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Comments on The Taylorville Energy Center Facility Cost Report

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Conclusion:

The Facility Cost Report for the proposed Taylorville Energy Center does not reasonably demonstrate that the proposed facility will only have a minor impact on the bills of electric ratepayers in Illinois. The claims and conclusions presented in the Facility Cost Report and its supporting analyses are biased in favor of the proposed Taylorville facility by a number of extremely optimistic assumptions concerning the facility's construction and operating costs, its operating performance, natural gas prices, and the annual revenues that Tenaska will be able to earn through the sale of the SYN gas, carbon dioxide ("CO_2"), sulfur, nitrous oxide ("NOx") allowances and the plant's capacity.

The Facility Cost Report also reveals that Tenaska will not bear any significant risks from the Taylorville Energy Center. Instead, the ratepayers of the state's investor-owned utilities and alternative electric suppliers will bear the main risks and burdens of the project.

Summary of Comments:

Comment No. 1. We have not had a reasonable opportunity to review the analyses underlying the Facility Cost Report and its supporting exhibits, such as the Pace Rate Impact Analysis and the Tenaska Secondary CO_2 Emission Analysis.

Comment No. 2. The Taylorville Energy Center will likely be heavily subsidized by the State of Illinois and the Federal government.

Comment No. 3: Tenaska assumes that the rate impact of the Taylorville Energy Center will be heavily mitigated by revenues from the sale of SYN gas, CO_2, sulfur, NOx allowances and plant capacity. However, Tenaska does not offer any guarantees that these revenues actually will be obtained. Instead, the risks associated with these sales are passed along to the ratepayers of the investor-owned utilities and the alternative retail energy suppliers through the 30 year sourcing agreements.

Comment No. 4. Despite all of the subsidies and incentives that may be provided by the state and federal governments, the cost of the power generated at the Taylorville Energy Center will be very expensive.

Comment No. 5. It is unclear what significant risks, if any, Tenaska will bear in the Taylorville Energy Center.

Comment No. 6. The results of the Rate Impact Analysis are heavily biased by the unrealistic assumption that the proposed Taylorville Energy Center will achieve extremely low heat rates.

Comment No. 7. There is a significant risk that the actual cost of constructing the proposed Taylorville Energy Center could be substantially higher than Tenaska's current estimate. The economic analyses in the Facility Cost Report should reflect this risk by including scenarios in which the cost of the proposed plant is 20 percent and 40 percent above the currently estimated cost.

Comment No. 8. The results of the Pace Rate Impact Analysis are heavily biased by the assumption that the Taylorville plant will achieve high annual capacity factors which, in turn, is dependent upon (1) the technology performing as well as Tenaska now claims and (2)Tenaska obtaining ‘must run’ status for the units for a significant portion of the year. If the units are not designed ‘must run’ as Tenaska has assumed and/or if it is not economic to sell SYN produced at the plant into the natural gas market, the rate impact of Taylorville will be substantially higher than Tenaska has projected because the same fixed costs will have to be recovered over a smaller number of megawatt hours (“MWh”) of output.

Comment No.9. The Pace Rate Impact Analysis is distorted by the assumption of high natural gas prices.

Comment No. 10. The Facility Cost Report significantly understates the potential for higher coal prices.

Comment No. 11. The Facility Cost Report is not persuasive in its claim that the proposed Taylorville Energy Center will capture more than 50 percent of the CO_2 that would otherwise be emitted.

Comment No. 12. Tenaska assumes a very low cost for sequestering the CO_2 from the Taylorville Energy Center.

Comment No. 13. The rate impact analyses presented by Tenaska and Pace that assume a 92 percent capacity factor for the Taylorville Energy Center are unrealistic.

Comment No. 14. It appears that the Tenaska Secondary CO_2 Emissions Analysis may significantly overstate the overall reductions in regional CO_2 emissions that would be attributable to the proposed Taylorville Energy Center.

Comment No. 15. It appears that the Pace Market Price Analysis may significantly overstate the overall market cost savings that would be attributable to the proposed Taylorville Energy Center.

Comment No. 1. We have not had a reasonable opportunity to review the analyses underlying the Facility Cost Report and its supporting exhibits, such as the Pace Rate Impact Analysis and the Tenaska Secondary CO_2 Emission Analysis

The Facility Cost Report and its supporting exhibits set forth the results of the various engineering, economic and modeling analyses Tenaska conducted plus conclusory statements regarding the benefits of the proposed Taylorville Energy Center.

As part of our review, we submitted a detailed set of questions and document requests to Tenaska seeking workpapers and computer output files that would reveal the assumptions and methodologies used in the FCR and supporting analyses. Tenaska declined to produce these materials and provided only a few short documents in response to our request. Tenaska did graciously allow us to conduct two phone conversations with their staff. But these phone conversations were not adequate substitutes for having the opportunity to complete detailed reviews of the workpapers, computer output files, and source documents for the substantial number of conclusions that are presented in the FCR and supporting exhibits. Nevertheless, our review of the materials that were made available did identify a number of serious flaws and biases in the Facility Cost Report, the Rate Impact Analysis, and the Secondary CO_2 Emissions Analysis. Our review also raised questions about the validity of the benefits that Tenaska has cited for the Taylorville Energy Center.

Comment No. 2. The Taylorville Energy Center will likely be heavily subsidized by the State of Illinois and the Federal government.

Tenaska assumes it will receive the following subsidies and incentives for the Taylorville Energy Center:

- A loan guarantee from the U.S. Department of Energy for up to $2.579 billion. This will result in interest savings of approximately $60 million per year.[1]
- Carbon sequestration credits under Section 45Q of the Internal Revenue Code.[2]
- The requirement that the investor-owned and alternative retail energy suppliers will have to enter into 30 year sourcing agreements for the power from the Taylorville Energy Center.
- Up to a $50 million cash grant from the Illinois Coal Revival Grant Fund.[3]
- An $18 million grant provided by the state to pay for preparation of the Facility Cost Report that will only be paid back if the Taylorville project "achieves financial closing.[4]

The financing plan for the Taylorville project also may include, in addition to the potential DOE guaranteed loan, debt financing to be provided by Illinois tax exempt solid waste disposal/wastewater treatment bonds, and moral obligation bonds.[5] As noted in the Facility Cost

1 Facility Cost Report, at page 11.
2 Id, at page 12.
3 Id, at page 49.
4 Id, at page 6.
5 Id, at page 50.

Report, the Illinois Finance Authority already has provided a preliminary inducement resolution in 2006 for $350 million of tax exempt solid waste disposal facilities revenue bonds and $149 million of moral obligation bonds financing for the purpose of attracting clean coal generating capacity to the State of Illinois.[6]

Comment No. 3: Tenaska assumes that the rate impact of the Taylorville Energy Center will be heavily mitigated by revenues from the sale of SYN gas, CO_2, sulfur, NOx allowances and plant capacity.[7] However, Tenaska does not offer any guarantees that these revenues actually will be obtained. Instead, the risks associated with these sales are passed along to the ratepayers of the investor-owned utilities and the alternative retail energy suppliers through the 30 year sourcing agreements.

