APPENDIX A - Geographic Sourcing - Other States' Requirements

Table 2. RPS Rules on Geographic Eligibility[1]

State	Geographic Eligibility
Arizona	State generation or interconnection
California	State generation or delivery (CAISO)
Colorado	No restrictions
Connecticut	Regional generation or delivery (ISO-NE)
Delaware	Regional generation or delivery (PJM)
District of Columbia	Regional generation or delivery (PJM) or from states adjacent to PJM
Hawaii	In-state projects only
Illinois	In-state projects only, unless cost-effective alternative available from adjacent state
Iowa	In-state projects only
Maine	Regional generation or delivery (ISO-NE)
Maryland	Regional generation or delivery (PJM) or from states adjacent to PJM
Massachusetts	Regional generation or delivery (ISO-NE)
Minnesota	State generation or delivery
Montana	State generation or delivery
Nevada	State generation or delivery
New Hampshire	Regional generation or delivery (ISO-NE)
New Jersey	Regional generation or delivery (PJM)
New Mexico	State generation or delivery
New York	State generation or delivery (NYISO)
North Carolina	State generation or delivery
Oregon	Regional generation or delivery
Pennsylvania	Regional generation or delivery (PJM)
Rhode Island	Regional generation or delivery (ISO-NE)
Texas	State generation or interconnection
Washington	Regional location or state delivery
Wisconsin	State generation or delivery

Since the release of the above NREL report, Kansas[2] and Ohio[3] have also adopted "delivery" requirements. In 2008, Michigan adopted an even stricter requirement that the renewable energy facility has to either be in the state or in the utility's service area.[4]

[1] From *Renewable Portfolio Standards in the States: Balancing Goals and Implementation Strategies*, Cory, K.S., Swezey, B.G., National Renewable Energy Laboratory, Technical Report, NREL/TP-670-41409, December 2007, p. 8.
[2] K.S.A. 2009 Supp. §§ 66-1256 through 66-1262.
[3] Case No. 08-888-EL-ORD Rules for Energy Efficiency, Alternative & Renewable Energy, Emission Controls and Amendments to Forecasting Chapters 4901:5-1, 4901:5-3, and 4901:5-5 of the Ohio Administrative Code, 4901:1-40-01(I) and 4901:1-40-03(A)(2)(b). Ohio requires 50% in state generation and 50% demonstrably deliverable into Ohio.
[4] M.C.L. § 460.1029 (2009).

APPENDIX B - Geographic Sourcing - Dormant Commerce Clause

A review of the jurisprudence on the dormant commerce clause as regards geographic sourcing in RES, which has been done in some legal journals, has resulted in the opinion that generated in or delivered into would *not* violate the dormant commerce clause.[1]

It is not about economic protectionism, but about many factors. When the New York Public Service Commission addressed the delivery requirement, it identified all of the important benefits that accrue to the state and the ratepayers:[2]

> As long as the cost of new electric generation from renewable resources continues to be higher than the cost of generation from other resources, our adoption of the RPS will necessarily increase the direct cost of electricity supplied to New York consumers. Since we are likely mandating an increase in costs, it is important that we structure the RPS in a manner that maximizes the benefits that can accrue to New York from an RPS, consistent with all applicable laws and treaties. The structure of the delivery requirement affects the contractual flow of electricity, the location of pollution reduction and economic development activities, and the levels of wholesale energy and capacity prices, resource diversity and energy security.
>
> * * *
>
> As stated in the RD and as argued by many of the parties, imposition of such a requirement is consistent with and in furtherance of our stated goals of increasing the amount of renewable energy retailed in the State, improving energy security, diversifying the State's electricity generation mix, reducing local air emissions and protecting against oil and natural gas price spikes or possible supply disruptions. Moreover, as noted by several parties, the requirement will also help ensure that New York State ratepayers enjoy the benefits from the costs they will incur to support the RPS program and its objectives.
>
> * * *
>
> [ ] we see no unnecessary burden on interstate commerce or potential violation of the Commerce Clause. The RPS concerns requirements for the retail sale of electricity in New York State. For commerce to occur, the product, electricity generated from renewable resources, must be in the State to be sold to retail customers. The RPS promotes interstate commerce by allowing imports on the same terms as electricity generated within the State. The delivery requirement applies to domestic generation as well as imports. Therefore, it is equivalently applied to in-State and out-of-State renewable generation sources and imposes only a minimal, if any, burden on commerce. In addition, the delivery requirement serves important State interests including supply security and diversity, and environmental benefits.

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[1] Nathan E. Enrud, *State Renewable Energy Portfolio Standards: Their Continued Validity and Relevance in Light of the Dormant Commerce Clause, the Supremacy Clause, and Possible Federal Legislation*, 45 HARV.J.ON LEGIS. 259, 270-274 (2008); Trevor D. Stiles, *Renewable Resources and the Dormant Commerce Clause*, 4 Envt'l & Energy L. & Pol'y J. 33, 63 (2009)

[2] NY PSC Order Regarding Retail Renewable Portfolio Standard in Case 03-E-0188, issued and effective September 24, 2004.

APPENDIX C – Retail Rate Impact – Recommendations of ICF

These comments address Section (5) of the Proposed Rule that relates to the cap on changes in revenue requirements that may be caused by the addition of renewable power. In this regard, the wind alliance asked ICF to develop a financial model that would capture the elements required to assess the conditions under which the 1% threshold in Missouri could be crossed, and to include the flexibility to test numerous scenarios. This model is described in some detail below, and we have attached some printouts from the ICF model to these comments, for the Commission and all participants to this proceeding to review. We have done so in order to advance the Commission's interest in finding the best way to determine the impact on revenue requirements of incremental renewables, and to support the idea that the calculation of the impacts of renewables should be straightforward and transparent.

