Rate Design for EV Fast Charging Stations:

A Case Study from Duke Energy Progress

Disclaimer – Duke Energy had the opportunity to provide feedback and review this white paper prior to publication. The company did not have editorial control over the final product and does not explicitly endorse any views or opinions expressed herein.

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Executive Summary

Electricity pricing models influence the pace the Energy Transition and this is especially the case for electric vehicle (EV) fast charging stations, whose economics are being challenged by high electric bills. High bills make it expensive to operate fast charging stations, reducing the build-out of EV charging infrastructure, increasing charging prices for drivers, and generally slowing the adoption of EVs.

The problem is the result of a common feature of non-residential bills called a "demand charge." This charge is applied to the maximum power, measured in kilowatts (kWs), that a customer uses during the billing period. Demand charges are different from volumetric charges, which reflect the total amount of power consumed during a month and which are measured in kilowatt hours (kWhs). Demand Charges are often substantial even though they only apply to power used during a very limited period of time. Duke Energy's rate design team has designed a way to address this problem: a reformed Hourly Pricing design. This paper explores why this type of design is an excellent option for both EV fast charging stations and many non-residential customers.

How does this happen? Fast charging stations have high maximum power demands compared to the total amount of energy consumed. For example, a fast-charging station may have a maximum demand of 1,000 kW but only consume 10,000 kWh over a month. In comparison, a manufacturing facility, also with a maximum demand of 1,000 kW, would consume something like 475,000 kWh over the same period. Therefore, the impact of a demand charge based on the 1,000 kW of maximum demand is significantly greater for fast-charging stations. Using Duke Energy Progress rates from January 2024, the hypothetical fast-charging station's demand charge is 87% of the total bill, compared with 38% for the manufacturing facility – resulting in the EV station's total cost per kWh being five times higher!

The challenge is well articulated by Ryan McKinnion, a spokesperson for Charge Ahead Partnership, who recently told Utility Dive that "Many [National Electric Vehicle Infrastructure]-funding recipients will struggle to turn a profit on EV charging because of demand charges, so expect to see increased calls for EV-charging-specific rates".[1]

As discussed below, there are several ways to address this problem, but Hourly Pricing is likely to be the best solution. Hourly Pricing addresses the two fundamental problems with demand charges when it comes to fast-charging stations.

The first problem is that traditional demand charges are not precise enough to properly price fast-charging stations. They treat all maximum demand as increasing the utility's cost to maintain sufficient generating capacity. However, a given customer's high electrical usage during times when there are ample reserves of generation will not incur these costs. For example, a charging station consuming 1,000 kW on a very cold winter morning when electric demand is high would be costly since the utility will need to build another power plant to maintain reliability. The same customer consuming 1,000 kW on a mild, sunny afternoon is not nearly as costly since there is plenty of capacity available to meet this demand.

Second, traditional demand charges are set using "embedded costs." This basically is the average cost of providing capacity to meet all demand. In some circumstances, however, it is more appropriate to use marginal costs – the cost of the next unit of capacity. This is especially the case when price-sensitive load is being added, i.e., electricity which may or may not be demanded depending upon the power's price.

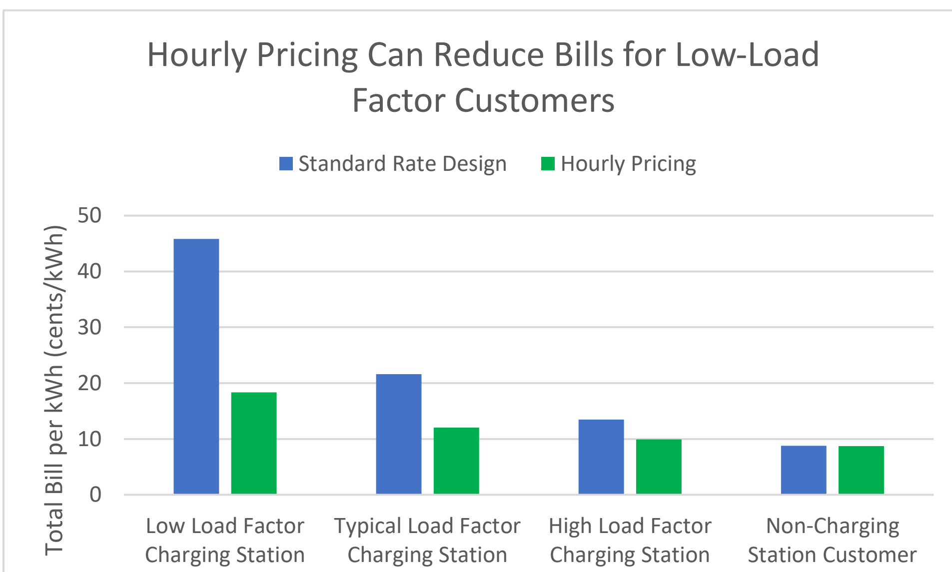
[1] 9 US power sector trends to watch in 2024 | Utility Dive

fast charging stations often meet this criterion, allowing pricing to reflect marginal costs. Marginal cost pricing is extremely useful, but must be carefully managed to ensure its application is appropriate and does not result in cross-subsidization.

Duke Energy has begun addressing these concerns with Hourly Pricing rate structures. Hourly Pricing is Duke's version of what many utilities call "real-time pricing"[2]. Here, a customer is sent hourly prices the day before based on the expected marginal cost. This allows participants to purchase a portion of their demand at marginal rather than embedded rates. It serves fast charging stations better because customers only end up paying for the generation capacity they use. Hourly Pricing thus recovers generation capacity costs more precisely, i.e., through higher volumetric (per kWh) charges for only those hours when the utility expects capacity to be scarce. The resulting demand charges are greatly reduced. Generation capacity (the largest category of capacity costs) is excluded, leading to a demand charge 4.5 times smaller than it would be under the standard rate design.