Tenaska makes very optimistic assumptions about its ability to sell the by-products from the Taylorville plant:

- **SNG Revenues –** "Over the first ten years of operation, revenues from SNG sales are projected to average $15.2 million annually in 2010$."
- **CO_2 Revenues –** "It is expected that the TEC will sell approximately 1.9 million [metric tonnes] of CO_2 per year to Denbury Onshore, L.L.C. Over the first 10 years of operation, revenues from CO_2 sales are projected to be approximately $9.0 million annually in 2010$."
- **Sulfur Revenues** – "On average, over the first 10 years of operation, revenues from molten sulfur sales are projected to be $3.6 million annually in 2010$."
- **NOx Allowance Revenues** –"Based on Pace's projected prices for NOx allowances, CCG estimates, on average, over the first 10 years of operation, revenues from the sale of surplus NOx allowances will be approximately $18.1 million annually in 2010$."
- **Electric Capacity Revenues –** "On average, over the first 10 years of operation, revenues from electric capacity sales are projected to be $21.9 million annually in 2010$."[8]

Thus, in total, Tenaska is assuming that it will receive $67.8 million, in 2010$, each year during the plant's first 10 years of operations, from the sales of SYN, CO_2, sulfur, NOx, and electric capacity. However, Tenaska does not bear any risk that these projections will be wrong. Instead, all of the risk will be passed along to the investor owned utilities and alternative retail energy suppliers who must enter into the 30 year sourcing agreements and their ratepayers.

6 Id, at page 51.
7 Facility Cost Report, at pages 10 and 11.
8 Id.

Comment No. 4. Despite all of the subsidies and incentives that may be provided by the state and federal governments, the cost of the power generated at the Taylorville Energy Center will be very expensive.

The Facility Cost Report notes that the projected cost of power from Taylorville will start at 16.3 cents per kilowatt hour in 2015, increasing to 19.1 cents per kilowatt hour in 2024, 22.6 cents per kilowatt hour in 2030, and 30.6 cents per kilowatt hour in 2045.[9]

These projected costs of power are significantly higher than reasonably estimated costs of implementing aggressive energy efficiency, wind resources, or new natural gas-fired combined cycle capacity. It is more than reasonable to expect that a portfolio of these alternatives could provide reliable electricity at a far lower cost than Taylorville. For example, even the levelized cost study presented in the Pace Rate Impact Analysis shows that energy from wind facilities would cost only $71/MWh, in 2010 dollars, or far less than the $150/MWh levelized price of power from Taylorville.

However, even the costs of generating power at Taylorville that are presented in the Facility Cost Report and Pace Rate Impact Analysis may be far too low as they assume that Taylorville will be able to operate at an average 75 percent annual capacity factor. If the plant does not operate at that high level of performance, the cost per kilowatt hour of generating power will go up, perhaps significantly.

Moreover, the costs of generating power in the Facility Cost Report are based on Tenaska's optimistic assumptions about future plant construction costs, financing costs, and coal prices. If the costs of building and/or operating the plant are higher than Tenaska now acknowledges, then the total cost of power from Taylorville will be even higher than the company now claims.

For example, Tenaska has acknowledged that the costs of power from Taylorville would be significantly higher if it does not obtain the federal credits and the revenues it is anticipating. For example, Tenaska notes that:

> In the event that CCG is not able to store its captured CO_2 either by delivering CO_2 to Denbury or by storing geologically in its own storage field (if, for example, there is a change in law that prevents CCG from obtaining an injection permit), CCG would earn no CO_2 sales revenue and would not receive any production tax credits, and would also incur the cost of purchasing carbon emission allowances (if applicable) for the CO_2 that it is not able to store. However, in this event CCG would not be compressing CO_2, so this cost would be saved. The projected net annual effect of these changes would be an increase in costs (as compared to delivering CO_2 to Denbury under the terms of the Denbury contract) of approximately $63 million per year on average for the first 10 years and $137 million per year on average over 30 years. In the first 10 years, the estimated average rate impact of these changes would be 0.398%. Over the 30-year period, the estimated average rate impact would be 0.838%.[10]

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9 Facility Cost Report, at page 12, and Pace Rate Impact Analysis, Exhibit 6, at page 8.

10 Facility Cost Report, at page 82.

But, according to the proposed plan for Taylorville, ratepayers, not Tenaska, would bear the risks of having to pay these additional CO_2 costs over the life of the Taylorville plant.[11]

Comment No. 5. It is unclear what significant risks, if any, Tenaska will bear in the Taylorville Energy Center.

Tenaska has received and will continue to receive significant incentives and funds from the federal government and the state of Illinois. The investor owned utilities in the state and the Alternate Retail Energy Suppliers will be required to enter into 30 year Source Agreements requiring them to purchase plant's generation. Moreover, as ComEd, the Retail Energy Supply Association, and the Illinois Competitive Energy Association have noted, there is no obligation on Tenaska's part to deliver any power whatsoever, yet the proposed Source Agreements would provide for full payment of the project annual revenue requirements—including costs and profits—whether or not any power is ever generated or delivered over the entire thirty-year term of the agreements. Under these circumstances, Tenaska should not be entitled to earn an 11.5 percent return on equity. Instead, the company's return on equity should be closer to a risk-free cost of long-term debt.

Instead, the state's investor-owned utilities and retail energy suppliers and their ratepayers are at risk that they have will to pay the capital and operating costs of the proposed Taylorville plant without any guarantees as to the output that Tenaska will provide from the plant

The only risk that representatives from Tenaska could cite as being borne by the company was the risk that the ICC would disallow imprudent costs that have been incurred as a result of the mismanagement of construction or operations. Although prudency reviews are important regulatory tools, this means that the state's investor owned utilities, alternative retail energy suppliers and their ratepayers will bear all of the risks that Tenaska is wrong (but not imprudent) about the future costs of building and operating the Taylorville project. Given all of the uncertainties associated with building and operating a new power plant over the next thirty five years (and continuing to operate the fleet of existing plants) it is reasonable to expect that Tenaska's current estimates will not be spot on. Yet Tenaska will reap a relatively high (11.5 percent) annual return on its equity investment whether or not the Taylorville plant provides economic benefits to ratepayers and/or actually reduces greenhouse gas and other air emissions.

Comment No. 6. The results of the Rate Impact Analysis are heavily biased by the unrealistic assumption that the proposed Taylorville Energy Center will achieve extremely low heat rates.

A generating unit's heat rate measures how efficiently it operates. The lower the heat rate, the more efficient the plant. The lower the heat rate, the less fuel a plant will burn and, as a result, the lower its fuel costs and emissions will be.

The heat rates assumed for the proposed Taylorville facility are presented on page 3 of the Pace Rate Impact Analysis:

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11 These risks are particularly noteworthy given that Denbury has not even determined yet whether a 700-mile long CO_2 pipeline from the Midwest to the Gulf Coast could be feasible. See, e.g., http://www.denbury.com/index.php?id=53.