With regard to the revenue requirement calculation, the wind alliance submits these comments for the Commission's consideration **in support of the Proposed Rule,** providing ideas for the implementation, as well as enhancements that we recommend that the Commission adopt in the Final Rule. In specific, our recommendations follow these six principles, which we have described in more detail below.

1. The Commission should calculate the revenue requirement impact of renewables only when there is an actual renewable project proposed and submitted to the Commission. In that context, it should require the utilities to perform and submit this calculation to the Commission with every RES filing.

2. The Commission should determine now, in the Final Rule, the detailed approach it will use to carry out the retail rate calculation

3. It is appropriate to determine the impact of renewables on an incremental basis; to do otherwise would compare "apples and oranges", and could constitute retroactive ratemaking.

4. It is appropriate to determine the impact of renewables on revenue requirements by averaging the cost of the renewable project over a 10-year period (although a longer period corresponding to the length of a PPA would make even more sense)

5. The method of actually calculating the impact – by comparing the revenue requirement of a portfolio of least-cost, non-renewable generation to the portfolio with the incremental renewable project – requires clarification.

6. To provide this clarification, the Commission should now adopt a spreadsheet approach similar if not identical to the one developed by ICF as the starting point for calculating the incremental revenue requirement impact of renewables in the future, with the understanding that this approach can be further enhanced

The balance of this document provides support for these six principles, and elaborates on the elements that the wind alliance believes should be in the Final Rule in order to enable the Commission to effectively implement it.

Principle #1 – The Commission Should Base the Revenue Requirement Calculation on Actual Projects and PPAs, and Establish the Approach Now.

There are two sub-parts to this principle:

A. In this proceeding, the Commission should indicate that the calculation of the impact of renewables on revenue requirements should only be calculated when there is an actual renewable project whose cost and location is known, and the utility files the relevant PPA terms with the Commission for its consideration as part of its RES filing.
B. As currently drafted, the Proposed Rules do not require the utilities to make such a calculation when they make their RES filing. We believe that the Commission should require the utilities to provide such a calculation with each RES filing, using a pre-approved approach.

With regard to the first sub-part, imagine the opposite. If the Commission calculated the impact of renewables on revenue requirements based on generalized or projected industry data, rather than actual PPA information, it could make assumptions that do not apply to the reality of the renewables that are being considered in Missouri. As a result, the Commission could falsely determine that the 1% threshold would be crossed or not crossed, based on those inputs.

The Proposed Rule makes clear this intention when it states, at the end of Section (5)(B) that "the comparison…..shall be conducted only when the electric utility proposes to add incremental renewable energy resource generation through the procurement or development of renewable energy resources."

The following is a sample of the variables that will affect the revenue requirement calculation (all of which are also embedded in the ICF financial model calculation). The variability of these factors clearly demonstrates that the best, and in fact only legitimate time to make the retail rate calculation is in the context of an actual proposed renewable project (or family of projects) that the utility files with the Commission to meet its RES requirements.

- The exact charges (for energy and capacity) to the utility under the power purchase agreement (PPA) with the renewable developer, and how those costs may vary over the term of the PPA;

- The fuel costs that are avoided by virtue of the renewable generation (this depends on the then-current pricing and outlook for the prices of coal and natural gas), which are a key part of the retail rate calculation, since the utility will save money when renewables offset the need to burn these fuels;

- The cost of the emissions allowances that the utility would otherwise have to purchase in order to emit air pollutants such as SOx, NOx and CO_2. The cost of SOx and NOx allowances can vary considerably, and it is not currently certain whether there will be a market for CO_2 allowances. By the time of the upcoming "milestone years" in the RES (2011, 2014, 2018 and 2021), when a new renewable project signs a PPA to sell power in Missouri, there should be much more certainty on this point.

- Related to the point above, the need for emissions control equipment. If the utility needs to install scrubbers, low-NOx burners, and/or CO_2 controls, the capital cost will be considerable, and this equipment can also markedly lower the efficiency of the fossil generation. This investment would measurably add to the utility's rate base, thus increasing the cost of non-renewable generation compared to renewables, and reducing the retail rate impact;

- The location of the renewables. The utilities could assume that some of the renewables they procure will not be located in Missouri, when in fact most if not all of those renewables end up coming from in the state. The Proposed Rule only provides out-of-state renewables with 80% of the credit for producing kilowatt-hours as renewables that are located in Missouri. Thus, making a pre-determined decision on where renewables will be located could skew the revenue requirement calculations. In-state projects will have less of a retail impact, all else being equal

- The level of load and sales growth. The faster this growth, the more kilowatt-hours the utility needs to purchase to meet the RES requirements in each milestone year. This in turn will affect the cost for the portfolio of renewables that the utilities procure, and thus change the cost

Thus, it is clear that the Commission should ensure that the utilities use <u>actual</u> data from <u>real</u> projects in making their RES filing, including the revenue requirement calculation, rather than hypothetical data that may or may not apply in Missouri.

To ensure that the calculation is carried out effectively, the wind alliance requests that in the final Rule, the Commission require the utilities to perform and make public this calculation whenever it makes a RES filing. It seems to the wind alliance that these two items – 1) the RES filing showing compliance with the level of renewables required in specific years, and 2) the calculation of the impact on revenue requirements of those additions - are tightly linked. Thus, we think there would be considerable benefit to the Commission, as well as to consumers, to know the incremental impacts of renewables at the time of the RES filing. Given the clear opportunity to be more transparent at the time of such filings, we encourage the Commission to require that the utilities show such transparency at that time. Without such a concurrent calculation of the impact then, developers will not know whether their projects have caused the 1% threshold to be crossed, and their projects could be placed in limbo.

Principle #2 – The Commission should establish in the Final Rule the approach and tool that it will use to determine the retail rate impact of renewable.

