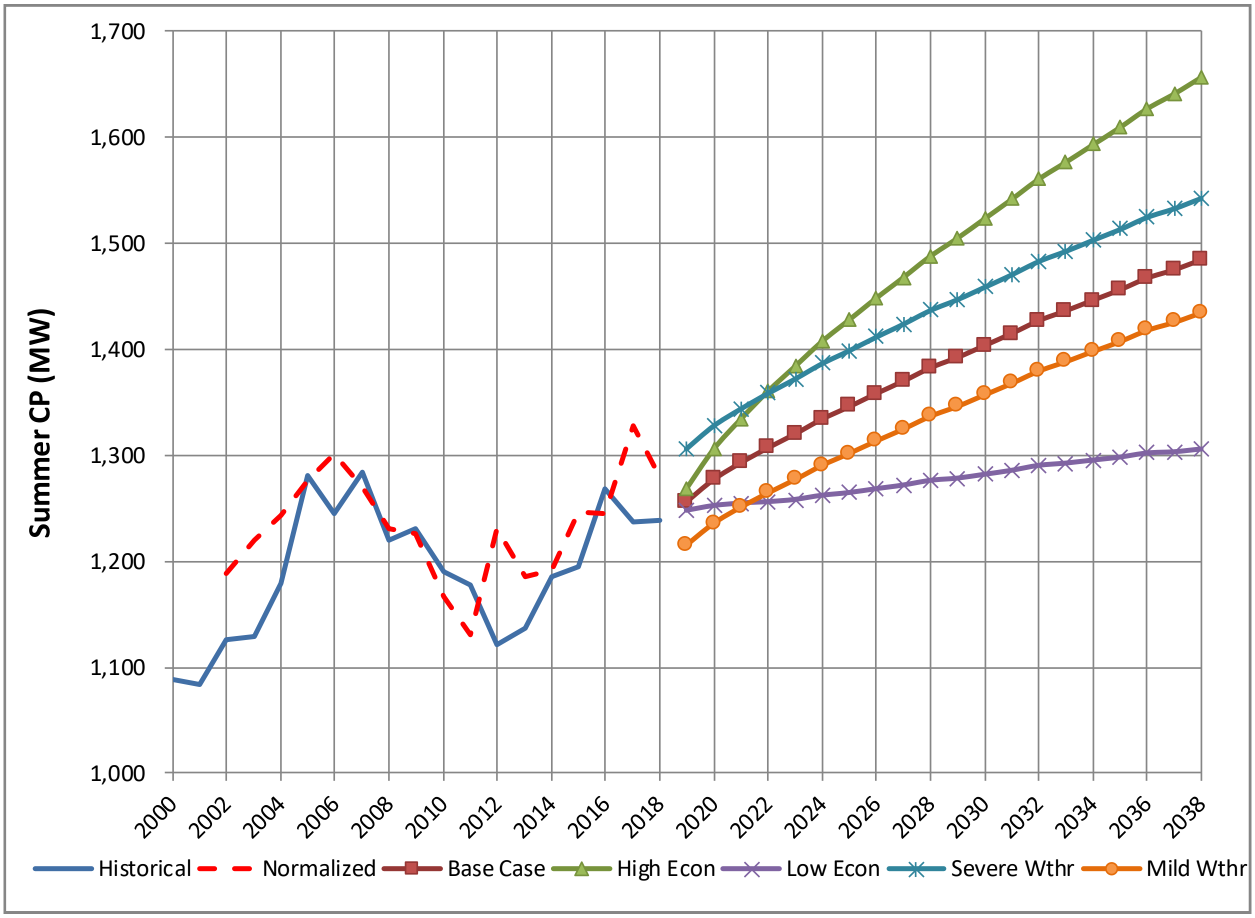

Figure ES-6: Forecast Scenarios of Coincident Peak Demand – Current Participants

The economic scenarios are derived from statistics provided by Woods & Poole regarding historical errors in their state-level forecasts across the United States over 1984-2017. nFront continuously monitors the error statistics published by Woods and Poole and updates these statistics for use in the Load Forecast as appropriate.

The weather scenarios simultaneously reflect more and less severe weather conditions in both seasons, which is less likely to happen than severe conditions in one season or the other. Accordingly, it should be recognized that annual NEL may be somewhat less volatile than the annual NEL variation shown herein. However, NEL in any particular month may be *more* volatile than shown herein, particularly in the off-peak months, which can exhibit weather conditions more like peak months. In addition, because of the methodology that derives peak demand from NEL via constant load factor assumptions, annual summer and winter peak demand may be somewhat more volatile with respect to weather than shown herein.

The following report and appendices detail the methodology, process, and results of the 2019 Load Forecast. The first section of the report provides an overview of the underlying methodology, including a general description of the econometric models and selected explanatory variables. This overview is followed by a description of the data sources that have been relied on for the various types of data needed for the Forecast. Next, a list of principal considerations and assumptions, which have been relied upon, are included to provide context for the results. The Base Case results are then summarized and demand and energy requirements of the ARP Participants are shown for selected years. Finally, concluding comments regarding interpretation of the forecast results and recommendations regarding the planning process are offered. Several appendices, containing the detailed results by ARP Participant and ARP grouping, accompany this report.

Section 1
OVERVIEW OF METHODOLOGY

The forecast of peak demand and net energy for load to be supplied from the ARP relies on an econometric forecast of each Participant's retail sales, combined with various assumptions regarding loss, load, and coincidence factors, generally based on an average of recent historical values for such factors, and summed across the Participants. Econometric forecasting makes use of regression to establish historical relationships between energy consumption and various explanatory variables based on fundamental economic theory and experience, building upon the body of empirical work accumulated in the utility industry.

In this approach, the forecast analyst poses a theoretical set of variables believed to explain energy consumption and estimates the parameters of these variables using statistical software. The reasonableness and statistical significance of each of the variables and the estimated parameters are evaluated using commonly accepted statistical measures and theoretical tests. Models that, in the view of the analyst and guided by industry best practices, best explain the historical variation of energy consumption and provide a reasonable basis for forecasting are selected. These historical relationships are generally assumed to continue into the future, barring any specific information or assumptions to the contrary. The selected models are then populated with projections of explanatory variables, resulting in projections of energy requirements.

Econometric forecasting can be a more reliable technique for long-term forecasting than trend-based approaches and other techniques, because the approach results in an explanation of variations in load rather than simply an extrapolation of history. This approach can enable utilities to anticipate departures from historical trends in energy consumption, given accurate projections of the driving variables. In addition, understanding the underlying relationships that affect energy consumption allows utilities to perform scenario and risk analyses, thereby improving decisions. The high and low economic and weather scenarios we have prepared are examples of this capability.

Forecasts of monthly sales were prepared by major customer classification for each Participant. In some cases, classifications were combined to eliminate the effects of class migration or redefinition. In this way, greater continuity is provided in the historical period upon which statistical relationships are based. Table 1-1 below shows the level of granularity at which the forecast was developed for each Participant. In the table below, the cases where no "X" appears in the categories of General Service Demand and Large Demand (e.g., Bushnell, Fort Pierce, Leesburg) implies that while there may actually be customers that are classified by the Participant as belonging in these categories, their sales are combined under General Service Non-demand for modeling and reporting purposes, primarily due to the similarity in the characteristics of these classes, significant migration that has occurred between classes historically, and/or greater tractability of the data.

Table 1-1
Rate Classification Analyzed by Participant

Participant	Residential	General Service Non-demand	General Service Demand	Large Demand	City/Other	Lights [1]
Bushnell	X	X				
Clewiston	X	X	X	X [2]		
Fort Meade	X	X				
Fort Pierce	X	X			X	X
Green Cove Springs	X	X	X	X	X	
Havana	X	X				
Jacksonville Beach	X	X	X		X	
Key West	X	X			X [3]	X
Kissimmee	X	X	X		X	X
Leesburg	X	X			X	
Newberry	X	X			X	
Ocala	X	X		X	X	X
Starke	X	X				

[1] Lighting classes may be projected based on assumption as opposed to econometric analysis.
[2] Represents a single customer, US Sugar. Separate analyses and assumptions were used to project US Sugar loads.
[3] Represents a single customer, the Key West Navy Base. Separate analyses and assumptions were used to project Key West Navy Base loads.

MODEL SPECIFICATION

The following discussion summarizes the development of econometric models used to forecast load, energy sales and customer accounts on a monthly basis. This overview presents a common basis upon which each classification of models was prepared. Additional details are provided in the accompanying appendices.

For the residential class, the analysis of electric sales was separated into residential usage per customer and the number of customers, the product of which is total residential sales. This process is common for homogenous customer groups. For other rate classifications, the total sales series is the primary forecasted variable, and the customer forecast is generated for reporting purposes and to check the sensibility of the sales forecast.

Residential class models typically reflect that energy sales are dependent on, or driven by: (i) the number of residential customers, (ii) real personal income per household, (iii) real electricity prices, (iv) energy efficiency trends, and (v) weather variables. The number of residential customers was projected on the basis of the estimated historical relationship between the number of residential customers of the Participants and the number of households in the Participant’s county. For a few Participants, the forecast of residential customers also includes a variable that captures the impact of speculative home buying on customer counts using data on mortgage originations in the state. For a few Participants, the residential sales forecast equation includes a variable to capture the retrenchment in consumer spending, represented by variations in the U.S. personal savings rate, either as a stand-alone variable or as an adjustment to income. In addition, the residential sales forecast for some Participants includes a variable that addresses the impact of variations in the housing vacancy rate. These variables and their data sources are discussed further in Section 2.

For the general service class models, the econometric models reflect that energy sales are best explained by: (i) total real personal income, employment, or retail sales as a measure of economic activity and population in and around the Participant's service territory, (ii) the real price of electricity, and (iii) weather variables. The selection of a variable to represent economic activity and population was made based on statistical measures and/or the sensibility of the resulting forecast. However, the forecasts for certain large customers of two Participants (Clewiston and Key West) were based on an assumption developed in consultation with FMPA staff and these Participants. In most cases, the impact of consumer spending retrenchment has been captured as a stand-alone variable or as an adjustment to personal income, similar to the residential sales forecast described above.

Weather variables include heating and cooling degree-days for the current month and for the prior month. Lagged degree-day variables are included to account for the typical billing cycle offset from calendar data. In other words, sales that are billed in any particular month are typically made up of electricity that was used during some portion of the current month and of the prior month.

In certain instances, Participant-specific modifications of the general theoretical model and additional variables were used to account for behavior that occurred during the study period or is expected to occur in the future but is unexplained by available data. Some of these additional variables address specific, known events, such as hurricane incidence or a recovery from the same, and are generally guided by information provided by the Participants. Others account for observations of the dependent variable that are believed to be anomalous. While these adjustments artificially increase the "fit" of regression equations and are typically discouraged, large deviations from expected behavior tend to have a significant impact on resulting parameters and sometimes undeservedly so. In consultation with Participants, we have treated certain anomalies as errors or otherwise removed certain observations from the regression process.

ARP Conservation Program Impacts

Beginning in 2008, the FMPA Executive Committee approved the creation of the ARP Conservation Program that is funded via the ARP Energy Rate. As part of this program, each Participant receives a load ratio share (based on NEL) of the total funding to implement their choice of conservation and energy efficiency measures. As part of the ARP Conservation Program, ARP Participants have the flexibility to implement specific programs based on the unique needs of their customers, which are then reimbursed by FMPA through this fund. In addition, some ARP Participants have implemented utility- or grant-funded conservation efforts as well. Energy efficiency measures that are part of the program include energy saving kits, rebates on major home appliances and programmable thermostats, and insulation upgrades, among other programs. FMPA collects data on a quarterly basis regarding the measures implemented by each Participant in each measure category, along with an accounting of the number of customers or quantity of items disbursed and an estimate of the associated load impact.

As part of its compliance obligations under NERC reliability standard MOD-031, FMPA has adopted an approach to addressing demand-side management (DSM), including conservation programs, in the forecasts of its Peak Demand and NEL. FMPA has established a threshold for the level above which the estimated impact of its Conservation Program will be explicitly taken into account in its load forecast. This threshold has been defined as 0.5% of ARP Peak Demand or ARP NEL in any year over a 20-year forecast horizon. For the purpose of testing whether the ARP Conservation Program is anticipated to have an impact that crosses FMPA's defined threshold, FMPA maintains a forecasting model to project the participation in and impact of individual DSM measures that comprise the Conservation Program. This model projects adoption of specific measures based on recent program data and the assumption that FMPA will continue funding the Conservation Program at similar levels over the forecast horizon and combines such projections with estimates regarding the incremental impacts of each measure on demand and energy reduction to forecast the total energy and demand impact.

The results of the updated Conservation Program forecasting model reflect that the projected program impacts are expected to increase somewhat over the next several years and slightly exceed the 0.5% threshold on an energy basis for the first time before subsiding to just below the threshold by the end of the forecast horizon. Projected impacts on ARP demand similarly increase somewhat over the next several years but remain below the threshold over the entire forecast horizon. As the projected impacts are only slightly above the planning threshold and only for a brief period on an energy basis and *below* the threshold on a demand basis, FMPA does not intend to explicitly account for the effects of the Conservation Program in its forecast of demand and net energy for load. However, as the impacts of recent energy efficiency program participation are captured in actual consumption data for recent years, some impact of the programs is *implicitly* incorporated in the current load forecast.

This model is updated annually in advance of each load forecasting effort to evaluate whether the threshold is likely to be met, using the projected ARP load determinants from the preceding load forecast. When and if the estimated future impact of the energy efficiency programs exceeds the 0.5% threshold in a sustained way, FMPA will evaluate the best methods for accounting for these programs in the forecast.

Net Metering Program Impacts

In June 2008, the ARP Participants adopted a Net Metering Policy to permit interconnection of customer-owned renewable generation to the Participants' distribution systems. This policy facilitates the purchase of excess customer-owned renewable generation and outlines the metering, billing and crediting procedures to be followed by ARP Participants. Thus, through the Net Metering Program, the ARP has been able to switch the fuel used to provide the energy requirements of certain residential and commercial customer loads from traditional ARP fuel sources to distributed solar photovoltaic ("PV") generation.

Table 1-2 summarizes the renewable generation installed on the Participants' distribution systems over 2009-2018. As of December 2018, the ARP had an estimated 6,324 kW-AC of nameplate solar PV renewable generation connected to the grid through the Net Metering Program.

