REsurety

ENERGYGPS CONSULTING LLC

The “P99 Hedge” That Wasn’t

An empirical analysis of fixed quantity energy price swap performance for ERCOT wind farms

Updated With 2018-2019 Data

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Contents

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Simplifying Assumption

All analyses in this white paper assume that the settlement point for any P99 Hedge and the interconnection point for all projects evaluated is the same, using ERCOT West Hub for both. In doing so, this analysis intentionally ignores the impacts of node-to-hub basis risk. This simplifying assumption is made in order to focus on the systemic issues caused by the variability of the wind as a fuel resource – and the financial impact that variability has on P99 Hedge performance – rather than on idiosyncratic transmission constraints.

Introduction

In the spring of 2018, REsurety and Energy GPS co-authored a white paper[1] describing the source and impact of a common error in forecasting hedged wind farm revenue. The error arises when valuing the revenue from a wind farm utilizing a fixed quantity energy price swap, commonly known as a "P99 Hedge". In the time since publishing that original white paper, the ERCOT power market has experienced both record-breaking levels of wind generation and record-breaking power prices — both of which have significantly impacted the settlements of P99 Hedges.

Our original white paper used generation data from July 2011 through February 2018 (the "**Original Period**"); this update uses data from March 2018 through September 2019 (the "**Update Period**"), and considers where, how, and why P99 Hedge performance during the Update Period differed from the Original Period.

This paper relies upon methodologies described and terms defined in the original white paper. We recommend reading it before continuing with this update. For reference, a glossary of defined terms is also provided in Annex II.

[1] https://resurety.com/uploads/The-P99-Hedge-That-Wasnt-a-REsurety-and-Energy-GPS-White-Paper.pdf

Executive Summary

Our analysis demonstrates that over the **Update Period** the average ERCOT wind project with a P99 Hedge would have fared poorly, realizing P99 Hedged Revenues[2] that were 43% below what would have been anticipated using the 80/20 Method — significantly worse than the 18% overestimation observed in our original analysis.

We found that the poor performance of P99 Hedges during the **Update Period** was largely driven — perhaps counterintuitively — by very high power prices. High power prices typically occurred during hours when most ERCOT wind projects were experiencing low wind speeds and therefore generation.

In contrast, low prices generally occurred during hours with very high wind generation. In short, our analysis suggests that the impact of negative "covariance" — the relationship between wind speeds and power prices at the hourly level — increased dramatically over the **Update Period**. As a result, the Unhedged Generation Value for the average wind project with a P99 Hedge during the **Update Period** was close to $0.

The table below shows some key results from the original white paper, compared to the same values over the **Update Period**:

During the Update Period

P99 Hedged Revenues were 43% below what would have been anticipated using the 80/20 Method.

High power prices typically occurred during hours when most ERCOT wind projects were experiencing low wind speeds and generation.

Unhedged Generation Value was worth a mere 5% of the Market Price over the same period.

Statistic	Original Period	Update Period
The percent of megawatt-hours generated that are actually hedged[3] by a P99 Hedge	56%	57%
The Unhedged Generation Value as a percentage of the Market Price of Power[4]	62%	5%
The percent by which the 80/20 Method overestimates actual P99 Hedged Revenues	18%	43%

[2] P99 Hedged Revenue is defined as the sum total value of Hedged Value, Long Value, Non-Gen Sale Value, and Short Value, as laid out in the original white paper. This definition, along with the definitions of all other defined capitalized terms, can be found in Annex II.

[3] Defined as the hourly minimum of i) generation and ii) the fixed quantity committed under the P99 Hedge.

[4] This statistic was presented as a discount in the original white paper, such that the 62% value would represent a 38% discount on Market Price.

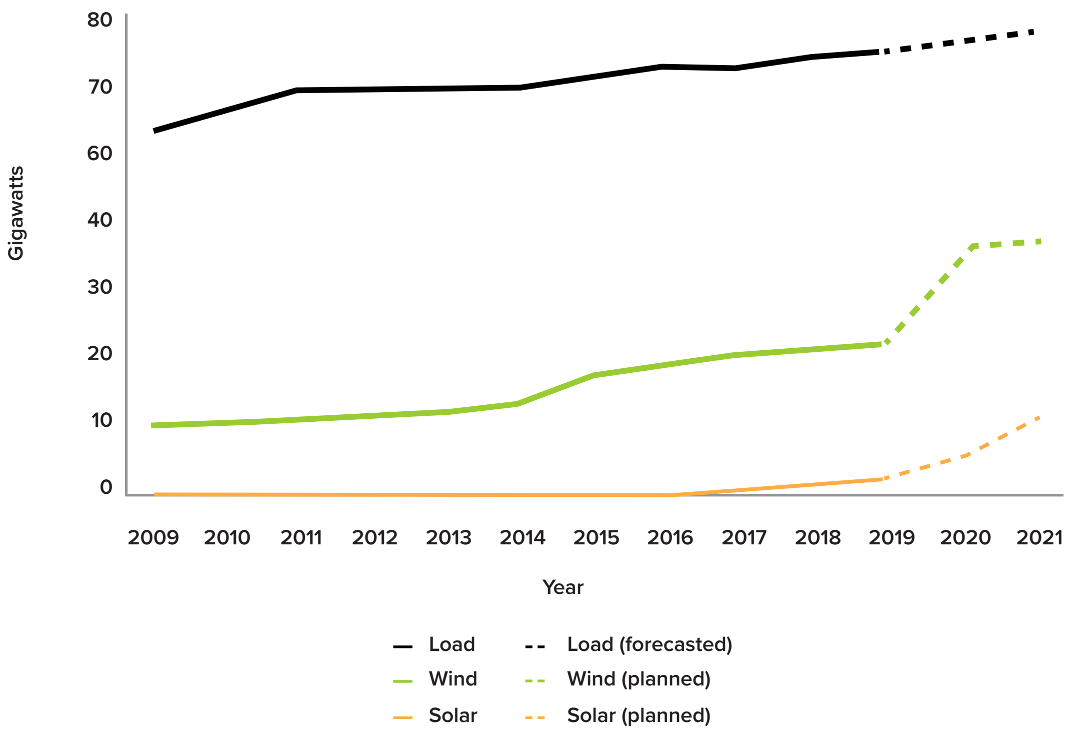
The Update Period: an Outlier, a New Normal, or Both?

