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ERCOT Ancillary Services and Wind Generation: The Factors that Influence the Requirements

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ERCOT Ancillary Services and Wind Generation:
The Factors that Influence the Requirements

by

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Report

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Dedication

To Sean, the Huynh family – Tho, Tam, Thao, Thuong, Thu, by extension Ed, Ngan, Vinay, the Leung family – Pak, Melinda, Mark, by extension Elsa and my daughter Kaylee, nieces Grace, Mina, Ava, and nephews Mason, Carson and Kabot, and the lotus to be. Thank you for giving me the strength to walk the stone path that is my life.

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Abstract

ERCOT Ancillary Services and Wind Generation: The Factors that Influence the Requirements

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This report presents the impact of wind generation and the factors in the ERCOT market design that have influenced service requirement changes over the years. The CPS1 and contingency reserve requirements from NERC BAL Standards are introduced. The ERCOT ancillary services and the progression of the values from 2007 to 2016 are presented in the report. ERCOT's economic dispatch and the various inputs and outputs of the dispatch in the Nodal market are explored. This also includes a description of how ancillary services are deployed within the realm of economic dispatch. The Nodal Protocol Revisions and System Change Requests that could influence reserve requirements are provided. The report presents a regression analysis of the ERCOT regulation reserves requirements in intervals of certain Nodal Protocol Revisions, System Change Requests, as well as using installed wind capacity, thermal capacity, daily load statistics and monthly ERCOT CPS1 scores. The regression analysis shows that there is room for more variables to be included and that the economic dispatch may benefit from including some factor of a predicted wind ramp within the dispatch interval.

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Acronyms

ERCOT	Electric Reliability Council of Texas
RTO	Regional Transmission Organization
RRS	Responsive Reserve Service
NSRS	Non-spinning Reserve Service
WGR	Wind Generation Resource
GTBD	Generation to be Dispatched
QSE	Qualified Scheduling Entity
CPS1	Control Performance Standard 1
NERC	North American Electric Reliability Corporation
SCED	Security Constrained Economic Dispatch
RUC	Reliability Unit Commitment
CDR	Capacity, Demand and Reserves Report
NPRR	Nodal Protocol Revision Request
SCR	System Change Request
BA	Balancing Authority
LFC	Load Frequency Control

CHAPTER 1

INTRODUCTION

Electricity is an essentially instantaneously consumed commodity and is constantly varying in demand within seconds time-scales. Generation, load, and transmission lines obey the laws of Gustav Kirchoff and are kept constantly balanced with complex and involved algorithms. Electricity grids are dependent on correctly allocating and analyzing conditions to be able to reliably serve all final consumers of electricity. In a macro-scale view of predicting what is needed there are several inputs to formulate the required capacity and cost of the operation at the final hour.

In the Electric Reliability Council of Texas (ERCOT) this starts with a planning process that foreshadows many different levels: long term planning, short term planning, seasonal assessments, and the most recent capacity, demand and reserves report. This is then passed on to different departments and computer systems: energy management system, network modeling, outage coordination, and operations analysis and planning. The market engines currently in place are tasked with appropriately studying and providing results to ERCOT operators. While there is a plethora of factors involved, this report will focus on ancillary service methodologies and the Nodal Real-Time Market. Because the study period starts in 2007, there will be limited references to what occurred in the Zonal market until the implementation of Nodal in December 2010.

To compensate for shortcomings due to unpredictable situations, there is a requirement for grids to have operating reserves, also known as ancillary services, to handle the changes. Some of those requirements are widely discussed but the following are brief descriptions of what is used in ERCOT to ensure a reliable electric grid.

1.1 Ancillary Services

1.1.1 Types of Reserves

The balance between generation and demand has to be maintained at all times. The real-time market will dispatch resources on the short-term demand forecast for the upcoming dispatch interval. Regulating reserve is the ancillary service needed to maintain frequency between the intervals of the dispatch despite continuous random uncertainties in load and generation.

ERCOT's following reserve is fulfilled by the real-time dispatch and non-spinning reserve service (NSRS). In the Zonal market, the real-time dispatch was on a 15-minute basis, whereas the Nodal market implemented on December 1, 2010 is on a 5-minute basis. The Nodal market real-time dispatch is also known as Security Constrained Economic Dispatch (SCED). NSRS is used to set aside capacity, offline or augmentation capacity, to handle any projected risk on the grid, unit trips, and missed load forecasts. Because some resources in ERCOT providing NSRS can be dispatched by SCED from offline to online in ten minutes, this can also be labeled as a following reserve.

The contingency reserve service is the operating reserve that is set aside to handle the loss of the largest unit(s) in a grid. ERCOT satisfies this with responsive reserve service (RRS).

The changes to the ERCOT ancillary service methodologies will be reviewed in detail for the study periods in this report: 2007 through 2016.

1.1.2 Deployment of Reserves

While the procurement of the appropriate amount of reserves is important, the method to deploy these reserves is just as crucial. If the reserves are not deployed well, then the grid may suffer during a major disturbance, and the quantity of required reserves may increase over time. This report will discuss some of these issues.

1.2 Net Load Ramping

ERCOT has a significant amount of installed wind in their generation fleet at a total of 18.9 GW at the close of 2016 [1]. Because wind is intermittent, there is a level of uncertainty in the change of wind generation within one interval of system dispatch. Figure 1 shows the histogram of ramping net load in five-minute intervals, which in the case below, is the load ramp minus the wind ramp that occurred within the five-minute interval. This report will discuss the market design and ERCOT tools implemented to handle the range of net load ramps.

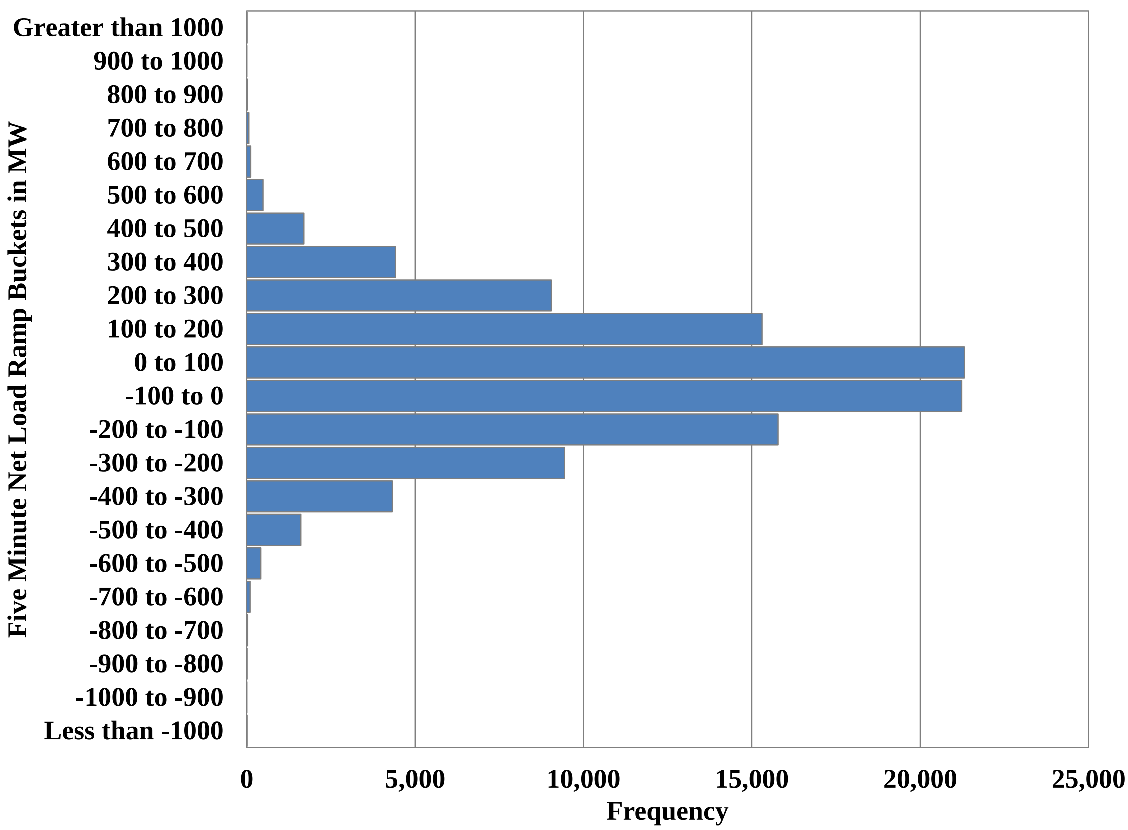

Figure 1: 2016 Histogram of 5-Minute ERCOT Net Load Ramps[1]

[1]Source: This graph is reproduced from [2].

1.3 ERCOT Markets and Procedures

Prior to December 2010, ERCOT operated the grid in what was called a Zonal market. ERCOT was dissected into four distinct congestion management zones, where each resource was homogenized to its respective zone. Resource dispatch was determined by the Qualified Scheduling Entity (QSE) based on the total signal, in each zone, given by ERCOT. The QSE would then determine which resources within the fleet would respond to fulfill the dispatch required by ERCOT.

When congestion arose as a result of this dispatch, ERCOT would send specific unit out-of-merit instructions to QSEs to maintain reliability. If there were constraints between congestion management zones, each resource in the respective zone would be treated equally.

ERCOT transitioned to a Nodal market in December 2010. The Nodal design has a Day-Ahead Market (DAM) that co-optimizes the energy and the ancillary services ERCOT must have for each hour in the next operating day. There is also a real-time market that is executed in a Security Constrained Economic Dispatch (SCED) engine that provides a 5-minute dispatch instructions to specific resources.

Both the Zonal and Nodal markets went through multiple revision requests proposed by ERCOT, stakeholders, or the Public Utility Commission of Texas. These are encapsulated in the form of Ancillary Service Methodology changes, Nodal Protocol Revision Requests (NPRR), and System Change Requests (SCR).

A previous white paper attempted to quantify the effect of renewable generation on regulating reserves, specifically installed wind capacity, thermal generation, load profiles, and protocol changes [3]. This report is designed to be more comprehensive and further refine the inputs, better account for the impacts, and also examine the economic dispatch and deployment of reserves in the ERCOT market. This report will focus only on the Electric Reliability of Texas (ERCOT) Nodal market and its market design, protocols, system changes, and procedures regarding ancillary services and economic dispatch. Pricing and market implications are not discussed.

CHAPTER 2

ERCOT REQUIREMENTS

Several factors influence ancillary service requirements. Chapter 2 will first discuss performance standards that are set in place for Regional Transmission Organizations (RTOs) to adequately provide electricity. Next, it will provide a chronological progression of the changing requirements for each of the ERCOT ancillary services. Another important aspect that can influence the ancillary service requirement is the interval length of dispatch for the electric grid. The last two sections will explore the revisions to the market by NPRRs or SCRs that may impact ancillary service requirements.

2.1 NERC Standards

Ancillary services may differ from area to area, but what is consistent are the North American Reliability Corporation (NERC) standards that each RTO must follow. Only two will be discussed in this report, namely Control Performance Standard 1 (CPS1) and Contingency Reserve.

2.1.1 Control Performance Standard 1 (CPS1)

The NERC Standard BAL-001-2 requires that each Balancing Authority (BA), in this case ERCOT, is required to control interconnection frequency within defined limits [4]. The metric of CPS1 should be greater than or equal to 100 percent for each rolling 12-month average, updated monthly. Figure 2 demonstrates that ERCOT has fulfilled this requirement and has successfully controlled frequency with CPS1 above 100 percent.

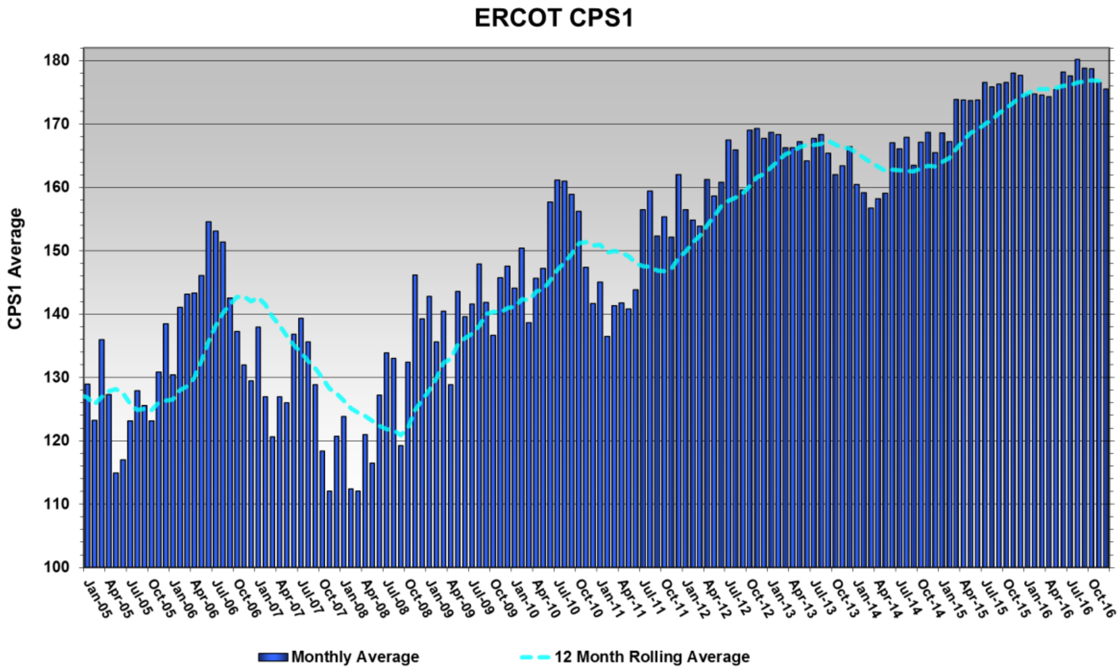

Figure 2: ERCOT CPS1 Performance[2]

2.1.2 Contingency Reserve

The NERC Standard BAL-002-1 refers to the Disturbance Control Performance. BAL-002-1 mandates that a BA must carry a contingency reserve. The contingency reserve should be at least as much as the most severe contingency. In ERCOT's case, this is the loss of one of the largest nuclear units. The divergence in ERCOT's procurement of quantity in excess of the capacity of one the nuclear units will be described in Section 2.2.2.

Also, if the BA were to have a disturbance that was 80 percent of the most severe contingency or greater, the BA shall recover the pre-disturbance frequency within fifteen minutes of the disturbance. If the contingency reserve were to fall below the required amount after a disturbance, then the BA shall replenish the reserve within 90 minutes of reaching the pre-disturbance frequency [6].

[2] Source: Figure taken from [5].

2.2 Ancillary Service Methodologies

Ancillary service methodologies are reviewed annually by ERCOT, and thoroughly vetted by the stakeholder process before being approved by the Board of Directors of ERCOT. The requirements must be sufficient to satisfy the performance standards mandated by NERC. The following subsections will track the progression of these changes for regulation, RRS, and NSRS from 2007 through 2016.

2.2.1 REGULATION

ERCOT procures regulation up and regulation down ancillary service. To qualify, resources must have demonstrated to ERCOT via a test that they are eligible to provide the service.

In 2007, for one month of regulation study, ERCOT would review the mean and the standard deviation of the 1-minute regulation deployment averages of the previous month as well as the same month of the prior year. There would also be the review of the exhaustion rate seen by the system. Deployments would be analyzed to determine whether the service, down or up, was at its maximum capacity for more than an aggregate 1.2 percent of the month. Also, the 98.8 percentile of the previous month for deployments of regulation up and regulation down would be calculated. The deployments for the RRS could also be taken into account when determining the regulation requirements for the next month [7].

The next big revision to the regulation requirement methodology was in 2009, when ERCOT took into consideration the study General Electric (GE) performed when determining additional requirements for every 1000 MW increase in installed wind generation [45]. Further, in lieu of looking at the previous month, it clarified that only 30 days prior to the study would be used to calculate deployments of both regulation services. The CPS1 scores were also reviewed in those 30 days, and if the CPS1 score was less than 100 percent in an hour, ERCOT could procure additional regulation for that hour [9].

Since the Nodal market was scheduled to go-live in December 2010, the 2010 methodology addressed this by stating that the calculated requirement would be divided by two, as the regulation service was changing from a ten-minute product to a five-minute product. This means that if a resource were to get a regulation deployment, the reserve is deployed within five minutes instead of ten minutes. There was also a delay of two months at the start of the Nodal market in using regulation deployment calculations. There was also further consideration if CPS1 scores fell below 90 percent for any hour, that ERCOT would increase the procured reserve by 20 percent [10].

The 2015 methodology outlined that ERCOT would annually calculate the incremental MW of regulation needed with real wind data using similar techniques to the GE study. At the start of 2015 there was roughly 12.8 GW of installed wind in ERCOT, and the increased capacity of wind is based on installed wind resources at the time of the study, minus the amount of wind in the ERCOT model [11].

For 2016, the methodology changed from a monthly study to an annual study. A variety of information is gathered at ERCOT to determine the next year's regulation requirements. They range from Resource Asset Registration information, CPS1 data, regulation deployments, aggregate output data, and ERCOT system load data. Also, the monthly percentile is based on the largest 95 percentile of the deployments from the two previous years of the same month. The next consideration is the incremental MWs based on the increased wind penetration. Exhaustion rates would be taken into account in the next annual study. However, if CPS1 scores were to perform poorly, ERCOT would adjust regulation requirements for the next month by the 20th day of the current month [11].

Figure 3 and Figure 4 displays the trends of daily average regulation requirements of up and down from 2007 through 2016. The large decrease in requirement for both figures coincides with the start of the Nodal market in December 2010. It is important to note, that even though the installed wind capacity continues to increase, both services are following a downward trend in daily average required values. A caution that the daily average does not indicate the increase in requirements for hours where there are risks of higher net load ramps.

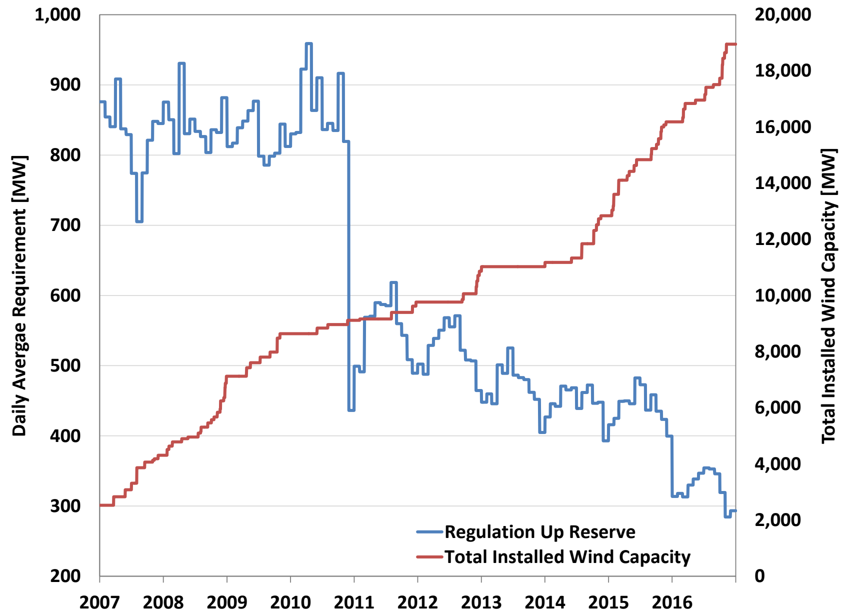

Figure 3: Regulation Up Reserve and Installed Wind Capacity[3]

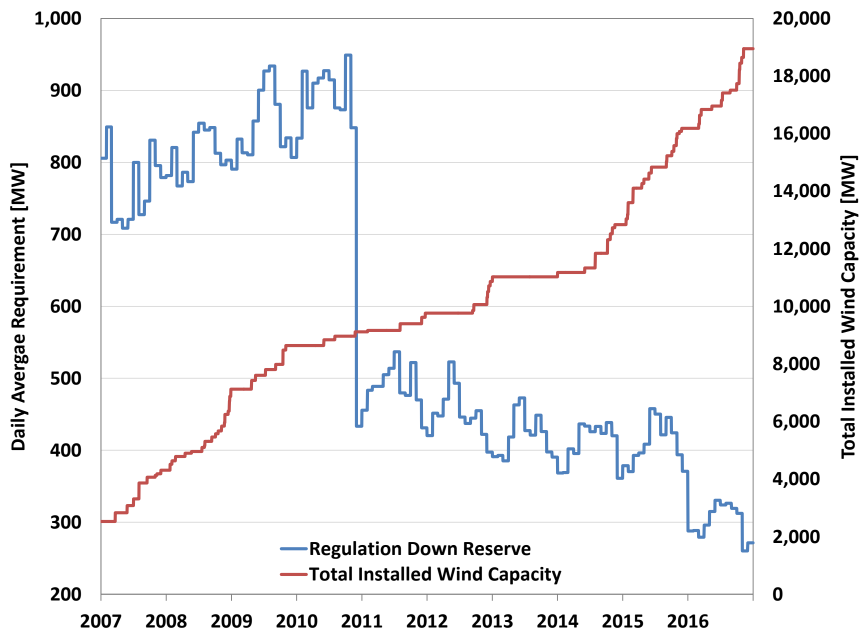

Figure 4: Regulation Down Reserve and Installed Wind Capacity[4]

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[3] Source: Figure produced from [12] and [1].
[4] *Ibid*

2.2.2 RESPONSIVE RESERVE

Although the NERC standard requires that ERCOT carry reserves at least equal to the most severe single contingency, loss of one nuclear unit, ERCOT was procuring 2300 MW at the beginning of this study period. The 2300 MW requirement was a result of a study demonstrating that 2300 MW is sufficient reserved frequency responsive capacity to withstand the loss of ERCOT's two nuclear units within the appropriate under-frequency load shed recovery standards mandated by NERC [13]. According to ERCOT CDRs, the largest nuclear unit in the study period of 2007 through 2016 varies from 1282 MW up to 1375 MW [14][19][21]. The values in each of these timeframes should essentially be the required contingency reserves ERCOT should have at all times based on the NERC BAL-002 standard. ERCOT also requires all RRS to be frequency responsive.

It is also important to note that RRS can be carried by load resources to the maximum 50 percent of the total RRS requirement. Load resources providing RRS means that at the frequency 59.8 Hz, the load must trip to help arrest frequency [38]. The Ancillary Service methodologies always permit ERCOT to increase RRS procurement for projected high risk periods. An example of this is evident in Figure 5 where for a short timeframe in 2008, the requirements were increased.

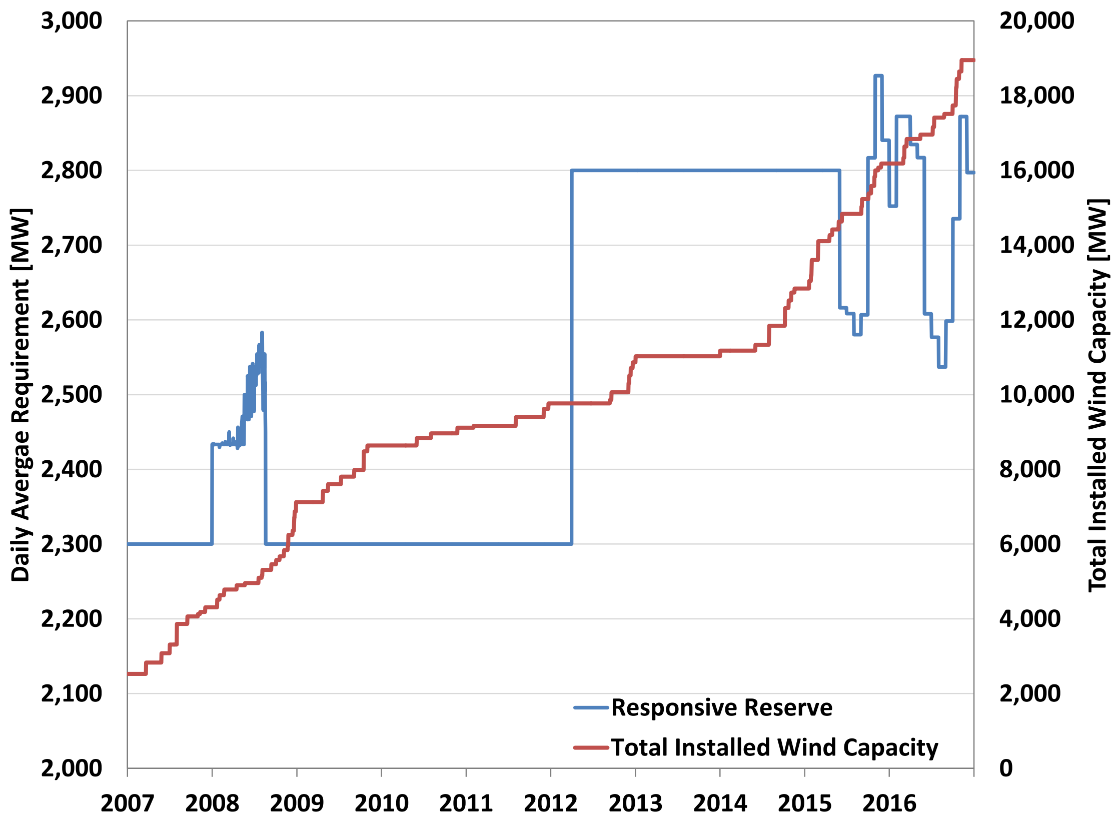


Figure 5: Responsive Reserve and Installed Wind Capacity

In 2012, the amount of reserves jumped to 2800 MW which was a result of discussions at the stakeholder's Reliability Deployment Task Force. There was also discussion on requirements of frequency responsiveness at the higher value of 2800, however, it was reverted back to all frequency responsive capacity in subsequent years. While RRS does provide a reliability need at 2300 MW, the value of a procurement of 2800 MW was intended to increase market prices.

"As a result of discussions between the ERCOT staff, ERCOT stakeholders, the Independent Market Monitor (IMM), and Public Utility Commission of Texas (PUCT) staff, a request was made to ERCOT staff by the Reliability Deployment Task Force (RDTF) that the methodology document be updated to transfer 500 megawatts (MW) of Non-spinning Reserve Service (NSRS) to Responsive Reserve Service (RRS). The intent of this transfer is to help alleviate the potentially negative

effects of reliability deployments on energy prices by having a larger amount of the total reserves be provided by online Resources" [32].

In June 2015, the methodology for RRS changed to incorporate the findings from the future ancillary service study and also for ERCOT to help meet the new NERC standard BAL-003-1.1. This NERC standard requires ERCOT have the ability to protect against under frequency load shed with the simultaneous loss of the two largest units [33]. ERCOT studies analyzed the amount of RRS that could reliably be provided from load resources versus generation. It was determined that the value provided by load resources was not a one-to-one relationship with the value provided by generation. In fact, at times RRS provided by loads is more valuable than generation. As the changes to RRS progress, there will be more defined capability of the service.

The level of RRS available was monitored in the Zonal at the aggregate QSE fleet to maintain appropriate headroom on their resources to satisfy their RRS obligation. In Nodal, resource-specific obligation of RRS is tracked in the energy management system. ERCOT also tracks at broader scale the total availability of all units. In Zonal this was in a form called Adjusted Responsive Reserve. Generally this is looking at the minimum of 20 percent of the capacity of a resource or the remaining headroom of the unit. The adjusted descriptor refers to the fact that ERCOT is trying to account for the possibility that not all of the capacity in the previous calculation would respond in a disturbance. ERCOT tracks this value in Nodal via the Physical Responsive Capability (PRC) value. The Nodal Protocols provide a more detailed description of what is included in PRC [34].

2.2.3 Non-Spinning Reserve

Non-Spin Reserve Service (NSRS) started out in 2007 as a projected high risk product as it was primarily used to handle missed load forecasts and respond to unit trips. In other words, ERCOT would purchase NSRS equal to the largest unit planned to be in operation for periods of high risk. In 2009, this changed to align to the 95th percentile of the net load forecast errors for the previous 90 days [9]. Figure 6 demonstrates that there is a clear downward trend even below the largest unit capacity starting in 2009. Again, a caution that the daily average does not indicate the increase in requirements for hours where there are risks of higher net load ramps.

In 2010, if the net load forecast error shows an over forecast, then that average uncertainty will be added back to the NSRS requirement value [10]. The calculated average uncertainty value for each NSRS value will be adjusted such that the sum of the two values does not exceed 2000. This will place a cap of 2000 MW on the NSRS requirement. This same adjusted average uncertainty value will also be subtracted from the ERCOT load forecasts during the month for the sets of hours to which it applies. This change was due to the fact that the mid-term load forecast selected for an operating day indicated there was a positive forecast bias, especially during on peak summer months [35]. While the load forecast would subtract the forecast bias, the NSRS would cover potential higher loads than expected, and additional units would not have to be called upon out of merit. Also, if the final calculation was below the largest unit, then the NSRS requirement would be adjusted to equal the capacity value of the largest unit, especially for the on-peak hours of hours ending 7 through 22.

Corresponding to the RRS 2800 MW requirement, NSRS had a cap at 1500 MW in 2012. The 95th percentile of the net load forecast error was decreased from 90 days to the previous 30 days [11].

In 2016, the requirement again changed to look at range of percentiles 70th to 95th of the hourly net load uncertainty [11]. Further clarification of the net load was used to evaluate the total wind that would be available if resources had not been curtailed. It was evident in ERCOT that many wind resources were curtailed because of congestion or the inability of conventional generation to ramp down in low load situations.