Predictive modeling for this new design looks promising. Hourly Pricing is expected to save fast-charging stations up to 35%, bringing the total cost per kWh close to that of typical non-residential customers. This is achieved without relying on any subsidization. EV fast charging stations can expect significant savings in the first four years of operations. Beyond these four years, significant savings are dependent on whether the station continues to increase its usage or if its usage is price responsive (i.e., load is reduced when hourly prices are high).

The risk that stations pay more over the course of a year under Hourly Pricing is minimal. The chart below shows modeled cost per kWh for different load factor EV fast charging stations, as well as an illustrative non-EV charging station customer.



Other proposals to mitigate the EV demand charge problem do not share these advantages. Mostly, these proposals offer discounts to fast-charging sites. These designs eliminate or discount demand charges,

[2] While this is the industry-standard term for these types of rate designs, I prefer the term "Hourly Pricing" since is not really "real-time" but is really day-ahead hourly pricing

while recovering more costs through the energy charge. For example, New York's PUC has required multiple utilities to offer an immediate 50% demand charge credit for all commercial EV charging-use cases. Longer term, the utilities are required to develop rates that reintroduce demand charges but have them scale with load factor (a measure of energy consumed compared to the maximum demand used).

There are three chief problems with these existing proposals. First, although demand charges are not perfect, they should not be eliminated without offering a better mechanism; demand charges exist for a reason. Utilities must serve customers maximum demand, even if reached infrequently. The demand charge reflects the cost of having this capacity available. Ignoring how these costs are incurred and offering discounts without a compensating mechanism will result in other customers having to pick up the tab (i.e., cross-subsidization).

Second, rate design should be end-use agnostic. Hourly pricing for all non-residential customers accomplishes this. To the utility, providing a kWh for a particular hour has the same cost regardless of if the end use is in an EV, in a factory, or to power your hair dryer. Why should these proposals for discounted demand charges exist for EVs but not for other non-residential customers? Many EV advocates would contest this, arguing that the need for public policies which promote EV adoption should outweigh this principle. However, more granular rate designs, such as Hourly Pricing, can achieve this goal without creating exceptions for EV charging.

Third, these proposals offer little incentive for fast charging stations to shape their load. Prices should reflect costs so that if a customer changes their load in a way that lowers costs for the system they are rewarded with a lower bill.

Utility rate designs can thus provide customers with the correct financial incentive based on costs and let them decide how best to operate and innovate to serve their needs. Under Hourly Pricing, fast-charging stations could experiment with many strategies to shape their load and further lower their bill: e.g., installing batteries, sending price signals to EV users, slowing maximum charging speed at certain times, or other creative solutions. Given the load shape of fast-charging stations and these additional opportunities, Hourly Pricing should offer significant savings to these customers. It is also likely a great option for fleet EV charging.

Hourly Pricing is thus a great solution to our national fast-charging station demand charge problem. Duke Energy's revamped Hourly Pricing rate designs have been recently approved by the North Carolina and South Carolina state utility commissions. Other utilities might consider how hourly or real-time pricing designs can benefit their customers.

The Demand Charge Problem

Most non-residential electric bills are composed of three basic types of charges. Fixed charges are a fixed price per bill. In theory, fixed charges should be based on the fixed costs that utilities incur. For example, a fixed charge could be $200 per bill and would be based on fixed costs such as installing and operating the billing system, installing electric meters, etc.

Energy charges are applied on a per kWh basis (i.e. based on the energy consumed). In theory, they should recover any costs that are incurred on a kWh basis, mostly fuel and purchased power. Energy charges are often what most people first think of when it comes to electricity bills. Indeed, almost all residential electric bills consist of a small, fixed charge and an energy charge. Since the fixed charge is often kept intentionally low, most costs are recovered through the energy charge.

Demand charges are applied to a customer's maximum power (per kW) used for the month. They are supposed to reflect the cost utilities incur to maintain sufficient capacity in the distribution, transmission, and the generation system to offer reliable electric service. For example, consider if a utility forecasts that it will have insufficient generation available to meet a future peak in system demand for electricity. If that utility were to build a new battery storage system or a natural gas plant to meet this future demand for electricity, then the costs involved would be classified as a "demand cost". Another example is if a utility needs to upgrade a distribution station because of expected increased load growth on that circuit. These are the types of costs that are supposed to be reflected in demand charges.

To demonstrate the challenge EV fast charging stations face, four hypothetical customers were considered using Duke Energy Progress rate designs for North Carolina. Three of the hypothetical customers are EV fast charging stations with identical demands but differing load factors. For comparison, a hypothetical fourth customer is also shown with an identical demand but a load factor indicative of a typical large general service customer. The table below shows load data and estimated bills for each of the hypothetical customers under the standard Large General Service (LGS) rate design, using prices as of January 1st 2024 (including riders).

	kWh	Non-Coincident Demand (kW)	Load Factor	Fixed Charge	Demand Charge	Energy Charge	Total Bill	Total Bill/kWh	Demand Charges as % of Bill
Low Load Factor	40,000	1,000	5.5%	$210	$15,980	$2,155	$18,345	$0.46	87%
Typical	100,000	1,000	13.7%	$210	$15,980	$5,387	$21,577	$0.22	74%
High Load Factor	200,000	1,000	27.4%	$210	$15,980	$10,774	$26,964	$0.13	59%
Non-EV LGS Customer	475,000	1,000	65%	$210	$15,980	$25,588	$41,778	$0.09	38%

LGS is typical of non-residential rate designs nationwide. There are three principal components to LGS – a fixed charge, energy charge and demand charge.

The fixed charge is that same for all four hypothetical customers at $210 per bill. The energy charge is 5.387 cents per kWh. This means that it scales with usage and load factor, meaning that the low-load factor station pays the least ($2,155), while the non-EV LGS Customer pays the most ($25,588).

In this example, all the fast-charging stations have the same maximum power demand that is set when all chargers are fully used simultaneously. Assuming this occurs in each billing period, this results in a consistent 1,000 kW of maximum demand across the different scenarios. The demand charge is $15.98 per kW, resulting in a total charge of $15,980. However, while the demand charge is consistent, its impact of the demand charge varies greatly for each of these hypothetical customers.