Table 1-2
Historical Net Metering Capacity Across the ARP[5]

Calendar Year	Annual Installs	Cumulative Installs	Cumulative Capacity (kW-AC)[6]	Estimated Generation (MWh-AC)[6]
2009	22	36	227	387
2010	41	77	430	732
2011	22	99	581	984
2012	28	127	782	1,323
2013	66	193	954	1,605
2014	33	226	1,859	3,139
2015	50	276	2,200	3,698
2016	87	363	2,769	4,656
2017	153	516	3,793	6,358
2018	365	881	6,324	10,635

In order to assist FMPA with determining the estimated impact on the ARP load forecast of distributed solar capacity, FMPA maintains a database and model to track net metering capacity and project impacts of this capacity on demand and energy requirements on a by-Participant basis. Historical installations are combined with an estimated hourly dispatch profile for a representative solar installation based on the National Renewable Energy Laboratory's PV-Watts™ model.[7] The hourly dispatch profile was used to estimate the "dependable capacity" at the time of the FMPA peak demand (i.e., coincident peak impact) by analyzing the hourly output as a percentage of capacity in

[5] Values do not include a 30 kW-DC system installed at a NOAA facility on the Keys Energy system. Estimated generation values reflect a 19.5 percent capacity factor, based on an industry standard model of PV production for mid-Florida, and degradation of 0.75 percent per year.

[6] Nameplate capacity. Not adjusted for coincidence with the FMPA peak or expected degradation of performance.

[7] PV Watts is an industry standard tool to estimate PV system generation. The dispatch profile was based on a representative solar installation in the Daytona Beach area, to approximate locations for Ocala and KUA and representing a mid-point for the Florida peninsula.

each hour. Annual energy impacts were derived by applying the capacity factor produced by the PV-Watts model run to the installed capacity.

In order to develop a projection of the future level of installed distributed PV capacity, nFront Consulting and FMPA have utilized multiple methodologies, including the following:

- **Trend analysis.** In this framework, the trend of total installed capacity is simply extrapolated into the future, typically using a linear function.
- **Bass Diffusion.** This methodology relies on the commonly understood behavior of the diffusion of new technologies, which go through phases of minimal penetration, very rapid adoption, and eventual saturation—a trend that typically has the appearance of an S-curve or logistic function. This methodology attempts to fit the historical trend of adoption to a logistic function, in which the eventual saturation level is either imposed or estimated directly from the data.
- **Econometric modeling of adoption.** This forecasting approach attempts to explain adoption rates as a function of the economics of distributed PV from an archetypical customer's perspective. For this purpose, nFront Consulting developed data regarding the approximate trend of the installed cost of small-scale PV equipment, based on industry research, and developed statistics regarding estimated payback for PV installation, based on assumptions regarding retail electricity rates, retail net metering policies, and the anticipated roll-off of investment tax credits.

As a result of the minimal level of existing penetration of distributed PV generation, the Bass Diffusion approach did not yield useful parameters from which to construct a forecast. Based on the trend analysis and econometric modeling of adoption approaches, nFront Consulting estimates that PV penetration among residential customers across the Participant systems will eventually grow from the current level of about 0.3 percent to between 0.7 and 2.1 percent by the end of the forecast horizon, or 2038. Using both approaches, projections of the number and capacity of PV installations were developed and adjusted for degradation over time. The resulting projected installed capacity was then combined with the performance assumptions described above to ascertain whether the projected effects of the net metering program warranted direct treatment in the load forecast, relative to the NERC MOD standard FMPA has adopted.[8]

The projected impacts of the Net Metering Program are expected to reduce ARP energy by approximately 0.8% by 2038. As this level is greater than FMPA's designated threshold for level of significance (0.5% of either the ARP Peak Demand or ARP NEL in any year over the 20-year forecast horizon), FMPA intends to develop a methodology to explicitly account for the impacts of the Net Metering Program in the next iteration of the forecast. However, it should be noted that as the net metering program has resulted in reduced customer consumption of utility generated electricity in

[8] Solar PV panel degradation is typically estimated at 0.75% per year, and inverter replacement is typically required after 15 years of use. Given the relatively small overall PV footprint within the FMPA system, such considerations did not impact the results above. As the program matures, more detailed performance modeling and renewal/replacement considerations may be warranted.

the recent past, such historical impacts have been captured in actual billed consumption data, and some level of impact of the program is *implicitly* included in the current load forecast through the impact on the parameters of the forecast equations.

While the Florida Public Service Commission allows municipal and cooperative utilities to set their own net metering policies, thus allowing for varying treatment of excess generation that flows back onto the utility system, Florida's investor-owned utilities must credit rooftop PV generation, up to the amount of billed consumption, back to the customer at the full retail rate. Remaining excess generation beyond the amount of billed consumption over a 12-month billing period is credited at the utility's avoided cost, which is typically far lower. Changes in the rate treatment of distributed generation and net metering could impact uptake of distributed PV in the future.

FMPA intends to continue monitoring the trend in installations of distributed generation across the Participants' systems and refining the forecasting methods discussed above. While the economics of distributed solar generation continue to improve, the economics of utility-scale solar are far superior. Additionally, utility-scale solar can make solar energy cost-effective for customers whose homes are not well suited for solar (as a result of orientation or shading) and customers who are not homeowners. Accordingly, FMPA and many of its members, including some ARP Participants have contracted for utility-scale solar generation. The Florida Municipal Solar Project has an expected contract in-service date of 2020.

PROJECTION OF NEL AND PEAK DEMAND

The forecast of sales for each rate classification described above are summed to equal the total sales of each Participant. Assumed distribution loss factors, typically based on a 5-year average of historical loss factors, are then applied to the total sales to derive monthly NEL, as measured at the wholesale meter used for ARP billing purposes. To the extent historical loss factors were deemed anomalous, they were excluded from these averages. In addition, in cases wherein historical losses appeared to be subject to a significant historical trend or shift, such historical trends or shifts were captured through a regression analysis of monthly losses, typically as a function of weather conditions, seasonal binaries, and binaries or trend variables intended to address these fluctuations. These trends and shifts are generally a function of distribution system improvements or changes in billing practices undertaken by the Participants.

Projections of peak demands were developed by applying projected load factors, generally based on an analysis of historical load factors, to the forecasted net energy for load on a total Participant system basis. However, prior to computing the necessary historical load factors from which to develop projections, historical impacts of load management and load-side generation resources (LM) of certain ARP Participants have been added back to the metered demands of these Participants. As a result, the forecasted peak demands for these Participants, and for the ARP in total, reflect the peak demands that the ARP must be prepared to serve irrespective of reductions in load that might be realized as a result of these resources, as they are not controlled by FMPA (and the FMPP Balancing

Authority) and cannot be counted on to be active during peak periods. The operation of such resources for peak-shaving purposes was curtailed effective October 2015 as a result of an ARP policy regarding such resources.

Projections of summer and winter non-coincident peak (NCP) demand were developed by applying projected annual load factors to the forecasted net energy for load on a total Participant system basis. The projected load factors are based on the average relationship between annual NEL and the seasonal peak demand generally over the period 2009-2018. In some cases, different averaging periods were selected, or certain years excluded, to address historical trends in load factor, frequently associated with large customer activity, and anomalies, including hurricane-related impacts.

Monthly peak demand is based on the average relationship between each monthly peak and the appropriate seasonal peak. This average relationship was computed after ranking the historical demand data within the summer and winter seasons and reassigning peak demands to each month based on the typical ranking of that month compared to the seasonal peak. This process avoids distortion of the averages due to randomness as to the months in which peak weather conditions occur within each season. For example, a summer peak period can occur during July or August of any year. It is important that the shape of the peak demands reflect that only one of those two months is the peak month and that the other is typically some percentage less.

Projected coincident peak demands related to the total ARP, the Participant groups, and the transmission providers were derived from monthly coincidence factors averaged generally over the most recent five to ten years, the longer averaging period being utilized to reduce the influence of recent anomalous weather (e.g., the very mild 2016/17 winter). The historical coincidence factors are based on historical coincident peak demand data that is maintained by FMPA. Similarly, the timing of the ARP and Participant group peaks were determined from an appropriate summation of the hourly load data. The peak demands coincident with the transmission providers, FPL and DEF, are based on hourly load data maintained by FMPA and information regarding the timing of peak demands of the transmission providers obtained by FMPA.

For long-term resource planning purposes, FMPA adds the anticipated real power losses over the transmission systems of the ARP's transmission service providers to the resulting NEL and peak demand values to derive expected ARP generation requirements. Generation-level NEL and CP demand are reported to the Florida Reliability Coordinating Council (FRCC) for purposes of determining Florida system reliability, and the Florida Public Service Commission as part of the Ten-Year Site Plan. However, all system load determinants presented herein are on a delivered, or "city gate," basis and exclude losses associated with transferring energy across the transmission systems of FPL and DEF.

Section 2
DATA SOURCES

HISTORICAL PARTICIPANT RETAIL SALES, LOAD MANAGEMENT, AND ARP CONSERVATION PROGRAM DATA

Data for each ARP Participant on numbers of customer accounts, electric sales, revenues, load management activity, ARP Conservation Program activity (including participation by measure, net expenditures, and marginal impacts), and Net Metering Program activity (including nameplate capacity and energy estimates by installed resource) collected and maintained by FMPA were furnished to nFront. Retail data were generally available and analyzed over January 1992 through September 2018 (Study Period). ARP Conservation Program data were provided by FMPA for the 2009-2018[9] program years, based on quarterly reports submitted by ARP Participants.

WEATHER DATA

Historical weather data has been provided by the National Climatic Data Center (a subsidiary of the NOAA). Weather stations, for which historical weather was obtained, were selected based on their quality and proximity to the Participants. In most cases, the closest first-order weather station (usually airports) was the best source of weather data. For Beaches Energy Services, however, weather data from a cooperative weather station, which was closer than the closest first-order station, appeared to more accurately capture the weather conditions that affect the Participants' loads than the closest first-order weather station.

The influence on electricity sales of weather has been represented through the use of two data series—heating and cooling degree-days (HDD and CDD, respectively.) Degree-days are derived by comparing the average daily temperature and a base temperature, typically 65 degrees Fahrenheit, the base relied on herein. To the extent the average daily temperature exceeds the base, the difference between that average temperature and the base is the number of CDD for the day in question. Conversely, HDD result from average daily temperatures that are below the base. Heating and cooling degree-days are then summed over the period of interest, in this case, months.

Weather conditions assumed over the forecast horizon are based on the thirty-year monthly HDD and CDD, from the period 1986 through 2015[10]. Figures 2-1 and 2-2 below depict historical data regarding winter HDD and summer CDD, respectively, for the Orlando airport weather station, with the winter period, for this purpose, comprising December of the prior year through February of the current year and summer comprising June through September. The figures include both actual

[9] Some data regarding 2018 was not yet available at the time of the analyses presented herein.
[10] The 1986-2015 period captures some of the recent warmer weather and will be updated when the new NOAA Normals for 1991-2020 are available or as conditions warrant.

historical values, long-term normal, and the expected range of potential conditions assumed for purposes of alternative scenarios, which are discussed in Section 4.

The figures show that HDD have been below normal over the last few winters (winter 2016/17 being far below normal), while CDD over the last few summers have generally been at or above normal (except for summer 2017, which was slightly below normal for a few weather stations, including Orlando airport).[11] These observations are similar for most other weather stations impacting the ARP Participants.

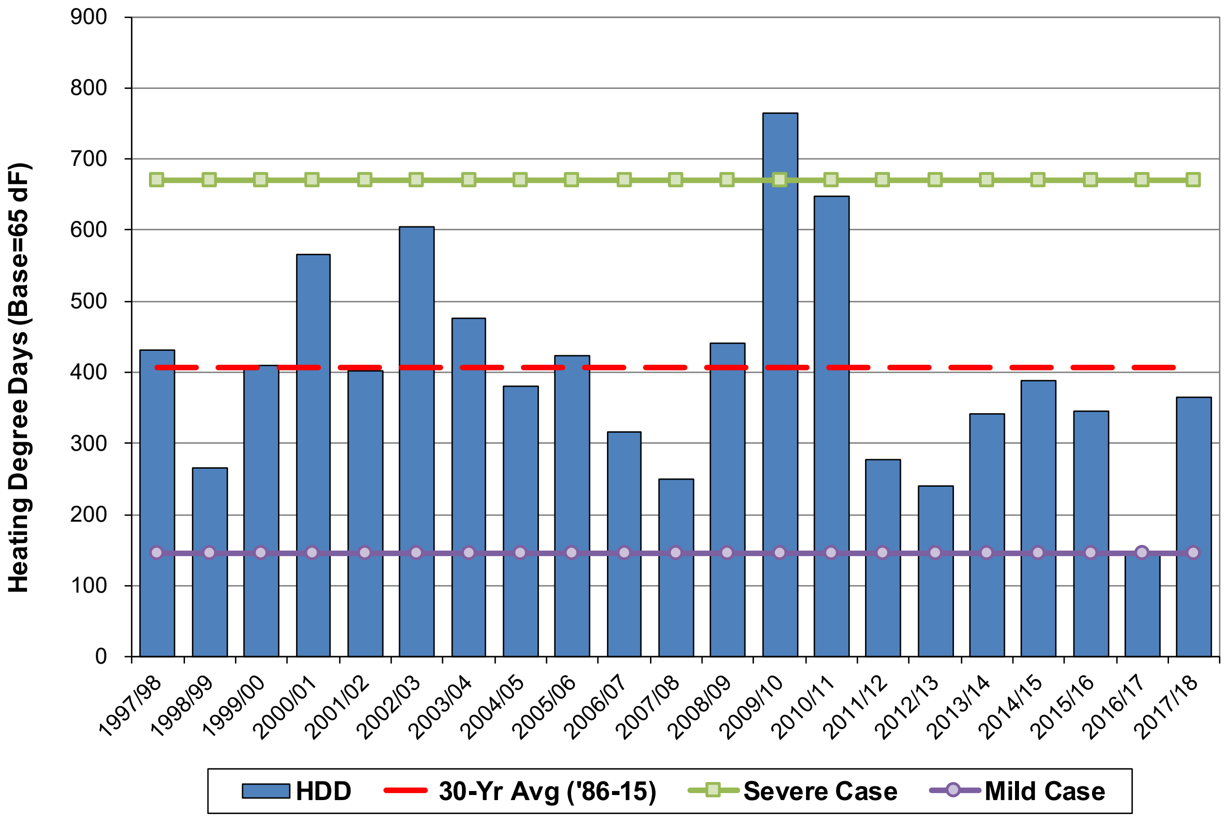

Figure 2-1: Historical v. Normal and Typical Range of Winter Heating Degree Days

[11] The Study Period of analysis for the Load forecast reflects an endpoint of September 2018.