The wind alliance strongly encourages the Commission to establish an agreed-upon approach and tool at this time that the utilities and the Commission will use during the RES filings to determine the renewables' impact on revenue requirements. To wait until there is an actual PPA being negotiated or signed would not be the most responsible way to do so, because at that time, the development of such an approach would be seen in terms of whether it would favor or affect the projects being proposed at that time. There would be pressures from the advocates and opponents of that project to modify the approach to suit their desires. Rather, the wind alliance believes that the methodology should be objective, so we strongly urge the Commission to adopt a common approach in the Final Rule.

In the earlier hearings leading up to the Proposed Rules, the Commission already reviewed an early version of the financial model developed by ICF, and there have been dozens of improvements in that model since then. It is certainly possible to enhance this tool, and we welcome the Commission's feedback on how to best do so. The key, however, is to have an approved approach before we enter the "cauldron" of a RES proceeding in which there are entrenched stakeholders with interests in specific projects. The Commission will be saving itself considerable difficulties later if it establishes such a methodology in the current proceeding.

From the attached print-outs from the model, the Commission will see that ICF has populated the model with numerous projections and assumptions about the items in the bullet list in Principle #1 above, among other variables, and has provided for a broad range within such assumptions. Considering a spectrum of factors and a reasonable range of variation within them (e.g., a range of natural gas prices) is important so that the Commission, utilities and all stakeholders know in advance of what it would take to reach or cross the 1% threshold, and exactly when such a threshold might be crossed. The assumptions in the current version of the model will almost certainly not turn out to match those at the time of the RES filings – those will be determined at the time of a utility's RES filing. Rather, the model provides an integrated, objective, transparent means for the Commission to assess how much impact the addition of renewables could have on retail rates as one changes the key input assumptions. We describe the rate impact model in more detail below.

As indicated in the Proposed Rules, a number of the key inputs to the model (e.g., sales growth, fuel prices, etc.) would come from other proceedings before the MPSC, such as the most recent rate case or integrated resource plan. One of the alliance's main purposes in asking ICF to develop this model was to create an approach that would be streamlined and straightforward for the Commission to implement. We do not believe that the intention of the statute is to recreate another extended proceeding that engages in a debate over inputs, models and optimal resources. We believe that the model that the wind alliance has developed with ICF's support provides the right balance between capturing the key elements in an integrated fashion, and providing a transparent tool, without the prospect of bogging the Commission down in long and contentious proceedings every time a utility files to add a renewable project to its portfolio. It is the right approach for this proceeding.

There is one more implication of this principle. Once the Commission reviews a utility's RES filing and conducts a retail rate calculation, the Commission should not revisit that analysis until the next time that renewable capacity is proposed. The assumptions underlying a resource planning proceeding change constantly, but the Commission does not re-review the utility's plan every time they do. Even though the underlying assumptions will constantly be in flux (e.g., as fuel prices change), the Commission should review the utility's RES filing and make the best assessment possible about the retail rate impact, and then let the matter rest until the next time that renewable generation is proposed, at which time the utility would make another RES filing. This approach would also ensure that the Commission would not get bogged down in renewable rate calculations that could otherwise occupy too much of the Commission's time.

In conclusion on this principle, we strongly recommend that the Commission:

- <u>Now</u> accept and establish a methodology for calculating the retail rate impact of renewables (an approach that the Commission may improve over time);
- Require the utilities to file a retail rate calculation every time they make a RES filing; and
- Only apply this retail rate methodology using <u>actual</u> offers for renewable power, and
- Once they make a decision, not re-open the assessment of the rate impact until the next RES filing

<u>Principle #3 – Determine the Impact of Renewables on Retail Rates in Missouri on an "Incremental Basis"</u>.

There are two fundamental options for calculating the impact of renewables on retail rates – incremental or cumulative.

- Under the <u>incremental</u> approach, a utility making a RES filing would look at the change in the revenue requirement caused by adding renewables in 2011 (or any one of the RES milestone years). In specific, they would assess whether the group of projects **added in that year** (with the cost spread out over an appropriate period) would cause the utility's revenue requirement to change by more or less than the 1% annual level, compared to the alternative of using non-renewable generation instead. They would do so by applying a methodology that is similar if not identical to the one the wind alliance has proposed. We discuss how that calculation would be performed below. If those projects do not cause an increase of more than 1% in any year under the approved approach, then the Commission would accept that RES filing, and those renewable projects would become part of the utility's resource plan, as well as part of the utility's revenue requirement going forward.

Then, when the utility adds the next increment of renewables, in 2014, the Commission would review the utilities' RES filings again, and determine whether the new group of renewables causes an increase in the revenue requirement of more than 1% in any year. The key is that under the incremental approach, the utilities would <u>not</u> add the cost of the renewable projects that the Commission already approved several years prior to the cost of the <u>current</u> renewables when making that calculation, except to the extent that the cost of the earlier projects is still being spread out or averaged out over an extended period, as the Proposed Rules state (the attached model makes clear how this works in practice).

While the precise methodology for carrying out the revenue requirement calculation is not provided in the Proposed Rule, at the end of Section (5) (B), it uses the word "incremental" to describe when the revenue requirement calculation should be performed.

- By contrast, under the <u>cumulative</u> approach, one would take the impact on revenue requirement due to the addition of renewable generation in a specific year such as 2011, and average that amount through for the agreed period (see below). Then, when the next increment of renewable generation is added (say in 2014), the cumulative approach would add the additional revenue requirement of the new generation to the impact of the renewables from the prior period to derive the total impact on revenue requirements in that milestone year. In other words, the impact of renewables "accumulates" under this approach.

In both approaches, the utilities should spread out the impact on revenue requirements over a period of years (see Principle #4 below), consistent with the Proposed Rule's statement in Section (5) (D) that these costs should be "averaged over a ten (10) year period".

