CITIZENSACTIONCOALITION
turning on citizen power *for 40 years*
603 E. Washington St., Suite 502, Indianapolis, IN 46204, (317) 205-3535
cacindiana cacindiana www.citact.org

March 26, 2017

The Honorable Representative David Ober
Chairman of the Committee on Utilities, Energy & Telecommunications
Indiana House of Representatives

Chairman Ober,

Attached is an analysis of **Senate Bill 309** prepared by Jennifer A. Washburn, Counsel for Citizens Action Coalition, at my request. I am sharing the analysis with you as it raises significant concerns with the proposed legislation and reinforces CAC's position against the bill.

Among others, Ms. Washburn identifies the following concerns and issues with respect to SB309:

- Whether the investments of current and future net-metering customers are indeed protected by the so-called grandfathering provisions within the bill. Specifically, Ms. Washburn states: ***If the intent was to protect grandfathered customers from additional fees or charges that could harm their economic investments, this may not have been accomplished as the bill stands today.***
- The ratemaking provisions within the bill for future distributed generation customers are ambiguous, vague, and uses terms undefined by the legislature. Specifically, Ms. Washburn states: ***The pricing provisions for excess distributed generation…are vague, inconsistent and contradictory and would likely lead to litigation over the credit due for excess distributed generation.***
- There is no guarantee that future distributed generation customers will receive a rate equal to "wholesale + a 25% bonus," despite statements to the contrary by proponents of the bill. Specifically, Ms. Washburn states: ***…Even this 125% of the average marginal price of electricity does not appear to represent a floor or minimum rate that would be guaranteed to customers who install distributed generation after June 30, 2022, when net metering will no longer be available, should the bill pass.***
- The bill as it stands today allows the utilities to seek approval for additional costs to be levied on distributed generation customers, and does not place a cap or any limits on those costs. Specifically, Ms. Washburn states: ***These create the same legal and financing uncertainties for the industry, leading to higher costs for Indiana customers. The net effect could be that investment flows to other states***.
- The 1% floor of summer peak load has been grossly mischaracterized as a "cap." Furthermore, there is already a process in place to address what happens if the utility chooses to avoid exceeding the 1% floor. Specifically, Ms. Washburn states: ***Thus, the Commission's current net metering rule already provides a way in which utilities can address the situation when the 1% minimum is met, should the utilities not choose to continue to offer the net metering rate already established.***

Ms. Washburn concludes her analysis by stating:

> ***In short, Senate Bill 309 has many problems and is likely to produce prolonged litigation. It is my recommendation that CAC continues to work against this bill or to work on an amendment that would ask the Commission to decide these highly technical and complex issues, particularly as it relates to the pricing and ratemaking provisions.***

I hope this memo helps to inform the process should SB309 continue to move through the legislature. Please reach out with any questions you may have or to discuss further.

Sincerely,

Kerwin L. Olson, Executive Director
Citizens Action Coalition of Indiana
603 E. Washington Street, Suite 502
Indianapolis, Indiana 46204
317-205-3535

Cc: Senator Brandt Hershman
Members of the House Committee on Committee on Utilities, Energy & Telecommunications
Members of the Senate Committee on Utilities

March 26, 2017

Kerwin L. Olson, Executive Director
Citizens Action Coalition of Indiana, Inc.
603 E. Washington Street, Suite 502
Indianapolis, Indiana 46204

Re: Senate Bill 309 – Distributed Generation

Dear Kerwin:

Pursuant to your request, I have developed the following analysis of amended Senate Bill 309, introduced by Senator Brandt Hershman (R-Buck Creek), which, among other things, changes the pricing structure provided to and the treatment of distributed generation customers.

In addition to the seemingly undesirable policy outcomes, several components of the bill suffer from legal infirmities that will likely result in extended litigation, chilling the marketplace and bringing uncertainty to customers and those in the industry. The following analysis is not meant to be exhaustive as other legal vulnerabilities appear to exist outside of those identified in this memo.

