Forecast Model Comparisons of ISO New England Electricity Demand

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Abstract
Reliable access and constant availability to electricity is important for the economy and safety of the residents of New England. The Independent System Operators (ISO) New England is responsible for meeting the electricity needs of the 6.5 million households and businesses in the New England region by managing the wholesale electricity market and overseeing the operation of the power generation and transmission system. ISO New England (ISO-NE) is composed of eight zones. The objective of this paper is to compare methods of forecasting short-term electricity demand in ISO-NE.

We are asking: can a predictive model be constructed that improves the Day Ahead Demand (DAHD) forecast? ARIMA, Artificial Neural Networks, Support Vector Machines, and Random Forests modeling techniques are tested on a data set for the calendar year 2012. Each of these approaches is compared for their predictive ability. Each zone within ISO-NE is modeled individually. The RMSE of the demand forecasts for each model are compared to the DAHD RMSE during the same period. Using one or more of the modeling tools can improve the DAHD hourly forecast values.

Key Words: Electricity Demand Forecasting, ARIMA, Artificial Neural Networks, Support Vector Machines, Random Forests

1. Introduction

The Independent System Operator (ISO) is responsible for managing the wholesale electricity market and overseeing the operation of the power generation and transmission system. They are responsible for matching generation capacity to demand in real-time. There are eight zones within the New England region which make up ISO-New England (ISO-NE). ISO-NE works to meet the electricity needs for approximately 6.5 million residential consumers and businesses within the region. The importance in producing accurate forecasts of electricity demand stems from the inability to easily or cost-effectively store electricity.

In order to facilitate the market-making role, ISO-NE produces day-ahead forecasts. These forecasts are created in accordance with the procedure described in the publication “Create Demand Forecast”. The ISO produces the forecasts using a model that incorporates an Artificial Neural Networks (ANN) model with vendor-sourced weather forecasts. The day-ahead electricity demand forecasts generated by this method require substantial involvement by a subject matter expert.

As a starting point this paper compares four modelling approaches which do not require such a high level of user involvement. ARIMA, Support Vector Machines (SVM), ANN, and Random Forests (RF) were chosen for comparison purposes.

Each of the modelling techniques was applied to the individual zones within the region. The models produced the forecast value for the hourly day-ahead demand. The data set of electricity demand used in this investigation is from ISO-NE for 2012. The hourly day-ahead demand forecasts produced by ISO-NE and those generated from each of the models were compared to the actual electricity demand for the hour. It was demonstrated that a ‘dumb’ operator could apply the above named modelling methods and achieve results that are competitive with the ISO-NE day-ahead forecasts.

2. Data

The data set being used in this investigation is publicly available from ISO-NE and is at the hourly level. The year 2012 had peak electricity demand of 25,550 MW on July 17 at 5:00 pm. The minimum value for the year occurred on October 30 and was 7,794 MW. The mean for the entire year was 14, 350 MW.

Several plots are included below at various time scales. In Figure 1 we observe that electricity demand has clear seasonality. The hours 4,000 – 6,000 are associated with the summer peak usage for cooling.

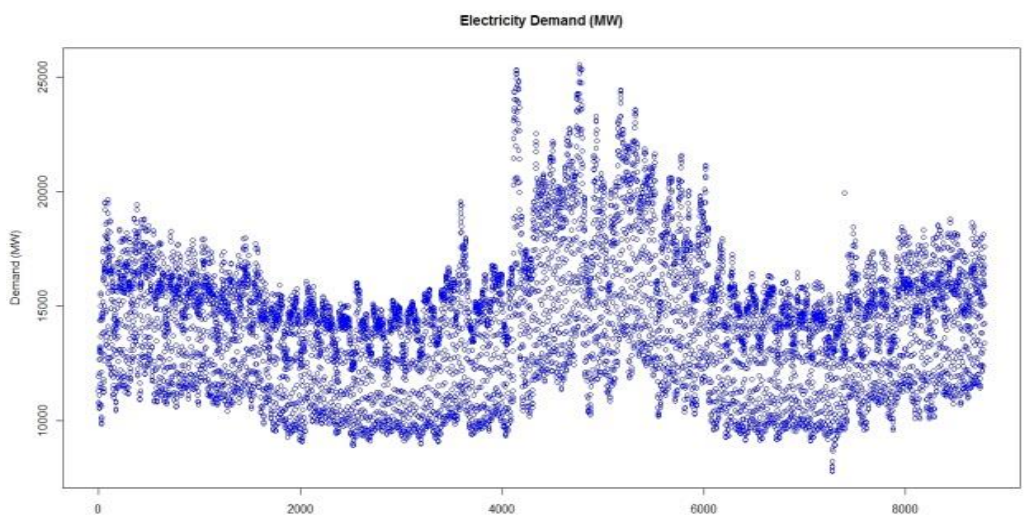

Figure 1: The Demand in Mega Watts is plotted for each Hour of the year 2012.

