135 FERC ¶ 61,038
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Marc Spitzer, Philip D. Moeller,
John R. Norris, and Cheryl A. LaFleur.

Oklahoma Gas and Electric Company — Docket No. ER11-2926-000

ORDER ON TRANSMISSION RATE INCENTIVES

(Issued April 19, 2011)

1. On February 18, 2011, Oklahoma Gas and Electric Company (OG&E) filed, under section 205 of the Federal Power Act (FPA),[1] for authority to implement certain incentive rate treatments pursuant to section 219 of the FPA[2] and Order No. 679.[3] Specifically, OG&E seeks to include 100 percent of prudently-incurred construction work in progress (CWIP Recovery) in its rate base and to recover 100 percent of prudently-incurred costs of transmission facilities that are cancelled or abandoned for reasons beyond OG&E's control (Abandoned Plant Recovery) associated with five transmission projects to be constructed by OG&E in the Southwest Power Pool, Inc. (SPP) region (Projects). As discussed below, in this order we grant the requested CWIP Recovery and Abandoned Plant Recovery with respect to the Projects, effective March 1, 2011, as requested.

I. **Background**

2. OG&E is an electric public utility that produces, transmits, and distributes electric energy to wholesale and retail customers in Oklahoma and western Arkansas. OG&E serves more than 750,000 retail customers and sells electric power at wholesale to other

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[1] 16 U.S.C. § 824d (2006).

[2] 16 U.S.C. § 824s (2006).

[3] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222, *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

electric utility companies, municipalities, rural electric cooperatives, and other market participants. OG&E's transmission system includes approximately 4,500 miles of transmission lines and 56 substations.[4]

3. OG&E is a transmission-owning member of SPP, a regional transmission organization. SPP serves as the transmission provider for all new transmission transactions on the OG&E system pursuant to the SPP Open Access Transmission Tariff (OATT). All new transmission service requests on OG&E's transmission facilities are obtained through the SPP OATT; however OG&E continues to serve two customers under existing long-term service agreements under the OG&E OATT.[5]

4. On October 12, 2010, in Docket No. ER11-112-000, OG&E filed a petition for CWIP Recovery and Abandoned Plant Recovery for a group of eight transmission projects, including the five projects that are the subject of the instant proceeding. In an order issued on December 30, 2010,[6] the Commission found that all eight projects met the rebuttable presumption, granted the requested incentives for two of the projects and denied the requested incentives for six of the projects without prejudice to OG&E refiling to demonstrate how each of the six remaining projects meets the nexus requirement.

II. OG&E's Filing

5. In its February 18, 2011 filing, OG&E states that the Projects[7] are the product of SPP's regional planning efforts implemented to meet North American Reliability Corporation (NERC) Reliability Standards, to relieve congestion, and to access a more diverse generation resource portfolio. According to OG&E, through its planning processes, SPP has identified the need for new large-scale transmission projects to facilitate expansive renewable resource developments in the western portion of the SPP system and to enable diverse resource options in load centers in the eastern portion of SPP and in neighboring balancing authority areas.

6. OG&E states that each of the Projects was vetted and selected through one of two SPP planning processes—i.e., SPP's Aggregate Transmission Service Study process[8] and

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[4] OG&E Filing at 2.

[5] *Id.* at 3.

[6] *Oklahoma Gas and Electric Co.*, 133 FERC ¶ 61,274 (2010) (December 30 Order).

[7] OG&E did not refile to request incentives for the Anadarko substation project.

[8] SPP's Aggregate Transmission Service Study process is conducted pursuant to Attachment Z1 of the SPP OATT.

SPP's Balanced Portfolio Process—and was included in the 2009 SPP Transmission Expansion Plan (2009 STEP).[9] Specifically, OG&E states that under SPP's Attachment Z1 procedures, SPP conducts an open season during which customers may make requests for long-term transmission service. Using these service requests SPP then performs an Aggregate Facilities Study, with the results used to determine the upgrades to be included in SPP's Attachment O integrated transmission planning study and analysis, which incorporates NERC Reliability Standards, load and capacity forecasts, and congestion within SPP and between SPP and other regions.[10] OG&E states that through this process, SPP has determined that OG&E's Sunnyside-Hugo and Sooner-Rose Hill Projects are necessary upgrades to alleviate congestion and thereby facilitate requests for transmission service in the region.

7. With regard to the other SPP planning process, OG&E states that SPP's Balanced Portfolio projects are intended to "reduce congestion on the SPP transmission system, resulting in savings in generation production costs."[11] According to OG&E, Attachment O of the SPP OATT provides that a Balanced Portfolio must be: (1) cost beneficial; and (2) balanced, meaning that the benefits must also equal or exceed the costs for each SPP zone.[12] OG&E states that its Sooner-Cleveland, Seminole-Muskogee, and Tuco-Woodward Projects are included in a Balanced Portfolio of network upgrades approved by the SPP Board of Directors in the 2009 STEP. According to OG&E, the final selection of the projects for this portfolio was conducted to ensure that a project was included for each SPP zone "with the most beneficial project chosen in each zone."[13] OG&E states that studies have demonstrated that the benefits of this portfolio of projects outweigh their costs and that the projects will relieve congestion by addressing "many of the top constraints in the SPP."[14] OG&E states that SPP concluded that this reduction in congestion will result in demonstrable cost savings to customers, providing a net benefit

[9] The 2009 STEP includes transmission upgrades relating to transmission service requests, generation interconnection service requests, and satisfaction of reliability criteria, as well as transmission upgrades that provide economic benefits.

[10] *See* OG&E Filing at 9-10 (citing SPP OATT, Attachment Z1).

[11] *Id.* at 10 (citing SPP Balanced Portfolio Report, Ex. No. OGE-16 at 3; Crissup Test., Ex. No. OGE-1 at 16).

[12] *Id*. at 11 (citing SPP OATT, Attachment O, section IV.3).

[13] *Id*. (citing SPP Balanced Portfolio Report, Ex. No. OGE-16 at 9).

[14] *Id*. (citing SPP Balanced Portfolio Report, Ex. No. OGE-16 at 35).

of $0.78 per month to the typical residential customer whose current monthly bill is $7.58.[15]

8. OG&E also states that, in accordance with the SPP OATT, SPP has issued a Notification to Construct[16] for each Project, which OG&E has accepted.

9. OG&E also states that its transmission rates are calculated pursuant to a Commission-approved formula and that it will populate its formula rate template with the CWIP balances for the Projects. OG&E adds that it has provided, for informational purposes, a populated version of the formula rate template illustrating the implementation of the CWIP incentive as Attachment 1 to its filing. With regard to the Abandoned Plant Recovery, OG&E states that it does not seek to recover any costs associated with abandoned plant at this time. However, in the event that some or all of the Projects are abandoned, in whole or in part, OG&E will submit a filing under section 205 of the FPA to recover such costs at that time.