	Units	Unit 1	Unit 2
Net Heat Rate (June-Sep)	Btu/kwh	7,583	6,649
Net Heat Rate (Nov-Feb)	Btu/kwh	7,114	6,487
Net Heat Rate (Mar-May & Oct)	Btu/kwh	7,225	6,476

Thus, Tenaska is claiming that Taylorville Unit 1 will achieve heat rates in the range of 7,114 to 7583 btu/kwh and that Unit 2 will achieve even lower heat rates in the range of 6,476 to 6,649 btu/kwh. These heat rates are not only unreasonably low compared to the heat rates for IGCC plants by other independent sources but are inconsistent with the heat rates projected for the plant in the January 2005 *TEC/IGCC Feasibility Analysis*, as well as the data presented in the Taylorville air permit application.

For example, the following table shows the heat rates projected for future IGCC units by the U.S. Department of Energy's National Energy Technology Laboratory, the *Future of Coal* study from the Massachusetts Institute of Technology, the engineering firm Black & Veatch and a utility that was evaluating coal-fired generating alternatives, Florida Power & Light.

Study	Units	IGCC Heat Rate Without CO_2 Capture	IGCC Heat Rate With CO_2 Capture
DOE/NETL *Cost and Performance Baseline for Fossil Energy Plants* (2007)	Btu/kwh	8,364-8,922	10,505 - 10,757
NETL *Current and Future Technologies for Gasification Based Power Generation (2009)*	Btu/kwh	9,649	11,214
MIT *Future of Coal* (2007)	Btu/kwh	8,891	10,942
Black & Veatch *Energy Market Perspective* (Fall 2009)	Btu/kwh	9,600	12,350
Florida Power & Light *Clean Coal Technology Selection Study* (2007)	Btu/kwh	8,990 - 9,360	

Thus, the heat rates assumed by Tenaska for Taylorville with CO_2 capture for its Facility Cost Report analyses are significantly lower than the heat rates projected for new IGCC facilities without any CO_2 capture.

The heat rates assumed by Tenaska for the Facility Cost Report analyses also are much lower than the 9,039 – 9,099 btu/kwh heat rates projected for the Taylorville plant in the January 2005 *TEC/IGCC Feasibility Analysis* prepared by the ERORA Group.[12] It is significant that this was for a plant without CO_2 capture. As can be seen from the table above, it is reasonable to expect that a plant's heat rate will be substantially higher with CO_2 capture than without.

The heat rates assumed for Taylorville for the Facility Cost Report analyses also are inconsistent with the information presented in Tenaska's air permit application. In that application, Tenaska

12 At pages 75 and 98.

said that the design heat content of the coal that would be used at Taylorville would be 10,750 btu/lb and that the design coal feed to the gasifiers would be 277 tons per hour. This translates into an HHV heat input to the gasifiers of 5,956 MMbtu/hour and a net heat rate of 9,453 btu/kwh with the designed net output of 630 MW presented in the air permit application.

In conclusion, the heat rates that Tenaska has assumed for the analyses in its Facility Cost Report are inconsistent with the heat rates projected for new IGCC plants by a wide range of government and industry studies, the Taylorville *Feasibility Analysis* and the information presented in Tenaska's air permit application. The use of the very low heat rates biases the results of the analyses in the Facility Cost Report in favor of the proposed plant. Tenaska should be required to redo those analyses with more reasonable heat rates.

Comment No. 7. There is a significant risk that the actual cost of constructing the proposed Taylorville Energy Center could be substantially higher than Tenaska's current estimate. The economic analyses in the Facility Cost Report should reflect this risk by including scenarios in which the cost of the proposed IGCC plant is 20 percent and 40 percent above the currently estimated cost.

Tenaska's currently estimated construction cost for the Taylorville plant is $2.616 billion, excluding financing costs, taxes, insurance and start-up costs.[13] However, none of this cost is currently subject to any cost cap and, it appears, none of the contracts for the project have been signed and no equipment has been purchased.

Coal power plant construction costs have risen dramatically in recent years as a result of a worldwide competition for design and construction resources, equipment, and commodities like concrete, steel, copper and nickel. Terms like "staggering" and "skyrocketing" have been used to describe these cost increases.[14] Coal-fired power plants that were estimated to cost $1500 per kilowatt in 2002 are now projected to cost in excess of $3500 per kilowatt.[15]

Almost all other coal-fired power plants (both those under construction and proposed) have experienced large cost increases in recent years. For example, the estimated per unit construction cost of Duke Energy Carolina's Cliffside Project increased by 80 percent between the summer of 2006 and June 2007. Similarly, AMP-Ohio cancelled its proposed Meigs County coal plant last fall after the estimated cost of the plant increased by 37 percent only 13 months after the previous estimate was issued. Consequently, it is reasonable to expect that the actual cost of building the Taylorville Energy Center will be significantly higher than Tenaska currently estimates.

Duke Energy Indiana's Edwardsport plant is the only IGCC project that is currently under construction in the U.S. This project's construction cost experience illustrates the cost increases that can be expected at Taylorville.

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13 Facility Cost Report, at page 10.

14 Although commodity prices remained flat or fell for a period from late 2008 through much of 2009, prices have rebounded since the 3rd quarter of 2009 and regained some of the ground lost during the preceding year, as Tenaska has noted at page 35 of the Facility Cost Report.

15 See the report, *Coal-Fired Power Plant Construction Costs*., a copy of which is available at: http://www.synapse-energy.com/Downloads/SynapsePaper.2008-07.0.Coal-Plant-Construction-Costs.A0021.pdf.

At the time it requested a certificate from the Indiana Utility Regulatory Commission in the spring of 2007, Duke Energy Indiana estimated that its proposed Edwardsport IGCC unit would cost $1.985 billion. However, in April 2008, just one year later, Duke announced an 18 percent increase in the estimated cost of its proposed IGCC coal plant. Duke indicated that higher than expected costs had been experienced when the Company actually began final procurement of equipment for the plant. Duke also said that "the increase in the cost estimate is driven by factors outside the Company's control, including unprecedented global competition for commodities, engineered equipment and materials, and increased labor costs."[16] Duke also noted in its Petition to the Indiana Utility Regulatory Commission that this projected increase in cost was "consistent with other recent power plant project cost increases across the country."[17]

Then, last fall, Duke announced another 6.4 percent increase in the IGCC unit and warned the Indiana Commission that there may be further increases in the project, which was 44 percent complete:

> The Edwardsport IGCC Project has made considerable progress in the six months since our previous filing. Construction is proceeding at an expected pace and the total project is approximately 44% complete. Yet, despite Petitioner's best efforts to rigorously manage the Edwardsport IGCC Project, we have experienced design modifications and scope growth above what was anticipated from the preliminary engineering design, adding capital costs to the Project. We are currently forecasting that the additional capital cost items will use the remaining contingency and escalation amounts in the current $2.35 billion cost estimate and add approximately $150 million, or about 6.4%, to the estimated cost of the Project. The Company is in the process of determining how this increase in capital costs will impact the total Project cost estimate, including the impact associated with additional contingency. Over the next few months, we will be examining items such as craft labor estimates, final engineering, procurement and start-up estimates to better understand the potential cost increases and how much additional contingency will be needed to complete the Project.[18]

In fact, just today, April 16th, Duke filed an update that increased the estimated cost of the Edwardsport IGCC Project by approximately $530 million, or 23 percent, above the $1.985 billion previous estimate. The new cost estimate is $2.88 billion including escalation and financing costs. This means that the estimated cost of the Edwardsport Project has increased by $895 million, or 45 percent, since the Project was approved by the Indiana Utility Regulatory Commission in the fall of 2007. Duke claims that the Project is now 57 percent complete.