The **Update Period** (March 2018 - September 2019) was unique in many ways for the ERCOT power market. First, renewables (wind and solar) reached record-high levels of cumulative installed capacity: 23 gigawatts (GW) for wind and 1.8 GW for solar. Demand for electricity also set a new record, exceeding 74 GW of load for the first time.

Second, ERCOT's reserve margin — measured as the expected available capacity in excess of weather-normal peak load — going into the 2018 and 2019 summers was well below the ERCOT long-term target of 13.75%[5]. All else equal, a low reserve margin leads to higher volatility of power prices as the probability of supply shortages (and resulting price spikes) increases.

This power price volatility was further amplified by changes to market rules: in 2019, the magnitude of the Operating Reserve Demand Curve ("ORDC") adder — a market mechanism that increases the price of power during a supply shortage — was increased.

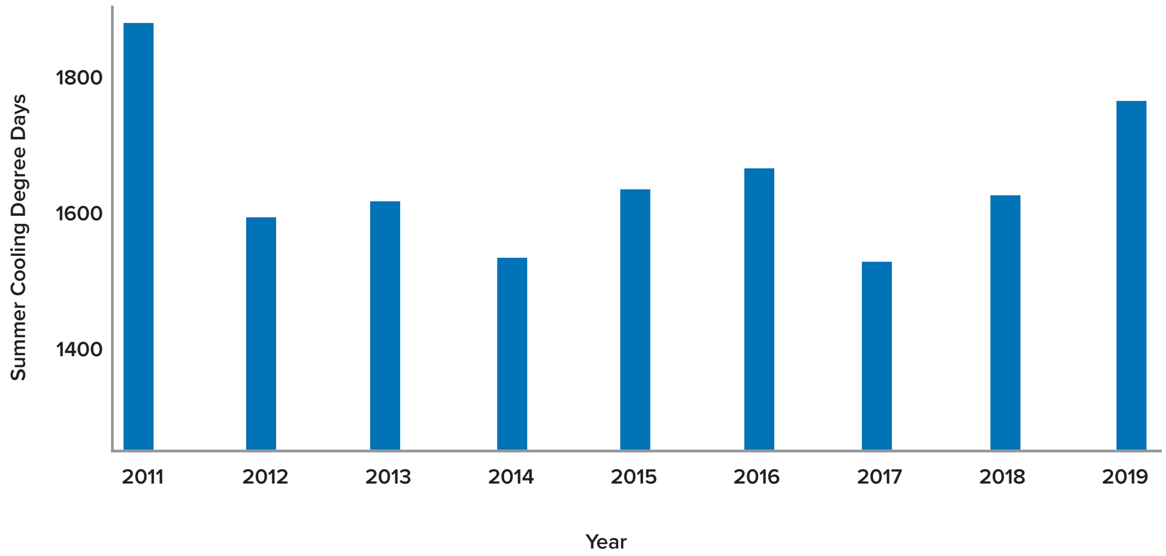
Figure 1. ERCOT Peak Load and Installed Wind & Solar Capacity[5]



The Update Period represents a potential window into the future.

[5] Source: ERCOT

Figure 2. Texas Summer (July, August, and September) Cooling Degree Days by Year



Third, in 2019 Texas experienced a relatively hot summer. As seen in Figure 2, the total number of cooling degree days ("CDDs") in the summer (July through September) of 2019 was only surpassed in the summer of 2011 — a year which holds the record for the hottest summer in Texas in the last 125 years[6]. Hotter summers lead to higher system-wide demand, in turn increasing power prices.

For these three reasons, the **Update Period** represented a unique set of circumstances that were stacked against the interest of most wind farms utilizing P99 Hedge contracts.

That said, the **Update Period** also represents a potential window into the future. The ERCOT interconnection queue holds a huge amount of planned future wind and solar development, ERCOT has already committed to another ORDC increase in 2020, and climate change is causing hot summers to be increasingly common. Accordingly, the **Update Period** could be interpreted as both a unique historical event as well as an indication of what may become increasingly common in the future.