10. OG&E requests waiver of the Commission's prior notice requirements to permit the requested incentives to be effective March 1, 2011. OG&E argues that good cause exists to grant its request for waiver because it has acted expeditiously to re-file its request for incentives pursuant to the December 30 Order and a March 1, 2011 effective date will mitigate the consequent delay in the implementation of the incentives. OG&E also argues that the proposed March 1, 2011 effective date is consistent with Commission policy and precedent as the Commission will generally grant waiver of the 60-day prior notice requirement where a filing lowers or has no effect on rates.[17] In OG&E's view, its request for CWIP Recovery will benefit ratepayers by supporting OG&E's cash flow, reducing interest expenses, and avoiding rate shock. OG&E also argues that the requested Abandoned Plant Recovery will have no effect on rates unless and until OG&E

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[15] *Id*. n.56 (citing Crissup Test., Ex. No. OGE-1 at 18; Balanced Portfolio Report, Ex. No. OGE-16 at 3).

[16] SPP issues Notifications to Construct to entities designated to construct facilities identified in the STEP. *See* SPP OATT Attachment O, section VI.4.

[17] OG&E Filing at 43 (citing *Central Hudson Gas & Electric Corp., et al.*, 60 FERC ¶ 61,106, *reh'g denied*, 61 FERC ¶ 61,089, at 61,357 (1992); *Midwest Energy, Inc.*, 75 FERC ¶ 61,224, at 61,743 (1996) (waiving notice where customer would "derive maximum benefit" from an earlier effective date for the rate change); *Southwestern Electric Power Co.*, 36 FERC ¶ 61,081, *reh'g denied*, 37 FERC ¶ 61,325 (1986) (waiving notice requirement for implementing CWIP since allowing a rate to decrease sooner would benefit the customer)).

makes an additional FPA section 205 filing to recover any abandoned plant costs and the Commission finds such costs to be prudent and outside of OG&E's control.

III. Notice of Filing and Responsive Pleadings

11. Notice of OG&E's filing was published in the *Federal Register*, 76 Fed. Reg. 12,098 (2011), with interventions and comments due on or before March 11, 2011. Timely motions to intervene were filed by East Texas Cooperatives,[18] Arkansas Electric Cooperative Corporation, American Electric Power Service Corporation, SPP, and Golden Spread Electric Cooperative, Inc. The Arkansas Public Service Commission filed a notice of intervention. No protests or adverse comments were filed.

IV. Discussion

A. Procedural Matters

12. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2010), the timely, unopposed motions to intervene and the notice of intervention serve to make the entities that filed them parties to this proceeding.

B. Substantive Matters

1. FPA Section 219 and Order No. 679 Incentives

a. Section 219 Requirements

i. OG&E

13. OG&E notes that the Commission has already held that OG&E has satisfied the first element of the FPA section 219 standard for transmission rate incentives for each of the Projects. Nevertheless, OG&E states that to ensure a complete record it has provided testimony and supporting exhibits which it states demonstrates the Projects' eligibility for the rebuttable presumption.[19]

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[18] East Texas Cooperatives are East Texas Electric Cooperative, Inc., Northeast Texas Electric Cooperative, Inc., and Tex-La Electric Cooperative of Texas, Inc.

[19] *See* OG&E Filing at 9-11 (describing the SPP planning processes in which the Projects were developed and approved).

ii. Commission Determination

14. The Commission has already found that OG&E adequately demonstrated that the Projects (as part of the group of eight projects addressed in Docket No. ER11-112-000) will ensure reliability and/or reduce the cost of delivered power by reducing transmission congestion, and therefore meet the requirements of FPA section 219 for incentive rate treatment.[20] OG&E has not presented any new information in its filing to require the Commission to reconsider that determination. Accordingly, each of the Projects continues to be eligible for the rebuttable presumption established in Order No. 679.

b. The Nexus Requirement

i. OG&E Nexus Demonstration

15. OG&E argues that the Projects fully satisfy the requirements for incentive rate treatment, consistent with the guidance provided in the December 30 Order, including the requirement that OG&E demonstrate the required nexus between the requested transmission rate incentives and each of the five Projects on a project-by-project basis. OG&E notes that the Commission has found particularly relevant whether a project is "routine,"[21] as compared to "other transmission projects or upgrades that are constructed in the ordinary course of maintaining a utility's transmission system to provide safe and reliable service."[22] OG&E states that the relevant factors to consider if a project is routine include: (1) the scope of the project (e.g., dollar investment, increase in transfer capability, involvement of multiple entities or jurisdictions, size, effect on region); (2) the effect of the project (e.g., improving reliability or reducing congestion costs); and (3) the challenges or risks faced by the project (e.g., siting, internal competition for financing with other projects, long lead times, regulatory and political risks, specific financing challenges, and other impediments).[23]

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[20] December 30 Order, 133 FERC ¶ 61,274 at P 35.

[21] OG&E Filing at 12 (citing *Baltimore Gas & Elec. Co.*, 120 FERC ¶ 61,084, at P 48 (2007), *reh'g denied*, 122 FERC ¶ 61,034 (2008) (*BG&E*)).

[22] *Id.* (citing *BG&E*, 120 FERC ¶ 61,084 at P 48; Order No. 679-A, FERC Stats. & Regs. ¶ 31,222 at P 60).

[23] *Id*. at 12 (citing *BG&E*, 120 FERC ¶ 61,084 at P 52*; PJM Interconnection, L.L.C.*, 133 FERC ¶ 61,273, at P 43 (2010); *Public Service Electric and Gas Co.*, 131 FERC ¶ 61,028, at P 19 (2010); *Great River Energy*, 130 FERC ¶ 61,001, at P 31 (2010)).

16. OG&E states that its routine transmission investments are designed and built to meet localized needs of customers while the Projects, which were approved through SPP planning processes, were designed and evaluated based on regional factors and are being built to provide regional benefits. According to OG&E, its typical transmission projects are constructed at 69-kV or 138-kV, which are smaller in stature, shorter in length, and typically follow a standard construction design. OG&E adds that its transmission construction and maintenance programs are heavily weighted towards these types of small projects. OG&E argues that in contrast to its typical projects, the five Projects for which is seeks incentives are each 345-kV. OG&E adds that in 2010 it built its first 345-kV project in eight years.

17. OG&E also argues that unlike the five Projects, the routine projects OG&E undertakes are of limited scope and cost. OG&E explains that from 2006 through 2009, OG&E's annual transmission capital investments averaged 24.6 miles of new transmission lines with an annual cost of $13.6 million and these projects rarely affected more than a single county. OG&E explains that, compared to OG&E's routine capital projects, the Projects range in length from 38 miles to 120 miles of 345-kV lines. OG&E adds that the least expensive of the Projects is expected to cost approximately $58 million (or more than ten percent of its net transmission plant), and the most expensive of the Projects is expected to cost $187 million (or approximately 33.5 percent of OG&E's net transmission plant). OG&E asserts that the capital costs of each of the Projects exceed OG&E's average annual expenditure of $53 million[24] over the past five years.

18. In addition, OG&E asserts that the Projects face substantial financial risks and challenges. According to OG&E, funding projects of this size and scope will require significant outlays of cash, decreasing OG&E's cash flow during the construction phase of the project. OG&E explains that its annual budgeting process aggregates the cost of the five individual Projects for financing purposes. OG&E anticipates that the annual capital expenditures associated with these Projects will average over $120 million and will be approximately $209 million in 2011 and $200 million in 2012.[25] OG&E contends that it will face a negative cash flow position as a result of meeting this level of capital expenditures because cash flows generated from operations will not be sufficient to cover the Projects. OG&E states that the decreased cash flow will put stress on OG&E's credit

[24] In 2010 OG&E constructed its first 345-kV EHV project in eight years thus skewing its average annual expenditure from $13.6 million, the 2006-2009 average, to $53 million, the 2006-2010 average.