Tenaska says that it intends the Taylorville Energy Center will be constructed through a combination of fixed price equipment purchase contracts (for the gas turbines, steam turbine, other major power block equipment, gasifiers, water treatment plant equipment, and coal handling equipment), fixed price engineering and installation contracts (for the water treatment plant, the power block and the coal handling facilities), and an incentivized cost reimbursable

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16 Verified Petition in Indiana Utility Regulatory Commission Cause No. 43114 IGCC-1, filed on May 1, 2008, at pages 3-4

17 Id, at page 7.

18 *Verified Petition and Motion for Subdocket Proceeding*, Duke Energy Indiana, Indiana Utility Regulatory Commission Cause No. 43114 IGCC-4, November 24, 2009, at page 3.

contract for construction project management and installation of other Core Plant components.[19] However, Tenaska provides absolutely no evidence that it is reasonable to assume that it will be able to obtain such fixed price equipment purchase contracts, fixed price engineering and installation contracts and/or incentivized cost reimbursable contract for construction project management and installation of Core Plant components. In the past, utilities were able to secure fixed-price contracts for their power plant construction projects. It is unclear whether that remains true today. Other proponents of new coal-fired power plants have explained that in recent years (that is, since about 2005) contractors have not been willing to assume the risk that the cost of a multi-year project would escalate significantly and, consequently, have not been willing to fix the price for the entire contract.[20]

A number of other IGCC plants have been proposed but many have been cancelled and, other than Taylorville, the remaining projects have either been formally delayed or are otherwise not moving forward very aggressively. For example, Xcel Energy announced in October 2007 that it was indefinitely deferring its plans to build an IGCC plant in Colorado because the development costs were higher than the utility originally expected.[21] Similarly, Tampa Electric cancelled a proposed IGCC plant in the fall of 2007 due to uncertainty related to CO2 regulations, particularly capture and sequestration issues, and the potential for related project cost increases. According to a press release, "[b]ecause of the economic risk of these factors to customers and investors, Tampa Electric believes it should not proceed with an IGCC project at this time," although it remains steadfast in its support of IGCC as a critical component of future fuel diversity in Florida and the nation. In addition, the Tondu Corp. announced in June 2007 that it was suspending plans to build a planned 600 MW IGCC facility in Texas citing high costs and other concerns related to technology and construction risks.[22]

In fact, due to cost and technological uncertainties, state regulatory commissions have denied rate recovery for investments in proposed IGCC plants or have refused to allow utilities to enter into a purchase power agreement for the output from a proposed IGCC plant. For example, in August of 2007, the Minnesota Public Utilities Commission refused to require Xcel Energy to enter into an agreement to purchase power from a proposed IGCC plant on the grounds that the terms and conditions of the proposed contract were not consistent with the public interest because they would result in unreasonably high prices for Xcel and unreasonably high rates for Xcel's ratepayers.[23]

Then, in April of 2008, the Virginia State Corporation Commission denied Appalachian Power Company's request to recover costs associated with a proposed IGCC plant from its Virginia ratepayers citing uncertainties of costs, technology, and unknown federal mandates.[24] The

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19 Facility Cost Report at page 24.

20 For example, see the *Consulting Engineer's Report for the American Municipal Power Generating Station located in Meigs County, Ohio*, prepared for the Division of Cleveland Public Power by Burns and Roe Enterprises, Inc., October 2007.

21 Denver Business Journal, October 30, 2007, available at: http://denver.bizjournals.com/denver/stories/2007/10/29/daily26.html

22 http://www.reuters.com/article/companyNewsAndPR/idUSN1526955320070615

23 Order in Docket No. E-6472/M-05-1993, issued on August 30, 2007, at page 17. Available at https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={825E0DB0-0D4B-4261-BF18-84643EAC49BD}&documentTitle=4762105.

24 Final Order in Case No. PUE-2007-00068, April 14, 2008. Available at http://scc.virginia.gov/newsrel/e_apfrate_08.aspx.

Commission found that the Company's ("APCo") cost estimate for project was "not credible"—it had not been updated since November 2006.[25]

The Commission also concluded that "… APCo has no fixed price contract for any appreciable portion of the total construction costs; there are no meaningful price or performance guarantees or controls for this project at this time. This represents an extraordinary risk that we cannot allow the ratepayers of Virginia in APCo's service territory to assume."[26]

It also noted the uncertainties surrounding federal regulation of carbon emissions and carbon capture and sequestration technology and costs and observed that the Company was asking for a "blank check."[27] On this basis, the Commission concluded that "We cannot ask Virginia ratepayers to bear the enormous costs—and potentially huge costs—of these uncertainties in the context of the specific Application before us."[28]

Tenaska claims that the current KBMD for the overnight construction cost estimate has a level of accuracy of +15%/-10%.[29] It is difficult, if not impossible, to give any credence to such a claim given the significant uncertainties associated with building new coal plants, the fact that Taylorville will be the first-of-a-kind IGCC facility and the substantial cost increases experienced by just about every other coal construction project in recent years (including Duke Energy's Edwardsport IGCC project). If Tenaska wants to proceed with the Taylorville Project, the ICC should require the company to agree that it will not seek recovery of any construction cost investment more than 15 percent above its current construction cost estimate. Then the ICC can determine whether Tenaska really has confidence that the level of accuracy for the overnight construction cost estimate is limited to +15 percent.

Comment No. 8. The results of the Pace Rate Impact Analysis are heavily biased by the assumption that the Taylorville plant will achieve high annual capacity factors which, in turn, is dependent upon (1) the technology performing as well as Tenaska now claims and (2)Tenaska obtaining 'must run' status for the units for a significant portion of the year. If the units are not designed 'must run' as Tenaska has assumed and/or if it is not economic to sell SYN produced at the plant into the natural gas market, the rate impact of Taylorville will be substantially higher than Tenaska has projected because the same fixed costs will have to be recovered over a smaller number of megawatt hours ("MWh") of output.

The Pace Rate Impact Analysis modeled a significant share of Taylorville's capacity as having 'must-run status,' indicating power generation output at full availability of one gas turbine and associated steam turbine. The remaining capacity, associated with the second gas turbine, was modeled with must-run status during peak hours and all hours between June 15 and September 15, but simulated to dispatch competitively in the spot power market during other times.[30]

[25] Id, at pages 4 to 5.
[26] Id, at page 5.
[27] Id, at page 10.
[28] Id, at page 10.
[29] Facility Cost Report, at page 25.
[30] Pace Rate Impact Analysis, Exhibit 10.0, at page 2.