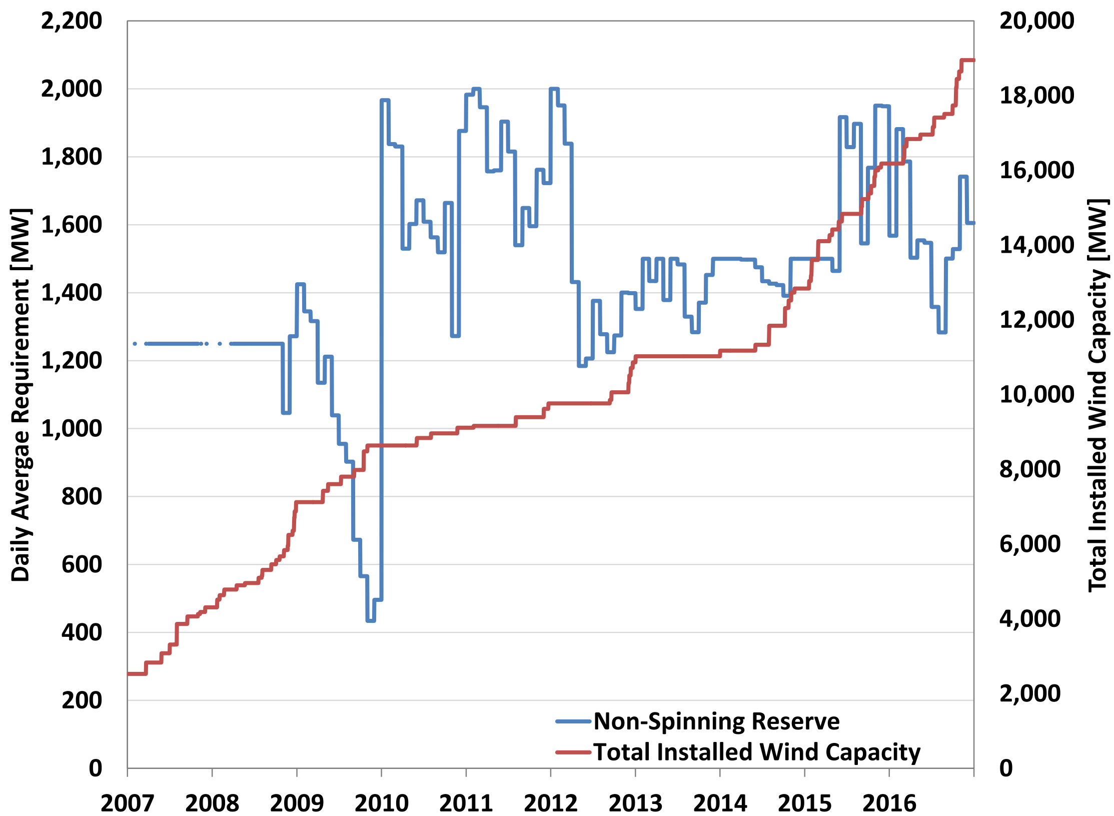


Figure 6: Non-Spin Reserve and Installed Wind Capacity

Nodal Protocols allows NSRS to be carried by either offline or online resources [31]. An offline resource must have the capacity to come online and to ramp to full output within 30 minutes from the time ERCOT deploys the service. Online NSRS is required to increase a resource's output within 30 minutes of ERCOT deployment. In Nodal, a number of quick start resources, resources that can be on within ten minutes, can provide online NSRS and be dispatched by SCED. This will be an important discussion in Section 2.3.2.

2.3 Security Constrained Economic Dispatch

ERCOT's real-time market main engine is the Security Constrained Economic Dispatch. This function is the black box that takes all important inputs of the electric grid;

current generation output, reliability congestion components (constraint shift factors), energy offer curves of every resource, and a short-term five-minute load forecast. With these inputs, SCED calculates desired base points for resources and prices each settlement point on the system appropriately. These prices are known as Locational Marginal Prices (LMPs). While pricing impacts of SCED does influence a market participant's willingness to provide ancillary services over energy, this report will not discuss these issues.

2.3.1 Generation to be Dispatched

The focus on the next section is to take a look at the inputs that go into the short-term five-minute calculation. The premise being that if the value is the closest prediction of where the system will be in five minutes that the regulation reserve between intervals will not have to work as hard to maintain frequency. This is the main reason why the regulation reserve requirement went down by a factor of two when ERCOT transitioned to Nodal. The dispatch window decreased from fifteen minutes between new base points, down to five minutes. Another benefit of Nodal was base points going to specific resources instead of QSEs managing dispatch movement to the QSE's fleet. Figure 7 demonstrates a theoretical regulating reserve performance between base point dispatches if the base point and units that received them exactly followed load ramp, but the base point does not account for wind output. The x axis is time in seconds where the y-axis is at t=0 at the beginning of the dispatch. Also, if the regulation reserve requirement was only 200 MW, the signal to deploy more than 200 MW would not be available.

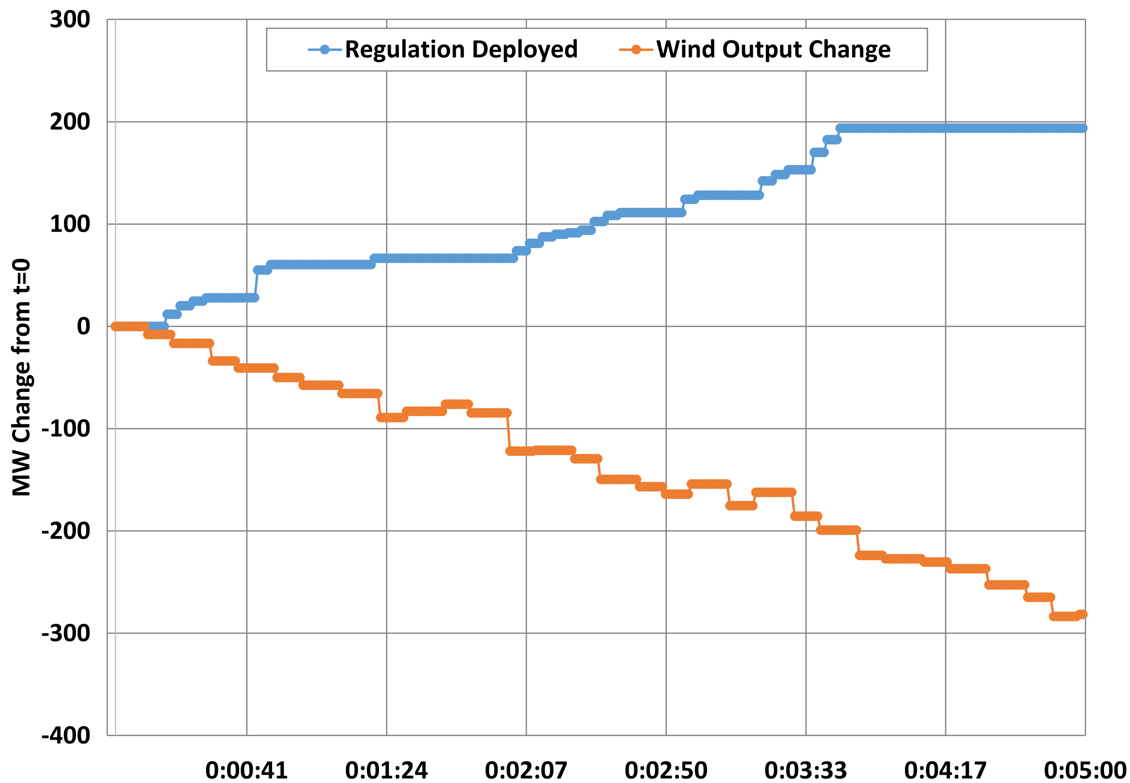


Figure 7: Theoretical Regulation Deployment versus Change in Wind

The short-term five-minute prediction used in SCED is called the Generation to be Dispatched (GTBD). The calculation at the beginning of December 2010 was as follows

GTBD = Total Gen + K_1*10*System Load Frequency Bias

+ K_2*[(net non-conforming Load) – (net filtered non-conforming Load)]

+ K_3*5*Projected Load Ramp per Minute

K_1, K_2, and K_3 are values that can be tuned to best predict GTBD. This allows the ability to account for season bias possibilities, i.e. higher K_3 for seasons that tends to be more volatile. ERCOT verified that K_1 and K_2 have not had a value since January 2011. Therefore, the calculation encompasses Total Gen at the start of the SCED interval which should essentially be the total load in ERCOT at time 0, and the K_3 term is the projected load change in five minutes [36].

Since the calculation assumes Total Gen is the load at time zero, the logic did not include consideration of deployed regulation reserves within the interval. SCR 773, implemented in May 2013, adds the K_4 configurable factor together with the rolling average of regulation deployed in the past X minutes where X can be a tuned value [36].

$$+ K_4 * \text{Regulation Deployed}$$

$$|\text{Regulation Deployed}| \leq \text{Max Regulation Deployed Feedback}$$

Since the K_4 factor could change quickly between SCED intervals because regulation should reset at the start of a new interval, another term was added to the equation. GTBD should consider longer-term Resources performance and accuracy regulation feedback. SCR 788, implemented in December 2016, resolves this by adding the K_5 configurable factor together with the Integral Area Control Error (ACE) calculated in the Energy Management System (EMS). The ACE algorithm subtracts the actual frequency in Hz from the scheduled system frequency (usually 60Hz), and multiplies the result by the frequency bias constant of MW/0.1 Hz [34]. Ability to integrate the Raw ACE over X seconds for use in the ACE Integral equation, where the variable X can be configured [37].

$$+ K_5 * \text{ACE Integral}$$

$$|\text{ACE Integral}| \leq \text{Max Integral ACE Feedback}$$

A worthy note is that the regulation deployed moves with wind changes within an interval. By adding the K_4 term allowed to also associate wind changes from a SCED interval. But it also essentially based on a look back on wind behavior and not a look forward.

2.3.2 Deployment of Reserves in SCED

Every unit in ERCOT has a calculation associated with it in the EMS via the Resource Limit Calculator. Telemetry containing unit ancillary service responsibilities and schedules are sent to ERCOT. The calculation will appropriately take the telemetered high sustained limit of the unit and the various ancillary service responsibilities, and provide a high ancillary service limit to show an adjusted value for regulation up, RRS, and NSRS. The low ancillary service limit is an adjusted value of the low sustained limit of a unit and its regulation down obligation. This will keep SCED from dispatching a unit out of their requirements to provide these ancillary services.

ERCOT's Load Frequency Control (LFC) signal is designed in such a way that the amount of MWs requested of the generator must be fulfilled within five minutes which is the mechanism to deploy regulation reserves. Since frequency is constantly changing, the LFC signal sends deployment requests in 4 second intervals and is tuned in such a way to maintain a desired frequency, mostly set at 60 Hz. ERCOT will periodically check the tuning of the LFC logic to get the best results.

RRS is not dispatchable by SCED unless ERCOT deploys the ancillary service. There is a secondary path that RRS would get deployed, and that is via the system frequency. If frequency drops below the trigger threshold of 59.8 Hz load RRS will be automatically deployed and the LFC will automatically send a deployment for generation RRS based on a threshold logic set by ERCOT [31]

NSRS that are offline and not participating in the quick start mode construct, or capacity reserved behind the high ancillary service limit are deployed by ERCOT. These units must be ready to be dispatched in SCED in 30 minutes [31]. Quick start units have the ability to be dispatched by SCED and be online and at the requested base point in ten minutes [38]. By reviewing 60 Day SCED Disclosure reports, many of the units participating in quick start mode provide NSRS [39].

2.3.3 Potential Wind Ramp Tool

With the increase in wind generation, ERCOT looked for ways to predict how quickly and how much the wind output would change. In 2010, ERCOT had access to a wind ramp tool that would give a view where the wind units might be in future hours [40].

"The large-ramp alert tool makes calculations six hours ahead to warn the system operators of the risk of large and rapid increases or decreases in wind output. The ramp forecast calculates the values of magnitude and duration, and estimates the probability of a large ramp event beginning in a particular interval."

2.3.4 Operator Input Manual SCED Runs and Offset

In the event that ERCOT needs to deal with disturbances in the system, ERCOT has the ability to initiate a manual SCED run [41]. SCED will still resume the next five minute interval at the start of the five minutes, but the rerun would help re-distribute the energy base points after the disturbance. Because SCED takes a snapshot of current telemetry, after a unit trip, it would be logical that the operator would need to add in an offset to account for the loss of the unit so SCED would be able to know that the snapshot of telemetered generation needs to make up for the loss of the unit. The manual offset data is publicly unavailable, but what can be estimated is the possible number of manual SCED reruns. Figure 8 provides an estimation of manual SCED runs by examining the duration of all SCED intervals. If the interval was less than four minutes, then the interval was counted as a manual SCED run. As such, since one SCED interval would result in two intervals shorter than four minutes, the count is cut in half. This logic will underestimate the number of SCED reruns that were executed.

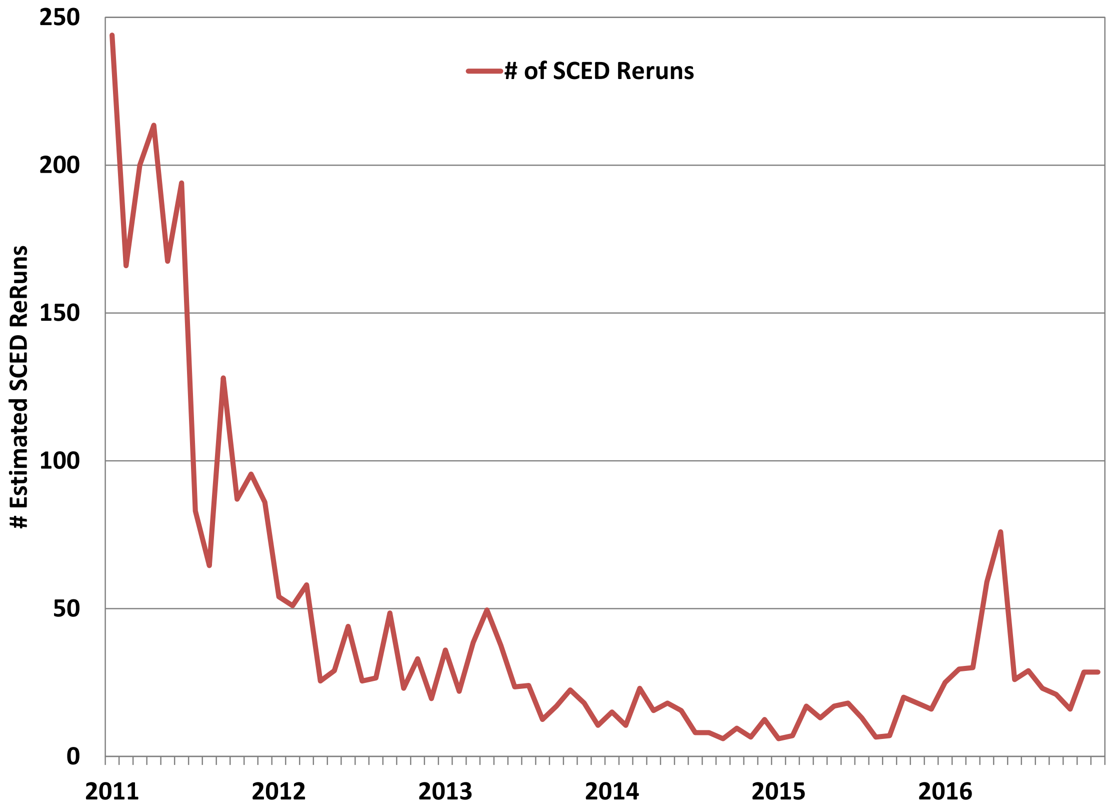


Figure 8: Estimated SCED Reruns in each Month 2007 to 2016[5]

The real-time operating desk presumably could have the ability to add in an offset for other reasons. In Zonal, ERCOT sent instructions to one QSE to either increase or decrease their generation through a Verbal Dispatch Instruction [42]. The difference between Zonal and Nodal, is that whereas in Zonal the QSE got the single generation request, under Nodal the SCED would appropriately distribute the instruction to the most cost effective resources out of multiple resources.

Additionally, since ERCOT takes a snapshot of generation, and wind output aside from curtailed capability, SCED would not take into account where the wind might be in

[5] Source: Graph reproduced from [39].

the next five minutes. It appears the manual offset would be able to give SCED the ability to account for this difference. The following illustration was taken from [43] and provides a simulation of the current scheduling and operations processes. In discussing possible enhancements for ERCOT to handle variation of high intermittent penetration, the conclusions in [43] are about a look-ahead dispatch process or refining the regulation reserve procurement requirements based on wind impacts. However, if GTBD were to embed the wind ramp then regulation reserve may not need to increase to handle wind variation. This is contingent that the short term forecasts for load and wind are as accurate as possible as not to further skew regulating reserve requirements.

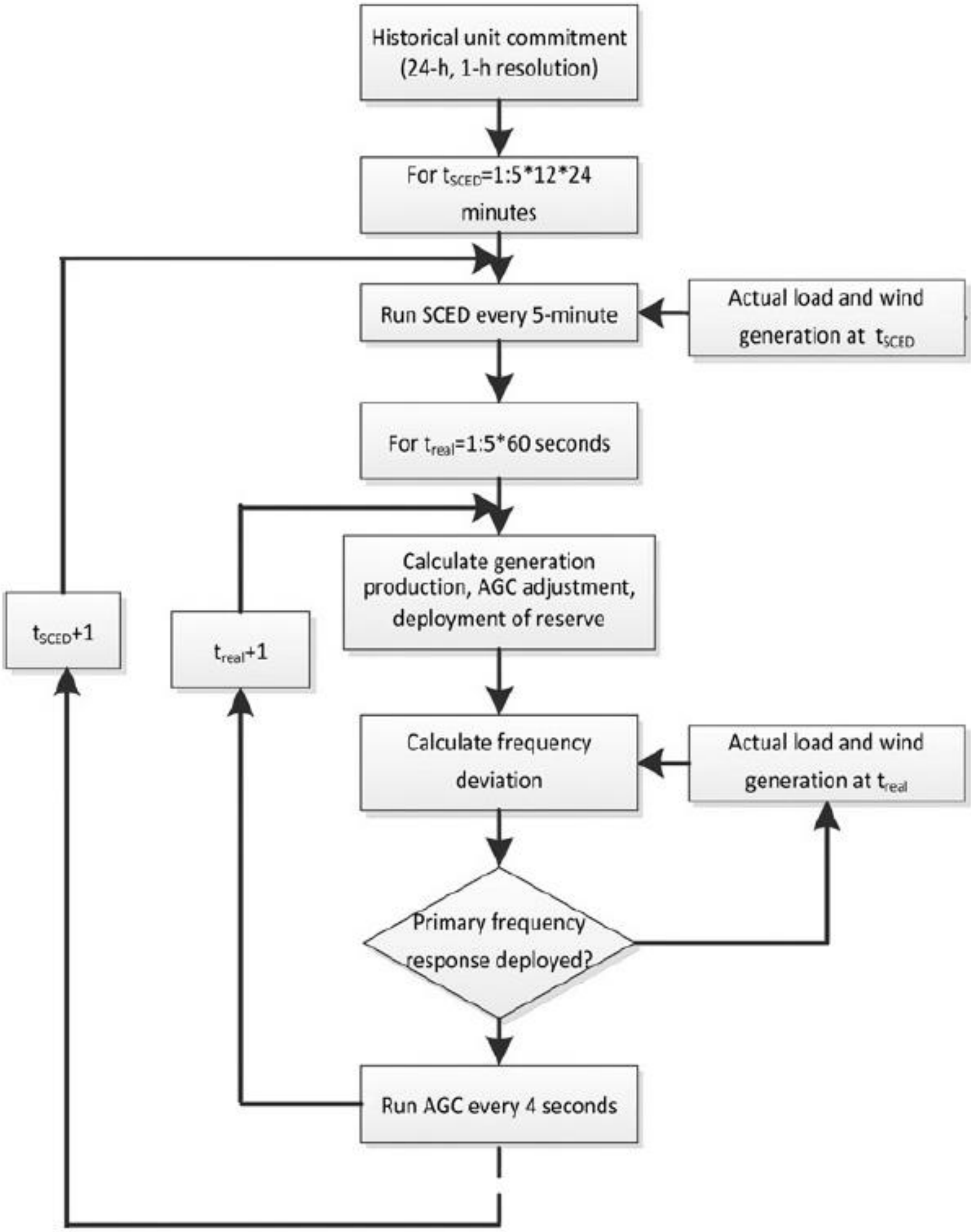


Figure 9: Flowchart of the ERCOT Simulation Tool[6]

[6] Source: Figure taken from [43].

2.3.4 RELIABILITY UNIT COMMITMENT

While there are many things to consider in Reliability Unit Commitments (RUC), the highlight for this report is that each QSE must submit a current operating plan for every commercial resource including wind, in advance of the operating hour [38]. This allows the ability for ERCOT to determine if there are enough resources in an operating hour to meet that hour's short-term load forecast and ancillary service obligations. This does not necessarily mean that the ramping capability of those resources would be sufficient to handle intra-hour generation movement.

2.4 Nodal Protocol Revisions

At the close of 2016, there were 811 Nodal Protocol Revisions proposed, of which 717 were approved protocol changes. There are a wide variety of categories that each revision addresses; ancillary services, pricing, SCED, intermittent resources, administrative, etc. These revisions may not directly change an ancillary service requirement value, they may change the performance of the ancillary service deployments or may acquire a different characteristic.

In Table 1 are the NPRRs that were identified as potential influences to ancillary service requirements. The NPRRs that coincide with the periods below are as follows: December 1, 2010 is the implementation of the Nodal market. July 25, 2011 coincides with the use of dynamic ramp rates in SCED. This allows resources to telemeter what they consider the actual capability of the unit to ramp output up and down. December 1, 2012 is the implementation of an NPRR that says wind ramp rates to be based no higher than 25% of the installed capacity of the resource. October 1, 2014 clarified how combined cycles should telemeter the high sustained limit when providing RRS. The last period encompasses a multitude of NPRRs that were implemented. Appendix A provides a description of all the NPRRs below as well as all the board approval and implementation dates associated with each.

Period	Start Date	End Date	Related AS, SCED and Wind NPRRs Implemented
1	1/1/2007	12/1/2010	NPRR045, NPRR239, NPRR050, NPRR069, NPRR150, NPRR159, NPRR177, NPRR178, NPRR189, NPRR192, NPRR210, NPRR214, NPRR258, NPRR270, NPRR273, NPRR277, NPRR281
2	12/1/2010	7/25/2011	NPRR275, NPRR352, NPRR282
3	7/25/2011	12/1/2012	NPRR332, NPRR389, NPRR426, NPRR427, NPRR428, NPRR423, NPRR361, NPRR424, NPRR433, NPRR434, NPRR354, NPRR446, NPRR348, NPRR425, NPRR460
4	12/1/2012	10/1/2014	NPRR487, NPRR531, NPRR538, NPRR561, NPRR575, NPRR573, NPRR577, NPRR581, NPRR555, NPRR576, NPRR598, NPRR616, NPRR614
5	10/1/2014	1/1/2017	NPRR611, NPRR678, NPRR669, NPRR694, NPRR680, NPRR663, NPRR699, NPRR272, NPRR764, NPRR686, NPRR285, NPRR524

Table 1: Nodal Protocol Revision Requests Allocated in Periods

2.5 System Change Revisions

System Change Requests are also important because they can fundamentally change how the market engines operate and alter the inputs. Below are the system change requests that were identified for the different time periods. SCR 754 was the implementation of ERCOT's wind forecast on June 24, 2009. This made the delivery of the forecasts timely so QSEs could input better forecasts to Current Operating Plans and RUC could better identify unit capacity or congestion needs in the studies. SCR 773 was previously described in Section 2.3.1. SCR 788, also described in Section 2.3.1, was too recent to use in the analysis. Appendix B provides more details for SCRs that could influence reserve requirements.

Period	Start Date	End Date	SCR Implemented
1	1/1/2007	6/24/2009	
2	6/24/2009	12/1/2010	SCR 754
3	12/1/2010	5/23/2013	Nodal
4	5/23/2013	1/1/2017	SCR 773

Table 2: System Change Requests Allocated in Periods

CHAPTER 3

METHODOLOGY

The following will describe different information used in the analysis of trying to look at the NPRR and SCR impact on reserve requirements. It will be followed by the regression linear models assumptions.

3.1 Installed Wind Capacity

The ERCOT QSE Managers Working Group consistently reviews monthly wind performances reports. In 2016, the report provided the date in which a WGR would energize to the grid. Those dates and the designations of West-North and South-Coastal were used in this report, where Panhandle capacity was included with West-North. The WGR approval dates and respective capacities can be found in Appendix C.

3.2 Capacity, Demand and Reserves Reports

ERCOT produces a report called Capacity, Demand and Reserves (CDR) that depict summer or winter conditions for the next five years. Assumptions were used to try and depict what current installed thermal generation, consisting of coal and gas, existed, by using the Summer Fuel Types tab. The first year in each report was assumed to have the most up-to-date thermal generation. This was taken one step further by removing Signed IA and Potential Non-Wind Resources from the summer capacities for the corresponding year. The idea is that such generation was not technically in service at the time of the report. Once the Nodal market was implemented, ERCOT provided SCED data after a 60 days of the operating day. By using this logic, new units that were consistently were shown as being on and dispatchable by SCED for an hour or more in its first operating day were considered as installed thermal generation. Appendix D provides some of the data surrounding the thermal trend in Figure 10**Error! Reference source not found.**.

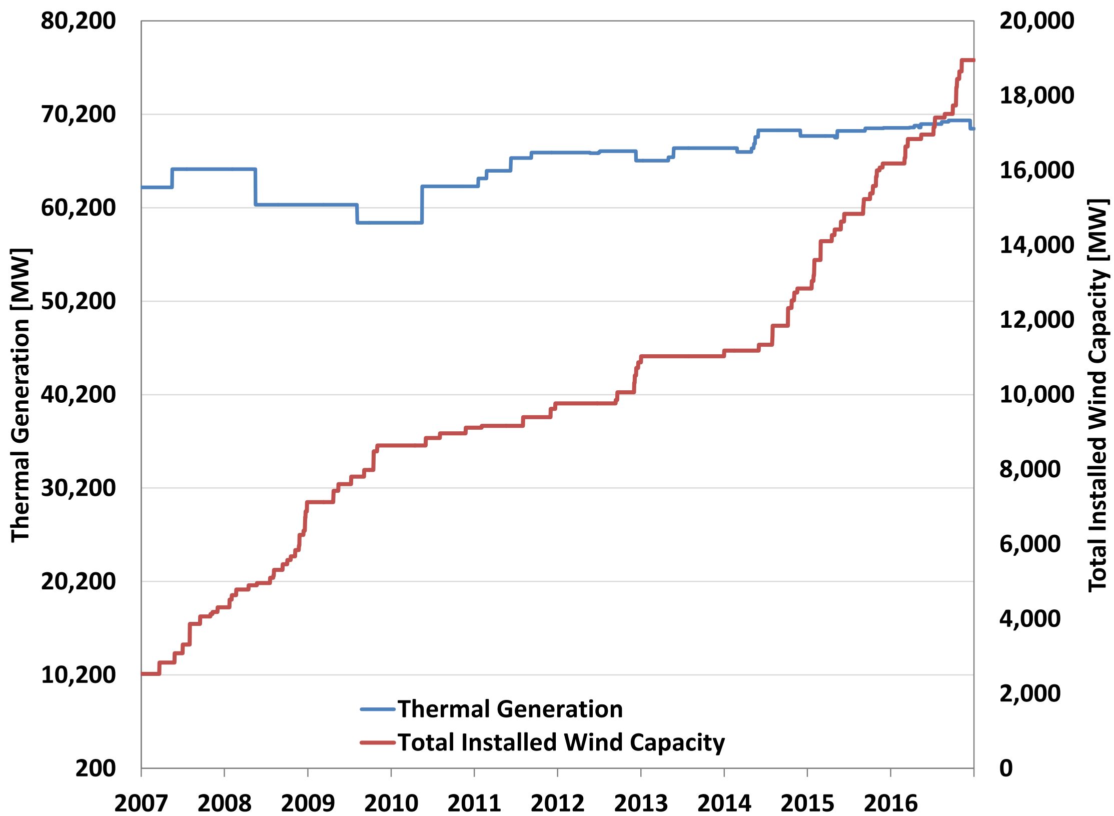


Figure 10: Thermal Generation and Installed Wind Capacity

3.3 Daily Load Statistics

Using ERCOT data, the following daily statistics are calculated for each day: the daily minimum, average, and maximum hourly load [44].

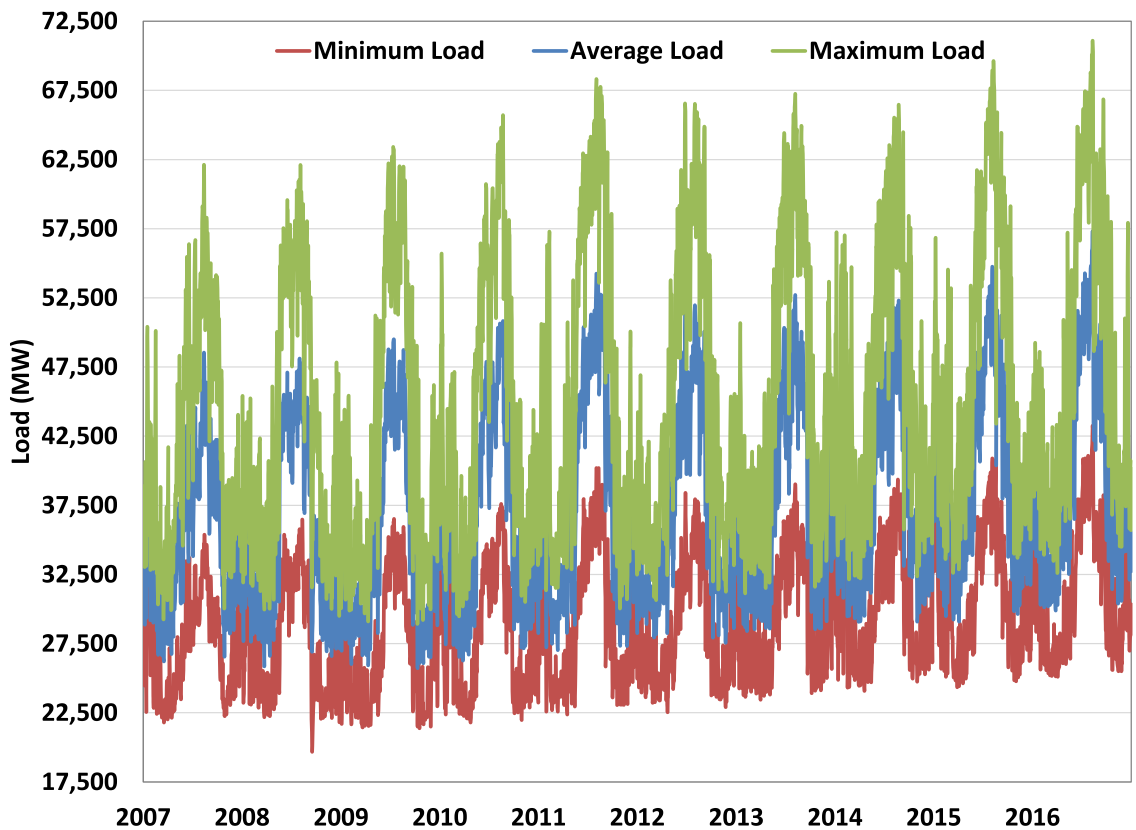


Figure 11: Minimum, Average and Maximum Hourly Load Averages

3.4 Regression Linear Models

Since RRS and NSRS procurements have just started being calculated including operating conditions in the last few years, only regulation up and regulation down were analyzed. Based on the descriptions of the various factors in this report, the following independent variables were picked.