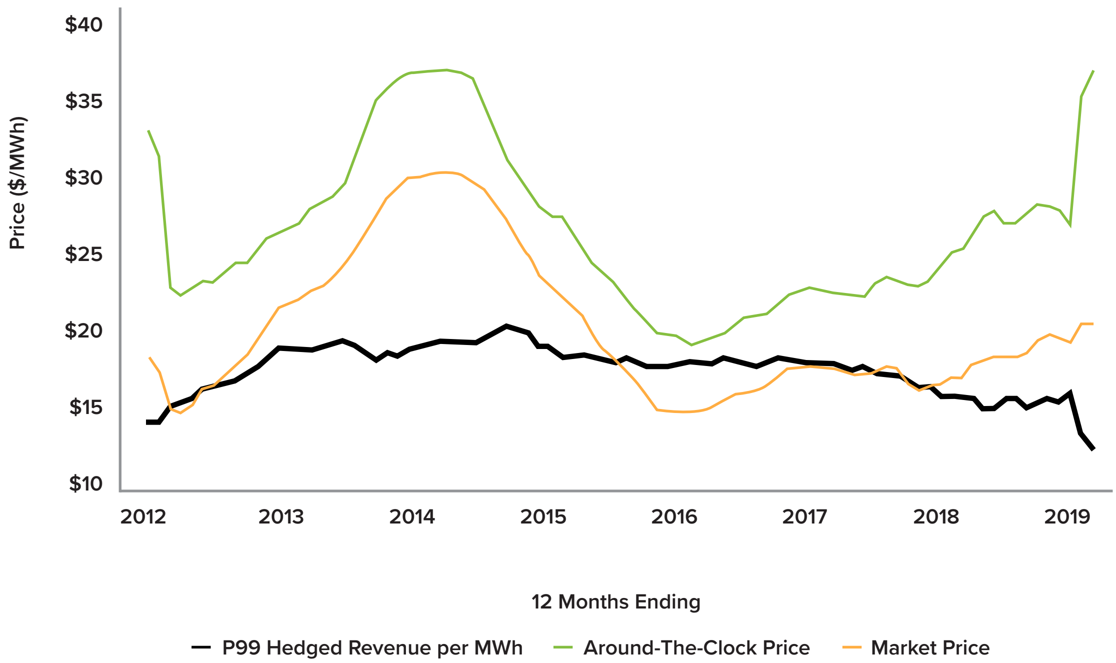
[6] Source: NOAA

Analysis and Results

As discussed in the original white paper, our research suggests that the use of a P99 Hedge tends to result in P99 Hedged Revenues that are significantly lower than many developers and owners expect. The conclusion of our original analysis was that the negative relationship between hourly wind energy production and power price is the key driver of these lower-than-expected P99 Hedged Revenues. In that original white paper, we analyzed hourly data from over 230 project-years of operational wind farms to quantify the value of P99 Hedged Revenues resulting from a P99 Hedge during the **Original Period**. In this update, we analyze how P99 Hedged Revenues from the same wind farms would have fared during the **Update Period**.

One of our most significant findings from the **Update Period** is that it represented an all-time low value for P99 Hedged Revenues. One way to view this is by looking at the project's P99 Hedged Revenue per MWh of generation. This is shown in Figure 3 (black), along with the wind generation weighted price of power (the "Market Price", orange) and the simple average - or "around-the-clock" - price of power (green). The decline in P99 Hedged Revene per MWh in the **Update Period** is proportional to the increase in the gap between the Market Price and around-the-clock price.

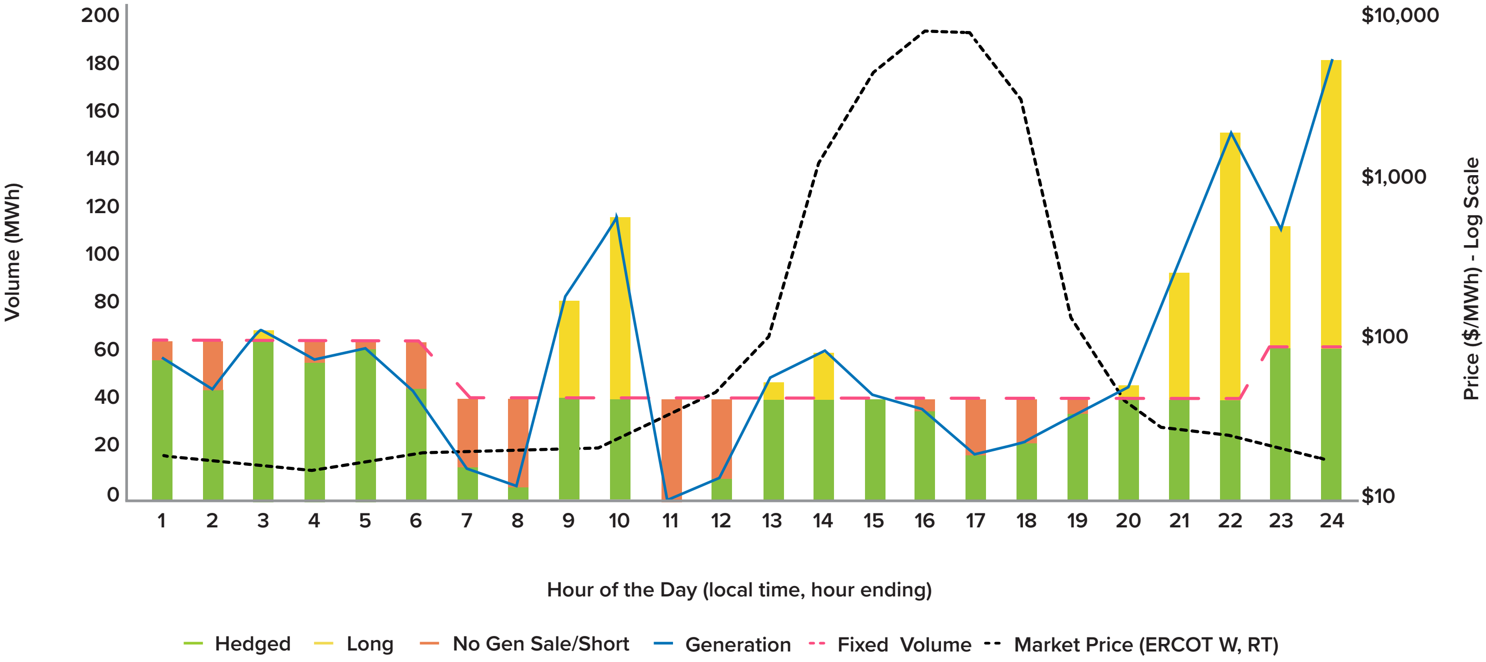
Figure 3. Average Project Trailing 12-Month P99 Hedged Revenue per MWh, Market Price, and Around-The-Clock Price at ERCOT West Hub, Real-Time