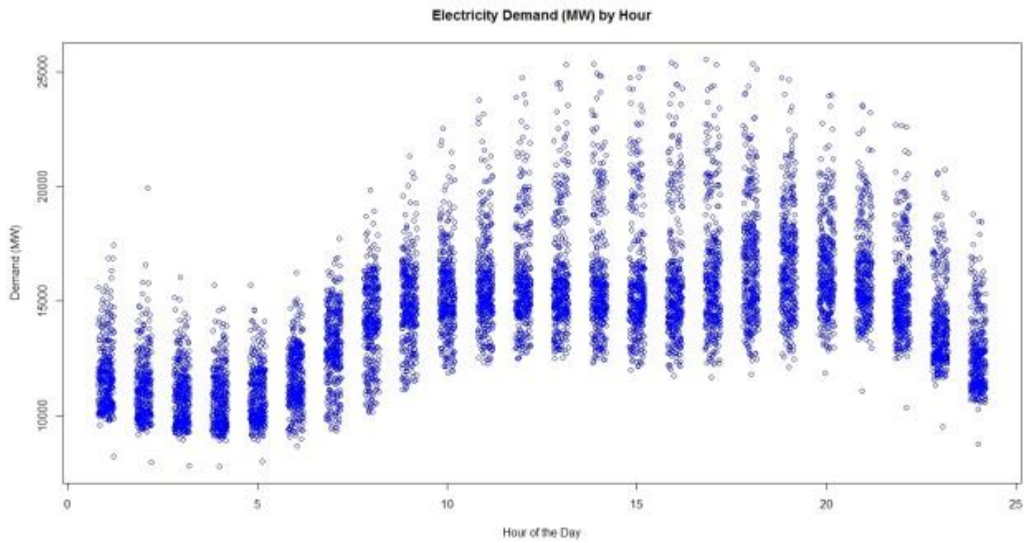

Figure 2: Demand (MW) is plotted by Hour.

When Demand is plotted by Hour, as in Figure 2, a pattern of increasing demand in the afternoon and early evening hours emerges. Additionally, dispersion within each hour also begins to increase during the morning and reaches a maximum in the afternoon/evening hours before tapering off.

We observe a similar pattern at the monthly level. Figure 3 below shows August Demand plotted by Hour.

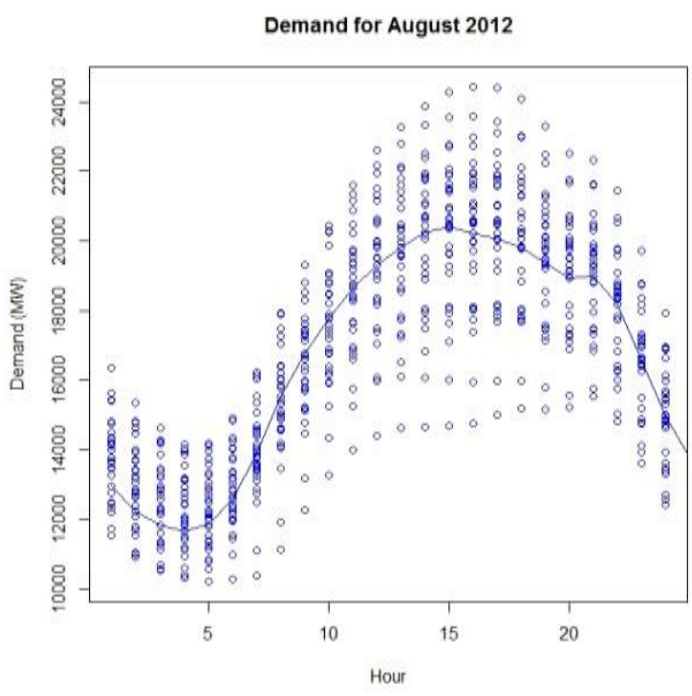

Figure 3: Demand for the month of August by Hour plotted along with mean hourly Demand.

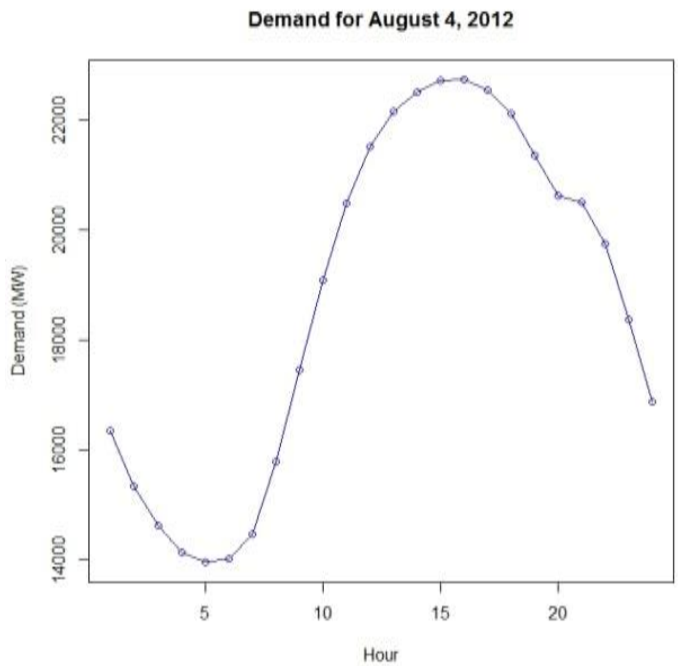

Figure 4: This plot of August 4, 2012 demonstrates the daily fluctuations in Demand typically observed during the summer months.