[25] OG&E Filing at 33.

metrics, increase the risk that the company may not be able to satisfy its financial obligations, and could harm OG&E's credit ratings.[26]

19. OG&E also argues that the expenditures for the Projects will increase OG&E's debt and burden OG&E's financial metrics, raising the risk of a credit downgrade. According to OG&E, strong credit ratings are important to its ability to borrow money at a lower cost and lower credit ratings will increase OG&E's cost of debt, which will be passed on to customers. OG&E also states that credit ratings also affect a company's access to capital markets and define its overall risk profile. Additionally, OG&E avers that internal competition for capital with other OG&E expenditures raises additional financing challenges as OG&E is facing aging utility infrastructure that will require investments higher than historical levels several years into the future. OG&E adds that it is investing in new Smart Grid technology over the next three years as well as additional obligations in renewable energy and environmental initiatives.

20. Finally, OG&E argues that it faces financial risks from the Projects' long lead times. OG&E explains that some of the Projects will not be placed into service until the end of 2013 or 2014 even though OG&E will incur significant costs in connection with those Projects immediately. OG&E argues that the long lead times open the door to unexpected cost increases, construction delays, and continually building carrying costs.

21. OG&E describes each Project and argues why it believes each Project meets the nexus requirement, as follows:

(a) <u>Sunnyside-Hugo Project (Transmission Upgrade)</u>

22. OG&E states that the Sunnyside-Hugo Project is a 345-kV, 120-mile transmission line with facility upgrades to the Sunnyside substation. OG&E estimates that the Project will cost $187 million and will be placed into service on April 1, 2012.[27] The investment to complete the Project will represent 33.5 percent of OG&E's current net transmission plant. Additionally, OG&E states that the transmission line will span 120 miles across southern Oklahoma and will connect to the Western Farmers Electric Cooperative substation near Hugo and Fort Towson, Oklahoma.

23. With regard to the effect of the Project, OG&E states that in its September 2008 Study, SPP evaluated 1,488 MW of long-term transmission "to identify system problems

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[26] *Id*.

[27] *Id.* at 16.

and potential modifications necessary to facilitate" the requested service.[28] OG&E states that the SPP September 2008 Study concluded that service requests made by Arkansas Electric Cooperative Corporation, American Electric Power West, and Oklahoma Municipal Power Authority each independently require the addition of the Sunnyside-Hugo Project. OG&E adds that combined, these requests constitute 1,436 MW, which is nearly the entire 1,488 MW of requests reviewed in the September 2008 Study.

24. With regard to risks and challenges, OG&E states that completion of the Sunnyside-Hugo Project requires coordination of construction with ITC Great Plains, LLC (ITC), which is completing the Hugo substation. OG&E contends that it has no control over the permitting or construction of the ITC portion of the Project, which means that any delay by ITC could delay OG&E's ability to place the Project into service. OG&E also asserts that obtaining rights-of-way for the Project will be challenging. OG&E acknowledges that rights-of-way are required for routine transmission projects but asserts that in this case, the length of the Project provides extraordinary challenges for OG&E with regard to obtaining rights-of-way over the Project's 120-mile route. OG&E explains that it must obtain rights-of-way from private landowners in five separate counties. According to OG&E, the risks associated with siting this transmission line have already materialized as approximately 100 condemnation cases covering 150 separate parcels of land in the Project's path have been filed.[29] OG&E adds that the Project faces additional siting challenges because it will cross Native American tribal lands, the ownership of which may be held by tribal entities directly, by individuals, or by the U.S Bureau of Indian Affairs (BIA) in trust. According to OG&E, the myriad ways property can be owned by a Native American Nation or individual affect the length of time it takes to acquire such property and the specific procedures that need to be followed. OG&E adds that the need to obtain rights-of-way for tribal lands presents additional complexity because state eminent domain laws and procedures often do not apply.

25. In addition, OG&E states that there are numerous environmental risks that could affect the Sunnyside-Hugo Project, including the Project's crossing the habitat of the endangered American Burying Beetle. OG&E explains that a survey of the activities of the American Burying Beetle was performed along the Sunnyside-Hugo route in 2010, but was found deficient by the U.S. Fish and Wildlife Service (USFWS) and will have to be repeated in 2011. OG&E adds that the survey cannot be performed again until the weather conditions are favorable to activity by the American Burying Beetle. OG&E

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[28] *See id*. (citing Aggregate Facility Study SPP-2006-AG3-AFS-11 for Transmission Service Requested by Aggregate Transmission Customers at 10-13 (SPP September 2008 Study), Ex. No. OGE-14).

[29] *Id.* at 18.

states that it is also performing environmental assessments required pursuant to the National Environmental Policy Act (NEPA) for the portions of the Sunnyside-Hugo Project that cross BIA lands. OG&E asserts that depending on the outcome of the NEPA assessments, OG&E could be required to mitigate potential environmental impacts, which could lead to additional costs, changes in the Project's proposed route, or delays in construction.

(b) <u>Sooner-Rose Hill Project (Transmission Upgrade)</u>

26. OG&E states that the Sooner-Rose Hill Project is a 345-kV, 88-mile transmission line of which OG&E will construct 43 miles. OG&E's portion of the Sooner-Rose Hill Project will cost $57.8 million, which represents over 10 percent of OG&E's current net transmission plant. The Sooner-Rose Hill Project has an estimated in-service date of June 1, 2012. Like Sunnyside-Hugo, under the SPP transmission service study procedures (conducted in March 2009), SPP identified the Project as one of the facility upgrades that must be built in order to provide requested transmission service while maintaining or improving system reliability.

27. OG&E states that the Project is designed to meet regional needs and that in SPP's March 2009 Study, SPP evaluated 1,359 MW of long-term transmission service requests and determined that service requests made by Kansas Power Pool, Aquila Inc., and Westar Energy each independently require the addition of the Sooner-Rose Hill Project.[30] OG&E adds that combined, these requests total 485 MW, which constitutes over one-third of the total 1,359 MW of requests reviewed in the March 2009 Study. In addition, OG&E states that in the 2009 STEP, SPP determined that the Sooner-Rose Hill Project was a "regional reliability upgrade" that could relieve the flowgate that monitors the 138-kV line from El Paso to Farber for the loss of the 345-kV line from Wichita to Woodring.

28. With regard to risks and challenges, OG&E explains that its portion of the Sooner-Rose Hill Project is only one part of a larger regional project to be built in Oklahoma and Kansas with OG&E constructing the transmission line and related facilities in Oklahoma and Westar Energy building its portion of the transmission line and related facilities in Kansas. OG&E avers that it has no role in the siting, permitting, or construction of the facilities to be located outside of Oklahoma, which face many of the same risks and challenges as the Oklahoma portion of the line. OG&E adds that any delay in the construction of the facilities to which OG&E will interconnect will delay OG&E's ability

[30] *See id.* at 20 (citing Aggregate Facility Study SPP-2007-AG1-AFS-12 For Transmission Service Requested by Aggregate Transmission Customers at 11-13 (Revised March 19, 2009), Ex. No. OGE-15).

to complete its portion of the Project and place it into service, and that Westar Energy's failure to build it portion of the Project could lead to abandonment of OG&E's portion of the Project.