The Update Period represented an all-time low value for P99 Hedged Revenues.

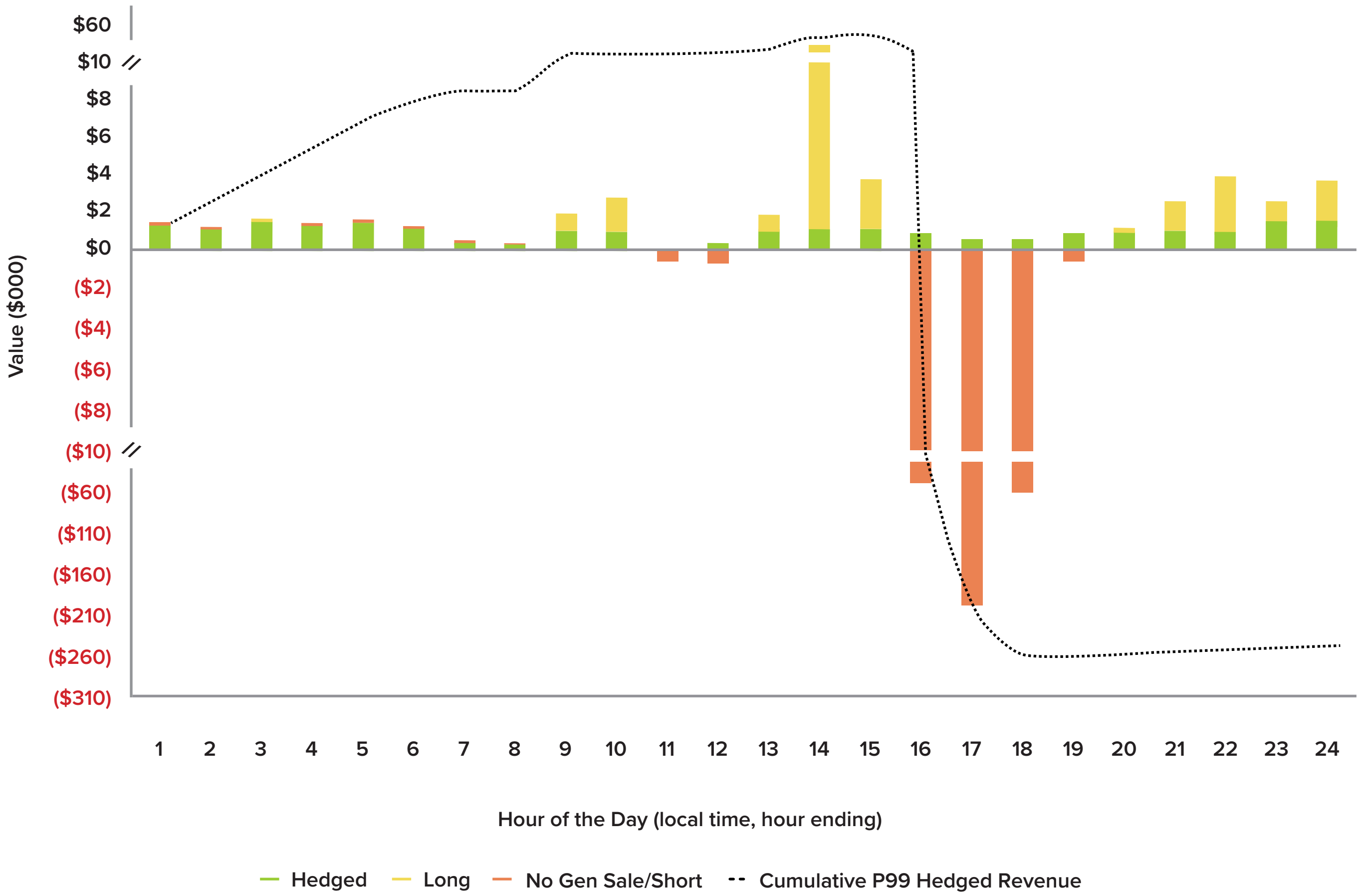
The drivers of this significant decline in value can be illustrated through the hourly mechanics of P99 Hedge settlement. The example in Figure 4 represents a "Day in the Life" of a wind farm in the ERCOT Panhandle that is utilizing an assumed $22/MWh P99 Hedge. The data shown reflects actual generation data from a day in August 2019, and (consistent with the original white paper) ignores the impact of basis. Over the course of the day, the project generates significantly more energy than is sold under the P99 Hedge, as expected. However, in certain hours the project generates less energy than it had committed to selling in that hour under the P99 Hedge — thereby requiring the project to buy that quantity of energy (the "Short Quantity") from the wholesale power market to fulfill its fixed delivery obligation. The cost of purchasing this power is the Short Value.