Symbol	Description	Units
$V_{1,t}$	ERCOT West-North wind generation accumulated installed power at time t	MW
$V_{2,t}$	ERCOT South-Coastal wind generation total installed power at time t	MW
$V_{3,t}$	ERCOT thermal generation total installed power at time t	MW
$V_{4,t}$	Daily average total load in ERCOT at time t	MW
$V_{5,t}$	Daily total minimum load in ERCOT at time t	MW
$V_{6,t}$	Daily total maximum load in ERCOT at time t	MW
$V_{7,t}$	Monthly CPS1 at time t	Percent

Table 3: Independent Variables for the Regression Linear Model

The linear model identified in the working paper [3] provides the following expected value of Regulation up noted by $\hat{U}_{p,t}$ and the Expected Value of Regulation Down noted by $\hat{D}_{p,t}$.

$$\widehat{U}_{p,t} = A_{p,0} + \sum_{j=1}^{7} V_{j,t} A_{p,j}$$

$$\widehat{D}_{p,t} = B_{p,0} + \sum_{j=1}^{7} V_{j,t} B_{p,j}$$

Also, since the data is in time series, there is the issue of autocorrelation, the test of independence in the regression model fails. This was also determined in the white paper [3]. Here are the equations to add in a 30 day lag to the dependent variable of the regression model.

$$\widehat{U}_{p,t} = A_{p,0} + \sum_{j=1}^{7} V_{j,t} A_{p,j} + + \sum_{j=1}^{30} F_{p,j} U_{p,t-j}$$

$$\widehat{D}_{p,t} = B_{p,0} + \sum_{j=1}^{7} V_{j,t} B_{p,j} + \sum_{j=1}^{30} G_{p,j} D_{p,t-j}$$

3.5 NPRR and SCR Periods

The periods that will be utilized in the regression models will be done in two different scenarios. The first period analysis will be using Table 1: Nodal Protocol Revision Requests Allocated in Periods.

The second period analysis will be using Table 2: System Change Requests Allocated in Periods. The reason for this second period analysis is that the review of ERCOT systems reveals that the economic dispatch could have an impact on the ancillary service requirements of regulation up and down. A recap of the SCRs show that the identified periods are based on changes within the GTBD calculation. Therefore, it will be interesting to see the results of the regression based on these periods.

CHAPTER 4

RESULTS

4.1 NPRR Period Regression Analysis

The following tables present the parameter estimate coefficients at 95% confidence level, 95% confident that the variable impacts the expected value of the ancillary service. The subscripts on the rows correspond to the *j* subscripts in the formulas, whereas the column periods represent the *p* subscript in the formulas.

Eq Ref	Period 1	p-value	Period 2	p-value	Period 3	p-value
A_0	914	0.0001	-9820	0.0001	4359	0.0001
A_1	-0.0036	0.0153	1.0879	0.0001	-0.0262	0.0001
A_2	0.0480	0.0001			-0.0568	0.0001
A_3			0.0227	0.0001	-0.0574	0.0001
A_4	0.0043	0.0150			0.0031	0.0284
A_5	-0.0030	0.0012			-0.0039	0.0001
A_6	-0.0032	0.0004				
A_7			1.3769	0.0117	1.2584	0.0001
Eq Ref	**Period 4**	**p-value**	**Period 5**	**p-value**		
A_0	1100	0.0001	456	0.0346		
A_1			-0.0198	0.0001		
A_2			-0.0853	0.0001		
A_3	-0.0108	0.0001	-0.0192	0.0001		
A_4	0.0046	0.0001	0.0038	0.0028		
A_5	-0.0061	0.0001	-0.0029	0.0001		
A_6						
A_7			9.9183	0.0001		

Table 4: NPRR Regression Statistics for Regulation Up[7]

Although there were values produced, the model does not satisfy the requirement that the residuals of the regression is independent. These values will not be discussed.

[7] Statistics are an output from SAS. ($\alpha = 0.05$) Appendix E have corresponding regression fit graphs.

Eq Ref	Period 1	p-value	Period 2	p-value	Period 3	p-value
A_0	35	0.0087	-4245	0.0001	366	0.0061
A_1			0.4630	0.0004		
A_2					-0.0076	0.0241
A_3			0.0121	0.0005	-0.0053	0.0145
A_5			-0.0038	0.0008		
A_7					0.1520	0.0388
F_1	0.9798	0.0001	0.4417	0.0001	0.9639	0.0001

Eq Ref	Period 4	p-value	Period 5	p-value
A_0				
A_1				
A_2	0.0196	0.0002	-0.0043	0.0036
A_3	-0.0009	0.0173		
A_5	-0.0003	0.0208		
A_7			0.3041	0.0083
F_1	0.9507	0.0001	0.9760	0.0001

Table 5: NPRR Regression Statistics for Regulation Up with Lag[8]

Period 2 was identified as an incomplete model and all of the parameter estimates were biased. These results are not conclusive to discuss the parameter estimates from the NPRR regulation up period analysis.

[8] *Ibid*

Eq Ref	Period 1	p-value	Period 2	p-value	Period 3	p-value
B_0	877	0.0001	-7079	0.0001	2868	0.0001
B_1	0.0143	0.0001	0.8723	0.0001	-0.0537	0.0001
B_2	0.0487	0.0001			-0.0536	0.0004
B_3	-0.0028	0.0001	0.0047	0.0001	-0.0269	0.0011
B_4	-0.0052	0.0015				
B_5					-0.0068	0.0001
B_6	0.0045	0.0001				
B_7			1.6657	0.0001		

Eq Ref	Period 4	p-value	Period 5	p-value
B_0			-1168	0.0001
B_1	-0.0243	0.0001	-0.0153	0.0001
B_2	0.0830	0.0002	-0.1098	0.0001
B_3	0.0067	0.0001		
B_4	0.0033	0.0059		
B_5	-0.0053	0.0001	-0.0024	0.0010
B_6				
B_7	0.9995	0.0001	9.5960	0.0001

Table 6: NPRR Regression Statistics for Regulation Down[9]

Although there were values produced, the model without lag does not satisfy the requirement that the residuals of the regression is independent. These values will not be discussed.

[9] *Ibid*

Eq Ref	Period 1	p-value	Period 2	p-value	Period 3	p-value
B_0			-5965	0.0001		
B_1	0.0007	0.0284	0.7410	0.0001		
B_2						
B_3			0.0040	0.0002		
B_5			-0.0011	0.0015		
B_7			1.5789	0.0001		
G_1	0.9810	0.0001			0.9689	0.0001
G_{28}	-0.1166	0.0020				
G_{29}	0.0903	0.0170				
G_{30}			-0.0318	0.0234		

Eq Ref	Period 4	p-value	Period 5	p-value
B_0				
B_1				
B_2	0.0135	0.0041	-0.0044	0.0072
B_3				
B_5	-0.0003	0.0474		
B_7			0.3235	0.0049
G_1	0.9772	0.0001	0.9736	0.0001
G_{28}				
G_{29}				
G_{30}				

Table 7: NPRR Regression Statistics for Regulation Down with Lag[10]

All of the periods were identified as incomplete models. Period 2 was identified as an incomplete model and all of the parameter estimates in period 2 were biased. These results are not conclusive to discuss the parameter estimates from the NPRR regulation down period analysis.

Chapter 5 will highlight some possible variables that could be included in future work.

[10] *Ibid*

4.2 Regression Analysis of SCR Periods

The following tables present the 95% confidence level parameter estimate coefficients.

Eq Ref	Period 1	p-value	Period 2	p-value	Period 3	p-value
A_0	1728	0.0001			-431	0.0001
A_1	-0.0103	0.0001	0.1080	0.0001	-0.0500	0.0001
A_2	0.0978	0.0001	-0.0809	0.0073	-0.0136	0.0166
A_3	-0.0103	0.0001			0.0237	0.0001
A_4	0.0046	0.0137	0.0072	0.0141	0.0075	0.0001
A_5			-0.0089	0.0001	-0.0057	0.0001
A_6	-0.0047	0.0001				
A_7	-1.3635	0.0001			-1.4412	0.0001

Eq Ref	Period 4	p-value
A_0		
A_1	-0.0124	0.0001
A_2	-0.0883	0.0001
A_3		
A_4	0.0050	0.0001
A_5	-0.0049	0.0001
A_6		
A_7	3.6471	0.0001

Table 8: SCR Regression Statistics for Regulation Up[11]

Although there were values produced, the model without lag does not satisfy the requirement that the residuals of the regression is independent. These values will not be discussed.

[11] Statistics are an output from SAS. ($\alpha = 0.05$) Appendix F have corresponding regression fit graphs.

Eq Ref	Period 1	p-value	Period 2	p-value	Period 3	p-value
A_0	89	0.0013				
A_1			0.0099	0.0018	-0.0175	0.0001
A_2						
A_3					0.0052	0.0001
A_4					0.0028	0.0001
A_5					-0.0021	0.0001
A_7					-0.2589	0.0163
F_1	0.9731	0.0001	0.9608	0.0001	0.7653	0.0001

Eq Ref	Period 4	p-value
A_0		
A_1		
A_2	-0.0021	0.0135
A_3		
A_4		
A_5		
A_7		
F_1	0.9887	0.0001

Table 9: SCR Regression Statistics for Regulation Up with Lag[12]

For all periods, the first lag variable shows 95% confidence the variable impacts the expected value of regulation up, meaning the previous day expected value of regulation up was correlated to the current day's expected value of regulation up. This makes sense as values of current months are influenced by previous months. For period 2 and period 3, the parameter estimate A_1 which corresponds to the West to North installed wind capacity, shows a sign difference between the two. Period 2 is positive, while period 3 is negative; this is particularly interesting due to the fact that this coincides with the implementation of Nodal. Before Nodal, the expected value of regulation up increased with wind capacity, while in Nodal, the requirement decreased. A_2 from period 4 is also negative, which shows that the South-Coastal wind capacity is negatively correlated to the expected value of regulation up.

[12] *Ibid*

Eq Ref	Period 1	p-value	Period 2	p-value	Period 3	p-value
B_0	1474	0.0001				
B_1	0.0116	0.0001	-0.0299	0.0008	-0.0588	0.0001
B_2	0.0377	0.0006	-0.2422	0.0001		
B_3	-0.0105	0.0001	0.0101	0.0001	0.0200	0.0001
B_4	-0.0042	0.0239			0.0046	0.0001
B_5	0.0041	0.0001			-0.0045	0.0001
B_6	0.0025	0.0102				
B_7	-1.1446	0.0001	4.4569	0.0001	-2.1461	0.0001

Eq Ref	Period 4	p-value
B_0	-800	0.0001
B_1	-0.0130	0.0001
B_2	-0.0836	0.0001
B_3	0.0139	0.0001
B_4	0.0025	0.0212
B_5	-0.0039	0.0001
B_6		
B_7	3.4677	0.0001

Table 10: SCR Regression Statistics for Regulation Down[13]

Although there were values produced, the model without lag does not satisfy the requirement that the residuals of the regression is independent. These values will not be discussed.

[13] *Ibid*

Eq Ref	Period 1	p-value	Period 2	p-value	Period 3	p-value
B_1					-0.0189	0.0001
B_2			-0.0253	0.0016		
B_3					0.0055	0.0001
B_4					0.0027	0.0001
B_5					-0.0021	0.0001
B_6					-0.0007	0.0384
B_7			0.4480	0.0006	-0.6183	0.0001
G_1	0.9727	0.0001	0.9595	0.0001	0.7135	0.0001
G_{28}	-0.1165	0.0168				

Eq Ref	Period 4	p-value
B_1		
B_2	-0.0024	0.0061
B_3		
B_4		
B_5		
B_6		
B_7		
G_1	0.9833	0.0001
G_{28}		

Table 11: SCR Regression Statistics for Regulation Down with Lag[14]

All of the periods for regulation down with lag were indicated to not be complete models. The first two lag variables of each of the periods G_1 and G_2 were shown to be biased. For all periods, the first lag variable is consistently shown with 95% confidence, however, a reminder that this parameter estimate was biased. For period 2, period 3 and period 4, the coefficients to the West-North and South-Coastal variable indicates a negative correlation of the expected value of regulation down. An interpretation of this is, the increase in the installed wind capacity, shows there is a decrease in the expected value of regulation down.

[14] *Ibid*

The interpretation of the results indicates the models are incomplete and there are other regressors that should be considered. Chapter 5 will highlight some possible variables that could be included in future work.

4.3 NPRR and SCR Causation Analysis

Because the estimates for the periods for NPRR and SCR showed there were many biased and the models were incomplete, a causation analysis was not performed.

CHAPTER 5

CONCLUSIONS AND FUTURE WORK

This report discusses many different aspects of ERCOT ancillary services, economic dispatch, and the impacts of wind generation. The regulation up, regulation down, RRS and NSRS requirement methodologies were reviewed for years 2007 through 2016. The ERCOT SCED engine dispatch calculation was discussed in detail; emphasizing that the current calculation as of December 2016 is a term based on projected load ramp, regulation feedback, and the performance of the generation to maintain frequency. The operators at ERCOT have the ability to view potential wind ramps in upcoming hours, as well as the ability to add an offset to the economic dispatch, and initiate manual SCED runs. The ERCOT stakeholder process produces a multitude of NPRRs and SCRs. A subset of the approved revision requests were identified in this report as potential impacts to the regulation up and regulation down requirements.

Regression models were developed for regulation up and regulation down, where to account for autocorrelation, a 30 lagged dependent variable was introduced. The regression models were made for two scenarios. The same data was ran through a model with NPRR periods, and the other model used the SCR period.

Since the NPRR analysis had incomplete models, a discussion of the values calculated at 95% confidence have little to no value. However, the SCR analysis yielded better results. A recap of the SCRs show that the identified periods are based on changes within the GTBD calculation. An interpretation of the difference in the models, is that the changes in the economic dispatch had a more significant impact than the NPRR changes. Notably, changes in economic dispatch in each of the periods led to a better regression fit. Alternatively, the NPRR periods only were split by a subset of all NPRRs that could affect the ancillary service requirements. It is possible that some of the NPRRs time periods would be able to provide a better regression fit.

When looking at the coefficients for the SCR Periods for the regulation up with lag analysis, associated with West-North and South-Coastal installed wind capacity, there were negative correlations after the implementation of Nodal. Prior to Nodal, only one coefficient showed a positive correlation. This technically could mean that with the increase in installed capacity after Nodal there appears to be a decrease in requirements. This seems counter-intuitive since more installed capacity should mean more wind ramps and the associated need for more reserves. These results for all of the regression analysis appear to show that there needs to be more variables added to the regression linear models.

Some variables that could be added to the model could be looking at the various K factor values used over the years. If the K factor provides estimates in GTBD that are not favorable, this could lead to more regulation reserve requirements. A variable that shows the 95th percentile or 98.8th percentiles that actually occurred in the study used for that month would be a good variable to include in the model. This would show actual performance of the procured amount of reserves. Because not all installed thermal generation is consistently online every day, the thermal generation variable could be changed to only include the maximum thermal generation operating that day. Next, the analysis was based on daily conditions, the study could be changed into more granular blocks, like the ancillary service blocks or hourly analysis.

Another issue that could not be explored is the frequency and value of the SCED manual offset. This is one more variable that could be added to the analysis. If in fact a manual offset is being used, this would mask the requirement for more regulation reserves. If ERCOT embeds into GTBD some factor of the five-minute forecasted wind ramping into GTBD this could allow minimal regulation reserve requirements as the base points should take into account both load and wind ramps in the dispatch interval. Regulation deployments would not have to adjust to the full amount of wind movement, which could potentially be significant at an installed capacity of 20 GW and above. This would also hold true for the rise in installed photovoltaic generation capacity. In short, instead of a projected load ramp rate, GTBD could incorporate a projected net load ramp rate.

With the ever changing nature of generation, installed technologies, and renewable characteristics, it will be intriguing to see how RTOs can accommodate these variations.

Appendix

Appendix A: Nodal Protocol Revision Requests

The following table is all approved Nodal Protocol Revision Requests deemed relevant to this report because of their possible effect on ancillary service requirements or performance [46]. These NPRRs are revisions made to various parts of the Nodal market; ancillary service requirements, energy offer curves, wind generation requirements, and SCED market designs. The implementation dates were acquired via a search in the archive of the market notice email distribution list [47].

NPRR #	Title	Date Posted	Approved	Implemented
45	Wind Power Forecasting	2/23/07	10/16/07	6/24/09
50	Clarifications for HSL Values for WGRs and WGR Values to be Used in the RUC Capacity Short Calculation	3/12/07	7/17/07	12/1/10
69	Changes to SURAMP	6/15/07	7/17/07	12/1/10
150	Responsive Reserve Service Offer Floor	8/28/08	11/17/08	12/1/10
159	Resource Category Startup Offer Generic Cap for Wind Resources	10/3/08	1/20/09	12/1/10
177	Synchronization of Nodal Protocols with PRR808, Clean-up and Alignment of RECs Trading Program Language with PUCT Rules	5/15/09	8/18/09	12/1/10
178	Regulation Reduction (GS-FR3) and Reg-Up/Reg-Down Allocation to QSEs	5/26/09	8/18/09	12/1/10
189	Ancillary Service Deployment Clarification	7/24/09	10/20/09	12/1/10
192	QSE Energy and Ancillary Service Compliance Criteria	8/11/09	9/15/09	12/1/10
210	Wind Forecasting Change to P50, Synchronization with PRR841	2/9/10	6/15/10	12/1/10
214	Wind-powered Generation Resource (WGR) High Sustained Limit (HSL) Update Process	3/12/10	5/18/10	12/1/10

239	Ramp Rate Limitation of 10% per minute of On-Line Installed Capability for Wind-powered Generation Resources	5/13/10	7/20/10	8/1/10
258	Synchronization with PRR824 and PRR833 and Additional Clarifications	7/23/10	11/16/10	12/1/10
270	Defining the Variable Used in the Wind Generation Formula	9/13/10	11/16/10	12/1/10
272	Definition and Participation of Quick Start Generation Resources	9/16/10	11/16/10	3/9/17
273	Allow Use of the ONTEST Resource Status to Indicate Resource Startup, Shutdown and Test Operations	9/16/10	10/19/10	12/1/10
275	Clarify QSE's Ability to Make Changes to Ancillary Service Resource Responsibility In Real Time	9/16/10	3/22/11	4/1/11
277	Removal of NPRR119 Language for LDL Calculation and Modification to the SCED Ramp Rate Calculation (formerly "Removal of NPRR119 Language for LDL Calculation")	9/16/10	11/16/10	12/1/10
281	Replace 7-Day Forecast Requirement for QSEs Representing WGRs	9/27/10	11/16/10	12/1/10
282	Dynamic Ramp Rates Use in SCED	9/28/10	3/22/11	7/25/11
285	Generation Resource Base Point Deviation Charge Corrections	10/13/10	11/16/10	5/18/11 and 6/1/11
332	Revise QSGR Processes for COP Reporting of QSGR Assigned Off-Line Non-Spin and Application of Emergency Operations Settlement	2/25/11	7/19/11	8/1/11
348	Generation Resource Start-Up and Shut-Down process	4/6/11	9/20/11	8/29/12
352	Real-Time HSL Telemetry for WGRs	4/13/11	5/17/11	6/1/11
354	Revisions to Non-Spin Performance Criteria Language and Provision for ICCP Telemetry of Non-Spin Deployment	4/15/11	9/20/11	6/28/12
361	Real-Time Wind Power Production Data Transparency	5/4/11	8/16/11	4/27/12
389	Modification of Voltage Support Requirements to Address Existing Non-Exempt WGRs	7/6/11	10/18/11	11/1/11

423	Add Voltage Support Requirement for IRRs and Allow SCADA Control of Static VAr Devices if Approved by ERCOT (formerly "Add Voltage Support Requirement for IRRs and Allow Manual Control of Static VAr Devices if Approved by ERCOT")	11/2/11	2/21/12	3/1/12
424	Reactive Capability Testing Requirements for IRRs	11/2/11	4/17/12	5/1/12
425	Creation of a WGR Group for GREDP and Base Point Deviation Evaluation and Mixing Turbine Types Within a WGR (formerly "Creation of a WGR Group for GREDP and Base Point Deviation Evaluation")	11/2/11	11/13/12	12/1/12
426	Standing Non-Spin Deployment in the Operating Hour for Generation Resources Providing On-Line Non-Spin	11/9/11	12/12/11	1/5/12
427	Energy Offer Curve Requirements for Generation Resources Assigned Reg-Up and RRS	11/9/11	12/12/11	1/5/12
428	Energy Offer Curve Requirements for Generation Resources Assigned Non-Spin Responsibility	11/9/11	12/12/11	1/5/12
433	Clarification of Ancillary Service Obligation Calculation Process	12/9/11	4/17/12	5/1/12
434	Increase the Capacity Limitation of a Generation Resource Providing RRS	12/27/11	2/21/12	5/10/12
446	Correction of Non-Spin Ancillary Service Schedule Telemetry for Standing Non-Spin Deployment	2/29/12	7/17/12	8/1/12
460	WGR Ramp Rate Limitations	5/2/12	11/13/12	12/1/12
487	QSGR Dispatch Adjustment	10/3/12	3/19/13	4/1/13
524	Resource Limits in Providing Ancillary Service	3/5/13	9/17/13	manual work around
531	Clarification of IRR Forecasting Process Posting Requirement	3/22/13	7/16/13	8/1/13
538	Clarification of the Non-Spin Energy Offer Curve Requirements for QSGRs	4/25/13	9/17/13	10/1/13
555	Load Resource Participation in Security-Constrained Economic Dispatch	7/3/13	9/17/13	6/1/14

561	Clarification of Shutdown Telemetry Status	8/9/13	12/10/13	1/1/14
573	Alignment of PRC Calculation	10/21/13	2/11/14	3/1/14
575	Clarification of the RUC Resource Buy-Back Provision for Ancillary Services	10/23/13	12/10/13	1/7/14
576	Changing Non-Spin Service to be Dispatched by ERCOT (formerly "Changing Non-Spin Service to an Off-Line Service")	10/24/13	4/8/14	6/1/14
577	As-Built Clarification for Portion of WGR Group GREDP Evaluation	10/31/13	2/11/14	3/1/14
581	Add Fast Responding Regulation Service as a Subset of Regulation Service	11/6/13	2/11/14	3/1/14
598	Clarify Inputs to PRC and ORDC	2/12/14	4/8/14	6/1/14
611	Modifications to CDR Wind Capacity Value	3/26/14	10/14/14	11/1/14
614	Clarification of Telemetered Value of HSL for Combined Cycle Generation Resources providing RRS	4/11/14	8/12/14	10/1/14
616	Clarification of Notification for Undeliverable Ancillary Services	4/18/14	8/12/14	9/1/14
663	Ancillary Service Insufficiency Actions	10/17/14	10/13/15	2/10/16
669	Maintaining Frequency Responsiveness from Generation Resources Providing RRS	11/21/14	2/10/15	6/1/15
678	Posting of Wind Peak Average Capacity Percentage Data	1/22/15	4/14/15	5/1/15
680	Allow QSEs to Self-Arrange AS Quantities Greater Than Their AS Obligation	1/28/15	6/9/15	12/10/15
686	Changing the IRR Forecast from Next 48 Hours to Next 168 Hours	3/9/15	6/9/15	12/10/15 partial
694	Non-Spin Schedule Requirements	4/9/15	8/11/15	9/1/15
699	Energy Offer Curve Caps for Make-Whole Calculations for Resource Type Other	4/29/15	8/11/15	2/10/16
764	QSE Capacity Short Calculations Based on an 80% Probability of Exceedance (P80)	3/30/16	6/14/16	3/9/17
775	Enhanced Implementation of Limits for Fast Responding Regulation Service	5/13/16	10/11/16	Pending
785	Synchronizing WGR and PVGR COPs with Short Term Wind and PhotoVoltaic Forecasts	6/8/16	10/11/16	Pending

Appendix B: System Change Request Implementation Dates

The table below is all approved System Change Requests deemed relevant to this report because of their possible effect on ancillary service requirements or performance [48]. The implementation dates were acquired via a search in the archive of the market notice email distribution list [47].