As the Commission can see from the attachments showing the results of the model, the cumulative case often leads to a higher figure for the impact on revenue requirements, but that is not the reason for the Commission to approve the incremental approach. Rather, the reasons for such an approach are as follows:

First, the assumptions under which the revenue requirement analysis are developed for the first increment of renewables in 2011 (such as fuel prices, emissions allowances, etc.), are certain to be different than the assumptions that make sense at the time of the second increment in 2014. Thus, if the utility is making a RES filing in 2014, and combining the rate calculation with another one that uses figures from 2011, there is a clear "apples and oranges" concern. The 1% calculation must be carried out with a consistent set of assumptions, and not with ones that could diverge widely. This factor alone should invalidate the cumulative approach.

Second, once the utility's calculation of changes in revenue requirements has been reviewed and approved by the Commission, using the best information available at the time (including data from prior rate cases and IRPs), there should be no revisiting of that calculation. Just as there is no re-visiting of a utility rate case or integrated resource plan, there should be no re-opening of the 1% calculation, even though the underlying assumptions may change.

We note that the wind alliance does believe that the Commission should establish an opportunity for stakeholders to review and comment on the assumptions that the utility uses in its calculation of revenue requirements in the RES filings. If there are possible errors or oversights, other stakeholders should have an opportunity to make this known to the Commission. We believe that the Commission can provide other stakeholders with the opportunity to provide such inputs in an abbreviated manner, without conducting a full litigated proceeding.

Third, by extension, once the Commission has included the cost of any generation (renewables or otherwise) in the "rate base", that rate base (and the approach to modifying it, such as for changes in fuel prices, and for depreciation) should be considered fixed until the next time that the Commission reviews it. Thus, the renewables that are part of the rate base should be considered fixed, and part of the total framework of generation resources that benefits consumers. Any changes to that portfolio should be considered on a going-forward basis. To do otherwise would mean that the Commission is calling into question the prior generation additions, and could be engaging in "retroactive ratemaking".

In sum, the wind alliance believes that the incremental approach is the only reasonable approach to calculating the retail rate impact of renewable additions.

Principle #4 – The Additional Revenue Requirement of Renewables Should be Spread out Over No Less than 10 Years for the Purposes of this Statute.

Clearly, renewable generation benefits consumers over many years, as does other utility generation, transmission and distribution assets. Thus, there is a strong logic that renewables should only be included in the utilities' revenue requirement calculation (and hence in rates) over a period of time, just like utility assets.

The Proposed Rule, in Section (5) (D), specifies 10 years as the appropriate period. The attached ICF model adopts this assumption in our reference case. However, it would also be entirely justified, in our opinion, for the Commission to approve a period of 20 years, on the logic that the period should closely match the time frame of the power purchase agreement (PPA) under which a renewable developer would sell its power to the utility. If the renewable developer has a 20-year PPA, then why should the utility not consider the impact on the revenue requirement to consumers over the full term? In fact, the Commission could approve an approach for purposes of this calculation that simply adopts the time frame of the PPA as the averaging period. If different renewable projects in a given year have PPAs of different lengths, then their revenue requirements could simply be divided by different numbers in calculating the overall renewable impact.

Thus, the wind alliance recommends that the Commission slightly modify this provision of the Proposed Rule to say that the period for distributing the revenue requirement for the purpose of the 1% calculation should match the period of the PPA that caused the utility to make a RES filing. This would match the impact of renewables on consumers with the sale of power to the utilities, which is better than choosing an arbitrary number of years

Principle #5 - The method of actually calculating the renewable impact requires clarification.

The Proposed Rule indicates, in Section (5) (B), that to carry out the 1% calculation, the utility needs to compare the revenue requirement of a portfolio of least-cost, non-renewable generation to the portfolio with the additions of renewables (the "RES-compliant portfolio"). If the revenue requirement of the portfolio with incremental renewables is less than 1% above the revenue requirement of the portfolio without them, using an appropriate averaging methodology, then the threshold is not crossed, and all the proposed renewable additions can take place.

One way of carrying out this calculation is through the approach of "least-cost dispatch". This approach requires the analyst to run a model that would simulate the operation of the entire utility network, including how utilities in Missouri would interact with the entire MISO network. In its most comprehensive form, it requires that the utility carry out an hour-by-hour assessment of which units would be on-line ("dispatched") for the entire term of the forecast.

As also described in Principle #2 above, the wind alliance does not believe that this type of analysis is appropriate for the RES proceeding. Rather, this is the type of analysis that comports with the development of an integrated resource plan, in which all of the assumptions can be reviewed, questioned, and challenged in a series of Commission hearings, rebuttal and testimony. The complexity of such a proceeding, and the time and expense it entails, is beyond what we believe is envisioned in this statute, and is a primary reason why the wind alliance engaged ICF to develop a simpler approach to carrying out the calculation of revenue requirement impacts.

Though the ICF approach is simpler than a full least-cost dispatch analysis, it is not simple. There are still many variables that such an analysis must take into account. A major benefit of the ICF approach, however, is that it is captured on a series of spreadsheets, in Excel, and that all the inputs and calculations are 100% transparent. It is not a black box, and it is quite sophisticated, within the constraints of a spreadsheet. The wind alliance believes that this approach strikes the right balance. If the

Commission were to require a full-blown dispatch analysis, the proceeding would be far too cumbersome, costly and time-consuming.

In fact, the Proposed Rule makes clear that the revenue requirement calculation should not be carried out as if it were an IRP, as Section (5) (B) states that the RES filing should utilize assumptions that have previously been established in proceedings such as the most recent utility resource plan, rate case and RES compliance plan. Thus the draft rules recognized explicitly that the revenue requirement calculation should not provide a basis for re-litigating assumptions that the Commission had already approved. We agree, and request that the Commission affirm in the proceeding the methodology that should be used for the revenue requirement calculation.

