Distributed Generation in Indiana: A Preliminary Policy Discussion

Michael J. Hicks and Mark L. Burton[1]

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Executive Summary

This study outlines issues regarding the growth, pricing and regulatory structure of distributed generation (DG) in Indiana. We make the following points. 1) Distributed generation, as a share, of overall electricity production in Indiana is still quite small; 2) While Indiana's projected growth in DG follows the form of national forecasts, its estimated magnitude is measurably smaller than elsewhere, but may still be quite large as compared to current levels; 3) Unlike most regions, wind-powered distributed generation is likely to play a greater role in Indiana than generation from solar PV production; and 4) Indiana's reliance on net metering to govern economic interactions between DG producers and incumbent utilities has sufficed as an introductory strategy, but is not adequate as DG grows toward its potential place in the state's long-run energy mix.

We note also that there are benefits to DG. Among them are DG: (1) allows, at least some, users to more directly control household and business-related energy costs, (2) provides a direct and potentially important vehicle for increasing the role of renewables in electricity generation, and (3) may ultimately moderate the need for future utility sector investment in additional generating capacity.

[1] Dr. Hicks is Director of Ball State University's Center for Business Research, and Dr. Burton is Director of Economic Research at the University of Tennessee's Center for Transportation Research.

1. INTRODUCTION

Current U.S. Federal energy policies support the use of renewable energy sources in the generation of electricity. This support encompasses public and investor-owned utilities, customer owned co-generation facilities, and finally, small-scale commercial and residential self-suppliers engaged in what is commonly called "distributed generation" (DG) or, sometimes "customer owned generation." While, utility sector use of renewable energy and renewable-based generation by independent power producers have been deftly managed by policy-makers and regulators, the rapid growth in DG, combined with its measurably different economic and technological attributes, has introduced a raft of new policy challenges that require thoughtful attention.

Like most states, Indiana has joined as a partner in federal efforts to support the use of renewable resources and, accordingly, has adopted policies that promote and support distributed generation. To a large extent these policies have been successful. Within the state, electricity generated through DG is expected to top 10,000KW for 2014. However, as Indiana's policy on this matter enters its second decade, there is evidence that current programs, at least in their present form, may not be in the long-run public interest and may, instead, require significant modification. Consequently, as in most jurisdictions, there are discussions in Indiana aimed at reevaluating the state's policies governing distributed electricity generation.[2] Our purpose in the remainder of the current document is to help inform these discussions by providing what must be characterized as "preliminary" information and guidance. Finally, while future policies regarding DG require the treatment of both technological and legal issues, we limit our comments to the economic elements inherent in this discussion.

We continue, in Section 2, with a general description of distributed generation and some of its economic challenges. Section 3 provides preliminary empirics describing DG's probable course and economic implications in Indiana. Section 4 begins a discussions of what we believe are economically sound and defensible policy alternatives. Finally, we offer concluding thoughts in Section 5.

[2] See Revised Final Agenda, IRP Contemporary Issues Technical Conference, Indiana Utility Regulatory Commission, October, 23, 2014.

2. THE ECONOMICS OF DISTRIBUTED GENERATION

Among an array of generally laudable impacts, the national policy focus on using renewable resources to generate electricity increasingly provides both residential and commercial customers the opportunity to self-supply some or all of their ongoing electricity needs through what is generally referred to as distributed generation (DG). DG can be accomplished through the use of small wind turbines, mini-turbines, or a number of other means, but most often relies on solar or photovoltaic (PV) energy as a fuel source.[3]

Within a DG setting, the commercial or residential producer generates electricity for self-use as conditions allow. When they are is unable to produce sufficient quantities, electricity is provided by a traditional utility to which it remains connected and, when the DG producer generates electricity in excess of its immediate needs, this excess is fed into the same utility's distribution system for consumption by other users.

There are two prevalent forms used to govern the economic relationship between the DG and the utility. These include "net metering" and "feed-in tariffs" (FITs). In Indiana, as in most states, the former of these – net metering – is specified under current policy.[4] If nothing else, the process is simple; the electricity the DG producer procures from the serving utility is metered, as is the amount of electricity it feeds into the utility's distribution system. At specified intervals (usually billing cycles) the net balance is calculated and settlement is made. Under most net metering scenarios, the electricity is valued at the applicable bundled retail rate without regard to the timing or origin of its generation.