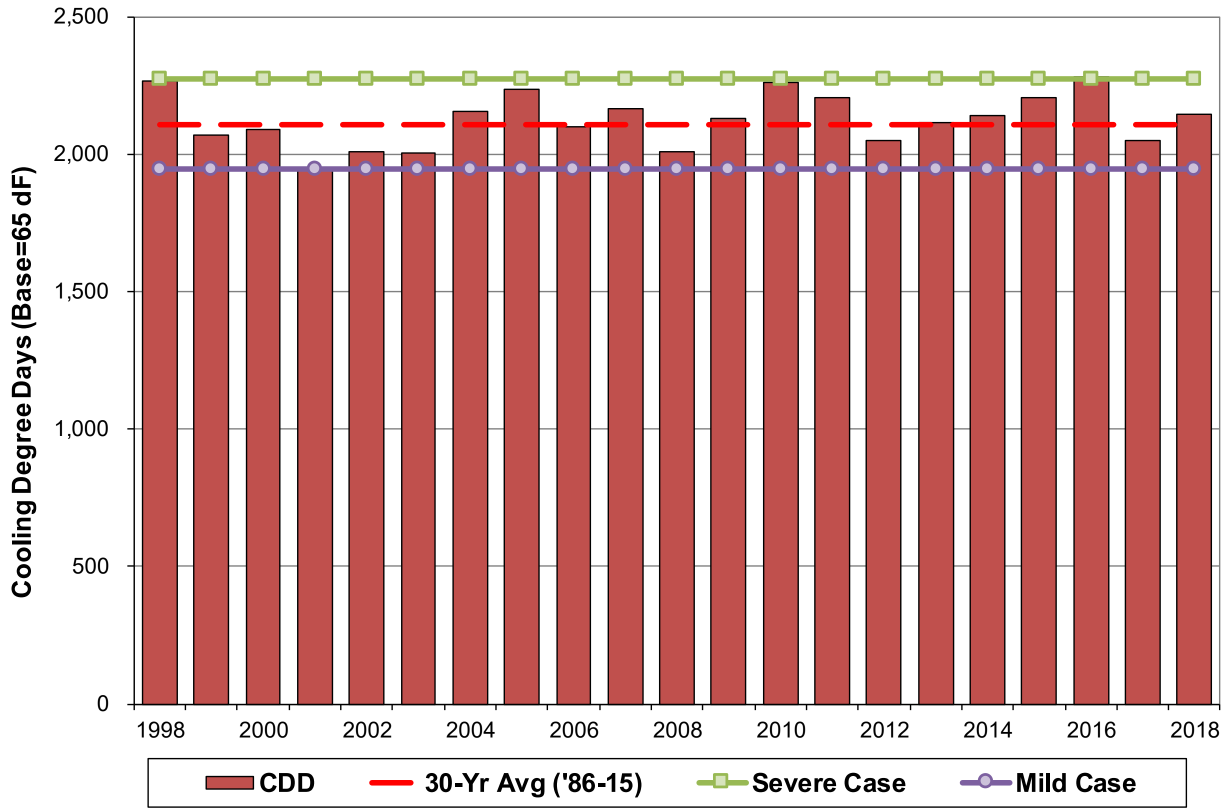

Figure 2-2: Historical v. Normal and Typical Range of Summer Cooling Degree Days

Appendix D includes a graphical comparison of historical and normal annual HDD and CDD for the weather station used in the forecast of each Participant's load.

Economic Data

Historical and projected economic and demographic data were obtained from Woods & Poole Economics (W&P), a nationally recognized provider of economic data. The data relied on include economic and demographic data for the 14 counties in which the Current Participants' service territories reside (the service territory of Beaches Energy Services includes portions of both Duval and St. Johns Counties). These data include county population, households, employment, personal income, retail sales, and gross domestic product. Although all data was not necessarily utilized in each of the forecast equations, each was examined for its potential to explain changes in the Participants' historical electric sales.

Population projections were also obtained from the University of Florida's Bureau of Economic and Business Research (BEBR), a widely used resource for Florida utilities. The BEBR projections reflect a slightly more conservative outlook for population growth across the ARP service territories than the W&P projections.

The historical and projected data used in the econometric analysis and resulting forecasting equations reflect a blending of the two data providers (Woods & Poole and BEBR), generally beginning in 2016. The population projections for the two data providers were generally blended by averaging the annual growth rates. All other economic and demographic data provided by Woods & Poole were adjusted by the resulting percentage difference from the Woods & Poole population projections to arrive at a similar blended outlook for these variables. This reflects the idea that population can be viewed as the key underlying indicator across all of these variables (e.g., employment variations imply similar population variations, barring temporary economic fluctuations due to the economic cycle). In limited cases, the forecast reflects varying weights between the two providers' projections, generally to err somewhat on the side of conservatism.

Two of the most influential variables in the 2019 Forecast, household counts and average real personal income, are shown in the Figures below, comparing the most current estimates and projections to those used in the 2018 Load Forecast.

Figure 2-3 depicts historical and projected data regarding the total number of households across the 14 counties in which the Current Participants provide service. The flattening of the growth in household counts beginning 2007 and extending through 2010 illustrates the impact of the recent recession, at the core of which was the extreme over-extension of the housing market.

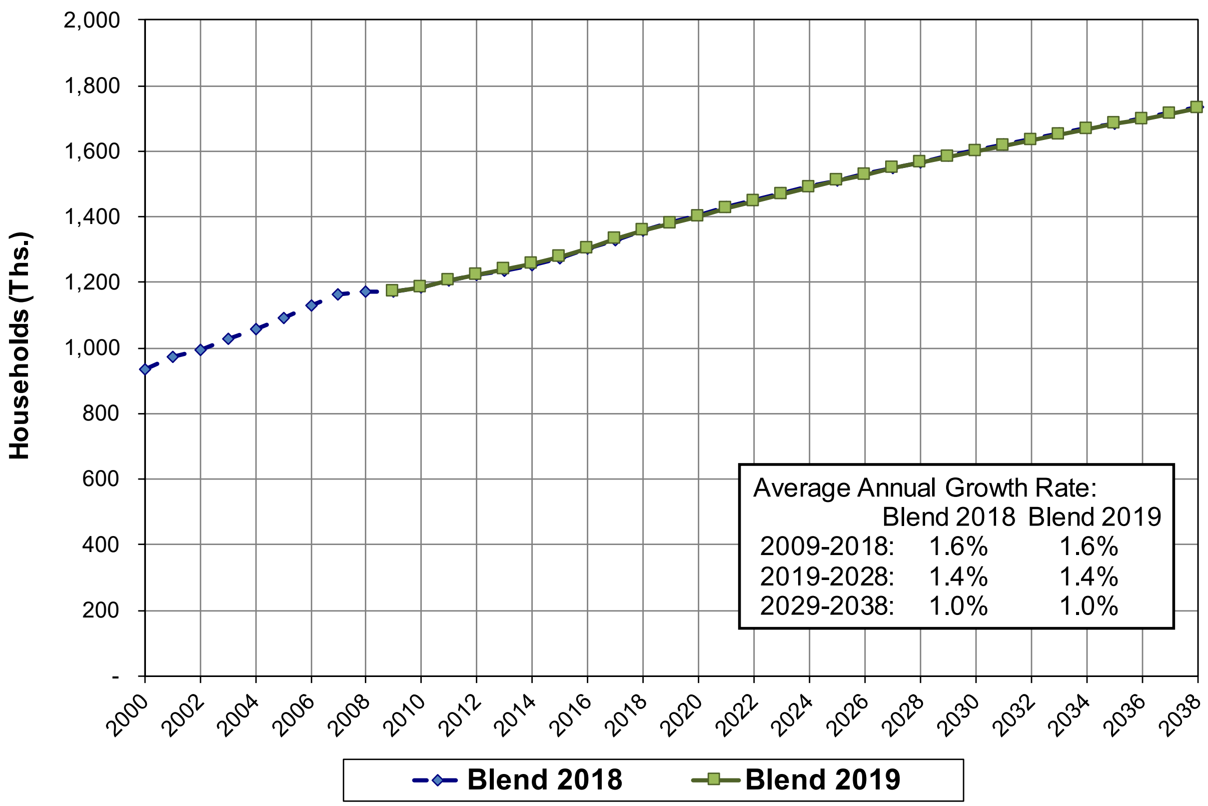

Figure 2-3: Household Counts Across the ARP Counties

Figure 2-4 depicts historical and projected data regarding the average real personal income per household across the counties in which the Current Participants provide service. Data shown are in constant dollars. The impact of the recent recession and the associated housing boom and bust is clearly visible over the 2004-2013 period. The projection reflects a gradual improvement, with the pace of increase projected to be slightly lower to that reflected in the 2018 Forecast.

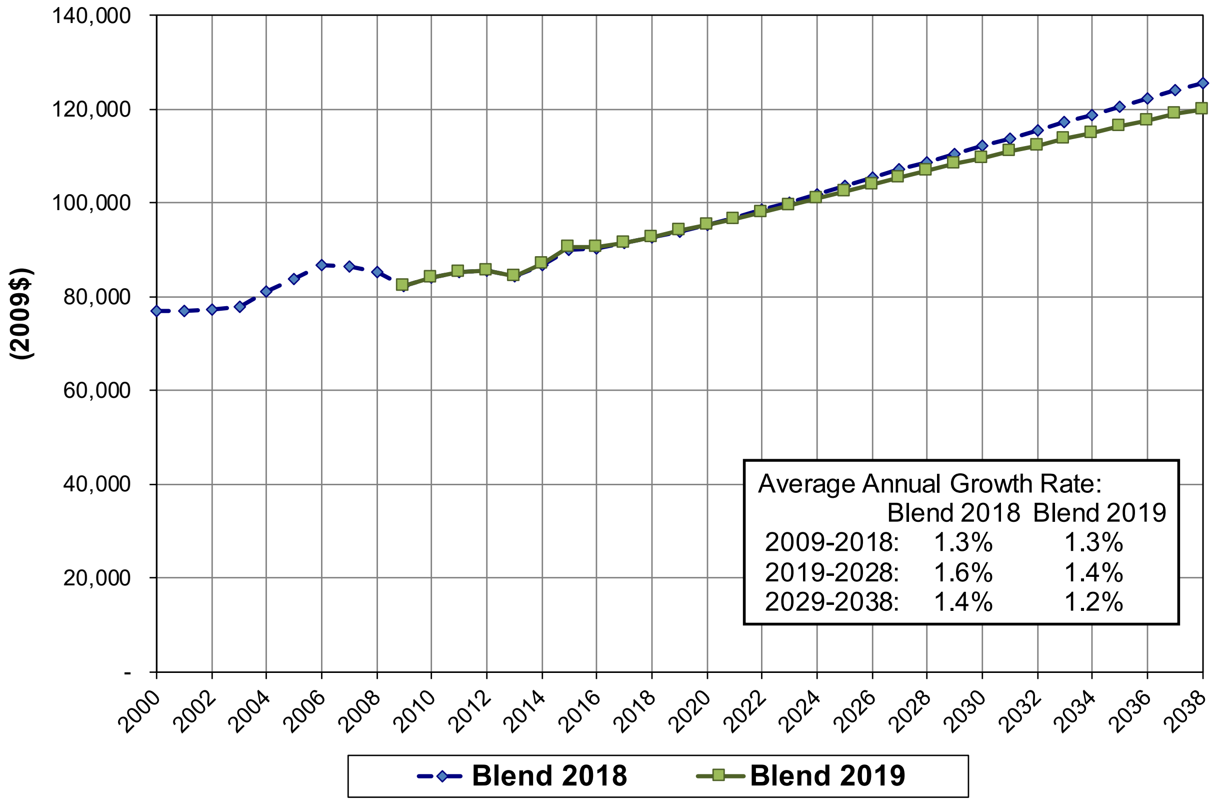

Figure 2-4: Real Average Personal Income per Household Across the ARP Counties

Historical and projected rates of change of the key economic drivers in the Forecast are detailed in the accompanying appendices, in the sections detailing forecasts by Participant. Note that personal income refers to the total income earned by the population in a county rather than average personal income per capita, thereby combining population and income per capita concepts.

In addition to the economic data by county discussed above and detailed in Appendix D for each Participant, data regarding the personal savings rate for the United States was obtained from the St. Louis Federal Reserve. Variations in the personal savings rate were tested to ascertain whether they help explain variations in energy consumption in one of two ways—either as a stand-alone variable or as an adjustment to real personal income (thereby capturing an effective consumed income term). The relevant theory is that the recent deep and prolonged recession and attendant impact on consumers' savings and home equity may have caused a long-term retrenchment in spending, both on retail goods and services and on energy.

Figure 2-5 depicts historical and projected data regarding the personal savings rate. Data over the forecast horizon reflects a short-term decrease from the 2018 level of 6.8%, to the long-term average of 6.5% which is the average over 1989-2018. Data on this variable specific to Florida are unavailable.

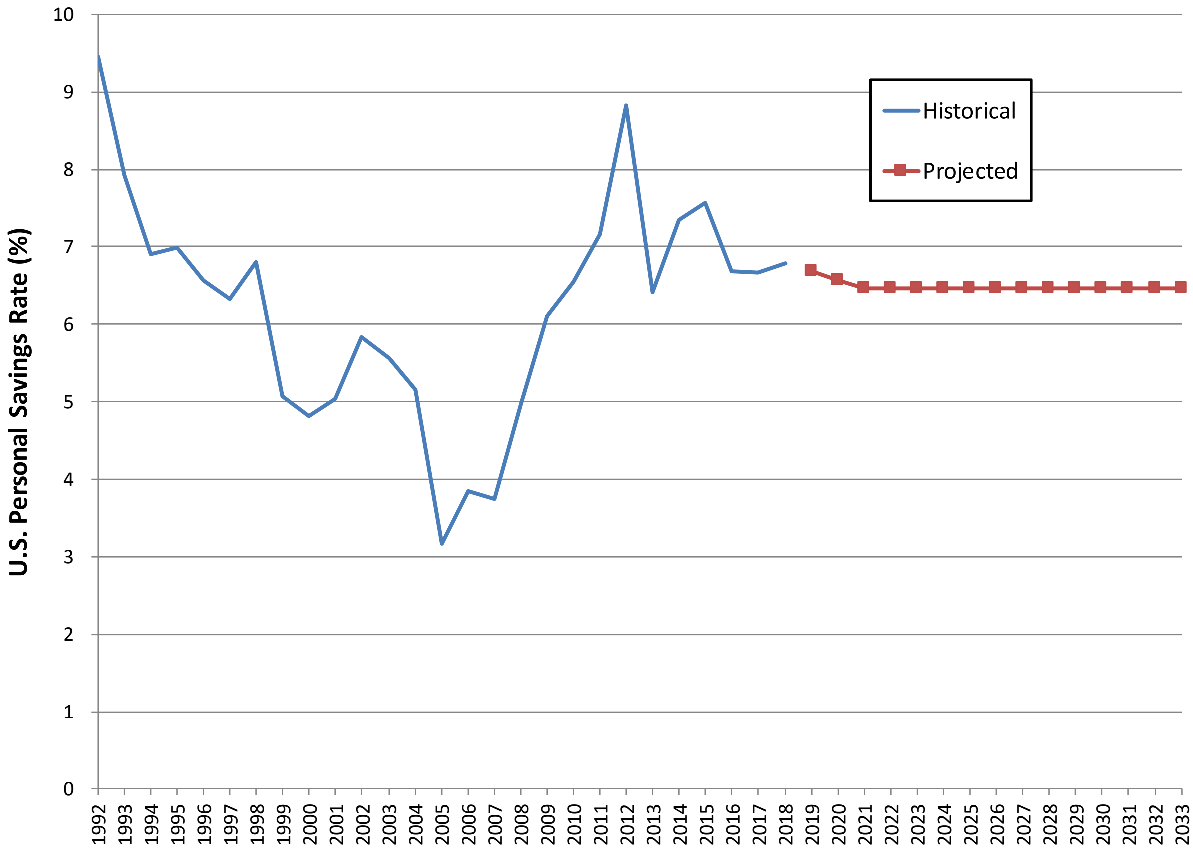

Figure 2-5: Historical and Assumed Future U.S. Personal Savings Rate

Real Estate Data

During the recent housing crisis, a large number of homes in Florida became vacant, as a result of both foreclosures and investment activity. Some of these homes may still be connected, billed by the Participants, and counted as residential customers, perhaps being owned by an investor or by a bank and minimally space-conditioned in order to maintain the home but otherwise vacant. These very low usage accounts would have reduced the average consumption of residential customers and have been a significant cause of the recently lower level of average consumption in the residential class across the ARP Participants. While some utilities in Florida tend to exclude very low usage customers in their customer counts, most have reported this phenomenon as well and have further reported some recent improvements in residential average use, likely as a result of improved occupancy.