I. GRANDFATHERING MAY NOT BE WHAT IT SEEMS

First, it is important to understand this concept: electricity suppliers are subject to the rules governing interconnection standards and net metering which guide the creation of their interconnection agreements and net metering tariffs, while net metering customers are subject to those agreements and tariffs.

Second, it is important to understand that the existing interconnection rule, 170 IAC 4-3 (Rule 4.3, Customer-Generator Interconnection Standards), prohibits the utilities from charging fees for installations of ten (10) kilowatts or less,[i] defined as Level 1[ii]. From my understanding, Level 1 installations represent the majority of residential installations. Furthermore, the interconnection rule places limits on fees that the utilities may charge to interconnect facilities larger than 10kW, [iii] which are defined as Levels 2 and 3.[iv]

Third, it is important to understand that the existing net metering rule, 170 IAC 4-2 (Rule 4.2, Net Metering), prohibits the utilities from charging additional fees for participating in net metering, in addition to prohibiting fees for metering or the initial inspection.[v]

Section 11 of Senate Bill 309 (which would be codified at Ind. Code § 8-1-40-11, should the bill pass) provides that changes cannot occur to “an electricity supplier’s net metering tariff” either by the electricity supplier or by the Commission until July 1, 2047; however, there is an exception stated in Section 11. Section 11 states that 21(b) is not subject to the language in Section 11.[vi] It should be noted that Section 11 is silent with respect to interconnection agreements. This is important given that Section 21(b) provides that the Commission may adopt changes to the rules governing both interconnection standards and net metering after June 30, 2017, “as necessary to: (1) ***update fees or charges***; (2) adopt revisions necessitated by new technologies; or (3) reflect changes in safety, performance, or reliability standards” (emphasis added). Thus, if the Commission updates the interconnection standards or net metering rules to update fees or charges, then that would require the utilities to update their agreements and tariffs. If the agreements and tariffs are updated, grandfathered customers would be subjected to those new agreements and tariffs containing updated fees or charges, unless there is an exception so stated.

However, there is no stated exception for grandfathered customers, should the Commission update fees or charges in the interconnection standards or net metering rules. It is notably absent from Section 21(b) in Senate Bill 309 and from the two sections discussing grandfathered customers, Sections 13 and 14.

If the intent was to protect grandfathered customers from additional fees or charges that could harm their economic investments, this may not have been accomplished as the bill stands today.

II. PRICING IS NOT WHAT IT SEEMS: WHOLESALE + 25% IS NOT A GUARANTEE

Currently, under the Commission's net metering rule, net metering customers who consume more energy than they produce during the billing period are "billed for the kWh difference" between "the kilowatt hours (kWh) delivered by the investor-owned electric utility to net metering customer" and "the kWh delivered by the net metering customer to the investor-owned electric utility" "at the rate applicable to the net metering customer if it was not a net metering customer."[vii] Similarly, net metering customers who deliver more energy to the utility than what they produce during the period are "credited in the next billing cycle for the kWh difference."[viii] In short, this means that net metering is not a cash transaction, but rather a netting or crediting of the bill at the rate the net metering customer pays for electricity on a per kWh basis.

Under Senate Bill 309's Section 17, it provides two options for utilities to file new rates for distributed generation customers, and one of those options is so vague as to be not understandable. In addition, Section 19 allows utilities to charge additional fees to future distributed generation customers, while Section 21 may allow the utilities to levy additional fees on net metering customers presumed to be protected by the so-called grandfathering provisions within Sections 13 and 14, as previously discussed herein.

A. One of the Two Options for Rates for Future Distributed Generation Customers Described in Section 17 Is So Vague as to Be Not Understandable.