Figure 4. A Day in the Life of a P99 Hedged Wind Farm on August 15, 2019



Unfortunately for this project, the Short Quantity purchases occur in several hours when power prices are high — very high. As a result, the project suffers a significant loss caused by having to buy power for ~$9,000/MWh and sell it for $22/MWh (the price of the P99 Hedge). Figure 5 shows the cumulative P99 Hedged Revenue generated by the project over the course of this day; it quickly becomes clear how just a few hours of under-production can erase all of the revenue generated the rest of the day — and then some.

Figure 5. Cumulative P99 Hedged Revenue for a P99 Hedged Wind Farm on August 15, 2019



The example here highlights one of the key reasons why the average project's P99 Hedged Revenue over the **Update Period** was materially lower than in the **Original Period**: prices were high during relatively low wind speed periods, leaving projects to absorb a very costly Short Value. It is worth noting that this phenomenon was not limited to August 2019. We found, based on the data we analyzed, that more than 85% of months in the **Update Period** contained multiple days where the average wind project realized negative P99 Hedged Revenue over the course of an entire day.

In theory, an increase in the cost of the Short Value could be offset by an increase in the Long Value. This would occur if power prices increased in all hours, independent of generation. However, when comparing the **Original Period** with the **Update Period**, we found that the opposite was true: while average prices increased during hours when the average project was experiencing a Short Quantity, average prices decreased during hours when the average project was experiencing a Long Quantity. This is visible in Figure 6. More metrics at the annual level — including gas price, number of negative LMP observations, and number of high price events — are available in Annex III.

Figure 6. Average Price of Long, Short, and Unhedged Generation Quantities During the Original and Update Periods

	Original Period	Update Period
Average Value of Long Quantity ($/MWh)	$18.87	$15.74
Average Cost of Short Quantity ($/MWh)	($32.75)	($42.27)
Unhedged Generation Value ($/MWh)	$12.96	$1.21

Our analysis found that the increase in cost of the Short Quantity and the decrease in value of the Long Quantity accounted for ~2/3 and ~1/3, respectively, of the total decline in P99 Hedged Revenue between the Original and the Update periods.

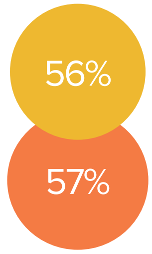
Key Findings: Comparison to Original Analysis

The original white paper included several statistics related to modeled P99 Hedge Performance. Here, we update these statistics using data from the **Update Period** and provide explanations for changes from the **Original Period**.

Key Finding #1

- **Original Period:** Only **56%** of the energy generated under a P99 Hedge is actually hedged.

- **Update Period:** Slight increase to **57%**.

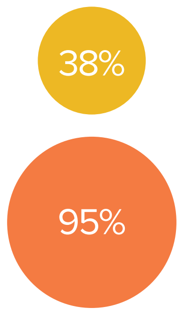


This number remained nearly constant across the two data periods. This metric is a function of the wind speed distribution - not power market volatility - so the consistency is expected.

Key Finding #2

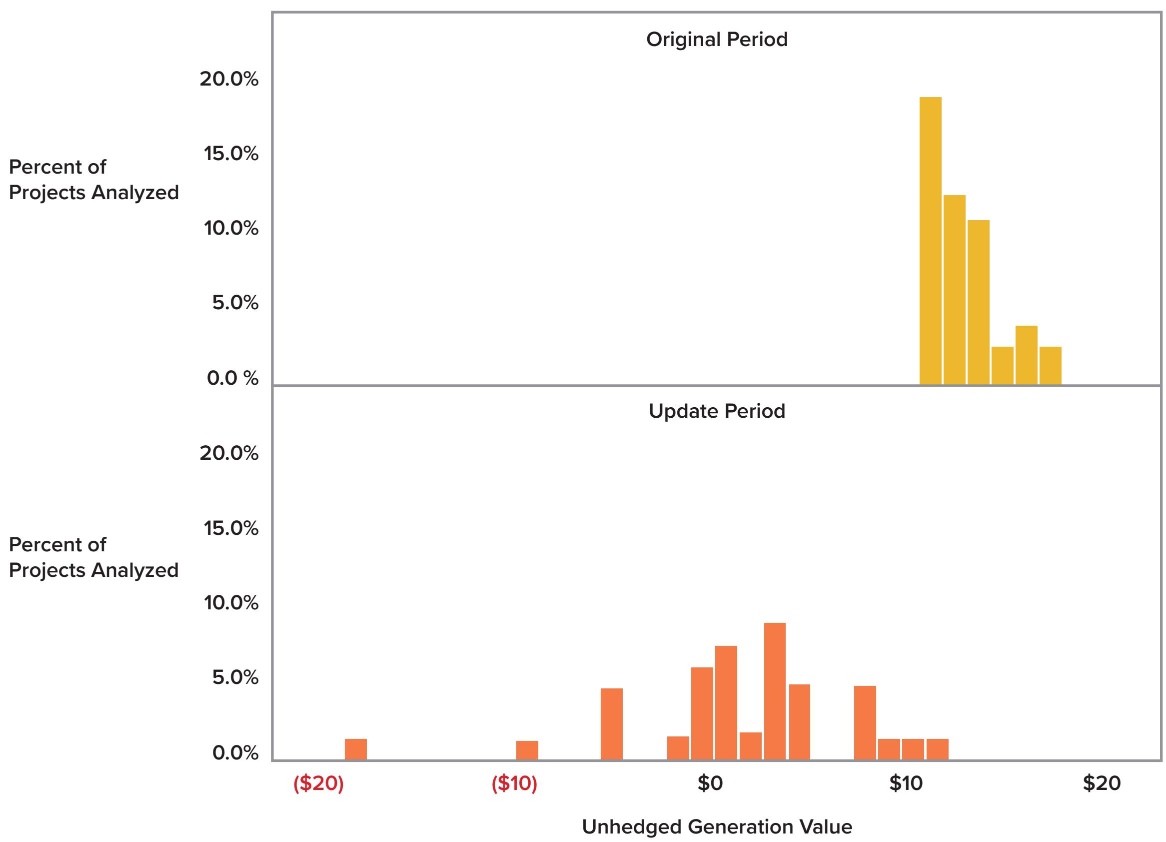
- **Original Period:** The Unhedged Generation of a wind project with a P99 Hedge has historically been **38%** less valuable than the Market Price of energy over the same period.