SCR #	Title	Date Posted	Approved	Implemented
754	Replace Email Delivery of WGRPP Forecasts (formerly "WGRPP Forecasts Posted on Zonal TML")	12/23/08	4/22/09	6/24/09
768	Automatic Non-Spin Redeployment and Deployment Based on Resource Availability	11/2/11	4/17/12	2/14/13
773	Addition of Regulation Feedback to Generation to be Dispatched Calculation	1/30/13	3/19/13	5/23/13
788	Addition of Integral ACE Feedback to GTBD Calculation	2/1/16	6/14/16	12/6/16
790	Wind Resource Power Production and Forecast Transparency	3/10/16	6/14/16	5/11/17

Appendix C: Wind Generation Resources Start Dates

The following table has the capacity values and dates used to consider when ERCOT wind units were energized to the grid [1]. West-North in the report contains Panhandle as well

Resource Name	Region	Resource Capacity	Part 2 Approval Date	Out Service Date
KUNITZ_WIND_NWP	WEST-NORTH	29	9/1/95	9/4/14
SGMTN_SIGNALMT	WEST-NORTH	28	5/27/99	
SW_MESA_SW_MESA	WEST-NORTH	80	6/1/99	
INDNNWP_INDNNWP	WEST-NORTH	83	6/1/01	
TRENT_TRENT	WEST-NORTH	150	7/9/01	
WOODWRD1_WOODWRD1	WEST-NORTH	83	7/31/01	
WOODWRD2_WOODWRD2	WEST-NORTH	77	7/31/01	
KING_NE_KINGNE	WEST-NORTH	79	8/11/01	
KING_SW_KINGSW	WEST-NORTH	79	8/12/01	
KING_NW_KINGNW	WEST-NORTH	79	9/21/01	
KING_SE_KINGSE	WEST-NORTH	40	12/1/01	
INDNENR_INDNENR	WEST-NORTH	84	1/1/02	
INDNENR_INDNENR_2	WEST-NORTH	77	1/1/02	
SWEETWND_WND1	WEST-NORTH	37	11/20/03	
BRAZ_WND_WND1	WEST-NORTH	99	12/24/03	
BRAZ_WND_WND2	WEST-NORTH	61	12/24/03	
SWEETWN2_WND2	WEST-NORTH	105	11/22/04	
SWEETWN2_WND24	WEST-NORTH	18	11/22/04	
CALLAHAN_WND1	WEST-NORTH	114	12/15/04	
RDCANYON_RDCNY1	WEST-NORTH	84	4/15/06	
BUFF_GAP_UNIT1	WEST-NORTH	121	4/21/06	
BUFF_GAP_UNIT3	WEST-NORTH	170	4/21/06	
HHOLLOW3_WND_1	WEST-NORTH	224	6/1/06	
HHOLLOW4_WND1	WEST-NORTH	115	6/1/06	
MCDLD_FCW1	WEST-NORTH	124	11/1/06	
MCDLD_SBW1	WEST-NORTH	90	11/1/06	
LNCRK_G83	WEST-NORTH	200	11/21/06	

SWEETWN4_WND4A	WEST-NORTH	118	3/21/07	
SWEETWN4_WND4B	WEST-NORTH	104	3/21/07	
SWEETWN4_WND5	WEST-NORTH	79	3/21/07	
CSEC_CSECG1	WEST-NORTH	131	5/26/07	
CSEC_CSECG2	WEST-NORTH	120	5/26/07	
BUFF_GAP_UNIT2_1	WEST-NORTH	116	7/1/07	
BUFF_GAP_UNIT2_2	WEST-NORTH	117	7/1/07	
CAPRIDGE_CR1	WEST-NORTH	215	8/1/07	
CAPRIDGE_CR2	WEST-NORTH	150	8/1/07	
CAPRIDGE_CR3	WEST-NORTH	186	8/1/07	
LNCRK2_G871	WEST-NORTH	100	9/15/07	
LNCRK2_G872	WEST-NORTH	100	9/15/07	
ENAS_ENA1	WEST-NORTH	63	10/31/07	
WEC_WECG1	PANHANDLE	57	11/9/07	
BRTSW_BCW1	WEST-NORTH	120	12/1/07	
TKWSW1_ROSCOE	WEST-NORTH	209	1/22/08	
SWEC_G1	WEST-NORTH	120	2/1/08	
GOAT_GOATWIN2	WEST-NORTH	70	2/21/08	
GOAT_GOATWIND	WEST-NORTH	80	2/21/08	
CAPRIDG4_CR4	WEST-NORTH	113	4/15/08	
FLTCK_SSI	WEST-NORTH	60	5/21/08	
PC_NORTH_PANTHER1	WEST-NORTH	143	7/18/08	
OWF_OWF	WEST-NORTH	59	8/1/08	
MWEC_G1	PANHANDLE	150	8/4/08	
KEO_KEO_SM1	WEST-NORTH	150	9/11/08	
WHTTAIL_WR1	WEST-NORTH	113	10/2/08	
STWF_T1	WEST-NORTH	98	10/17/08	
TTWEC_G1	WEST-NORTH	170	11/5/08	
ELB_ELBCREEK	WEST-NORTH	119	11/21/08	
TGW_T1	SOUTH-COASTAL	142	11/24/08	
TGW_T2	SOUTH-COASTAL	142	11/24/08	
PC_SOUTH_PANTHER2	WEST-NORTH	116	12/12/08	
INDL_INADALE1	WEST-NORTH	197	12/18/08	
NWF_NWF1	WEST-NORTH	93	12/19/08	
NWF_NWF2	WEST-NORTH	60	12/19/08	
HWF_HWFG1	WEST-NORTH	164	12/21/08	

PYR_PYRON1	WEST-NORTH	249	12/27/08	
PENA_UNIT1	SOUTH-COASTAL	161	4/22/09	
PENA_UNIT2	SOUTH-COASTAL	142	4/22/09	
BULLCRK_WND1	WEST-NORTH	88	5/14/09	
BULLCRK_WND2	WEST-NORTH	90	5/14/09	
PC_SOUTH_PANTHER3	WEST-NORTH	200	7/9/09	
PAP1_PAP1	SOUTH-COASTAL	180	9/4/09	
HHGT_HHOLLOW1	WEST-NORTH	213	10/15/09	
HHGT_HHOLLOW2	WEST-NORTH	184	10/15/09	
LONEWOLF_G1	WEST-NORTH	50	10/15/09	
LONEWOLF_G2	WEST-NORTH	51	10/15/09	
LGD_LANGFORD	WEST-NORTH	155	10/31/09	
COTTON_PAP2	SOUTH-COASTAL	200	6/1/10	
CHAMPION_UNIT1	WEST-NORTH	127	8/2/10	
CEDROHIL_CHW1	SOUTH-COASTAL	75	11/23/10	
CEDROHIL_CHW2	SOUTH-COASTAL	75	11/23/10	
LONEWOLF_G3	WEST-NORTH	26	2/1/11	
LONEWOLF_G4	WEST-NORTH	24	2/1/11	
PENA3_UNIT3	SOUTH-COASTAL	101	8/2/11	
SWEETWN3_WND3A	WEST-NORTH	29	8/2/11	
SWEETWN3_WND3B	WEST-NORTH	101	8/2/11	
TRINITY_TH1_BUS1	WEST-NORTH	118	12/1/11	
TRINITY_TH1_BUS2	WEST-NORTH	108	12/1/11	
KEO_SHRBINO2	WEST-NORTH	145	12/21/11	
EXGNWTL_WIND_1	SOUTH-COASTAL	90	9/11/12	
REDFISH_MV1A	SOUTH-COASTAL	100	9/18/12	
REDFISH_MV1B	SOUTH-COASTAL	104	9/18/12	
ANACACHO_ANA	SOUTH-COASTAL	100	12/1/12	
SENATEWD_UNIT1	WEST-NORTH	150	12/1/12	
LV1_LV1B	SOUTH-COASTAL	202	12/4/12	

LV1_LV1A	SOUTH-COASTAL	200	12/10/12	
BCATWIND_WIND_1	WEST-NORTH	150	12/19/12	
BLSUMMIT_BLSMT1_5	WEST-NORTH	9	12/31/12	
BLSUMMIT_BLSMT1_6	WEST-NORTH	126	12/31/12	
MOZART_WIND_1	WEST-NORTH	30	12/31/12	
GWEC_GWEC_G1	WEST-NORTH	149	12/31/13	
SSPURTWO_WIND_1	PANHANDLE	161	6/1/14	
PH1_UNIT1	PANHANDLE	109	7/30/14	
PH1_UNIT2	PANHANDLE	109	7/30/14	
MIAM1_G1	PANHANDLE	144	7/31/14	
MIAM1_G2	PANHANDLE	144	7/31/14	
GRANDVW1_GV1A	PANHANDLE	107	10/7/14	
GRANDVW1_GV1B	PANHANDLE	104	10/7/14	
PH2_UNIT1	PANHANDLE	94	10/7/14	
PH2_UNIT2	PANHANDLE	97	10/7/14	
WNDTHST2_UNIT1	WEST-NORTH	68	10/7/14	
SGMTN_SIGNALM2	WEST-NORTH	7	10/15/14	
HRFDWIND_WIND_G	PANHANDLE	100	10/23/14	
HRFDWIND_WIND_V	PANHANDLE	100	10/23/14	
SRWE1_UNIT1	WEST-NORTH	211	11/3/14	
KEECHI_U1	WEST-NORTH	110	11/17/14	
LHORN_N_UNIT1	PANHANDLE	100	1/19/15	
LHORN_N_UNIT2	PANHANDLE	100	1/19/15	
GPASTURE_WIND_I	WEST-NORTH	150	1/27/15	
LV3_UNIT_1	SOUTH-COASTAL	200	1/30/15	
MESQCRK_WND1	WEST-NORTH	106	1/30/15	
MESQCRK_WND2	WEST-NORTH	106	1/30/15	
BAFFIN_UNIT1	SOUTH-COASTAL	100	2/27/15	
BAFFIN_UNIT2	SOUTH-COASTAL	102	2/27/15	
HRFDWIND_JRDWIND1	PANHANDLE	146	2/27/15	
HRFDWIND_JRDWIND2	PANHANDLE	154	2/27/15	
SRWE1_SRWE2	WEST-NORTH	165	4/17/15	
ROUTE_66_WIND1	PANHANDLE	150	4/29/15	
LGW_UNIT1	WEST-NORTH	104	5/27/15	
LGW_UNIT2	WEST-NORTH	106	5/27/15	

RSNAKE_G1	WEST-NORTH	104	6/10/15	
RSNAKE_G2	WEST-NORTH	103	6/10/15	
SSPURTWO_SS3WIND1	PANHANDLE	96	9/2/15	
SSPURTWO_SS3WIND2	PANHANDLE	98	9/2/15	
SPLAIN1_WIND1	PANHANDLE	102	9/4/15	
SPLAIN1_WIND2	PANHANDLE	98	9/4/15	
BRISCOE_WIND	PANHANDLE	150	10/2/15	
SHANNONW_UNIT_1	WEST-NORTH	204	10/14/15	
BORDAS_JAVEL18	SOUTH-COASTAL	20	10/28/15	
BORDAS_JAVEL20	SOUTH-COASTAL	230	10/28/15	
CAMWIND_UNIT1	SOUTH-COASTAL	165	10/31/15	
EXGNSND_WIND_1	SOUTH-COASTAL	76	11/13/15	
LV5_UNIT_1	SOUTH-COASTAL	110	11/26/15	
VERTIGO_WIND_I	WEST-NORTH	150	3/1/16	
SPLAIN2_WIND21	PANHANDLE	149	3/5/16	
SPLAIN2_WIND22	PANHANDLE	152	3/5/16	
GRANDVW1_COLA	PANHANDLE	100	3/15/16	
GRANDVW1_COLB	PANHANDLE	100	3/15/16	
GUNMTN_G1	WEST-NORTH	120	5/13/16	
LV4_UNIT_1	SOUTH-COASTAL	200	7/6/16	
WAKEWE_G1	PANHANDLE	115	7/12/16	
WAKEWE_G2	PANHANDLE	142	7/12/16	
SANROMAN_WIND_1	SOUTH-COASTAL	95	8/24/16	
HORSECRK_UNIT1	WEST-NORTH	131	9/29/16	
HORSECRK_UNIT2	WEST-NORTH	99	9/29/16	
MIRASOLE_MIR11	SOUTH-COASTAL	50	10/13/16	
MIRASOLE_MIR12	SOUTH-COASTAL	100	10/13/16	
MIRASOLE_MIR21	SOUTH-COASTAL	100	10/13/16	
MARIAH_NORTE1	PANHANDLE	115	10/14/16	
MARIAH_NORTE2	PANHANDLE	115	10/14/16	
DIGBY_UNIT1	WEST-NORTH	99	10/17/16	

DIGBY_UNIT2	WEST-NORTH	131	10/17/16	
BORDAS2_JAVEL2_A	SOUTH-COASTAL	96	10/27/16	
BORDAS2_JAVEL2_B	SOUTH-COASTAL	74	10/27/16	
BORDAS2_JAVEL2_C	SOUTH-COASTAL	30	10/27/16	
SALTFORK_UNIT1	PANHANDLE	64	11/7/16	
SALTFORK_UNIT2	PANHANDLE	110	11/7/16	
TYLRWIND_UNIT1	WEST-NORTH	126	11/7/16	

Appendix D: Thermal Generation Data

The table below has the underlying data used to calculate the thermal generation in each year from 2007 through 2016. Capacity, Demand and Reserves report provides a tab that lists all of the different fuel types for each corresponding year of the report [Sources 14 through 30]. Based on the first year of the report, different values were subtracted from the fuel types with the assumption that the generation reported in the summer capacities tab was not in service at the time. After the Nodal market, ERCOT provided SCED data 60 days after the operating day [39]. Through that data, the date that a new unit came online, was captured in the highlighted rows below. From those start dates, the calculated thermal generation would take the CDR capacity of that unit into account.

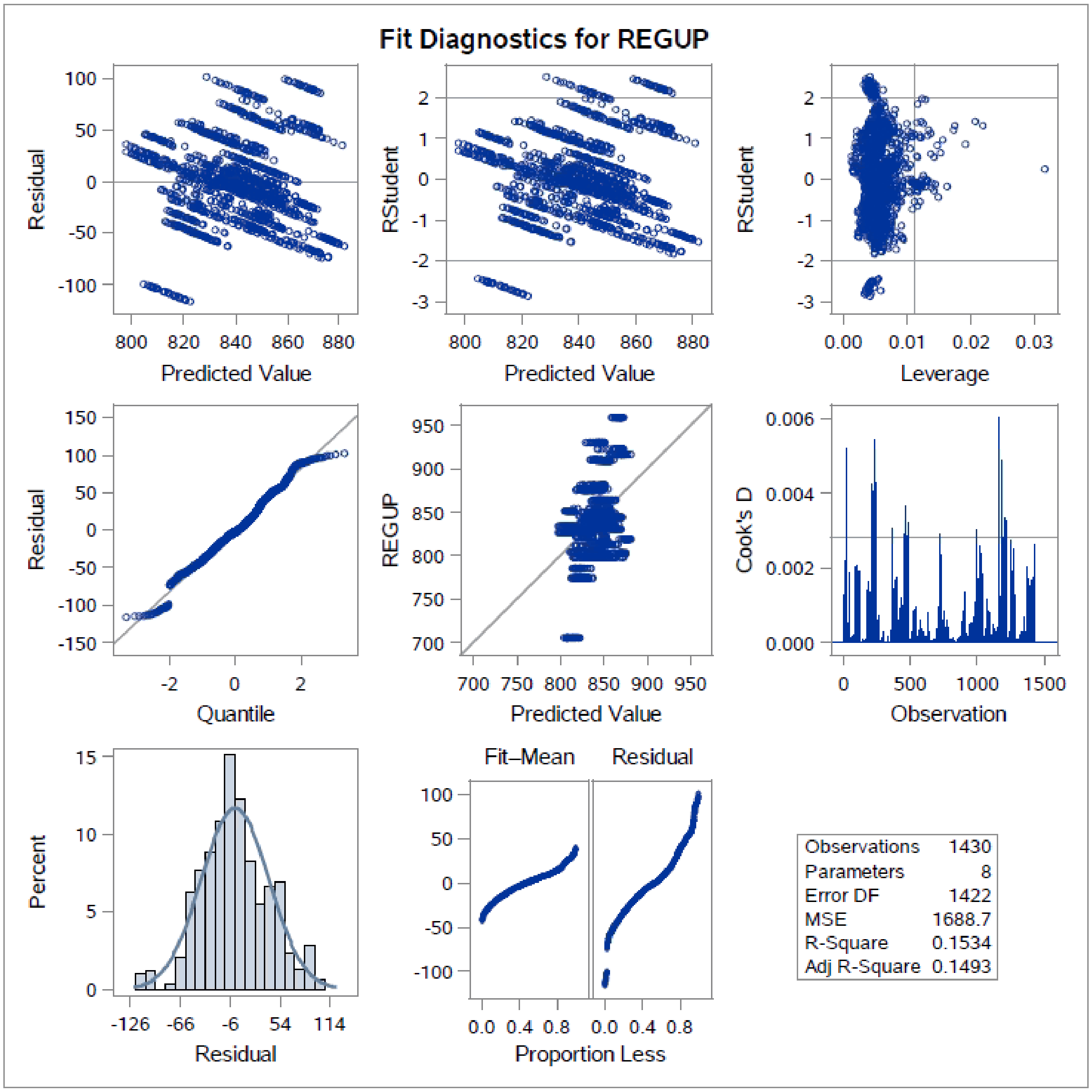
CDR Date/ Start Date	CDR/Resource	Gas	Coal	Mothball	Signed IA not in service	Potential Non-Wind	CDR Gen	Gen in CDR	Delta	Thermal Gen
8/17/06	August 2006 CDR	55,496	15,729	8,833			62,392			62,392
5/17/07	May 2007 CDR	55,093	15,709	5,707		775	64,320			64,320
5/16/08	May 2008 CDR	50,256	15,839	4,314	851	400	60,530			60,530
8/5/09	August 2009 CDR	49,026	15,875	5,879	0	420	58,602			58,602
5/17/10	May 2010 CDR	49,908	18,767	2,478	1,832		64,365	OGSES 1, 2, Pearsal AGR A,B,C, D	-1,867	62,498
1/17/11	OGSES_UNIT1A		840						840	63,338
2/23/11	OGSES_UNIT2		825						825	64,163

CDR Date/ Start Date	CDR/Resource	Gas	Coal	Mothball	Signed IA not in service	Potential Non-Wind	CDR Gen	Gen in CDR	Delta	Thermal Gen
6/10/11	June 2011 CDR	46,943	19,034		260		65,717	Pearsal AGR A,B,C, D	-202	65,514
9/7/11	JCKCNTY2_CC1	595							595	66,109
5/22/12	May 2012 CDR	48,123	19,140		925	89	66,249	Pearsal AGR A,B,C, D	-202	66,047
6/29/12	PEARSAL2_AGR_D	51							51	66,097
6/29/12	PEARSAL2_AGR_C	51							51	66,148
7/4/12	PEARSAL2_AGR_A	51							51	66,198
7/4/12	PEARSAL2_AGR_B	51							51	66,249
12/10/12	December 2012 CDR	47,018	19,140		925		65,233			65,233
5/1/13	May 2013 CDR	49,337	19,115		2,837		65,615			65,615
5/23/13	SCES_UNIT1		970						970	66,585
2/27/14	February 2014 CDR	46,292	19,882				66,174			66,174
5/1/14	May 2014 CDR	49,451	19,219		2,112		66,557			66,557
5/11/14	FERGCC_CC1	510							510	67,067
5/17/14	PANDA_T1_CC1	702							702	67,769
5/30/14	PANDA_S_CC1	717							717	68,486
12/1/14	December 2014 CDR	48,947	19,219		294		67,872			67,872
5/1/15	May 2015 CDR	50,290	19,191		1,780		67,701			67,701
5/12/15	PANDA_T2_CC1	717							717	68,418

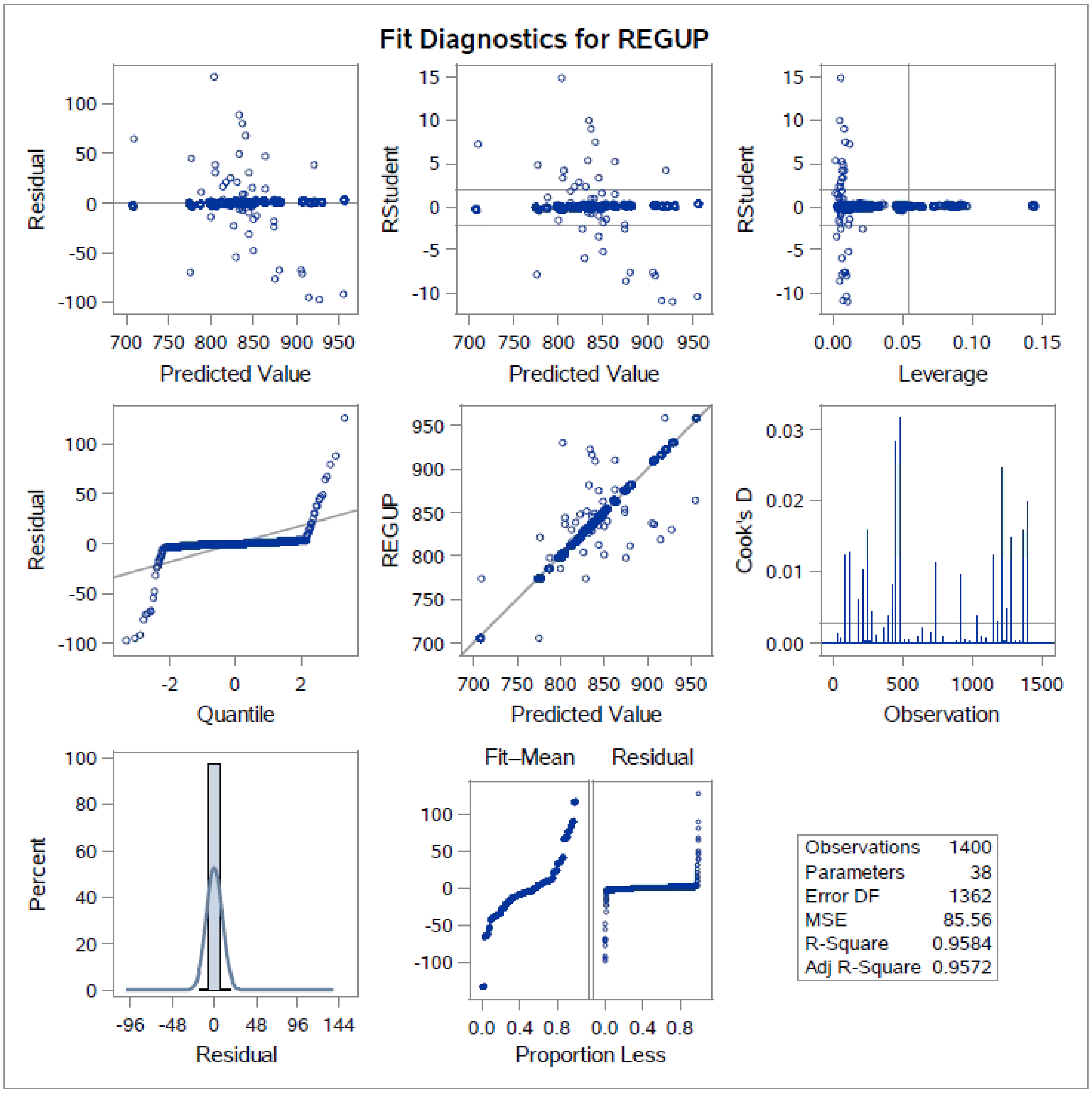
CDR Date/ Start Date	CDR/Resource	Gas	Coal	Mothball	Signed IA not in service	Potential Non-Wind	CDR Gen	Gen in CDR	Delta	Thermal Gen
9/11/15	ECEC_G1	147							147	68,565
9/12/15	ECEC_G2	147							147	68,712
12/1/15	December 2015 CDR	50,526	19,286		1,068		68,744			68,744
3/23/16	SKY1_SKY1A	27							27	68,770
3/23/16	SKY1_SKY1B	27							27	68,797
4/14/16	AEEC_ELK_1	190							190	68,987
5/3/16	May 2016 CDR	50,509	19,209		1,124		68,594		190	68,784
5/12/16	AEEC_ELK_2	190							190	68,974
5/12/16	AEEC_ELK_3	190							190	69,164
8/12/16	REDGATE_AGR_A	56							56	69,220
8/12/16	REDGATE_AGR_B	56							56	69,277
8/12/16	REDGATE_AGR_C	56							56	69,333
8/12/16	REDGATE_AGR_D	56							56	69,389
9/11/16	AEEC_ANTLP_1	55							55	69,444
9/11/16	AEEC_ANTLP_2	55							55	69,499
9/11/16	AEEC_ANTLP_3	55							55	69,553
12/15/16	December 2016 CDR	52,109	19,209		2,660		68,658			68,658