29. As is the case with Sunnyside-Hugo, OG&E will also need to obtain rights-of-way across four different Native American tribal lands for the Sooner-Rose Hill Project, and as of January 1, 2011, there are twenty tracts of land along the Project route that involve the BIA. In addition, OG&E is currently performing environmental assessments required by NEPA, the results of which could require OG&E to mitigate potential environmental impacts, which could lead to additional costs, route changes, delays in construction, or abandonment of the Project.

(c) <u>Seminole-Muskogee Project (Balanced Portfolio Project)</u>

30. The Seminole-Muskogee Project is a single-circuit, 345-kV, 120-mile transmission line being built by OG&E from its Seminole substation to its Muskogee substation, with associated upgrades to both substations. The total cost will be approximately $179.1 million, which represents over 32 percent of OG&E's current net transmission plant. The Project's expected in-service date is December 31, 2013. OG&E states that in the 2009 STEP, SPP determined that Seminole-Muskogee was one of seven upgrades included in a Balanced Portfolio that, by reducing congestion, would result "in savings in generation production costs," and would provide "significant benefit versus cost to the SPP region."[31] Specifically, OG&E states that SPP determined that the Seminole-Muskogee Project could relieve congestion on the flowgate that monitors the 138-kV line from Okmulgee to Henryetta for the loss of Okmulgee to Kelco and on the flowgate monitoring the 138-kV line from Riverside Station to Okmulgee City for the loss of the 138-kV line from Riverside Station to Explorer Okmulgee.[32] OG&E adds that the Seminole-Muskogee transmission line also was part of a series of extra high voltage transmission projects designed by SPP as a regional "overlay" to the existing transmission system.

31. In OG&E's view, the risks and challenges the Project faces separate it from OG&E's routine projects. OG&E states that because the Project will span 120 miles, it will need to obtain rights-of-way from private landowners in six separate counties, including two different Native American tribes. Additionally, OG&E states that the proposed route for the Seminole-Muskogee Project crosses the Arkansas River and that it

[31] *Id*. at 25 (citing Crissup Testimony, Ex. No. OGE-1 at 39, 2009 STEP, Ex. No. OGE-10 at 27).

[32] *See id.* at 25-26 (citing 2009 STEP, Exhibit No. OGE-10 at 22, 25).

has already studied five possible crossings over that river. OG&E adds that all five possible crossings have generated considerable local interest. OG&E states that, regardless of the crossing point, it will need to obtain a permit from the U.S. Army Corps of Engineers and will require a negotiated agreement with the Arkansas Riverbed Authority, which is a consortium of three Native American tribes that control access to the Arkansas River. OG&E may also be required to perform environmental assessments required by NEPA for the portions of the Seminole-Muskogee Project that cross BIA lands, which could lead to project modifications, cost increases, or Project cancellations. In regard to other environmental risks, OG&E states that it will need to address concerns about the Project's route near or through the Deep Fork Wildlife Refuge, which protects wetlands along the Deep Fork River, and is a sanctuary for the American Burying Beetle, the Interior Least Tern, the Whooping Crane, and the Piping Plover. Lastly, OG&E argues that the Project's long lead time puts it at risk for increased materials costs and regulatory policy changes while the Project is being constructed.

(d) <u>Tuco-Woodward Project (Balanced Portfolio Project)</u>

32. OG&E state that Tuco-Woodward Project is a 345-kV, 250-mile transmission line to be built from OG&E's Woodward District substation to the Southwestern Public Service Company (SPS) Tuco substation. OG&E's portion of the Project is 72 miles long extending from OG&E's Woodward substation to a reactor station to be constructed at the Oklahoma-Texas border. OG&E's portion of the Project will cost approximately $120 million, which represents over 22 percent of OG&E's current net transmission plant. The expected in-service date is May 19, 2014. OG&E states that in the 2009 STEP, SPP determined that Tuco-Woodward was one of seven upgrades included in a Balanced Portfolio that, by reducing congestion, would result in production cost savings and provide significant benefit versus cost to the SPP region. Specifically, OG&E states that SPP identified the Project as one that could relieve congestion on the flowgate that monitors the 115-kV transmission line from Randall County substation to Pal Duro for loss of the 230-kV line from Amarillo to Swisher.[33] OG&E adds that the Tuco-Woodward transmission line also was part of a series of extra high voltage transmission projects designed by SPP as a regional "overlay" to the existing transmission system.

33. OG&E states that the Project faces coordination challenges and risks. According to OG&E, it will connect the Tuco-Woodward Project with the SPS's 175-mile portion of the Project, which SPS is building in Texas. In OG&E's view, SPS will face similar risks and challenges that OG&E is facing with respect to right-of-way concerns, siting and permitting challenges, and environmental risk factors. OG&E argues that any of these factors could delay SPS's construction of the Project putting OG&E's ability to place its

[33] *Id*. at 30 (citing 2009 STEP, Exhibit No. OGE-10 at 27).

portion into service at risk. Additionally, OG&E states that it needs to acquire rights-of-way from private landowners in six counties for its 72-mile portion of the Project, including rights-of-way over Native American tribal lands.

34. With regard to environmental risks, OG&E states that the Project will cross the federally-protected Black Kettle National Grasslands, which is a 31,300-acre protected grassland, 30,724 acres of which are in Oklahoma. OG&E argues that routing this large transmission project through this protected area presents special risks and challenges, including federal permitting issues and environmental mitigation requirements, which could require rerouting the Project and lead to cost increases and delays or a cancellation altogether. OG&E states the Tuco-Woodward Project will also pass through the natural habitat of the Lesser Prairie Chicken, which is a Candidate Species under the USFWS Endangered Species Act and that, in the State of Oklahoma, is under the jurisdiction of the Oklahoma Department of Wildlife Conservation (ODWC). OG&E will also be required perform environmental assessments required by NEPA for the portions of the Tuco-Woodward Project that cross BIA lands. Further, OG&E claims that the Project's long lead time may present issues associated with costs of materials increasing or regulatory policies changing over time.

(e) Sooner-Cleveland Project (Balanced Portfolio Project)

35. OG&E states the Sooner-Cleveland Project, which is a 345-kV, 38-mile transmission line to be constructed by OG&E with upgrades to the Sooner and Cleveland substations, has a total investment of approximately $64 million, which represents 11.5 percent of OG&E's current net transmission plant. OG&E states that it will construct the entire Sooner-Cleveland line, which has an expected in-service date of March 31, 2013.[34] OG&E states that in the 2009 STEP, SPP determined that Sooner-Cleveland was one of seven projects in a Balanced Portfolio that, by reducing congestion, would result in production cost savings and provide a significant benefit versus costs to the SPP region.[35]

36. Further, OG&E argues that the Sooner-Cleveland Project faces a number of risks and challenges, which make the Project non-routine. First, OG&E states that it will need to coordinate the Project's construction with two different utilities, each in different states. OG&E explains that the Project must be coordinated with the permitting and construction of the improvements at the Sooner substation, which, in turn, is contingent on the completion of the Sooner-Rose Hill Project, which includes a portion to be built by Westar Energy in Kansas. OG&E adds that Sooner-Cleveland is also dependent on the

[34] *Id*. at 21.