- **Update Period:** Increase to **95%**.



Stating this metric another way, for the average project with a P99 Hedge, the Unhedged Generation was worth only 5% of the value of the Market Price over the **Update Period**. This is because the cost of the Short Value erased nearly all of the revenue earned by the Long Value. As illustrated in Figure 7, a significant portion of the projects analyzed even experienced a negative[7] value of unhedged generation over the course of the **Update Period**.

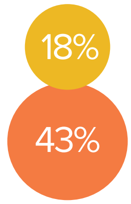
Figure 7. Value of Unhedged Generation



[7] To be clear: this negative value was not driven by negative power prices; it was driven by the cost of buying the Short Value outweighing any revenue from the Long Value.

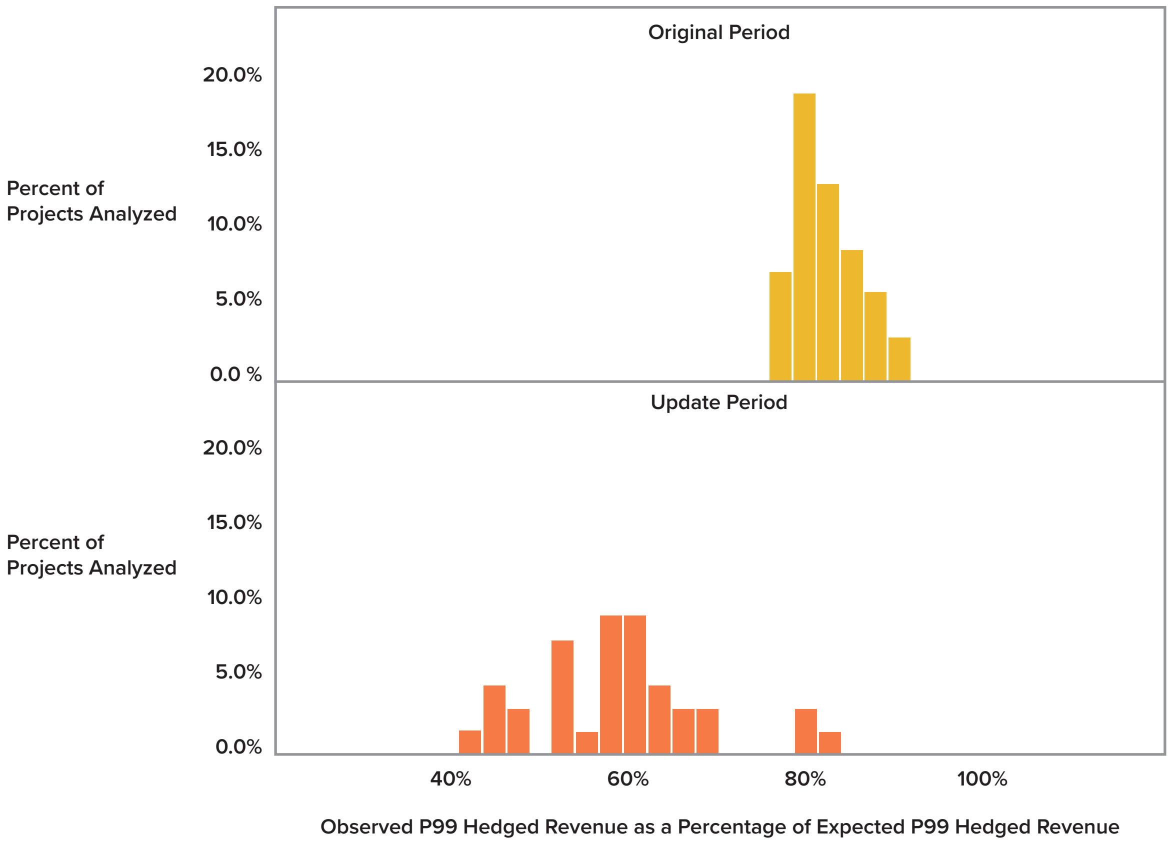
Key Finding #3:

- **Original Period:** The 80/20 Method overestimates observed P99 Hedged Revenues by **18%**.
- **Update Period:** Increase to **43%**.