Appendix E: NPRR Regression Fits

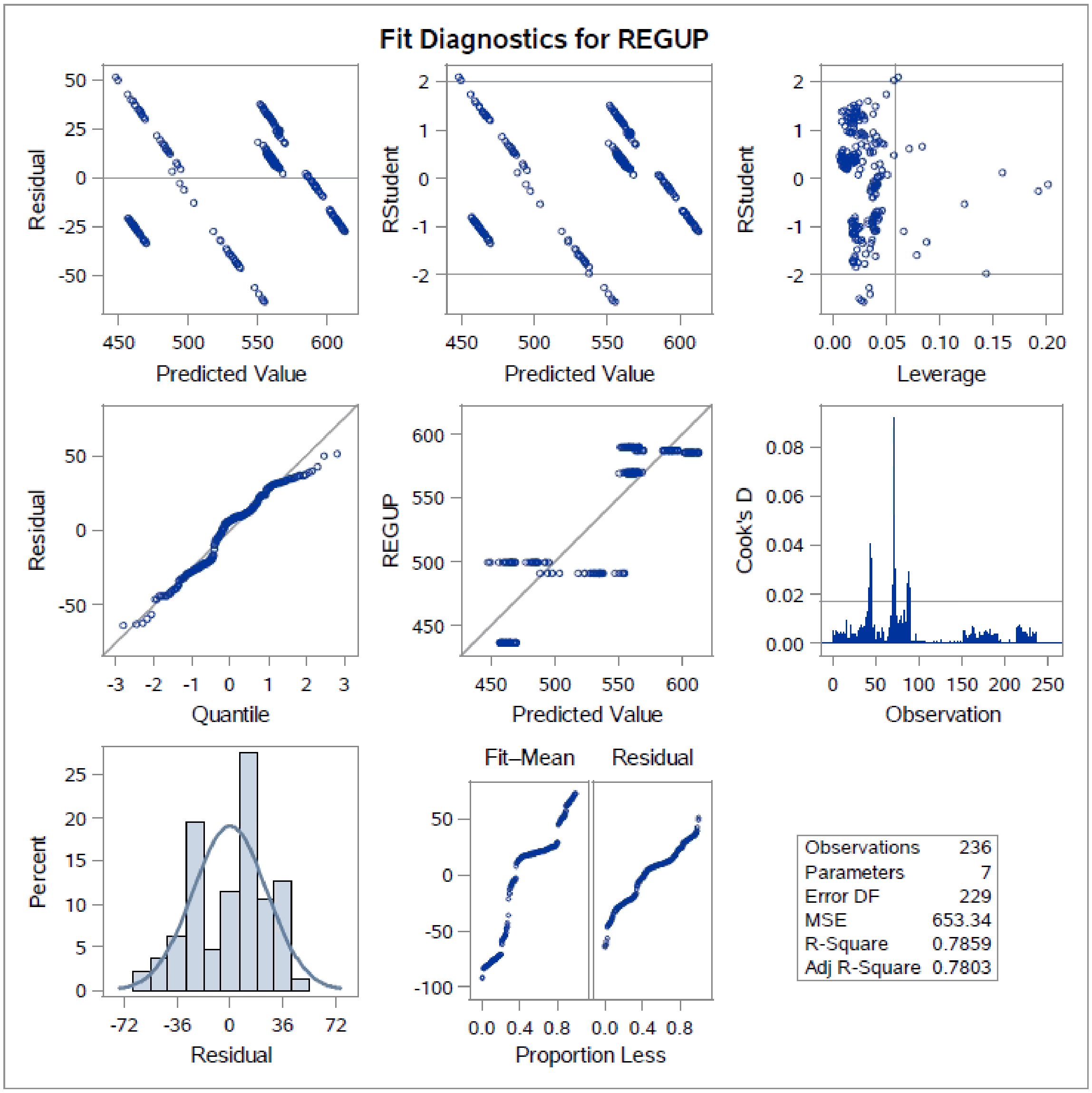
NPRR Period 1 Regulation Up



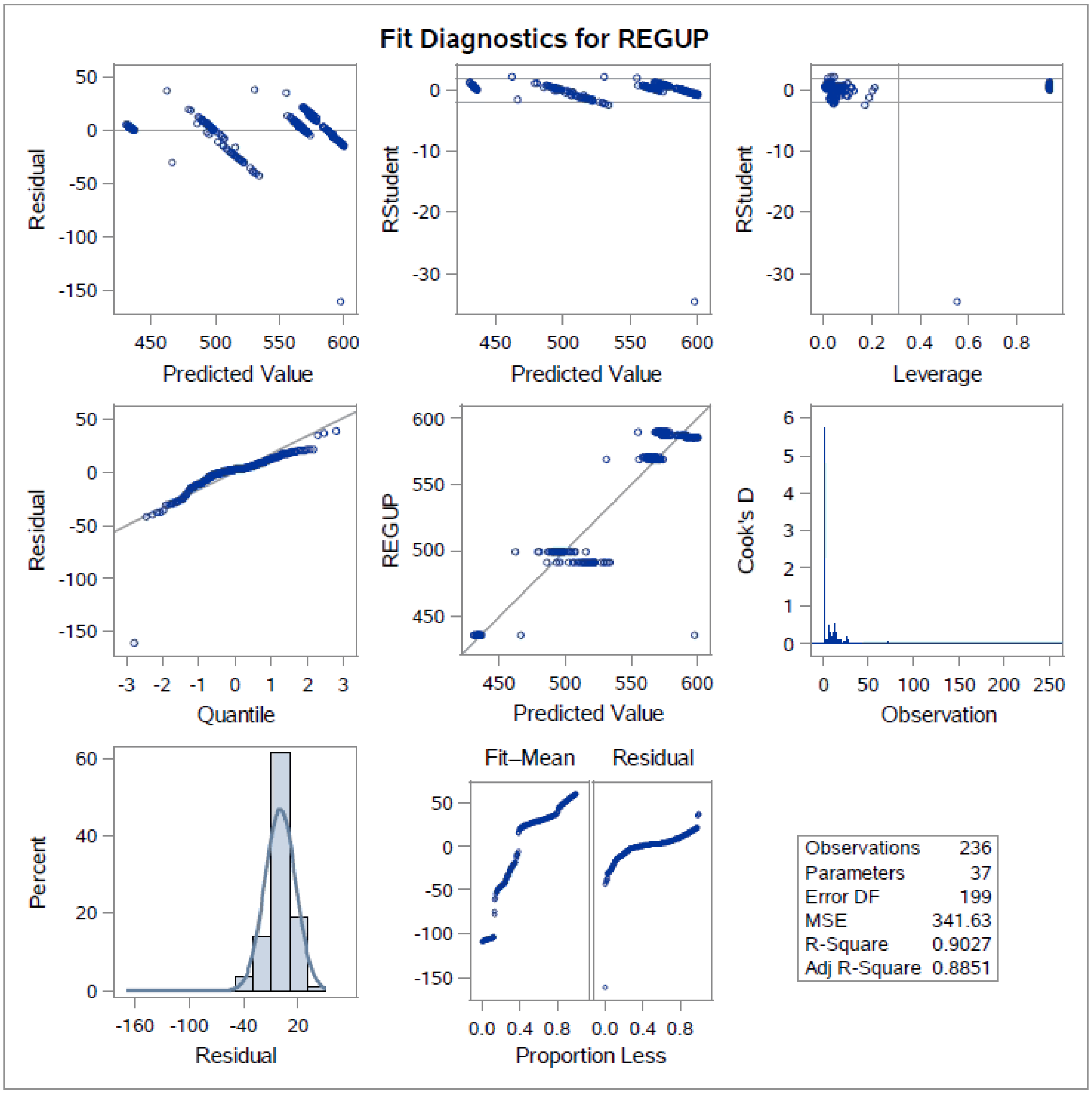
NPRR Period 1 Regulation Up with Lag



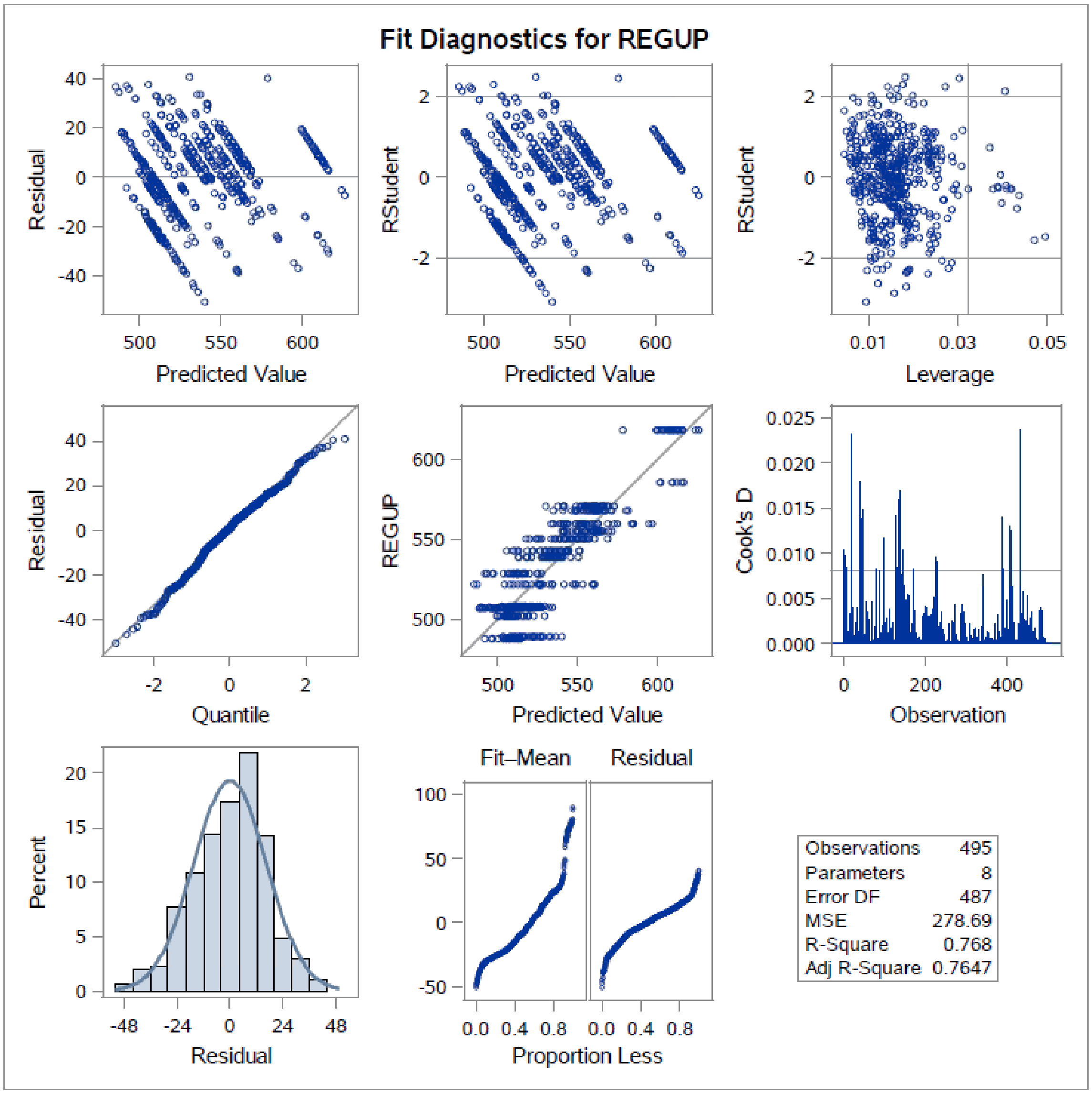
NPRR Period 2 Regulation Up



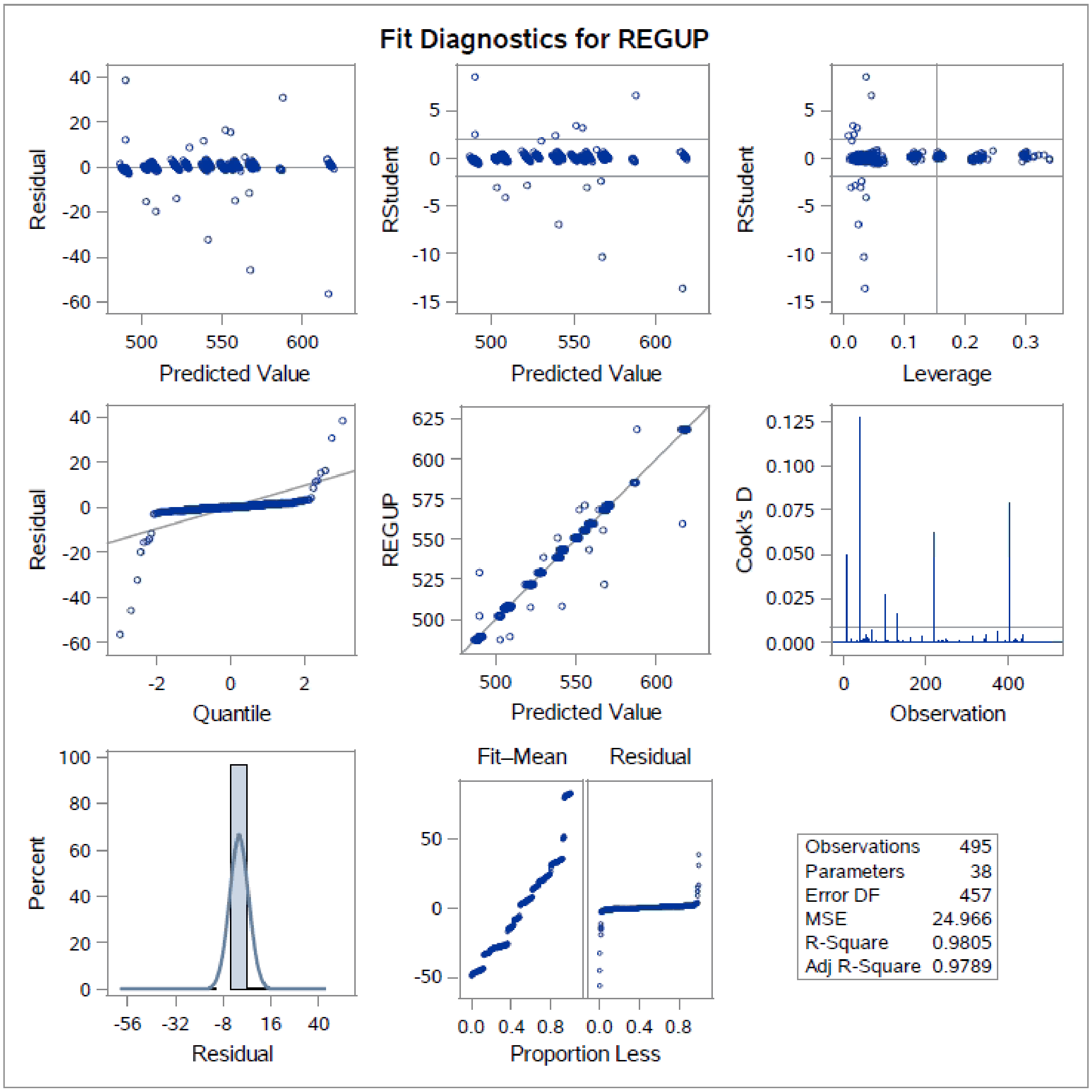
NPRR Period 2 Regulation Up With Lag



NPRR Period 3 Regulation Up



NPRR Period 3 Regulation Up With Lag



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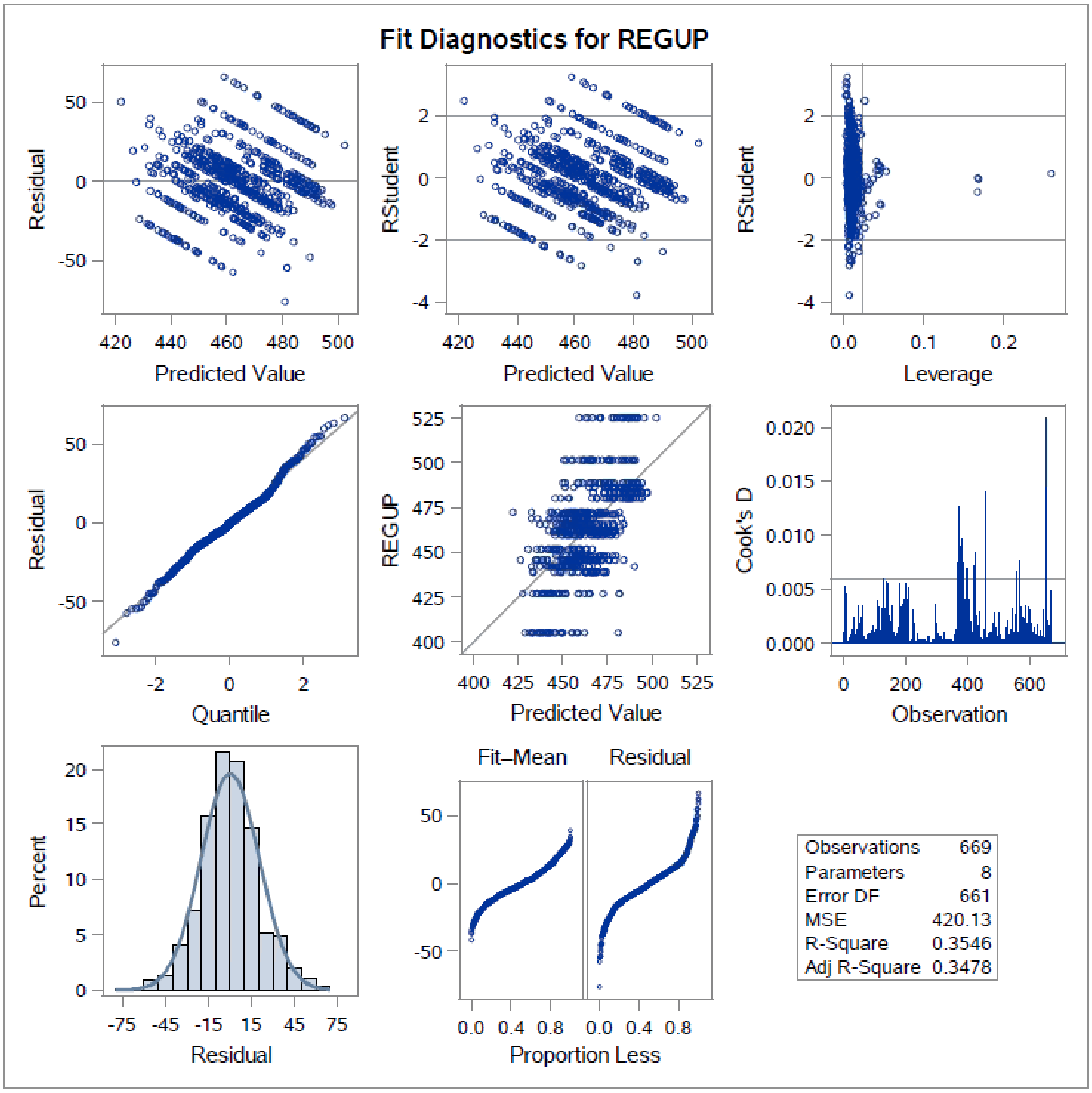

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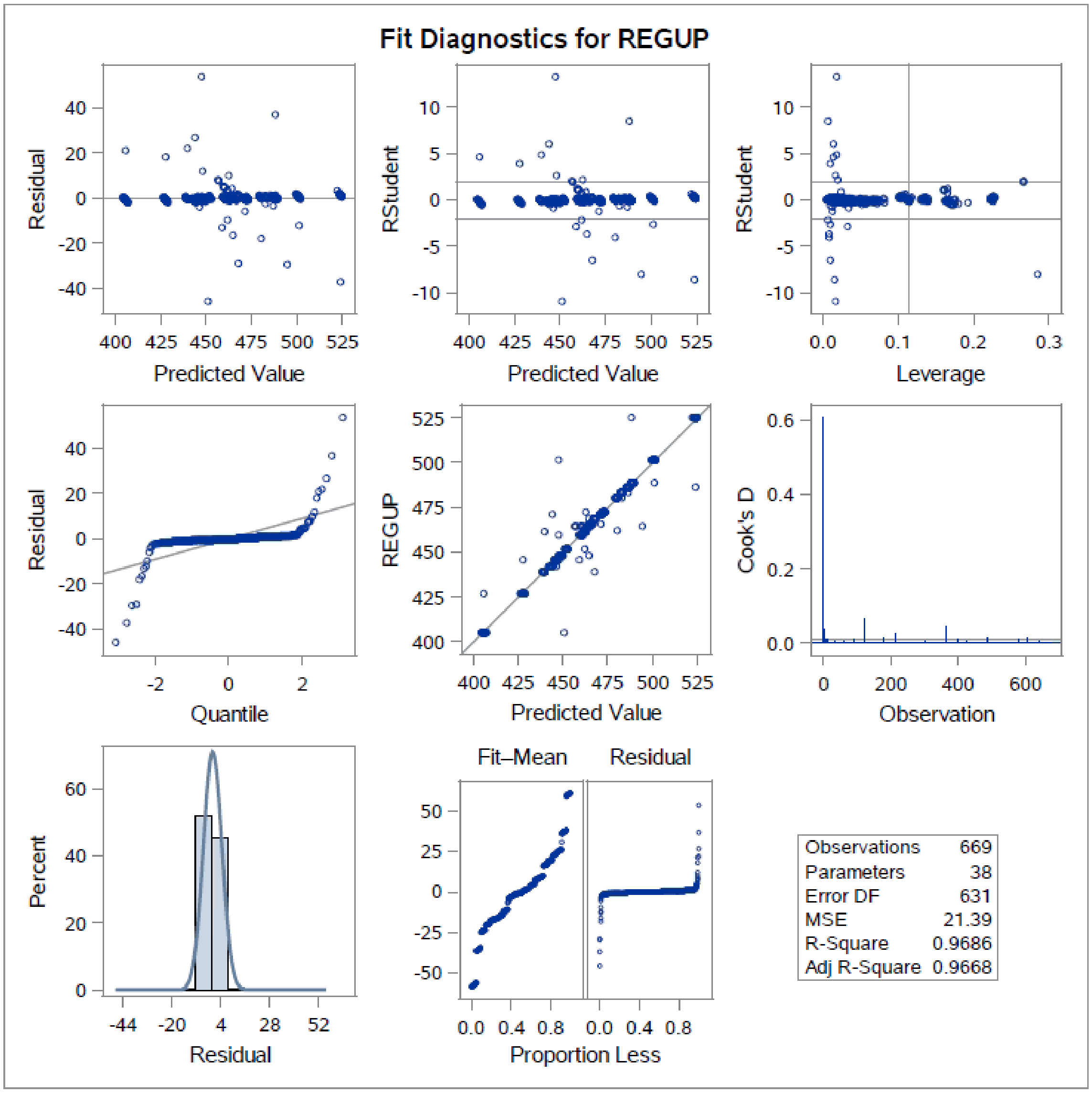

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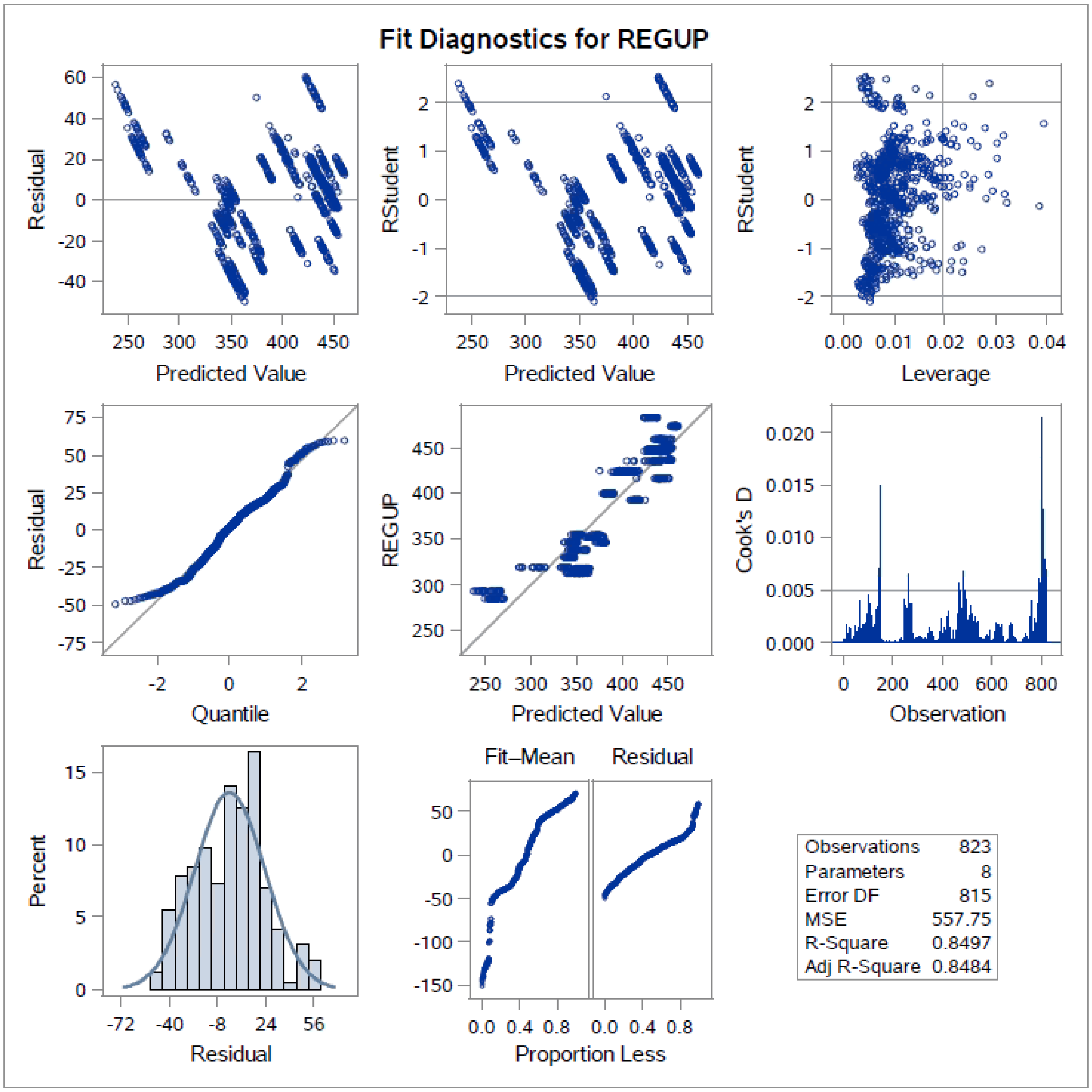
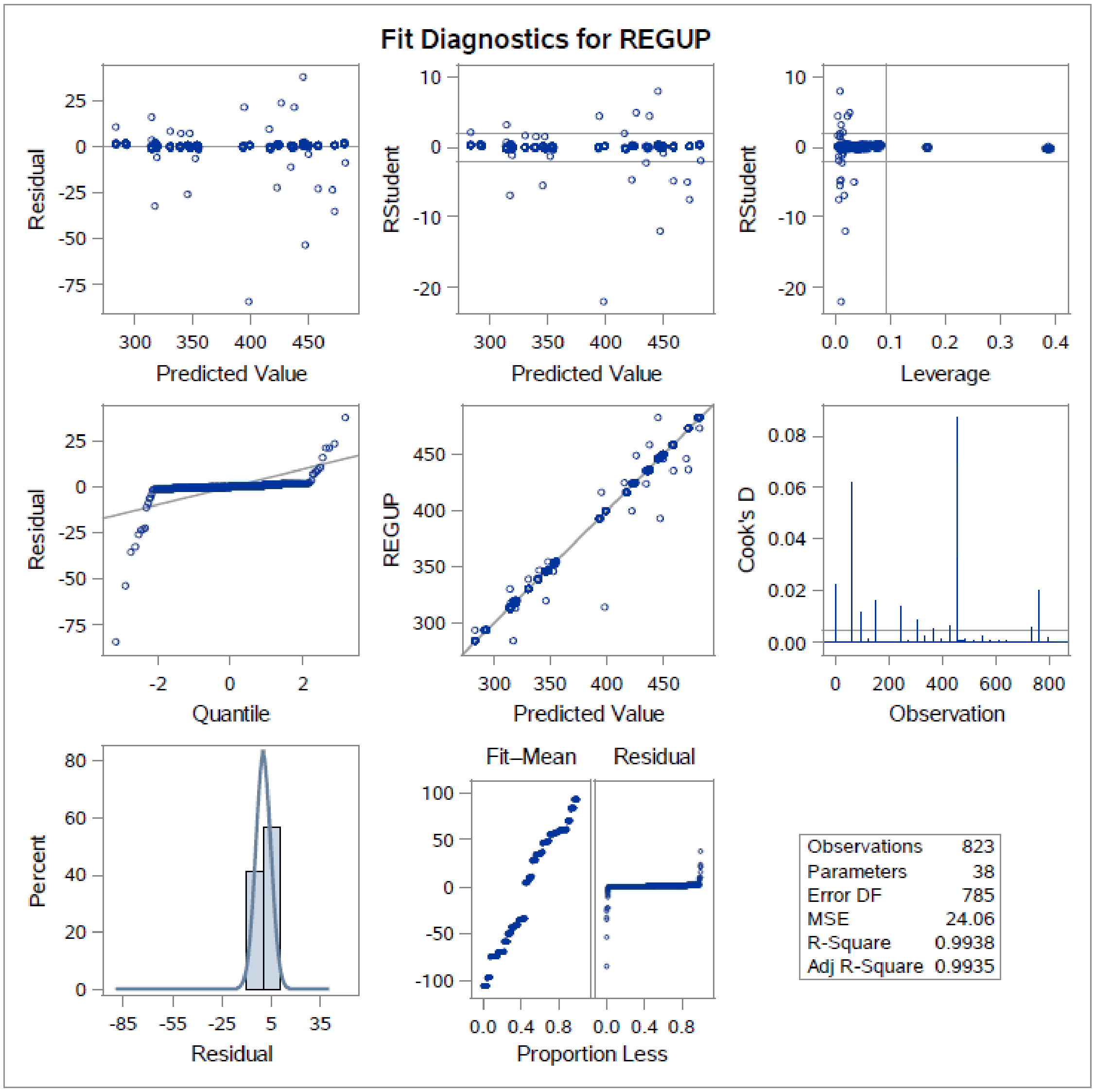


NPRR Period 5 Regulation Up with Lag



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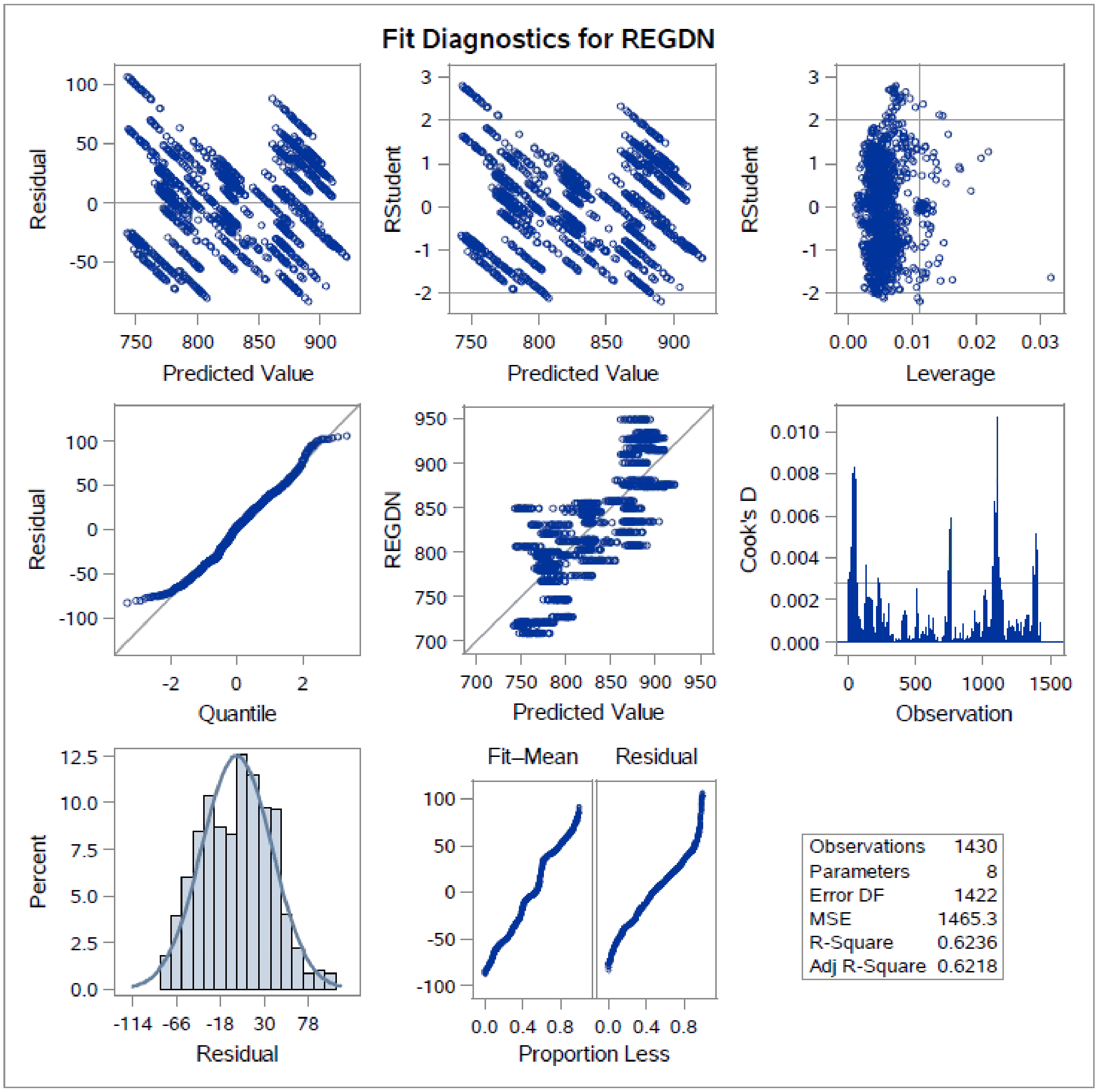

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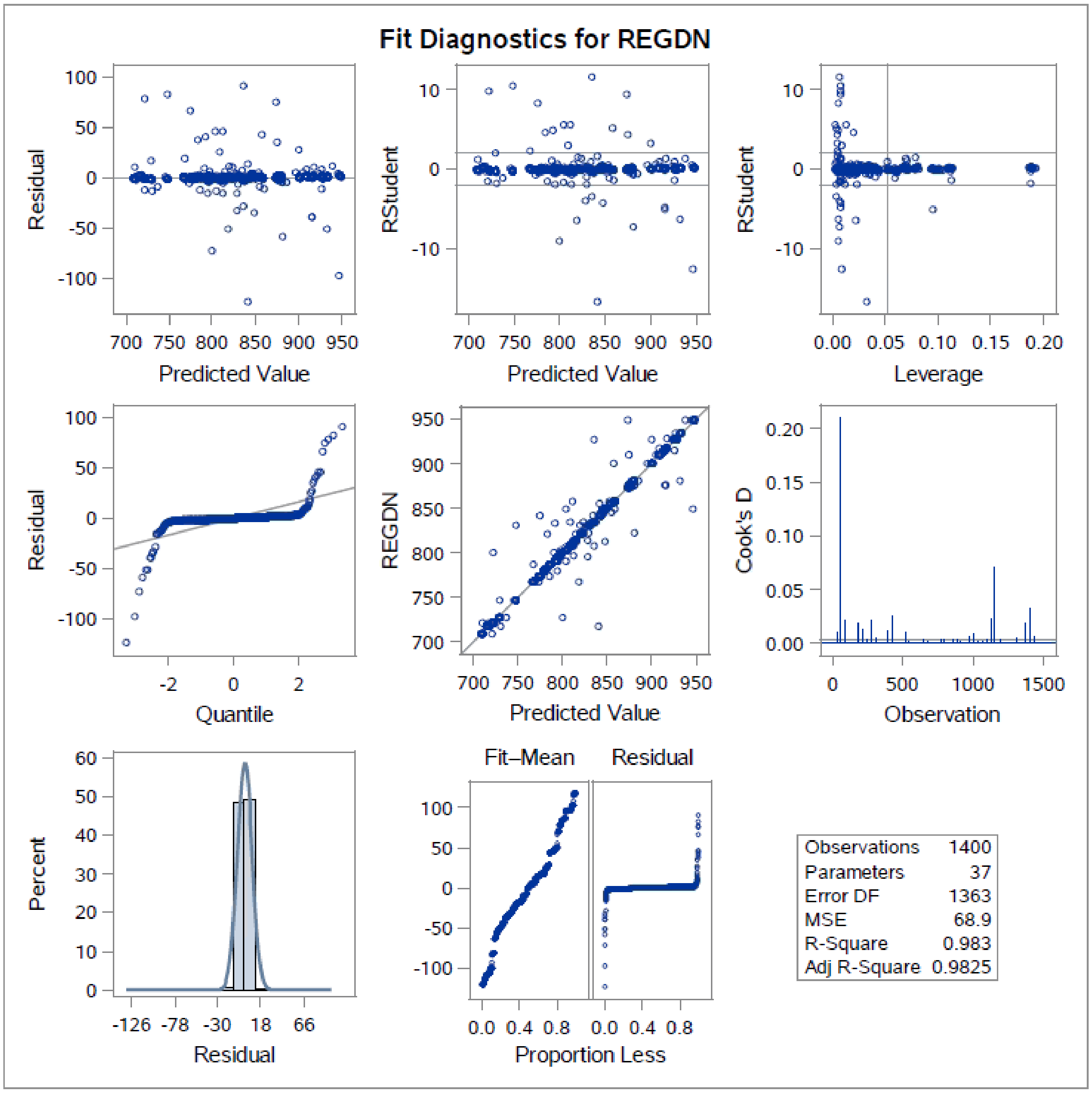