According to Pace, these parameters were provided by Tenaska based on initial commercial negotiations— but no explanation or justification was provided.

The Rate Impact Analysis also modeled the Taylorville plant as achieving a 92 percent availability. This is a very optimistic assumption for what will be a first-of-its-kind plant with a new mix of technology operating at large electric generating scale for large periods of each year.

Both of these were key assumptions for the Rate Impact Analysis. As a result, the analysis reflected that the Taylorville would operate at a high, 75 percent, average annual capacity factor. The lower the plant's capacity factor, the fewer MWhs of electricity it would be assumed to be generated. This would mean that the very high capital costs of building and financing the plant would have to be spread over fewer units of output. As a result, the price of power from the plant on a per kilowatt hour basis would increase as the capacity factor decreased.

Just how significant an assumption this was can be seen from the levelized cost study presented in the Rate Impact Analysis where Pace assumed that a new gas-fired combined cycle unit would operate at an average 15-22 percent annual capacity factor under reference case assumptions and between 25 percent and 50 percent average annual capacity factors under the three other "states of the world" examined by Pace.[31] This is a very pessimistic assumption for the operating performance of new natural gas-fired combined units and puts the gas-fired plant at a significant disadvantage in an economic comparison with Taylorville. A more appropriate "apples-to-apples" levelized cost comparison would have assumed a higher average annual capacity factor (*e.g.*, in the range of 60 percent to 70 percent) for the gas-fired plant.

Tenaska tells us that the Pace analysis assumed that, unlike Taylorville, the new combined cycle unit would not have 'must-run' status and thus would be assumed to be dispatched competitively in the spot power market throughout the year. The per kilowatt hour price of power from Taylorville would be significantly higher if that plant were assumed to have only a 25 percent to 50 percent capacity factor, let alone an even lower 15 percent capacity factor.

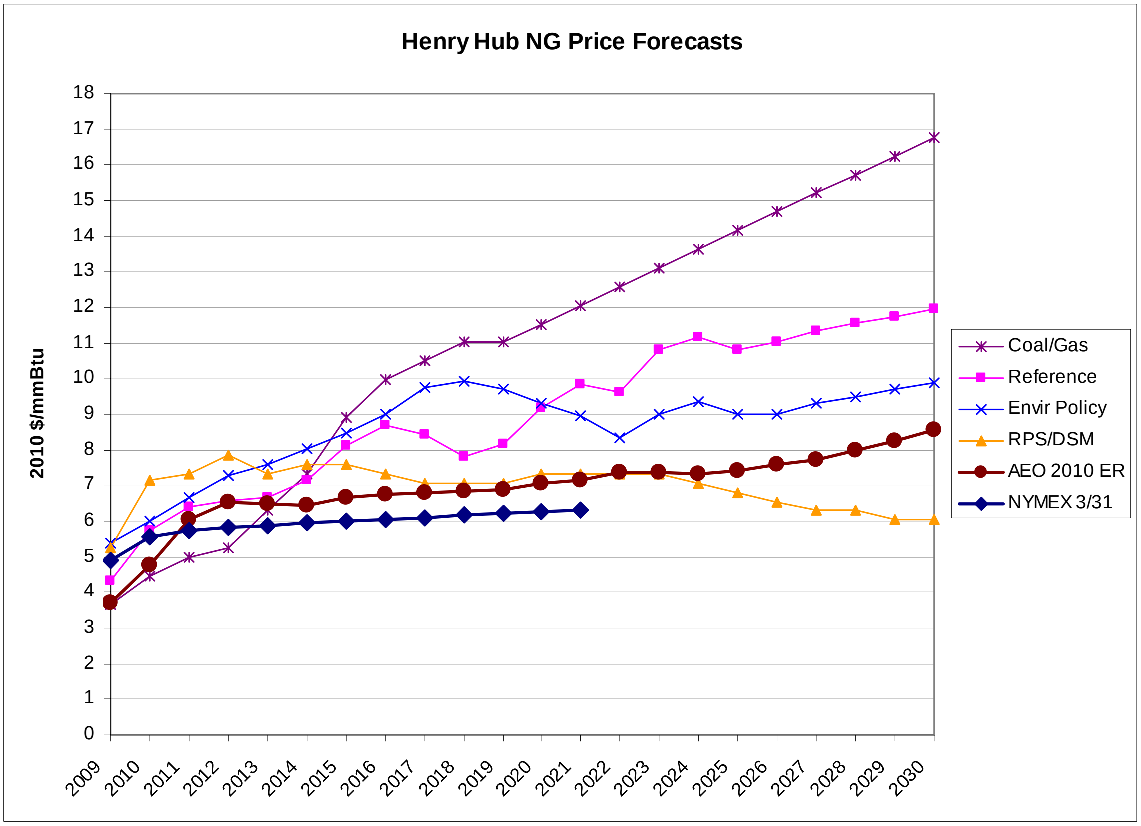
Similarly, the Tenaska Secondary CO_2 Emissions Analysis examined how effective a new natural gas-fired combined cycle plant would be in reducing total CO_2 emissions. This analysis presumably also assumed that the new combined cycle unit was not 'must-run' and instead would be dispatched competitively in the spot power market. As a result, the projected capacity factor for this new combined cycle unit was only 11 percent, much lower than the assumed 78 percent capacity factor assumed for the Taylorville plant.[32] This suggests that Taylorville's annual capacity factor would be significantly lower and its cost of power dramatically higher if it too were assumed to be dispatched competitive in the power market instead of being afforded the benefit of "must-run" status.

Comment No. 9. The Pace Rate Impact Analysis is distorted by the assumption of high natural gas prices.

As can be seen in the following figure, the natural gas prices assumed in three of the four scenarios modeled by Pace ("states of the world") are higher than current NYMEX future prices through 2022 and the most recent long-term price forecast from the Energy Information Administration ("EIA") of the U.S. Department of Energy. In two of the four scenarios,

31 Id, Exhibit 33, at page 37.
32 Exhibit 12.0, at page 4.

"Reference" and "Coal/Gas," the natural gas prices are significantly higher than the current NYMEX prices and EIA forecast.



The lower NYMEX and EIA gas price forecasts are based on new estimates of domestic U.S. natural gas reserves. These increased natural gas supplies can be expected to exert downward pressure on gas prices as shown by the significantly lower NYMEX futures prices in the above figure.

Indeed, Entergy Corporation has described these new supplies of natural gas as a structural change in the natural gas market. This structural change has two important impacts on the resource planning for companies like Mississippi Power. First, as a result of the existing and expected supply glut, current and projected prices of natural gas have been reduced. At the same time, the dramatically larger domestic supplies of natural gas should be able to accommodate any increased demands from any fuel switching due to federal regulation of greenhouse gas emissions without causing significant increases in natural gas prices.