In order to capture this potential issue across the ARP, historical data regarding housing vacancy rates were obtained from the Bureau of the Census and tested for inclusion in the forecast equations for the residential class. In several cases, housing vacancy rates do appear to be an important driver of average residential consumption, although the lack of data specific to the Participants' service areas is a significant limitation. Projected data are developed based on a return to the long-term historical average over a brief period.

Figure 2-6 depicts historical and projected data regarding the housing vacancy rate for both owned and rented housing units.[12] The chart reflects that vacancy rates did increase markedly over the 2006-2012 period but have since returned to levels that are more representative of the long-term history. Rental vacancy rates appear to have fallen somewhat below that level, which is reflective of the current tight rental market.

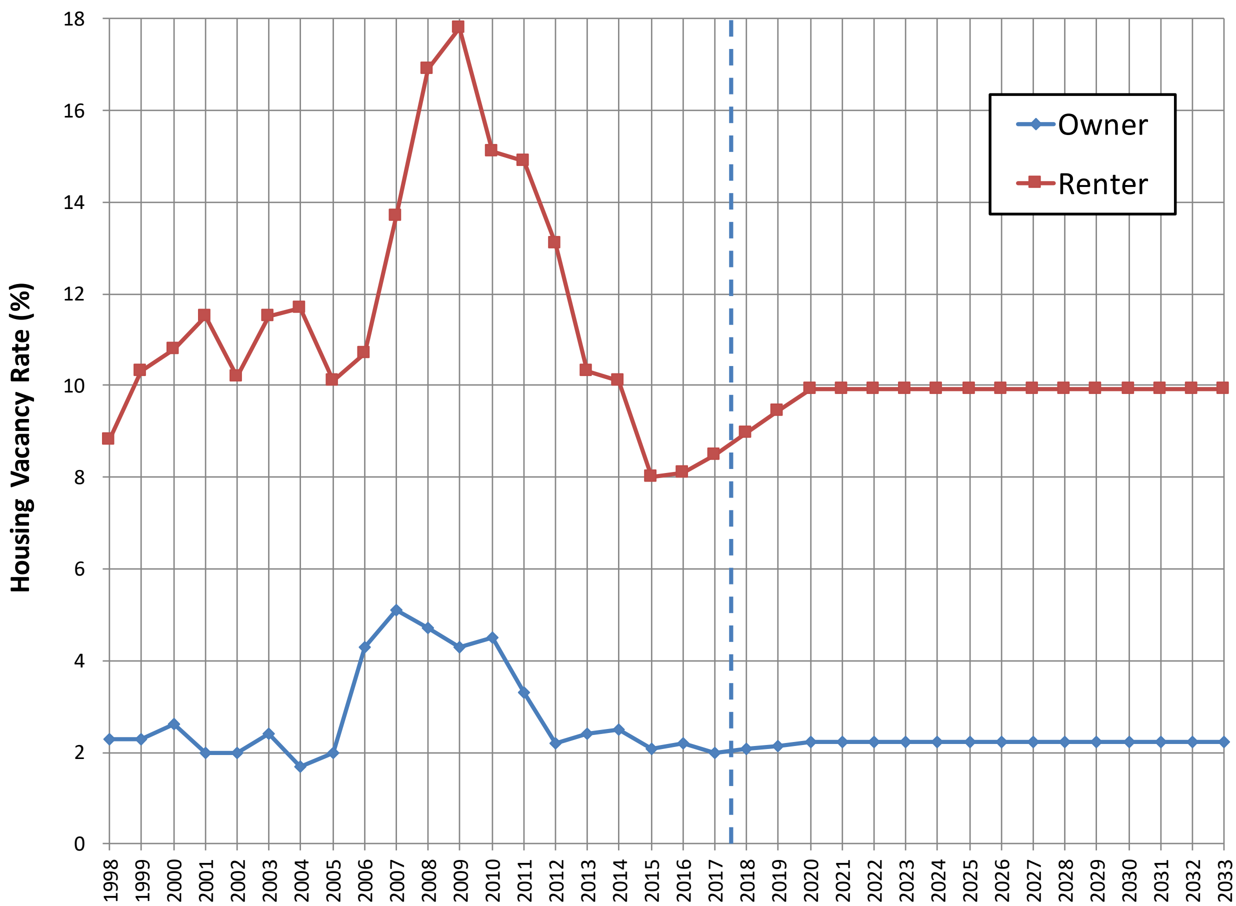

Figure 2-6: Historical and Assumed Future Florida Housing Vacancy Rates

REAL ELECTRICITY PRICE DATA

The real price of electricity is generally represented as a multi-month moving average of real average revenue, based on retail billing data submitted by the Participants to FMPA staff. The moving average

[12] Status of housing units, in terms of occupancy and owned versus rental units are determined as part of the Current Population Survey, which combines telephonic surveys with on-site fieldwork. The rental vacancy rate for the U.S. is a component of the index of leading economic indicators, which is used to gauge the current economic climate.

period varies from 12 to 60 months (i.e., one to five years) but is in multiples of twelve months to avoid the seasonality that is typical of average electricity revenues, which would be correlated with weather-related influences. It is expected that consistent changes in electricity prices in a given direction over longer periods of time are more likely to yield significant and greater variations in load versus short-term price fluctuations. However, the strong negative correlation between electricity prices and economic data precluded a lengthier lag treatment for the price variable in many cases.

Projected electricity prices are generally based on the 2018 Annual Energy Outlook (AEO) Clean Power Plan Case, published by the Energy Information Administration (EIA). While the Clean Power Plan (CPP) or similar federal regulation is unlikely to be in effect for several years at least, FMPA is assuming herein, for conservatism, that FMPA and the Participants will move toward a greater mix of renewable resources over time, thereby producing similar resulting electricity costs as the CPP. Projected electricity prices in the 2018 AEO CPP Case reflect that average real electricity prices in the state of Florida are expected to grow at approximately 0.4% per year over 2019 through 2038. Given an average price elasticity[13] across the retail customers of the ARP Participants of 0.2, this has resulted in a decrease in the projected rate of growth in NEL across the ARP Participants of approximately 0.08% per year.

ENERGY EFFICIENCY STANDARDS

While the economic and electricity price variables are intended to capture discretionary responses of electricity consumers to such economic and market signals, the federal government has additionally engaged in policy actions intended to bring about greater efficiency of energy consumption over many years. The National Appliance Energy Conservation Act of 1987 (NAECA) instituted the first national appliance efficiency standards for a variety of major appliances. Subsequent legislation in 1988, 1992, 2005, and 2007 increased the numbers of end uses with mandated efficiency, now numbering more than 50 products. These laws generally set initial minimum standards and directed the Department of Energy (DOE) to conduct reviews on a regular schedule to determine whether any further increases in the standards were technically feasible and economically justified. For example, the NAECA set the minimum efficiency for split system central air conditioning at the seasonal energy efficiency ratio (SEER) of 10.0, effective January 1992. Later regulatory action by the DOE, supported by the required review and public involvement process, increased the required SEER level for such systems as shown below.

[13] Elasticity is a measure of the influence of one variable on another, describing the amount of change that can be expected in one variable from a one-percentage point change in another variable. Therefore, a price elasticity of 0.2 reflects that a one percent change in price will yield a 0.2% impact on demand (while this influence is in the opposite direction in this case, price elasticity is traditionally shown as a positive value). In most cases, including this Load Forecast, this impact occurs after a lag, sometimes as long as several years.

Table 2-1
Florida Energy Efficiency Standard for Split System Air Conditioners and Heat Pumps

Effective Year	SEER
1992	10.0
2006	13.0
2015	14.0
2023	15.0

Similar data regarding other major end uses was combined with estimated delivered efficiency of "white goods" (i.e., clothes washers, electric dryers, refrigerators) provided by the Association of Home Appliance Manufacturers to result in an estimate of total consumption for a typical range of major household end uses. Similar estimates for household lighting were developed capturing the transition of lighting from incandescent to compact fluorescent and light emitting diode (LED) technologies. While future efficiency standards changes are highly uncertain, and there is evidence that the economics of increasing standards are challenging, some continued improvement in such standards was assumed over the forecast horizon.

The resulting time series was combined with residential customer counts data by Participant and an assumed overall useful life to develop an estimate of average consumption of the stock of appliances at constant levels of utilization. This set of time series across the Participants was then translated into indices by dividing the value in 1992 by the current year value for potential use in the forecast equations for residential average consumption by Participant.

Figure 2-7 depicts a representative index associated with new stock in the given year and the installed stock, the former immediately impacted by standards changes and the latter impacted over time as (i) appliances are replaced due to aging and (ii) new customers are added with all new stock. It is clear from this data that the standards changes in the 2005-06 timeframe (primarily driven from the HVAC standards discussed above) have had a large impact on home energy efficiency over the succeeding decade or more. The more limited standards changes since then imply far less improvement in home energy efficiency moving forward, unless future regulations of similar impact to those in 2005-06 are introduced.

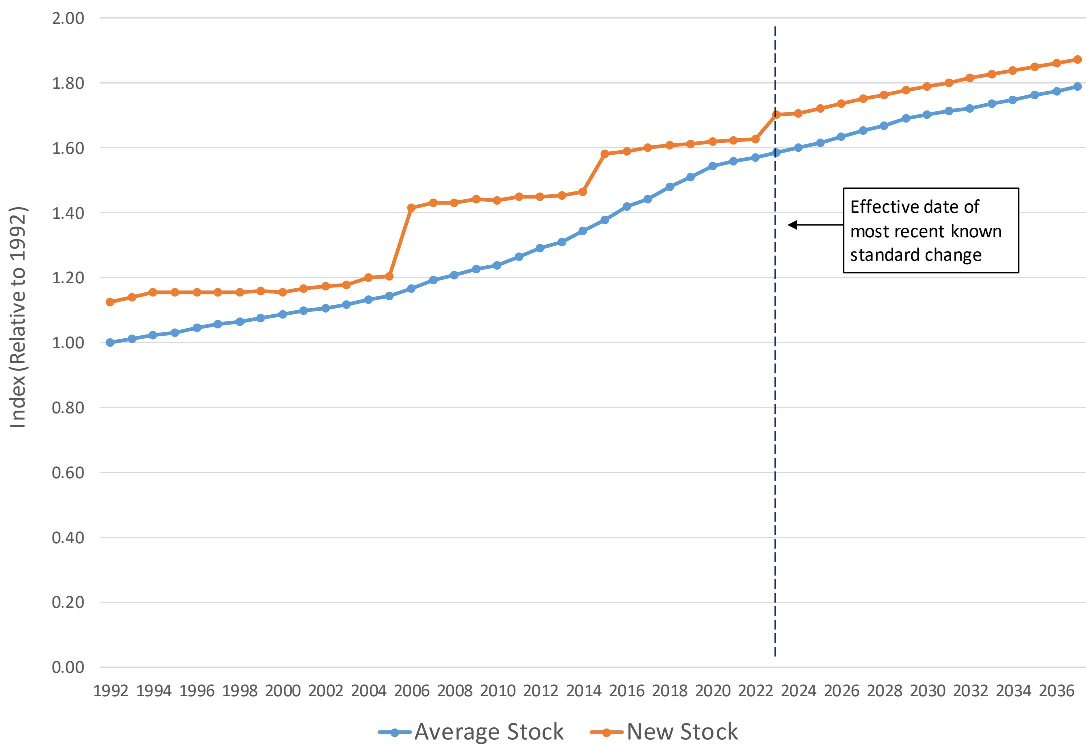

Figure 2-7: Historical and Projected Residential Energy Efficiency Index

The resulting energy efficiency indices were experimented with for inclusion in the residential average use forecast equations for all of the Participants, and in many cases, were retained in the final equation. In some cases, however, the resulting equation parameters and/or diagnostics precluded their inclusion in the final forecast equations. It appears that the energy efficiency indices tend to be too highly correlated with other important drivers to determine statistically significant and reasonable parameters for the variables in question. However, as these efficiency improvements were active over the historical period, there has been some impact on consumption and the parameters for other variables (e.g., average income), and as such, there is an implicit impact on the forecast of efficiency improvements. Importantly, historical efficiency improvements appear to be more significant than those projected over the next several years, particularly due to the apparent economic constraint on future increases in required residential HVAC efficiency. FMPA intends to continue working to explicitly capture energy efficiency improvements through refining this methodology and developing forecast scenarios to understand the potential impacts of significant improvements in efficiency.

Section 3
PRINCIPAL CONSIDERATIONS AND ASSUMPTIONS

In preparing the 2019 Load Forecast, as summarized in this report, we have made certain assumptions, primarily related to economic, demographic, and weather conditions that may occur in the future. With regard to certain of these factors, we have used and relied upon information provided to us, or prepared by others. While we believe the assumptions made by us in preparing the 2019 Load Forecast are reasonable for the purposes of the forecast, they are dependent on future events, and actual conditions may differ from those assumed. While we believe the sources of the information provided to us, or prepared by others, to be reliable and the use of such information to be reasonable for the purposes of the forecast, we offer no other assurances with respect thereto.