When distributed generation was in its infancy, the economic asymmetries and distortions inherent in net metering were generally judged as trivial compared to the gains this simple process helped achieve in increased renewable use. However, by virtue of technological advance, corresponding reduction in DG costs and because of the

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[3] Nationally, solar power accounts for nearly 90 percent of all distributed generation. However, in Indiana, solar DG share is just over 37 percent. See American Public Power Association (APPA), "Distributed Generation: An Overview of Recent Policy and Market Developments, November 2013, available at http://www.publicpower.org/files/PDFs/Distributed%20Generation-Nov2013.pdf

[4] The specific attributes of Indiana's current policy are briefly discussed in Section 3. However, as an example of the state's current policy, readers are directed to Duke Energy Indiana, Inc. IURC NO. 14, Fifth Revised Sheet No. 57.

incentives net metering creates, DG continues to grow rapidly[5]. Indeed, in the extreme, estimates suggest that self-supply through DG could account for 50 percent of residential and commercial consumption by 2050.[6] While other estimates are less aggressive, nearly any assessment of DG's potential role in future energy outcomes supports renewed attention to the form and effects of net metering.

As described, net metering routinely relies on a single bundled retail price to account for the difference in volume of electricity deliveries between the serving utility and the DG producer. In the case of electricity produced by the utility and made available for use by the DG, this retail price is appropriate; it accounts for the utility's generation cost and the cost of transmitting power across the utility's distribution network. However, when the DG produces more electricity than it purchases from the utility, it is credited with the same retail price even though the DG isn't required to build or maintain the transmission network used to deliver its excess production to other network customers. Instead, those costs are again incurred by the utility.

The fundamental price distortion outlined here can have a number of undesirable consequences. First, to the extent that the utility's full array of prices are effectively regulated, its recovery of the costs incurred in accepting and transmitting DG-produced power will likely fall on other non-DG rate payers, thereby imposing a cross-subsidy.[7] Moreover, to the extent that the set of rate payers negatively affected by this transfer may have incomes that are lower than those of the DG customers, this transfer is inherently regressive.[8]

In the extreme and over a prolonged period of time, the distortions introduced by net metering could, in fact, be wholly debilitating to any incumbent utility that is required to

[5] For a discussion of DG technologies and reduced generating costs see AAPA (2013).

[6] See Citi Research, "*Rising Sun: Implications for US Utilities,"* (Aug. 8, 2013).

[7] Formally defined, a cross-subsidy would require that the DG customers face an effective price that is less than their incremental cost in the transaction and that a corresponding set of rate payers pay a price that exceeds their stand-alone cost (the cost of supplying them absent the DGs). This outcome is only assured if the utility in question faces regulated rates in all markets. See Faulhaber, G. R. (1975). Cross-Subsidization: Pricing in public enterprises. *American Economic Review, 65*, 966–977.

[8] This was recently documented to be the case in California. See California Public Utilities Commission, "California Net Energy Metering (NEM) Draft Cost Effectiveness Evaluation (2013), available at http://www.cpuc.ca.gov/NR/rdonlyres/BD9EAD36-7648-430B-A692-8760FA186861/0/CPUCNEMDraftReport92613.pdf.

provide services in an area where DG has gained a prominent share of supply. Raskin (2013) outlines precisely this scenario in his assessment of the potential legal issues surrounding distributed generation.[9] Essentially, if broadly applied, net metering could impose losses sufficiently large so that the incumbent utility finds it impossible to fully recover those losses from the set of non-DG rate payers. In such a case, the incumbent utility would gradually find itself in possession of large amounts of stranded capital assets for which it cannot pay.[10] While this sort of doomsday scenario is difficult to imagine, its functional possibility, when combined with the longevity of electric utility industry capital, may lend weight to Raskin's concluding caution that:

> Over the long term, any required unwinding of the utility-owned grid due to distributed generation will be extraordinarily complex and will raise many novel and intractable legal and policy issues.[11]

3. DISTRIBUTED GENERATION IN INDIANA

Indiana electric power generators produce roughly 114,000 GWh, with coal as the dominant fuel source.[12] Total consumer demand for base load electrical power generation has ranged from 59,000 GWh in the early 1980's to a projected 112,000 GWh in 2030.[13] Indiana's electrical power demand mimic's the national growth in per capita usage, but is more coal intensive and less reliant upon nuclear, hydroelectric, wind or photovoltaic than the nation as whole.