[35] *See id.* (citing 2009 STEP, Ex. No. OGE-10 at 27).

Grand River Dam Authority's (GRDA) upgrades at the Cleveland substation. OG&E argues that it has no role in the siting, permitting, or construction of the facilities to be built by Westar Energy and GRDA. Second, OG&E argues that the Sooner-Cleveland Project will require rights-of-way across three different Native American tribal lands in addition to rights-of-way from individual landowners. OG&E adds that the proposed route will cross Sooner Lake and the Arkansas River, requiring approval from the U.S. Army Corp of Engineers, which may result in delays due to required environmental assessments pursuant to NEPA and other environmental mitigation or route changes. Third, OG&E states that it will also have to address issues regarding the habitat of the American Burying Beetle as well as address USFWS requirements due to the presence of the American Bald Eagle and migratory waterfowl along the proposed route. OG&E explains that studies of the effects of the Project on these species are underway in conjunction with the USFWS and the ODWC. Finally, OG&E also argues that the Project's long lead time puts it at risk for increased materials costs and regulatory policy changes while the Project is being constructed.

ii. Commission Determination

37. In addition to satisfying the section 219 requirement, an applicant for a transmission rate incentive must demonstrate that there is a nexus between the incentive sought and the investment being made. In evaluating whether an applicant has satisfied the required nexus test, the Commission will examine the total package of incentives being sought, the interrelationship between the incentives, and how any requested incentives address the risks and challenges faced by the Project.[36] In Order No. 679-A, the Commission clarified that its nexus test is met when an applicant demonstrates that incentives requested are "tailored to address the demonstrable risks or challenges faced by the applicant."[37] The nexus test is fact-specific and requires the Commission to review each application on a case-by-case basis.

38. As part of this evaluation, the Commission has found the question of whether a project is "routine" to be particularly probative and has clarified how it will evaluate projects to determine whether they are routine.[38] Specifically, to determine whether a project is routine, the Commission will consider all relevant factors presented by an

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[36] 18 C.F.R. § 35.35(d) (2010); Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 26. *See also* Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 21 ("By this we mean that the incentive(s) sought must be tailored to address the demonstrable risks and challenges faced by the applicant in undertaking the project.").

[37] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 40.

[38] *BG&E*, 120 FERC ¶ 61,084 at P 48.

applicant. For example, an applicant may present evidence on: (1) the scope of the project (e.g., dollar investment, increase in transfer capability, involvement of multiple entities or jurisdictions, size, effect on region); (2) the effect of the project (e.g., improving reliability or reducing congestion costs); and (3) the challenges or risks faced by the project (e.g., siting, internal competition for financing with other projects, long lead times, regulatory and political risks, specific financing challenges, other impediments).[39] Additionally, the Commission clarified that "when an applicant has adequately demonstrated that the project for which it requests an incentive is not routine, that applicant has, for purposes of the nexus test, shown that the project faces risks and challenges that merit an incentive."[40] A company may file for incentives for numerous individual and unconnected projects at the same time and even in a single filing, but the company still must provide sufficient justification for why each project qualifies for incentives.[41]

39. We recognize the challenges project developers face in planning, financing, and constructing new transmission facilities. However, the presence of a unique or unusual challenge or risk of an environmental, siting, financial, regulatory, or other nature, does not in and of itself make a project "non routine" under the nexus test. Furthermore, sheer size of a project or inclusion in a regional planning process alone does not make a project worthy of incentives. That is, a project may be difficult to construct but that alone does not mean it qualifies to receive transmission rate incentives under section 219 of the FPA and Order No. 679. Our mandate under section 219, Order No. 679, and our precedent requires an evaluation of all of the relevant factors an applicant presents, in accordance with *BG&E*, to determine on a case-by-case basis whether the totality of factors makes a particular project non-routine for purposes of the nexus requirement. An applicant's particular risks, challenges, and circumstances, including the use of advanced technologies, will be considered in evaluating whether a project is "non routine" in a particular case. In this regard, OG&E's application was helpful in providing a detailed description of its typical (or "routine") transmission projects.

40. Pursuant to this framework, we find that OG&E has demonstrated that each of the Projects meet the nexus requirement, as discussed below.

(a) <u>Sunnyside-Hugo</u>

41. The Sunnyside-Hugo Project, which is a 120-mile 345-kV line, is estimated at $187 million in investment, representing 33.5 percent of OG&E's current net

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[39] *Id.* P 52-55.

[40] *Id.* P 54.

[41] *See PJM Interconnection, L.L.C.*, 133 FERC ¶ 61,273 at P 45.

transmission plant. In addition, this Project has been identified in the SPP 2008 Study to be a necessary regional project to address a total of 1,436 MW in requested transmission capacity, which is about 96 per cent of the entire 1,488 MW of requests reviewed in the SPP September 2008 Study. OG&E has also provided evidence that completion of the Project is dependent on ITC completing construction of the Hugo substation—a project over which OG&E has no control. OG&E is also faced with the challenge of obtaining rights-of-way for this 120-mile Project, which is significantly longer than its recent annual average additions of 24.6-miles of transmission line, in multiple counties and from individual land owners as well as Native American tribes. OG&E reports that there are approximately 100 condemnation cases covering 150 separate parcels of land in the Project's path. There are also specific environmental risks that will need to be mitigated for the Project to move forward. Based on all of these factors, the Commission finds that OG&E has demonstrated that the Sunnyside-Hugo Project is non routine.

(b) Sooner-Rose Hill

42. OG&E's Sooner-Rose Hill Project is part of a regional 88-mile 345-kV transmission line with OG&E constructing 43 mile in Oklahoma and Westar Energy constructing 45 miles in Kansas. OG&E's portion of the line will cost approximately $57.8 million, representing approximately 10 percent of OG&E's current net transmission plant. In addition, OG&E states that in the 2009 STEP SPP determined that the Sooner-Rose Hill Project was necessary to provide 485 MW of requested transmission service and that the Project is a regional reliability upgrade that could relieve the flowgate that monitors the 138-kV line from El Paso to Farber for the loss of the 345-kV line from Wichita to Woodring. Additionally, the Project will pass through lands owned by four separate Native American tribes and, as of January 1, 2011, there are twenty tracts of land along the Project route that involve the BIA. Further, OG&E states that environmental assessments for the portion of the proposed route that crosses BIA lands are underway the results of which could result in changes in the Project's proposed route, or delays in construction.