In concept, as embedded in the financial model we have developed, the wind alliance believes that the calculation of the revenue requirement under a least-cost non-renewable portfolio should be carried out in the following manner:

1. Start with the utility's existing revenue requirement (we have used Ameren in our model as an example), whether from the most recent rate case, RES filing or IRP proceeding
2. Project broadly how that revenue requirement will increase or decrease over the term of the calculation (e.g., 10 years or more, as described in Principle #3 above) due to least-cost changes in:
    a. Fuel prices
    b. Depreciation of existing capital
    c. Significant generation additions (e.g., new generation to meet capacity and energy requirements)
    d. Other major capital additions (e.g., scrubbers, CO_2 reduction equipment)
    e. The need to purchase allowances to emit SO_x, NO_x and CO_2
3. Modify the revenue requirement in each year due to the changes in 2. above

This will form the "baseline" from which the changes due to adding renewables can be compared.

Clearly, performing this calculation requires the utility to make assumptions with regard to what the cost of fuel, emissions allowances, capital additions, etc. will be. At the time of the RES filings, there will be objective market information available for many of those assumptions (e.g., natural gas and prices from the utility contracts, the price of emissions allowances sold on the existing exchanges). It is necessary to use such figures to carry out the revenue requirement calculation. In our model, we have provided a range of projections for those key inputs – e.g., low gas prices, mid-level (or reference case) gas prices, and high gas prices. The same is true for all the key input assumptions in our analysis. The ICF model provides the flexibility to test hundreds of possible scenarios. As described in Principle #6 below, the wind alliance has provided the Commission with a tool that allows it to assess the potential impacts of renewables on revenue requirement by adopting logical groups of assumptions ("low", "reference" and "high"), though the model allows the user to "mix and match" as they see fit.

Once the utility has its baseline revenue requirement for the RES filing, it should calculate what the revenue requirement would be under the scenario in which renewable generation is added to meet the RES requirement (i.e., 2% in 2011, 5% in 2014, 10% in 2018, and 15% in 2020). As described in Principle #1 above, they should use real project information to do so, not hypothetical project costs. In that calculation, we would recommend carrying out the revenue requirement calculation in each milestone year as follows:

1. Start with the utility's existing revenue requirement
2. Add the cost of the renewable projects from known PPAs, including the energy, capacity, and other charges, and including all types of renewables (solar, wind, biomass, etc.)
3. Add the cost of retail solar installations using net metering in that year
4. Reduce the revenue requirement due to the "avoided cost" caused by the reductions in charges to consumers from the consumption of less fuel (e.g., coal, gas)
5. Reduce the revenue requirement due to the savings in expenditures for SO_2, NO_x and CO_2 allowances no longer required due to the renewable generation
6. Take the resulting figure and average it out over a 10 year period (or longer – See Principle #3 above)

The result of this calculation will be to compare the incremental revenue requirement using renewables to the revenue requirement using a least-cost non-renewable portfolio, as the Proposed Rule anticipates. The Commission would be well-served to adopt this general approach.

Principle #6 – The Commission should adopt an approach similar if not identical to the ICF model as the approach for the utilities to use in calculating the incremental impact on revenue requirements of renewables.

The Commission would also be well served to adopt a tool for calculating the change in revenue requirement that is similar if not identical to the one that the wind alliance has used in this proceeding, developed by ICF. We have described many of the features and benefits of this financial model above.

As attachments to this filing, we have provided the Commission with several exhibits that show the results of exercising the ICF model. Note that we have modeled Ameren UE in this calculation, but the same methodology would apply to each utility in Missouri.

These exhibits include:

- Three pages which show the key variables that it is possible to modify in the model. While there are thousands of possible combinations of assumptions in the model, we have grouped the key variables (ones that substantially affect the revenue requirement) into three combinations or scenarios entitled "low case", “reference” case” and “high case” for ease of review by the Commission. It is possible to “mix and match” any of these assumptions in the actual model.

- These three pages also show what the impact would be on the utility’s revenue requirement using each of the three scenarios, under both the “cumulative” and the “incremental” approach.
- The other exhibits show – in the form of bar charts – what the impact on revenue requirements would be under each scenario and each approach

What this analysis shows is that there are conditions under which the impact on revenue requirements would be less than the 1% threshold (generally associated with the low and reference case), and other conditions under which the impact would be greater than 1%, particularly in the cumulative approach (these are generally associated with the high case).

As we go further out in time, the greater the impact of renewables on revenue requirements. This is true even in the incremental case, when the 10-year averaging means that the addition of renewables in the first milestone year of 2011 overlaps with the addition of renewables in 2014 and 2018. The impact is less than in the cumulative case however, where the full impact of renewables in each milestone year is added to that of the subsequent ones.

We believe that this model demonstrates to the Commission a fair and balanced tool and approach that it could utilize to carry out the required revenue requirement calculations in future RES filings. The wind alliance would be pleased to provide the Commission with more information on how we carried out this analysis.

RETAIL RATE IMPACT MODEL FOR AMEREN UE

PRELIMINARY DRAFT

Scenario Analysis

- Low Impact Case
- Reference Case
- High Impact Case

Variable Parameters

Retail Sales Growth Rate	:	AmerenUE Base Case	1.36%
Avoided Cost Calculation	:	Gas/Coal Mix	3
Rate Impact Averaging	:	10-year Avg.	1
Gas Price Forecast	:	EIA Forecast	$9.02
CO2 Price Forecast	:	ICF Base Case	$29.49
PTC Forecast	:	Reduces Post-2012	$5.06
Environmental Retrofit	:	Firmly Planned Retrofits	20%
In State Generation	:	70% of Generation is In-State	70%

RATE IMPACT		
Year	Cumulative	Incremental
2011	0.13%	0.13%
2014	0.31%	0.27%
2018	0.41%	0.39%
2021	0.47%	0.41%
Max	0.47%	0.41%