Distributed Generation within Indiana remains a modest share of generation, but is growing rapidly. Regulations regarding DG net metering service are contained in Indiana Code 8-1-37-4(a)(1) through Indiana Code 8-1-37-4(a)(1)(8). These regulations generally stipulate the size, type, technical, production and insurance requirements for these facilities, which are typically

[9] David B. Raskin, "The Regulatory Challenge of Distributed Generation," The Harvard Business Law Review Online, Volume 4, 2013, available at http://www.hblr.org/2013/12/the-regulatory-challenge-of-distributed-generation/

[10] Except for its gradual nature, the stranded cost scenario developed by Raskin (2013) is similar to depictions proffered by economists in the early 2000s as related to competitive entry in a vertically separated electric utility industry. See, J. Gregory Sidak and Daniel F. Spulber, "Deregulatory Takings and Breach of the Regulatory Contract," 71, *New York University Law Review*, 851 (1996).

[11] Supra, Note 9.

[12] GWh is a unity of electrical energy equal to a billion Watt hours. MWh is million watts, and KWh is a thousand watts.

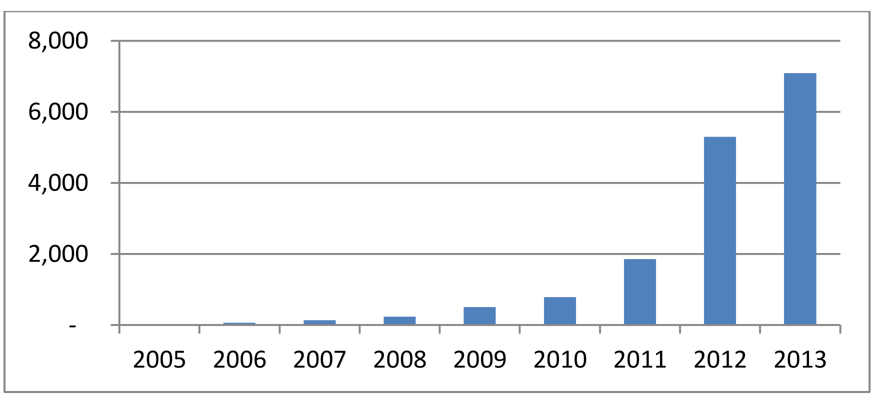
[13] See Indiana Electricity Projections: The 2013 Forecast, State Utility Forecasting Group (SUFGSUFG), December 2013.

designed to provide power generation for a residence. Electric suppliers which provide power typically establish net metering riders. An example follows:

> Monthly charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the Company's standard service tariff under which the customer would otherwise be served, absent the customer's eligible net metering facility. Energy charges under the customer's standard tariff shall be applied to the customer's net energy for the billing period to the extent that the net energy exceeds zero. If the customer's net energy is zero or negative during the billing period, the customer shall pay only the non-energy usage portions of the standard tariff bill. If the customer's net energy is negative during a billing period, the net metering customer shall be credited in the next billing period for the kWh difference. When the net metering customer elects to no longer take service under this Net Metering Service Rider, any unused credit shall revert to the Company. (*IMPC Rider NMS, Original Sheet No 33.2*)