43. While OG&E's portion of the Project may not be either significantly longer or more costly than OG&E's typical projects, given the scope of the entire project extending through Oklahoma and Kansas and the additional risk that third parties will timely complete their portion of this overall project combined with the additional risks OG&E faces with respect to construction of its portion, we find the Sooner-Rose Hill Project to be non-routine for OG&E. In addition to the specific siting and environmental risks OG&E faces for its portion of the 88-mile 345-kV transmission line, OG&E's ability to put the Sooner-Rose Hill Project into service is dependent on Westar Energy completing its portion of the Project in Kansas. OG&E has no role in the siting, permitting, or construction of the Kansas portion of the Project, which puts it at risk if Westar Energy itself faces any environmental, siting, financial, regulatory or other challenges in building its portion of the Project or if Westar is required to abandon the Project altogether. We

find that OG&E has demonstrated that this Project is non routine under the nexus test based on the totality of the size, scope, effect, risks and challenges the Sooner-Rose Hill Project faces.

(c) Seminole-Muskogee

44. The Seminole-Muskogee Project includes a 120-mile transmission line with associated upgrades to OG&E's Seminole and Muskogee substations. The total $179.1 million investment represents over 32 percent of OG&E's current net transmission plant and the Project has a December 31, 2013 expected in-service date. OG&E states that SPP identified Seminole-Muskogee, as a Balanced Portfolio project expected to relieve congestion on the flowgate that monitors the 138-kV line from Okmulgee to Henryetta for the loss of Okmulgee to Kelco and on the flowgate monitoring the 138-kV line from Riverside Station to Okmulgee City for the loss of the 138-kV line from Riverside Station to Explorer Okmulgee. This 120-mile Project, for which OG&E will need to obtain rights-of-way from private landowners in six separate counties, including two different Native American tribes, will also require OG&E to obtain a permit from the U.S. Army Corps of Engineers and a negotiated agreement with the Arkansas Riverbed Authority to allow the Project to traverse the Arkansas River. OG&E may also be required to perform environmental assessments for the portions of the Seminole-Muskogee Project that cross BIA lands and address concerns about the Project's route near or through the Deep Fork Wildlife Refuge. The Commission finds that OG&E has demonstrated that this Project is non-routine under the nexus test based on the totality of the size, scope, effect, risks, and challenges of the Seminole-Muskogee Project.

(d) Tuco-Woodward

45. Like Sooner-Rose Hill, the Tuco-Woodward Project is part of a larger transmission project to be constructed by OG&E and another utility. Specifically, OG&E will construct its 72-mile portion of the line in Oklahoma and SPS will construct 175 miles in Texas. OG&E's 72-mile portion of the line will cost approximately $120 million, which represents over 22 percent of OG&E's current net transmission plant, and has a May 19, 2014 expected in-service date.

46. In addition, OG&E has provided evidence that the Project faces siting and environmental risks and challenges, including the need to acquire rights-of-way from private landowners in six counties over the 72-mile span, including rights-of-way from Native American tribes, and the need to acquire federal permits and address environmental mitigation requirements resulting from the Project's proposed path across the Black Kettle National Grasslands and habitats of protected species.

47. Furthermore, because OG&E will connect its portion of Tuco-Woodward with SPS's 175-mile portion of the Project, delays in SPS's construction of the Project could hinder OG&E's ability to place Tuco-Woodward in-service. Accordingly, based on the

totality of the size, scope, effect, risks, and challenges of this Project, the Commission finds that OG&E has demonstrated that Tuco-Woodward is a non-routine project, and therefore meets the requirements of the nexus test.

(e) Sooner-Cleveland

48. While Sooner-Cleveland may not be either significantly longer or more costly than OG&E's typical projects, it faces particular siting and environmental risks, has a long lead time, and has additional risk that third parties will not timely complete interconnecting facilities. OG&E explains in part that the Sooner-Cleveland Project will require rights-of-way across three different Native American tribal lands and approvals from the U.S. Army Corps of Engineers to cross Sooner Lake and the Arkansas River, and must also meet USFWS requirements given certain habitats and species along the proposed route. In addition to these siting and environmental risks OG&E faces in constructing Sooner-Cleveland, OG&E's ability to put the Project into service is dependent on GRDA's upgrades to the Cleveland substation and upgrades to the Sooner substation being constructed by OG&E, which, in turn, is contingent on the completion of the Sooner-Rose Hill Project, which includes a portion to be built by Westar Energy in Kansas. OG&E does not have control over GRDA's completion of the upgrades required to the Cleveland substation. Also, as discussed above, OG&E has no role in the siting, permitting, or construction of the Kansas portion of the Sooner-Rose Hill Project, which puts it at risk if Westar Energy itself faces any environmental, siting, financial, regulatory or other challenges in building its portion of the Sooner-Rose Hill Project or if Westar is required to abandon that Project altogether. Accordingly, we find that OG&E has demonstrated that that the Sooner-Cleveland Project is not routine under the nexus test based on the totality of the size, scope, effect, risks and challenges the Sooner-Cleveland Project faces.

c. Construction Work in Progress for Projects

i. OG&E's Proposal

49. OG&E seeks inclusion of 100 percent of CWIP in rate base for the Projects. OG&E states that including 100 percent of CWIP in rate base will provide the up-front regulatory certainty and cash flow needed to support such a substantial investment in new and advanced transmission facilities. OG&E further contends that including 100 percent of CWIP in rate base will allow for additional cash flow during construction of the Projects. The additional cash flow will allow OG&E to reduce its short-term borrowings and related costs, maintain healthy credit metrics, and meet other financial obligations. OG&E also states that the substantial capital expenditures during the construction period would have an adverse impact on OG&E's cash flows and liquidity metrics, which would put downward pressure on OG&E's credit ratings.

ii. Commission Determination

50. We will grant OG&E's request for the CWIP incentive for the Sunnyside-Hugo, Sooner-Rose Hill, Seminole-Muskogee, Tuco-Woodward, and Sooner-Cleveland Projects. In Order No. 679, the Commission established a policy that allows utilities to include, where appropriate, 100 percent of prudently-incurred transmission-related CWIP in rate base.[42] The Commission stated that this rate treatment will further the goals of section 219 by providing up-front regulatory certainty, rate stability, and improved cash flow, reducing the pressures on an applicant's finances caused by investing in transmission projects.[43] We find that OG&E has shown a nexus between the proposed CWIP incentive and its investment in the Projects.

51. OG&E has demonstrated that its capital budget may be strained as it builds the Projects while conducting needed improvements to its existing transmission infrastructure. In addition, further strain will be placed on OG&E's capital budget as it constructs the two projects approved in the December 30 Order along with the Sunnyside-Hugo, Sooner-Rose Hill, Seminole-Muskogee, Tuco-Woodward, and Sooner-Cleveland Projects. Without CWIP Recovery, OG&E appears likely to experience negative cash flows, with a converse increase in interest expenses from debt and a potential further negative impact to its credit rating.[44]

52. In addition, we find that allowing OG&E the requested CWIP Recovery for the Projects will provide greater rate stability for customers. As the Commission has explained in prior orders, when large-scale transmission projects come on line, consumers may experience "rate shock" if CWIP is not permitted in rate base.[45] By granting OG&E CWIP Recovery, the rate impact can be spread over the entire construction period mitigating any potential rate shock on OG&E's customers.

53. Accordingly, we find that authorizing CWIP Recovery for the Sunnyside-Hugo, Sooner-Rose Hill, Seminole-Muskogee, Tuco-Woodward, and Sooner-Cleveland Projects

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[42] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 29, 117.

[43] *Id.* P 115.