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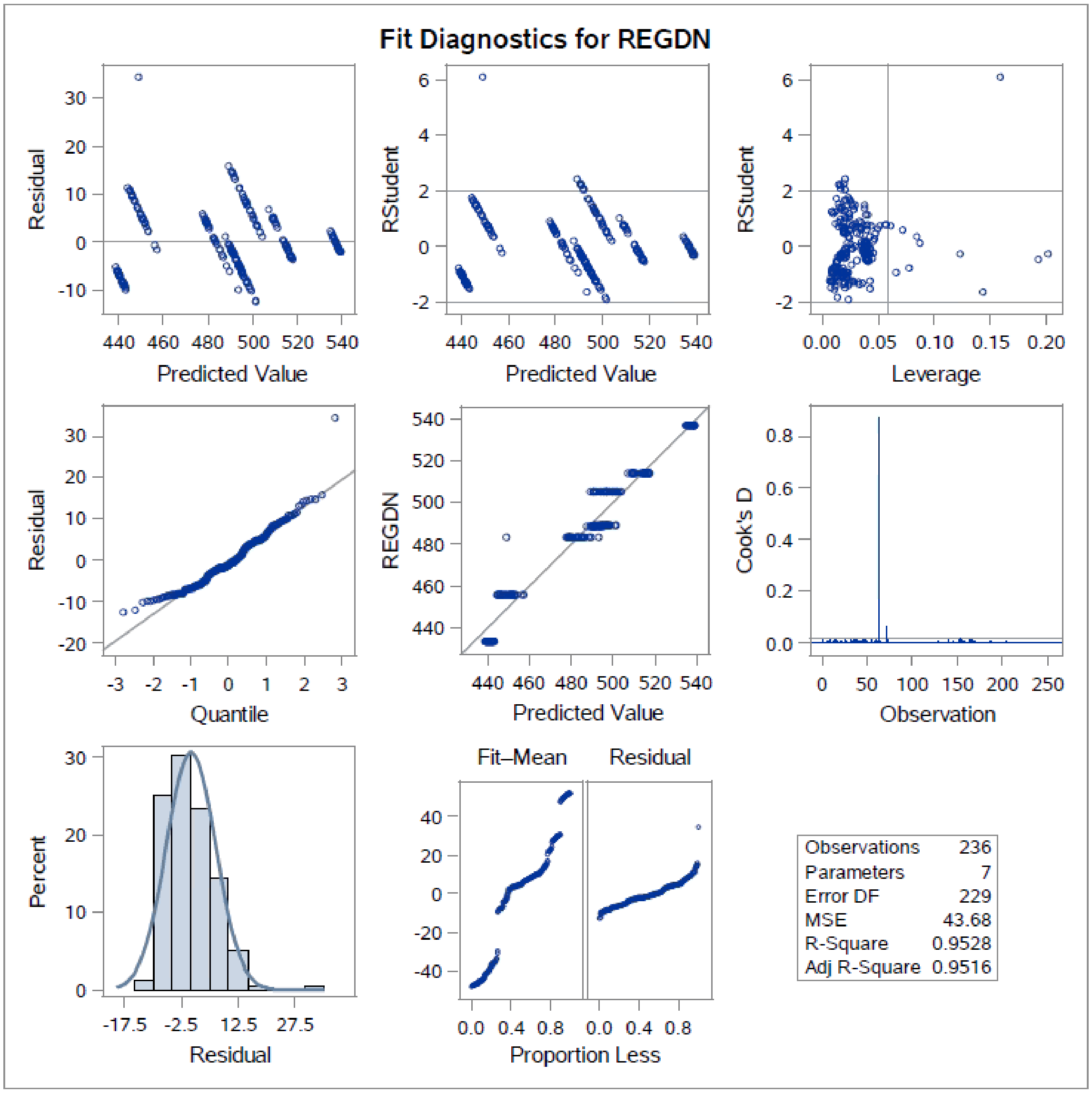

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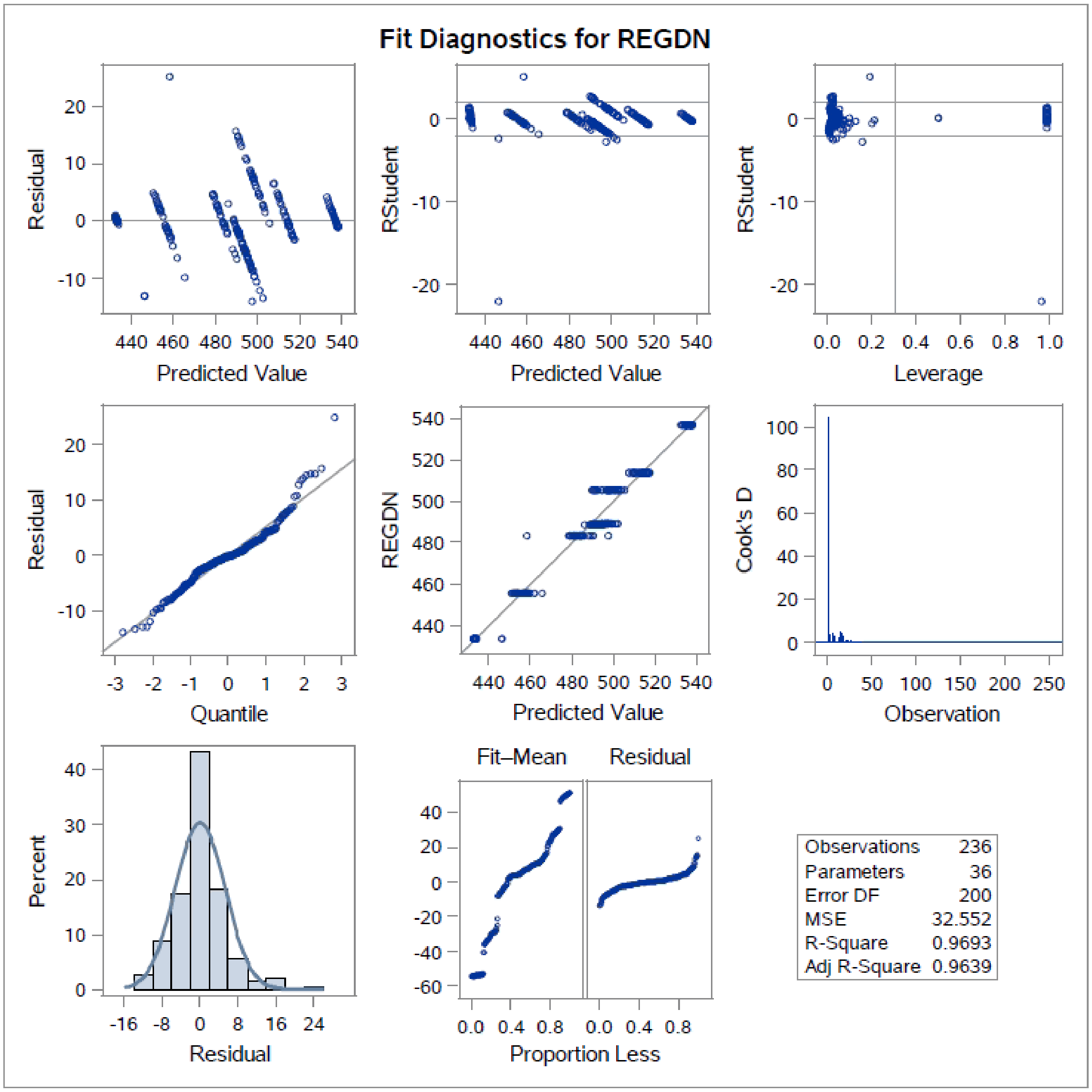

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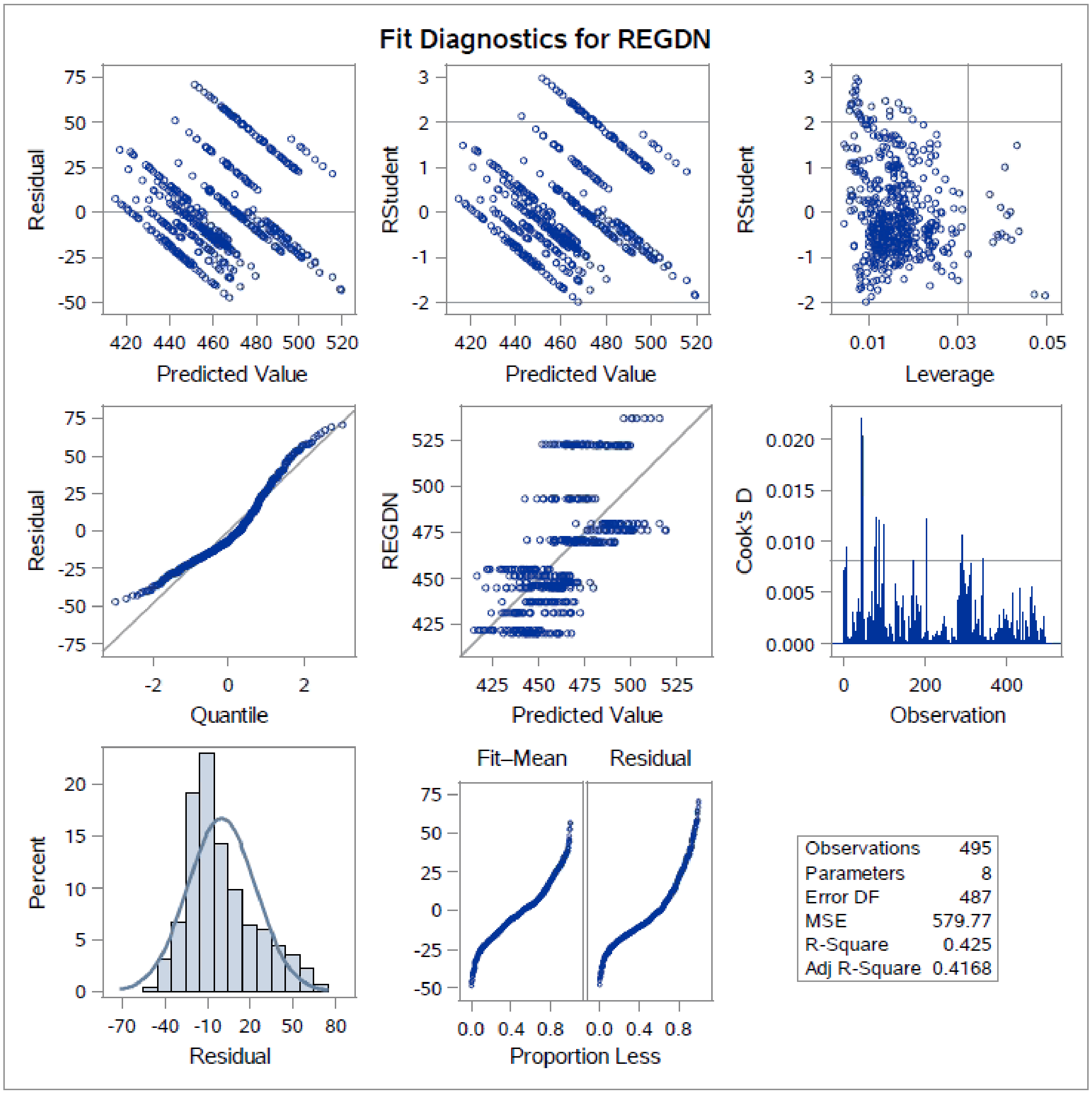

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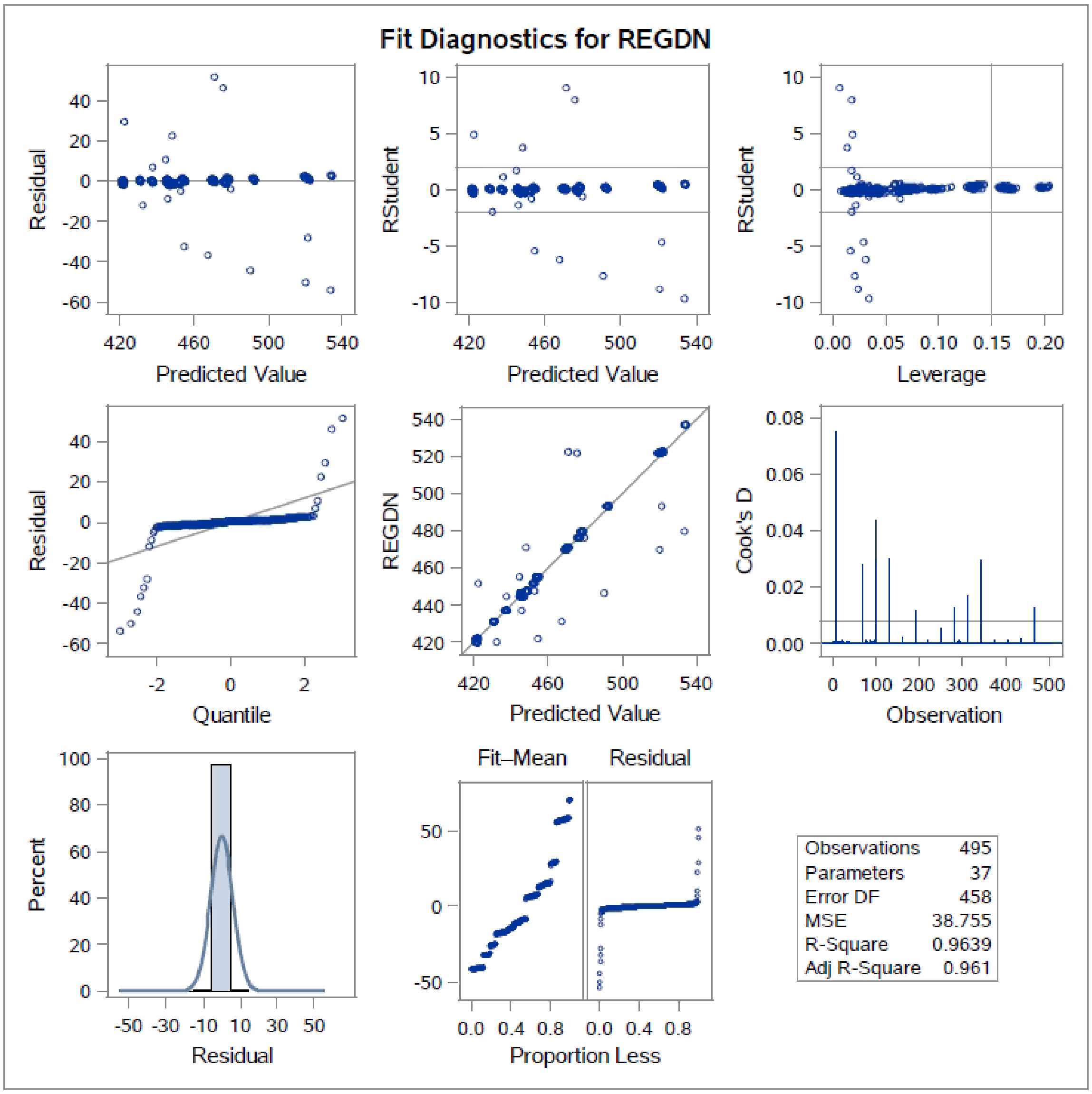

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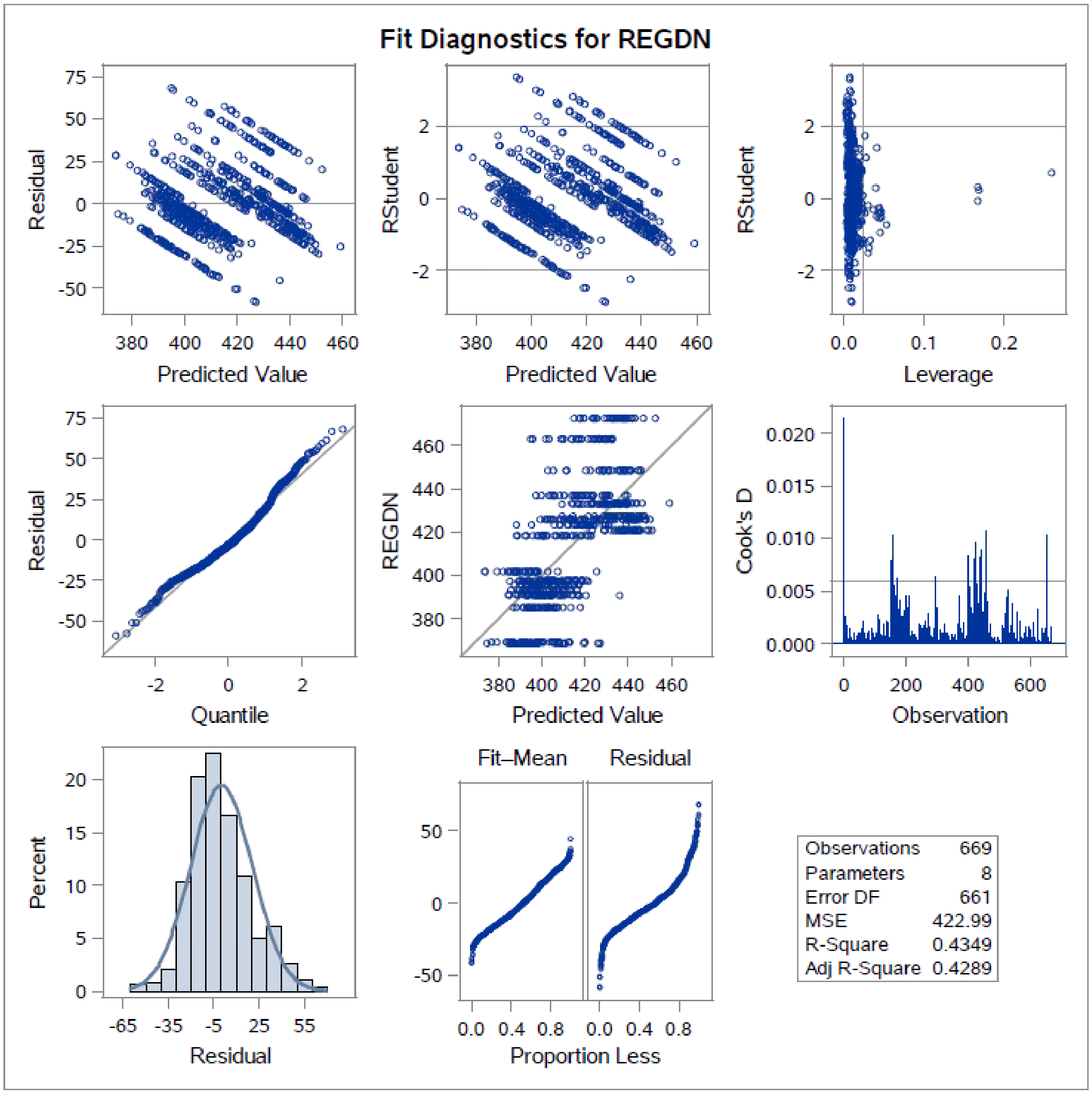

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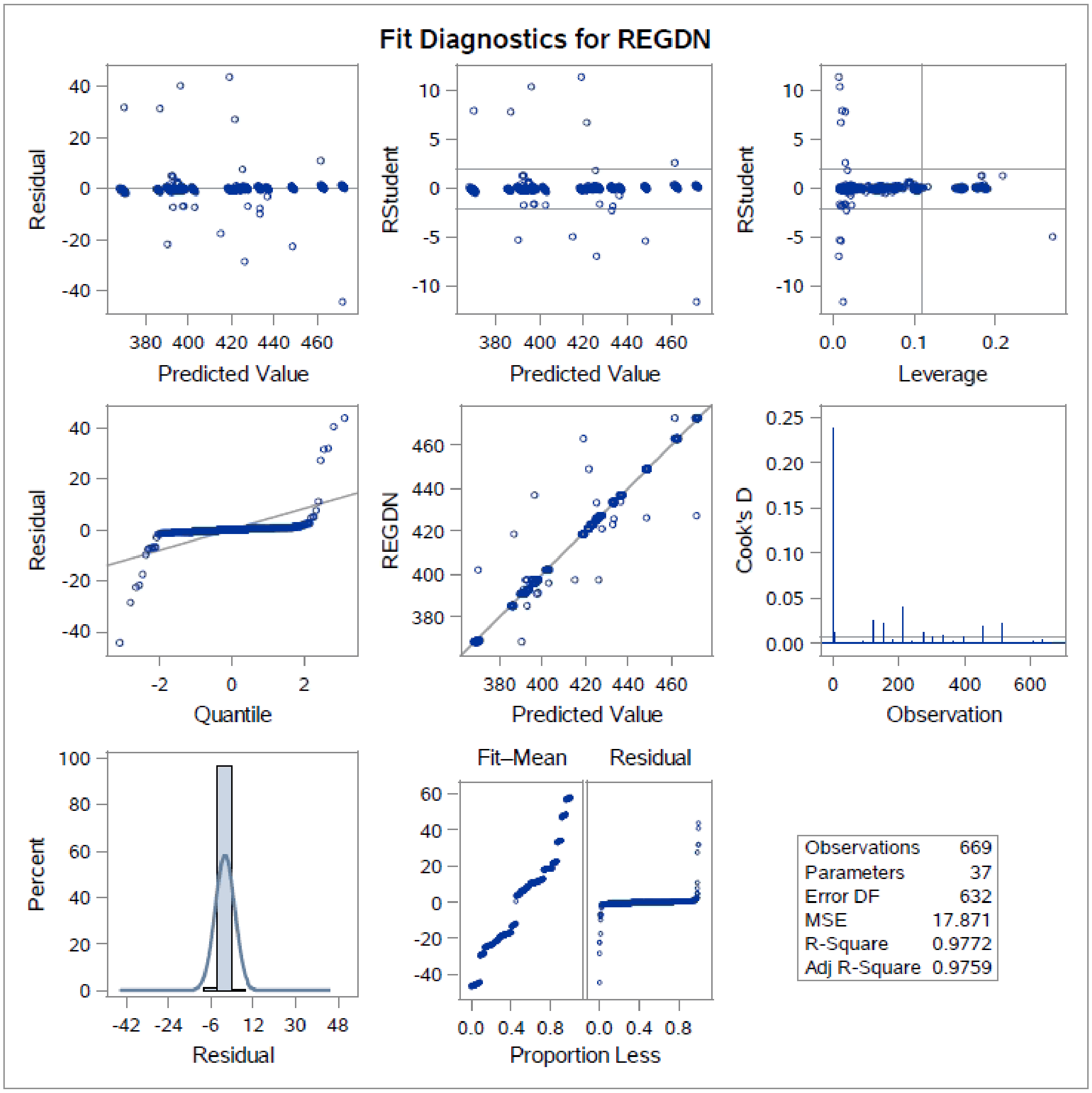

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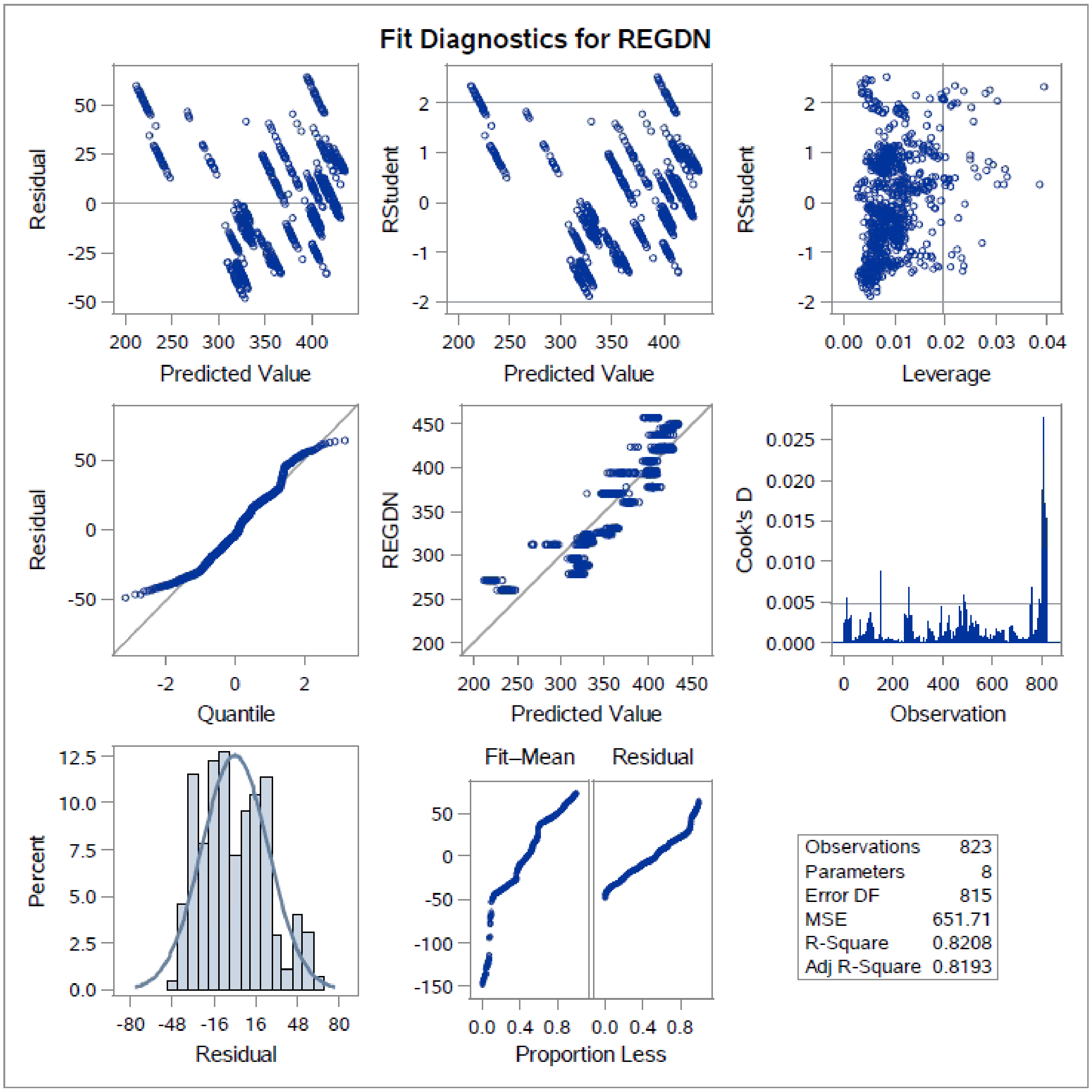

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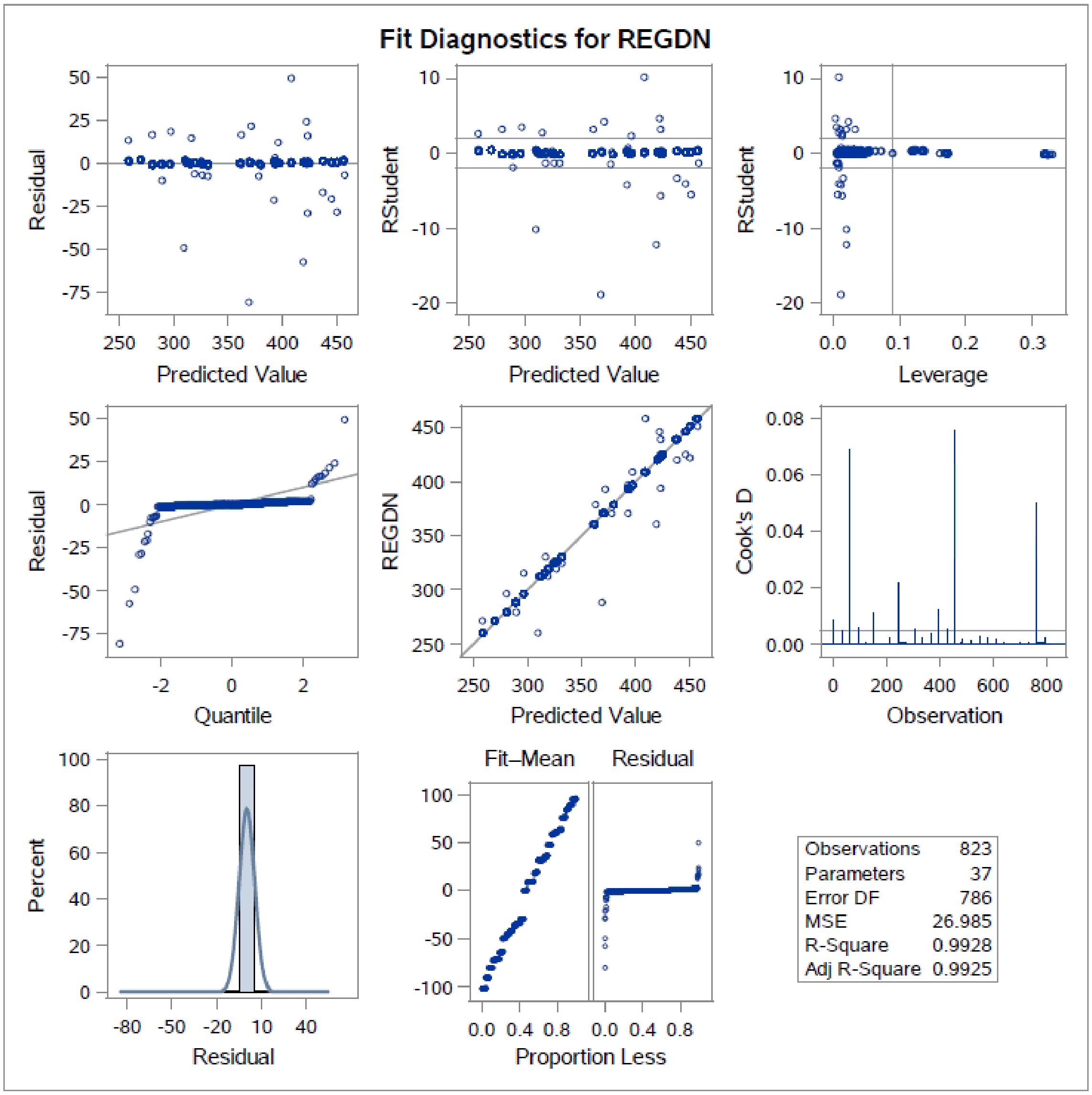
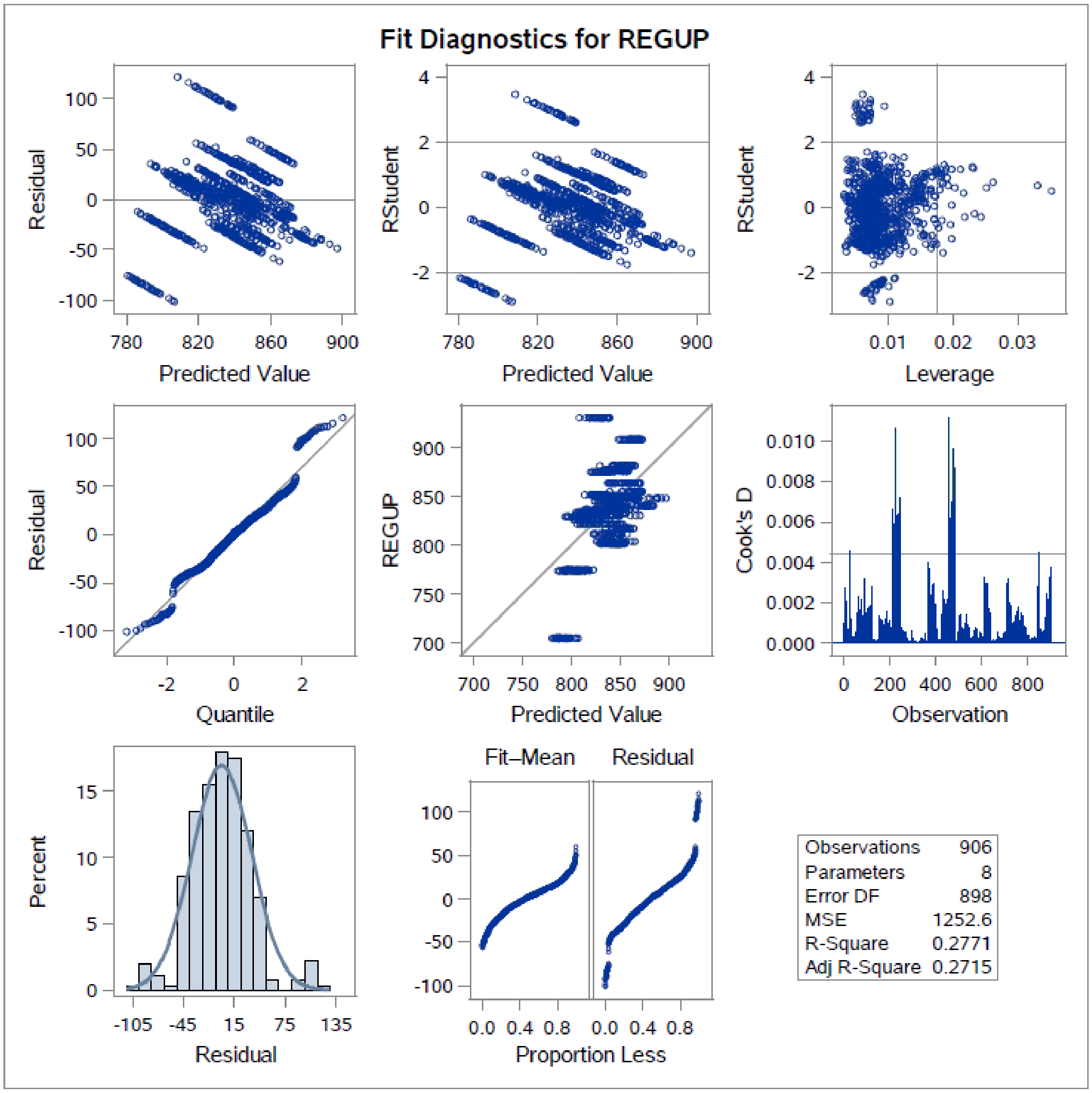


