Sec. 4 – "Clean Energy Resource"

Question: *May participating electric suppliers use existing resources to meet the CPS goals?*

Recommendation: Participants must use new clean energy resources which are in service after the date of the Commission's approval of an electricity supplier's participation in the CPS program. The exceptions to this requirement are:

(1) an electricity supplier may count "equipment installed, or customers enrolled "after January 1, 2010, pursuant to "(d)emand side management or energy efficiency initiatives." *See* Indiana Code § 8-1-37-4(a)(16), or

(2) a supplier may count "electricity that is generated from natural gas at a facility constructed in Indiana after July 1, 201l which displaces electricity generation from an existing coal fired generation facility. *See* Sec. 4(a)(21).

Discussion: The intent of the legislature was to encourage the addition of new clean energy resources to the State's generation fleet. Section 11(c)(2) states "the electricity supplier submitting the application has demonstrated that the electricity supplier has a reasonable expectation of obtaining clean energy to meet the requirements…" The use of the word "obtaining" indicates the legislature intended to encourage new generation to meet this standard, not rely on existing resources. Similar language can also be found in Section 10(a) which states, "the program established under this section must be a voluntary program that provides incentives to participating electric suppliers that undertake to supply specified percentages of the total…" Again, the use of the word "undertake" implies new, not existing resources.

In addition, statutory construction requires statutes to be applied prospectively, unless stated otherwise. Given that this program is voluntary, the goals are relatively modest, and there is no penalty for failure to meet the specified goals, utilities will not be unfairly penalized if existing resources cannot be used to meet the standard, except as otherwise specified in the new law. Any past performance would have been based upon an economic analysis supporting the decision. Utilities did not require additional incentives to undertake projects at that time and should not be rewarded with these current incentives for past decision making.

Question: *How should demand side management and energy efficiency resources be treated under the standard in terms of incentives??*

Recommendation: DSM/EE initiatives that are mandatory or are already eligible for a shareholder incentive under an IURC Order are not eligible for an additional incentive under the INVCEPS Program. For example, if a utility implements programs that are mandated (ex. Core DSM) or eligible for an incentive (ex. Core Plus DSM), a utility would be able to count those toward the voluntary goal, but those savings would not be eligible for an additional incentive under the INVCEPS Program. Incentives that are awarded must be based on program and related administrative costs only and exclude the costs of EM&V.

- To be considered for the incentive, the DSM or EE initiative must be cost effective, i.e. it must score greater than 1.0 on the Total Resource Cost (TRC) test at the time of proposal. Incentives will be awarded based on net energy saved, and will be subject to results of EM&V.
- Lost revenues as a result of DSM/EE initiatives will be awarded on a net basis and will be subject to the results of EM&V. To be eligible for an incentive, the program must be measureable. Programs that are primarily educational in nature will not qualify for an incentive.
- Utilities must provide accounting records to validate equipment installed or customer enrollment in programs after January 1, 2010. For existing programs, only material changes in equipment installations or customer enrollment will be considered for purposes of earning an incentive.

Question: *How should net metering resources be accounted for as a clean energy resource?*

Recommendation: Net metering resources should be counted in terms of gross production at the site of the installation.

Discussion: While gross production may be difficult to measure if the site has a single meter, counting gross production recognizes the total amount of energy being produced by clean resources. Given that some meters used for net-metering may roll back for credits, care must be taken to ensure an accurate accounting for those sites with a single meter.

Sec. 10 – "Adoption of Rules Establishing the Program"

Question: *Who may participate in the Indiana CEC Market?*

Recommendation: The OUCC recommends that the CEC market be open to all parties that intend to sell CECs. Any entity, such as municipal electricity producers, electricity cooperatives, or third party brokers with available CECs may sell to the IOUs.

Discussion: Any entity should be able to sell credits in the Indiana CEC market, including municipals and cooperatives. Allowing Hoosier Energy, Wabash Valley, and IMPA to participate in the Indiana CEC market allows the State to increase the supply of clean energy produced in Indiana that meets this voluntary standard. Allowing electricity producers other than the five IOUs in the State to sell credits will spur greater economic development for these resources inside the State because other producers will have greater financial incentives to produce clean energy resources. Finally, allowing others inside the State the ability to sell CECs will reduce the need for participating electricity suppliers to seek clean energy credits outside of Indiana.

Question: *How should the tracking and trading system be established for clean energy credits in Indiana?*

Recommendation: The OUCC recommends the use of a tracking system similar to the MISO, Michigan, or PJM – GATS system to verify and document credits. The system can be tailored to make it specific to the needs of the INVCEPS program.