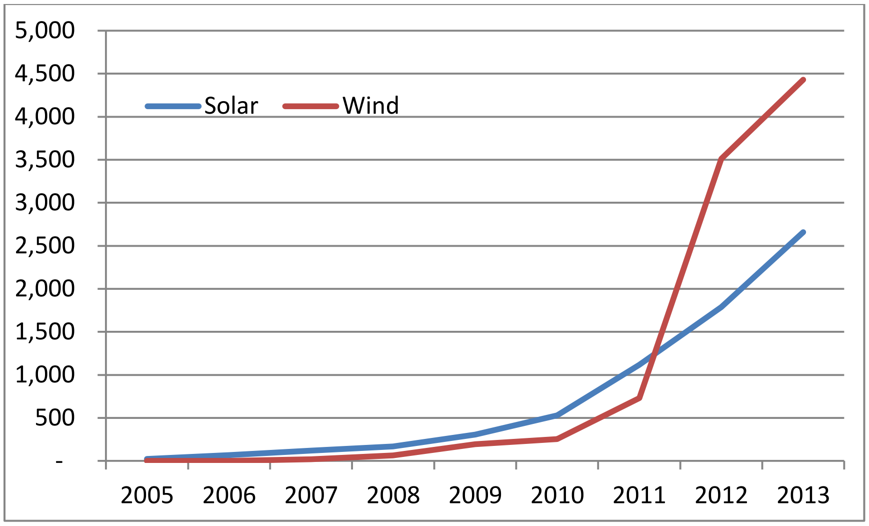
As clearly outlined, this Net Metering Service (NMS) rider allows the DG customer to earn credits at the KWh retail rates set forth in utility tariffs for DG production greater than her demand for power. As outlined in the section above, this pricing mechanism creates incentives that generate rapid growth in DG. As with the United States in general, Indiana has experienced this rapid growth of DG production from 23 KWh to 7,087 KWh produced per year from 2005 to 2013. See Figure 1.

Figure 1, Distributed Generation Growth in Indiana (KWh) (Source, IURC)



However, unlike states with the largest share of DG production, Indiana's DG producers are far more reliant upon wind generation than solar production. This should be unsurprising given that Indiana ranks low (40th) in the number of days with sunshine.[14] As a consequence, wind power generation growth has been faster in Indiana, and now comprises almost two thirds of all DG power production in the state. See Figure 2.

Figure 2, Solar PV and Wind DG in Indiana (kW) (Source, IURC)



This is important because forecasts of growth of DG suggest that the bulk of growth nationally will be in solar generation. For example, a recent forecast predicted significant growth of solar PV generation to roughly 52,000 GWh by 2030, with virtually no growth in wind or hydroelectric generation and sluggish growth in biomass across the eastern United States.[15] This suggests that the Hoosier experience with DG will be large, but experience a less dramatic growth period than DG in areas in which solar PV are more cost effective due to a higher number of generating days.

To contextualize DG in Indiana, we extend the historical production data with a forecast of DG across the state through 2030. We note that though the growth displayed in Figures 1 and 2 are dramatic, the DG share of energy production in Indiana is currently small. For example in 2013 only 7,087 kW of DG were recorded (nameplate capacity) in Indiana, while overall base load demand for commercial electrical power was 100,621 GWh. DG customers are likewise a small share of overall energy connections in the state, with only 522 participants as of 2013 compared to approximately 2.3 million customers of the investor owned utilities. However modest current levels of DG are, the very obvious rapid growth which has occurred in the relatively brief period

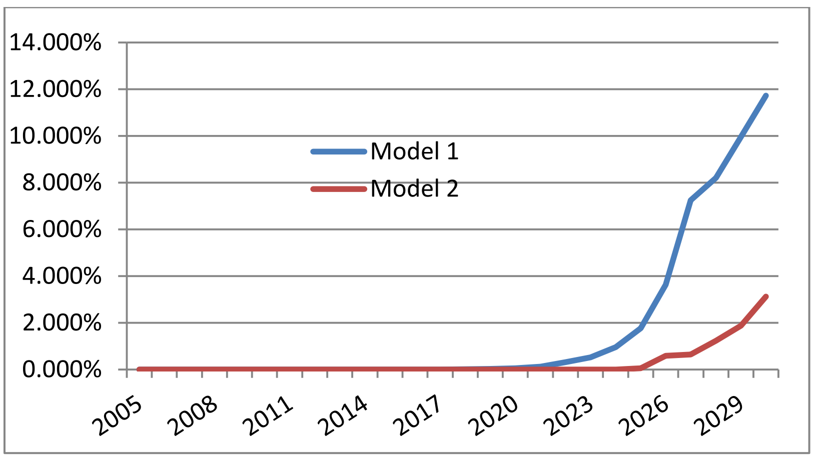
[14] See Comparative Climactic Data for the United States through 2012, National Oceanic and Atmospheric Administration, National Climactic Data Center, Asheville, NC.
[15] See Assessment of Demand-Side Resources with the Eastern Interconnection, Navigant Consulting, March 2013.

reported in Figures 1 and Figure 2 implies a significant future share of total generation capacity in Indiana could be comprised of DG.