As discussed in the original white paper, the 80/20 Method ignores the negative relationship between wind energy generation and power prices, resulting in an over-estimation of P99 Hedged Revenues. As such, when that negative relationship — or "negative covariance" — worsens, the 80/20 Method becomes increasingly inaccurate.

Figure 8. Observed P99 Hedged Revenue as a Percentage of Expected P99 Hedged Revenue Using the 80/20 Method



Conclusions

Despite its name, a P99 Hedge leaves a substantial portion of project revenues exposed to resource intermittency risk: when and how much the wind blows, relative to power prices. The impact of this exposure on project revenues is determined by the strength of the relationship between power prices and wind speeds. Unfortunately for holders of P99 Hedges, this relationship was particularly strong and negative during the **Update Period**, significantly degrading the efficacy of a P99 Hedge as compared to the **Original Period**.

Looking forward, large uncertainties exists. How much more wind will get built in Texas? How much will growth of solar, storage or gas peakers reduce or reverse the covariance trend facing wind projects? What is known is that the current environment — high wind penetration with increasingly volatile weather — could limit the value and stability of P99 Hedged wind projects.

Risks Held by C&I Buyers of Power

The original white paper and this update both focus on hedge efficacy from the wind project's perspective. However, for projects with a virtual PPA ("vPPA") signed with a Commercial & Industrial buyer ("C&I"), exposure to hourly covariance risk shifts away from the project and to the C&I.

Under a traditional vPPA contract, a C&I agrees to buy the power generated by a given wind project, irrespective of how much power is generated or when that power is generated. For a C&I seeking to use a vPPA as a hedge on its physical energy consumption, that presents a problem.

For example, consider a C&I with consistent, around-the-clock energy demand who has financial exposure to wholesale market rates for that consumption. The C&I signs a vPPA with a wind project in the same market, eager to not just to purchase renewables, but also to stabilize its future energy costs.

Unfortunately, the project will inevitably produce more or less power than the C&I needs in any given hour. This mismatch in generation and consumption is nearly identical to the challenge faced by a wind project utilizing a P99 Hedge. The ability of a vPPA to effectively hedge energy consumption costs is largely dependent on weather-driven variables: the timing and volume of generation by the wind farm in each hour. In simulating vPPA settlement over nearly 300 project-years of data, our analysis shows that these variables resulted in highly variable energy costs for the C&I. During the **Update Period**, the data suggests that a C&I pairing fixed quantity physical demand with a $22/MWh vPPA would have paid more than $37/MWh for that power after the settlement of the vPPA – with significant cost variability quarter-to-quarter.

This is, perhaps, counterintuitive, as the C&I bought the same total quantity of power as the load that it was serving. Why was the cost of serving the load so much higher than the vPPA price? The answer is the hourly timing of generation dramatically impacted the efficacy of the vPPA as a hedge on energy costs. Because the wind project generated very little power during the largest power price spikes, the C&I still had to serve the majority of its load through wholesale purchases of expensive power.

Figure 9. Quarterly Cost of Serving Around-The-Clock Load for a C&I with a $22/MWh vPPA

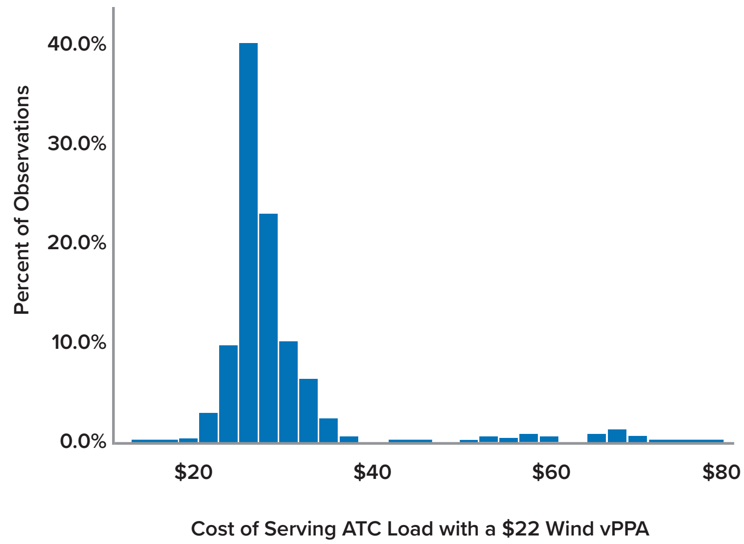
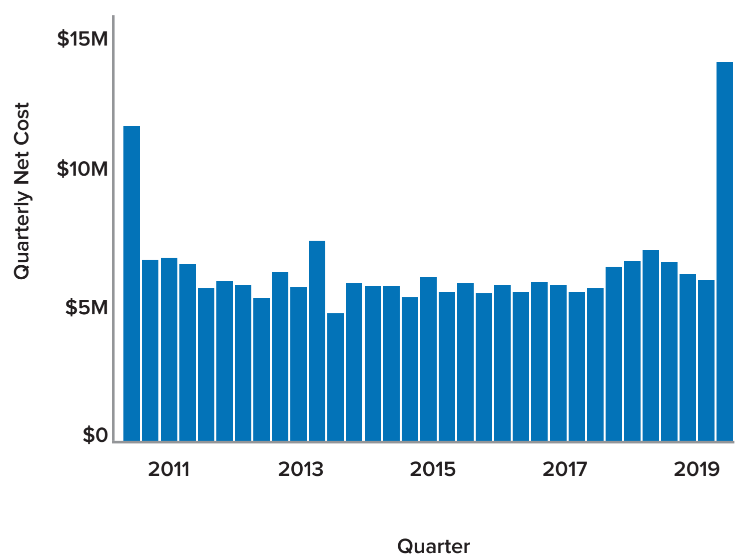