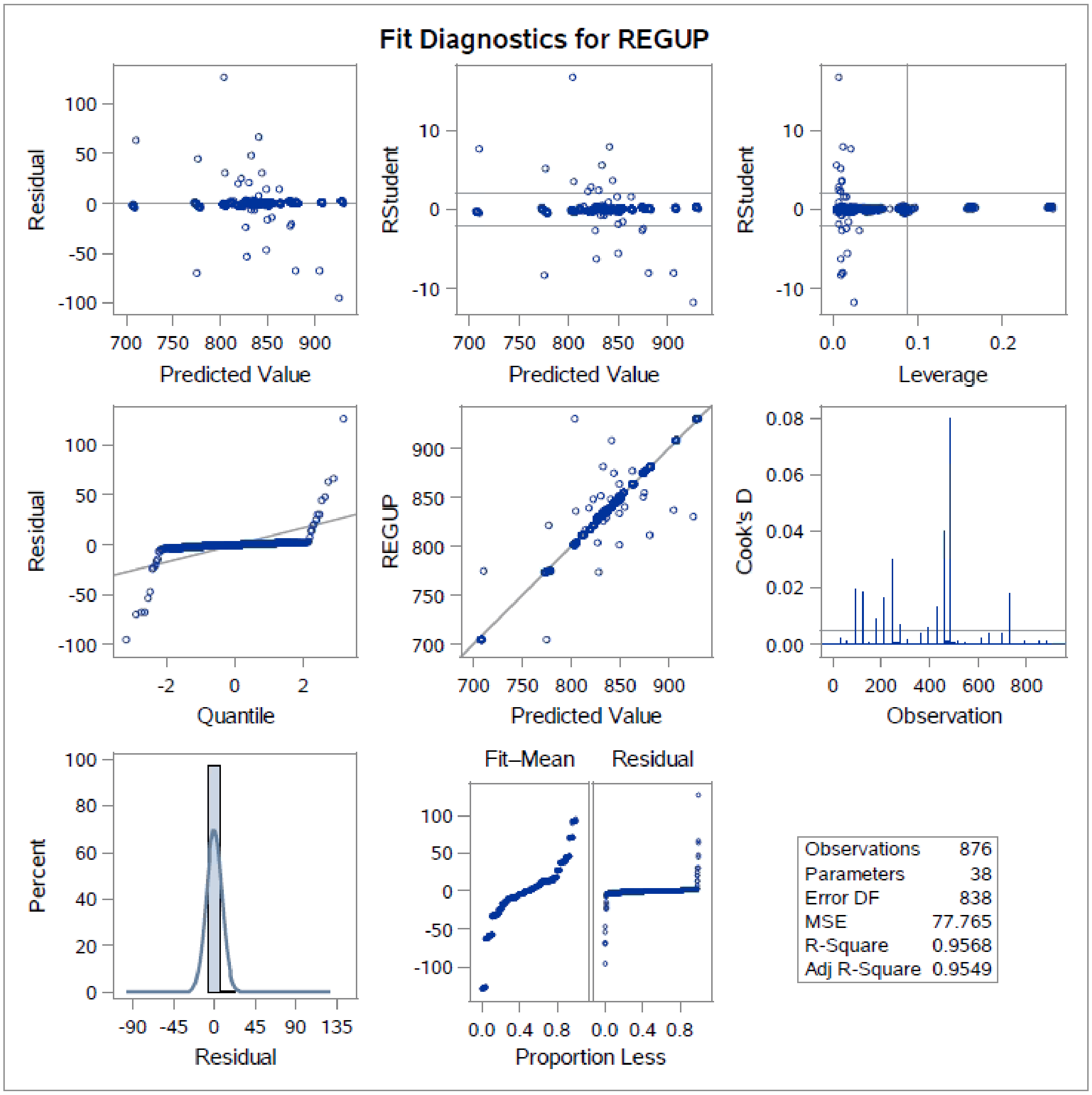
Observations	823
Parameters	37
Error DF	786
MSE	26.985
R-Square	0.9928
Adj R-Square	0.9925

Appendix F: SCR Regression Fits

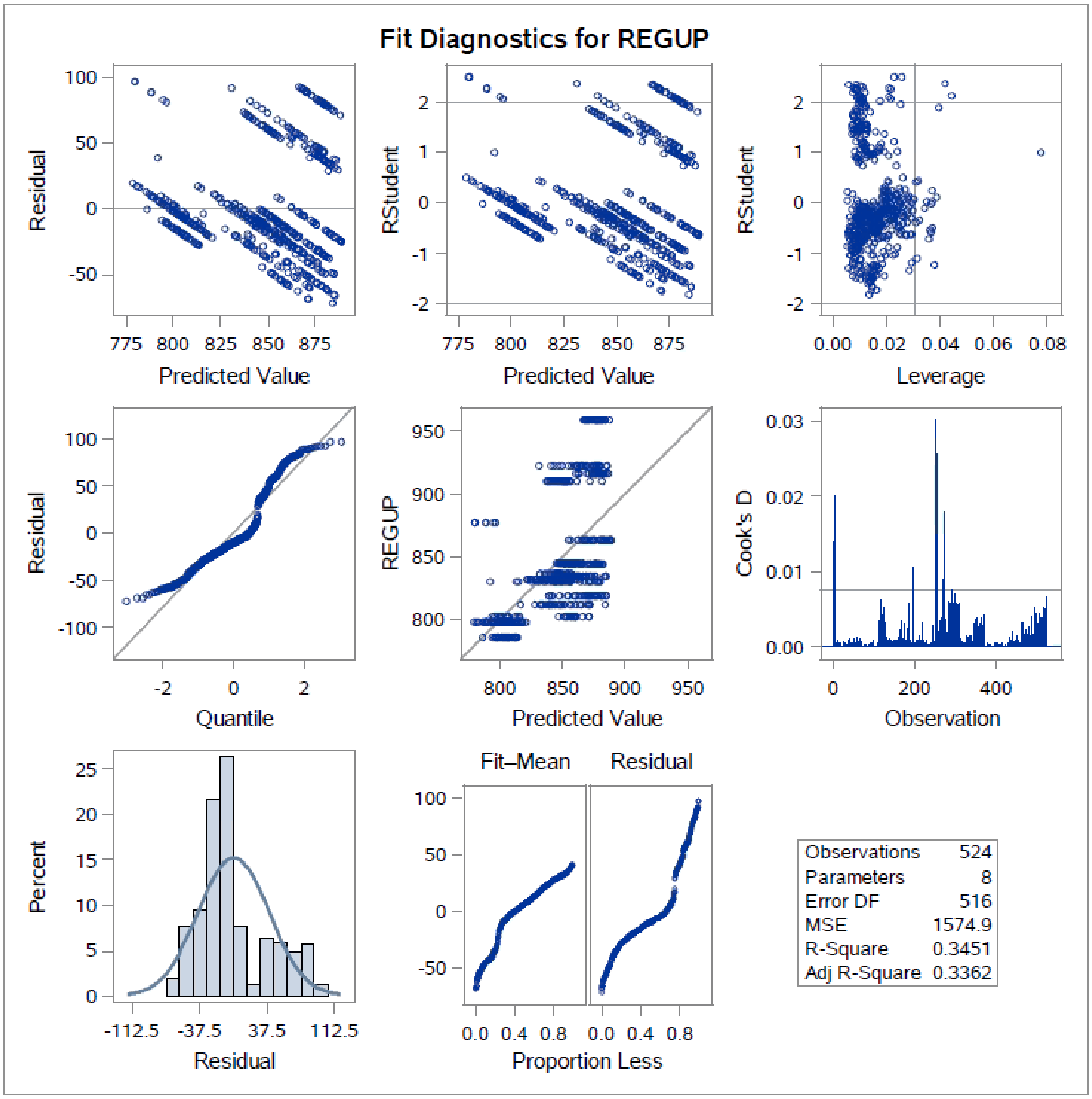
SCR Period 1 Regulation Up



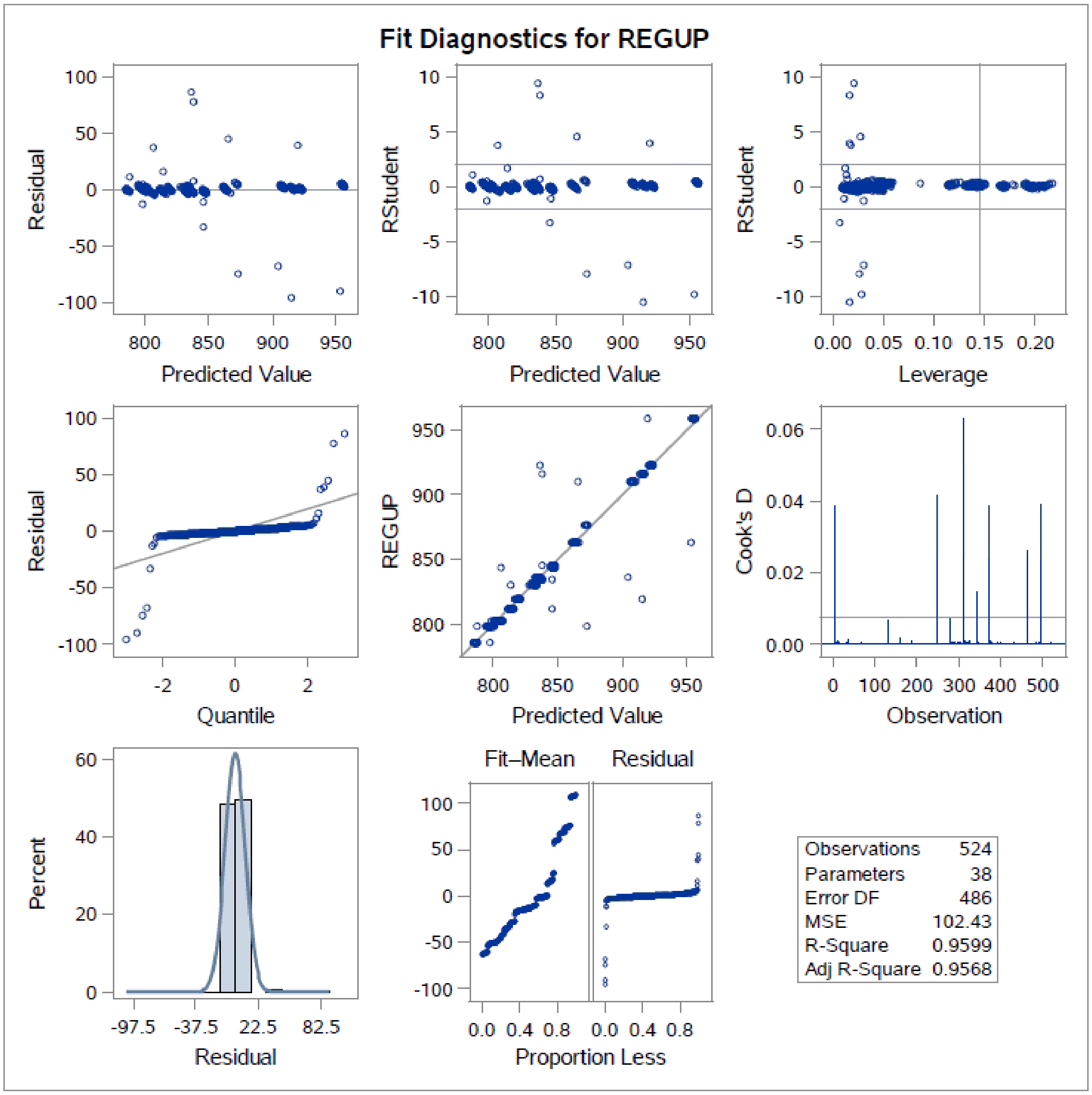
SCR Period 1 Regulation Up with Lag



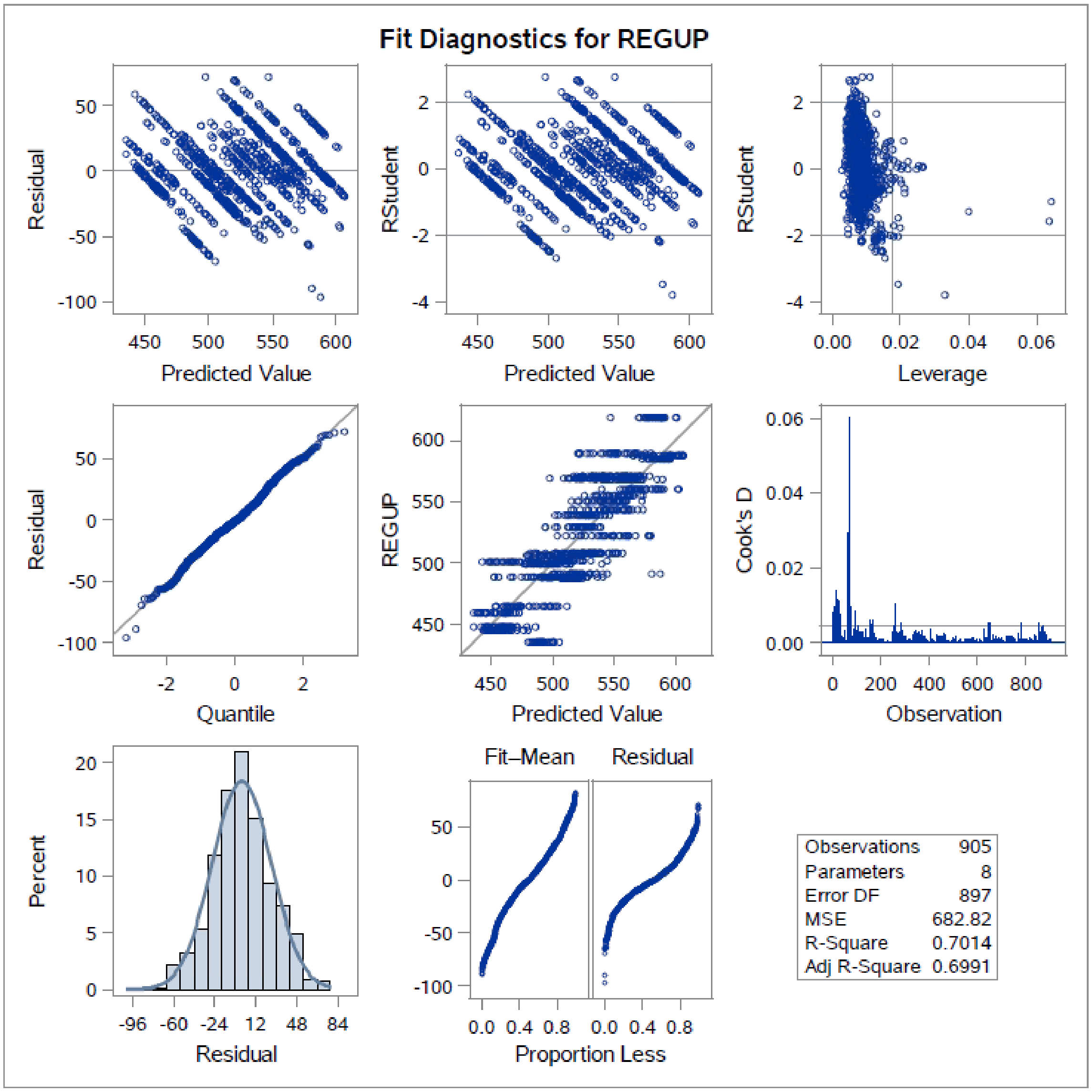
SCR Period 2 Regulation Up



SCR Period 2 Regulation Up with Lag



SCR Period 3 Regulation Up



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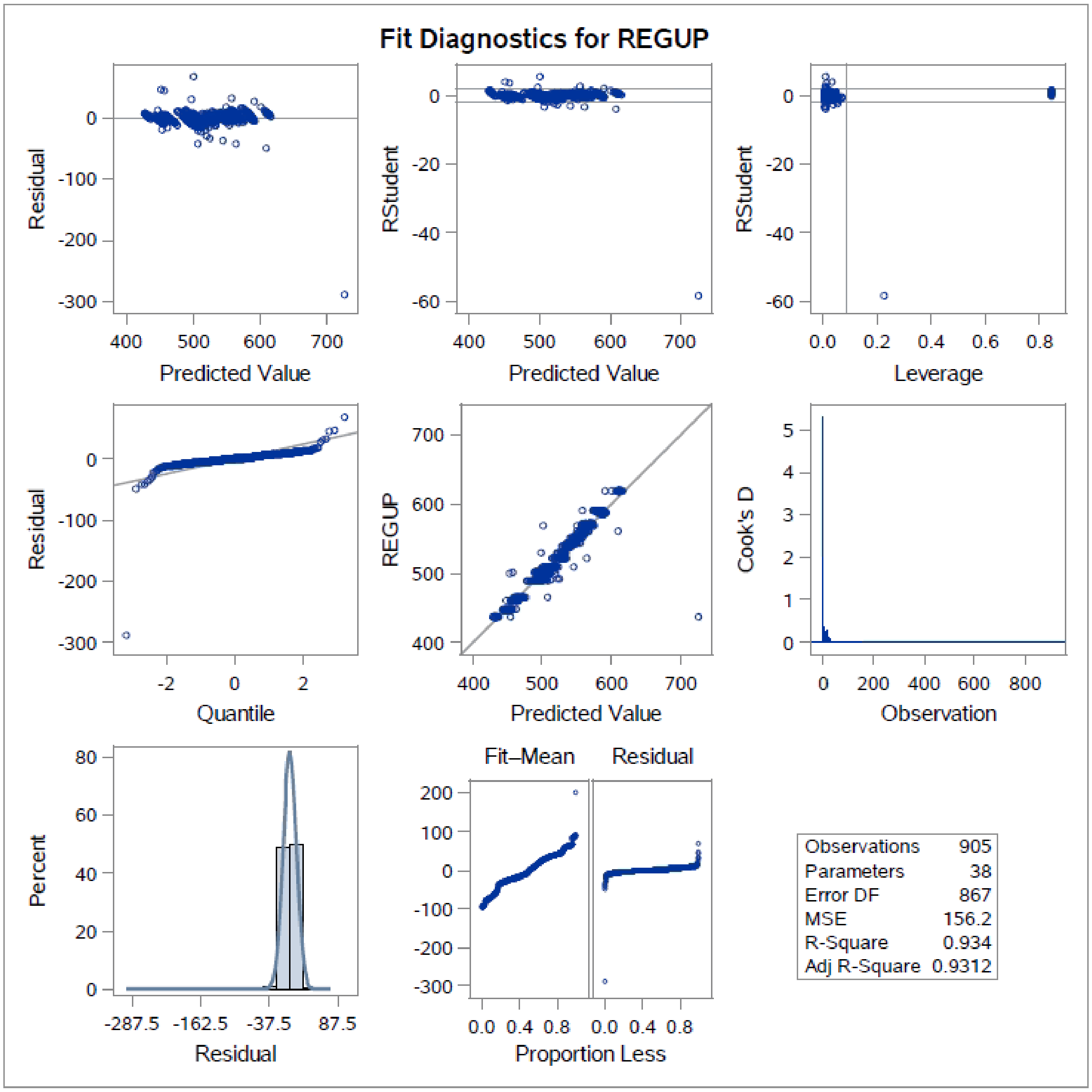

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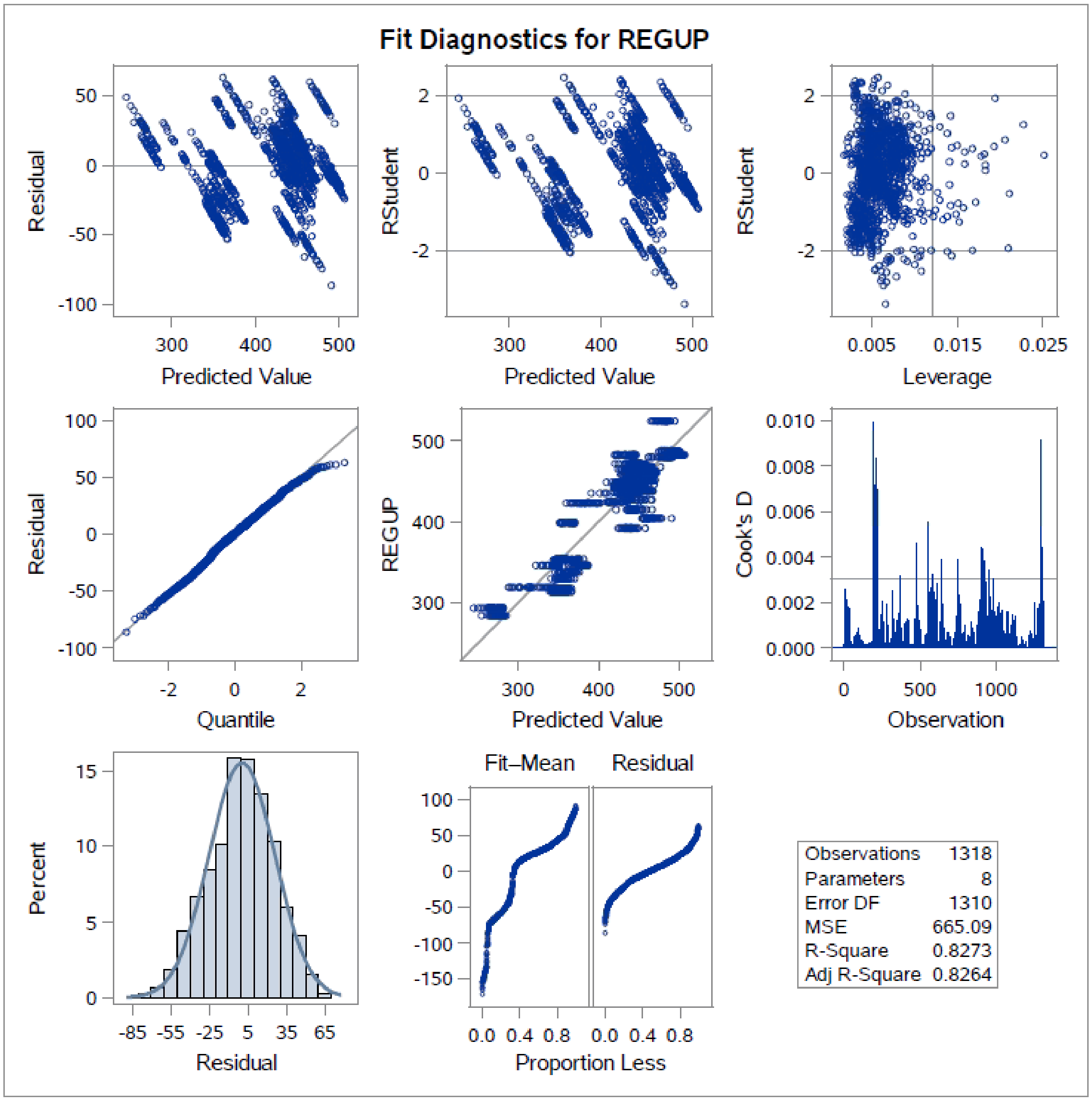

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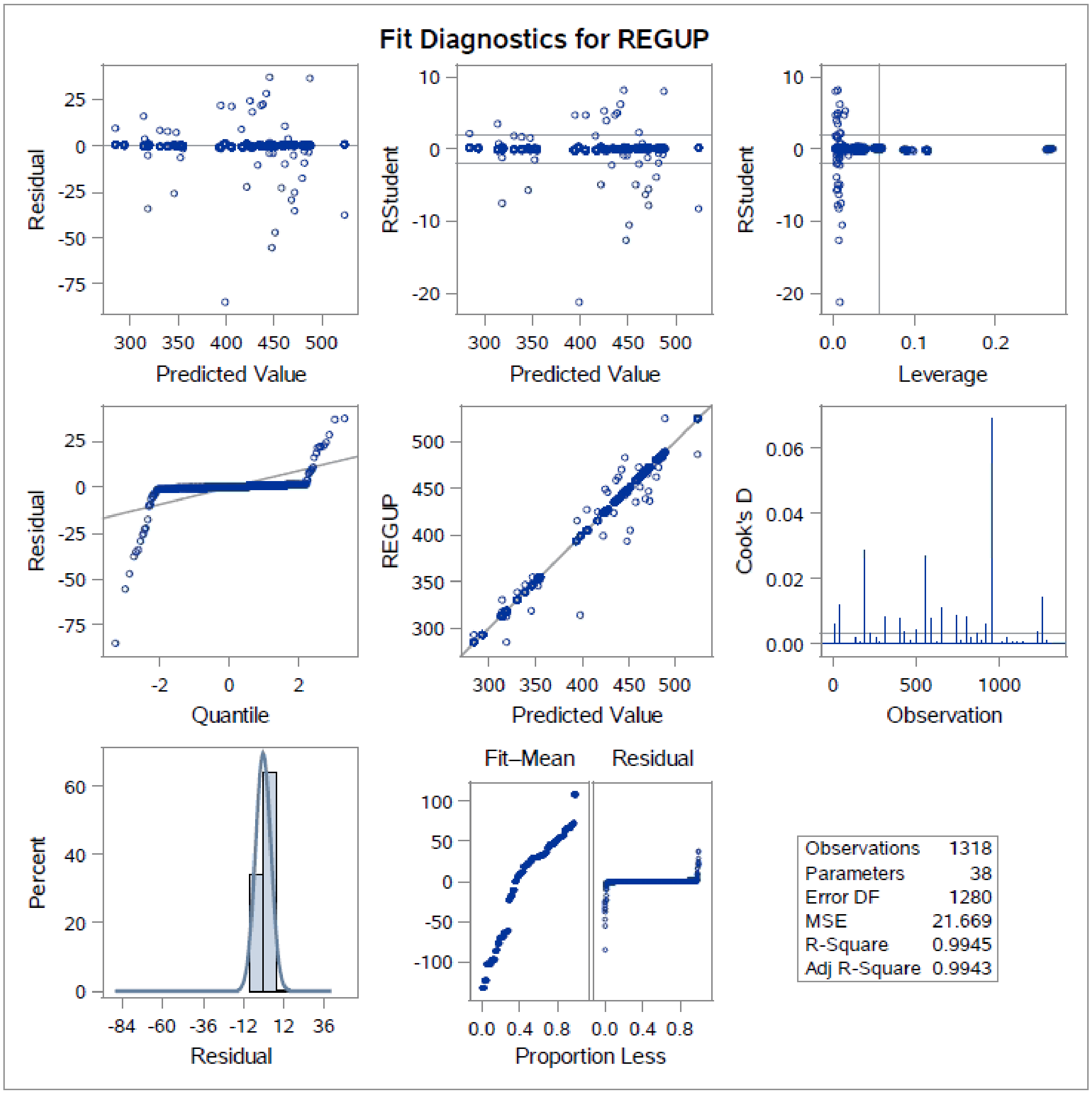
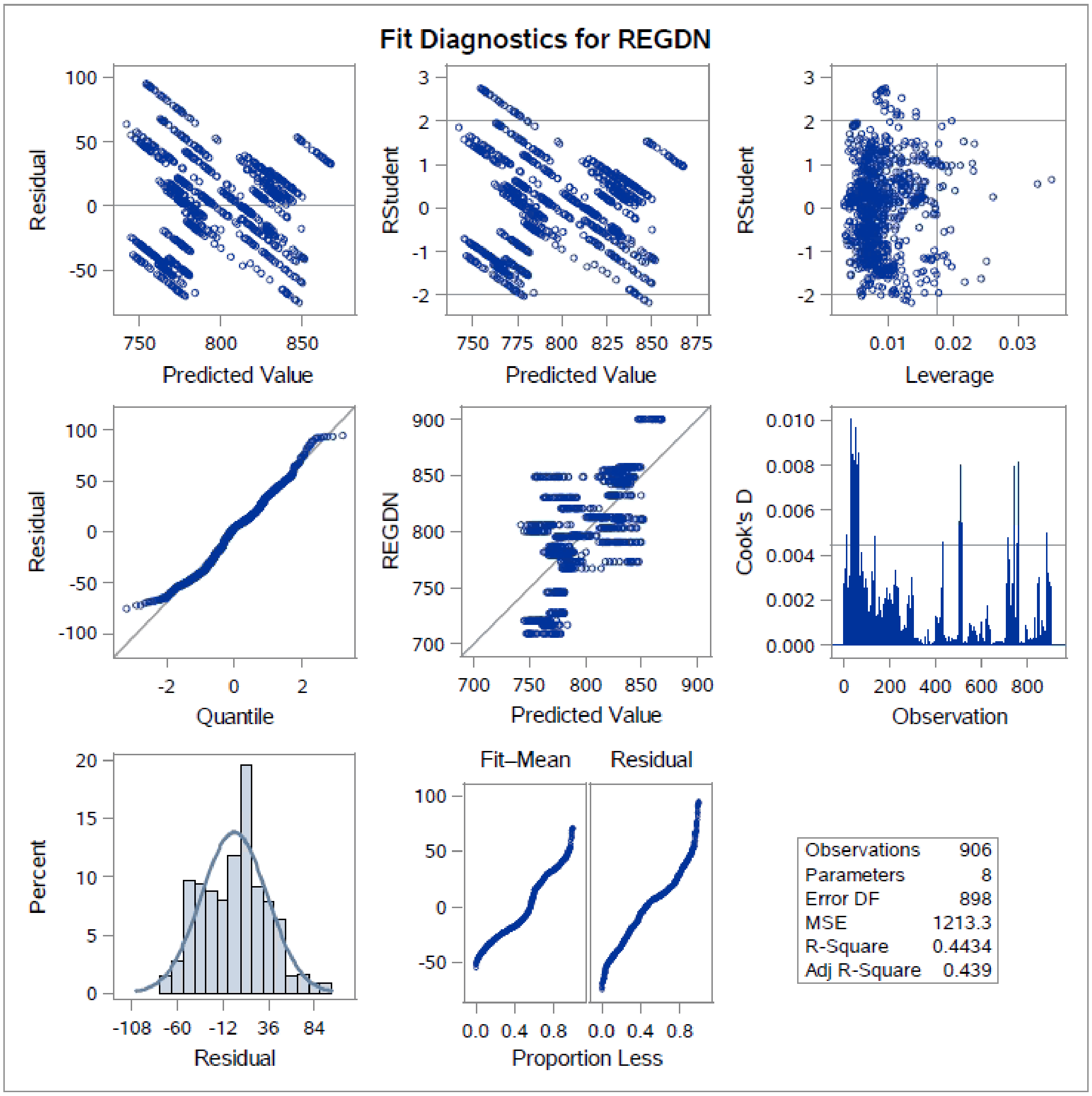