To the extent that economic, demographic, weather, or other conditions occur that are different from those assumed by us or from the information provided to us or prepared by others, the actual load on the ARP Participants' systems can be expected to vary from the forecast. It should be emphasized that the confidence associated with any forecast varies inversely with the length of the forecast horizon. The probability of other factors affecting forecasted values increases with uncertainty about future developments; this uncertainty increases with the length of the forecast horizon. With this in mind, the 2019 Load Forecast should be seen as providing reasonable estimates of future demand and energy requirements of the ARP and its Participants for the purposes for which the forecast is intended; however, these estimates are subject to the future effects of factors that cannot be reasonably foreseen at this time.

The development of the 2019 Load Forecast was based upon the following principal consideration and assumptions:

- The future influence on energy sales of the economic, demographic, and weather factors, on which the econometric models are based, was assumed to be similar to their estimated influence generally over the period 1992 through 2018.
- Although the econometric models implicitly account for the historical relationships between energy usage and the following factors to the extent they have occurred in the past, the 2019 Load Forecast does not explicitly reflect extraordinary potential future effects of: (a) increases in appliance design efficiency or building insulation standards; (b) significant conservation efforts, including those funded by the ARP, the state of Florida, and the federal government, that are <u>not</u> a function of changes in electricity or natural gas prices; (c) development of substitute energy sources, or behind-the-meter generation; (d) consumers switching to traditional or new types of electrical appliances from other alternatives (e.g., electric vehicles); (e) consumers switching from electrical appliances to other alternatives; or (f) variations in load that might result from legal, legislative, regulatory, or policy actions.

- The recent average historical relationships between annual summer and winter non-coincident demands and annual NEL and between monthly NCP demands and annual winter and summer NCP demands were assumed to represent reasonable approximations of future load relationships between demands and energy requirements.
- Ft. Meade elected to take service from the ARP under a Contract Rate of Demand (CROD), effective January 1, 2015. However, as a result of a supplemental power sales agreement, the ARP continues to serve Ft. Meade's full requirements. As the supplemental agreement expires in September 2027, the 2019 Forecast assumes the ARP will serve Ft. Meade under a CROD, set at 9.009 MW, beginning October 2027.
- The CROD for Green Cove Springs, effective January 1, 2020, is based on projected load levels during 2019 and has been reflected herein at differing levels as determined for each scenario.
- nFront Consulting annually prepares, with FMPA's assistance, planning level projections of Conservation Program activity and load impacts. For this purpose, data regarding the ARP Conservation Program, including historical participation and marginal impacts, are assumed to be accurate. As discussed in Section 1, FMPA has elected not to explicitly capture these projected impacts in the 2019 Load Forecast, as they do not materially exceed FMPA's threshold for significance. To the extent Conservation Program activity expands in a significant way relative to these projections, there may be a significant impact on future loads to be served by the ARP that is not captured herein.
- As discussed in Section 1, nFront Consulting annually prepares, with FMPA's assistance, projections of impacts from FMPA's Net Metering Program. For this purpose, data regarding installed distributed generation are assumed to be accurate and represent all distributed generation (other than certain generation resources utilized by the Participants for emergency purposes). Such projections prepared as part of the 2019 Load Forecast effort reflect that the Program is likely to exceed FMPA's threshold for explicit inclusion in the Load Forecast, which has been set at 0.5 percent of load over the 20-year planning horizon. As this is the first forecast iteration to reflect that the threshold is likely to be exceeded, the 2019 Load Forecast does not explicitly account for potential load reductions resulting from the Net Metering Program. FMPA is considering whether and how to address this issue in the next iteration of the load forecast.

Section 4
OVERVIEW OF RESULTS

Results of the load forecast included herein for the total ARP are presented in the following two ways:

- **Current Participants:** Reflecting the total load of ARP Participants currently served by the ARP (Current Participants) over the entire historical period and forecast horizon irrespective of the fact that certain Participants were not yet served by the ARP in certain historical periods and certain Participants are anticipated in the future to receive service under a CROD or to discontinue service from the ARP altogether. This allows for results to reflect a consistent set of ARP Participants over the entire historical and forecasted period, which aids in the comparison of growth rates over the period shown.[14]
- **Supplied Load:** Reflecting in each period the total load of ARP Participants actually supplied by the ARP (the "Supplied" loads), which has varied through time as a result of ARP Participants initiating and discontinuing service from the ARP.

The Current Participants basis results are presented first, as this basis reflects a consistent set of ARP Participants over the entire historical and forecasted period, which aids in the comparison of growth rates over the period shown. Subsequently, results are shown on a Supplied basis, which reflects the load that the ARP must actually serve and is directly used in downstream FMPA planning analyses.

The results of the Forecast reflect that the net energy for load (NEL) of the Current Participants[15] is expected to grow at compound annual growth rates of 1.1% per year over fiscal years 2019-2028 and 0.7% over 2029-2038. This compares to historical compound annual growth over 2009-2018 of 0.5% per year. However, as discussed further below, load growth across the Florida peninsula has been impacted by a deep and prolonged recession from which Florida and the ARP Participants have been recovering. The load of the ARP Participants bottomed out in 2012, well after the official end of the recession in late 2009. Since 2012, the NEL of the Current Participants has grown by 1.3% per year.

The 2019 Forecast reflects that the coincident peak demand of the Current Participants is expected to grow at compound annual growth rates of 1.1% per year over 2019-2028 and 0.7% over 2029-2038. This compares to historical compound annual growth over 2009-2018 of just 0.1% per year and over 2012-2018 of 1.7% per year. The Base Case projected fiscal year 2019 NEL and coincident peak of the Current Participants are 5,986 GWh and 1,255.4 MW, respectively.

The historical growth rates for both NEL and CP demand are significantly impacted by the recent deep and prolonged recession from which the Florida economy has been recovering. The recent recession had significant negative effects on the housing market, construction and total employment,

[14] The load of Green Cove Springs served by the ARP is expected to decrease somewhat as a result of a CROD effective January 1, 2020. However, this is a small impact on the ARP load, and forecast data for the Current Participants shown herein include the *total* load of Green Cove Springs rather than the load that is expected to be served by the ARP.

[15] This excludes the loads of Lake Worth and Vero Beach, which are no longer supplied by the ARP, effective January 2014 and January 2010, respectively (as discussed in more detail elsewhere below).

consumer spending, and visitation by tourists and other seasonal residents. Since 2012, these factors have all improved considerably, as shown in the table below.

Table 4-1
Recent Trends in Florida Economic Indicators

Economic Indicator	2008 Value	2012 Value	2018 Value
Home Price Index (2016$)	213,905	153,928	254,505
Gross State Product (2009$; $M)	764,086	726,372	916,975
Unemployment Rate	6.3%	8.5%	3.7%
Total Employment (Ths)	10,297	10,256	12,406
Construction Employment (Ths)	693	502	743
Tourist Visitation Counts (millions)	82.5	89.7	126.1

Sources: Florida Association of Realtors, Bureau of Economic Analysis, Bureau of Labor Statistics, Woods and Poole Economics, and Visit Florida

This improvement in the economic conditions has been accompanied by a sustained recovery in the demand for electricity in the service areas of the ARP Participants. The economy is anticipated to continue growing at an above-normal pace over the early years of the forecast horizon, which should result in continued growth in the load served by the Participants. The forecasted growth rates in NEL and coincident peak demand for the ARP over 2019-2028 discussed above reflect the impact of this above-normal growth. The forecast results reflect that the fiscal year NEL of the Current Participants is expected to exceed the 2006 level, for the first time, next year (i.e., in FY 2020).

Figure 4-1 depicts the historical, weather-normalized historical, and forecasted fiscal year NEL of the Current Participants. As mentioned above, these results reflect the Current ARP Participants and do not account for the initiation or discontinuation of full requirements service by the ARP of certain Participants during the historical period or over the forecast horizon. Weather during fiscal year 2018 was significantly warmer than normal across much of the Florida peninsula during the summer and somewhat colder than normal during the winter (winter 2017/18). The estimation of weather's impact on energy consumption during fiscal year 2018 reflects that NEL across the Current Participants would have been approximately 1.8% lower had weather been normal, although it should be noted that anomalies in the weather data for certain weather stations may have over-stated the severity of summer conditions and inflated this statistic somewhat.

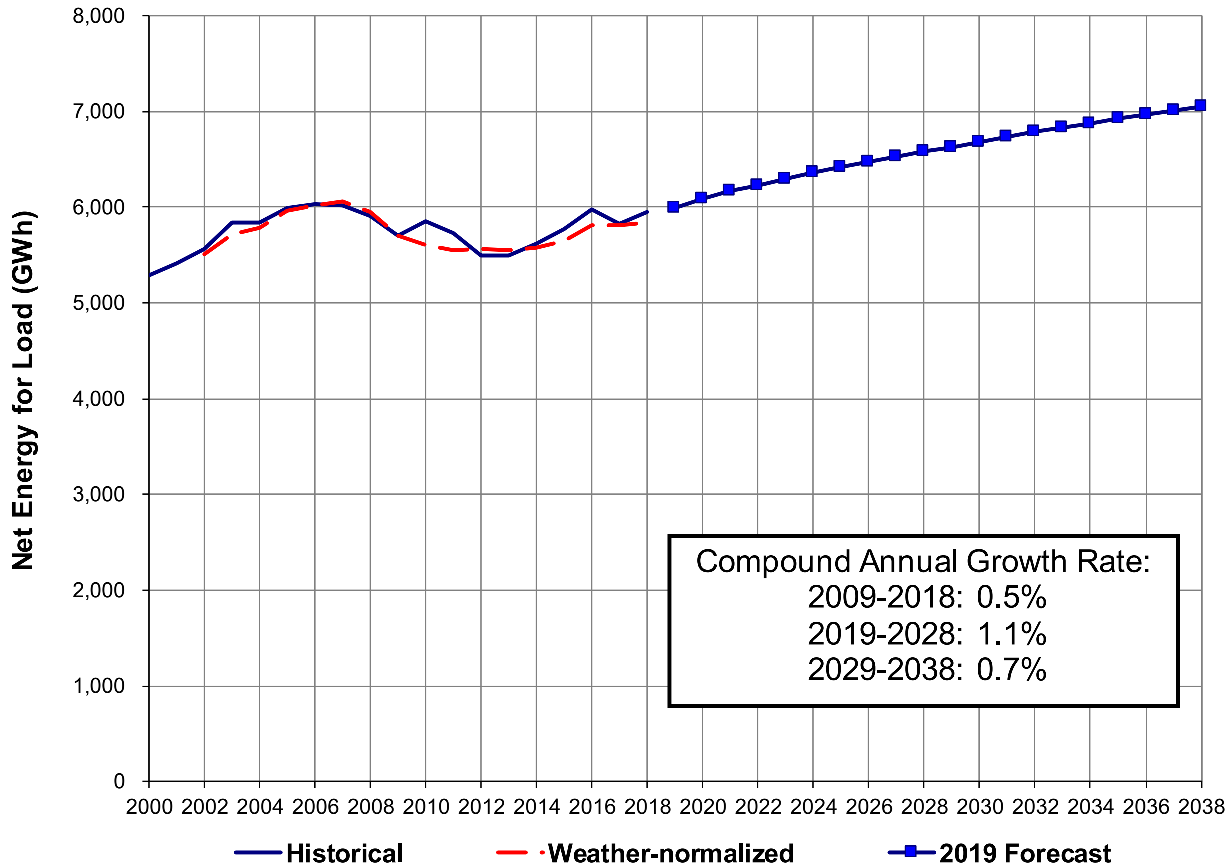

Figure 4-1: Fiscal Year Net Energy for Load of Current Participants

Figure 4-2 below depicts the historical and forecasted summer and winter peak demand of the Current Participants (i.e., excluding Lake Worth and Vero Beach for all historical and future periods). As the figure shows, the ARP annual coincident peak typically occurs in the summer. As a result of very low penetration of natural gas heating and the generally poor efficiency of electric space heating at low temperatures, the winter coincident peak demand is significantly more volatile than the summer peak and can exceed the summer peak, as it did during winter 2010 and 2011, winter being defined herein as the period November of the preceding year through March of the current year. The more recent winter peak conditions were milder, resulting in a more typical seasonal demand relationship of summer peaks being higher than winter peaks. This relationship is expected to continue in the forecast period, which assumes normal weather conditions.

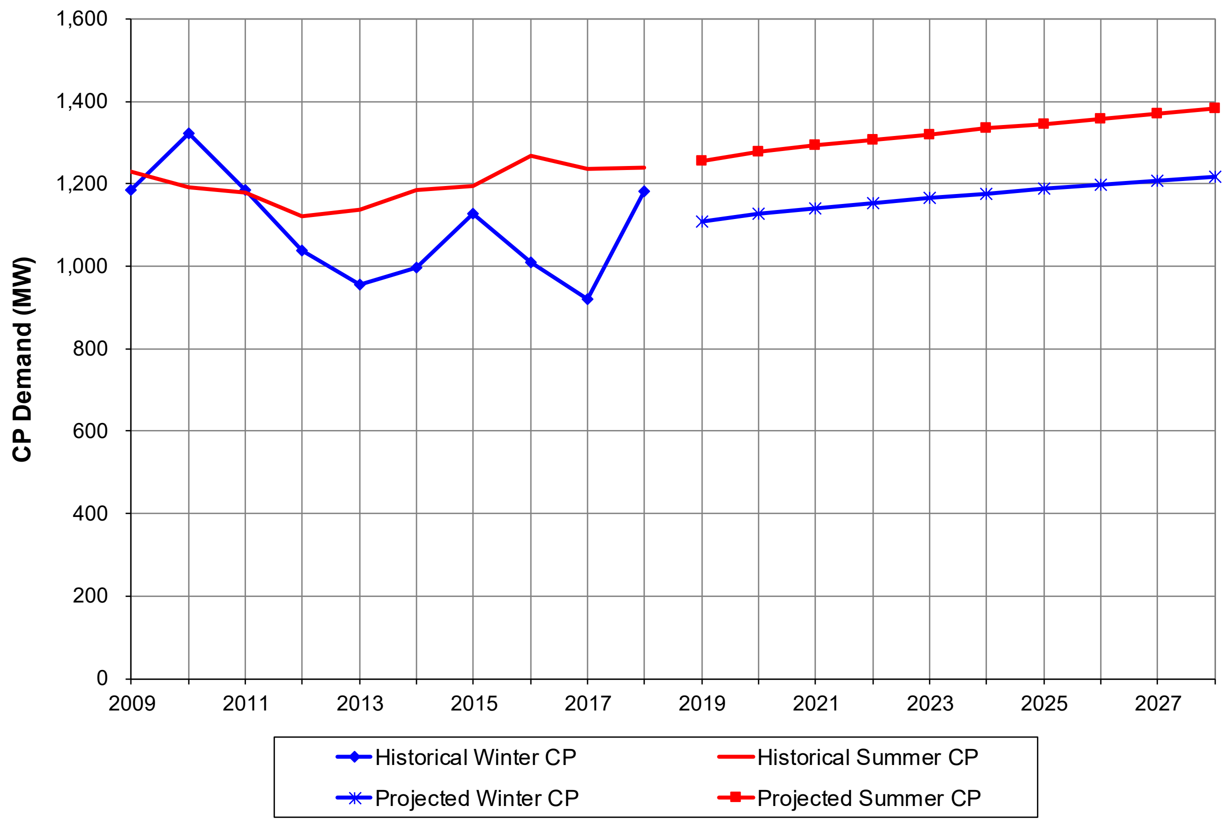

Figure 4-2: Seasonal Peak Demand of the Current Participants

The loads actually served by the ARP (Supplied Load) historically have varied from those depicted in Figures 4-1 and 4-2 as a result of the timing of ARP Participants initiating or discontinuing service from the ARP. For example, Kissimmee Utility Authority and Lake Worth began taking service from the ARP in October 2002. Conversely, as a result of the establishment of Contract Rate of Demand (CROD) for Vero Beach, effective January 1, 2010, it was determined in December 2009 that the ARP would serve none of the load for Vero Beach beginning January 2010. Similarly, as a result of the establishment of CROD for Lake Worth, effective January 1, 2014, the ARP no longer serves any of Lake Worth's load. Accordingly, the forecast of load supplied by the ARP excludes the load of those two utilities after the respective effective dates of CROD. Furthermore, the forecast of load supplied by the ARP reflects establishment of CROD for Green Cove Springs beginning January 2020, with an estimated CROD value in the Base Case of 25.74 MW. Service under a CROD for Ft. Meade was effective January 2015 at a CROD originally established at 10.36 MW. However, as a result of a supplemental service agreement, the ARP supplies all of Ft. Meade's requirements. As part of the same agreement, the CROD level was reduced to 9.009 MW. The supplemental service agreement expires in September 2027; hence, the forecast assumes Ft. Meade is served on a CROD basis beginning October 2027.