3. Forecasting Methods

Four modelling methods were chosen for this comparative study. ARIMA, ANN, SVM, and RF models were generated to produce forecasts of electricity demand in ISO-NE. The data set used spanned the entire year of 2012. The data set was first split into separate Training and Test sets. The R packages forecast, neuralnet, e1071, and randomForest were used to build the ARIMA, ANN, SVM, and RF models, respectively.

The ANN, SVM, and RF models included variables for the Hour of the day, Locational Marginal Price (LMP), Dry Bulb Temperature, and Dew Point. The Hour 2 values for these variables were missing for March 11. The missing values were replaced with the average values of Hour 1 and Hour 3.

For each model the RMSE of the Test data predictions for a 24 hour period was calculated. This measure was compared to the value obtained from the ISO-NE Day-Ahead forecast for the same period.

4. Results

The results from the forecast models chosen for comparison to the ISO-NE forecasts present a somewhat mixed record of performance. Table 1 below summarizes the performance of each model by Zone. The RMSE was chosen as the measure of performance. A decrease in RMSE indicates a model that performed better than the ISO-NE forecast on the Test data. Table 1 identifies these with green highlighting.

Region	Day Ahead Forecast RMSE	RF RMSE	ANN RMSE	ARIMA RMSE	SVM RMSE
Maine	150.559	47.3631	106.8029	84.859	64.9068
New Hampshire	59.1474	50.7888	118.8508	111.2664	66.6375
Vermont	132.5702	26.0766	63.1138	63.1202	28.1834
Connecticut	131.5099	138.4703	275.9235	310.7116	176.4852
Rhode Island	43.3906	43.4085	78.2272	88.8809	49.9303
SEMASS	160.8242	79.1042	168.5524	169.0862	77.7201
WCMASS	75.679	120.3837	164.9837	167.6204	149.1388
NEMASS Boston	101.1523	138.6941	263.5493	293.7368	99.4971

Table 1: RMSE for ISO-NE and Model forecasts for each ISO-NE Zone. Values that are highlighted in green represent an improvement in the Model RMSE compared to the ISO-NE Day-Ahead forecast.

Thirty two models were constructed, but only twelve showed an improvement on the Day-Ahead forecast. The worst performance was observed in the NEMASS Boston zone. The ARIMA model produced predictions with an RMSE that was an *increase* of 190%. The best performance was achieved by the RF model in the Vermont zone. This RF model resulted in a *decrease* in RMSE by 80%.

Although no model performed well in all zones, it should be noted that the RF and SVM models showed an average decrease in RMSE of 14.0% and 3.7% respectively.

5. Summary and Conclusions

The modelling techniques of ARIMA, ANN, SVM, and RF were applied to forecasting electricity demand within the ISO-NE region. Forecasts for each model were compared to the Day-Ahead forecasts generated by ISO-NE in terms of RMSE.

The models generated forecasts which performed with mixed results when compared to the ISO-NE forecasts by RMSE. Although RF and SVM models were able to decrease RMSE, in some Zones substantially, no single model emerged as the clear and obvious best performer. The performance of ANN was surprising given the use of an ANN model in the Day-Ahead ISO-NE forecasts. It should be noted that despite the performance increase, none of the tested models were able to achieve lower RMSE values for the Connecticut, Rhode Island, or WCMASS zones.

Areas of further investigation include expanding the data set beyond 2012 to include data from before the 2008 financial crisis. ISO-NE has since 2013 started to provide hourly forecasts for three days-ahead. This represents an opportunity to apply the modelling techniques used here to a longer forecast period. There is also the ability to evaluate how an hourly forecast updates as t+3 transitions to t+1. Using a multi-year data set has the advantage of allowing the seasonal effects to be better fit. Future work will likely test models on data at different seasons, with further exploration of the segmentation approach to this problem taken by Feng *et al*. warranted.

One noticeable drawback in the models used was that they do not distinguish between weekday and weekends. Variables for these will be included in subsequent work with the expectation that doing so will greatly increase the predictive performance of the models.

Additionally, there may be some benefit to using ensemble methods. Combining exponential smoothing and a PCA has shown to increase model performance (Taylor *et al.*, 2006). Singh *et al.* (2013) also observed that the trend in load forecasting is to use of hybrid models. By using the information captured uniquely from each model it is anticipated that the resulting model will be demonstrate an improvement in RMSE.

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