RETAIL RATE IMPACT MODEL FOR AMEREN UE

PRELIMINARY DRAFT

Scenario Analysis

- Low Impact Case
- Reference Case
- High Impact Case

Variable Parameters

Retail Sales Growth Rate	:	AmerenUE DSM Adj.	1.05%
Avoided Cost Calculation	:	Gas Only	2
Rate Impact Averaging	:	10-year Avg.	1
Gas Price Forecast	:	EIA Forecast	$9.02
CO2 Price Forecast	:	ICF Base Case	$29.49
PTC Forecast	:	Continues Indefinitely	$23.63
Environmental Retrofit	:	All Coal Capacity Retrofits	100%
In State Generation	:	100% of Generation is In-State	100%

RATE IMPACT		
Year	Cumulative	Incremental
2011	0.06%	0.06%
2014	0.14%	0.15%
2018	0.03%	0.09%
2021	-0.01%	0.03%
Max	0.14%	0.15%

RETAIL RATE IMPACT MODEL FOR AMEREN UE

PRELIMINARY DRAFT

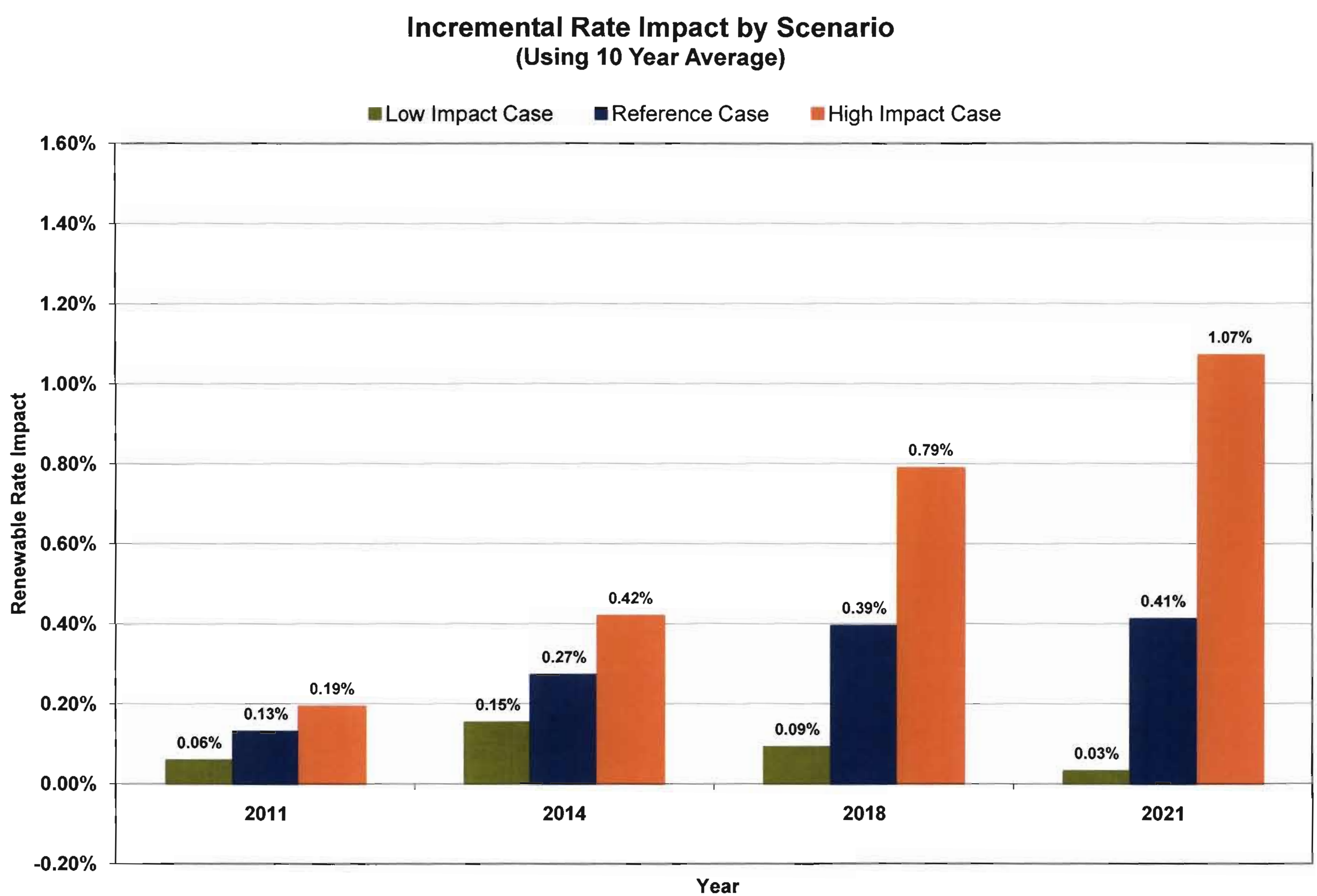
Scenario Analysis

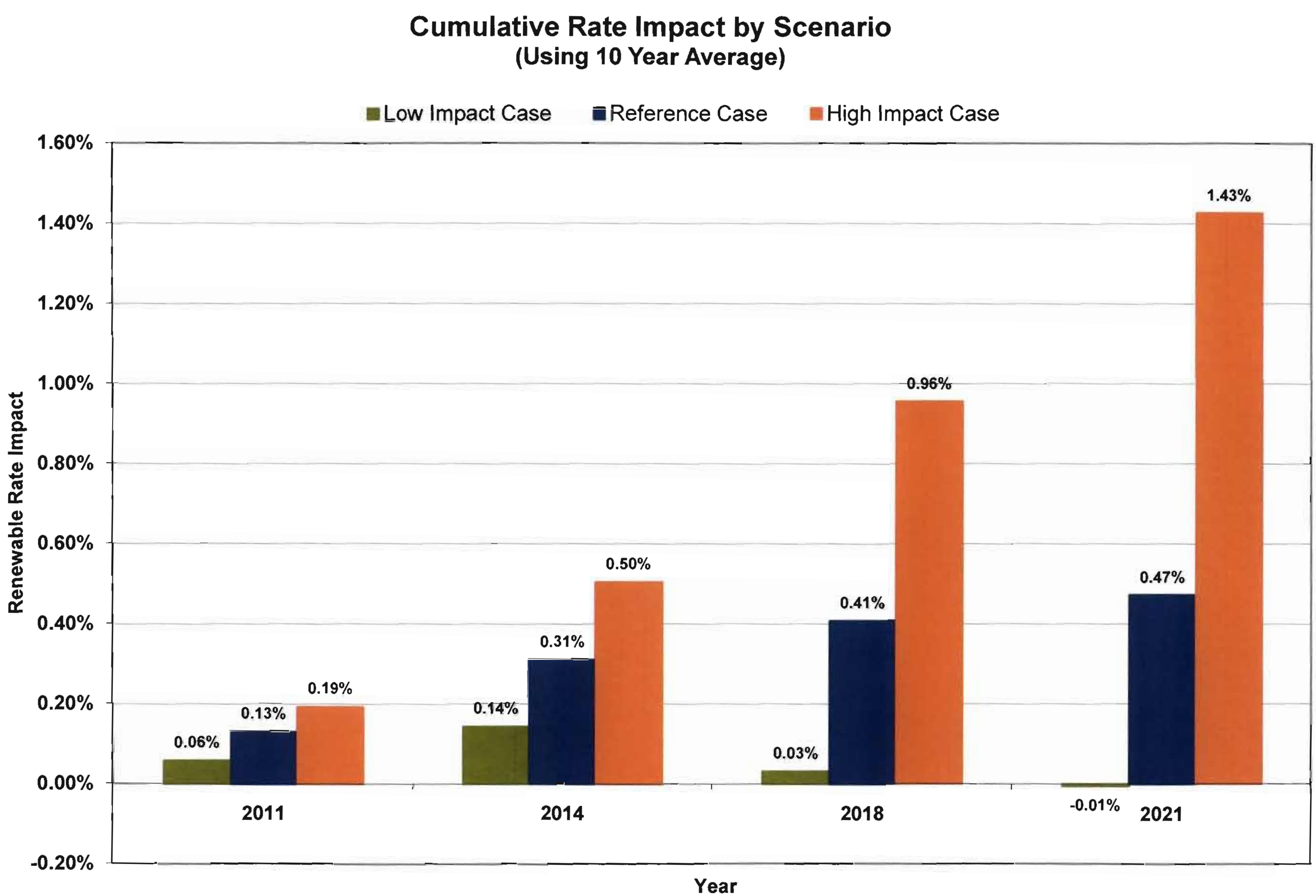
Low Impact Case
Reference Case
High Impact Case

Variable Parameters

Retail Sales Growth Rate	:	ICF Base Case	2.00%
Avoided Cost Calculation	:	Historical Mix	1
Rate Impact Averaging	:	10-year Avg.	1
Gas Price Forecast	:	ICF Base Case	$8.39
CO2 Price Forecast	:	No CO2	$0.00
PTC Forecast	:	Ends in 2012	$3.38
Environmental Retrofit	:	No Scrubber Retrofits	0%
In State Generation	:	50% of Generation is In-State	50%

RATE IMPACT		
Year	Cumulative	Incremental
2011	0.19%	0.19%
2014	0.50%	0.42%
2018	0.96%	0.79%
2021	1.43%	1.07%
Max	1.43%	1.07%


Incremental Rate Impact by Scenario
(Using 10 Year Average)
Low Impact Case
Reference Case
High Impact Case
Renewable Rate Impact
1.60%
1.40%
1.20%
1.00%
0.80%
0.60%
0.40%
0.20%
0.00%
-0.20%
0.06%
0.13%
0.19%
0.15%
0.27%
0.42%
0.09%
0.39%
0.79%
0.03%
0.41%
1.07%
2011
2014
2018
2021
Year


Cumulative Rate Impact by Scenario
(Using 10 Year Average)
Low Impact Case
Reference Case
High Impact Case
Renewable Rate Impact
1.60%
1.40%
1.20%
1.00%
0.80%
0.60%
0.40%
0.20%
0.00%
-0.20%
0.06%
0.13%
0.19%
0.14%
0.31%
0.50%
0.03%
0.41%
0.96%
-0.01%
0.47%