Figures 4-3 and 4-4 depict the historical and forecasted fiscal year NEL and annual peak demand expected to be supplied from the ARP, reflecting the additions through time of new ARP Participants and the establishment of CROD for Vero Beach, Lake Worth, Green Cove Springs, and Ft. Meade. As shown below, the NEL supplied by the ARP was reduced by approximately 11% over fiscal years 2009 to 2011 and by an additional 7% over fiscal years 2013 to 2015, as a result of establishment of CROD for Vero Beach and Lake Worth, respectively (as the data shown is on a fiscal year basis, and the effective dates of CROD in both cases was January, the impact of CROD is spread over two years each). The historical growth rates and those for the initial ten-year horizon are impacted by the portion of load of ARP Participants that the ARP actually served. The impacts of the initiation of service under a CROD for Ft. Meade and Green Cove Springs is not specifically noted in the Figures below, as it is not sufficiently visible in the charts. Values in 2036 and beyond are negatively impacted by the anticipated departure of Starke from the ARP, effective October 2035, and Green Cove Springs, effective October 2037.

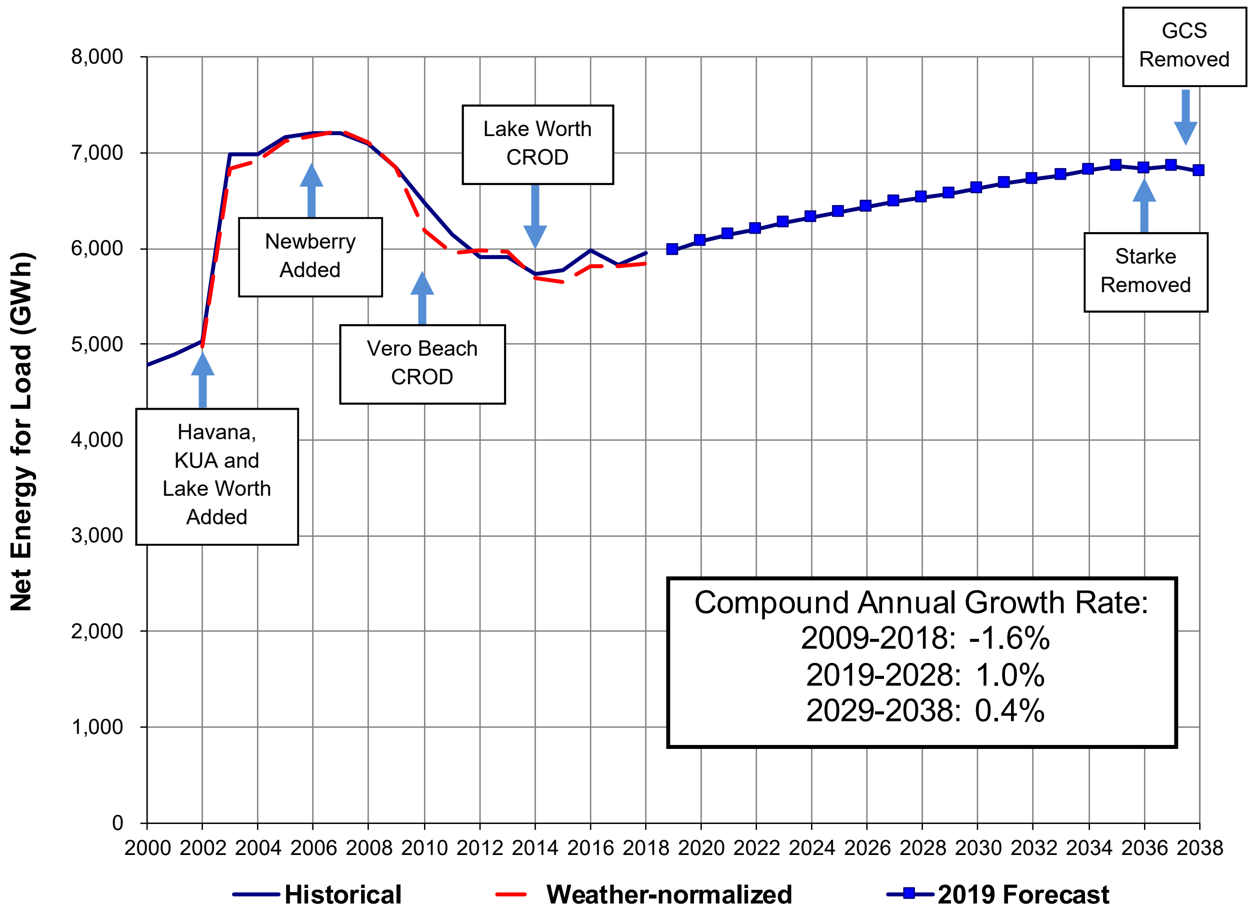

Figure 4-3: Fiscal Year Net Energy for Load Supplied from the ARP

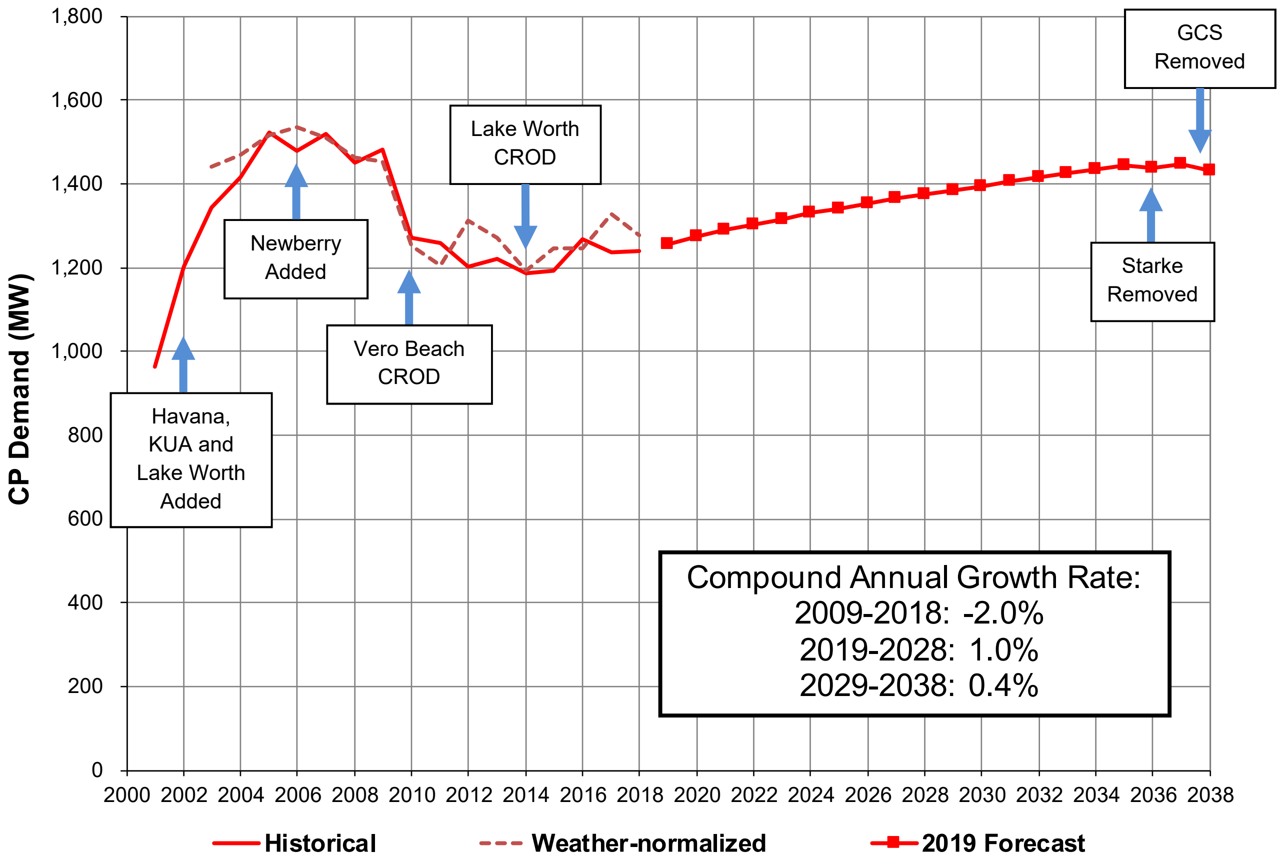

Figure 4-4: Summer Peak Demand Supplied from the ARP

The ARP annual coincident peak typically occurs in the summer, and more often in August than other summer months. However, the annual peak occurs almost as frequently in July. In addition, as discussed previously, the winter coincident peak demand is significantly more volatile than the summer peak and under certain conditions can exceed the summer peak.

Figure 4-5 below depicts the historical and projected summer and winter peak demand to be supplied from the ARP. In this figure, winter is defined as November of the preceding year through March of the current year, with January being the typical winter peak month. Note that the 2017 winter peak (i.e., 2016/17 winter) occurred in March during mildly warm conditions across most of the Florida peninsula, with the estimated impact of weather reducing the peak by approximately 6% from the level it would have been had winter peak day weather been normal in the month of January.

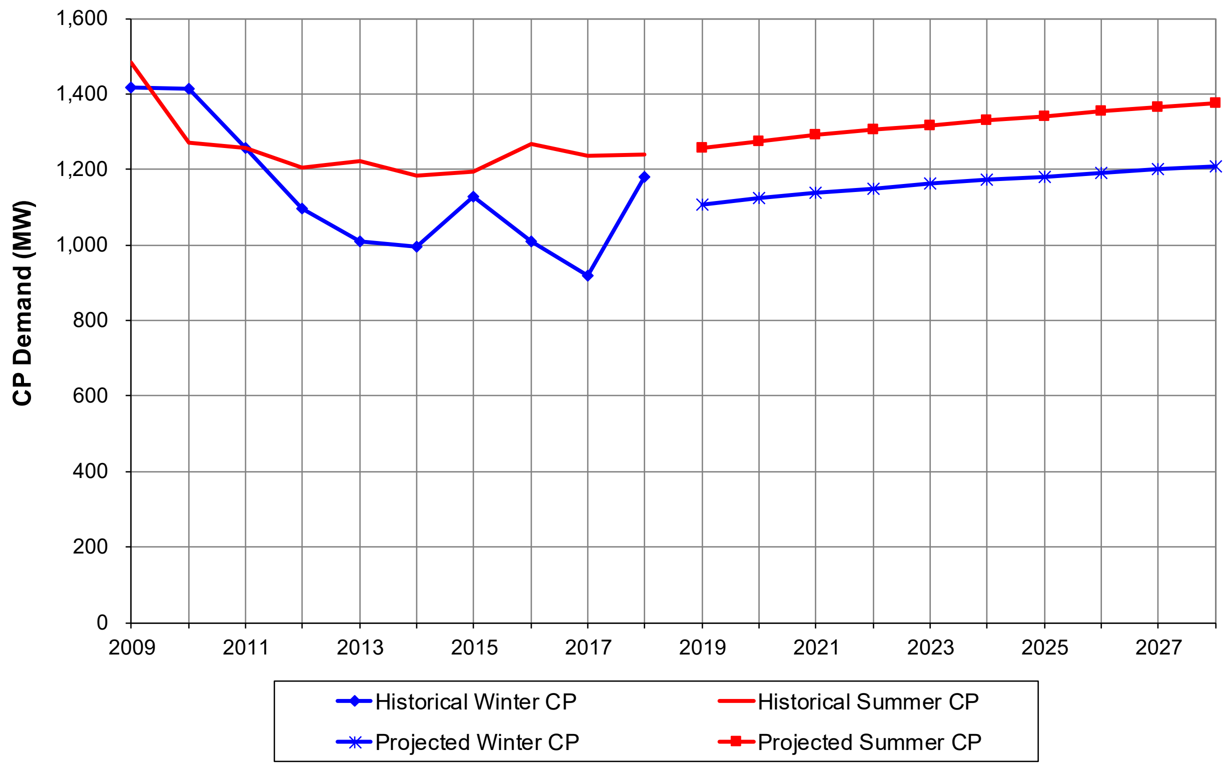

Figure 4-5: Seasonal Peak Demand Supplied from the ARP

The results of the Forecast, irrespective of when Participants are added to, leave the ARP, or otherwise establish service under a CROD, are summarized in Table 4-2 below. As the totals in the table below reflect the sum of *all* Current Participants, they will not tie to those discussed above. Projections by Participant and major customer classification are available in Appendix D that accompanies this report.