[44] We note that it would be useful for an applicant to also provide an explanation and description of the cost per MW-mile for each project for which it seeks incentives to aid in the Commission's decision making process.

[45] *See, e.g., PPL Elec. Utils. Corp. and Pub. Serv. Elec. and Gas Co. Corp.*, 123 FERC ¶ 61,068, at P 40-43 (2008); *Am. Elect. Power Serv. Corp.*, 116 FERC ¶ 61,059, at P 59 (2006), *order on reh'g*, 118 FERC ¶ 61,041, at P 27 (2007).

will help mitigate potential rate shock, enhance cash flow, reduce interest expenses, assist OG&E with obtaining favorable financing, and improve the coverage ratios used by rating agencies to determine OG&E's credit quality by replacing non-cash capitalized allowance for funds used during construction (AFUDC) with cash earnings. In turn, this will reduce the risk of a down-grade in OG&E's investment ratings. These factors are comparable to those that the Commission has taken into consideration in authorizing CWIP in rate base for other utilities.

d. Abandoned Plant Recovery

i. OG&E's Proposal

54. OG&E requests Abandoned Plant Recovery to recover prudently incurred costs if the Projects are abandoned due to forces outside of OG&E's control. OG&E states that Abandoned Plant Recovery is appropriate here because of the Projects' long lead times, and the permitting risks and possible re-routing each project faces as a result of the siting issues associated with obtaining rights-of-way from multiple landowners and Native American tribes. OG&E also states that Abandoned Plant Recovery is appropriate due to the environmental and/or coordination risks each project faces. OG&E further states that each of the Projects must be approved by various state and federal regulatory agencies including the ODWC, the USFWS, the BIA, and others.

ii. Commission Determination

55. In Order No. 679, the Commission found that Abandoned Plant Recovery is an effective means to encourage transmission development by reducing the risk of non-recovery of costs.[46] The Commission also found that in order to recover abandonment costs, an applicant for incentives that is granted Abandoned Plant Recovery must submit a filing under section 205 of the FPA showing that abandonment is a result of factors outside of its control.[47]

56. We find that OG&E has shown a nexus between the requested Abandoned Plant Recovery incentive and its planned investments in each of the Sunnyside-Hugo, Sooner-Rose Hill, Seminole-Muskogee, Tuco-Woodward, and Sooner-Cleveland Projects, consistent with Order No. 679. Besides their scope and size these projects present special risks for OG&E because they each face a number of environmental and regulatory challenges that could subject each project to potential cancellation or modification due to decisions and factors beyond OG&E's control, including the inability to secure regulatory

[46] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 163.

[47] *Id*. P 163, 165-66; *see also Alleghany Energy, Inc., et al.*, 116 FERC ¶ 61,058, at P 122 (2006).

approvals, rights-of-way and necessary lands. OG&E has demonstrated that the risk of not being able to obtain rights-of-way from private landowners, including various Native American tribes throughout Oklahoma, is a significant challenge that could prevent one or more of the projects from being completed.

57. Accordingly, we find that OG&E's request for Abandoned Plant Recovery for the Projects meets the nexus requirement. We note, however, if any of the five Projects are cancelled before they are completed, OG&E is required to make a filing under section 205 of the FPA to demonstrate that the costs were prudently incurred before it can recover any abandoned plant costs. OG&E must also propose in its section 205 filing a just and reasonable rate and cost allocation method to recover these costs. Order No. 679 specifically requires every utility seeking abandonment recovery to submit such a section 205 filing.[48]

e. Nexus with Total Package of Incentives

i. Total Package of Incentives

58. As we have stated above, the incentives requested must be tailored to address the demonstrable risks or challenges faced by the applicant. This nexus test is fact-specific and requires the Commission to review each application on a case-by-case basis. Consistent with Order No. 679, the Commission has, in prior cases, approved multiple rate incentives for particular projects as long as each incentive satisfies the nexus test.[49]

59. We find that OG&E has shown that the total package of incentives is tailored to address the demonstrable risks or challenges faced by OG&E in investing in each of the Sunnyside-Hugo, Sooner-Rose Hill, Seminole-Muskogee, Tuco-Woodward, and Sooner-Cleveland Projects.[50] Consistent with Order No. 679, the Commission has, in prior

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[48] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 166.

[49] *See id*. P 55; *see, e.g.*, *Allegheny Energy, Inc.*, 116 FERC ¶ 61,058 at P 122 (approving ROE at the upper end of the zone of reasonableness and 100 percent Abandoned Plant Recovery); *Duquesne Light Co.*, 118 FERC ¶ 61,087, at P 55 (2007) (granting an enhanced ROE, 100 percent CWIP, and 100 percent Abandoned Plant Recovery); *PPL Elec. Utils. Corp. and Pub. Serv. Elec. and Gas Co.*, 123 FERC ¶ 61,068 at P 39, 42, 46 (approving ROE at the upper end of the zone of reasonableness, 100 percent CWIP, and 100 percent Abandoned Plant Recovery).

[50] *See* Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 21, 27.

cases, approved multiple rate incentives for particular projects.[51] This is based upon our interpretation of FPA section 219 as authorizing the Commission to approve more than one incentive rate treatment for an applicant proposing a new transmission project, as long as each incentive is justified by a showing that it satisfies the requirements of FPA section 219 and that there is a nexus between the incentives being proposed and the investment being made.

60. Here, we find that the total package of incentives requested by OG&E is tailored to the risks it faces in investing in each of the Projects. As discussed above, OG&E has demonstrated that each of the requested incentives will reduce the risks that OG&E faces and will remove potential obstacles to the construction of the Projects.

2. <u>Section 205 Demonstration</u>

a. <u>OG&E</u>

61. OG&E argues that the proposed incentive rates are just and reasonable. According to OG&E, the Commission has found that CWIP Recovery "merely affects the timing of cost recovery, and not the level of cost recovery."[52] OG&E also states that the CWIP incentive may serve to lower costs paid by OG&E's customers by preventing increases in OG&E's borrowing costs and by reducing financing expenses associated with AFUDC. OG&E adds that approval of the requested Abandoned Plant Recovery incentive will not affect OG&E's existing transmission rates because OG&E is not seeking to recover these costs currently but will make an FPA section 205 filing demonstrating that the costs to be recovered were prudently incurred and that the Projects were abandoned for reasons beyond OG&E's control, if OG&E seeks to recover abandoned plant costs

b. <u>Commission Determination</u>

62. In the December 30 Order, the Commission found OG&E's proposed formula rate revisions to implement the requested incentives are just and reasonable.[53] Accordingly, in the instant proceeding OG&E does not propose to revise its formula rates. Instead, OG&E seeks to populate the CWIP amounts as they are incurred and to make an FPA section 205 filing to recover any Abandoned Plant Recovery costs, if necessary.

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[51] *See, e.g.*, *Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188 (2008); *Southern Cal. Edison Co.*, 121 FERC ¶ 61,168 (2007).

[52] *See* OG&E Filing at 38 (citing *Great River Energy*, 130 FERC ¶ 61,001 at P 40; Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 38).

[53] December 30 Order, 133 FERC ¶ 61,274 at P 56.