The pricing provisions for excess distributed generation established in Senate Bill 309 at Section 17 (codified at Ind. Code § 8-1-40-17, should the bill pass) are vague, inconsistent and contradictory and would likely lead to litigation over the credit due for excess distributed generation. The pricing provisions of proposed Section 17 have been touted by proponents of the bill as providing a guarantee of a rate for distributed generation that is 125% of the average marginal price of electricity, which is a great divergence from the 1:1 kWh swap currently afforded to customers under the IURC's current net metering rule at 170 IAC 4-4.2-7(2).

Yet, even this 125% of the average marginal price of electricity does not appear to represent a floor or minimum rate that would be guaranteed to customers who install distributed generation after June 30, 2022, when net metering will no longer be available, should the bill pass. Specifically, subsection 17(a) establishes that:

> the commission … shall approve a rate … for excess distributed generation if … the rate … equals the product of: (1) the average marginal price of electricity paid by the electricity supplier during the most recent calendar year; multiplied by (2) one and twenty-five hundredths (1.25).

But, subsection 17(a) is expressly "subject to subsection (b)." Under traditional rules of statutory interpretation, this means that the terms in subsection 17(a) are controlled or limited by subsection 17(b). Subsection 17(b) provides that the Commission "shall approve":

> a rate equal to the average marginal price of electricity during the most recent calendar year … if the commission determines that the break even cost of excess distributed generation effectively competes with the cost of generation produced by the electricity supplier.

The term "break even cost of excess distributed generation" in subsection 17(b) is undefined by the bill and very ambiguous. In the absence of a statutory definition, one could use the dictionary definition to determine the plain meaning, although there is the risk that one could arrive at different meanings of these words depending on which dictionary or definition is used. However, in technical or specialized areas like utilities, one could argue that the interpretation should be consistent with the way those words are used in the relevant industry, and it appears that "break even cost" may be an industry term.[ix] Unfortunately, even if "break even cost" is found to be an industry term, it still seems likely that litigation and price uncertainty will ensue. A report by the National Renewable Energy Laboratory in 2009 both provided a complicated formula for "break even cost" and presented findings that "[a]chieving PV [solar] breakeven is a function of many variables, including the solar resource, local electricity prices, and various incentives… Currently, the break-even cost of PV [solar] in the United States varies by more than a factor of 10 despite a much smaller variation in solar resource. Overall, the key drivers of the break-even cost of PV [solar] are non-technical factors, including the cost of electricity, the rate structure, and the availability of system financing, as opposed to technical parameters such as solar resource or orientation."[x] Without guidance from the legislature, excessive litigation may result in attempting to determine various aspects about subsection 17(b)'s "break even cost of excess distributed generation." This could include litigating over what the appropriate "break even cost" formula is, the appropriate inputs to plug into the "break even cost" formula, how often to update the various inputs and outputs of the formula, etc.

The term "effectively competes" is similarly undefined in subsection 17(b). Again, in the absence of a statutory definition, one could use the industry term (which seems unlikely for "effectively competes") or the dictionary definition to determine the plain meaning, although there is the risk that one could arrive at different meanings of these words depending on which dictionary or definition is used. Precisely what the language in subsection 17(b) would mean for future distributed generation customers is so ambiguous as to be unintelligible and is likely to bring excessive litigation from both sides. In addition to the risk of litigation, another problem is that the industry cannot predict how the Commission or the courts would interpret these provisions, which will likely make it much more difficult to finance projects, thereby increasing costs to Indiana customers. Regardless of policy preferences, creating complicated and ambiguous regulations is bad for marketplace certainty.

B. Customers Who Install Distributed Generation after June 30, 2022, Could Be Subject to Additional Costs, and There is No Limit in Place for Those Potential Additional Costs.

Section 19 under Chapter 40 (creating Ind. Code § 8-1-40-19) adds the following provisions:

> (a) To ensure that customers that produce distributed generation are properly charged for the costs of the electricity delivery system through which an electricity supplier:
>
> (1) provides retail electric service to those customers; and
>
> (2) procures excess distributed generation from those customers;

the electricity supplier may request approval by the commission of the recovery of energy delivery costs attributable to serving customers that produce distributed generation.