For the low-load factor fast charging station, the demand charge dwarfs the other charges, comprising 87% of the bill, resulting in a total cost per kWh is more than 5 times that of the non-EV LGS customer. The typical load factor fast charging station still has a total cost per kWh that is 2.5 times the non-EV LGS customer.

The high electricity bills for fast charging stations caused by demand charges is a significant problem that is being grappled with by charging station owners, utilities, and public utility commissions nationwide. There are currently proceedings opened or action taken in many states including Indiana, New York, Wisconsin, Massachusetts, Kansas, and California to address this issue.

Nevertheless, demand charges that appropriately recover the fixed costs of grid infrastructure allow for very low per-kWh energy costs. Like many utilities, Duke Energy Progress also offers a time-of-use option called Large General Service Time-of-Use (LGS-TOU). The TOU design makes the demand charges more targeted, with very low demand charges during times typically characterized by excess grid capacity. For example, the peak demand charge only considers demands set during a three-hour window each workday. For EV fleet charging, the fleet owner might be able to avoid much of the demand charges by concentrating charging into specific discount periods on the time-of-use rate. In essence, the presence of demand charges enables energy purchases for fleet managers at a very low per-kWh price because much of those demand costs can conceivably be avoided. In contrast, an EV fast charger site, even if not consistently used during peak times, could see high demand charges even from a small number of charging sessions during peak times. Therefore, while time-of-use rates might significantly benefit fleet EV owners with managed charging patterns, unmanaged EV fast charger stations need additional consideration.

Other Proposed Solutions

Utilities around the nation have tried to solve this demand charge problem in a variety of ways. Most attempts offer rates without demand charges (which recovers more costs through the energy charge) or offer specific discounts to fast charging sites. For example, Massachusetts eliminated demand charges for low demand EV customers and implemented a sliding scale for higher demand EV customers. Kansas provided a three period TOU rate for these customers that eliminated demand charges. The table shows a variety of other examples from around the country of these types of proposed reforms.

	Existing Solution Type	Example
Kansas	Rates without Demand Charges	Evergy offers a Business EV Charging Service which has three time-of-use (TOU) periods and only a small kW-based facility charge (<$3/kW)
Virginia	Rates without Demand Charges	Dominion provides an all-volumetric low-load factor rate applicable to non-residential customers with a load factor below 200 kWh per kW
Wisconsin	Demand Charge Discounts	Madison Gas and Electric provides a 50% discount for customer with load factors <15%
New York	Demand Charge Discounts & Demand Scaling with Load/Usage	• New York PSC ordered IOUs to provide a 50% discount on existing demand charges for all public DCFC site owners as a "short-term" solution • New York is pursuing scaling charges as their "long-term" solution

There are three chief problems with these existing proposals. First, demand charges exist for a reason. Theorized by John Hopkinson in 1892, the concept of demand charges has stood the test of time. A utility has to be ready to provide capacity to serve the customer's maximum demand even if this demand is only reached infrequently. The demand charge reflects the cost of having this capacity available. Ignoring how these costs are incurred and offering discounts will result in other customers having to pick up the tab (i.e., cross-subsidization). Scaling demand charges with load factor is better, but many perpetually low load factor sites could be subsidized in perpetuity.

Some rates, including most residential rates, do not utilize demand charges in an effort to simplify rate design and reduce bill volatility, benefits which can sometimes outweigh the improved alignment with cost causation brought by demand charges. The growing advocacy for time of use energy rates is an acknowledgement that the classic non-TOU energy charge rates can sometimes be suboptimal for accurately recovering utilities' costs. Although demand charges are still generally seen as a bridge too far for residential rates, sophisticated EV charging infrastructure companies do not raise the same administrative or public policy concerns as residential customers.

Second, rate design should be end-use agnostic, in keeping with the goal of rates to be not unduly discriminatory. To the utility, providing a kWh has the same cost regardless of if the end use is EV charging, widget production, or powering your hair dryer. EV-specific demand discounts thus afford one set of customers a benefit at the expense of other customers who might also bring public benefits. Many EV advocates would contend that increasing EV adoption is a policy goal, but many non-residential customers (e.g. schools, manufacturing, etc.) would likely argue for similar favorable rate treatment based on public policy.

Third, "discount" proposals offer little incentive for fast charging stations to manage potentially costly charging behaviors. Prices should reflect costs so that if a customer changes their load in a way that lowers costs for the system they are rewarded with a lower bill. For EV fast-charging stations this could be accomplished in many ways – installing batteries, sending price signals to the end-use customers[3], slowing maximum charging speed at certain times, or other creative solutions.

[3] The bills referred to here are for the owners of the fast-charging station who pay the utility. The "end-use" customer" is the actual EV owner using the charging station.

Similarly, EV fast-charging stations using a "discount" approach do not have the ability to offer deeply discounted charging pricing to end-use customers during low-usage times. For example, weekend or holiday charging (when long road trips are typical) could be priced much lower than average, encouraging grid-beneficial charging and increasing the charging station's energy consumption without increasing grid capacity needs or costs.

Utility rates should be agnostic about which method fast charging stations use to reduce bills, provided bill reductions correspond to reductions in grid operating costs by correctly sending price signals for customers to beneficially shape their load. Owners of these stations could decide to adopt none of these strategies and pay a higher bill, but at least the utility has given them appropriate price signals in case these strategies become financially viable in the future.

PG&E in California offers an interesting example. The California Public Utilities Commission ordered the incorporation of day ahead hourly energy pricing into a rate design that also included a volumetric energy generation capacity charge and a demand-based subscription fee.[4] The three parts of the rate were deemed to best fully recover the utility's cost while concurrently satisfying public policy goals. Day ahead hourly pricing was approved to be calculated based on the California Independent System Operator (CAISO) wholesale day ahead prices, specifically loss-adjusted day-ahead prices at PG&E's default load aggregation points.[5] The volumetric rate adder was added to "collect non-marginal generation costs as necessary to ensure the rate is revenue neutral".[6] The CPUC noted that it was keeping a demand-based subscription charge because fully incorporating capacity costs across the system in a hourly manner was not supported by the existing record at the time and would require more research and analysis.[7]

This partial day ahead hourly pricing option was made available to all ratepayer on the PG&E business electric vehicle (BEV) rates. The California example has not been widely copied in other jurisdictions, likely because implementation had not occurred as of the end of 2023.