Our forecast model of DG in Indiana is a tentative approach to the issue. The very short time period available for modeling, uncertain technological change and likelihood of regulatory changes argue against using a forecasting model for long term planning purposes. However, for better understanding issues in pricing structure related to DG, this forecast should prove useful.

To generate the forecast we offer two models, which include both trend and variables which account for overall forecasted demand (SUFG forecasts) and variables which account for past values and the error structure of the time series.[16] To contextualize this growth we report the share of base load demand forecasted for DG through 2030. See Figure 3.

Figure 3, Forecasted DG Share of Base Load Demand in Indiana, 2014-2030



The divergence in the model results can be attributed to different assumptions regarding the trend of overall growth from the historical period through the forecast horizon. Without additional data further refinement is not possible. However, the rate structure issues outlined in section 2 above become problematic for Indiana within a decade.[17] Thus, under even modest expectations of growth, the size of DG generation in Indiana in both MWh and residential revenues argue that policy considerations over the long term rate structure are timely.

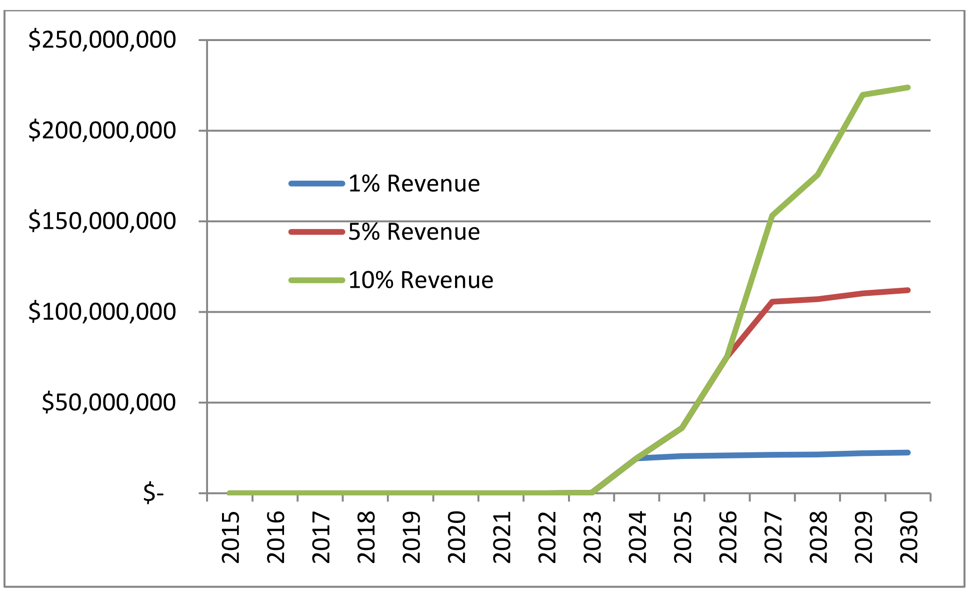
[16] The models are an ARIMA(1,1) with a trend, and an ARIMA(1,0) with the forecasted demand. Both models included a dampening filter and were fitted on 2005-2013 data over a forecast horizon of 2030 (2014-2030 forecast).

[17] Tariff rate structure for net metering can be found in the tariff of Indiana Michigan Power Company at Original Sheet No. 7.1, Tariff R.S, TOD2 (Experimental Residential Time of Day Service) with NMS Rider. Note, this is current price, which is not the forecasted real price from SUFG deployed in our revenue estimates.

To better contextualize the magnitude of the issue facing policy debate, we provide estimates of revenue associated with distributed generation over the forecast period under existing regulatory frameworks. At the outset, we outline some technical challenges in performing these estimates. In Indiana, as in most states, electricity is provided by several producers and individual tariffs very widely. As a consequence, the delivered price of electricity and the costs of producing electricity vary across consumers. Since we have not undertaken sub-state geographic forecasts of DG growth, we cannot firmly assign prices to each name-plated DG site, and so must rely upon statewide averages. To do so, we use a single SUFG real price forecast (SUFG, 2013) to project retail prices for all users in 2014-2030. We then offer two revenue scenarios which depict the potential cross-subsidization of DG users by ratepayers. We use Model 1 estimates across three policy scenarios; a) using current DG restrictions of 1 percent of summer peak load capacity, b) a hypothesized 5 percent of summer peak load capacity, and c) a hypothesized 10 percent summer peak load (across all generation types). As we noted earlier, an element of these revenues are often referred to as a cross-subsidy of DG consumers/producers by other ratepayers. The conditions for this cross subsidization are too extensive to test in each of Indiana's electricity markets.[18]