Figure 10. Quarterly Cost of Serving 100 MW of ERCOT West Around-The-Clock Load for a C&I with a $22/MWh vPPA



The hourly timing of generation dramatically impacted the efficacy of the vPPA as a hedge on energy costs.

Connect with us!

Do you have an operational or development wind or solar project with a P99 Hedge, and want to know how to manage the risk you hold as a result? REsurety offers hedging products to mitigate the residual risks held by P99 Hedged projects. To learn more, please contact Adam Reeve (areeve@resurety.com).

Do you have an operational or development wind project and want to know how the analyses presented in this white paper apply to your project specifically? Energy GPS has deep expertise in providing project-specific advice on this topic. To learn more, please contact Tim Belden (tbelden@energygps.com).

Annex I : Analytical Methods

The analytical methods used in this analysis were identical to the methods described in the original white paper; refer to Annex I in that paper (link here) for more information.

Annex II : Glossary of Terms

Term	Definition
80/20 Method	A revenue modeling method in which 80% of the expected p50 volume is assumed to be hedged using a P99 Hedge, and 20% of the expected p50 volume is assumed merchant. This modeling is incorrect, as we outline in this and the previous white paper.
C&I	A Commercial & Industrial buyer of energy; often a large corporation.
Hedged Quantity	All MWh that are both generated by the project and sold at the Fixed Price under the P99 Hedge.
Hedged Value	The revenue obtained by selling the Hedged Quantity at the Fixed Price.
Long Quantity	All MWh that are generated by the project in excess of the P99 Hedge Quantity, which must be sold at the spot market price.
Long Value	The revenue obtained by selling the Long Quantity at spot market prices.
Market Price	The generation-weighted spot market value of energy produced by the wind farm.
Non-Generated Sale Quantity	All MWh that were sold at the Fixed Price under the P99 Hedge, but for which there is no generation by the project to supply that sale.
Non-Generated Sale Value	The revenue obtained by selling the Non-Generated Sale Quantity at the Fixed Price.
Original Period	July 2011 through February 2018, this is the period of data analyzed in the white paper published in early 2018.
P99 Hedge	A fixed quantity energy price swap, in which a project agrees to sell fixed volumes in every hour at a fixed price to their hedge counterparty, independent of the project's generation.
P99 Hedged Revenue	The sum total value of Hedged Value, Long Value, Non-Gen Sale Value, and Short Value.
P99 Hedged Revenue per MWh	The value, per MWh, of a project's generation after settlement of a P99 Hedge. Calculated as the project's P99 Hedged Revenues divided by its total generation over a given period.
Short Quantity	All MWh that had to be purchased at the spot market price in order to satisfy the Non-Generated Sale Quantity.
Short Value	The cost of purchasing the Short Quantity at spot market prices.
Unhedged Generation	All generation that is not directly hedged under a fixed volume swap, this is identical to the sum of the Long Quantity.
Unhedged Generation Value	The sum of the Long Value, Short Value, and Non-Generated Sale Value, divided by the Unhedged Generation quantity.
Update Period	March 2018 through September 2019, this is the additional period of data analyzed in this white paper.
vPPA	A Virtual Power Purchase Agreement, also known as a Contract for Differences, in which a power buyer agrees to financially buy the energy and RECs produced by a renewable energy project.

Annex III : Annual Metrics

Year	Gas Price ($/MMBtu)	Around-The-Clock Price	Market Price	Hours of LMP <$0	Hours of LMP >$250	Average Price of Long Quantity	Average Price of Short Quantity	Average Price of Unhedged Generation	P99 Hedged Revenue per MWh
2011*	$3.73	$45.39	$24.27	146	64	$17.00	$49.41	$3.73	$13.70
2012	$2.76	$23.29	$17.01	339	24	$14.70	$31.36	$10.29	$16.70
2013	$3.73	$29.69	$24.50	165	24	$22.43	$34.35	$16.12	$19.40
2014	$4.37	$36.34	$29.83	50	36	$28.18	$46.55	$16.71	$19.51
2015	$2.63	$23.78	$18.92	129	23	$17.40	$28.05	$13.12	$18.21
2016	$2.52	$20.53	$15.88	274	21	$14.54	$24.17	$13.32	$18.17
2017	$2.98	$22.31	$17.22	363	13	$15.19	$27.03	$12.03	$17.77
2018	$3.18	$27.92	$18.35	439	57	$15.63	$35.38	$6.44	$15.29
2019**	$2.62	$39.10	$19.87	196	80	$15.73	$49.39	($3.48)	$ 11.74

*2011 partial year: uses data from July through December

**2019 partial year: uses data from January through September

All units in $/MWh unless otherwise stated

Gas location is Henry Hub, power price location is ERCOT West Hub Real-Time