3. Other Matters

a. Accounting and CWIP Requirements

i. Accounting Procedures

63. Under Order No. 679 and the Commission's regulations, an applicant must propose accounting procedures that ensure that customers will not be charged for both capitalized AFUDC and corresponding amounts of CWIP in rate base.[54] To satisfy this requirement, OG&E states that it will not accrue AFUDC in Account 107, Construction Work in Progress. Further, OG&E states that it will use the SAP plant accounting system to maintain its accounting records for CWIP electric plant assets during construction and after the Projects are placed into service. OG&E indicates that the SAP system includes the capability to identify specific work orders that should not be included in the calculation and capitalization of AFUDC. OG&E states that work orders related to the Projects will be identified in SAP, and no AFUDC will be calculated on their balances.

64. Additionally, OG&E states that if it is accorded different ratemaking treatment of CWIP by state commissions, it will record any accrued AFUDC in Account 182.3, Other Regulatory Assets. OG&E indicates that the regulatory asset would be amortized over the depreciable life of the Projects to Account 407.3, Regulatory Debits, and that the AFUDC regulatory asset and associated amortization would not be included in the rate charged to OG&E's wholesale transmission customers. OG&E indicates that these procedures will prevent a double-recovery of CWIP and capitalized AFUDC on the same rate base items.[55]

ii. Commission Determination

65. The Commission finds that the proposed accounting procedures OG&E filed in Exhibit No. OGE-18 sufficiently demonstrates that it has appropriate accounting procedures and internal controls in place to prevent recovery of AFUDC to the extent that OG&E is allowed to include CWIP in rate base.

iii. Comparability of Financial Information

66. OG&E notes in its supporting testimony that in cases where the Commission has authorized 100 percent of CWIP in rate base, the Commission has required specific accounting treatment to promote comparability of financial information among entities.

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[54] 18 C.F.R. § 35.25(f), Accounting Procedures (2010).

[55] *See* Direct Testimony of Mr. Donald R. Rowlett, OG&E Filing at Ex. No. OGE-18.

OG&E states that the Commission has granted waiver of that accounting treatment and permitted utilities, in lieu, to use footnote disclosures.[56] To comply with this requirement, OG&E requests waiver of the specific accounting treatment and proposes instead to use footnote disclosures.

iv. Commission Determination

67. Public utilities that receive a current return on CWIP through rate base recover this cost in a different period than it would ordinarily be charged to expense under the general requirements of the Commission's Uniform System of Accounts (USofA). To promote comparability of financial information between entities, the Commission has required a specific accounting treatment or the use of footnote disclosures to recognize the economic effects of having construction work in progress in rate base.[57] The Commission accepts OG&E's proposal to use footnote disclosures to provide comparability of financial information.

68. Accordingly, for the reasons discussed above, we will grant the requested CWIP Recovery and Abandoned Plant Recovery incentives for the Sunnyside-Hugo, Sooner-Rose Hill, Seminole-Muskogee, Tuco-Woodward, and Sooner-Cleveland Projects, effective March 1, 2011, for good cause shown,[58] and deny the requested incentives for the Sooner-Cleveland project, as discussed above.

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[56] *Id.*

[57] *See, e.g.*, *American Transmission Co. LLC*, 105 FERC ¶ 61,388 (2003), *order on reh'g*, 107 FERC ¶61,117 (2004); *Trans-Allegheny Interstate Line Co.*, 119 FERC ¶ 61,219, *order on reh'g*, 121 FERC ¶ 61,009 (2007); *Southern California Edison Co.*, 122 FERC ¶ 61,187 (2008); *Tallgrass Transmission, LLC*, 125 FERC ¶ 61,248 (2008); *Pioneer Transmission, LLC,* 126 FERC ¶ 61,281 (2009).

[58] *Central Hudson Gas & Electric Corp., et al.,* 60 FERC ¶ 61,106.

<u>The Commission orders</u>:

OG&E's request for CWIP Recovery and Abandoned Plant Recovery is granted as discussed in the body of this order.

By the Commission. Commissioner Norris is concurring with a separate statement attached.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company Docket No. ER11-2926-000

(Issued April 19, 2011)

NORRIS, Commissioner, *concurring*:

I concur in the decision in today's order to grant Oklahoma Gas and Electric Company's (OG&E) request to include 100 percent of prudently-incurred construction work in progress (CWIP Recovery) in its rate base and to recover 100 percent of prudently-incurred costs of transmission facilities that are cancelled or abandoned for reasons beyond OG&E's control (Abandoned Plant Recovery) for five transmission projects the company will build in the Southwest Power Pool, Inc. (SPP) region.

In my partial dissent from the Commission's order on OG&E's prior request for CWIP Recovery and Abandoned Plant Recovery for these projects,[1] and in my partial dissent from another Commission order issued that day on a similar request by Public Service Gas & Electric Company,[2] I noted that CWIP Recovery can be a useful regulatory tool in circumstances where an entity is embarking on large new investments in transmission infrastructure that will substantially increase its rate base.[3] Here, OG&E explains that the estimated total cost of the five projects at issue is approximately $608 million, an amount that exceeds its current net transmission plant of $558 million.[4] These projects have estimated in-service dates all within a two-year period from 2012 to 2014.[5] OG&E adequately demonstrates that, in light of this substantial investment in a short amount of time, CWIP Recovery will provide tangible benefits to both the company and consumers.[6]

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[1] *Oklahoma Gas and Electric Co.*, 133 FERC ¶ 61,274 (2010), Norris, *dissenting in part* (*OG&E I*)

[2] *PJM Interconnection, L.L.C.*, 133 FERC ¶ 61,273 (2010), Norris, *dissenting in part* (*PJM*).

[3] *See PJM*, Norris, *dissenting in part* at 3.

[4] Exhibit No. OGE-18 at 5.

[5] OG&E will also be investing in two additional projects (which were approved in *OG&E I*) with estimated in-service dates in 2014 and a total cost of $313 million, bringing its total investment during this period to approximately $921 million. *Id.* at 6.

[6] *Oklahoma Gas & Electric Co.*, 135 FERC ¶ 61,038 at P 50-53 (2011) (*OG&E II*).

However, as I stated in my partial dissent in *PJM*, it is not clear to me that it is appropriate to consider CWIP Recovery under our existing incentive-based ratemaking policies.[7] Under the policy first articulated in *Baltimore Gas & Electric Company*,[8] the Commission relies heavily on a determination of whether a transmission project is "routine" or "non-routine", but this paradigm may not be relevant to the question of whether CWIP Recovery should be granted. Regardless of whether the five projects at issue are routine or non-routine, they, together with the two additional projects the Commission approved in *OG&E I*, still represent a dramatic increase in OG&E's current rate base in a short period. Thus, OG&E will face the same financial risks and its customers will face the same risk of rate increases and rate shock that can make CWIP recovery just and reasonable. For this reason, as I stated in *PJM*, CWIP Recovery may be more properly considered under general ratemaking principles, with an eye toward the benefits such rate treatment can provide both regulated entities and their consumers, rather than under an incentive-based ratemaking policy.

John R. Norris, Commissioner

[7] *PJM*, Norris, *dissenting in part* at 3.

[8] 120 FERC ¶ 61,084 at P 48 (2007), *reh'g denied*, 122 FERC ¶ 61,034 (2008).