The structural change in the natural gas markets already has had a significant impact on utilities' resource planning. For example, in early April of this year, Entergy Louisiana informed the Louisiana Public Service Commission of its intent to defer (and perhaps cancel) the proposed retirement of an existing gas-fired power plant and its replacement by a new coal-fired unit. Entergy explained that it no longer believed that a new coal plant would provide economic benefits for its customers due to its current expectation that future gas prices would be much lower than previously anticipated:

Perhaps the largest change that has affected the Project economics is the sharp decline in natural gas prices, both current prices and those forecasted for the longer-term. The prices have declined in large part as a result of a structural change in the natural gas market driven largely by the increased production of domestic gas through unconventional technologies. The decline in the long-term price of natural gas has caused a shift in the economics of the Repowering Project, with the Project currently – and for the first time – projected to have a negative value over a wide range of outcomes as compared to a gas-fired (CCGT) resource.[33]

4. Recent Natural Gas Developments

Until very recently, natural gas prices were expected to increase substantially in future years. For the decade prior to 2000, natural gas prices averaged below $3.00/mmBtu (2006$). From 2000 through May 2007, prices increased to an average of about $6.00/mmBtu (2006$). This rise in prices reflected increasing natural gas demand, primarily in the power sector, and increasingly tighter supplies. The upward trend in natural gas prices continued into the summer of 2008 when Henry Hub prices reached a high of $131.32/mmBtu (nominal). The decline in natural gas prices since the summer of 2008 reflects, in part, a reduction in demand resulting from the downturn in the U.S. economy.

* * * *

However, the decline also reflects other factors, which have implications for long-term gas prices. During 2008, there occurred a seismic shift in the North American gas market. "Non-conventional gas"—so called because it involves the extraction of gas sources that previously were non-economic or technically difficult to extract—emerged as an economic source of long-term supply. While the existence of non-conventional natural gas deposits within North America was well established prior to this time, the ability to extract supplies economically in large volumes was not. **The recent success of non-conventional gas exploration techniques (e.g., fracturing, horizontal drilling) has altered the supply-side fundamentals such that there now exists an expectation of much greater supplies of economically priced natural gas in the long-run….**

* * * *

Of course, it should be noted that it is not possible to predict natural gas prices with any degree of certainty, and [Entergy Louisiana] cannot know whether gas prices may rise again. Rather, based upon the best available information today, it appears that gas prices will not reach previous levels

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33 *Report and Recommendation Concerning the Little Gypsy Unit 3 Repowering Project*, submitted by Entergy Louisiana to the Louisiana Public Service Commission, April 1, 2009, at pages 6-8.

> for a sustained period of time because of the newly discovered ability to produce gas through non-traditional recovery methods…[34] [Emphasis added]

Entergy's conclusion that there has been a seismic shift in the domestic natural gas industry was confirmed in early June 2009 by the release of a report by the American Gas Association and an independent organization of natural gas experts known as the Potential Gas Committee, the authority on gas supplies. This report concluded that the natural gas reserves in the United States are 35 percent higher than previously believed. The new estimates show "an exceptionally strong and optimistic gas supply picture for the nation," according to a summary of the report.[35]

A Wall Street Journal Market Watch article titled "U.S. Gas Fields From Bust to Boom" similarly reported that huge new gas fields have been found in Louisiana, Texas, Arkansas, and Pennsylvania and cited one industry-backed study as estimating that the U.S. now has enough natural gas to satisfy nearly 100 years of current natural gas-demand.[36] It further noted that

> Just three years ago, the conventional wisdom was that U.S. natural-gas production was facing permanent decline. U.S. policymakers were resigned to the idea that the country would have to rely more on foreign imports to supply the fuel that heats half of American homes, generates one-fifth of the nation's electricity, and is a key component in plastics, chemicals and fertilizer.
>
> But new technologies and a drilling boom have helped production rise 11% in the past two years. Now there's a glut, which has driven prices down to a six-year low and prompted producers to temporarily cut back drilling and search for new demand.[37]

The use of high assumed natural gas prices influences the Pace Rate Impact Analysis in several ways, all of which bias that analysis in favor of the proposed Taylorville plant:

- Higher gas prices inflate the cost of power from gas-fired power plants, thereby, improving the relative economics of the Taylorville Energy Center; and
- The higher gas prices also inflate the projected revenues that Tenaska assumes it will receive from the sale of SYN into the market.

Comment No. 10. The Facility Cost Report significantly understates the potential for higher coal prices.

The Taylorville Facility Cost Report contains a *Delivered Price of Coal* study prepared by Wood Mackenzie, who was retained to prepare a 30 year forecast of the delivered price of coal, inclusive of the Illinois Fuel Use Tax for the Taylorville Energy Center (TEC). The plant is required to use coal mined in Illinois for the project period 2015 to 2045. It is expected to consume high sulfur coal at a rate of 2.1 and 2.4 million short tons per year.

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34 Id, at pages 17, 18 and 22.

35 *Estimate Places Natural Gas Reserves 35 percent Higher*, New York Times, June 9, 2009. Available at: http://www.nytimes.com/2009/06/18/business/energy-environment/18gas.html.

36 Available at http://online.wsj.com/article/SB12410459891270585.html.

37 Id.

The Wood Mackenzie analysis concludes that:

> U.S. power generators are adding environmental equipment to coal plants in response to increasingly stringent emission regulation and the use of this new equipment is having the effect of increasing demand for the higher sulfur Illinois coal. The abundant, accessible and easily mineable Illinois coal supply is expanding to meet this increasing demand. No shortage of Illinois coal is expected over the forecast period from 2015 through 2045. With no looming supply shortage, there is little upward pressure on coal price beyond that normally associated with the cost of mining.[38]

Wood Mackenzie also concludes that:

> While it is possible to determine the expected least cost of coal to TEC from all the sources available to the plant over time, reason and prudence dictate that forecasting a delivered price at TEC should be done by basing the forecast upon the average delivered price of a group of coal sources. The forecast delivered price at TEC is defined as the lowest average delivered price at TEC from one of six subdivisions that represent geographical mining areas of the State of Illinois. The least cost coal, fully evaluated for energy content, sulfur and transportation, is derived from Subdivision 3 (West-Central Illinois). Mining Subdivision 3 (West-Central Illinois) is the mining region geographically closest to TEC wherein transportation costs from mine to TEC will be lower than from other regions.[39]

The Wood Mackenzie total forecast and projection of coal suitable for TEC (Exhibit 14) shows relatively flat production from 2015 through 2018, with a sharp increase through 2023, relatively flat production through 2032, followed by an increase in annual average production levels of almost 20 million tons per ton.

The Wood Mackenzie analysis understates the potential for a supply shortage driven by intensified demand

The Wood Mackenzie analysis makes only passing reference to the rapid depletion of Central Appalachia as an alternative source of low/medium sulfur, high energy content thermal coal. A recent investor analysis by Arch Coal (a leading owner of both CAPP and ILB coal) shows that the 2008-2010 drop-off in CAPP production to be the “largest fall-off in production yet”. And, this production decrease is viewed as permanent.[40] Massey Energy, the dominant coal player in the CAPP region, has adopted an aggressive strategy for its remaining reserves as an exporter for the global steel industry.[41] Its assessment of both the domestic and international steel markets and the remaining use of its thermal reserves in the domestic markets is summarized in a recent

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[38] *Exhibit 6.0, The Delivered Price of Coal to the Taylorville Energy Center*, at page 8 of 64.