Demand charge discounts are becoming increasingly common nationwide. As suggested last summer at the 36th International Electric Vehicle Symposium and Exhibition in Sacramento, CA (June 2023): "In the absence of holistic approaches that more exactly assign capacity-related costs to a customer based on location and time of their system utilization, utilities have turned to other near-term solutions to demand charge issues."[8] To address that absence, Duke Energy's Hourly Pricing approach follows cost causation principles and assists customers who avoid peak demand capacity utilization.

Hourly Pricing

Mechanics of hourly charges

Hourly Pricing does not fully replace a customer's standard tariff rate, but rather acts as a complementary mechanism that allows customers to purchase incremental amounts of energy and demand based on

[4] California Public Utility Commission https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M424/K557/424557371.PDF.
[5] Id at 9.
[6] Id. at 10.
[7] Id at 14.
[8] Michelle Levinson, Lori Bird, "A New Direction: Considerations for Vehicle-to-Grid Rate Design," *presented at the* 36th International Electric Vehicle Symposium and Exhibition (EVS36) Sacramento, California, USA, June 11-14, 2023, accessed athttp://evs36.com/wp-content/uploads/finalpapers/FinalPaper_Levinson_Michelle.pdf, page 2

marginal-cost pricing. For each hour of the year, a customer has a predetermined customer baseline (CBL). The impact of Hourly Pricing is fundamentally a function of two things: the difference between a customer's CBL to their actual usage and the difference between the hourly price and standard tariff rates.

To better understand the mechanics, examples of how Hourly Pricing affects both demand and energy charges are provided below.

Energy Charge Example

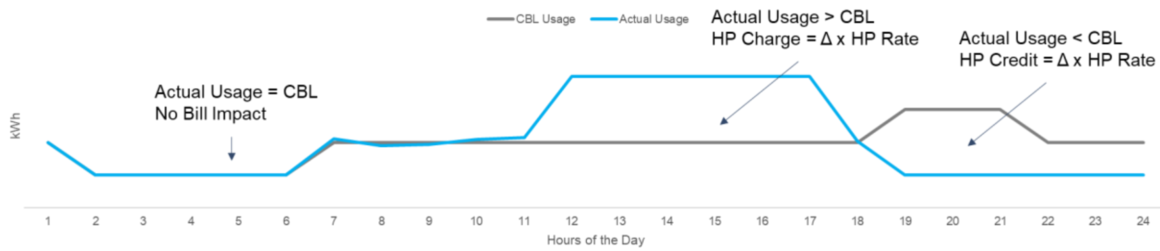
For example, a customer may have a CBL of 2,000 kWh for a particular hour. The customer always purchases their CBL at standard tariff rates regardless of their actual usage. Let us say that the LGS energy rate is 5 cents/kWh and the hourly price is 3 cents/kWh. In this case, the energy charge for the CBL for this particular hour will be $50, and this is charged regardless of actual usage.

If the customer consumes exactly 2,000 kWh, then Hourly Pricing will have no effect on their bill for this hour – the customer neither benefits nor is harmed by being on Hourly Pricing. However, if they consume 3,000 kWh then they would be purchasing an incremental 1,000 kWh at the hourly rate. This incremental 1,000 kWh is purchased at 3 cents/kWh rather than the standard 5 cents/kWh, resulting in a saving of $20 for this hour versus full service under the standard tariff.

Such pricing is typical during most hours of the year as the hourly price is a function of marginal energy and capacity costs. For most hours the utility has sufficient capacity, meaning that there are no marginal capacity costs associated with that hour. Similarly, the marginal unit is often relatively efficient, resulting in low marginal energy rates relative to standard tariff rates. Therefore, customers typically desire low CBLs to maximize the energy and demand purchased at an hourly rate, thereby maximizing their savings. Note that loads served perpetually above the CBL are not fully supporting embedded cost recovery for the assets used to serve that load, hence such hourly pricing rates have been historically restricted to incremental loads – that is, loads that would not materialize absent of Hourly Pricing.

Hourly prices will increase when capacity becomes scarce – creating marginal capacity costs and increasing marginal energy costs. Consider a scenario when the hourly price is 30 cents/kWh – six times the hypothetical standard LGS energy charge. In this case, the customer has an extra incentive relative to being on the standard rate design to reduce their usage because each incremental kWh costs 30 cents/kWh compared to 5 cents/kWh under LGS. In fact, if a customer reduces usage below their CBL a credit is applied.

The hypothetical customer would pay $50 for their CBL usage, as before. However, they would earn a credit equal to the difference between their CBL and actual usage multiplied by the hourly price. In this case, the difference in usage is 1,000 kWh and the hourly price is 30 cents/kWh, resulting in a credit of $300. Even considering the $50 charge associated with the CBL, the customer would receive a net credit of $250 associated with this hour. This example is shown in more detail in the figure below.



Hour	Difference between CBL and Actual Load (a)	Hourly Price (b)	Hour Price Charge/Credit (a x b)
4	0	3 cents/kWh	$0.00
15	1,000 kWh	5 cents/kWh	$50
20	-1,000 kWh	30 cents/kWh	($300)

In summary, Hourly Pricing allows customers to purchase incremental energy when marginal costs are low, while also incentivizing energy conservation when marginal costs are high. The difference between marginal and embedded costs typically results in customer savings over the course of a year unless the customer consumes a significant amount of energy when the utility is capacity constrained.