1.43%
2011
2014
2018
2021
Year

APPENDIX D – Siemens Letter on Kansas' House Bill 2662

SIEMENS

Randy H. Zwirn
Chief Executive Officer

February 11, 2010

Dear Chairman Holmes and Members of the Committee,

On behalf of Siemens Energy, Inc., we appreciate the opportunity to provide to the House Energy and Utilities Committee our position regarding proposed HB 2662 as it relates to the development and permitting of wind generation projects in Kansas. By way of introduction, Siemens Energy is the world's leading supplier of a complete spectrum of products, services and solutions for the generation, transmission and distribution of power and for the extraction, conversion and transport of oil and gas. We entered the wind power market in 2004 and have substantially expanded worldwide manufacturing capacity to stay ahead of the ever-increasing demand for clean, wind power. You may know that we broke ground last fall on a 300,000-square-foot wind turbine nacelle assembly facility in Hutchinson. It is scheduled to become operational in fall 2010 and will employ approximately 400 green-collar employees.

Siemens Energy, Inc. evaluated many locations for our new facility but chose Hutchinson in part because Kansas has the 3rd largest wind resource in the U.S., and Kansas billed itself as a green state that was open to wind development. In fact, HB 2369 established a renewable portfolio standard for electric suppliers in Kansas to procure at least 20 percent of the supply used to serve Kansas customers from renewable resources by 2020.

Having a manufacturing facility in close proximity to wind projects is a competitive advantage from a transportation cost perspective. Therefore, if wind developers scale back their development efforts in Kansas as a result of new siting requirements, the result can be that it becomes more difficult for us to keep our new Hutchinson facility full.