[39] Id.

[40] Arch Coal, Inc, *Investor Presentation*, March 2010, p. 12. The analysis shows a 70 million drop-off in production and sees this kind of reduction in the historical context as a precursor to a period of sharp price increases. Available at: http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9MzcyNjExfENoaWxkSUQ9MzcwMDU0fFR5cGU9MQ==&t=1

[41] Don Blankenship, Chairman and CEO, Massey Energy, *Steel Demand Globally and in the U.S.*, “Go East Young Man, Go East,” Slide 2, Coaltrans Americas Conference, January 28, 2010.

investor presentation: "As CAPP depletion, over-regulation and consolidation continue, causing regional production to decline Massey's reserves and production become increasingly more valuable, not less."[42]

The view among utilities that CAPP coal is becoming scarce and more expensive is well known. Utility consumers with historic business relations with CAPP producers are switching to the ILB, and others are looking. Recently, Santee Cooper made market news by settling a deal for a reported 2 million tons per year out of the ILB.[43] Additional utilities currently entertaining deals are Progress Energy, Duke Energy and Southern Company. American Electric Power has also announced its intention of procuring an initial contract of 150,000 tons per month from the ILB (with options for 2 million tons per year for three to five years).[44]

Industry analysts see significant current price differentials between ILB and CAPP coal, and basic market strategies of CAPP owners moving toward the higher end European, Asian and South American met markets in the long term. Even with the relative high sulfur content of ILB coal, the market activity is now. The intention is for long term relationships for coal with qualities that is found in the ILB, and with the dwindling supply from the CAPP region the ILB rises to relative dominance. The risk of price increases in such a climate seems apparent, notwithstanding the statement by Wood Mackenzie that TEC operators can expect "little upward price pressure."

Wood Mackenzie understates the potential for significantly higher mining costs in the region.

Although Wood Mackenzie states that it accounts for mining costs, its overall characterization of the climate for mining in the ILB is at variance with mine owners and detailed federal analysis. The risk is that mining costs may rise beyond those typically considered within the "norm."

For example, Wood Mackenzie says that "Illinois coal is usually easily mined from stable geologies and has high energy content…" Although the United States Geological Survey does characterize the Illinois Basin as a mature mining region with high production costs,[45] Arch Coal's recent investor analysis identifies several production challenges in the ILB: higher mining costs than the PRB, capital investments that are significant, long lead time for permits, and difficult geology in some areas.[46]

Moreover, unlike the PRB Gillette minefields, the ILB has not yet been the subject of an intensive USGS review with regard to stated coal reserves. When such a review of the Gillette minefields was conducted, cost of production considerations substantially reduced the

42 Massey Energy, *Raymond James 31st Annual Institutional Investors Conference, March 9, 2010.*

43 The deal received extensive coverage in Coal and Energy Price Report, *Market Commentary*, March 19 and 30, 2010.

44 *American Electric Power: American Electric Power Seeks Bids for Coal,* Trading Markets.com, March 23, 2010. Available at: http://www.tradingmarkets.com/news/press-release/aep_american-electric-power-american-electric-power-seeks-bids-for-coal-865577.html.

45 United States Geological Survey, *Coal Resource Availability, Recoverability and Economic Evaluations in the United States—A Summary,* The National Coal Resource Assessment Overview, U.S. Geological Survey Professional Paper 1625-F

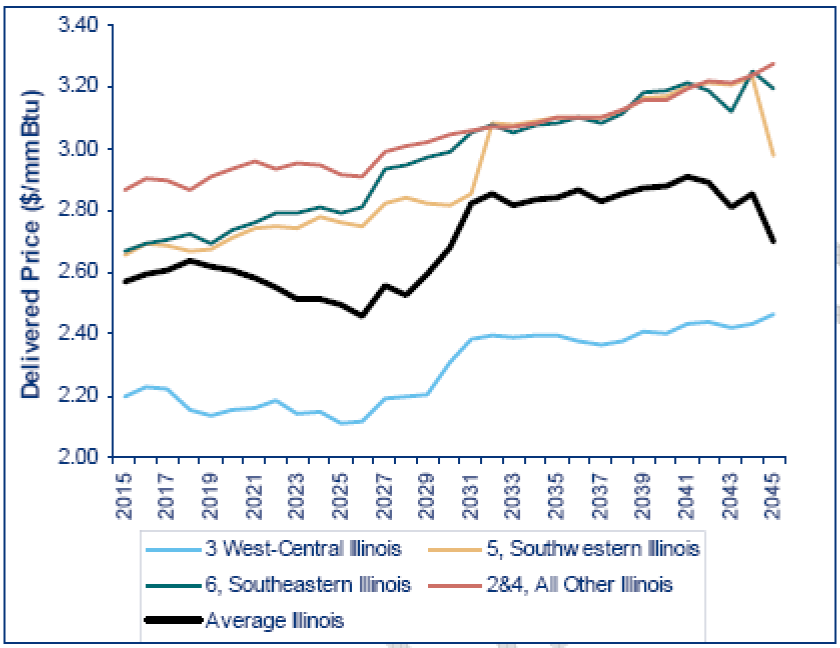
46 Arch Coal, *Op Cit*

economically recoverable reserve figures.[47] If aggressive mining was to take place in the ILB, as Wood Mackenzie anticipates, the price of coal might have to rise precipitously to cover both the higher costs of production and a rate of return sufficient to satisfy investors.

The price of coal will be significantly higher if TEC is unable to purchase coal from Subdivision 3 and/or that supply is disrupted for any reason.

As shown in Exhibit 63 from the Wood Mackenzie Report (Exhibit 6.0 to the Facility Cost Report), the delivered price of coal at TEC would be significantly lower in Subdivision 3 than from the other Subdivisions in the State of Illinois.

Exhibit 63 – Delivered Price of Coal at TEC from All Subdivisions in Illinois, Graph, 2009 $/mmBtu



Consequently, the price of the coal used at TEC could be substantially higher is assumed in the Facility Cost Report, and the supporting Pace Rate Impact Analysis, if the plant is not able to obtain all of its supply from Subdivision 3 and/or if that supply is disrupted for any significant period of time. In fact, as shown in Exhibit 63 from the Wood Mackenzie report, in any particular year, the delivered price of coal from other Subdivisions in Illinois could be between 20 percent and 33 percent higher than the delivered price of coal assumed in the Facility Cost Report and Pace Rate Impact Analysis.

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47 United States Geological Survey, *Assessment of Coal Geology, Resources and Reserves in the Gillette Coalfield, Powder River Basin, Wyoming:* Open-File Report 2008-1202. Available at: http://pubs.usgs.gov/of/2008/1202/.

Comment No. 11. The Facility Cost Report is not persuasive in its claim that the proposed Taylorville Energy Center will capture more than 50 percent of the CO_2 that would otherwise be emitted.