Demand Charge Example

Demand charges are significantly different under a marginal energy rate such as Hourly Pricing. Demand charges predominantly reflect generation capacity costs – the cost of maintaining enough generation units to meet demand at peak times. Under Hourly Pricing, this category of costs is recovered on a marginal basis through an adder on the hourly prices rather than through a demand charge. This results in a significantly reduced demand charge that only recovers distribution and transmission costs. It should be noted that Hourly Pricing changes both the way generation capacity costs are recovered (through adders to hourly prices), but also the total amount intended to be recovered (based on marginal rather than embedded costs).

Consider a hypothetical Duke Energy Progress customer with a monthly demand of 2,500 kW. Under LGS, the demand charge (using base rates only) is $14.39/kW, resulting in a charge of $35,975. A customer on Hourly Pricing has a CBL for demands as well as energy. If their CBL is 1,000 kW then their demand charge is $14,390 for the CBL. The incremental 1,500 kW of demand is subject to an "Incremental Demand Charge" of $3.80, resulting in a charge of $5,700. Therefore, under Hourly Pricing, the total demand charges are $20,090 compared to $35,975 for a savings of $15,885 for the month. This is summarized in the table below.

Example #	Demand Charge CBL (a)	Actual Demand (b)	LGS Rate (c)	CBL Demand Charge d = (a x c)	Incremental Demand Rate (e)	Incremental Demand Charge ((b-a) x e)	Total Charges	
HP	1,000 kW	2,500	$14.39	$14,390	$3.80	$5,700	$20,090	$15,885 savings
No HP		2,500	$14.39				$35,975	

Thus, assuming the loads remain incremental and do not contribute to growth in capacity expansion costs, hourly pricing can recover generation capacity costs on a marginal basis through hourly rates rather than demand charges, benefitting low load factor customers while remaining aligned with cost-causation principles and encouraging price-responsiveness While certainly true for the short-run, importantly, long-run sustainability of this construct and the avoidance of cross-subsidization is necessarily linked to CBL management, as described below.

The Theory Behind Customer Baselines

CBL management policies are the central mechanism for ensuring Hourly Pricing reflects long-run cost causation. Marginal cost pricing is appropriate only for marginal usage; indeed, typical utility marginal pricing rates only reflect short-run marginal costs. If all usage was priced at marginal costs, then the utility's revenues would not be recovering an appropriate amount of embedded costs (i.e., the revenue requirement). There would not be an appropriate recovery of investments, for example, in baseload generation plants – resulting in either an under- or over-recovery of costs.

For example, if the average marginal energy cost was 3 cents/kWh for a year, but the utility's average embedded costs were 5 cents/kWh then the utility would face a revenue shortfall of 2 cent/kWh. This does not imply that customers are being overcharged, but merely reflects the utility's cost structure as being predominantly fixed costs that do not increase linearly with incremental energy usage. The next year's average marginal energy costs could be 6 cents/kWh and embedded costs remain at 5 cents/kWh, resulting in an overcollection of 1 cent/kWh. Marginal costs are typically much more volatile since they are an estimate of the cost of the next unit of energy, while embedded costs reflect the actual revenue the utility needs to recover (and in this way reflect the average cost of energy). Therefore, it is critical that most usage is priced according to embedded costs.

Nevertheless, marginal cost pricing is appropriate for incremental or price-sensitive usage. In this case, so long as the incremental usage is priced above marginal cost, its addition puts a downward pressure on rates for all other customers. For example, consider a company that is considering building a factory. Under standard tariff rates, this factory may have an expected annual electricity bill of $10 million – this represents the factory's allocated share of embedded cost recovery. However, the factory may be uneconomic if it is charged more than $9 million per year. The marginal cost of this factory, the costs for the next unit of energy or demand, are only $7 million. In this case, if the utility charged $9 million – a savings of $1 million per year for the customer – then there is still an excess of $2 million per year above the marginal costs incurred. This $2 million surplus is essentially an extra contribution to recovering the utility's revenue requirement, thereby reducing the amount that needs to be recovered from all other customers. This theory underpins most pricing behind economic development rates.

The same logic applies on a shorter time horizon. Consider a factory, whose economics are extremely sensitive to the price of electricity. Its operations are only profitable when consuming energy at a rate of 4 cents/kWh or lower. Using only the LGS energy rate of 5 cents/kWh this factory would never be profitable to operate. The factory would shut down if this was the only pricing option available. However, for much of the year, marginal costs may be 3 cents/kWh. When this occurs, the factory could pay 3.5 cents/kWh to operate profitably, resulting in a surplus of 0.5 cents/kWh to the benefit of all other customers.

The CBL is critical because it is the determination of what usage should be priced at marginal or embedded rates. The CBL should reflect the usage that would occur in the absence of Hourly Pricing – the usage under the standard tariff rates. Any deviation from the CBL is in theory due to the effect of offering lower marginal rates (to encourage beneficial load growth) or higher marginal rates (to encourage lower usage when costs are high).

Setting the Customer Baseline

Like many utilities with a Real-Time Pricing design, Duke Energy's hourly pricing tariffs indicate the CBL should reflect one full year of hourly loads representing the customer's energy use. Adjustments to the CBL are allowed under some situations such as the permanent removal or addition of equipment.

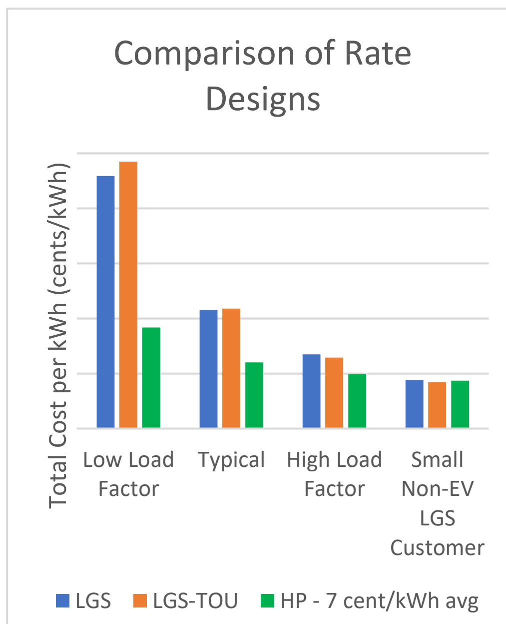
Duke Energy introduced a new Hourly Pricing design in 2023 which requires customers on Hourly Pricing to reestablish their CBL every four years. Such updates help ensure CBLs are adjusted frequently enough to appropriately reflect estimated usage in the absence of Hourly Pricing – requiring the incorporation of a price responsiveness component, described as follows.