Table 4-2
Forecasted Loads to be Supplied from the ARP

Participant	Annual Coincident Peak Demand (MW) [1]					Annual Net Energy for Load (FY; GWh)				
	2019	2023	2028	2033	2038	2019	2023	2028	2033	2038
Bushnell	5.6	12.8	13.4	13.9	14.4	25	58	61	63	65
Clewiston	21.6	21.9	22.3	22.5	22.8	107	108	110	111	112
Ft Meade [2]	8.9	9.3	7.7	7.7	7.7	41	43	35	35	35
Ft Pierce	110.7	112.1	113.3	113.9	114.1	585	593	599	602	603
Green Cove Springs [2]	23.7	22.2	22.2	22.2	0.0	114	103	103	103	0
Havana	4.9	5.0	5.0	5.1	5.1	26	26	26	27	27
Jacksonville Beach	154.0	162.5	165.9	169.6	172.8	727	761	777	794	809
Key West	137.1	140.6	142.3	143.3	144.3	760	786	795	801	807
Kissimmee	362.4	389.2	424.0	454.9	484.5	1,644	1,765	1,924	2,065	2,199
Leesburg	108.6	112.3	117.6	121.4	124.4	504	522	546	564	578
Newberry	8.8	9.3	9.9	10.4	10.8	40	42	45	47	49
Ocala	294.1	306.0	317.4	327.1	334.7	1,341	1,393	1,446	1,491	1,525
Starke	15.0	15.3	15.8	16.0	0.0	72	74	76	77	0
Total ARP [3]	1,255.4	1,318.7	1,376.8	1,428.2	1,435.5	5,986	6,273	6,543	6,781	6,810

[1] Annual peak demand is the summer peak coincident with the All-Requirements Project.
[2] The forecast reflects that Ft. Meade and Green Cove Springs are served under CROD arrangements effective October 2027 and January 2020, respectively, as the supplemental service agreement with Ft. Meade expires at the end of September 2027.
[3] Totals may not equal the sum of the Participant values due to rounding.

The 2019 Forecast results are strongly influenced by the return of strong population growth to the Florida peninsula and the rebound in growth in residential customer counts and economic activity that this growth in population entails. Importantly, residential average use is projected to be relatively flat over the forecast horizon and is not a growth driver. Figure 4-6 below depicts the comparative growth rates in residential customer counts over 2019-2038 across the ARP Participants ordered by descending compound average growth rate (CAGR), with the line across the chart representing the ARP average growth rate. Bushnell reflects the highest growth rate by far due to the assumed acquisition of additional service area and customers of a bordering utility. Kissimmee reflects the next highest growth, which significantly affects the overall ARP, as it is the largest ARP member and has by far the largest base of residential customers.

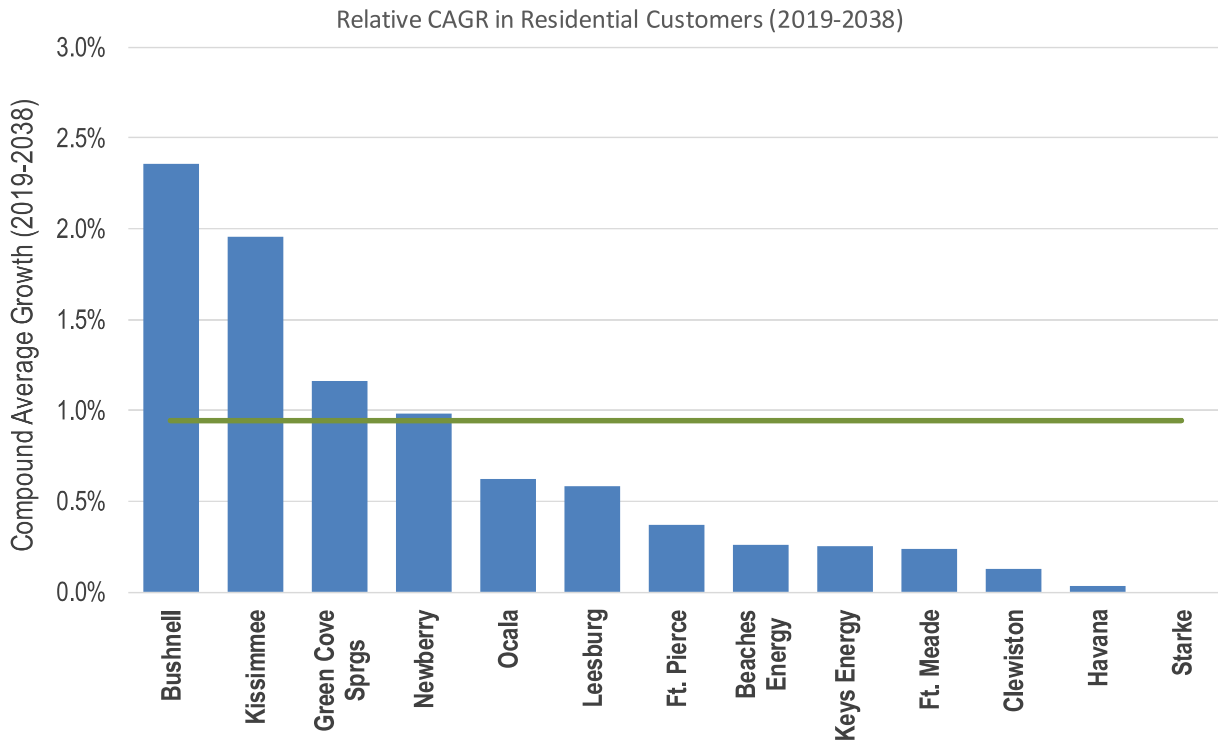

Figure 4-6: Compound Average Growth in Residential Customers over the Forecast Horizon

COMPARISON TO ACTUAL RESULTS AND THE 2018 LOAD FORECAST

A similar forecast was completed in early 2018 (2018 Forecast). Net energy for load of the Current Participants for fiscal year 2018, as projected in the 2018 Forecast, was 0.3% higher than the actual value and 2.1% higher than the weather-normalized value, although anomalous weather data for a portion of the ARP may have inflated this value. The forecasted 2018 summer coincident peak from the 2018 Forecast was approximately 1.4% higher than the actual 2018 summer coincident peak but 1.7% lower than the weather normalized 2018 peak. The summer peak day exhibited slightly milder than normal weather conditions, and it is estimated that, had more typical summer peak day weather conditions occurred, the summer 2018 peak would have been 3.2% higher.

Figures 4-7 and 4-8 compare the forecasted fiscal year net energy for load and peak demand, respectively, supplied by the ARP, from the current 2019 Load Forecast and the 2018 Forecast. Differences in forecasted NEL for the 2019 Forecast versus 2018 Forecast range from 1.1% lower in FY2019 to 3.6% lower in FY2037, and differences in annual peak demand range from 1.3% lower in FY2019 to 3.8% lower in FY2037. These lower projected load levels are driven primarily from slightly lower projected growth in average income across the ARP Participants and the enhanced representation of impacts from energy efficiency trends across the Participant forecast equations. However, these figures reflect that the current Forecast is very similar to the 2018 Forecast.

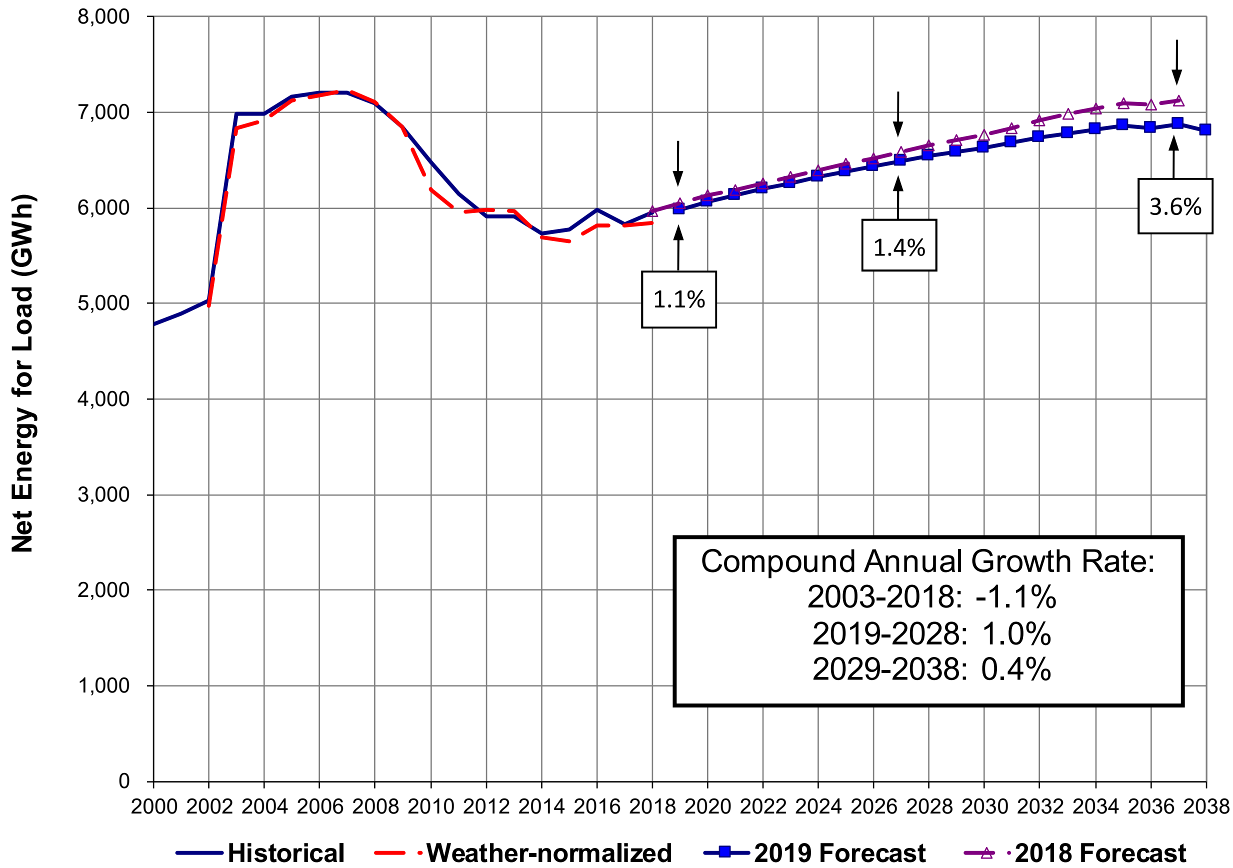

Figure 4-7: Annual Net Energy for Load Supplied by the ARP

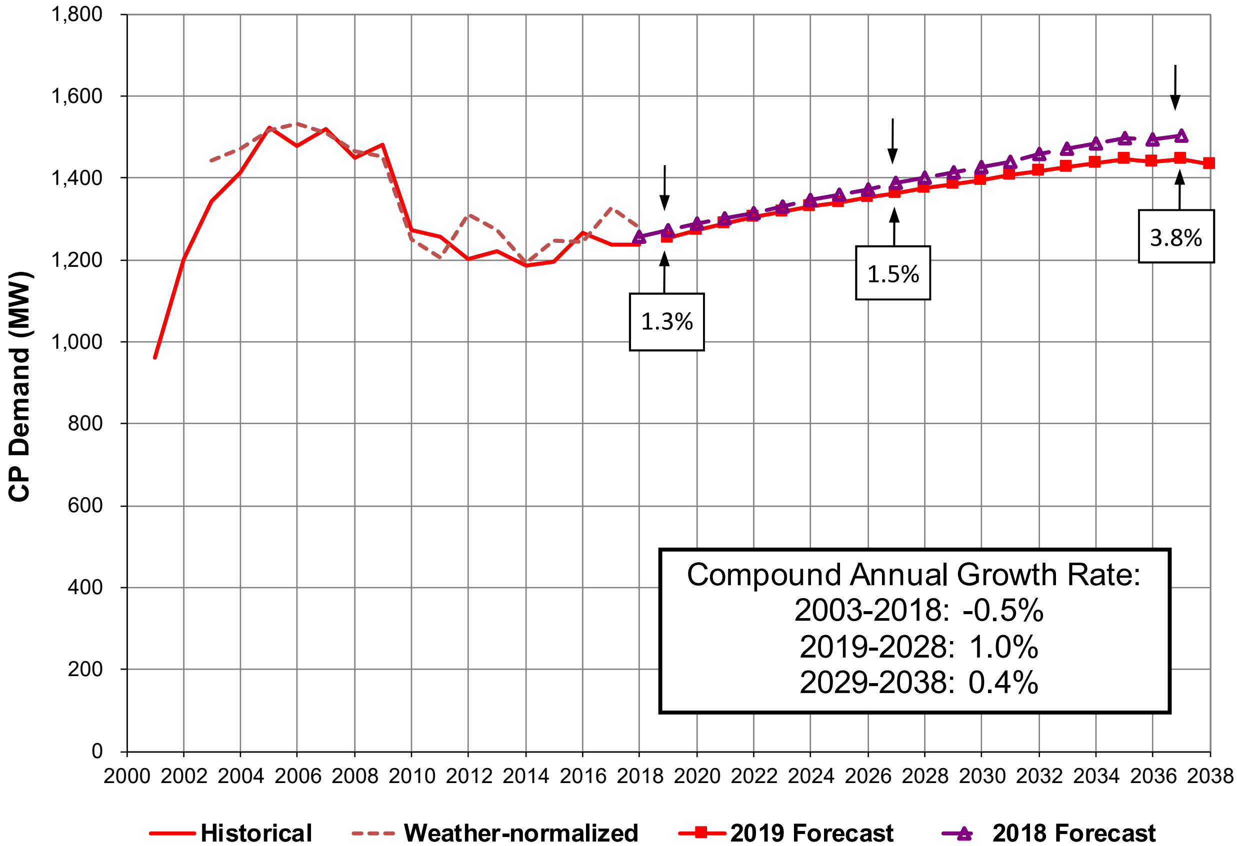

Figure 4-8: Annual Peak Demand Supplied by the ARP

UNCERTAINTY OF THE FORECAST

While a forecast that is derived from projections of the driving variables, obtained from reputable sources, provides a sound basis for planning, there is significant uncertainty in the future level of such variables. To the extent that economic, demographic, weather, or other conditions occur that are different from those assumed or provided, the actual Participant load can be expected to vary from the forecast. For various purposes, it is important to understand the amount by which the forecast can be in error and the sources of error.

At the direction of FMPA staff, we have produced high and low range results that address potential variance in driving economic and weather variables from the values assumed in the Base Case. There is a significant difference between these two sources of uncertainty. Economic uncertainty tends to result in a deviation from the trend, while weather uncertainty results in volatility around the basic trend. Accordingly, we have produced separate high and low results to address both economic uncertainty and weather uncertainty. These ranges are intended to capture approximately 90% of occurrences (i.e., 1.7 standard deviations).