The Facility Cost Report says that the Taylorville plant is "expected to capture 1.9 [million metric] tons which is more than 50% of the CO2 that would otherwise be emitted at the facility."[48] In other words, according to Tenaska, the emissions of CO_2 from the Power Island will be the same as the emissions from a similarly sized, highly efficient natural gas power plant.[49]

However, it is not clear from the Facility Cost Report on what basis Tenaska has reached these conclusions. Moreover, it appears that Tenaska has not considered either (a) the CO_2 that would be emitted by the trucks that would be needed to bring the roughly 2.1 to 2.4 million tons of coal that would be processed at Taylorville each year[50] or (b) the CO_2 that would be emitted by the SYN gas that Tenaska plans to sell into the market.

Comment No. 12. Tenaska assumes a very low cost for sequestering the CO_2 from the Taylorville Energy Center.

Tenaska assumes a very low cost for sequestering the CO2 that would otherwise be emitted by the Taylorville plant. This low cost is based on the following conclusion of the Schlumberger analysis that is presented in Exhibit 13.2.b. of the Facility Cost Report:

> Schlumberger found that based on its evaluation and understanding of Project requirements – including pending regulation – costs for *typical* carbon storage projects are likely to be in the range of $5.00 to $10.00/MT of CO_2 stored over the life of the field. However, Schlumberger found the TEC's estimated costs to be lower than this range due to the very favorable geologic setting of the Mt. Simon formation, the assumptions concerning Project requirements, and other conditions for CO_2 injection specific to the TEC.[51] [Emphasis in original]

However, there are no *typical* carbon storage projects operating in the United States so there is no actual experiential basis for the $5.00 to $10.00 per metric tonne cost range identified by Schlumberger. Moreover, given the extremely uncertain nature of future carbon storage practices and costs, it would have been better for Tenaska and Pace to have assumed a wider and higher range of carbon storage prices in the Rate Impact Analysis than the single price they assumed.

Comment No. 13. The rate impact analyses presented by Tenaska and Pace that assume a 92 percent capacity factor for the Taylorville Energy Center are unrealistic.

The Facility Cost and Report and the Pace Rate Impact Analysis present the results of a scenario in which it was assumed that the proposed Taylorville plant would operate at a 92 percent average annual capacity factor.[52] However, there is no reasonable expectation that the new Taylorville plant, with its first-of-a-kind mix of technology operating at electric generation scale,

48 Facility Cost Report, at page 17.
49 Id, at page 76.
50 Id, at page 18.
51 Id, at page 79.
52 For example, see pages 13, 74 and 75 of the Facility Cost Report.

could operate at such an extremely high level over an entire 30 year period. Even less complicated, new natural gas-fired combined cycle plants are not expected to operate at 92 percent average annual capacity factors. Therefore, the results presented by Tenaska and Pace that are based on an assumed 92 percent capacity factor are completely unrealistic and have no probative value.

Comment No. 14. It appears that the Tenaska Secondary CO_2 Emissions Analysis may significantly overstate the overall reductions in regional CO_2 emissions that would be attributable to the proposed Taylorville Energy Center.

We have not received the workpapers for the Tenaska Secondary CO_2 Emissions Analysis (Exhibit 12.0 to the Facility Cost Report). Therefore, it is impossible to conduct a detailed evaluation of that analysis. However, the results appear to overstate the overall reductions in regional CO_2 emissions that would be attributable to the Taylorville plant.

First, the analysis does not appear to account for the expectation that some, perhaps, many, of the regions existing coal plants will be displaced or retired over the coming decades, even without Taylorville, as a result of the increasing stringency of federal and state air emissions requirements and/or low natural gas prices. Thus, many of the CO_2 emissions reductions that Tenaska claims for Taylorville, can be expected to happen even if the proposed IGCC plant is not built.

Second, as noted above, Tenaska has assumed unreasonably low heat rates for the Taylorville plant. The use of more correct, that is, higher, heat rates would suggest that Taylorville may not displace as many older, more inefficient gas and coal plants as the Tenaska Secondary CO_2 Emissions Analysis has assumed.

Third, it is reasonable to expect that other new generating units will be built in the region in the coming years. They too can be expected to displace generation at, and hence, CO_2 emissions from, existing coal-fired power plants in the region. Again, these reductions in CO_2 emissions can be expected to occur even if the proposed Taylorville plant is not built.

Moreover, it is entirely possible that additional generation at existing natural gas-fired combined cycle units in Illinois could provide a lower cost option for reducing regional CO_2 emissions. As shown in the following table based on 2008 data reported in the U.S. Environmental Protection Agency's Clean Air Markets Database, the existing combined cycle units in the state are operating at very low capacity factors. Increasing the generation at these facilities can be expected to displace significant generation at existing coal-fired units without requiring a three billion dollar investment in a new generating unit.

Unit	County	Unit Type Info	Max Capacity (MW)	Generation in 2008 (MWh)	Capacity Factor
Grand Tower	Jackson	Combined Cycle	244	40,641	1.9%
Grand Tower	Jackson	Combined Cycle	246	45,971	2.1%
Exxonmobil Oil Corporation	Will	Combined Cycle	21	12,301	6.7%
Kendall Energy Facility	Kendall	Combined Cycle	307	211,016	7.8%
Kendall Energy Facility	Kendall	Combined Cycle	309	244,445	9.0%
Kendall Energy Facility	Kendall	Combined Cycle	314	166,569	6.1%
Kendall Energy Facility	Kendall	Combined Cycle	316	445,741	16.1%
Cordova Energy Company	Rock Island	Combined Cycle	281	73,961	3.0%
Cordova Energy Company	Rock Island	Combined Cycle	285	80,238	3.2%
Morris Cogeneration, LLC	Grundy	Combined Cycle	92	137,960	17.1%
Morris Cogeneration, LLC	Grundy	Combined Cycle	95	71,467	8.6%
Morris Cogeneration, LLC	Grundy	Combined Cycle	93	80,484	9.9%
Holland Energy Facility	Shelby	Combined Cycle	338	90,370	3.1%
Holland Energy Facility	Shelby	Combined Cycle	338	106,195	3.6%

Comment No. 15. It appears that the Pace Market Price Analysis may significantly overstate the overall market cost savings that would be attributable to the proposed Taylorville Energy Center.

We have not received the workpapers for the Pace Rate Impact Analysis (Exhibit 10.0 to the Facility Cost Report). Therefore, it is impossible to conduct a detailed evaluation of any portion of that analysis, including Tenaska's claim that the proposed Taylorville plant would lead to lower regional market energy and capacity prices. However, several factors suggest that the results of the analyses overstate the overall reductions in regional energy and capacity prices that would be attributable to the Taylorville plant.

First, as noted above, the unreasonably low heat rates assumed for the Taylorville Energy Project will reduce its expect operating costs, inflate its expected operating performance and, consequently, improve its impact on regional prices.

Second, new energy efficiency and new renewable resources also will work to reduce regional energy and capacity prices and perhaps at a lower cost than Taylorville. These alternatives should have been modeled as part of alternative resource portfolios to the proposed Taylorville plant.[53]

53 In fact, although we have not had an opportunity to review the workpapers for the Rate Impact Analysis, it appears that Pace has modeled only very low levels of energy efficiency savings (in both MW and MWh).