Discussion: This type of tracking and trading system offers many advantages. First, the interface is very simple and easy to use. Second, the tracking system can be designed to be specific to ensure compliance with Indiana laws and requirements. Third, this interface and market infrastructure design allow for connection to other renewable energy credit markets such as the PJM GATS market and the MISO Renewable Energy Trading System. Fourth, using this interface allows for easy reporting of compliance, transparency of transactions and detailed audit trails for oversight.[1] The NYSE Blue interface can be adapted to collect and report all of the information required by Ind. Code § 8-1-37-14(a)(1-3). This system will allow the Commission to also meet the obligations required under Section 10(b)(1)(B), which requires "the Commission to establish methods for measuring and evaluating a participating electricity supplier's compliance with the CPS goals set forth in Section 12(a) of this chapter."

Sec. 11 - "Application to Program; Review by the commission"

Question: *In which manner should utilities apply to the program?*

Recommendation: The OUCC recommends the application process be a docketed proceeding with the Program Application (Ind. Code § 8-1-37-11) and Incentive or Periodic Rate Adjustment Mechanism Application (Ind. Code § 8-1-37-13) separated into two distinct phases further discussed below for the following reasons:

1. A docketed cause may be tracked by the Commission throughout the succeeding application process and goal periods.

2. As stated in Ind. Code § 8-1-37-11 (c)(3) "The electricity supplier that submitted the application under subsection (2) bears the burden of proving to the commission that the application meets the requirements set forth in this subsection." By requiring electricity suppliers to maintain the burden of proof, the General Assembly would necessarily require that there be some basis in an evidentiary record supporting the approval of the electricity supplier's participation in the program. That evidentiary record should be associated with a docketed, numbered proceeding.

Phase I – Program Application

The electricity supplier will file with the IURC a request for a certificate of public convenience and necessity (CPCN) that serves two primary functions:

- Substantiates the electricity supplier's reasonable expectation of obtaining clean energy to meet the energy requirement of its Indiana retail electric customers during the calendar year ending December 31, 2025, in an amount equal to at least ten percent (10%) of the

[1] MIRECS FAQ http://www.mirecs.org/about/FAQ.asp

total electricity supplied by the participating electricity supplier to its Indiana retail electric customers during the base year, as set forth in section 12(a)(3) of this chapter (Ind. Code § 8-1-37-11(c)(2)).

- Affirms that implementation of the plan proposed in the application will not result in an increase to the retail rates and charges of the electricity supplier above what could reasonably be expected if the application were not approved (Ind. Code § 8-1-37-11(c)(3)).

Although the OUCC does not recommend a specific time frame for this phase, the OUCC is mindful that the regulatory process should not be unreasonably delayed in order for the supplier to receive its CPCN to achieve these INVCEPS goals commencing in 2013.

<u>Components of the Program Application</u>

The Program application will include, at a minimum, the following:

- Total electricity obtained by the electricity supplier to meet the energy requirements of its Indiana retail electric customers during the base year in MWh.
- Program Application Plan to obtain clean energy to meet the energy requirements of its Indiana retail electric customers during the calendar year ending December 31, 2025 in an amount equal to at least ten percent of the total electricity supplied to applicant's Indiana retail electric customers during the base year. (Ind. Code § 8-1-37-11(c)(2)).
    - The application must be a detailed, business plan with annual milestones to ensure a participating energy supplier will meet the self-established CPS goals. Although each milestone in Goal Period I, for example, will not be required to be a minimum of 4%, at the end of the Goal Period I (December 31, 2018), the electricity supplier shall have averaged 4% of the total electricity obtained by the participating electricity supplier to meet the energy requirements of its Indiana retail electric customers during the base year. This process is described in more detail in OUCC's Sec. 13 comments below.
    - Affirmation by the electricity supplier that its Program Application Plan contains no more than thirty percent (30%) of any of the clean energy resources listed in Ind. Code § 8-1-37-4(a)(17) – 4(a)(21).
    - Annual projections of energy produced by kWh per resource type, including CECs will be submitted as part of the plan.
    - A complete description of the project including the scope, cost and location.
    - Justification of the need for the generation through updated IRP modeling.
    - If the electricity supplier chooses to use its last IRP model runs, it must demonstrate there have been no changes in load or supply mix since the time of the IRP model run.
    - Other generation options considered alternatives to the final clean energy resources listed in the Program Application Plan.
    - Justification that the resources listed in the Program Application Plan are the optimal, economic choices. This justification shall be in the form of a cost / benefit study and IRP modeling, and include at a minimum the following information:

        - Estimate of anticipated level of emission reduction by year;
        - Project estimated costs, including;
        - Pre-construction costs;
        - Depreciation;
        - Commodity costs;
        - Administration costs;
        - Operation and maintenance;
        - Fuel;
        - Taxes;
        - Labor;
        - Contingency; and
        - AFUDC.
    - Ratepayer Impact shall be determined by the supplier:
        - Discussing how it intends to validate its clean energy production;
        - Explaining how the supplier determined the impact on rates if the Project Application is not approved and subsequently placed in-service. (*See* Sec. 11(c)(3), "…will not result in an increase to the retail rates and charges of the electricity supplier above what could reasonably be expected if the application were not approved."); and
        - Providing documentation regarding the impact on rate if the project is approved.
- An explanation as to how this portfolio addition fits into the applicant's existing generation plan.
- Identification of incentives currently being received for the projects listed in the Program Application, including, but not limited to:
    - Federal, state and local tax incentives;
    - Federal, state and local grants; and
    - Shareholder incentives, lost margins, etc. received by the supplier.
- Work papers detailing all considerations and calculations.