SCR Period 1 Regulation Down



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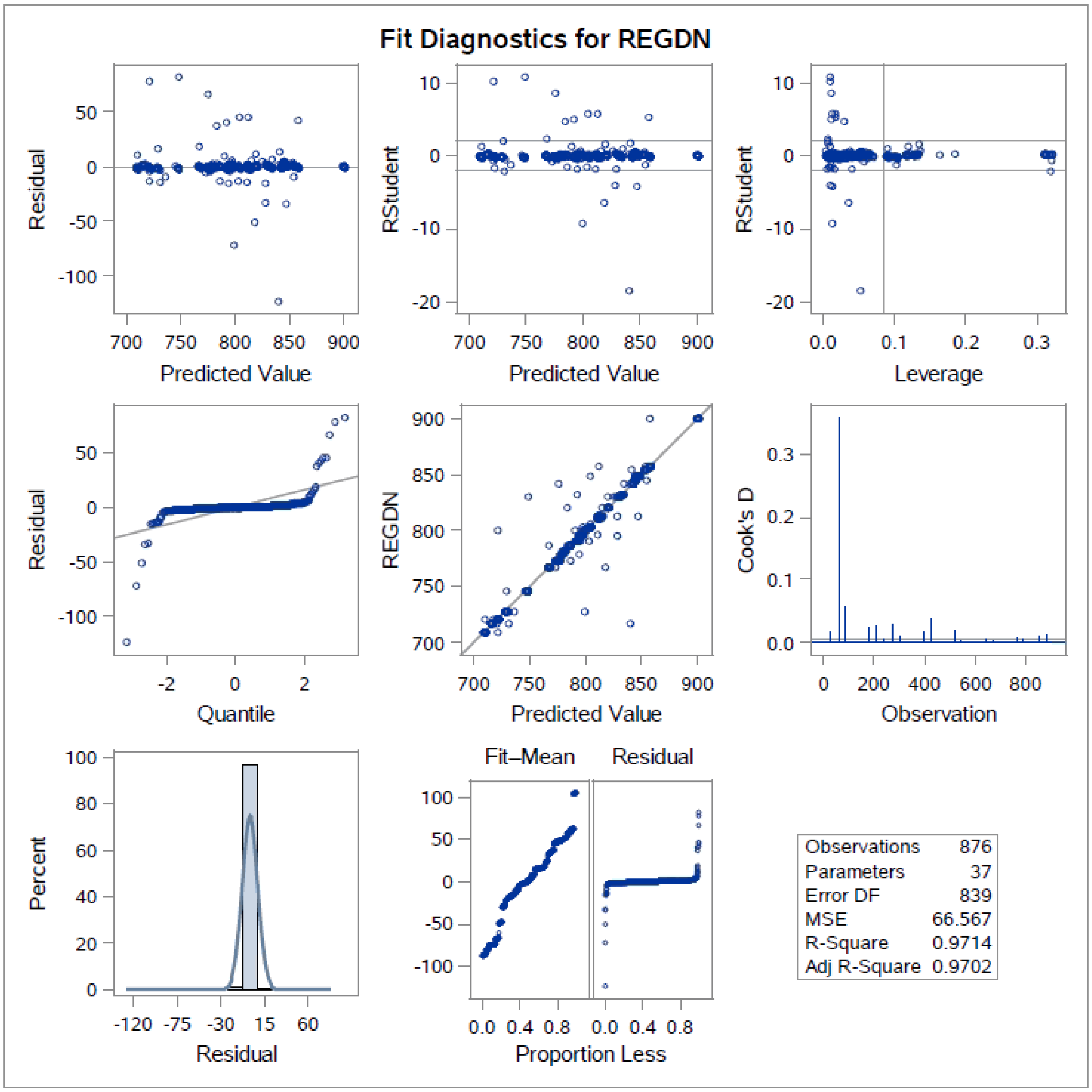
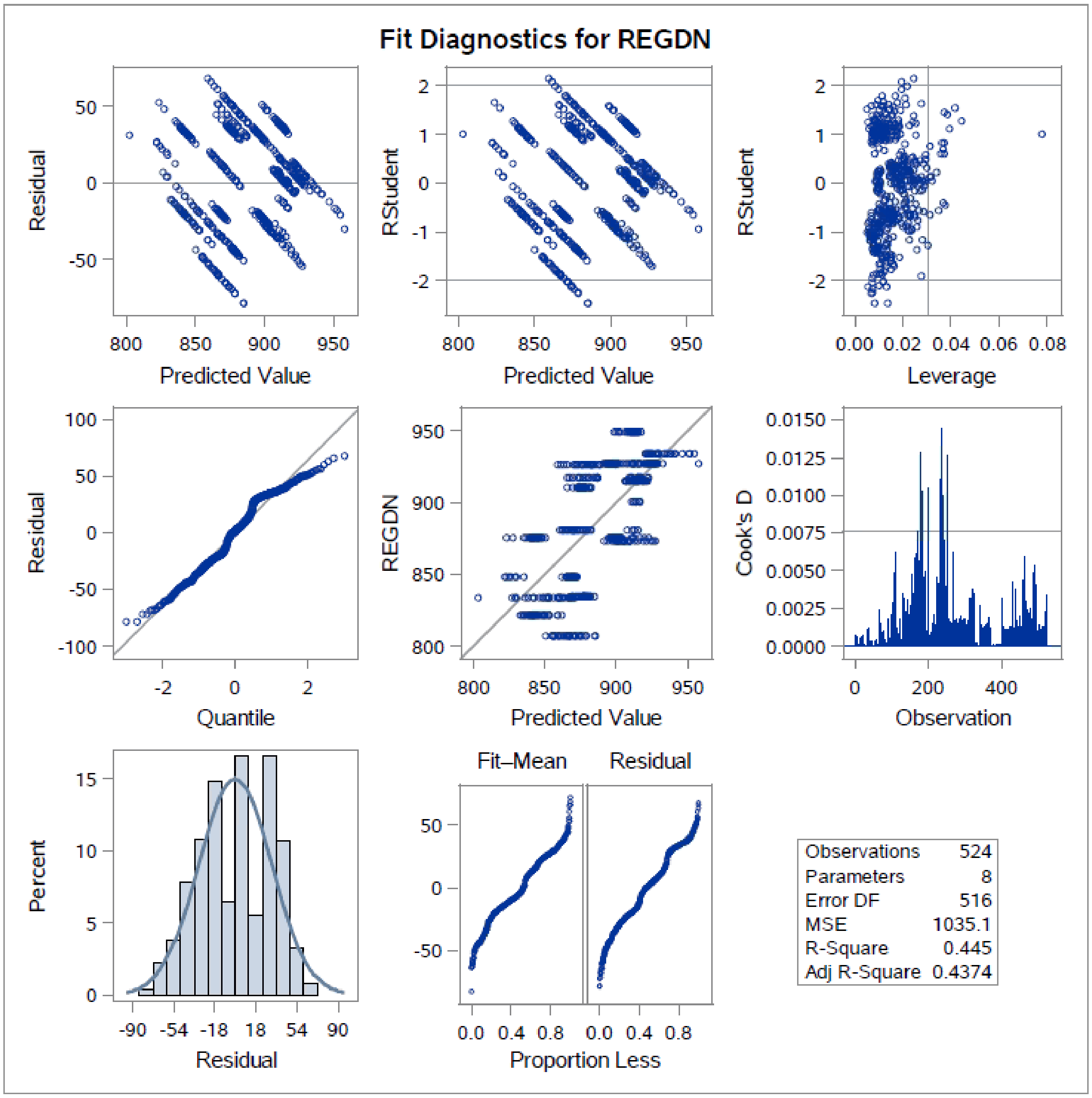


Observations	876
Parameters	37
Error DF	839
MSE	66.567
R-Square	0.9714
Adj R-Square	0.9702

SCR Period 2 Regulation Down



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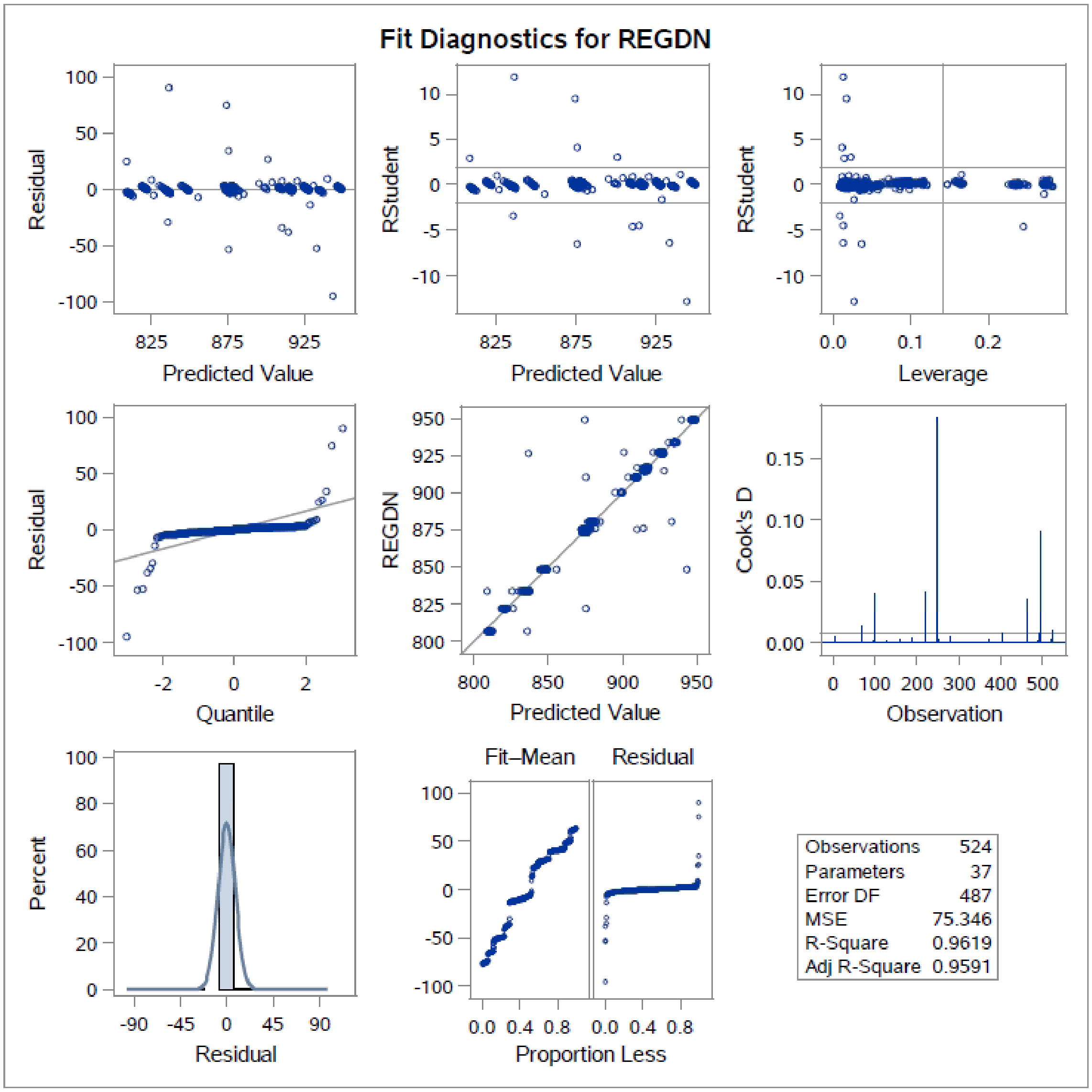

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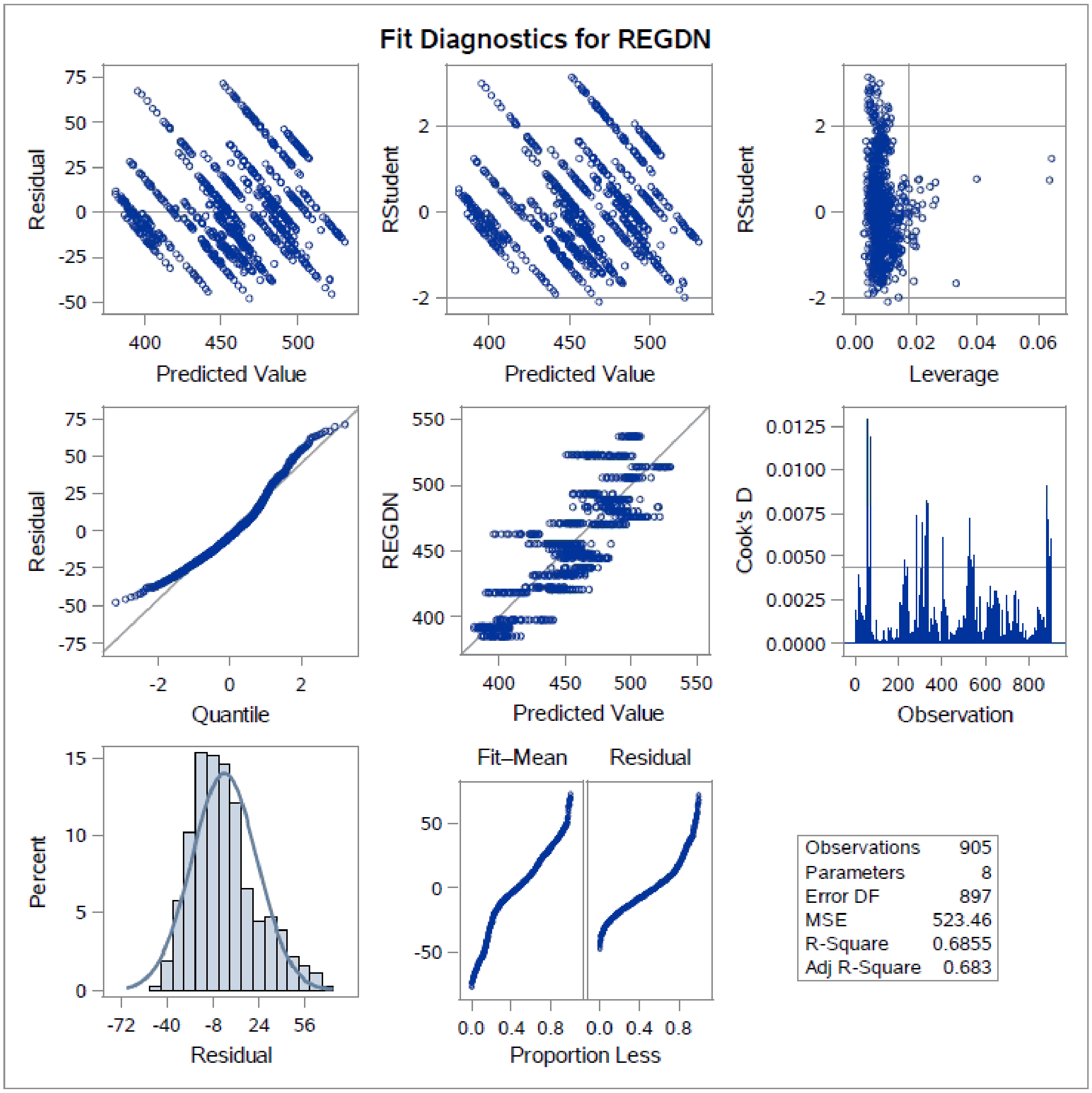

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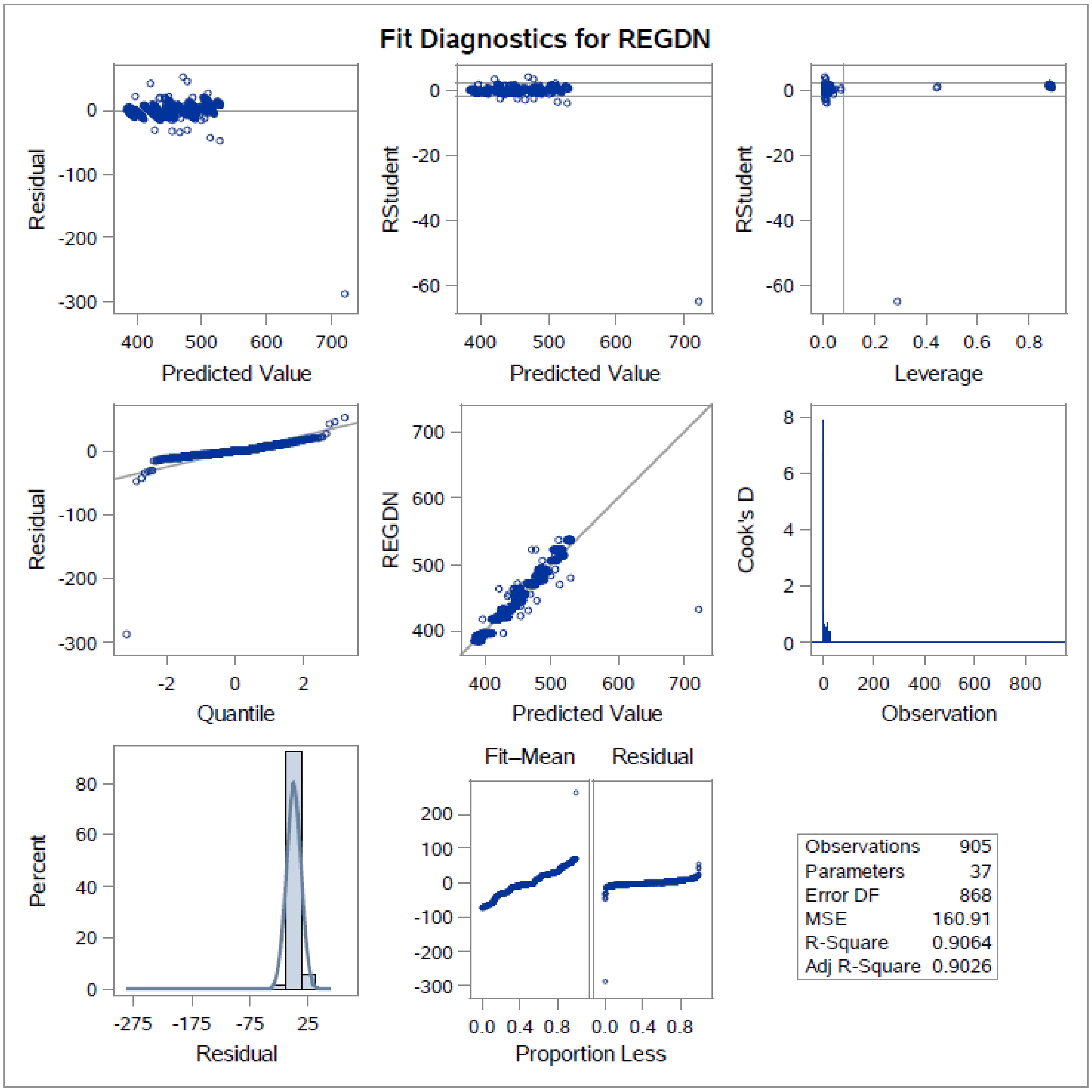

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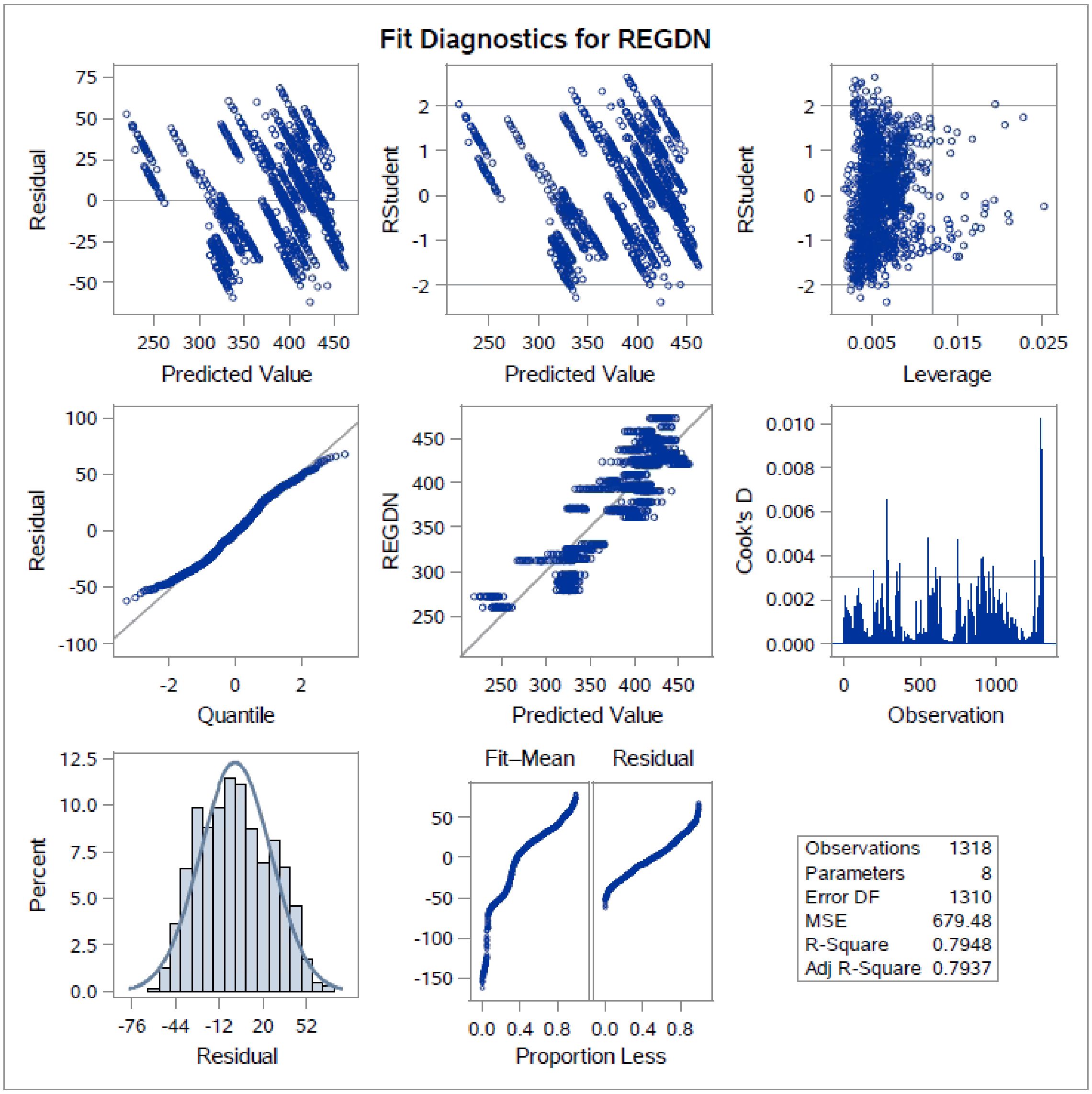

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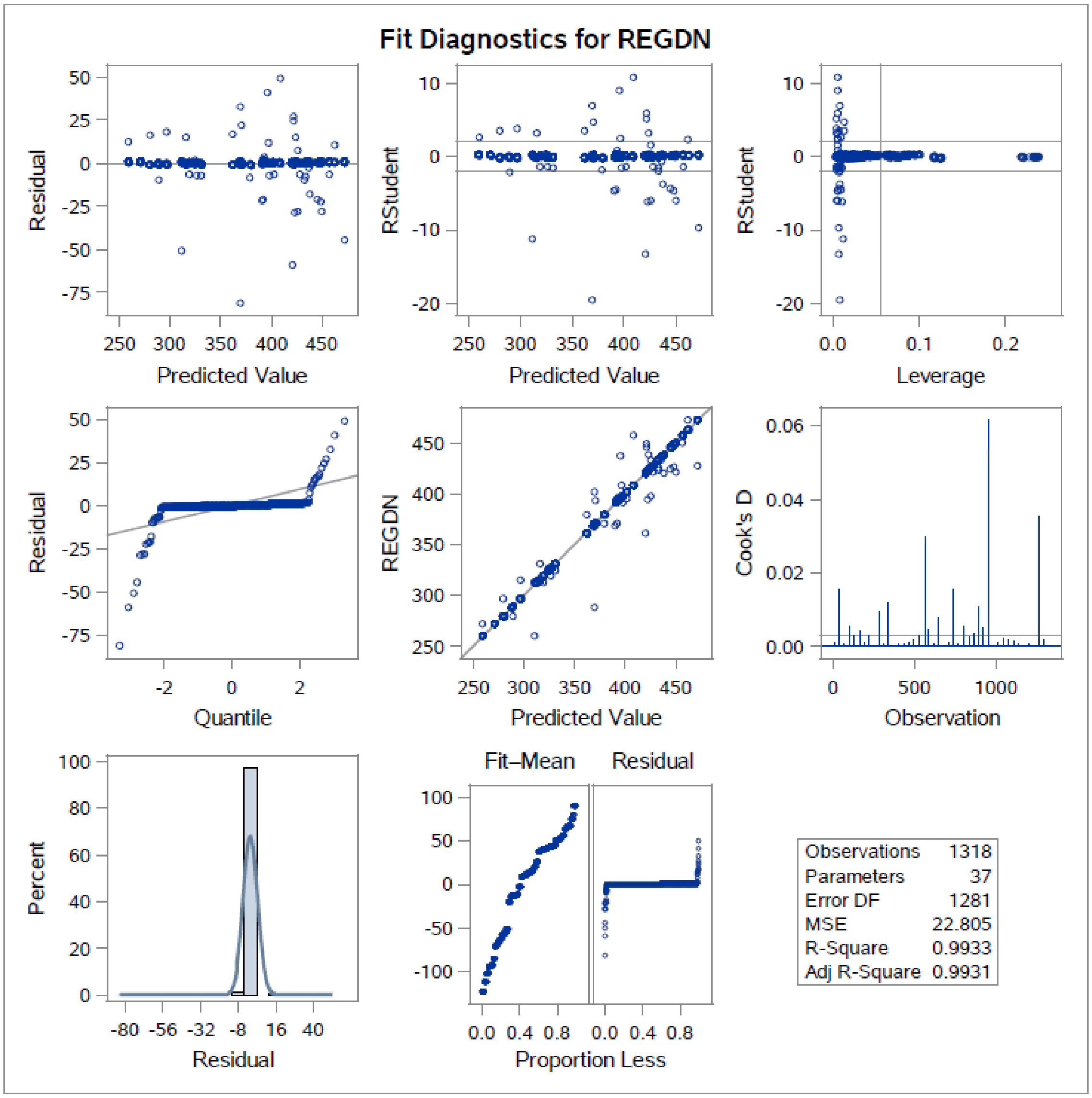

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