Price-responsiveness is incorporated through a Load Response Adjustment for customers that have LGS-TOU as their underlying rate design. LGS-TOU has three time-of-use periods: peak, off-peak, and discount. The adjustment reduces the customer's CBL for demonstrated usage reductions on days when generation capacity is scarce. The Company will calculate what percentage of the customer's usage is responsive to prices, called a Load Response Factor. The customer's peak CBL (both energy and demand) will be reduced by the full Load Response Factor. The customer's off-peak CBL will be reduced by half of the Load Response Factor.

The Load Response Factor adds an additional incentive for customers to respond to prices. In short, if a customer is consistently responsive to prices, they can lower their CBL to purchase more energy and demand at marginal rates – typically a meaningful savings and especially attractive for low load factor customers like EV fast charging stations.

Applying Hourly Pricing to EV Fast Charging Stations

Hourly Pricing offers significant potential savings to EV fast charging stations. The figure to the right shows the total cost per kWh for the four hypothetical customers assuming an averaged consumed hourly price of 7 cents/kWh. The impact is greatest for the lowest load factor customers. In essence, Hourly Pricing functions like it is a demand charge that scales with load factor – except for the critical exception that is a dynamic rate design based on cost causation.



Potential EV fast charging customers may see the benefits of Hourly Pricing but also be concerned that switching to Hourly Pricing is exposing them to risk. This concern is understandable but likely overstated.

The pricing risk of Hourly Pricing is a function of both the hourly prices over any given time period, in addition to the customer's load shape. For example, the average hourly prices for a month may be relatively high at 7 cents/kWh, but a customer with a certain load shape may consume energy disproportionately at lower cost hours. The customer's average hourly price consumed could be 5 cents/kWh given their load shape. Therefore, the "risk" really comprises of two parts – 1) what will hourly prices be? and 2) what will the load shape of the customer be?

The first risk is mitigated due to the inherent benefits of marginal cost-based pricing. The average hourly price consumed would likely have to be 36 cents per kWh in Duke Energy Progress for a low load factor EV fast charging station to be better off purchasing energy and demand on LGS rather than Hourly Pricing. The equivalent "break-even" point for typical or high-load factor charging stations is roughly 15 and 10 cents per kWh, respectively. Hourly Pricing is based on the dispatch costs of a marginal unit. While this varies by hour, by season, and certainly with fuel costs, if the marginal unit is an efficient combined cycle with a heat rate of 6 and gas prices are $4/mmbtu, the marginal energy price is likely to be below 3 cents per kWh, a fraction of the per-unit energy costs a low-load factor customer would pay under the standard tariff. Therefore, there is currently very low risk that low load factor EV fast charging stations will pay a higher annual bill under Hourly Pricing compared to standard rate designs. The increased risk is clearly worth it for EV fast charging stations as a whole.

Another important conclusion of this analysis is that low load factor EV fast charging stations will almost certainly benefit from CBLs being as low as possible – allowing them to purchase more energy and demand under Hourly Pricing as opposed to the standard tariff rates. For this reason, it is critical that utilities, such as Duke Energy Progress, have appropriate policies in place to set CBLs to ensure the rate design properly reflects cost causation.

The second risk is that EV fast charging stations will have a load profile that consumes energy during higher cost hours. In other words, the typical hourly price may be low, but perhaps EV fast charging stations disproportionately consume energy during hours that are higher cost?

While this is a valid concern in theory, it is very unlikely to have an effect that is greater than the impact of using marginal cost pricing. As explained above, the average consumed hourly price would have to be very high to offset the benefits of Hourly Pricing.

Furthermore, the assumption that EV fast charging stations have a load shape that exposes them to disproportionately high hourly prices is far from certain. In fact, there is reason to believe that the load shapes of these customers will naturally result in usage during lower cost hours. In Duke Energy Progress, the highest cost of service hours tends to be cold winter mornings before 9 am in the morning. Most EVs are expected to be charged overnight and therefore usage and demand at fast charging stations is not expected to be particularly high during cold winter mornings.

However, there still is the risk that fast-charging stations sometimes consume a significant amount of energy and demand during high-cost hours. This reinforces a key benefit of Hourly Pricing – it reflects cost causation! If fast charging stations are a driver of peak demand and higher system costs, then they should be charged accordingly to avoid shifting costs to other customers. This is achieved through Hourly Pricing.

Likely Outcomes

Hourly Pricing's details are complex and so it may be helpful to summarize the expected total effect of this rate design on EV fast charging station's bills. Significant savings are expected for the first four years of operations. During this time, since the station can be considered marginal load to the system, a relatively low CBL may be justified, enabling a large portion of energy and demand to be purchased under hourly, marginal prices.

Beyond the initial four years, the impact of Hourly Pricing will depend on two factors. First, what is the growth in usage or load factor at the station? If usage grows substantially after the CBL is reset in year four then the station will continue to purchase a large share of energy and demand under Hourly Pricing and continue to benefit.

The second factor is whether the station can be responsive to prices. In theory, there are many ways this could be achieved - installing batteries, sending price signals to EV users, slowing maximum charging speed at certain times, or other creative solutions including encouraging charging when system prices are very low (i.e. valley filling). To the extent the station can be price responsive, it can continue to get a relatively low CBL and benefit from Hourly Pricing.

There is a greater risk that high load factor EV fast charging stations may be better off under the standard rate designs rather than Hourly Pricing for certain months. However, this is expected to occur in only a few months every year, meaning that annual savings are expected under the vast majority of circumstances.