Economic and Demographic Uncertainty

The Base Case forecast relies on a set of assumptions, developed from projections provided by Woods & Poole and BEBR, about future population and economic activity in the counties surrounding the Participants. However, such projections are unlikely to exactly match the resulting data as future periods become history. While it is sensible to place significant weight on the Base Case, it would be useful to develop some estimate of the range of potential outcomes and the impact on load.

While BEBR does not publish information regarding the potential error of their projections, we relied on such statistics from Woods & Poole, which relies on a similar underlying data set and methodology. Woods & Poole publishes several statistics that define the average amount by which various projections they have prepared over 1984 through 2017 are different from actual results. We have utilized these statistics to develop ranges of the trends of economic activity and population representing approximately 90% of potential outcomes (i.e., 1.7 standard deviations). Table 4-3 below provides the amount by which the economic projections were adjusted upward and downward from the Base Case assumptions to develop the High and Low Economic Cases. Other economic data, such as retail sales and gross domestic product, were assumed to vary by the same degree as income.

Table 4-3
Economic Scenarios – Assumed Variance from Base Case (+/-)

	Population	Employment	Income	Income Per Capita
2019	2.1%	4.1%	5.5%	4.1%
2020	3.3%	6.1%	7.9%	5.7%
2021	4.3%	7.8%	9.7%	7.0%
2022	5.1%	9.1%	11.3%	8.0%
2023	5.9%	10.4%	12.6%	8.9%
2024	6.7%	11.5%	13.9%	9.7%
2025	7.4%	12.6%	15.0%	10.5%
2026	8.0%	13.6%	16.1%	11.2%
2027	8.7%	14.5%	17.1%	11.8%
2028	9.3%	15.4%	18.1%	12.4%
2029	9.9%	16.3%	19.0%	13.0%
2030	10.4%	17.1%	19.8%	13.5%
2031	11.0%	17.9%	20.7%	14.0%
2032	11.5%	18.7%	21.5%	14.5%
2033	12.1%	19.5%	22.3%	15.0%
2034	12.6%	20.2%	23.0%	15.4%
2035	13.1%	20.9%	23.7%	15.9%
2036	13.6%	21.6%	24.5%	16.3%
2037	14.0%	22.3%	25.1%	16.7%
2038	14.5%	23.0%	25.8%	17.1%

Figure 4-9 below depicts the forecast of summer CP demand resulting from the High and Low Economic Cases as compared to historical and weather-normalized data and the Base Case for the

Current Participants. The Low and High Economic Cases reflect compound annual growth rates for the net energy for load and summer coincident peak of the Current Participants that range from approximately 0.2% to 1.8% over 2019 to 2028 and from 0.2% to 1.1% over 2029 to 2038. This compares to compound annual growth rates for the Base Case of 1.1% over 2019 to 2028 and 0.7% over 2029 to 2038. Note that the upper end of the potential forecast range reflects the fact that growth is somewhat attenuated in the forecast models by the assumptions surrounding limits to growth for certain Participants, including Fort Pierce, Jacksonville Beach, and Key West.

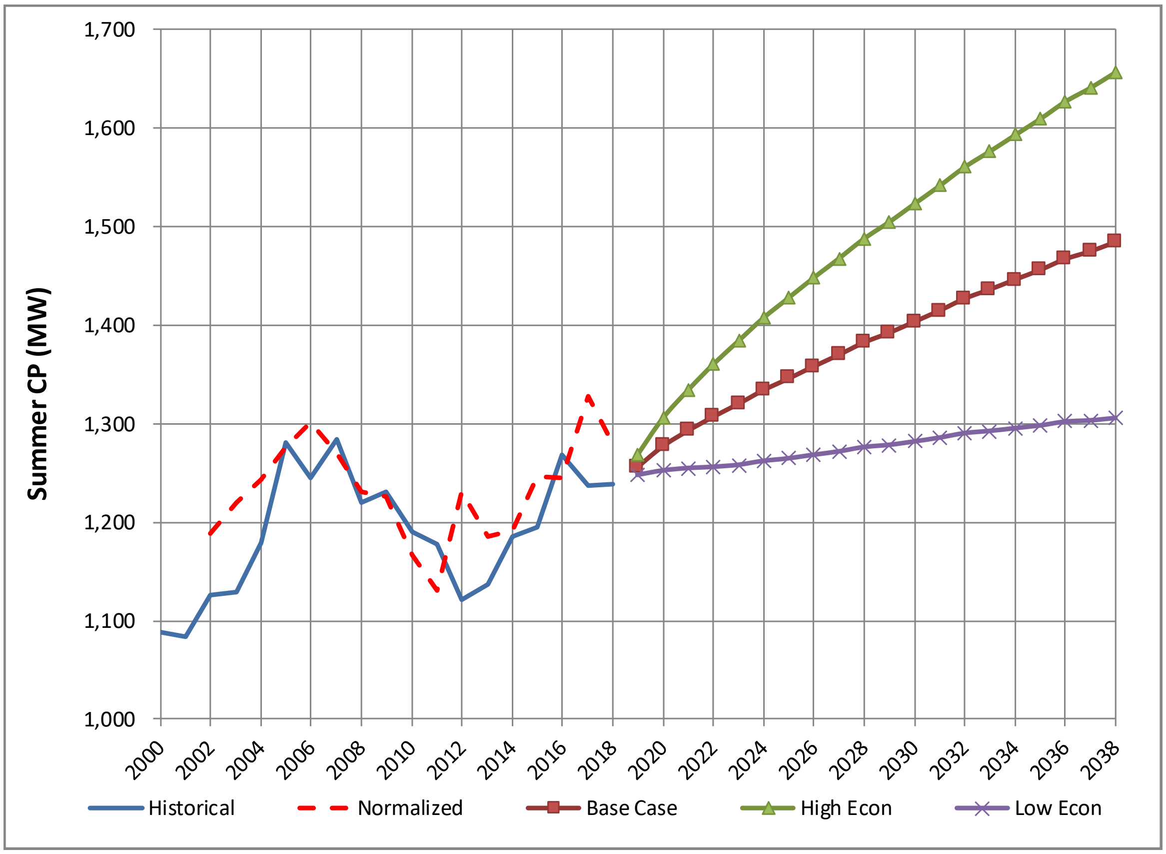

Figure 4-9: Economic-related Uncertainty in Summer CP Demand – Current Participants

We have relied on potential error statistics related to projections at the state level so that the projections of each Participant can be summed to represent a consistent case. However, the projections of the Participants are not perfectly correlated. By its very nature, the aggregate economy and population comprising the load supplied from the ARP will exhibit significantly less volatility than any individual Participant's service area. Therefore, care should be exercised when using these alternative growth scenarios, as the plausible range of results for any *individual* Participant may be considerably wider than that shown.

Finally, the statistics obtained from Woods & Poole regarding historical economic forecasting error pertain to statistics both over a specific historical period and across the U.S. The majority of this period happened to be relatively stable by long-term standards and in comparison to the recent recession. Similarly, the economy of Florida may exhibit fluctuations of different magnitude than represented by the combined range of errors exhibited across all of the states in the U.S. These statistics are updated annually by Woods & Poole. nFront continuously monitors these error statistics published by Woods and Poole and updates the assumptions for use in the Load Forecast, as appropriate.

The ranges of forecasts shown in Appendices E and F imply that the load projections of the individual Participants exhibit different levels of sensitivity to variation in the driving variables. This is due to differences in: (i) the responsiveness of the energy requirements of the Participants to changes in the input assumptions and (ii) the percentage of the total Participant sales that certain large customers comprise of various Participants' total loads. These large customers' energy sales were forecasted separately based on information provided by the Participants or FMPA staff, and such forecasts were assumed to be independent of changes in the local economy and, in some cases, weather. Although this assumption is somewhat simplified, it does illustrate that the energy requirements of some of the Participants are very dependent on a few large customers.

Weather Uncertainty

In addition to the Base Case forecast, which relies on normal weather conditions, we have developed high and low forecasts, referred to herein as the Severe and Mild Weather cases, intended to capture the volatility resulting from weather variations equivalent to 90% of potential occurrences. Accordingly, load variations due to weather should be outside the resulting "band" between the Mild and Severe weather cases less than 1 out of 10 years.

The potential weather variability was developed using weather data specific to each weather station generally over the period 1971-2018. While these weather volatility statistics are generally updated each year, they tend to be fairly stable given the lengthy historical data period (setting aside significant deviations from normal, such as winter 2016/17, which can have a noticeable impact).

The scenarios are intended to represent the range of potential weather experienced in the summer and winter seasons, encompassing June through September and December through February, respectively. These weather scenarios simultaneously reflect more and less severe weather conditions in both seasons, although this is less likely to happen than severe conditions in one season or the other. This was done to support downstream analyses to be prepared by FMPA staff. It should be recognized that for other purposes, annual NEL may be somewhat less volatile than the annual NEL variation shown in the appendices.

Finally, the weather assumptions reflect that the variability of seasonal weather among the weather stations is perfectly correlated. While this is not generally the case in continuous data, the correlation increases dramatically at the extremes. In other words, the years of extreme weather, mild or severe, tend to be widespread.

Figure 4-10 below depicts the forecast of summer CP demand resulting from the Severe and Mild Weather Cases as compared to historical and weather-normalized data and the Base Case for the Current Participants. The weather scenarios result in bands of uncertainty around the Base Case that are essentially constant through time, so that the projected growth rate is the same as the Base Case.

The differential between the Severe Case and Base Case is somewhat larger than between the Mild Case and Base Case as a result of a somewhat non-linear response of load to weather.

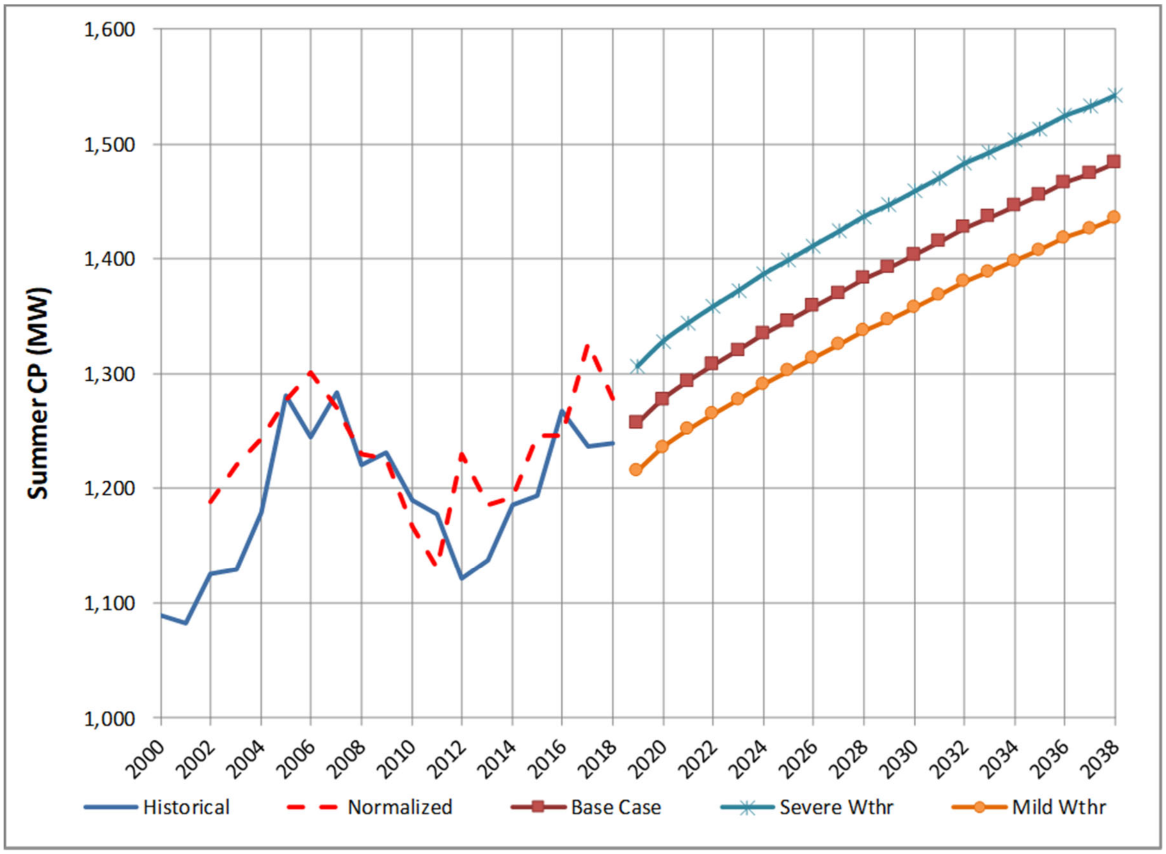

Figure 4-10: Weather-related Uncertainty in Summer CP Demand – Current Participants

Net energy for load for the summer season in any particular year in the Severe Case was higher than the Base Case by 4.2% and lower in the Mild Case by 3.8%. Winter NEL was higher in the Severe Case by 8.9% and lower in the Mild Case by 7.1% than the Base Case results. The band around winter NEL is larger than the summer NEL primarily because the uncertainty of winter weather is greater than for the summer.

It should be noted that these weather scenarios are focused on specific seasons, in total, rather than individual months. NEL in any *particular* month may be more volatile than shown herein, and the off-peak months, which sometimes exhibit weather conditions more like peak months, may also be more volatile than the winter or summer seasons. In addition, because of the methodology that derives peak demand from NEL via constant load factor assumptions, annual summer and winter peak demand may be somewhat more volatile with respect to weather than shown herein.

Detailed forecast results by ARP Participant for these scenarios are shown in Appendix D.

Section 5
CONCLUSIONS AND RECOMMENDATIONS

It is important to recognize that no forecast will prove to be perfectly accurate once projected periods become history. The 2019 Load Forecast is no exception. The econometric equations on which the Forecast is based demonstrate that energy consumption is driven by population, economic forces, end use technology, and weather in fairly predictable ways. However, these drivers are anything but predictable. Overall population growth is somewhat predictable, but migration rates and the pace of economic activity are highly uncertain. At the local level, the uncertainty of future population and economic growth increases dramatically, both due to increased migration volatility and the focus on a smaller number of economic agents (residents, businesses, industries, etc.). It is in this environment that forecasts of the power requirements of the ARP Participants must be developed.

The 2019 Load Forecast represents a reasonable and prudent basis for typical utility planning purposes. However, considering the uncertainties discussed above and further herein, the ARP Load Forecast must be viewed as a guide only, and plans for large capital expenditures, which are based on such forecasts, made with care and with an allowance for flexibility.

In consultation with nFront Consulting, FMPA has a process in place to continually review factors that may be impacting energy consumption across the ARP Participants, whether and how those factors are represented in the ARP load forecast, and if any improvements in this representation is warranted. In addition, FMPA periodically prepares alternative projections reflecting variations in the representation of these factors as load forecast scenarios to aid in its long-term planning process.