The three scenarios described, employing real retail prices of $0.095 kWh, result in DG customers earning total revenues of $22 million, $111 million, and $223 million by 2030. While far more extensive analysis will be required to determine the share of these revenues which comprise cross-subsidies to DG producers, it is clear that the magnitude of the estimates are sufficient to warrant policy consideration. See Figure 4.

Figure 4, DG Revenues under 1%, 5% and 10% Caps, 2015-2030



[18] See Supra Note 7.

In this section, we have briefly illustrated that Indiana's treatment of DG is in line with many states that are only now recognizing the inadequacies with the current tariff repayment for net metering and in general, policies regarding DG pricing. The potential impact of this is significant, and in our forecasting model involves perhaps $223 million of DG production by 2030 under very conservative estimates of DG production growth. In the next section, we outline the context for reconsideration of pricing policies for DG.

4. AN ECONOMIC DISCUSSION OF A SUSTAINABLE, LONG-RUN PRICING POLICY FOR DISTRIBUTED GENERATION

As noted, net metering is used in roughly 40 states and, as such, is the dominant economic mechanism used to govern the relationship between incumbent utilities and distributed residential and commercial generators of electricity. Again, the most common form of net metering relies on a single price – the full bundled retail price applicable to the DG – as the means of valuing both the DG's purchases of electricity and any surplus power they make available for other network users.

As an initial approach to a nascent concept, simple net metering has provided the advantage of ease and has helped to encourage the growth in distributed generation. However, as that growth continues, the broader, long-run consequences of this pricing practice suggest that it is likely to have a finite useful life. Our purpose here is not to propose an alternative policy or to even offer a comprehensive critique of net metering as a pricing regime. We do, however, hope to underscore a few of net metering's characteristics and consequences as a way to motivate and inform further discussion.

In looking more closely at the economics of distributed generation, one of the first verities to emerge is that, rather than involving a single set of prices, the relationships inherent in DG involve three linked groups of prices – the prices the utilities charge to DG producers when self-supply is inadequate, the prices paid to DGs when their self-supply yields surplus power, and the prices paid by other network customers who are uninvolved in any aspect of distributed generation.

In discussions of DG pricing governance, proponents of its use have embraced a wide array of possible policies. Here, we focus on the proposals proffered by the Solar Energy Industries

Association (SEIA) as generally representative.[19] While the SEIA proposals contain various specific provisions, they can generally be characterized as (1) embracing prices based on long-run incremental costs (LRIC prices) and (2) calling for careful attention to the incorporation of market externalities within the determination of these prices.

LRIC-based pricing is a construct that found considerable recognition in regulatory reforms to the telecommunications industry.[20] In its basic form, the relevant costing element is typically an individual service. However, in instances where the provision of various services can entail common costs that are not easily made incremental to distinct services, the costing increments can instead be reduced to the network components used in varying combinations to produce services.[21] In either case, regulated prices are set to equal the long-run, forward-looking, efficiently incurred incremental cost, thereby mirroring the prices that might be expected in a more traditional competitive environment.

The long-run nature of LRIC prices is intended to assure that these prices afford adequate returns to capital investments and, in telecommunications, where average value-weighted asset lives are typically measured in months, not years, the requirement that underlying costs be forward-looking is not particularly problematic. However, as experience proved in the early 2000s, application of LRIC prices to a vertically separated electric utility sector would be much more difficult. The principal problem is that asset lives in both the generation and transmission of electricity are sometimes measured in decades. Market changes that measurably alter the nature of forward-looking technologies or practices do not negate the financial requirement to recover the still ongoing cost of past investments. Any pricing regime that fails to recognize this can easily lead to stranded capital costs.[22] Distributed generation may materially alter both the nature and scale of required incumbent utility capacity, but in doing so, it does not dismiss the costs incurred in developing existing capacity. Pricing – for some combination of customers must reflect that for utilities to remain financially viable.