We worry that the proposed HB 2662 is conflicting with Kansas' existing legislative support for the development of the wind market in the state due to the increased complexities in the process and the potential of increasing the cost of wind farms in Kansas. In light of these concerns, I respectfully ask that you reconsider proposing HB 2662 and instead reinforce Kansas' sustainability leadership by supporting wind power as a clean, reliable energy supply that will help meet the ever-growing demands of the citizens and industries of Kansas.

Again, thank you for your consideration of our concerns in this matter.

Sincerely,

Randy H. Zwirn
President and CEO

Siemens Energy, Inc.
4400 Alafaya Trail
MC Q1-400
Orlando, FL 32826
Tel: (407) 736-3319
Fax: (407) 736-5019

APPENDIX E – Federal Subsidies to Coal, Natural Gas and Nuclear Energy

Coal and Natural Gas:

In September 2009, The Environmental Law Institute issued a report titled Estimating U.S. Government Subsidies to Energy Sources: 2002-2008 ("ELI Report").[1] As set forth in the ELI Report, subsidies for traditional fossil fuels far exceed those for renewable energy.

Examples of subsidies for coal and natural gas[2] (quoted from the ELI Report but also noted in other sources) are as follows:[3]

Credit for Production of Nonconventional Fuels ($ 14,097) - IRC Section 45K. This provision provides a tax credit for the production of certain fuels. Qualifying fuels include: oil from shale, tar sands; gas from geopressurized brine, Devonian shale, coal seams, tight formations, biomass, and coal-based synthetic fuels. This credit has historically primarily benefited coal producers.

Characterizing Coal Royalty Payments as Capital Gains ($986) - IRC Section 631(c). Income from the sale of coal under royalty contract may be treated as a capital gain rather than ordinary income for qualifying individuals.

Exclusion of Benefit Payments to Disabled Miners ($438) **-** 30 U.S.C. 922(c). Disability payments out of the Black Lung Disability Trust Fund are not treated as income to the recipients.

Other-Fuel Exploration & Development Expensing ($342) - IRC Section 617. Identical provisions as applied to oil and gas [see footnote[4]]. Including, for example, the costs of surface stripping, and construction of shafts and tunnels.

Other-Fuel Excess of Percentage over Cost Depletion ($323) - IRC Section 613. Taxpayers may deduct 10 percent of gross income from coal production.

Credit for Clean Coal Investment ($186) - IRC Sections 48A and 48B. Available for 20 percent of the basis of integrated gasification combined cycle property and 15 percent of the basis for other advanced coal-based generation technologies.

Special Rules for Mining Reclamation Reserves ($159) - IRC Section 468. This deduction is available for early payments into reserve trusts, with eligibility determined by the Surface Mining Control and Reclamation Act and the Solid Waste Management Act. The amounts

[1] A copy can be located at http://www.elistore.org/Data/products/d19_07.pdf.
[2] The ELI Report did not address nuclear subsidies with the exception of a liability limitation which is discussed in these comments.
[3] The dollar amounts are in millions of dollars and cover FY02-FY08.
[4] *Oil and Gas Exploration & Development Expensing ($7,100)* **-** IRC Section 617. Intangible Drilling Costs (IDC) (for example, wages, costs of machinery, or unsalvageable materials) may be deducted as business expenses rather than amortized. Integrated oil companies may deduct only 70 percent and must amortize the remainder.

attributable to mines rather than solid-waste facilities are conservatively assumed to be one-half of the total.

Natural Gas Distribution Lines Treated as Fifteen-Year Modified Accelerated Cost Recovery System (MACRS) Property ($138) - IRC Section 168(e)(3)(E)(viii). The normally applicable depreciation period is shortened for qualifying natural gas distribution lines.

84-month Amortization Period for Coal Pollution Control ($102) - IRC Section 169(d)(5). Extends the amortization period used in calculating the deduction from the generally applicable 60-month period available for other types of pollution control facilities.

Expensing Advanced Mine Safety Equipment ($32) - IRC Section 179E. The costs of qualifying mine safety equipment may be expensed rather than recovered through depreciation.

Nuclear:

Nuclear, in the near future, may be receiving even more subsidies based upon energy policies proposed by the President and the Department of Energy.[5] Regardless of the future, we can look at what already exists or took place in the past, especially when civilian/commercial nuclear energy was a nascent technology. The Renewable Energy Policy Project issued a study in July 2000 on federal subsidization of energy. The research report is titled "Federal Energy Subsidies: Not All Technologies Are Created Equal." (REPP Report")[6] The REPP Report points out a few interesting subsidies for nuclear.

"Commercial, fission-related nuclear power development received subsidies worth $15.30 per kilowatt-hour (kWh) between 1947 and 1961." Commissioner Davis is noting that the Renewable Energy Production Tax Credit gives wind farms 2 cents per kWh. And between 1947 and 1999, nuclear received federal subsidies totaling $115.07 billion[7] in direct program subsidies and another $30.29 billion in indirect subsidies.[8]

Another subsidy for nuclear energy is the Price-Anderson Act of 1959, as amended, 42 U.S.C. § 2210. The statute limits the liability of a nuclear facility for off-site damage in the event of a nuclear accident. The current limit is $10 billion per year.[9] This cap on liability means lower insurance premiums for nuclear facilities. But in the event a nuclear accident causes more than that amount of damage, the costs shift to the federal government and therefore the taxpayers. It was important to the emergence of the private nuclear industry, but it also clearly saves the facilities on insurance premiums, although there may be disagreement as to how to assign a value to that.[10]

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[5] *Remarks by the President on Energy in Lanham, Maryland*, Feb. 16, 2010, found at http://www.whitehouse.gov/the-press-office/remarks-president-energy-lanham-maryland.
[6] A full copy may be found at http://www.repp.org/repp_pubs/pdf/subsidies.pdf.
[7] In 1999 dollars.
[8] REPP Report, p. 7.
[9] ELI Report, p. 27.
[10] REPP Report, pp. 14-15.