Challenges and Barriers to Adoption

In spite of the many benefits of Hourly Pricing, there are several potential barriers to adoption that need to be addressed.

Complexity – Hourly Pricing is significantly more complex than offering a simple discount on demand charges. Stakeholders will need to understand that the benefits of this rate design outweigh the learning curve.

Concerns over Price Risk – Many potential customers may be deterred from trying Hourly Pricing because the rate design is more dynamic than standard rates. This can be overcome through modeling (such as the analysis presented above) and through limited trials of hourly pricing. Importantly, however, EV fast charging station owners that embrace Hourly Pricing and deploy effective strategies to encourage beneficial charging practices will create a durable strategic advantage over those that do not. Risk is indeed two-sided, with material potential upside for those who learn to manage this risk effectively.

Eligibility Requirements – Many Hourly Pricing or Real-Time Pricing programs have eligibility requirements that may limit participation. Duke Energy Progress's legacy Real-Time Pricing program had a cap on the number of participants due to administrative concerns. With the recent introduction of the revamped Hourly Pricing program, Duke Energy has created a program that is scalable and therefore has removed this limit on participation. However, the revamped program still requires customers to have a contract demand of 1,000 kW. While there are some EV fast charging stations that meet this threshold, many likely have a contract demand less than this threshold.

Conclusion

The existing proposals for solving EV fast charging station's demand charge problem are admirable but have significant drawbacks. Hourly pricing may be a better option that promises to promote the expansion of the EV charging network while also having a rate design that reflects cost causation. Hourly pricing adoption by fast charging stations can be beneficial for the station owner, the EV drivers, and, importantly, all other customers requiring electric grid services. Duke Energy's revamped Hourly Pricing rate designs have been recently approved by the North Carolina and South Carolina state utility commissions. Other utilities might consider how hourly or real-time pricing designs can benefit their customers.

Appendix

Applicability of Load Shapes and Rate Designs

These rate designs are broadly reflective of non-residential designs nationwide, consisting of a fixed charge, energy charge, and demand charge. While the load shapes are illustrative and are not derived from any real-world customers, they are broadly consistent with EV fast charging stations, non-residential load, and publicly available data on EV fast charging stations. The maximum non-coincident demands are slightly larger than the typical EV fast charging stations, although there are stations with demands that exceed this level. This was done to allow for consistent comparison across the Large General Service Rate Class.

Hourly Pricing Tariff – As of January 2024

HOURLY PRICING
SCHEDULE HP

AVAILABILITY

This Schedule is available, at the Company's option, for electric service to non-residential customers with a Contract Demand that equals or exceeds 1,000 kW. Customer must be eligible for service under Schedule LGS, LGS-HLF, or LGS-TOU for their baseline load.

This Schedule is not available: (1) for short-term or temporary service; (2) for electric service in conjunction with Incremental Power Service Rider IPS and Dispatched Power Rider No. 68; (3) for electric service in conjunction with Large Load Curtailable Rider LLC, or Economic Development Rider EC, except as provided for in the Baseline Charge; (4) to a customer who had discontinued receiving service under this Schedule, or its predecessor, during the previous 12 months; or (5) for any new customer with a Contract Demand in excess of 50,000 kW. Power delivered under this Schedule shall not be used for resale, except as otherwise provided in NCGS § 62-3. Also, power delivered under this Schedule shall not be used as a substitute for power contracted for or which may be contracted for under any other schedule of Company, except at the option of Company, under special terms and conditions expressed in writing in the contract with Customer. Customer shall be required to furnish and maintain a communication link and equipment suitable to support remote reading of Company's meter serving Customer and to support daily receipt of Hourly Prices.

APPLICABILITY

This Schedule is applicable to all electric service of the same available type supplied to Customer's premises at one point of delivery through one meter.

TYPE OF SERVICE

The types of service to which this Schedule is applicable are alternating current, 60 hertz, three-phase 3 or 4 wires, at Company's standard voltages of 480 volts or higher. When Customer desires two or more types of service, which types can be supplied from a three-phase 4 wire type, without voltage transformation, only the type of service necessary for Customer's requirements will be supplied under this Schedule.

MONTHLY RATE

The monthly rate shall consist of the following charges:

I. Baseline Charge = sum of charges under the Customer's baseline rate schedule for their Customer Baseline Load
II. Administrative Charge = $200 per month
III. Energy Charge = sum of [(New Load kWh – Reduced Load kWh) x Hourly Energy Price]
IV. Capacity Charge = sum of [(New Load kWh – Reduced Load kWh) x Hourly Capacity Price]
V. Incentive Margin = 0.6 cents per kWh of Net New Load
VI. Incremental Demand Charge = $3.80 per kW of Incremental Demand for Distribution Service
= $2.76 per kW of Incremental Demand for Transmission Service
VII. Taxes = NC Regulatory Fee (currently 0.1475%)

DEFINITIONS

Customer Baseline Load (CBL): The CBL is one full year of hourly loads representing the Customer's energy use and load pattern on their baseline rate schedule. The CBL, as agreed to by the Customer and the Company, is defined in terms of average kWh per hour and max kW, by calendar month and by time-of-use (TOU) period, if applicable. The CBL is based on the Customer's historical usage, where available, and may be adjusted for load responsiveness as described in the Customer Baseline Load provisions below. The Customer is billed or credited at Hourly Prices for actual usage above or below their CBL.

New Load: New Load (kWh) is the amount by which actual kWh exceeds CBL kWh for any hour.

Reduced Load: Reduced Load (kWh) is the amount by which actual kWh is less than CBL kWh for any hour.

Net New Load: Net New Load (kWh) is equal to New Load minus Reduced Load.

Incremental Demand: Incremental Demand (kW) is the amount by which actual kW (maximum integrated 15-minute demand during the month for which the bill is rendered) exceeds CBL kW for the same month.

Contract Demand: The maximum demand to be delivered under this Schedule.