While the issue of stranded costs is, perhaps, speculative, the immediate disconnect between net metering, the incremental cost of maintaining network distribution capacity, and payments

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[19] The SEIA proposals were gleaned from a variety of undated documents available through the organization's web site. See http://www.seia.org/

[20] For a description of TELRIC as applied by the Federal Communications Commission, see, Timothy J. Tardiff, "Pricing Unbundled Network Elements and the FCC's TELRIC Rule: Economic and Modeling Issues," *Social Science Research Network*, available at http://papers.ssrn.com/sol3/papers.cfm?abstract_id=339001

[21] In the case of telecommunications, this latter form of LRIC pricing was generally referred to as Total Element Long Run Incremental Cost (TELRIC) pricing. *Ibid*.

[22] *Supra* Note 8.

to DGs for the surplus power they make available is not. In Indiana, as in most states, DGs receive the full bundled retail rate for any surplus power they provide for resale by the utility. This practice robs utilities of any compensation for their supply of the network facilities over which the DG's surplus is distributed. *To be sure, one might argue that the incremental distribution cost incurred by utilities is close to zero during the typically off-peak periods when DG power is available for redistribution.* However, the same off-peak nature of DG surpluses also diminishes the value of the surplus electricity they provide. Indeed, Raskins (2013) estimates that the actual average value of DG-supplied power is between 2 cents and 3 cents per KwH, while the average retail rate is roughly 12.5 cents per KwH.[23] If negligible incremental distribution costs justify ignoring the burden that DG generation places on network facilities, then the negligible incremental value of that production should also be reflected in net payments to DGs.

Finally, proponents of distributed power advocate pricing policies that adequately account for the market externalities that occur when those outside a transaction, nonetheless, enjoy benefits or suffer costs because that transaction takes place. There are a variety of external impacts related to the generation, distribution, and consumption of electricity and it is quite true that a failure to account for them can lead to a less than optimal overall outcome.

From a theoretical vantage, accounting for externalities is in the public interest. However, in practice, doing so can impose additional complexities that are not easily overcome. Typically, when transactions impose costs on nonparticipants, the policy response is to somehow tax the transaction and use the proceeds to compensate those who are harmed by the subject activity. Similarly, when a transaction confers benefits to entities outside its bounds, the policy response is to tax those who receive these external benefits and use the proceeds to subsidize the subject transaction. Either way, the use of taxation to support compensation or subsidies as corrective measures can make even the simplest policy setting contentious. In the current setting, incorporating the existence of externalities into policies governing distributed generation would mean manipulating the prices paid by or to DGs in order to mitigate external transaction effects. This, alone, suggests that strict adherence to incremental costs as guideposts in the pricing process may be undesirable.

5. CONCLUDING OBSERVATIONS

[23] *Supra* Note 9.

Our discussion, to this point, leads to a handful of early, but fairly robust conclusions. These include:

1. Distributed generation, as a share, of overall electricity production in Indiana is still quite small;

2. While Indiana's projected growth in DG follows the form of national forecasts, its estimated magnitude is measurably smaller than elsewhere, but might still be quite large as compared to current levels;

3. Unlike most regions, wind-powered distributed generation is likely to play a greater role in Indiana than generation from solar PV production; and

4. In Indiana's reliance on net metering to govern economic interactions between DG producers and incumbent utilities has sufficed as an introductory strategy, but is not adequate as DG grows toward its potential place in the state's long-run energy mix.

In closing, we would be remiss if we failed to note the *benefits* of distributed generation. It is a component of both federal and state policies with good reason. Among its numerous positive attributes, DG: (1) allows, at least some, users to more directly control household and business-related energy costs, (2) provides a direct and potentially important vehicle for increasing the role of renewables in electricity generation, and (3) may ultimately moderate the need for future utility sector investment in additional generating capacity.

While we are compelled to describe the important economic complexities inherent in distributed generation's further management, these complexities do not negate DG's potential future value to Hoosiers. Instead, distributed generation's growth from novelty toward probable reality simply means that policy-makers and stakeholders should prepare to take the next prudent and necessary steps in what is potentially a very productive policy course.