(b) The commission may approve a request for cost recovery submitted by an electricity supplier under subsection (a) if the commission finds that the request:

(1) is reasonable; and

(2) does not result in a double recovery of energy delivery costs from customers that produce distributed generation.

This provision permits the utilities to apply to the Commission to recover any "energy delivery costs attributable to serving customers that produce distributed generation" that are not already being recovered from those customers. Please note that the term "Energy delivery costs" is not defined in the bill. Thus, the following questions arise, which would likely be litigated:

- Would a dictionary be used to define "energy delivery costs," or is there an industry definition available? If there is an industry definition available, is there a standard formula or does it vary?
- Do "energy delivery costs" include only distribution costs not otherwise recovered, or might they also include transmission and generation costs not otherwise recovered?
- Would utility "lost revenues" attributable to the distributed generation produced and consumed by the distributed generation customer be included in this additional cost?
- Would "customers that produce distributed generation" in Section 19 also include supposedly "grandfathered" net metering customers still covered by the IURC's Net Metering Rule (170 IAC 4-4.2)?

These unanswered questions are cause for concern, especially when subsequent provisions of the bill are also considered. Additionally, there is no "cap" or limit placed on those potential costs, creating risk and more uncertainty for those customers and investors considering distributed generation. These create the same legal and financing uncertainties for the industry, leading to higher costs for Indiana customers. The net effect could be that investment flows to other states.

III. SENATE BILL 309 PREMATURELY CIRCUMVENTS THE PROCESS ALREADY CLEARLY AVAILABLE TO UTILITIES WHEN THE 1% FLOOR IS MET.

The Commission's current net metering rule at 170 IAC 4-4.2-4 provides in pertinent part that:

> The investor-owned electric utility may limit the aggregate amount of net metering facility nameplate capacity under the net metering tariff to one percent (1%) of the most recent summer peak load of the utility, with at least forty percent (40%) of the capacity reserved solely for participation by residential customers. ***However, the investor-owned electric utility may increase the limit on the aggregate amount of net metering facility nameplate capacity at the investor-owned electric utility's sole discretion***. (emphasis added)

First, the 1% floor has been mischaracterized as a "cap." As evidenced by the Commission's current net metering rule at 170 IAC 4-4.2-4, the 1% represents a floor established by the Commission, not a ceiling or a "cap." Should the utility desire to continue to offer net metering to new net metering facilities once it reaches or reasonably anticipates reaching the 1% floor or minimum, then the utility may do so under the Commission's current net metering rule.

However, if the utility does not wish to extend net metering beyond the 1% minimum under the Commission's current net metering rule, the utility may petition the Commission to open a docket to establish an appropriate reimbursement rate for new net metering facilities. This is due to the Filed Rate Doctrine, which is codified at Ind. Code §§ 8-1-2-38, 8-1-2-39, and 8-1-2-103. The Filed Rate Doctrine established by the U.S. Supreme Court in *Arkansas Louisiana Gas Co. v. Hall*, 453 U.S. 571, 578, (1981), should preclude the utility from implementing a rate other than the net metering rate until the Commission establishes the new rate through ratemaking.

This is to say that net metering would <u>not</u> go away once the 1% minimum is met, but that a utility who chooses not to extend net metering beyond the 1% must return to the Commission to open a docket so that the situation and proposed tariffs can be examined. It is important to note that thirty (30) day filings under Ind. Code § 8-1-2-42 provide for a process wherein the utility can seek relief on an expedited basis, should that be a concern of a utility.

Thus, the Commission's current net metering rule already provides a way in which utilities can address the situation when the 1% minimum is met, should the utilities not choose to continue to offer the net metering rate already established.