While the Program Application Plan must document the Applicant's need for the requested generation and tie in to the utilities' most recent IRP, the OUCC recommends that the IURC not tie the filing of the Program Application Plan to the IRP filing dates in order to allow adequate time for review of each application.

<u>Phase II – Incentive or Periodic Rate Adjustment Mechanism Application</u>

The OUCC recommends the Phase II application be filed no earlier than IURC approval of a Phase I application. Per Sec. 13(f), the Commission shall issue a determination "after notice and hearing" regarding the applicant's eligibility for the incentive sought "no later than 120 days after the date of the application unless the commission finds that the applicant has not cooperated fully in the proceeding." The OUCC views the "application" date, as referenced from the Ind.

Code § 8-1-37-13(f) language above, as the filing date of the Petitioner's Phase II testimony in support of its application. This will ensure the IURC has adequate time to complete its Phase II review in this compressed time frame.

Sec. 12 – "Qualifications for shareholder financial incentive; application; considerations and determinations by the commission"

Question: *May INVCEPS participants purchase RECs or CECs from a regional transmission organization (RTO) of which they are not a member?*

Recommendation: The OUCC recommends the IURC allow Indiana's Investor Owned Utilities (IOUs) to access renewable energy credits through either the PJM or MISO RTOs.

Discussion: Of Indiana's five IOUs, four are members of MISO, while one, Indiana Michigan, is a member of PJM. Section 12(c)(2) states "the commission shall only consider energy that is generated by a facility located in a control area that is part of a regional transmission organization of which an electricity supplier is a member." This language infers that commission can only consider energy that is produced in one of the two RTOs that Indiana utilities are members. Allowing the utilities to choose between the two not only grants Indiana Michigan access to the renewable energy credits within the MISO footprint, but also potentially allows the four MISO-member IOUs to access renewable energy credits in the PJM footprint – an opportunity which may offer economic benefit and reduced costs.

Sec. 13 – "Shareholder Financial Incentive."

Question: *When will the Commission authorize any incentive?*

Recommendation: The OUCC recommends that the Commission only award an incentive following an evaluation of the annual report supplied to the Commission on March 1 of each year in a INVCEPS goal period (Ind. Code § 8-1-37-14). If the program application is to outline how a participant will meet annual goals to achieve the averages set forth in Section 12(a), then the incentive should be awarded based on the progress of the participant in relation to the goals outlined in the initial program application.

Question: *How will the shareholder incentive be calculated?*

Recommendation: **Sec 13 (a**) states, "The commission may establish a shareholder incentive consisting of the authorization of an increased overall rate of return on equity, not to exceed fifty (50) basis points over a participating electricity supplier's authorized rate of return on equity…" An incentive under this section is not guaranteed. Should the Commission award an incentive, the OUCC recommends the electricity supplier calculate a weighted average cost of capital with the approved equity incentive amount included in its cost rate for equity that had been established by the Commission in a previous proceeding involving the utility's base rates and charges per 170 IAC 4-6-14. An equity incentive shall be limited to an investment in utility plant that is deemed necessary to achieve the CPS goals.

Question: *When shall costs be recovered?*

Recommendation**: Sec 13 (b)** identifies conditions in which the Commission may authorize the recovery of costs by means of a periodic rate adjustment mechanism. Since progress toward INVCEPS goals are evaluated on an annual basis, the OUCC recommends recovery of costs also be done via periodic rate adjustment mechanism on an annual basis.

Question: *How should depreciation and amortization of costs be calculated?*

Recommendation**: Sec 13(c)(2)** defines program costs as administrative costs, ancillary costs, capacity costs, costs associated with CECs, capital costs , depreciation costs, tax costs, and financing costs incurred in connection with an activity described in 13(c)(1)or (2). Depreciation of plant will not be at an accelerated rate, but instead will be spread over the estimated life of the asset. Initial start up costs will be amortized over the length of a program. No other capital or financing costs may be permitted, other than what is included in this statute in relation to investment in plant that contributes to CPS goal attainment, nor should company overhead be permitted in the tracker. All administrative and ancillary operating costs will be directly associated with the CPS project and not allocated from the utility base rates into the tracker, or related to any other project by the utility. This prohibition includes labor and benefits that are already included in a utility's base rates.