CUSTOMER BASELINE LOAD

Initial CBL Establishment:

An initial CBL will be established based on the Customer's load history in the previous 12 calendar months, as determined by the Company and agreed to by the Customer. Adjustments or use of prior load history may be allowed in such cases as permanent removal or addition of equipment; installation of permanent energy efficiency measures; installation of parallel generation; nonrepresentative load patterns from extraordinary events; and plant shutdowns.

CBL Modifications:

CBL's are required to be re-established after four (4) years. Subsequent CBL's will be established using the same process and considerations as the initial CBL for existing customers, in addition to the Load Response Adjustment described below. Customers may request an update to their CBL no earlier than 12 months from their previous CBL.

Load Response Adjustment:

For customers on a TOU baseline schedule, CBL modifications may include a Load Response Adjustment, at the Customer's option and requiring at least 48 months of representative load history on Schedule LGS-HP or LGS-RTP. The Adjustment reduces the Customer's CBL for demonstrated load reductions on days when Hourly Capacity Prices are in effect. The Company will calculate the Customer's weighted average Load Response Factor, as a percentage of load, over the previous 48 months. The Customer's On-Peak CBL (kW and kWh) will be reduced by the full Load Response Factor, and the Customer's Off-Peak CBL will be reduced by half of the Load Response Factor. CBL's for Discount hours will not be adjusted.

VII. Hourly Pricing

Each business day by 4:00 p.m., the Hourly Energy Prices and Hourly Capacity Prices (if applicable) for the 24 hours of the following day will be communicated to the Customer. Prices for weekends and Company holidays will be communicated to the Customer by 4:00 p.m. on the last business day before the weekend or holiday. The Customer is responsible for notifying the company if he or she fails to receive the price information.

Hourly Energy Prices are based on the Company's forecasted marginal energy cost in each hour, which includes marginal fuel, variable operating and maintenance expenses, and an adjustment for delivery line losses.

Hourly Capacity Prices are applicable when the daily forecast indicates a reserve ratio of 1.15 or less, calculated as available generation divided by system demand. The Hourly Capacity Price is zero for all other hours of the year. When applicable, the Hourly Capacity Price is a tiered rate based on the forecasted reserve ratio, reflecting the marginal cost of production capacity.

VIII. Rider Adjustments

The following Riders are applicable to service supplied under this schedule. The currently approved cents/kWh rider increment or decrement must be added to the cents/kWh rates shown above to determine the monthly bill.

Leaf No. 601	Rider BA**
Leaf No. 602	Rider JAA*
Leaf No. 604	Rider EDIT-4*
Leaf No. 605	Rider CPRE
Leaf No. 609	Rider ESM*
Leaf No. 610	Rider PIM*
Leaf No. 612	Rider RAL-2*

*Riders JAA, EDIT-4, RAL-2, ESM, and PIM are not applicable to the Net New Load kWh usage.
**The DSM/EE component of Rider BA is applicable to incremental kWh usage if the customer is opted-in to the DSM/EE charges. The base fuel, fuel adjustment, and EMF rates are not applicable to the incremental kWh usage.

IX. Customer Assistance Recovery Rider (CAR)

The monthly bill shall include a CAR Adjustment (Leaf No. 611) to fund the Customer Assistance Program Credit Program for residential customers that qualify for the Low Income Energy Assistance Program (LIEAP) or Crisis Intervention Program (CIP) as is further explained in Leaf No. 718.

X. Storm Securitization Charge:

A Storm Securitization charge will be added to the monthly bill based on the currently approved cents/kWh incremental rate as shown in the Storm Securitization Rider (Leaf No. 607 Rider STS).

XI. Renewable Energy Portfolio Standard (REPS) Adjustment:

The monthly bill shall include a REPS Adjustment based upon the revenue classification. Upon written request, only one REPS Adjustment shall apply to premises serving the same customer for all accounts of the same revenue classification. If a customer has accounts which serve in an auxiliary role to a main account on the same premises, no REPS charge should apply to the auxiliary accounts regardless of their revenue classification (see Leaf No. 601 Annual Billing Adjustments Rider BA).

PROVISION OF STANDBY SERVICE

If service is received under a standby service tariff prior to service under this Schedule, the use of standby service shall be excluded from initial determination and update of the CBL. The Baseline Charge, as set forth in the Monthly Rate section above, shall include billing of Supplementary Service but shall not include any charges related to reservation or use of Standby Service. The Monthly Rate provisions of the applicable standby service tariff shall be calculated assuming no standby service was used. Any use of Standby Service will be billed pursuant to the Energy Charge provisions of this Schedule. All other provisions of the applicable standby service tariff apply.

SALES TAX

To the above charges will be added any applicable North Carolina Sales Tax.

PAYMENT

Bills are due when rendered and are payable within 15 days from the date of the bill. If any bill is not so paid, the Company has the right to suspend service in accordance with its Service Regulations. In addition, any bill not paid on or before the expiration of twenty-five (25) days from the date of the bill is subject to an additional charge of 1% per month as provided in Rule R12-9 of the Rules and Regulations of the North Carolina Utilities Commission.

CONTRACT PERIOD

The Contract Term shall be monthly and will be automatically renewed unless terminated by either party by giving not less than thirty (30) days written notice of termination.

GENERAL

Service rendered under this Schedule is subject to the provisions of the Service Regulations and any changes therein, substitutions therefore, or additions thereto lawfully made.

Where Customer's other source of power is connected electrically or mechanically to equipment which may be operated concurrently with service supplied by Company, Customer shall install and maintain at his expense such devices as may be necessary to protect his equipment and service and to automatically disconnect his generating equipment, which is operated in parallel with Company, when service used by Customer is affected by electrical disturbances on Company's or Customer's systems. Should Company determine that Customer's facilities are not adequate to protect Company's facilities, Company may install the necessary facilities and Customer shall pay for the extra facilities in accordance with Company's Service Regulations.

Company makes no representation regarding the benefits of Customer subscribing to this Schedule. Customer, in its sole discretion, shall determine the feasibility and benefits of Customer subscribing to this Schedule.