To add some context, the Commission's 2016 Net Metering Required Reporting Summary[xi] released in March of 2017 shows that not one of Indiana's five investor-owned utilities is anywhere near the 1% floor, Indeed, the utility closest to the 1% floor is Vectren. Yet the Commission's report provides that Vectren has 10MW of capacity still available to their customers, representing 83% of the 1% floor still remaining. Clearly, there is ample time to address any concerns that may exist relative to the 1% floor found in the Commission's current net metering rule as it does not appear likely that one of the investor owned monopoly utilities would reach the 1% floor anytime soon.

IV. A POTENTIAL CONFLICT EXISTS BETWEEN PURPA AND SENATE BILL 309.

The federal Public Utility Regulatory Policies Act (PURPA) requires electric utilities to purchase available energy and capacity from qualifying small power producers and facilities. *See* 16 U.S.C. § 824a-3 (the "must-buy" requirement). Rates for purchases by electric utilities must be "just and reasonable" and may not "discriminate" against qualifying small power producers. *Id.* FERC has delegated to states the authority to set "qualified facility" (QF) rates, but there are limits. Under FERC's implementing regulations, upheld by the U.S. Supreme Court in 1983, avoided cost rates must be set at the utility's full avoided cost. *Am. Paper Inst.*, 461 U.S. at 406 (1983). In other words, avoided costs must include all of the costs that the utility does not incur as a result of the purchase from the QF. *Id*. FERC explicitly sets out factors that must be considered when determining avoided costs, such as reductions in line losses and deferral of capacity additions. *See* 18 C.F.R. 292.304(e).

There is potential for conflict between PURPA and Senate Bill 309 because the bill's definition of "distributed generation" (Ch. 40, Sec 3) overlaps with PURPA's criteria for certification as a "qualified facility" (18 C.F.R. 292.204). To the extent that the state law mandates payment to QFs through terms that conflict with PURPA, then PURPA would preempt the state law under the Supremacy Clause of the federal Constitution. *See, e.g., Freehold Cogeneration Assoc. v. Bd. of Regulatory Comm'rs of New Jersey*, 44 F.3d 1178 *(3d Cir.1995).*

V. CONCLUSION

In short, Senate Bill 309 has many problems and is likely to produce prolonged litigation. It is my recommendation that CAC continues to work against this bill or to work on an amendment that would ask the Commission to decide these highly technical and complex issues, particularly as it relates to the pricing and ratemaking provisions.

Sincerely,

Jennifer A. Washburn

Jennifer A. Washburn, Counsel
Citizens Action Coalition of Indiana
603 E. Washington Street, Suite 502
Indianapolis, Indiana 46204
317-735-7764
jwashburn@citact.org

---

[i] 170 IAC 4-4.3-4(e)(1) (concerning application and interconnection review fees for Level 1).
[ii] 170 IAC 4-4.3-4(a)(1)(defining eligibility for Level 1 review procedure).
[iii] 170 IAC 4-4.3-4(e)(2)-(3) (concerning application and interconnection review fees for Levels 2 and 3).
[iv] 170 IAC 4-4.3-4(a)(2)-(3) (defining eligibility for Level2 and Level 3 review procedures).
[v] 170 IAC 4-4.2-6(b).
[vi] Section 11 also provides an exception for Section 12.
[vii] 170 IAC 4-4.2-7(2).
[viii] *Id*.
[ix] National Renewable Energy Laboratory, *Break-Even Cost for Residential Photovoltaics in the United States: Key Drivers and Sensitivities*, December 2009, available at: http://www.nrel.gov/docs/fy10osti/46909.pdf. *See* Appendix A: Calculation of Break-Even Cost.
[x] *Id*. at iv.
[xi] Indiana Utility Regulatory Commission ("IURC") 2016 Net Metering Required Reporting Summary, March 2017, available here: http://www.in.gov/iurc/files/2016%20Net%20Metering%20Required%20Reporting%20Summary.pdf..